PART 4
NATIONAL ENERGY ACT

HEARINGS

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER

OF THE

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE HOUSE OF REPRESENTATIVES

NINETY-FIFTH CONGRESS

FIRST SESSION

ON

H.R. 6831, H.R. 687, H.R. 1562, H.R. 2088, H.R. 2818, H.R. 3317, H.R. 3664, H.R. 6660, and all similar and identical bills

BILLS TO ESTABLISH A COMPREHENSIVE NATIONAL ENERGY POLICY

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- Welden, Robert, Foster Wheeler Energy Corp.

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American Iron and Steel Institute:
- Corbin, Fred, assistant superintendent, facilities planning, Inland Steel Co.
- Gray, William R., general manager, corporate planning, Inland Steel Co.
- Haney, James, director of taxes, Inland Steel Co.

American Paper Institute, Loren V. Forman, vice president, environmental resources, Scott Paper Co.

American Textile Manufacturers Institute:
- Morrissey, James A., secretary, Energy Policy Committee.
- Price, James U., chairman, Finishers Energy Conservation Subcommittee.

Association of American Railroads, William H. Dempsey, president.

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Celanese Corp., Daniel F. Twomey, director of traffic, Chemical Group.

Consolidation Coal Co., Ralph E. Bailey, chairman and chief executive officer.

Dean Witter & Co., Joel Price, vice president, research.

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- Neuworth, Martin B., Acting Director, Coal Conversion and Utilization.
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Environmental Policy Center, John L. McCormick.
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THE NATIONAL ENERGY ACT

WEDNESDAY, MAY 25,1977

House of Representatives,
Subcommittee on Energy and Power,
Committee on Interstate and Foreign Commerce,
Washington, D.C.

The subcommittee met at 9:30 a.m., pursuant to notice, in room 2123, Rayburn House Office Building, Hon. Anthony Toby Moffett, presiding, Hon. John D. Dingell, chairman.

Mr. Moffett. The subcommittee will come to order.

Today the Energy and Power Subcommittee initiates three days of hearings on the coal conversion portion of H.R. 6831, the National Energy Act.[1]

Almost 3 years ago, Congress enacted the Energy Supply and Environmental Coordination Act (ESECA) ordering the Federal Energy Administration to prohibit certain powerplants from using natural gas or petroleum and to require them to burn coal. The act also provided authority to order coal conversion of major industrial concerns. As of today, however, no utility or industrial plant has switched to coal due to an FEA order.

The failure of the program is due in large part to poor program management, unduly intricate regulations, disputes between program officials and attorneys with FEA, lack of resources, and delay in promulgating the implementation of the regulations. More recently, the FEA has taken steps to implement the law and remove the obstacles.

H.R. 6831 seeks to rewrite the coal conversion provisions of ESECA. Instead of ordering conversions, the bill establishes a system by which utilities and industrial firms may obtain temporary or permanent exceptions or exemptions from the general prohibitions on the use of oil or natural gas as a fuel. This approach may be sound, but we are fearful that it might end up in endless proceedings and a sea of paperwork. We want to learn more about how it will work.

We are also concerned that a massive coal conversion program not create new environmental problems and that conversion not sacrifice environmental gains made in the last decade. At the same time, those who convert should have some assurance that environmental controls will not cause further and costly changes within

[1] The text of H.R. 6831 appears in part 1 of these hearings.

just a few years after the conversion. The best available control technology should be installed at the time of the conversion.

It is interesting to learn that the National Coal Association (NCA), which represents many companies in the coal industry, opposes this legislation, partly on the grounds that FEA efforts thus far have not caused any conversions and partly because such conversion could lead to a mandatory Federal coal allocation and price control program. We want to learn more about the NCA's views and what that organization believes would be the best way to increase coal use.

Our first panel today is going to focus on the overview of supply issues. I will call that panel to the table in a moment. Before I do that, I would like to acknowledge the presence in our hearing room today of some constituents of mine from Forestville. We are very happy to have you from St. Matthew. I welcome you.

I would like to at this time call to the witness table the Honorable Guy Richard Martin, Assistant Secretary of the Interior for Land and Water Resources; Mr. Harry Perry from Resources for the Future; Carl Bagge, President of the National Coal Association; Mr. John McCormick, Environmental Policy Center; and Mr. James Boyd of Materials Associates, Washington, D.C.

Welcome, gentlemen.

We would appreciate it if you would for the record identify yourselves starting from my right, please, and your affiliation.

STATEMENTS OF JOHN L. McCORMICK, ENVIRONMENTAL POLICY CENTER; HON. GUY R. MARTIN, ASSISTANT SECRETARY OF THE INTERIOR FOR LAND AND WATER RESOURCES, U.S. DEPARTMENT OF THE INTERIOR; CARL E. BAGGE, PRESIDENT, NATIONAL COAL ASSOCIATION, ACCOMPANIED BY JOSEPH W. MULLAN, VICE PRESIDENT, GOVERNMENT RELATIONS, NATIONAL COAL ASSOCIATION; JAMES BOYD, PH.D., PRESIDENT, MATERIALS ASSOCIATES, INC.; AND HARRY PERRY, CONSULTANT, RESOURCES FOR THE FUTURE

Mr. McCORMICK. John McCormick with the Environmental Policy Center.

Mr. MARTIN. Guy Martin, Department of Interior.

Mr. BAGGE. Carl Bagge, National Coal Association.

Mr. BOYD. James Boyd, Materials Associates.

Mr. PERRY. Harry Perry, private consultant, appearing for Resources for the Future.

Mr. MOFFETT. We would like to begin with Mr. McCormick. If you would paraphrase your statement or if you feel you should read it, that is all right too. We would like you to start.

STATEMENT OF JOHN L. McCORMICK

Mr. McCORMICK. Thank you.

Mr. Chairman and members of the subcommittee, I want to thank you for providing me this opportunity to testify before you this morning on this important legislation. While the Nation's attention has been focused on the President's proposed gasoline tax, the coal conversion program is the heart of his energy plan. Failure of his attempts to convert new and existing utility and industrial boilers from oil and gas to coal, may jeopardise his entire program, thereby creating a chaotic condition in the Nation's energy economy. From the outset of my testimony, I want to establish the fact that the Environmental Policy Center is in support of the goal the President has set for the Nation and it intends to work for a conversion program which accomplishes the goals without trading off the health and safety of the coal miners digging the coal or any of the environmental laws enacted to protect the public and its resources.

Rather than discussing specific provisions of part F, of H.R. 6831, I will make a number of general comments on the program itself. While the language of the bill is unnecessarily complicated, my strongest criticism of the legislation is its lack of a comprehensive approach to the massive task at hand and the lack of a directive to have pollution control devices in place before the conversion takes place.

The President's energy plan calls for doubling coal production in this Nation by some 600 million new tons of coal annually by 1985. On the average, that represents more than a 60 million ton per year increase, or about a 10 percent growth rate in the Nation's coal industry each year. To date, the coal industry has not shown a capability of achieving, much less sustaining such a level of growth. Despite the fact that the 50 largest coal companies produce about 64 percent of the total coal production, the industry is a fragmented one, slow to accepting innovative technology and divided on the issues of strict mine safety law enforcement and labor-management relationship improvement. Given past performances and the administration's present policy, I seriously doubt that the industry can attain that level of production even by 1990.

Any dramatic increase in coal production means a great many new, inexperienced coal miners entering the mines. A majority of them, if not all of them, will not receive the benefits of a thorough training program. Yet, they will be entering one of the more dangerous professions available to the work force. If the energy plan is adopted, it must include the following in order to assure that a steady supply of coal is assured:

A mandatory manpower training program must be established to provide new miners with a rudimentary understanding of the function and safe operation of the machinery they will be working with, in addition to life-saving techniques to be used in the event of an accident.

An aggressive research and development program designed to bring about safer and more efficient mining equipment, mining methods and safety procedures.

The establishment of several federally funded model underground coal mines where research programs and manpower training sessions can be carried on using simulated mining operation conditions.

A no-nonense approach to the strict enforcement of the coal mine safety laws.

The commencement of the $750 million loan guarantee program for the development of new, low sulfur, or compliance coal, underground coal mines.

The enforcement of all the provisions of the Federal strip mining law once it is enacted.

If the coal is mined in ever-increasing amounts, that will place a greater burden on the eastern and midwestern railroads. While the main lines of these companies are being improved with and without Federal assistance, the branch lines coming out of the coal fields and stretching up into nontraditional coal markets in the Northeast and elsewhere must be constructed and improved. This will require a tremendous amount of capital and the railroads must be assured that this conversion program will be permanent. They were lured into making such investments a generation ago, particularly in the Northeast, only to see imported oil take their market from them. Their reluctance to construct and refurbish the trackage will continue in the absence of a clear indication that this program will not be scrapped if a major oil field is discovered off the East coast.

The three serious air pollution problems associated with the increased burning of coal, sulfur dioxide, nitrogen oxide and fine particulates will continue to represent the strongest detraction to the conversion program. The public, particularly in oil and natural gas consumptive regions, will have an understandable reluctance to accomodating coal-fired electric utility plants in their neighborhoods. Their opposition will be strengthened as the electric utilities and manufacturing associations continue to propagandize that pollution control devices are not available or do not operate properly and call for a weakening of the clean air laws in several regions of the country and it is not likely to accept greater amounts of pollution. Therefore, the energy plan must include:

A research and development plan designed to bring on line, technologies that allow for the clean-burning of coal. Low Btu coal gasification in small, centrally located facilities, fluidized-bed coal combustion furnaces, solvent refining of coal and fine grinding and other, more advanced, coal cleaning technologies must be brought on line as soon as possible and certainly before the bulk of the conversion orders are sent out.

OMB has decided not to proceed with the Federal cost-sharing of a number of small, low Btu coal gasifiers under the assumption that the technology is ready for the marketplace. This would be an unfortunate occurrence since thousands of small industrial boilers are going to be ordered to switch to coal and still comply with rigid air quality standards. Low Btu gasification of the coal may be the only coal burning solution available to them in the short term. They will need all of the encouragement the Federal Government can give them. Supplying a great many of these gasifiers to a broad spectrum of industrial demands may provide the necessary proof that clean coal burning technologies do exist.

The President's environmental message contained the announcement of a new emphasis upon researching more efficient pollution control devices such as scrubbers. While this is essential, the problem of disposing of scrubber sludge, spent-bed material from fluidized-bed boilers and fly ash from the coal combustion processes will have to be solved, particularly in urban areas unaccustomed to handling coal.

The greater reliance upon coal for electric generation will require even more stringent conservation measures, particularly in the area of residential heating and cooling where a large portion of electric energy waste occurs. The untrapped particulates and SO_2 and NOx, as well as the increased buildup of CO_2 in the atmosphere, will require that we cut back on our use of energy as we switch from cleaner fuels. If nitrogen oxide emissions are not controlled in the coal burning process, health effects could be dramatic. Presently, the only real NOx control mechanism is low boiler heat range. The fluidized-bed boiler can accomplish this to some degree. Failure to control NOx will require the Carter administration to attack the problem of NOx buildup in the automobile industry by imposing accelerated compliance deadlines for the control of that pollutant in auto emissions. The President cannot have it both ways. He will either have to get tough with Detroit or come up with technologies to solve the problem in the utility and industrial boilers. A program that sacrifices human health for increased energy is totally unacceptable and is contrary to everything the President has said in his public statements. His support of tougher clean air amendments will be proof that he recognizes the dangers inherent in pursuing increased coal utilization without cracking down on existing sources of pollution.

Conversion orders should not be given in a region where ambient standards cannot tolerate additional pollutants. By carefully monitoring SO_2 and NOx levels in the air, the State or Federal EPA can make a determination that the levels that have gone down sufficiently to warrant reconsideration of the conversion order for a particular plant. That may require the region to take strong measures to limit auto emissions or the use of automobiles to accommodate industrial switching to coal.

A dramatic increase in the use of coal will, obviously, accelerate the depletion of those reserves. If we double our coal production in the near future, we will be taking more than that amount of coal from the reserve column. In the mining operation, a considerable amount of coal is left in the ground because of the nature of the mining method or because the remaining coal is too marginal for recovery. Therefore, we cannot look upon our coal reserves, particularly our strippable reserves as being inexhaustible. Greater reliance upon coal will necessitate an increase in underground coal mining. The Federal Government should begin preparing for that eventuality now by reexamining its policies based upon coal extraction R & D in the context of a better understanding of the nature and quantity of our coal reserves. In some coal regions of Appalachia, the strippable coal reserves are limited to less than 10 years of reserves at present extraction levels. We cannot allow for market forces to open new underground coal mines as they are needed. That will require a comprehensive effort on the part of private interests and the government.

Finally, all of the points I have raised require their own lead time. The absence of any one of them could mean the failure of the conversion program. Therefore, it is essential that the coal conversion program begin with a realistic timeframe. It took this Nation 50 years to convert from wood fuel to coal and about 25 years to reach the level of oil and gas consumption witnessed in our electric utility and industrial boilers. A switch back to coal, during this era of environmental awareness, is going to be a long and very expensive process but there are no real alternatives in sight which can prevent the consequences if we fail to do so.

I suggest that it is a monumental task for this Nation to consider converting boilers that are under construction or planned for construction in the near future, to coal. If that were the only accomplishment of this legislation, it would represent a major commitment away from the use of oil and gas as boiler fuels. In addition to those new starts, there are boilers which can and should be converted to coal with little expense and down time. Among that number, are those boilers located in urban areas where air quality requirements will necessitate the most effective pollution control equipment. The cost of those devices, relative to the amount of oil or gas saved, must be taken into account. When a hard list of the most acceptable conversion candidates is obtained, conversion orders should be issued. But I doubt whether they will collectively amount to a significant amount of oil and gas savings. Nonetheless, a conversion program should be pursued immediately.

If we can adopt a prohibition on the use of oil and gas for new facilities and be less concerned with a deadline for retrofitting existing boilers, we may have a workable program. In summary, we have to allow technological advances to catch up to our coal utilization visions lest we degrade our environment beyond the danger levels in the name of creating a secure energy future.

Mr. MOFFETT. Thank you, Mr. McCormick.

Mr. Martin, I would like to welcome you. Before you begin, I want to express the concern of the Chair over the fact that for one of our panels tomorrow we were scheduled—you may not know about this, but I hope you will carry the message back to the Department—we were scheduled to have the Director of Mining Enforcement and Safety Administration, and that was supposedly being arranged through Joan Davenport, the Assistant Secretary for Minerals. The Secretary has been informed that it is not possible, as I understand it, to send a witness. We would like to express our concern about this since it is such an important topic. We know that Department witnesses are called to testify all over the place and all over the Hill, but this is a very important matter, as I think you know, and I hope you will convey our concern about this back to the leadership of the department.

STATEMENT OF HON. GUY R. MARTIN

Mr. MARTIN. I share your concern, and I will see what I can do about it, Mr. Chairman.

Mr. Chairman, I have attempted to edit my remarks pursuant to your request, and I will indicate that I will be submitting my written comments for the record, and I will be submitting the answers to the questions that were formulated by the committee within the 1-week deadline which you indicated. We have not put the answers to the questions through our clearing procedure, but we will have those. We are also prepared to answer some of those questions that you pose today verbally if it necessary in the hearing.

I have also limited my remarks, Mr. Chairman, to the topic which is assigned to the panel, somewhat narrower in scope than the previous witness' testimony I believe, and really dealt with the supply question.

If I could, I will proceed to deal with my edited remarks.

I think that your hearing is timely, and we are very interested in continuing to participate with you. I think it might be said right at the beginning, although it is well known to the people on this panel, that the availability of inexpensive oil and gas, following World War II, encouraged those energy users who could to depend on oil and gas. As a result, coal production fell considerably following World War II. Coal production for steelmaking and other industrial processes, for electric power generation, and for export, largely to foreign steelmakers, has stayed near 600 million tons a year in record years.

Most of that production, nearly 90 percent of it on an annual basis, has come from privately owned coal reserves, from mines located east of the Mississippi River. Most of those coals are high in energy content. The high-energy bituminous coal of the Midwest contains medium to high amounts of sulfur, and much of the Appalachian bituminous coal is low in sulfur content. Most of the low-sulfur coal now produced in this country comes from the Appalachian reserves. Many of the Appalachian low-sulfur reserves are of coking quality, are essential to steel production, and are owned by American or foreign steel producers.

Until recently, the other great coal reserves in the United States, those of the Rocky Mountain and Northern Plains regions, were of little interest except to coal users in the Western States. That is because most of the western coal is sub-bituminous, and much lower in energy content than are the coals of the East and Midwest. Alaska aside, bituminous coals are found in substantial amounts in the West only in Colorado and Utah, and in parts of Wyoming. The western coals are generally low in sulfur content.

The Department of the Interior is the custodian of vast amounts of these western coals, although substantial amounts of coal are held by the State governments, Indian tribes, and private owners.

The Department of the Interior's responsibility, as custodian of the coal reserves owned by the United States, is complex. The Department must award or deny access to the coal, making it available or keeping it in U.S. Government ownership, within a framework of different, and often competing or conflicting, private and public interests. Perhaps at the top coal is only one of many resources that can be beneficially developed on the public lands. The others are well known to this committee and include such things as other minerals, water, timber, and forage, wildlife, recreation—all of the multiple uses and benefits derived from the public lands—are affected by the development of federally owned coal. Plans for development of the coal are, in turn, affected by the way those other resources are valued and managed. And, to make matters even more complicated, the rate at which Federal coal is introduced into the private economy has a considerable influence on the potential for development of non-Federal coal, both within the western coal fields and in the coal regions of the Midwest and East.

Until recently, not much attention has been paid to the Department of the Interior's success or failure in understanding and balancing all of these responsibilities. The growth of the West's economy, and the ability of the Nation to meet its resource needs, have long depended on the development, harvest, and mining of water, minerals, timber and forage from the federally owned public lands. But for generations, public and private uses of land in the West have been planned and carried out as if the coal there were a local resource, to be mined and burned without serious conflict. Community development, homesteading, farming and grazing, allocation of scarce water, and the evolution of attitudes about the basic character of the region—its economy, its culture, and its physical environment—have depended on the assumption that the West would not be seriously disturbed by coal development.

Your committee is certainly aware of how wrong that assumption was. This is not the place to catalogue the many resource management, social, environmental, and political conflicts that arise from present and contemplated coal development, in the West or elsewhere in the Nation. There are, however, some general policy decisions that have brought us to the present state of conflict, and others that may make the management of Federal coal more rational, acceptable and useful.

It has been assumed that when a demand was made for the transfer of a resource from the public domain to another owner, that demand itself was proof enough that the American economy had a genuine need for the resource.

The Department of the Interior's responsibility, under that definition of broader Federal responsibility, was generally translated into awarding a Federal coal lease in any area in which interest was expressed. The awarding of a lease did not, in theory or in practice, have a strong relationship to how the lessee planned to utilize and develop the coal. The process, which continued until Secretary Rogers Morton declared a leasing moratorium in 1971, resulted in the transfer of more than 17 billion tons of Federal coal to private ownership. Another category of leasing has given other private owners claims to an additional 9 billion tons of coal.

Almost all of that coal is still sitting in the ground. This administration has found little evidence of prior U.S. Government activity to determine how much of that coal could and should be developed or to determine the specific reasons why it has not, or what can be done to encourage its development. Whatever level of demand for the use of Federal coal might be assumed, there has been no attempt to test the economic value or the social and environmental liabilities of that coal which has already been leased. When the 1973 oil embargo caused renewed interest in federally owned coal reserves, the Interior Department's money and workpower resources were directed into planning the leasing of even more coal—still under a system that included no effective policy for deciding how to require or encourage strongly the actual production of Federal coal that was leased. Departmental attempts to identify that Federal coal which could be produced at the least social, economic, and environmental cost were discouraged.

In brief, the existing situation is intolerably contrary to the national interest. Some federally owned coal that should be turned into energy is now held by companies that have no apparent plans for development of the coal. Other interests that would make immediate use of Federal coal either did not or could not participate in earlier leasing, and feel their demands for coal will not be economically met unless more Federal coal is leased. Utilities serving local or State needs feel it unfair if they are forced to outbid regional or national interests in order to purchase coal that may be less than a mile from the local utility's powerplant. Other local or regional utilities want favored access to Federal coal, in order to become brokers in the delivery of energy to other companies that would not, themselves, be able to get the Federal coal on such favorable terms.

It is our intent to design a Federal coal leasing system that recognizes the difference between coal leasing and coal production, reconciles the different demands of distinct classes of coal users, and assures the people of the United States a fair economic return for each ton of coal produced from the public domain. There are two other sets of challenges, though, that should be reviewed here. The President has recognized them, Secretary Andrus, EPA Administrator Costle, and White House Energy Policy Advisor Schlesinger are following the President's direction in working on them, and the Federal coal program must be viewed as an element and an instrument of these broader policies.

The Department of the Interior is reviewing its coal-related programs, to take into account the new coal policy directions outlined by the President. Those parts of the President's National Energy Plan that have the most impact on the Department's coal programs are the recognition that the use of coal is constrained by demand rather than by supply, the determination that overall economic impacts of coal use are most favorable when coal production and development take place near the consuming markets, and the direction that production increases should be encouraged in the East and Midwest coal regions.

In order to make certain that Interior's management of Federal resources in the West does not actually inhibit the President's policies, it will be necessary to achieve much more accurate analysis of regional coal demand, regional coal production potential, the relationship of transportation policy to coal development, and the regional impacts of choices in coal combustion and conversion technologies. Secretary Andrus and Dr. Schlesinger are working together to build a process that will assure the appropriate contribution of federally owned coal resources to the national energy budget.

Another important challenge in developing a workable national coal policy is overcoming the delay, conflict, and confusion that have characterized the national debate over coal.

The President's Environmental Message shows his determination that, while America will depend on coal as a transition fuel to take us from our dependence on oil and gas to reliance on other energy

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systems, the transition will not degrade the American environment. The President has recognized the long and thoughtful efforts by Congress to set the kind of standards that will encourage a truly responsible, productive, expanding coal industry to meet American energy needs. Many of these were mentioned in earlier testimony. These include protecting the health and safety of mine workers, avoiding mining practices that would reduce our agricultural productivity or permanently damage our lands and waters, assuring that the use of coal will not damage the public's health or destroy the natural and recreational values of our public lands, seeing that coal development respects the economics and cultures of communities where coal production takes place—all of those goals that the Congress has worked on for years, but that have been seen by some as impediments to expanded coal use—are shared by President Carter as goals that should be pursued cooperatively.

The President, in his Energy and Environmental Messages to the Congress, has reconciled what we believe were fatal conflicts in government policy. The evidence is clear that an effort to stimlulate coal use, combined with an equally strong effort to ignore or override laws that protect society from the damage caused by coal, will not work.

For example, everyone concerned with coal—the mining companies and the miners, the utilities and their consumers, people who have to live with the impacts of mining and people who have to breathe air polluted by coal—was forced to choose up sides and fight with somebody else, if not with everyone else, because previous energy and environmental policies were ambiguous, out of step, or in conflict about the relationship between the burning of coal and the enforcement of air quality standards. Whatever position one might take about the merits of any argument in that complicated issue, it is clear that the principal result of the argument was to convince many coal companies, and many utilities, that the only way to have a reasonable chance of burning coal was to look for coal so low in sulfur content that debates about combustion technology would be beside the point. That answer overlooks the many other pollutants that may be found in coal that is low in sulfur, ignores the low energy content and high transportation costs of much of the low-sulfur coal, and presumes that most coal users will never get beyond the present fairly primitive state of coal burning technology. But it is presented as an answer, so an industry that is understandably anxious to get on with the job responded by, among other things, stepping up demands for more leasing of federally owned low sulfur western coal.

In calling for the application of best available control technology on all new coal-burning facilities, the President has made clear his intention to improve air quality. This will also mean that energy content will become more important in measuring the value of coal. Application of combustion and conversion technologies will make all our Nation's coal resources useful to our economy.

Planning to make regional coal resources available for regional use will reduce those pressures that resulted from earlier assumptions that western coal had to serve as the national energy breadbasket. Quoting from the President's National Energy Plan, "Coal development and production is most economical when it is near major markets. Although coal production will expand in many areas, there should be large production increases in the highly populated Eastern and Midwest regions, where coal use in industry and utilities could grow considerably in the future. The required use of best available control technology for new powerplants should stimulate even greater use of high sulfur midwestern and eastern coals." For the purpose of reviewing the Federal coal leasing program, the President's energy program reinforces the instructions to the Secretary of the Interior contained in the Environmental Message delivered by the President Monday.

The President has recognized that continuing with the existing leasing program will not do the job. We must take seriously the Federal Government's obligation to analyze the environmental and social impacts of potential future leasing. Not just because we are required to do so by the National Environmental Policy Act, or because a court may have found earlier environmental impact analysis to be inadequate. And not even because the Governors of seven Rocky Mountain States have demanded relief for their citizens from the negative social and economic impacts of the Federal Government's present energy programs. But because what some interests may have seen as an opportunity to use Federal power to overcome obstacles to coal development should really be seen as an opportunity for Federal leadership.

That Government, in one place, might own or manage many resources which in another part of the country would be controlled by diverse public and private interests, does not mean the government's unity of management should expedite coal development at the expense of the other resources. Reconciling the legitimate competing and conflicting uses, rights, and interests affected by coal development is no less difficult on Federal land in Montana or Colorado than on private land in Illinois, Ohio, or West Virginia.

The United States Government, because it does happen to own substantial reserves of coal, is in a unique position to set the example for the kind of responsible development that President Carter and the Congress have demanded of all coal owners. We can see that it is mined and burned with respect for workers, their communities, and the environment. And we can prove that socially responsible coal development can be done in a way that satisfies the economic rights of the owners of the coal—the people of the United States—without imposing undue economic burdens on the people who have to pay the bills for the power made from our coal. If that sounds ambitious, it's no more than is expected of any private coal producer in our eceonomic and regulatory system. To ask less of the government would mean that producers of power derived from Federal coal would meet fewer social and economic obligations than those met by companies that depend on privately owned coal.

The President has directed the Secretary of the Interior to manage the Federal coal leasing program to assure that it can respond to reasonable production goals by leasing only those areas where mining is environmentally acceptable and compatible with other land uses, and with respect for the rights of private surface owners.

Here are the specific directions from the President:

The Secretary of the Interior, using environmental reviews, coal assessments, and indications of market interest, should determine which lands are appropriate to offer for lease.

Land use plans should be completed before a decision to offer specific tracts for sale.

No tract should be leased unless the Secretary is satisfied that the environmental impact of mining would be acceptable and that the Federal Government will receive a fair market value for the lease.

In response to concern about the large numbers of non-producing Federal coal leases in the Western States, I am directing the Secretary of the Interior to scrutinize the existing leases—and applications for preference right leases—to determine whether they show prospects for timely development in an environmentally acceptable manner. He should take whatever steps are necessary to deal with non-producing and environmentally unsatisfactory leases and applications. These may include the following:

Exchange of environmentally unsatisfactory leases or applications for environmentally acceptable coal lands of equivalent value;

Reassessment of the basis for granting or denying preference right leases.

Submission of legislation to authorize the condemnation of outstanding rights upon payment of reasonable compensation, if necessary to prevent environmental damage.

I think the tenor of my testimony is obvious, and I think it is important to recognize as an overall thought at the end that we do believe the coal conversion program is a good one. We think it is important, and, generally speaking, we believe it is achievable as long as we follow these guidelines.

Mr. MOFFETT. Thank you very much.

Mr. Bagge.

STATEMENT OF CARL E. BAGGE

Mr. BAGGE. Mr. Chairman, I have a paper in chief which we presented, which I would like to have introduced into the record. It is our formal statement. It is a rather extensive statement. I won't attempt to read the entire thing.

We have also submitted, and I want to suggest that it be included in the record, our response to the 61 questions posed by Chairman Dingell, our letter being dated May 23. I would like to have that included in the record of these hearings.

Mr. MOFFETT. Without objection that will be done.

Mr. BAGGE. Mr. Chairman and members of the subcommittee:

My name is Carl E. Bagge. I am president of the National Coal Association, which represents the major coal producing and sales companies of the Nation as well as many of the organizations concerned with production, transportation and use of coal. We appreciate the opportunity to present the coal industry's views on part F of H.R. 6831 which you are considering today. The stated purpose of this legislation is to require greater use of coal—instead of oil and gas—by electric utilities and other major fuel-burning installations.

We strongly support the objective of making greater use of coal in supplying the Nation's growing energy requirements and reducing our dependence on imported oil and dwindling natural gas supplies. However, we strongly oppose the mandatory approach to greater coal use.

Since it may seem strange that the coal industry would oppose a bill which has the stated purpose of increasing coal use, this statement provides in some detail our analysis of the matter, the reason for our position, and our suggestions for an approach that would achieve the desired objectives—without the disadvantages of the bill you are considering.

Briefly, Mr. Chairman, I plan to cover several major points in this statement:

First, I plan to list governmental requirements—not recognized or dealt with in H.R. 6831—which are the principal obstacles to greater use of coal and thus conflict with the bill's objectives. I am referring to requirements concerned with air quality, surface mining, leasing, electric rate setting, and pricing of oil and natural gas.

Second, I plan to discuss our principal reasons for opposing part F of H.R. 6831 which, in summary, are that:

a. The proposed regulatory program would add little, if anything, to the trends toward coal—and away from oil and natural gas—that are already underway in the case of electric generating plants and major fuel-burning installations.

b. The 3-year-old FEA coal conversion program has, itself, not contributed enough to the movement toward coal to warrant its continuation or expansion.

c. Efforts to force conversion of existing facilities may even detract from the overall objective of substituting coal for oil and gas.

d. The bill would lead to a costly new or expanded regulatory program and bureaucracy which are not necessary or desirable.

e. The mandatory conversion requirements of the bill could easily lead to Federal coal allocation and price controls—steps that have proven counterproductive and damaging in the case of natural gas and oil, and which could discourage planned expansion of coal production.

Third, I plan to describe the principal issue in the debate over mandatory conversion—as revealed in our detailed analysis of the subject, and summarize the principal arguments that have emerged.

Fourth, I will outline and recommend an alternative program which would contribute more to the basic objectives of the bills you are considering but which would avoid the pitfalls.

Fifth, I will discuss the ability of the coal industry to respond to the expected increase in demands for coal on the supply side, and what our industry's present plans are for between now and 1985.

Finally, I will list briefly other existing or potential constraints on coal production and use which warrant attention—so that the matter of coal conversion can be considered in its proper context.

There are two general points deserving attention before I expand on those just listed:

Coal can make a major contribution. For each 100 million tons of domestic coal used instead of foreign oil, the Nation can avoid importing about 400 million barrels of oil and avoid the outflow of over $5 billion and many U.S. jobs. That is an important point underlying our consideration of this issue.

The second general point I would like to make is that the Congress has a rare opportunity to do something about unnecessary bureaucracy and regulation. Many Americans are fed up with excessive regulation and bureaucracy and we believe many in Congress share that view. Certainly President Carter has expressed that point of view many times. It is a rare opportunity because the Congress can now say "no" to a proposal to continue to expand an ineffective regulatory program. The purported objectives can be achieved just as well through voluntary plans that are already well along.

I would now like to expand upon the six topics discussed earlier.

I. Government-Imposed Obstacles to Coal Use.

First Mr. Chairman, coal is now demand limited and I believe the Congress has an obligation to recognize and address the obstacles to the use of coal in lieu of oil and gas that are present in existing governmental requirements. If these conflicting requirements are not dealt with, objectives for greater coal use simply will not be realized with either a voluntary or regulatory approach.

A. Air Quality Requirements. Undoubtedly, the most important obstacle to greater coal use are State and Federal air quality requirements. Several points warrant attention:

1. State Requirements. Sulfur oxide control requirements imposed by many States are much tighter than needed to meet national health standards and these requirements are preventing the use of coal. Such requirements—which were encouraged and approved by the Federal Environmental Protection Agency—were imposed before their implementations, particularly for energy, were understood. Instead of dealing with this problem, the bill you are considering merely provides that applicable environmental requirements must be met.

Thus far, the Federal Government has ducked its real responsibility for helping States to change requirements which are unnecessary to meet Federal health standards and which, in the public interest, should be changed. Instead, the Federal Government—hiding behind a "States rights" cloak—has left to Governors and State governments the burden—including the political burden—of trying to adopt less restrictive and more balanced clean air requirements.

The conflict is further illustrated by the fact that the House is now considering amendments to the Clean Air Act which would, unnecessarily, make coal use even more difficult—without adequately taking into account the energy and economic impacts.

Meanwhile, utilities and other major fuel users are forced to use natural gas or expensive foreign oil.

Federal EPA requirements and enforcement actions have been directed toward forcing electric utilities to install flue gas desulfurization equipment (scrubbers) on many new and existing plants, at great cost to customers. EPA provides no assurance that they will be adequate to meet new requirements and standards that EPA or States might establish in the future. In the face of these uncertainties, utilities have been reluctant to invest additional sums in coal-burning facilities and found it easier to continue burning natural gas and imported oil in existing plants.

A second obstacle to greater coal use results from State utility commission treatment of electric rates. In most States, the full cost of fuel—even if higher priced than alternatives—can be passed through automatically to customers. Utilities face quite a different situation when they want to invest in coal-related equipment. In many States, costs of construction work in progress (CWIP) for new facilities are not even eligible for consideration in electric rates. New facilities must be completed and in use before rate commissions will consider including these costs in the rate base. This must be done in an often lengthy hearing which results in regulatory delay before rates are adjusted. The utility thus faces a cash flow problem, out-of-pocket costs and the burden of the borrowing needed for the new facility.

This different treatment of costs provides a powerful incentive to postpone or avoid expenditures—even if customers would benefit from lower total costs through the use of lower-priced fuel with the new facility. This problem can be solved to the benefit of consumers and to our national energy situation if rate commissions acted more promptly and allowed the utilities to earn a return to cover the costs of construction work in progress by inclusion in the rate base. While it is a national problem, the Federal Government has traditionally failed to deal with it because it would be necessary to interfere with States' rights to control utility rates.

A third governmental obstacle to increased use is the Federal controls which hold oil and natural gas prices to artificially low levels. These controls discourage domestic production of these fuels and encourage greater dependence on imports. Even more important for this forum, controlled prices have had the effect of encouraging wasteful use of oil and gas under utility and industrial boilers. Parts of H.R. 6831 being considered by other committees would increase oil and natural gas prices to aid conservation efforts and provide additional incentive to encourage voluntary conversion to the use of coal.

I would now like to turn our five principal reasons for opposing mandatory coal use requirements.

First, a mandatory regulatory program would add little to the voluntary trend away from oil and gas in utilities and industry.

In the case of new electric utility plants, our computer analysis (summary at appendix A) of data reported to the FPC by utilities on plans for new steam-generating facilities planned to come on line by 1985 show and overwhelming commitment toward coal and nuclear and away from oil an natural gas. Specifically, they show:

250 new coal-fired units providing capacity of 123,000 megawatts.

125 new nuclear units providing 135,000 megawatts.

No oil-fired units expected after 1982. Twenty-six units providing 13,500 megawatts would come on line by 1982.

No gas-fired units expected after 1979. Nine units supplying 1,500 megawatts would come on line in 1977 and 1979.

This commitment is particularly important since new plants are much larger and more efficient and can replace several older and smaller oil or gas-fired plants.

In the case of existing electric generating plants, no coal is being burned as a result of an FEA order under the existing program, which you, Mr. Chairman, pointed out in introducing these hearings—yet our analysis (summary at appendix B) shows that utilities are voluntarily switching to coal, largely due to higher prices for intrastate natural gas and imported oil and uncertainties of supply of these fuels. For example, the 11 units in FEA's first round selections which have been certified by EPA as able to burn coal within environmental requirements were using coal for 69 percent of its fuel needs in 1975—compared to 36 percent in 1973. The percentage was undoubtedly higher in 1976 and this should be demonstrated by data that FPC is now compiling.

Also, in the case of many existing electric generating plants, it will not be practicable or feasible to switch back to the use of coal and some utilities have made it clear that they will oppose FEA forcing attempts where switching is impossible, impractical or economically questionable.

In the case of new industrial facilities, less data are available (FEA has yet to release summaries of the data it has collected over the past 5 months from firms planning new fuel burning installations in the industrial section, but data reported by the American Boiler Manufacturers Association show a trend toward new facilities with coal-burning capability.

In the case of existing industrial facilities:

Conversions to coal are virtually impossible without installing new units if the existing unit never had coal-burning capability.

Conversions back to coal may not be practicable, e.g., due to need for handling and storage facilities.

Despite these constraints, the Bureau of Mines' data show a 19-percent increase in industrial use of coal from January 1976 to January 1977.

Our second reason for opposing a mandatory program is our conclusion that the FEA coal conversion has not made a significant contribution to increased coal use. In fact, no coal is yet being burned by plants covered by orders that FEA may someday issue, but that is due to utility decisions—not to FEA prohibition orders. Pertinent facts about the program for converting existing electric generating plants are summarized at appendix B. It is clear that:

Based on past experience, the potential for converting utility plants from oil and gas to coal is very limited. The program is cumbersome, time-consuming and bureaucratic with regulations, hearings, orders, findings, exceptions, and people who may or may not be well-equipped to make decisions that are in the best interests of the customers served.

The incremental impact of the program—beyond what would occur without the program—is hard to identify.

The cost to taxpayers is high: $5.8 million in fiscal year 1978, and this will increase if authority is extended.

We don't think that the marginal benefit of this program at $5.8 million of the taxpayers' money, with no conversions, can be justified or extended.

Our third reason—and this is a very important reason, Mr. Chairman—for opposing a mandatory program is that such efforts with respect to existing plants would interfere with actions leading to new coal-burning facilities and greater voluntary uses of coal.

New electric generating units are larger, more efficient, and used more often (i.e., most coal-fired units are base load units), and it is easier and cheaper to meet environmental requirements. The 250 new coal-fired units already planned average about 500 megawatts.

Existing plants on which FEA has focused attention are older, smaller and less used—and their use is declining steadily as new base load units come on line. This is clear from data in appendix B.

We have completed, Mr. Chairman, and I would like to introduce into the record, a special analysis of the existing electric generating units covered by FEA's attempts to force the use of coal. I would like to submit that, if I may, for the record. It is a study we just completed, but it lays out the facts concerning this entire program in terms of projection of that program under the SEC authority. Our principal conclusions concerning this data, which is each of the units as identified in the study, is that utilities are voluntarily using more coal in a number of existing electric generating units covered by the FEA efforts even though the government has not reached the stage in its complex process of ordering coal use.

Secondly, the existing units covered by FEA efforts tend to be small in size, averaging about 150 megawatts, and this is a very important consideration, Mr. Chairman.

Now these are the teakettles. Instead of taking the expertise and the capital and the engineering talent of the utility industry, and involving lawyers in these kinds of regulatory proceedings and focusing on the teakettles in this country, we have got to direct the engineering talent and the capital to new plants. The 150 megawatts were a $5 million investment in taxpayers' money in the program that hasn't converted a single plant. We think it ludicrous. The units covered by FEA efforts are being used less frequently, and are being used even less frequently as time passes, presumably because of the new base load units that are available to the utilities. Even though the units are being used less, the use of coal was increased voluntarily from 1973 to 1975 both in absolute terms from $5 million to $7.6 million, and as a percentage of the total fuel used in the units. Increased coal use is probably due to its lower price relative to oil and natural gas and greater certainty of supply.

Finally the total potential for increased coal use in existing units covered by FEA efforts is small when compared to the potential for new base load coal-fired units and plants.

This study I would like to have incorporated. I think it is a very important contribution to this dialogue, Mr. Chairman.

Mr. MOFFETT. Without objection.

Mr. BAGGE. In fact, mandatory conversions of existing plants may divert capital and manpower from the planning, justifying, siting and construction of new coal burning facilities. We should emphasize reduced consumption of oil and gas, not conversion of powerplants just for the sake of conversion. We should be concerned with running new and existing coal-fired plants more and running gas and oil plants less.

Our fourth reason for opposing a mandatory program is fundamental disadvantages of the regulatory program that is required and the bureaucracy that would be needed to carry it out. While one purpose of part F of H.R. 6831 may be to switch the burden of proof to utilities and industrial organizations, there would remain a need for a major regulatory program. This means a long string of regulations, orders, assessments, impact statements, evaluations and administrative costs; a need to evaluate the justification for the many exceptions and exemptions provided for in the bill; the potential for considerable litigation if fuel users, their customers or others affected by enforcement actions disagree; and a large staff of Federal employees. We believe all of this can be avoided by an effective and realistic program to encourage—rather than enforce—switching from oil or gas to coal.

Our final reason for opposing a mandatory program is the considerable likelihood that a mandatory program would lead to extensive Federal coal allocation and price controls. The Energy Supply and Environmental Coordination Act (ESECA), which H.R. 6831 would amend, already has provided the basis for FEA's assertion that it has allocation and price control authority, and FEA regulations prescribing the circumstances under which it would become operative have already been adopted. We hope that serious consideration will be given to this extensive analysis we have made, and particularly of the unit-by-unit analysis that we have made of the electric generating units that are covered by the FEA's present attempts to force the use of coal. We hope you will conclude that the Nation's interests would best be served by directly focusing the attention and talent and expertise of the utilities and industrial sector of the new base load plants where the action is and the new commitments have already been made.

Thank you very much.

[Mr. Bagge's prepared statement; the responses to questions on section F; and the study referred to, follow:]

NATIONAL COAL ASSOCIATION

STATEMENT BY

CARL E. BAGGE
President
National Coal Association

before the

SUBCOMMITTEE ON ENERGY AND POWER

of the

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

with respect to

PART F (REVISION OF COAL CONVERSION PROGRAM) OF
H.R. 6831, NATIONAL ENERGY ACT

May 25, 1977

U.S. House of Representatives
Washington, D. C.

Mr. Chairman and Members of the Subcommittee:

My name is Carl E. Bagge. I am President of the National Coal Association, which represents the major coal producing and sales companies of the Nation as well as many other organizations concerned with production, transportation and use of coal. We appreciate the opportunity to present the coal industry's views on Part F of H.R. 6831 which you are considering today. The stated purpose of this legislation is to require greater use of coal -- instead of oil and gas -- by electric utilities and other major fuel-burning installations.

We strongly support the objective of making greater use of coal in supplying the Nation's growing energy requirements and reducing our dependence on imported oil and dwindling natural gas supplies. However, we strongly oppose the mandatory approach to greater coal use.

Since it may seem strange that the coal industry would oppose a bill which has the stated purpose of increasing coal use, this statement provides in some detail our analysis of the matter, the reasons for our position, and our suggestions for an approach that would achieve the desired objectives -- without the disadvantages of the bill you are considering.

Briefly, Mr. Chairman, I plan to cover several major points in this statement:

- First, I plan to list governmental requirements -- not recognized or dealt with in H.R. 6831 -- which are the principal obstacles to greater use of coal and thus conflict with the bill's objectives. I am referring to requirements concerned with air quality, surface mining, leasing, electric rate setting, and pricing of oil and natural gas.

- <u>Second</u>, I plan to discuss our principal reasons for opposing Part F of H.R. 6831 which, in summary, are that:

a. The proposed regulatory program would add little, if anything, to the trends toward coal -- and away from oil and natural gas -- that are already underway in the case of electric generating plants and major fuel-burning installations.

b. The 3-year old FEA coal conversion program has, itself, not contributed enough to the movement toward coal to warrant its continuation or expansion.

c. Efforts to force conversion of <u>existing</u> facilities may even detract from the overall objective of substituting coal for oil and gas.

d. The bill would lead to a costly new or expanded regulatory program and bureaucracy which are not necessary or desirable.

e. The mandatory conversion requirements of the bill could easily lead to Federal coal allocation and price controls -- steps that have proven counterproductive and damaging in the case of natural gas and oil, and which could discourage planned expansion of coal production.

- Third, I plan to describe the principal issue in the debate over mandatory conversion -- as revealed in our detailed analysis of the subject, and summarize the principal arguments that have emerged.
- Fourth, I will outline and recommend an alternative program which would contribute more to the basic objectives of the bills you are considering but which would avoid the pitfalls.
- Fifth, I will discuss the ability of the coal industry to respond to the expected increase in demands for coal.
- Finally, I will list briefly other existing or potential constraints on coal production and use which warrant attention -- so that the matter of coal conversion can be considered in its proper context.

There are two general points deserving attention before I expand on those just listed:

. Coal can make a major contribution. For each 100 million tons of domestic coal used instead of foreign oil, the Nation can avoid importing about 400 million barrels of oil and avoid the outflow of over $5 billion and many U.S. jobs.

. The Congress has a rare opportunity to do something about unnecessary bureaucracy and regulation. Many Americans are fed up with excessive regulation and bureaucracy and we believe many in Congress share that view. It is a rare opportunity because the Congress can now say "no" to a proposal to continue and expand an ineffective regulatory program. The purported objectives can be achieved just as well through voluntary plans that are already well along.

I would now like to expand upon the six topics discussed earlier.

I. GOVERNMENT-IMPOSED OBSTACLES TO COAL USE.

First, Mr. Chairman, coal is now demand limited and I believe the Congress has an obligation to recognize and address the obstacles to the use of coal in lieu of oil and gas that are present in existing governmental requirements. If these conflicting requirements are not dealt with, objectives for greater coal use simply will not be realized with either a voluntary or regulatory approach.

A. Air Quality Requirements. Undoubtedly, the most important obstacle to greater coal use are state and Federal air quality requirements. Several points warrant attention:

1. State Requirements. Sulfur oxide control requirements imposed by many states are much tighter than needed to meet national health standards and these requirements are preventing the use of coal. Such requirements -- which were encouraged and approved by the Federal Environmental Protection Agency -- were imposed before their implications, particularly for energy, were understood. Instead of dealing with this problem, the bill you are considering merely provides that applicable environmental requirements must be met.

Thus far, the Federal Government has ducked its real responsibility for helping states to change requirements which are unnecessary to meet Federal health standards and which, in the public interest, should be changed. Instead, the Federal Government -- hiding behind a "states rights" cloak -- has left to Governors and state governments the burden -- including the political burden -- of trying to adopt less restrictive and more balanced clean air requirements.

The conflict is further illustrated by the fact that the House is now considering amendments to the Clean Air Act which would, unnecessarily, make coal use even more difficult -- without adequately taking into account the energy and economic impacts.

Meanwhile, utilities and other major fuel users are forced to use natural gas or expensive foreign oil.

2. Uncertainties about future clean air requirements. Federal EPA requirements and enforcement actions have been directed toward forcing electric utilities to install flue gas desulfurization equipment (scrubbers) on many new and existing plants, at great cost to customers. EPA provides no assurance that they will be adequate to meet new requirements and standards that EPA or states might establish in the future. In the face of these uncertainties, utilities have been reluctant to invest additional sums in coal-burning facilities and found it easier to continue burning natural gas and imported oil in existing plants.

B. Regulatory biases against investment in coal-related equipment and in favor of higher cost oil. A second obstacle to greater coal use results from state utility commission treatment of electric rates. In most states, the full cost of fuel -- even if higher priced than alternatives -- can be passed through automatically to customers. Utilities face quite a different situation when they want to invest in coal-related equipment. In many states, costs of contruction work in progress (CWIP) for new facilities are not even eligible for consideration in electric rates. New facilities must be completed and in use before rate commissions will consider including these costs in the rate base. This must be done in an often lengthy hearing which results in regulatory delay before rates are adjusted. The utility thus faces a cash flow problem, out-of-pocket costs and the burden of the borrowing needed for the new facility.

This different treatment of costs provides a powerful incentive to postpone or avoid capital expenditures -- even if customers would benefit from lower total costs through the use of lower-priced fuel with the new facility. This problem can be solved to the benefit of consumers and to our national energy situation if rate commissions acted more promptly and allowed the utilities to earn a return to cover the costs of construction work in progress by inclusion in the rate base. While it is a national problem, the Federal Government has traditionally failed to deal with it because it would be necessary to interfere with states' rights to control utility rates.

C. Controls on oil and natural gas prices. A third governmental obstacle to increased coal use is the Federal controls which hold oil and natural gas prices to artifically low levels. These controls

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discourage domestic production of these fuels and encourage greater dependence on imports. Even more important for this forum, controlled prices have had the effect of encouraging wasteful use of oil and gas under utility and industrial boilers. Parts of H.R. 6831 being considered by other committees would increase oil and natural gas prices to aid conservation efforts and provide additional incentive to encourage voluntary conversion to the use of coal.

II. REASONS FOR OPPOSING MANDATORY COAL USE.

I would now like to turn to our five principal reasons for opposing mandatory coal use requirements.

A. Mandatory requirements would add little to the trend away from oil and gas. First, a mandatory-regulatory program would add little to the voluntary trend away from oil and gas in utilities and industry.

- In the case of new electric utility plants, our computer analysis (summary at Appendix A, page 21) of data reported to the FPC by utilities on plans for new steam-generating facilities planned to come on line by 1985 show an overwhelming commitment toward coal and nuclear and away from oil and natural gas. Specifically, they show:
  - 250 new coal-fired units providing capacity of 123 thousand megawatts.
  - 125 new nuclear units providing 135 thousand megawatts.
  - No oil-fired units expected after 1982. 26 units providing 13.5 thousand megawatts would come on line by 1982.

. No gas-fired units expected after 1979. 9 units supplying 1.5 thousand megawatts would come on line in 1977 and 1979.

This commitment is particularly important since new plants are much larger and more efficient and can replace several older and smaller oil or gas-fired plants.

- In the case of <u>existing electric generating plants</u>, no coal is being burned as a result of an FEA order under the existing program -- yet our analysis (summary at Appendix B, page 23) shows that utilities are voluntarily switching to coal, largely due to higher prices for intrastate natural gas and imported oil and uncertainties of supply of these fuels. For example, the 11 units in FEA's first round selections which have been certified by EPA as able to burn coal within environmental requirements were using coal for 69% of its fuel needs in 1975 -- compared to 36% in 1973. The percentage was undoubtedly higher in 1976 and this should be demonstrated by data that FPC is now compiling.
- Also, in the case of many <u>existing electric generating plants</u>, it will not be practicable or feasible to switch back to the use of coal and some utilities have made it clear that they will oppose FEA forcing attempts where switching is impossible, impractical or economically questionable.
- In the case of <u>new industrial facilities</u>, less data are available (FEA has yet to release summaries of the data

it has collected over the past 5 months from firms planning new fuel burning installations), but data reported by the American Boiler Manufacturers Association show a trend toward new facilities with coal-burning capability.

- In the case of existing industrial facilities:
  - Conversions to coal are virtually impossible without installing new units if the existing unit never had coal-burning capability.
  - Conversions back to coal may not be practicable, e.g., due to need for handling and storage facilities.
  - Despite these constraints, the Bureau of Mines' data show a 19% increase in industrial use of coal from January 1976 to January 1977.

B. Accomplishments of the FEA program do not justify its continuation or expansion. Our second reason for opposing a mandatory program is our conclusion that the FEA coal conversion has not made a significant contribution to increased coal use. In fact, no coal is yet being burned as a result of an FEA order. Additional coal is being burned by plants covered by orders that FEA may someday issue, but that is due to utility decisions -- not to FEA prohibition orders. Pertinent facts about the program for converting existing electric generating plants are summarized at Appendix B. It is clear that:

- Based on past experience, the potential for converting utility plants from oil and gas to coal is very limited. The program is cumbersome, time-consuming and bureaucratic with regulations, hearings, orders, findings, exceptions, and people who may or may not be well-equipped to make decisions that are in the best interests of the customers served.

- The incremental impact of the program -- beyond what would occur without the program -- is hard to identify.
- The cost to taxpayers is high: $5.8 million in FY 1978, and this will increase if authority is extended.

B. Efforts to force conversion of existing facilities can detract from voluntary use of coal in new plants. Our third reason for opposing a mandatory program is that such efforts with respect to existing plants would interfere with actions leading to new coal-burning facilities and greater voluntary uses of coal.

New electric generating units are larger, more efficient, and used more often (i.e., most coal-fired units are base load units), and it is easier and cheaper to meet environmental requirements. The 250 new coal-fired units already planned average about 500 megawatts.

Existing plants on which FEA has focused attention are older, smaller and less used -- and their use is declining steadily as new base load units come on line. This is clear from data in Appendix B.

In fact, mandatory conversions of existing plants may divert capital and manpower from the planning, justifying, siting and construction of new coal burning facilities. We should emphasize reduced consumption of oil and gas, not conversion of power plants just for the sake of conversion. We should be concerned with running new and existing coal-fired plants more and running gas and oil plants less.

D. New or expanded regulatory program and bureaucracy are unnecessary. Our fourth reason for opposing a mandatory program is fundamental disadvantages of the regulatory program that is required and the bureaucracy that would be needed to carry it out. While one purpose of Part F of H.R. 6831 may be to switch the burden of proof to utilities and industrial organizations, there would remain a need for a major regulatory program. This means a long string of regulations, orders, assessments, impact statements, evaluations and administrative costs; a need to evaluate the justification for the many exceptions and exemptions provided for in the bill; the potential for considerable litigation if fuel users, their customers or others affected by enforcement actions disagree; and a large staff of Federal employees. We believe all of this can be avoided by an effective and realistic program to encourage -- rather than enforce -- switching from oil or gas to coal.

E. Mandatory conversion requirements would lead to Federal coal allocation and price controls. Our final reason for opposing a mandatory program is the considerable likelihood that a mandatory program would lead to extensive Federal coal allocation and price controls. The Energy Supply and Environmental Coordination Act (ESECA), which H.R. 6831 would amend, already has provided the basis for FEA's assertion that it has allocation and price control authority, and FEA regulations prescribing the circumstances under which it would become operative have already been adopted.

We are well aware of the damaging effects of Federal allocation and price controls in the case of oil and natural gas -- damaging in terms of distorted markets, reduced competition, reduced incentive for new production and reduced incentive for new investments. We can only assume that the adverse effects of regulatory requirements would be just as severe for coal as they have been for gas and oil. Further, allocation and price controls mean still more Washington-dictated standards, criteria, regulations, exceptions, etc., and a larger and more costly government.

We are not concerned about the ability of the industry to meet demands for increased coal production -- as I will discuss in more detail below. Instead, the road to allocation and price controls could begin -- even with ample supplies -- with a few forced conversions where those ordered to act felt that prices were too high or supplies not readily available under conditions the user so ordered felt were to his advantage.

Major coal producers have a vivid recollection of the price controls imposed in the 1971-1973 period which were directly responsible for substantial operating losses by nearly all major companies. Those price controls also prevented the necessary expansion of coal production capacity which contributed to temporary market distortions during the Arab oil embargo. Such losses cannot help but discourage the increased investments that the Nation is counting on to increase coal production in the years ahead.

III. SUMMARY OF THE PRINCIPAL ISSUES AND ARGUMENTS ON MANDATORY CONVERSION

At this point, I would like to summarize briefly the areas of agreement, the remaining issues and the arguments for and against a mandatory program.

A. Areas of Agreement. There seems to be general agrement on several major points, specifically:

- That it is in the national interest, and generally in the interest of consumers because of the lower cost of coal, to encourage switching from oil and gas to coal wherever practicable.
- That there are powerful incentives now operating on utilities and industries in the form of fuel price advantages and threats of interrupted natural gas and oil supplies -- to encourage switching.
- There remain some serious obstacles which are discouraging switching such as unnecessary air quality requirements, regulator disincentives, and price controls.
- That there is a very strong trend toward using coal in steam electric facilities and an expanded interest in the case of industrial plants.

B. Remaining Issues. The remaining issues are (1) whether the trends will continue and increase, and (2) whether switching back to oil and gas will be avoided -- unless there is a mandatory federal regulatory program.

C. Arguments Against A Mandatory Program. Briefly, the principal arguments against a mandatory program are that:

- It adds very little, if any, of marginal value to the trends that are already underway due to existing incentives and voluntary actions.
- Experience with the FEA program is unfavorable.

. Forced conversion of existing facilities could detract from the objective of greater coal use.

. A mandatory conversion program and bureaucracy are inherently costly to the taxpayer and counter to the objectives of reducing Government regulations and red tape.

. A mandatory program would lead to allocation and price controls.

D. Arguments for a Mandatory Program. On the other hand, the principal arguments for a mandatory program appear to be that:

. Even more conversions should be occurring than are now planned and a mandatory program will help.

. A mandatory program is necessary to overcome the obstacles such as regulatory biases which discourage capital investment.

. A mandatory program is needed as a "threat" to encourage conversion to coal and to prevent switching back.

IV. A RECOMMENDED ALTERNATIVE.

In view of the coal industry's strong opposition to the mandatory features of the legislation you are considering, it is only reasonable that you expect our industry to recommend a alternative. We are fully prepared to recommend such a program which we believe would be effective and meet the arguments of those who support mandatory coal conversion programs. Our alternative program has three major parts:

A. Reducing or Overcoming Obstacles. To deal with the obstacles to coal use identified earlier, we recommend the following steps:

1. In the case of clean air requirements:

a. The congress should refrain from tightening clean air requirements as proposed in the amendments now pending before the Senate and House and provide relief from existing significant deterioration and non-attainment regulations promulgated by EPA. The Congress should extend deadlines for meeting presently unattainable air quality standards, particularly since deadlines have passed and in many instances cannot be met.

b. The Federal Government should override state air quality requirements that are not necessary to meet national health standards when such requirements are encouraging use of oil or natural gas instead of coal.

c. The Federal Government should guarantee to those installing available pollution control equipment to comply with Federal or state standards -- and to their customers who must pay for such equipment -- that the equipment will be deemed acceptable and that no new requirement will be imposed requiring additional expenditures or change in operations for at least ten years or until the investment is amortized -- whichever is sooner.

2. In the case of state regulatory biases which discourage investment in new facilities, the Congress should place restrictions on Federal aid to states which are contingent upon actions by state agencies to (a) speed up rate revisions, and (b) allow construction work in progress to be included in the rate base.

3. In the case of price controls, the Congress should act promptly to remove Federal price controls from wellhead prices of new natural gas and phase out the remaining petroleum price and allocation controls.

4. In general, the Congress should accept the obligation of identifying conflicting requirements before laws are enacted and find a balance among objectives that is in the national interest -- including tradeoffs among environmental, energy and economic objectives. We believe that progress can be made simultaneously toward all these objectives if some arbitrary and and unnecessary features of existing and proposed requirements are avoided.

B. Providing incentives and encouragement for voluntary conversion. To supplement existing price and supply incentives -- and help overcome obstacles, the Congress should:

1. Provide for more rapid writeoff of expenditures for pollution control and coal handling and utilization equipment and facilities.

2. Increase the investment tax credit for investments in such facilities.

3. Allow oil and natural gas prices to rise to market levels. The excise tax on the use of oil or gas in industrial and utility facilities that could and should be using coal would encourage conversion by off-setting artificially low oil and gas prices which are due to Federal regulation and controls. It would be far better public policy

merely to remove the price controls, particularly since such a tax does nothing to encourage production.

C. Assuring continued progress toward conversion. There is a much easier and less costly way of providing a "threat" that would help encourage progress toward conversions. This approach would avoid the evils of a regulatory approach. Specifically, I propose that the Congress:

1. Provide such additional authority as needed, if any, to obtain advance information from fuel users on plans for building new fuel burning facilities and on the type of fuels that will be used.
2. Require the new Department of Energy to monitor the reports and notify Congress immediately of any significant trends that appear counter to the objective of greater coal utilization.

This approach would allow the Congress to investigate and, if then found essential, enact mandatory requirements.

V. ABILITY TO PROVIDE THE COAL THAT WILL BE NEEDED.

One matter that is certain to be of interest when considering steps to increase the use of coal is the ability of the coal industry to produce the amounts required. Subject to potential constraints which I will list later, we are confident that our coal industry can increase production to meet expected demand. We base that conclusion on several important factors:

A. Coal production has, for years, been demand-limited. In 1976 the coal industry could have added an estimated 50-60 million tons to the 665 million produced.

B. NCA studies of planned new mines and major expansions completed in August 1976 showed cumulative additions planned by 1986 of more than 500 million tons. (Study provided for the record.)

C. A recently completed FPC study (summarized at Appendix C) of new coal supply for new electric generating plants shows that 85% of the 173.9 million of new tonnage required in 1980 and 68% of the 357.7 million of new tonnage required in 1985 for the 223 plants covered by FPC <u>is already under contract</u>.

We are also encouraged that a large share of the required new production is already covered by transportation contracts, particularly in the West. However, the picture for rail transportation in the East is less promising and additional action will be needed by several lines to meet demands.

While we are confident of our ability to produce the coal required, several developments could add severe constraints on that ability. In addition to the air quality standards mentioned earlier, these include:

- Potentially restrictive Federal surface mining requirements which could cut expected production and prevent mining of reserves that already have been assembled into logical mining units for production in the years just ahead.
- Reinstitution of the moratorium on leasing of Federal coal lands.
- New mine health and safety law amendments -- which could severely cut production with no improvement in safety.

- Unreasonable water quality requirements imposed under the 1972 amendments to the Water Pollution Control Act.
- Horizontal divestiture requirements which would take away needed capital and management talent.
- Delays by Federal agencies in compelling necessary environmental impact statements.

VI. <u>OTHER ELEMENTS OF A FEDERAL COAL POLICY AND PROGRAM</u>.

Finally, in order that you might have the full context for the actions you are considering today, I would like to list other actions that are needed and warranted as a part of a realistic Federal coal policy and program. These are:

- An increase in Federal funding for coal-related research, development and demonstration. Particularly important, funding for the development of new mining technology should be increased to at least $70 million in fiscal year 1978 (compared to $57.8 million in 1977) -- rather than cut to $55 million as proposed in the President's 1978 budget. Improved mining technology is needed to overcome the productivity loss the industry has experienced since 1969.
- Increased support for the Federal share of costs of improving rail and water transport facilities needed to move coal.
- Right of eminent domain for coal slurry pipelines.
- Roll in pricing (rather than incremental pricing) by FPC for gas produced from coal; and assistance for industry to build commercial scale synthetic fuels plants.

- Federal encouragement for new uses for coal, for coal exports, and for mining research and mining engineer training.
- A focus for coal-related activities in the proposed new Department of Energy.

* * * * * * * * * * *

In conclusion, we believe the facts and analyses presented herein lead inescapably to the conclusion that mandatory features of the bills you are considering are <u>not</u> in the public interest.

Thank you for the opportunity to present my statement. I will be pleased to respond to any questions you might have.

 APPENDIX A

SUMMARY OF NEW STEAM UNITS PROJECTED FOR 1977-1985

	COAL NO OF UNITS / CAP (MW)	NUCLEAR NO OF UNITS / CAP (MW)	OIL NO OF UNITS / CAP (MW)	GAS NO OF UNITS / CAP (MW)
UNITED STATES				
1977	24 / 11976	9 / 8247	8 / 4410	8 / 1436
1978	29 / 11770	6 / 6104	6 / 2497	0 / 0
1979	31 / 13062	11 / 10916	6 / 3013	1 / 100
1980	34 / 16659	9 / 10592	2 / 1210	0 / 0
1981	29 / 14986	15 / 15841	1 / 775	0 / 0
1982	27 / 13039	17 / 18034	3 / 1635	0 / 0
1983	23 / 12775	16 / 18428	0 / 0	0 / 0
1984	25 / 13536	22 / 24140	0 / 0	0 / 0
1985	28 / 15518	20 / 22570	0 / 0	0 / 0
UNITED STATES TOTAL	250 / 123350	125 / 135872	26 / 13540	9 / 1536
NEW ENGLAND REGION				
1978	0 / 0	0 / 0	1 / 600	0 / 0
1981	0 / 0	2 / 2300	0 / 0	0 / 0
1982	0 / 0	1 / 1150	0 / 0	0 / 0
1983	0 / 0	3 / 3480	0 / 0	0 / 0
1984	0 / 0	1 / 1150	0 / 0	0 / 0
NEW ENGLAND TOTAL	0 / 0	7 / 8080	1 / 600	0 / 0
MIDDLE ATLANTIC REGION				
1977	2 / 1475	0 / 0	2 / 1206	0 / 0
1978	0 / 0	1 / 880	0 / 0	0 / 0
1979	1 / 825	2 / 1935	1 / 850	0 / 0
1980	0 / 0	1 / 1050	0 / 0	0 / 0
1981	0 / 0	1 / 873	0 / 0	0 / 0
1982	1 / 700	3 / 3195	0 / 0	0 / 0
1983	1 / 850	1 / 1120	0 / 0	0 / 0
1984	1 / 800	5 / 5613	0 / 0	0 / 0
1985	1 / 850	3 / 3470	0 / 0	0 / 0
MIDDLE ATLANTIC TOTAL	7 / 5500	17 / 18136	3 / 2056	0 / 0
EAST NORTH CENTRAL REGION				
1977	3 / 1600	1 / 906	3 / 1673	0 / 0
1978	11 / 3170	1 / 1050	3 / 1080	0 / 0
1979	6 / 1882	3 / 2966	2 / 1285	0 / 0
1980	6 / 2010	3 / 3402	0 / 0	0 / 0
1981	5 / 1695	3 / 2881	0 / 0	0 / 0
1982	8 / 3281	6 / 5664	0 / 0	0 / 0
1983	3 / 1853	1 / 904	0 / 0	0 / 0
1984	2 / 630	5 / 5388	0 / 0	0 / 0
1985	4 / 1725	4 / 4074	0 / 0	0 / 0
EAST NORTH CENTRAL TOTAL	48 / 17926	27 / 27235	8 / 4033	0 / 0
WEST NORTH CENTRAL REGION				
1977	8 / 3739	0 / 0	0 / 0	0 / 0
1978	4 / 2420	0 / 0	0 / 0	0 / 0
1979	4 / 1876	0 / 0	0 / 0	0 / 0
1980	4 / 1254	0 / 0	0 / 0	0 / 0
1981	7 / 3662	1 / 1150	0 / 0	0 / 0
1982	4 / 1620	1 / 1150	0 / 0	0 / 0
1983	2 / 720	2 / 2200	0 / 0	0 / 0
1984	2 / 980	1 / 350	0 / 0	0 / 0
1985	1 / 100	1 / 1260	0 / 0	0 / 0
WEST NORTH CENTRAL TOTAL	36 / 16971	6 / 6210	0 / 0	0 / 0

SUMMARY OF NEW STEAM UNITS PROJECTED FOR 1977–1985
(Continued)

	COAL NO OF UNITS / CAP (MW)	NUCLEAR NO OF UNITS / CAP (MW)	OIL NO OF UNITS / CAP (MW)	GAS NO OF UNITS / CAP (MW)
SOUTH ATLANTIC REGION				
1977	1 / 280	4 / 3347	3 / 1531	0 / 0
1978	1 / 870	2 / 2114	1 / 525	0 / 0
1979	2 / 1026	3 / 2883	2 / 390	0 / 0
1980	3 / 2646	0 / 0	2 / 1210	0 / 0
1981	2 / 1161	3 / 3029	1 / 775	0 / 0
1982	3 / 2143	2 / 1955	3 / 1623	0 / 0
1983	2 / 1320	1 / 1150	0 / 0	0 / 0
1984	4 / 2455	4 / 4470	0 / 0	0 / 0
1985	6 / 3800	4 / 4790	0 / 0	0 / 0
SOUTH ATLANTIC TOTAL	24 / 15701	23 / 22746	12 / 6074	0 / 0
EAST SOUTH CENTRAL REGION				
1977	4 / 1750	2 / 1974	0 / 0	0 / 0
1978	4 / 1232	1 / 1148	0 / 0	0 / 0
1979	2 / 450	3 / 3132	0 / 0	0 / 0
1980	3 / 1540	3 / 3640	0 / 0	0 / 0
1981	3 / 1762	1 / 1243	0 / 0	0 / 0
1982	1 / 662	0 / 0	0 / 0	0 / 0
1983	2 / 1162	2 / 2466	0 / 0	0 / 0
1984	7 / 3991	4 / 4949	0 / 0	0 / 0
1985	3 / 2151	2 / 2518	0 / 0	0 / 0
EAST SOUTH CENTRAL TOTAL	29 / 14716	18 / 20940	0 / 0	0 / 0
WEST SOUTH CENTRAL REGION				
1977	5 / 2629	0 / 0	0 / 0	8 / 1436
1978	4 / 2543	1 / 912	0 / 0	0 / 0
1979	8 / 4152	0 / 0	1 / 480	1 / 100
1980	12 / 5830	1 / 1250	0 / 0	0 / 0
1981	7 / 4410	3 / 3255	0 / 0	0 / 0
1982	5 / 2253	2 / 2400	0 / 0	0 / 0
1983	7 / 4190	2 / 2090	0 / 0	0 / 0
1984	6 / 3020	0 / 0	0 / 0	0 / 0
1985	7 / 4380	2 / 2350	0 / 0	0 / 0
WEST SOUTH CENTRAL TOTAL	61 / 34047	11 / 12257	1 / 480	9 / 1536
MOUNTAIN REGION				
1977	1 / 415	0 / 0	0 / 0	0 / 0
1978	5 / 1535	0 / 0	0 / 0	0 / 0
1979	8 / 2521	0 / 0	0 / 0	0 / 0
1980	5 / 2300	0 / 0	0 / 0	0 / 0
1981	5 / 2296	0 / 0	0 / 0	0 / 0
1982	5 / 1720	1 / 1270	0 / 0	0 / 0
1983	6 / 2680	0 / 0	0 / 0	0 / 0
1984	3 / 1650	1 / 1270	0 / 0	0 / 0
1985	6 / 2512	0 / 0	0 / 0	0 / 0
MOUNTAIN TOTAL	44 / 17989	2 / 2540	0 / 0	0 / 0
PACIFIC REGION				
1977	0 / 0	2 / 2120	0 / 0	0 / 0
1978	0 / 0	0 / 0	1 / 292	0 / 0
1980	1 / 500	1 / 1250	0 / 0	0 / 0
1981	0 / 0	1 / 1140	0 / 0	0 / 0
1982	0 / 0	1 / 1250	0 / 0	0 / 0
1983	0 / 0	4 / 4910	0 / 0	0 / 0
1984	0 / 0	1 / 950	0 / 0	0 / 0
1985	0 / 0	4 / 5100	0 / 0	0 / 0
PACIFIC TOTAL	1 / 500	14 / 16728	1 / 292	0 / 0

FACTS ABOUT THE FEA PROGRAM TO CONVERT EXISTING ELECTRIC GENERATING PLANS BACK TO COAL

1. Steps in the Process. Once FEA identifies promising candidates (after considering plant capacity and condition, coal and transportation availability, economics, etc.), the following steps are needed for each plant:
   - FEA issues a Notice of Intent (NOI) to issue an order prohibiting the use of fuel other than coal.
   - FEA holds public hearing on proposed order.
   - FEA issues the Prohibition Order (PO).
   - FEA begins an Environmental Assessment or Environmental Impact Statement (EIS) on each order.
   - EPA, if it so concludes, certifies that the ordered conversion can be accomplished within air quality requirements & standards.
   - When FEA's environmental analysis is completed (including hearings for EIS's), FEA can issue a Notice of Effectiveness (NOE) which defines the date and schedule for implementing the order.
   - FEA enforces order -- which should lead to burning of coal.

2. Elapse Time. FEA estimates that a period of 4 to 8 years is required to achieve forced conversion, depending on many factors including whether orders are challenged by the utility or others.

		Approx. No. of Units	Sites	Approx. Capacity (megawatts)
3.	Potential Candidates for Conversion Back to Coal.			
	. Boilers identified as potential candidates	680		62,600
	. Rejects - considered too old (built before 1950) or too small (25 MGW or less)	425	80	21,700
4.	FEA's First Round Orders.	74	32	11,296
	EPA Conclusions on air quality on 1st round.			
	. Eligible for immediate coal use	11		938
	. Can convert only if additional pollution control equipment installed	51		7,705
	. No conclusion yet reached	12		2,653
5.	FEA's Second Round Orders (NOI's April 1977).	31		4,686
6.	Potential Future Orders, if Authority Extended. (Identified by FEA contractor as of March 77)	148		25,000

7. No coal is being burned in reconverted plants as a result of an FEA order.

8. However, utilities -- especially those in round one that can meet environmental requirements -- voluntarily have increased their use of coal. Specifically:

	Units	Mega-watt capacity	Tons of coal burned 1973	1975	Coal as % of total fuel used 1973	1975
			(000 tons)			
1st Round (Totals)	(74)	(11,296)	(4,386)	(6,386)	(16%)	(29%)
. EPA-cleared units	11	938	899	1,253	36%	69%
. More pollution control needed	51	7,705	2,853	4,239	15%	29%
. No EPA decision	12	2,653	634	894	11%	18%
2nd Round-NOI's						
. Issued April 1977	31	4,686	568	1,205	5%	12%

FPC does not yet have available the unit by unit data for 1976, but overall plant data for those plants where the above units are located show that coal use increased substantially in 1976 over 1975 for all categories in the first round -- with percent of power generated by coal jumping from 29% in 1973 to 36% in 1975 and 48% in 1976.

9. Estimated 1978 Funding Required for FEA Program: $5.8 million.

10. More detailed summary of data for plants and units covered by FEA Orders and Notices of Intents is provided in the summary table on the next page. Plant by plant data are available in an NCA May 1977 analysis.

SUMMARY

Category Round One	Installed Capacity: Total Plant (MW)	Installed Capacity: Unit(s) Effected (MW)	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 Tons)	% Generation by Coal	% Generation by Oil	% Generation by Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons)	% Generation by Coal	% Generation by Oil	% Generation by Gas
11 units certified to burn coal immediately	1,893	938	1973	8,714	1,473	33	31	37	4,592	899	36	20	44
			1975	5,612	1,816	61	9	30	3,714	1,253	69	-	31
			1976	6,517	2,568	76	5	19					
51 units - can burn coal after equipment modification	11,340	7,705	1973	57,014	7,940	33	54	13	37,813	2,853	15	69	16
			1975	45,244	8,654	41	49	10	30,618	4,239	29	61	10
			1976	45,492	11,300	55	39	6					
12 units - no decision made	4,232	2,653	1973	16,755	655	10	89	1	14,249	634	11	87	2
			1975	17,035	1,218	16	80	4	11,526	894	18	79	3
			1976	18,871	1,583	20	80	1					
Total 74 Round One Units 1/	17,465	11,296	1973	82,483 1/	10,068 1/	29	59	12	56,654	4,386	16	70	14
			1975	67,891 1/	11,688 1/	36	53	11	45,858	6,386	29	61	10
			1976	70,880 1/	15,451 1/	48	47	5					
Round Two													
NOI's issued April, 1977 31 units	7,346	4,686	1973	37,021	599	4	82	14	27,733	568	5	87	8
			1975	33,660	1,494	10	79	11	23,937	1,205	12	82	6
			1976	31,449	789	5	84	11					

1/ Total plant statistics include some duplication of data.

NATIONAL COAL ASSOCIATION

Coal Building | 1130 Seventeenth Street, Northwest | Washington, D. C. 20036 | (202) 628-4322

CARL E. BAGGE
president

March 10, 1977

MEMORANDUM TO NCA MEMBERS

FROM: Carl E. Bagge

The Federal Power Commission has just completed the most extensive study ever undertaken by a federal agency on new coal supply for new electric generating units. The attached study, "Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985," was done by combining existing data with a phone survey to all of the power companies planning new coal-fired units. The base year is 1975 and the study covers a ten-year period. The major findings were:

1. The annual amount of coal required by the new units is 173.9 million tons in 1980 and 357.7 million tons in 1985. (The 1985 figure includes the 1980 amount.)

2. The amount of this coal already under contract is 85 percent in 1980 and 68 percent in 1985. See pages 34-37 for a <u>unit by unit</u> breakdown on the amount of coal contracted.

3. The average length of contracts signed was (by coal-producing area):

Appalachia	20 years
Texas	35 years
Western	26 years

4. The projected breakdown by mode of transport is as follows:

	1980	1985
Railroad	65%	61%
Barge	10	8
Truck & Conveyor Belt (Mine-mouth)	25	28
Pipeline	-	3

NATIONAL COAL ASSOCIATION

5. The percentage of coal with a transportation contract by mode of transport is as follows:

	1980	1985
Railroad	57%	33%
Barge	66	66
Truck & Conveyor Belt	92	78
Pipeline	-	-

6. The following general points were also indicated by the study:

(a) The further you go into the future, the less coal is under contract.

(b) The average length of transportation contracts is for the duration of the supply contracts.

(c) 94 percent of the coal to be produced West of the Mississippi is projected to be used West of the Mississippi.

(d) Contractual agreements for transportation are not always concluded simultaneously with supply contracts.

(e) Only a relatively small share of the total projected rail shipments, particularly from Appalachia to geographic regions in the eastern United States, is committed to contract. The level of contracts is also low for rail shipments from the Northern Great Plains, although not as low as from Appalachia.

(f) The bulk of the shipments by barge will be from Appalachia, and to a lesser extent from the Interior Basin, to various regions in the East.

NATIONAL COAL ASSOCIATION

Memorandum to NCA Members
March 10, 1977
Page 3

(g) Shipments by truck and belt, reflecting the extent of mine-mouth plant developments, will take place almost entirely in the West.

(h) Coal deliveries across the Great Lakes to new units in the East North Central Region will originate in the Northern Great Plains and the first leg of the shipments will be by rail.

(i) The pipeline deliveries are projected for proposed coal-slurry shipments from the Rockies to plants in the Mountain Region (from Utah to Utah and to Nevada).

Also attached are two tables NCA has constructed based on some of the report's most pertinent data.

I hope that this information will be helpful to you.

CEB:vh

TABLE 1.

ORIGIN AND AMOUNT OF COAL
UNDER CONTRACT FOR NEW UNITS

APPALACHIA		1980	Coal % Contract	1985	Coal % Contract
Dist.	State				
1	PA	1.3	100	3.2	41
4	OHIO	10.5	72	11.9	68
6	W VA	.4	100	.4	0
8	KY, VA, TN, W VA	9.5	36	30.1	32
13	AL, GA, TN	1.7	58	6.6	46
	APPALACHIA TOTAL	23.4	58	52.2	43
INTERIOR					
Dist.	State				
9	W KY	8.4	96	12.0	82
10	IL	11.7	99	15.9	95
11	IN	3.2	100	8.5	66
15	MO, OK	.4	100	2.2	21
	INTERIOR TOTAL	23.7	98	38.6	80
WESTERN					
Dist.	State				
15	TX	21.4	91	51.4	76
16	CO	3.8	97	4.3	97
18	NM	9.1	100	18.3	94
19	WY	55.6	90	92.6	78
20	UT	4.5	80	15.8	85
21	ND	8.7	100	18.1	100
22	MT	19.3	83	48.4	53
	WESTERN TOTAL	122.4	91	248.9	76
	UNKNOWN	4.4		17.8	
	US	173.9	85	357.7	68

TABLE 2.

PROJECTED DELIVERY MODE OF COAL TO NEW UNITS 1980

(Million Tons)

Mode/Region	Appalachian	Percent Regional Total	Interior	Percent Regional Total	Western	Percent Regional Total	U. S. Total	Percent of Total
Railroad	9.8	41.9	18.5	78.1	81.7	66.7	110.0	64.9
Barge	11.6	49.6	3.6	15.2	1.0	0.9	16.2	9.5
Truck & Conveyor Belt	2.0	8.5	1.6	6.7	39.7	32.4	43.3	25.6
	23.4	100.0	23.7	100.0	122.4	100.0	169.5	100.0

PROJECTED DELIVERY MODE OF COAL TO NEW UNITS - 1985

(Million Tons)

Mode/Region	Appalachian	Percent Regional Total	Interior	Percent Regional Total	Western	Percent Regional Total	U. S. Total	Percent of Total
Railroad	34.1	65.3	28.2	73.1	145.3	58.4	207.6	61.1
Barge	16.0	30.7	6.8	17.6	5.4	2.2	28.2	8.3
Truck & Conveyor Belt	2.1	4.0	3.6	9.3	88.4	35.5	94.1	27.7
Pipeline	-	-	-	-	9.8	3.9	9.8	2.9
	52.2	100.0	38.6	100.0	248.9	100.0	339.7	100.0

NATIONAL COAL ASSOCIATION

Coal Building | 1130 Seventeenth Street, Northwest | Washington, D. C. 20036 | (202) 628-4322

May 23, 1977

CARL E. BAGGE
president

Honorable John D. Dingell, Chairman
Subcommittee on Energy and Power
Committee on Interstate and
  Foreign Commerce
U. S. House of Representatives
Washington, D. C. 20515

Dear Chairman Dingell:

Thank you for the opportunity to respond to the very perceptive set of questions enclosed with your letter of May 18, 1977, concerning Section F of H.R. 6831.

Our responses, which include considerable data bearing on the issues that you raise, are enclosed with this letter. We have taken the liberty of providing, as a part of our responses, certain introductory data which point out that most, if not all, of the President's goal of increased coal production and use would occur under voluntary plans that are well along -- without the need for continuing a burdensome, unnecessary and costly regulatory program. In short, the marginal contribution over and above what would be achieved under voluntary plans is very small. The costs of a mandatory program -- particularly when the bureaucracy, delays, etc. are considered -- would be high.

Since it may seem unusual for the coal industry to oppose a program that has the objective of increasing coal use, we have taken special care to provide information that will explain our reasons for opposing the program. We hope that the information will be useful to you.

Sincerely,

Carl E. Bagge

Carl E. Bagge

Enclosure

BACKGROUND INFORMATION AND RESPONSES TO QUESTIONS RELATING TO SECTION F OF H.R. 6831 ON COAL CONVERSION

FOR

THE ENERGY AND POWER SUBCOMMITTEE OF THE HOUSE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

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CURRENT SITUATION AND PLANS FOR INCREASED COAL PRODUCTION AND USE

Certain facts about plans for and constraints upon increased coal production and use are important as background for considering whether Section F of H.R. 6831 is necessary and what its marginal contribution might be.

1. The goal of increasing coal production and use by at least 400 million tons by 1985 is modest because plans for even larger amounts are well along. The goal of an increase of 400 million tons over the 665 million tons of 1976 could easily be exceeded if constraints are reduced or avoided. The goal is modest because:

   On the demand side:

   - Utilities have already reported to the FPC plans for voluntarily bringing on line 250 new coal-fired electric generating units by 1985 -- which units will require about 390 million tons of additional coal in 1985.

   - In a study in November 1976 covering 211 of these 250 units, FPC found that 68% of the coal required in 1985 was already under contract.

   - Utilities are voluntarily converting existing plants to the use of coal where it is practicable, makes sense economically, and can be done within environmental constraints. For example, even though no coal is being burned due to an FEA order, the 74 units covered by FEA's first round orders were already using coal for more than 29% of its fuel in 1975 -- up from 16% in 1973 -- and the percentage was even higher in 1976 -- probably in the neighborhood of 50%.

   - Major industrial users are making a major shift to boilers that can burn coal in their plans for new units reported to FEA.

   - Industrial coal use in existing facilities is increasing voluntarily and rapidly, according to Bureau of Mines' estimates which show a 19% increase from January 1977 over January 1976.

   On the supply side:

   - Production has been demand-limited for years. Coal industry could have produced a minimum of 50-60 million additional tons of coal in 1976 -- over and above the 665 million tons produced.

- The FPC study conducted in November 1976 showed that 68% of the coal required in 1985 was already under contract -- so mining as well as user plans are well along.

- An NCA survey in August 1976 revealed plans for new mine expansions and additions of 500 million tons by 1985.

- The FPC study showed that a large share of 1985 coal was also covered by transportation contracts.

2. The principal constraints that could make it difficult to achieve the goal of increasing the use of coal and reducing reliance on natural gas and oil are:

 · On the demand side, environmental and other requirements which discourage, delay or prevent constructing new facilities or converting existing facilities to the use of coal, principally:

  - Air quality requirements, including

   · Existing Federal and State air quality requirements which are tighter than necessary to meet Federal health standards.

   · Requirements proposed by the Administration or being considered in the Congress which are even more rigorous including those concerned with areas already meeting air quality standards (non-significant deterioriation areas) and those not meeting standards (non-attainment areas).

  - State utility commission regulations which discourage capital investments in new facilities, including pollution control equipment (e.g., not allowing construction work in progress in rate base) and encourage use of higher priced fuel -- such as imported oil.

  - Federal regulations which hold domestic oil and natural gas prices at artifically low levels.

 · On the supply side:

  - Federal Surface Mining legislation -- which could cut expected production and prevent mining of some of the Nation's most accessible reserves. For example, an Administration supported amendment adopted on the House floor would prohibit mining affecting alluvial valley floors. An independent study performed for CEQ and EPA indicated such a prohibition would prevent more than 200 million tons of production expected in 1985. The Senate-passed prohibition on mining affecting prime agricultural lands would preclude considerable mining in the Mid-West, even though the lands involved can be reclaimed and restored to high-yield uses. (Annually, according to an OMB study, about 1 million acres of prime farm lands are taken out of production -- most permanently -- for highways, urban development, etc. Surface mining affects -- only temporarily -- about 28,000 acres of prime agricultural lands, which can be reclaimed.)

- De facto moratorium on leasing of Federal coal lands -- which has been in effect since 1971. Coal must be mined in both the East and West and by surface and deep mining to meet expected demands. Over half of the Nation's reserves are on Federal lands, primarily in the West.

- Proposed new mine safety requirements (by Interior Department) which would not contribute to safety but which would further reduce productivity. (Productivity has declined in underground mines from 15.6 tons per man per day in 1969 to 8.5 in 1976.)

- Wildcat strikes which have grown rapidly (from about 500,000 lost man days in 1973 to more than 2 million in in 1976 and an even greater rate in 1977.) This problem must be resolved by labor and management in the coal industry.

PART A - GENERAL QUESTIONS

Question #1

Q: We request your views, comments and recommendations concerning the provisions of Part F of H.R. 6831.

A: In summary, the coal industry favors strongly the objective of increasing coal production and use but it strongly opposes a mandatory program to force coal use such as is proposed in Section F of H.R. 6831 -- for several reasons:

1. The bill does nothing to deal with the constraints and obstacles that have held down the demand for coal and which could be made even worse under proposals now pending. These constraints are discussed on page 2 and include:

   - Unnecessarily tight air quality requirements and uncertainties which have delayed investments in pollution control systems.

   - State regulatory biases against investment in coal-related facilities and in favor of higher cost oil.

2. The proposed regulatory program would add little, if any, in increased coal use over what will be achieved voluntarily under plans that are well along -- yet the program has many disadvantages. More specifically, the justifications for opposing a mandatory coal use program are:

   a. A mandatory program would add little to the voluntary trend away from oil and gas in utilities and industry.

      - In the case of new electric utility plants, our computer analysis (summary at Appendix A, page 29) of data reported to the FPC by utilities on plans for new steam-generating facilities planned to come on line by 1985 shows:

        - 250 new coal-fired units, providing 123 thousand megawatts of capacity. (These are listed in Appendix B.)
        - 125 new nuclear units providing 135 thousand megawatts.
        - No oil-fired units expected after 1982. 26 units providing 13.5 thousand megawatts are planned by 1982.
        - No gas-fired units expected after 1979. 9 units supplying 1.5 thousand megawatts are planned for 1977 and 1979.

      - In the case of existing electric generating plants, no coal is being burned as a result of an FEA order under the existing program -- yet our analysis (summary at Appendix C, page 38) shows that utilities are voluntarily switching to coal. For example, the 11 units in FEA's first round selections which have been certified by EPA as able to burn coal within environmental requirements were using coal for 69% of their fuel needs in 1975 -- compared to 36% in 1973. The percentage was undoubtedly higher in 1976. (Firm data will be available from FPC soon.)

      - Also, in the case of many existing electric generating plants, it will not be practicable or feasible to switch back to the use of coal. In fact, some utilities have made clear that they will oppose FEA forcing attempts. It seems clear that switching is taking place voluntarily in large part due to higher prices for intrastate natural gas and imported oil and uncertainty of supplies of these fuels.

- In the case of new industrial facilities, less data are available (FEA is yet to release summaries of the data it has collected over the past 5 months from firms planning new fuel burning installations), but data reported by the American Boiler Manufacturers Association show a trend toward new facilities with coal-burning capability.

- In the case of existing industrial facilities:

  - Conversions to coal are virtually impossible without installing new units if the existing unit never had coal-burning capability.
  - Conversions back to coal may not be practicable, e.g., due to need for handling and storage facilities.
  - Despite these constraints, the Bureau of Mines' data show a 19% increase in industrial use of coal from January 1976 to January 1977.

b. Accomplishments of the 3-year old FEA program do not justify continuation or expansion. The FEA conversion program -- though manned by dedicated and well-intentioned people -- has not made a significant contribution to increased coal use. No coal is yet being burned as a result of an FEA order. (Pertinent facts on the program included in Appendix C, page 38). The incremental value of the program -- beyond what will be done voluntarily -- is negligible or absent. The cost to taxpayers is high: $5.8 million in FY 1978 and this will increase if the authority is extended.

c. Efforts to force conversion of existing facilities can detract from much greater voluntary use of coal in new plants.

  - New electric generating units are larger, more efficient, and use more (i.e., most coal-fired units are base load units) and it is easier and cheaper to meet environmental requirements. The 250 new coal-fired units already planned average about 500 megawatts.

  - Existing plants on which FEA has focused attention are older, smaller and less used -- and their use is declining steadily as new base load units come on line. As the data in Appendix C show (a) average size of units is small, and (b) their use is declining. Specifically:

	Average size of unit (megawatts)	Estimated generation (million kwh)	
		1973	1975
· First Round (totals)	152	56,700	45,900
- EPA cleared units (11)	85	4,600	3,700
- More pollution controls needed (51)	151	37,800	30,600
- No EPA decision (12)	221	14,200	11,500
· Second Round (31)	151	27,700	23,937

- Efforts to force conversions of existing plants can be expected to divert capital and manpower from construction of new units.

- Objective should be reduced use of oil and natural gas -- not conversion for the sake of conversion. Focus should be on running new and existing coal-fired plants more and running oil and gas units less.

d. A new or expanded regulatory program and bureaucracy are unnecessary and undesirable. A major regulatory program and bureaucracy would flow from the provisions of Section F of H.R. 6831.

- The bill attempts to shift the burden of proof to utilities and industrial organizations but there would remain a need for regulations and people -- particularly to handle the numerous exceptions and exemptions. Implementing Section F would mean regulations, orders, assessments, perhaps impact statements, evaluations, administrative costs; high potential for litigation if fuel users, their customers or others affected by enforcement actions disagree; and a large staff of Federal employees.

- Decisions about the desirability and feasibility of using a particular fuel for a utility or industrial plant require knowledge of specifics in numerous situations that cannot reasonably be expected or found in people who would administer the program -- often thousands of miles from the real world situation.

e. Mandatory conversion requirements would lead to Federal coal allocation and price controls. H.R. 6831 would provide authority for coal allocation. The Energy Supply and Environmental Coordination Act of 1974 (ESECA) which Section F would amend already has provided the basis for FEA's assertion that it has allocation and price control authority, and FEA regulations prescribing the circumstances under which it would become operative have already been adopted.

The concern is not with inability of producers to supply needed coal. Instead, it is to be expected that a user ordered to switch to coal who didn't want to could claim that he could not obtain coal at a price he found reasonable. FEA might then conclude that allocation -- followed by price controls -- is the logical answer.

Allocation and price controls have had damaging effects in both the oil and natural gas industries -- distorting markets, reducing competition, reducing incentives for new production and for new investments -- and encouraging inefficient uses. Effects could be as bad for coal. Price controls on coal producers in the 1971-1973 period were responsible for operating losses by major companies. This prevented expansion of production capacity and contributed to temporary market distortions. Such losses cannot help but discourage increased investments needed to expand coal production.

Recommendations are that:

- Section F of H.R. 6831 not be passed by the Congress.
- An alternative program for encouraging voluntary use of coal -- as outlined in a formal statement to the Subcommittee on May 25 -- be adopted.

Question #2

Q: Please identify specific provisions that give you concern and provide, if possible, proposed amendments to meet your concerns.

A: The entire Section F is unnecessary. Specific bill language to implement the recommended alternative program will be provided to the Subcommittee if desired.

Question #3

Q: 3(a) - How much coal was produced (by tons) in the United States in 1974, 1975, 1976?

A:

	Bituminous and Lignite	Anthracite	Total
	(000 Tons)		
1974	603,406	6,617	610,023
1975	648,438	6,203	654,641
1976 p/	665,000	6,200	671,200

Q: 3(b) - How much coal was exported (by tons) in those years?

A:

	Bituminous and Lignite Exported	Exports for Metallurgical Use	Percent Total Exports for Met Use
	(000 Tons)		
1974	59,926	51,666	86.2%
1975	65,669	50,620	77.1%
1976 p/	59,406	NA	NA

Q: 3(c) - What were the principal markets for coal in the United States, 1975, 1976?

A:

	1975		1976 p/	
Market	Quantity 1/ (000 Tons)	Percent Total	Quantity 1/ (000 Tons)	Percent Total
Electric Utilities	403,249	64.8%	445,750	67.9%
Coking Coal	83,272	13.4	84,324	12.8
General Industrial	62,498	10.0	60,505	9.2
Retail Deliveries	7,282	1.2	6,900	1.1
Export	65,669	10.6	59,406	9.0
Total	621,969	100.0%	656,885	100.0%

p/ Preliminary numbers.

1/ Bituminous and lignite only.

Q: <u>3(d)</u> - How much coal was produced by deep, surface mining, 1974, 1975, 1976?

A:

	Deep	Surface	Total
	(000 Tons)		
1974	277,309	326,097	603,406
1975	292,826	355,612	648,438
1976 p/	292,384	372,616	665,000

Note: Bituminous and lignite only.

Q: <u>3(e)</u> - How much coal was produced from (i) Federal lands, (ii) Indian lands, (iii) other lands in those years?

A:

	Federal Lands	Indian Lands	Other Lands	Total
		(000 Tons)		
1974	20,600	11,500	571,306	603,406
1975	26,900	16,700	604,838	648,438
1976 p/	NA	NA	NA	665,000

Note: Bituminous and lignite only.

Q: <u>3(f)</u> - How much coal was produced from States east of Mississippi, west of Mississippi, in those years?

A:

	East of Mississippi	West of Mississippi	Total
	(000 Tons)		
1974	511,500	91,906	603,406
1975	537,504	110,934	648,438
1976 p/	530,003	134,997	665,000

Note: Bituminous and lignite only.

<u>Question #4</u>

Q: <u>4(a)</u> - What are the estimates of coal production in the U.S. for 1977, 1980, 1985 and 1990?

A: A wide variety of projections of expected or desired coal production have been made over the past few years -- and all vary in assumptions used, objectives, extent to which constraints on supply and/or demand are considered and in other ways. Examples of projections include:

- <u>FEA</u> - 1977 National Energy Outlook (Draft)

  - 1985: 1,050 million tons.
    This reference case projection is based on legislation and policies in effect as of November 1976. Includes conversion effects of ESECA.

- <u>Department of the Interior</u> (Bureau of Mines) from "Energy Through the Year 2000."

  - 1980: 806 million tons
  - 1985: 998 million tons
  - 2000: 1,660 million tons

- <u>Exxon U.S.A.</u> - Energy Outlook, 1977-1990

  - 1980: 814 million tons
  - 1985: 1,068 million tons
  - 1990: 1,477 million tons

- <u>Shell</u>, the National Energy Outlook 1980-1990.

  - 1980: 700 million tons demand, 870 million tons supply potential
  - 1985: 916 million tons demand, 1,102 million tons supply potential
  - 1990: 1,190 million tons demand, 1,260 million tons supply potential

- <u>President Carter's National Energy Plan</u>

  - 1985: From about 1,065 to 1,230 million tons.

- <u>NCA Estimates</u>

  - NCA's economics committee has estimated <u>1977</u> use to be about 700 million tons, and production to be 670 million tons.

  - Depending upon the effects of constraints and, hopefully, incentives for coal production and use, future production could easily range from:

    - 1980: 820 - 825 million tons
    - 1985: 1,050 - 1,250 million tons
    - 1990: 1,400 - 1,600 million tons

Question #5

Q: 5(a) - Dr. Hans H. Landsberg at Resources for the Future recently said that to meet the National Energy Plan, the coal industry must increase the 1976 coal production by 665 million tons by 1985. He said it was "highly unlikely, if not impossible" for the coal industry to increase output by 60 million tons annually. Your views and comments on this statement would be appreciated.

A: The President's goal for increased coal production and use -- above the 665 million tons achieved in 1976 -- appears to range from 400 million tons (address to Congress) and 565 million tons (page 95 of the National Energy Plan).

The chances of meeting these goals depends directly on the impact of constraints -- principally those applied by the Government and listed on page 2, above -- which affect supply and demand for coal.

Assuming obstacles and constraints can be reduced or avoided, the coal industry is highly confident that the President's higher goal can be achieved -- principally for the reasons cited on page 1 above which, to summarize and supplement, are:

- 250 new coal-fired electric generating units -- which would require about 390 million tons of coal in 1985 -- have already been reported to FPC.
- FPC found that nearly 70% of the coal required for the 211 units studied in November 1976 was already under contract -- meaning that plans for supply and use are well along.
- Additional coal is being used by existing utility plants.
- Industry is increasing use of coal and planning more installations with coal using capacity.
- Demand for coking coal is expected to increase.
- Technology for new ways of using coal -- both for combustion and feedstock -- are emerging.
- On the supply side, an NCA survey of its members showed plans for mine expansion and additions of more than 500 million tons by 1985. Compared to other projections, the NCA survey is conservative, as shown in Appendix D which compares similar mine expansion surveys. Plans for new mine additions range from NCA's 500 million tons to the

Bureau of Mines' 714 million tons. However, all these projections must be evaluated in light of newer constraints on production such as the pending surface mining legislation and the moratorium on coal leasing.

Q: 5(b) - What are the economic constraints for the coal industry's increasing output by 665 million tons by 1985?

A: Capital requirements for bringing new mines into production will be substantial but not insurmountable. In February 1976, FEA estimated that 1975-84 capital requirements for the coal production industry would be about $17.7 billion (P.309, National Energy Outlook), in 1975 dollars. This estimate was increased to $23 billion in FEA's Draft Executive Summary of the 1977 National Energy Outlook. This estimate contrasts with capital spending of $6.5 billion between 1965 and 1974 (1975 dollars). Roughly similar -- but often higher -- estimates have been made by others.

The size of this problem is reduced somewhat by the plans that have already been made to proceed with mine additions and expansions. However, the problem could be made much more manageable with incentives such as rapid amortization of mining equipment, an increased depletion allowance, and an increased investment tax credit.

As discussed in response to a later question, the price of coal is expected to remain low relative to other fuels.

Capital requirements of utilities -- the coal industry's largest customer -- may be a more difficult problem than for the coal producing industry. Also, risk capital is slow in coming for commercial scale demonstrations of technologies to produce a liquid or gaseous fuel from coal -- because of uncertainties.

Q: 5(c) - What are the transportation constraints to such increased coal production?

A: The FPC study referred to earlier (summarized at Appendix C) covered transportation arrangements for coal required in 1985. That study shows that for 339.7 million tons of coal required in 1985 for which delivery mode had been projected and contract arrangements made were as follows:

	Projected delivery mode		% of tonnage covered by transportation contract
	Tonnage	% of total	
· Railroad	207.6	61.1	33%
· Barge	28.2	8.3	66%
· Truck and Conveyor belt	94.1	27.7	78%
· Pipeline	9.8	2.9	-
	307.7	100.0	

The same study showed that 57% of coal to be shipped by rail in 1980 for new plants was already under contract.

There are constraints on rail transportation in some areas of the country at present (e.g., Kentucky) and the absence of adequate rail transportation is a constraint on greater use of coal in New England States.

The President announced on April 20, 1977, his intention of appointing a Commission to study energy transportation matters and report to him by the end of the year.

Federal assistance for certain railroads and waterways undoubtedly will be required.

Passage of legislation granting eminent domain for coal slurry pipelines would be a positive step, favored by the coal industry.

Q: 5(d) - What are the environmental constraints to such increased coal production?

A: The principal environmental constraints to increased coal production are:

- Unnecessarily rigorous air quality requirements described in detail on page 2.

- Unnecessarily rigorous reclamation requirements and prohibitions on surface mining contained in surface mining legislation which has now passed the House and Senate in somewhat differing bills. For example, the Administration backed amendment adopted on the House floor to ban surface mining affecting alluvial valley floors could -- according to an independent study done for EPA and CEQ -- prevent mining of over 200 million tons of coal planned in the West for 1985. Water quality requirements which were promulgated only last month have added to uncertainties for expansion.

Q: 5(e) - What are the labor constraints to such increased production?

A: There are four factors deserving comment:

- Declining productivity - Productivity has declined steadily -- dropping in the case of underground mines from 16.5 tons per man per day in 1969 to 8.5 tons in 1976. Additional health and safety requirements are being proposed by the Interior Department which would further reduce productivity but not contribute to safety. A total review by Congress of the implementation of the Coal Mine Health and Safety Act is needed. (Oversight hearings scheduled in the House for early June.)

- Manpower for Mines - In general, the industry expects the supply of manpower to be adequate though training will continue to be a challenge.

- Supervisory manpower could be a problem because of current burdens placed on first line supervisors by mine safety regulations -- over which supervisor has no control. This has caused problems.

- Wildcat Strikes - have been a significant and growing problem -- with lost man-days growing from 500,000 in 1969 to over 2,000,000 in 1976 and the trend sharply upward in 1977 as shown in data below on man-days lost for the first few months this year. This problem must be solved by labor and management.

Man-Days Lost

	1977*	1976
January	64,300	94,300
February	233,700	91,200
March	136,800	113,800
April	196,100	74,800
Total	630,900	374,100

* Preliminary

Q: 5(f) - What lead time must be given to allow the coal industry sufficient time to meet demands for new coal that would result from Part F of H.R. 6831?

A: Part F of H.R. 6831 is not expected to provide any significant demand for coal over and above that which would result voluntarily -- as explained on pages 1 and 4-6, above. Also, as shown on those pages, contracts for nearly 70% of the coal required for new electric generating plants in 1985 is already under contract. FPC found that 85% of that required in 1980 was already under contract in November 1976.

(More)

PART B - QUESTIONS ON IMPACT OF THE PROGRAM

Question #6: Questions 6(a) through 6(d) refer primarily to impact on user industries and presumably are addressed primarily to FEA and the user industries. We would mention, in response to question 6(b) on economic impact on users, that economic impact should be favorable in many cases due to the much lower relative cost of coal compared to oil and gas and the much greater reliability of supply.

Q: 6(e) - What effect will this Part (F) have on the price of coal over the next decade?

A: Coal industry analysis and comments on price are consolidated with question 8, below, which deals in more detail with coal price matters.

Question #7: Question 7 on effect on competition among industrial firms forced to switch to coal presumably is directed to FEA and potential user industries.

Question #8:

Q: 8(a): To what extent will this program increase the price of coal and what will be the economic impact of such increased coal prices?

A: Sharply increased use of coal -- which is already being planned voluntarily -- together with increasing costs of production and rapidly declining labor productivity will undoubtedly contribute somewhat to higher coal prices. However, there are a number of factors at work which will continue to hold coal prices sharply lower than prices for oil and natural gas if those are priced at their market levels. The wide disparity between oil and coal prices is shown in the graph and chart on the next page which shows delivered prices of oil, natural gas and coal to steam electric plants from 1973 through early 1977 on the basis of $ per million Btu's. It shows that oil prices are currently more than double coal prices and that natural gas prices -- even though still under controls -- began to exceed coal in September 1975, but are still well below oil. The several factors that have will continue to hold coal prices at relatively lower levels include:

- The large number of economic units -- over 3,000 -- in competition in the coal industry. The industry has been and continues to be highly competitive.*

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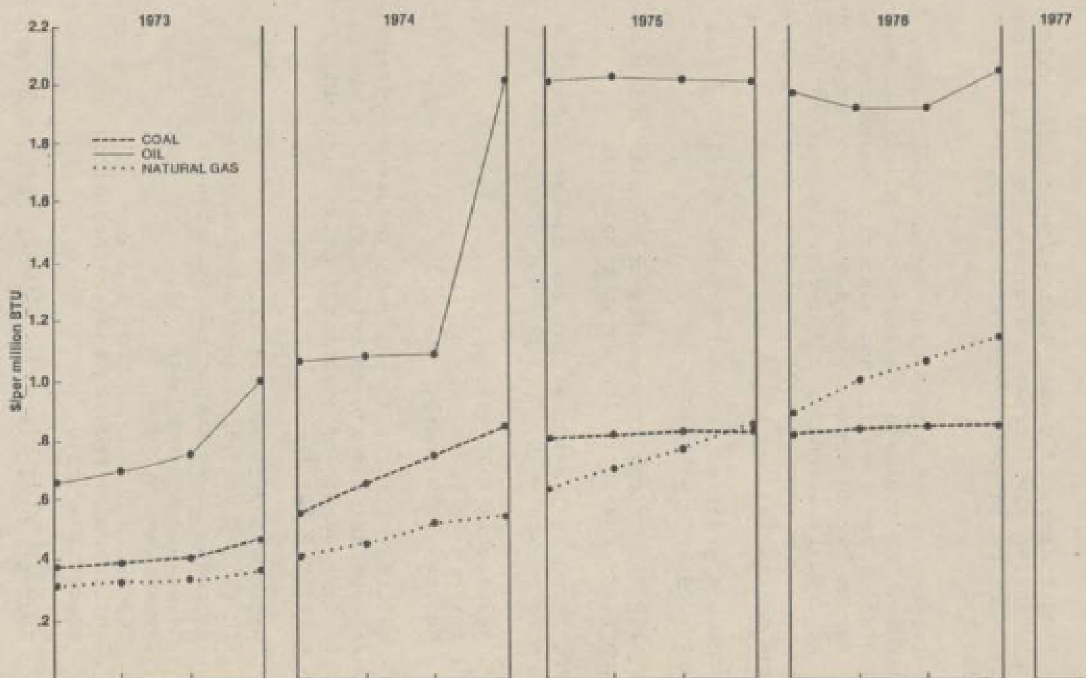
* For additional information on coal price history and outlook, see Council on Wage and Price Stability (Executive Office of the President), A Study of Coal Prices, March 1976.

Comparison of delivered prices for coal, oil and natural gas used by utilities — in $ per million BTU's from 1973 to 1976

(Nationwide averages)



	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
COAL	.384	.396	.401	.437	.566	.664	.765	.857	.809	.813	.817	.818	.817	.843	.864	.867
OIL	.678	.706	.774	1.043	1.789	1.903	1.960	2.014	2.018	2.048	2.010	2.006	1.978	1.930	1.925	2.059
GAS	.310	.336	.340	.357	.400	.453	.516	.539	.632	.711	.790	.850	.913	1.011	1.074	1.114

. The long history of demand limited production which -- even with sharply increased demand -- could continue because of relatively unrestrained entry into the industry.

. The large share of future demand that is already under contract. As indicated earlier, FPC found that nearly 85% of coal required for new electric generating plants in 1980 is already under contract and that nearly 70% of the coal required for 223 new units studied by FPC last November for 1985 (357.7 million tons) was already under contract.

. The common practice in the industry of selling coal under long-term contracts.

- Nearly 85% of coal is usually sold under long-term contracts and about 15% in spot markets.

- FPC found in its study that the average length of contracts was -- by coal producing area:

  . Appalachia - 20 years.
  . Texas - 35 years.
  . Western - 26 years.

- Long-term contracts in the coal industry typically have escalation features but escalation is generally tied to a number of specific factors including, but not limited to: 1/

  . Wages and fringe benefits.
  . Increased contributions to welfare fund.
  . Increase in workmen's compensation and insurance.
  . Materials and supplies.
  . Royalties.
  . Taxes.
  . Influence of Federal and state legislation on production costs.

1/ Source: Analysis of Steam Coal Sales and Purchases.

With respect to economic impact of increased coal prices, the impact will have at least two favorable aspects:

- Coal prices per Btu are lower and will undoubtedly trail well behind oil and natural gas -- thus there will be a favorable impact on users' costs and to consumers -- particularly of electricity.

- Increased production and use of domestic coal, to the extent it offsets imported oil, will not only be cheaper but will keep U.S. dollars and jobs in the U.S. Each 100 million tons of coal used in lieu of imported oil would reduce the need for more than 400 million barrels of oil imports and avoid the need for the outflow of over $5 billion.

Q: 8(b) - What was the average spot price, average contract price and total coal average price in 1973, 1974, 1975, 1976?

A:

	Average Spot Price (delivered)		Average Contract Price (delivered)		Total Coal Avg. Price (delivered)	
	Per Ton	¢MMBTU	Per Ton	¢MMBTU	Per Ton	¢MMBTU
1973	$10.81	46.2	$ 8.59	39.1	$ 9.01	40.5
1974	26.55	118.8	12.00	55.5	15.46	71.0
1975	23.81	104.6	16.25	76.0	17.63	81.4
1976 p/	21.33	92.0	17.90	83.5	18.38	84.8

Note that prices are for steam coal delivered to electric utilities. (Source: FPC). p/ Preliminary.

Question #9:

Q: What will be the impact of this program in western communities that are sparsely settled?

A: There undoubtedly will be social and economic impact in some sparsely settled communities as the result of the development of energy resources nearby -- including coal. Much of it will have a favorable impact.

Several steps have been and are being taken to reduce adverse effects:

. Companies producing coal in western states have, in conjunction with the affected communities, been active in dealing with socio-economic impacts that result from new energy development. For example:

- A number of companies, including the Carter Mining Company, jointly developed the Indian Hills housing development in Gillette, Wyoming.

- The Atlantic Richfield Company sponsored the Killarney Subdivision in Gillette and a new housing development is being created by Amax Coal Company. Atlantic Richfield is also in the process of developing and rejuvenating Reno Junction, a former mining town in Wyoming, providing housing, sewage, a school and other necessities.

- Coal companies are also involved in planning for other community services. For example, Carter Mining has provided medical advisers to help develop programs to attract more doctors to Gillette and to expand existing medical facilities.

- Carter and Atlantic Richfield are also active in working with local vocational technical schools to train people for jobs in the area and both companies have given substantial scholarship support to Casper College in Casper, Wyoming.

. The Coal Leasing Act Amendments of 1976 increased the state share of royalty income from federal coal leases (from 37½% to 50%) -- which should increase revenue to areas affected.

. A number of Federal agencies have programs for planning and other assistance and -- as a result of concern about potential adverse effects and shortages of front end money for public facilities -- have made special efforts to help communities that might be affected.

Question #10

Q. Should the bill include impact aid to communities to avoid boom and bust problems? Please explain.

A. Part F of the bill should not be enacted (Part F, H.R. 8631) but the question deserves an answer. The coal industry believes that actions listed in response to question #9 will go a long way toward reducing problems. If impact aid is needed, it should be handled as a part of a more general program to assist communities impacted by resource development -- not limited only to those communities impacted by coal development.

PART C - ENVIRONMENTAL QUESTIONS

Question #11

Q: Should any firm be required to convert without first meeting ambient air quality standards?

A: The appropriate approach -- and one that would permit going farthest in meeting energy and air quality goals at the same time -- is to consider meeting national primary ambient air quality standards on a site specific basis. As state implementation plans are now written in many cases, restrictions are far more rigorous than needed to meet Federal health standards. For example, a plant may be located in an area where there is no violation of ambient air quality standards but the area happens to be part of a much larger -- and often ill-defined -- air quality control region of which some part does not meet ambient standards on some occasions. The result in such situations often is that the plant can not be permitted to use coal. This is one example of "overkill" in state requirements which should not be allowed to prevent coal use. The plant should not be allowed to convert if its emissions would result in unacceptable violation of primary health standards in its area. Otherwise, conversion should be permitted.

A key point is that reasonable steps can be taken which will permit progress towards energy and environmental objectives at the same time. However, as the Clean Air Act has been implemented, there are numerous instances where arbitrary requirements have been established which prevent reasonable actions to provide energy at reasonable costs. Those implementing actions often are not necessary to meet national health standards for ambient air quality.

Question #12:

Q: What emission estimates are available by air quality control regions to show the effect of conversion by 1980, 1985, and 1990?

A: We assume this question is directed primarily to EPA, FEA and ERDA, and perhaps to major utility and industrial fuel users. However, there are several general points that should be recognized in dealing with data on emission estimates so that there is a meaningful basis for decisions:

- Air quality regions, as they are now defined, generally are not meaningful in terms of understanding the relationship between emissions and air quality. Instead, air quality regions have been defined along geographic or political boundaries. New York State air quality officials, for example, have concluded that decisions must be based on an understanding of the relationship between emissions and the atmospheric conditions that determine the real result in terms of ambient air quality -- not on the basis of arbitrarily defined "air quality control regions."

. Those attempting to find the best answers to energy-environment conflicts -- so that progress can be made toward both objectives -- need to have available much more exacting information than is typically provided by the Federal EPA. For example, information should be provided on such factors as:

- Whether standards are being violated in particular, meaningfully defined areas, and if so:

  . Which standard (i.e., which pollutant, whether a Federal or State standard, and what is being protected by meeting the standard).

  . How often is the standard violated and for what length of time. (This is needed because many areas that "do not meet standards" often are in that condition only for a few hours and at a few times during any given year.

  . Is the deteriorated air quality condition at a level where adverse health effects are known to occur -- or instead is it in the area known as the "margin of safety" that is taken into account in setting ambient standards and which has led the EPA Administrator to set health standards at a level much tighter than needed to protect the level where health effects are believed to occur.

- When state air quality requirements are being abridged, the basis for setting the state requirements. As now widely observed, state requirements have often been set -- with encouragement from the Federal EPA -- at levels far tighter than needed to meet Federal health standards. For example, requirements established in many states (in State implementation plans or SIP's) were based on actions that would be needed to bring the dirtiest area of the state into line with ambient air quality standards. That is, the actions required to bring the dirtiest area into compliance (e.g., limits on sulfur content in fuel) have in some states been applied to all areas of the State. This is an example of "overkill" in state requirements.

- Whether sources of the pollutants of concern -- other than those emitted by energy producing facilities -- are important in determining whether ambient air quality standards are met. For example, natural sources of some pollutants (e.g., dust, hydrocarbons) apparently will preclude ever meeting ambient standards in some areas.

Questions #13

Q: 13(a): Should the environmental certification for coal conversion now required by ESECA be made by EPA or the States? What are the advantages and disadvantages of the States doing the certification?

A: As a general rule, if EPA has turned the air quality enforcement resonsibility over to a state, that state -- and not the Federal EPA -- should have responsibility for certification.

However, a decision on this issue must take into account the problem of "overkill" in some state air quality implementation plans -- as discussed earlier in response to question 12. Because of the origin and problems of the "overkill" problem (as discussed in Carl E. Bagge's May 25 statement to the subcommittee), some Federal override of states may be necessary to get reasonable balance between energy and environmental requirements.

Q: 13(b) - What provision exists in Part F or other law to provide reasonable certainty to a firm that, once substantial investment and effort is made to convert to coal under a certified clean air plan, subsequent plans would not impose additional requirements on the facility or that such additional requirements would be reasonable?

Neither Section F of H.R. 6831 nor pending Clean Air Act amendments takes adequate account of this problem.

A: This question highlights a fundamental problem that has retarded commitments and investments in pollution control equipment. That is, that the Federal EPA often seeks to force adoption of pollution control technologies with little or no assurance for the firm -- or the customers who must pay the costs involved -- that the technology will be sufficiently reliable to warrant the cost and will not be rendered obsolete or worthless by new requirements that would be established before the investment is amortized.

Q: 13(c) - What consideration has been given by FEA and EPA to the problem of storing coal and disposing of ash, particularly at facilities where coal has never been and where available land is scarce?

A: Question intended for FEA and EPA. This consideration must be taken into account and would be by a user considering coal use. Certainly, if a Government-forced approach were adopted, it is one of the practical questions that should be considered in determining capability to convert.

Q: 13(d) - What will be the impact of ash disposal on nearby communities and homes considering that it must be transported somewhere, often on poor roads, and stored?

A: Again, we assume that the question is directed to FEA and EPA. However, we would point out that the ash that will be available is an attractive resource. Such ash has long provided a good source of land fill and road base material. Much ash and flyash is sold in today's markets.

Q: 13(e) - What is the current state of the art of technology to control emissions from coal and the cost of installing and operating such technology?

A: Extensive information on this issue has been compiled by FPC, FEA, EPA and ERDA; by utility and industrial users; and by architect and engineering firms. We assume that the Subcommittee will be obtaining information from those sources.

Question #14

Q: 14(a) - To what extent does weather transport pollutants from one area to another and adversely affect lakes, rivers, wildlife, and farm lands?

A: This is an area characterized by relatively little firm scientific knowledge and great controversy among experts. The Federal Government should be spending more on objective research -- preferably through agencies and organizations that do not have a stake in the outcome -- better to define potential problems, fill gaps in knowledge and reduce the range of disagreement among experts.

As you may be aware, questions of both health and environmental effects of coal and nuclear power were considered extensively and reported on in Chapters 5 and 6 of the Ford Foundation-Mitre report entitled "Nuclear Power Issues and Choices." On many questions, the group of experts involved concluded that knowledge now available does not permit firm conclusions.

We offer the above reference as one source of information but would not necessarily conclude that it is the best available.

Q: 14(b) - Will increased use make this problem a more severe one?

A: See response to question 14(a), above.

PART D - QUESTIONS ON SPECIFIC LEGISLATIVE ISSUES

Question # 15.

Q: The Part F requires in several definitions and elsewhere (e.g., Sec. 107(a)(4)) that the Administrator issue rules. Do you agree with this approach? Should the legislation require promulgation of such rules by a date certain? Please explain your reply.

A: This question needs to be considered in the context of questions 16, 17, 18, 19, 20, 21, 22, and 24 -- all of which do an excellent job in illustrating why it is impracticable and undesirable, if not impossible, for any group of people (however bright and well-intentioned) to sit in Washington and develop and administer a program that will force decisions throughout the country to use coal.

A decision on whether or not to use coal in a particular unit in a particular location must take into account dozens of factors and problems that are known to or understood by people removed from the situation -- and often without adequate knowledge of the circumstances. The factors that should be considered involved detailed physical, economic, environmental, and other matters. Generalizations seldom apply.

The questions and the draft bill itself illustrate the problem by recognizing the need, if the bill were passed, for detailed regulations, exemptions, exceptions, reviews, assessments, permits, government staff and cost to taxpayers. Delays and litigation and frustration for all -- legislators, executive branch officials, bureaucrats, energy users, equipment suppliers and fuel suppliers -- are a virtual certainty.

Recognizing the marginal contribution of a mandatory program will be small(if any), the best course of action is to proceed with voluntary efforts and allow decisions to be made in the locations and by the people who have the knowledge and expertise needed. This would avoid the need for the bill and the inevitable regulations.

Question #16:

Q: 16(a) through (e) deal with proposed exceptions and exemptions and the possibility of requiring FEA to identify alternatives to coal conversion.

A: These questions would most appropriately be answered by potential users who would be targets of the bill.

Question #17:

Q: 17(a) through (c) deal with the Administration's proposal to exempt Federal actions under the bill from requirements that a NEPA Environmental Impact Statement be prepared.

A: We understand that one of the reasons the bill (and S.977 now pending in the Senate) has been drafted in its current manner is to try to avoid the need for FEA to prepare environmental impact statements. Apparently FEA has considered the need for EIS's a part of the reason for the absence of any demonstrated contribution from its 3-year old program.

Since voluntary actions by utilities and industry are achieving the desired goal of increasing coal use and reducing dependence on oil and gas, the EIS issue seems moot. As indicated earlier and documented in Appendices A, B and C, switches to coal are occurring without FEA's mandatory-regulatory acts.

We are aware of numerous cases where NEPA requirements have been used as delaying actions -- rather than straight forward actions to assure consideration of alternatives -- and we'd prefer that unnecessary delays and paperwork be avoided. However, we can offer no justification for the approach proposed in H.R. 6831 and S. 977 to avoid EIS's if the only real difference is who (a user or FEA) initiates the action that may warrant an EIS. If an exemption from EIS requirements is granted for coal utilization facilities, a similar exemption should be provided for coal production and preparation facilties.

Question #18

Q: 18(a) and (b) deal with criteria for exceptions, exemptions and determinations proposed by the Administration in H.R. 6831.

A: Questions apparently intended for an Administration response.

Question #19

Q: 19(a) and (b) deal with criteria for judging utility plans.

A: Questions apparently intended for an Administration response.

Question #20

Q: 20(a), (b) and (c) deal with dates for proposed prohibitions on use of natural gas in power plants, the impacts on plants by state, and exemptions and exceptions proposed.

A: Questions apparently intended for an Administration response.

Question #21

Q: Question deals with the prohibition against burning petroleum in existing electric power plants after April 20, 1977 and the allowance of a 5-year temporary exception, the costly and time consuming exception process, and the possibility of a later deadline date.

A: Only the Administration might have the answers to these.

Question #22

Q: Please review the provisions of sections 110, 111, and 113 of the bill and provide your views and comments thereon.

A: Section 110 deals with disruption of natural gas contracts and we have no specific comments to offer.

Section 111 deals with coal allocation. As indicated on pages 6 and 7 (in subparagraph (e)) in the response to question #1, we object strongly to providing any authority to FEA to allocate coal. As explained earlier, the whole mandatory approach is unnecessary and undesirable. Similar approaches in the case of oil and natural gas have had devasting effects, contributing to wasteful uses of energy, limited competition, market distortions and other effects not in the public interest.

Limited coal allocation authority for FEA in the Energy Supply and Environmental Coordination Act (ESECA) led FEA to assert authority for both coal allocation and price controls. Neither are needed or warranted -- as explained on pages 6 and 7.

Section 113 deals with emergency powers. We have no specific comments to offer.

Question #23

Q: 23(a) Please provide the report required by the Act of July 25. 1956 (70 Stat, 652) concerning part F of the bill.

A: Apparently intended for the Administration.

Q: 23(b) Please state how many persons are administering the current coal conversion program at FEA, including those in the General Counsel's office, as of May 1, 1977 and state the cost thereof for FY 1977.

A: This question is intended for FEA, but we would urge that the Subcommittee consider expanding it to include:

. A detailed statement of how FEA would propose to implement the program, what marginal benefits (over and above those that will be achieved under voluntary plans) are being promised, and a draft of proposed regulations.

. Firm estimates (approved by the President as consistent with his planned future budget requests) of the people that would be required to administer the program in each of the next 3 years and the total costs to taxpayers.

Question #24.

Q: Section 101(b)(1) of the bill states that a purpose of the Part is to assist in meeting energy needs "in a manner which is consistent, to the fullest extent practicable, with existing national commitments to protect the environment".

(i) What is meant by the words "to the fullest extent practicable"?

(ii) Is the word "existing" intended to include the clean air and water pollution amendments now being considered by Congress?

A: Question apparently intended for the Administraion.

Question #25.

Q: 25(a) - Please review the tax provisions of H.R. 6831 and indicate to what extent those tax provisions which are designed to encourage conversion to coal may affect the financial ability of a firm to convert to coal.

A: This question would be answered better by user utilities and industries' representatives. Certainly an added investment credit should provide an added incentive for conversion from gas and oil to other fuels.

However, with respect to the subject of taxes, we would point out that Title II of H.R. 6831 provides nothing in the way of direct incentives for the coal industry. Yet, the coal industry must bear the principal fuels burden for the foreseeable future. The estimates for capital requirements to double coal production over the next ten years vary from $18 to more than $25 billion, in 1977 dollars. (See answer to Question 5(b) on page 12.)

To make the coal industry more attractive to the financial community, tax incentives should be expanded by the Congress. Since Title II of the bill is within the jurisdiction of the Ways and Means Committee, suggested amendments to the Internal Revenue Code will not be detailed here. We would note that stimuli such as rapid amortization for mining equipment, an increase in the percentage depletion allowance, and an increased investment credit would contribute substantially toward the coal industry's goal of doubling production.

Q: 25(b) - In the case of a regulated utility, would those tax provisions be passed on to the rate payer?

A: Question apparently intended for government agencies and utilities.

SUMMARY OF NEW STEAM UNITS PROJECTED FOR 1977-1985

	COAL NO OF UNITS / CAP (MW)	NUCLEAR NO OF UNITS / CAP (MW)	OIL NO OF UNITS / CAP (MW)	GAS NO OF UNITS / CAP (MW)
UNITED STATES				
1977	24 / 11976	9 / 8247	8 / 4418	8 / 1436
1978	29 / 11770	6 / 6104	6 / 2497	0 / 0
1979	31 / 13062	11 / 10916	6 / 3013	1 / 100
1980	34 / 16688	9 / 10592	2 / 1210	0 / 0
1981	29 / 14986	15 / 15841	1 / 775	0 / 0
1982	27 / 13039	17 / 18034	3 / 1635	0 / 0
1983	23 / 12775	16 / 18428	0 / 0	0 / 0
1984	25 / 13536	22 / 24140	0 / 0	0 / 0
1985	28 / 15518	20 / 23570	0 / 0	0 / 0
UNITED STATES TOTAL	250 / 123350	125 / 135872	26 / 13540	9 / 1536
NEW ENGLAND REGION				
1978	0 / 0	0 / 0	1 / 600	0 / 0
1981	0 / 0	2 / 2300	0 / 0	0 / 0
1982	0 / 0	1 / 1150	0 / 0	0 / 0
1983	0 / 0	3 / 3400	0 / 0	0 / 0
1984	0 / 0	1 / 1150	0 / 0	0 / 0
NEW ENGLAND TOTAL	0 / 0	7 / 8000	1 / 600	0 / 0
MIDDLE ATLANTIC REGION				
1977	2 / 1475	0 / 0	2 / 1206	0 / 0
1978	0 / 0	1 / 880	0 / 0	0 / 0
1979	1 / 825	2 / 1935	1 / 850	0 / 0
1980	0 / 0	1 / 1050	0 / 0	0 / 0
1981	0 / 0	1 / 873	0 / 0	0 / 0
1982	1 / 700	3 / 3195	0 / 0	0 / 0
1983	1 / 850	1 / 1120	0 / 0	0 / 0
1984	1 / 800	5 / 5613	0 / 0	0 / 0
1985	1 / 850	3 / 3470	0 / 0	0 / 0
MIDDLE ATLANTIC TOTAL	7 / 5500	17 / 18136	3 / 2056	0 / 0
EAST NORTH CENTRAL REGION				
1977	3 / 1680	1 / 906	3 / 1673	0 / 0
1978	11 / 3170	1 / 1050	3 / 1050	0 / 0
1979	6 / 1882	3 / 2966	2 / 1285	0 / 0
1980	6 / 2010	3 / 3402	0 / 0	0 / 0
1981	5 / 1695	3 / 2881	0 / 0	0 / 0
1982	8 / 3281	6 / 5664	0 / 0	0 / 0
1983	3 / 1853	1 / 904	0 / 0	0 / 0
1984	2 / 630	5 / 5388	0 / 0	0 / 0
1985	4 / 1725	4 / 4074	0 / 0	0 / 0
EAST NORTH CENTRAL TOTAL	48 / 17926	27 / 27235	8 / 4038	0 / 0
WEST NORTH CENTRAL REGION				
1977	8 / 3739	0 / 0	0 / 0	0 / 0
1978	4 / 2420	0 / 0	0 / 0	0 / 0
1979	4 / 1876	0 / 0	0 / 0	0 / 0
1980	4 / 1854	0 / 0	0 / 0	0 / 0
1981	7 / 3662	1 / 1150	0 / 0	0 / 0
1982	4 / 1620	1 / 1150	0 / 0	0 / 0
1983	2 / 720	2 / 2300	0 / 0	0 / 0
1984	2 / 900	1 / 350	0 / 0	0 / 0
1985	1 / 100	1 / 1260	0 / 0	0 / 0
WEST NORTH CENTRAL TOTAL	36 / 16971	6 / 6210	0 / 0	0 / 0

SUMMARY OF NEW STEAM UNITS PROJECTED FOR 1977-1985
(Continued)

	COAL NO OF UNITS / CAP (MW)	NUCLEAR NO OF UNITS / CAP (MW)	OIL NO OF UNITS / CAP (MW)	GAS NO OF UNITS / CAP (MW)
SOUTH ATLANTIC REGION				
1977	1 / 280	4 / 3347	3 / 1531	0 / 0
1978	1 / 870	2 / 2114	1 / 525	0 / 0
1979	2 / 1026	3 / 2883	2 / 398	0 / 0
1980	3 / 2646	0 / 0	2 / 1210	0 / 0
1981	2 / 1161	3 / 3029	1 / 775	0 / 0
1982	3 / 2143	2 / 1955	3 / 1635	0 / 0
1983	2 / 1320	1 / 1150	0 / 0	0 / 0
1984	4 / 2455	4 / 4470	0 / 0	0 / 0
1985	6 / 3800	4 / 4798	0 / 0	0 / 0
SOUTH ATLANTIC TOTAL	24 / 15701	23 / 23746	12 / 6074	0 / 0
EAST SOUTH CENTRAL REGION				
1977	4 / 1758	2 / 1874	0 / 0	0 / 0
1978	4 / 1232	1 / 1140	0 / 0	0 / 0
1979	2 / 458	3 / 3132	0 / 0	0 / 0
1980	3 / 1548	3 / 3640	0 / 0	0 / 0
1981	3 / 1762	1 / 1213	0 / 0	0 / 0
1982	1 / 662	0 / 0	0 / 0	0 / 0
1983	2 / 1162	2 / 2466	0 / 0	0 / 0
1984	7 / 3991	4 / 4949	0 / 0	0 / 0
1985	3 / 2151	2 / 2519	0 / 0	0 / 0
EAST SOUTH CENTRAL TOTAL	29 / 14716	18 / 20940	0 / 0	0 / 0
WEST SOUTH CENTRAL REGION				
1977	5 / 2629	0 / 0	0 / 0	8 / 1436
1978	4 / 2543	1 / 912	0 / 0	0 / 0
1979	8 / 4182	0 / 0	1 / 460	1 / 100
1980	12 / 5830	1 / 1250	0 / 0	0 / 0
1981	7 / 4418	3 / 3255	0 / 0	0 / 0
1982	5 / 2653	2 / 2400	0 / 0	0 / 0
1983	7 / 4150	2 / 2090	0 / 0	0 / 0
1984	6 / 3030	0 / 0	0 / 0	0 / 0
1985	7 / 4380	2 / 2350	0 / 0	0 / 0
WEST SOUTH CENTRAL TOTAL	61 / 34047	11 / 12257	1 / 460	9 / 1536
MOUNTAIN REGION				
1977	1 / 415	0 / 0	0 / 0	0 / 0
1978	5 / 1535	0 / 0	0 / 0	0 / 0
1979	8 / 2821	0 / 0	0 / 0	0 / 0
1980	5 / 2300	0 / 0	0 / 0	0 / 0
1981	5 / 2296	0 / 0	0 / 0	0 / 0
1982	5 / 1780	1 / 1270	0 / 0	0 / 0
1983	6 / 2680	0 / 0	0 / 0	0 / 0
1984	3 / 1650	1 / 1270	0 / 0	0 / 0
1985	6 / 2512	0 / 0	0 / 0	0 / 0
MOUNTAIN TOTAL	44 / 17989	2 / 2540	0 / 0	0 / 0
PACIFIC REGION				
1977	0 / 0	2 / 2120	0 / 0	0 / 0
1978	0 / 0	0 / 0	1 / 292	0 / 0
1980	1 / 500	1 / 1250	0 / 0	0 / 0
1981	0 / 0	1 / 1140	0 / 0	0 / 0
1982	0 / 0	1 / 1250	0 / 0	0 / 0
1983	0 / 0	4 / 4918	0 / 0	0 / 0
1984	0 / 0	1 / 950	0 / 0	0 / 0
1985	0 / 0	4 / 5100	0 / 0	0 / 0
PACIFIC TOTAL	1 / 500	14 / 16720	1 / 292	0 / 0

Appendix B

STATE-BY-STATE LISTING OF THE 250 NEW COAL-FIRED STEAM ELECTRIC GENERATING UNITS PLANNED FOR THE 1977-1985 PERIOD -- AS REPORTED BY UTILITIES TO THE FEDERAL POWER COMMISSION (FPC)

May 1977

NEW COAL STEAM UNITS PROJECTED FOR 1977-1985

UTILITY	PLANT	UNIT NO	CAP (MW)	FUEL TYPE	COMPLETION DATE ORIG	COMPLETION DATE CURRENT
ALABAMA						
ALABAMA POWER (SC)	MILLER	1	662	COAL	6/78	6/78
ALABAMA ELECTRIC COOP	TOMBIGBEE	2	210	COAL	12/75	6/78
ALABAMA ELECTRIC COOP	TOMBIGBEE	3	210	COAL	12/75	6/79
ALABAMA POWER (SC)	MILLER	2	662	COAL	6/79	6/81
ALABAMA POWER (SC)	MILLER	3	662	COAL	6/80	6/82
ALABAMA POWER (SC)	MILLER	4	662	COAL	6/81	6/83
ALABAMA POWER (SC)	UNLOCATED	1	801	COAL	6/83	6/84
ALABAMA POWER (SC)	UNLOCATED	2	801	COAL	6/84	6/85
ARIZONA						
ARIZONA PUBLIC SERVICE	CHOLLA	2	250	COAL	8/73	6/78
ARIZONA ELECTRIC POWER COOP	APACHE STATION	4	175	COAL	6/78	6/78
SALT RIVER PROJECT	CORONADO	1	350	COAL	5/78	4/79
ARIZONA PUBLIC SERVICE	CHOLLA	3	250	COAL	8/73	6/79
ARIZONA ELECTRIC POWER COOP	APACHE STATION	5	175	COAL	6/79	6/79
SALT RIVER PROJECT	CORONADO	2	350	COAL	5/79	4/80
ARIZONA PUBLIC SERVICE	CHOLLA	4	350	COAL	6/78	6/80
ARIZONA PUBLIC SERVICE	CHOLLA	5	350	COAL	0/83	0/83
TUCSON GAS & ELECTRIC	SPRINGERVILLE	1	312	COAL	6/84	4/85
SALT RIVER PROJECT	UNSITED	1	250	COAL	0/ 0	10/85
ARKANSAS						
SOUTHWESTERN ELEC PWR (CSW)	FLINT CREEK	1	528	COAL	2/78	5/78
ARKANSAS POWER & LIGHT (MSU)	WHITE BLUFF	1	700	COAL	1/78	6/80
ARKANSAS POWER & LIGHT (MSU)	WHITE BLUFF	2	700	COAL	5/78	4/81
ARKANSAS POWER & LIGHT (MSU)	WHITE BLUFF	3	700	COAL	1/80	1/83
ARKANSAS POWER & LIGHT (MSU)	WHITE BLUFF	4	700	COAL	1/81	1/85
COLORADO						
COLORADO-UTE ELEC ASSOC	CRAIG	1	380	COAL	4/78	4/78
PUBLIC SERVICE CO OF COLORADO	PAWNEE	1	500	COAL	0/ 0	4/79
COLORADO-UTE ELEC ASSOC	CRAIG	2	380	COAL	4/79	4/79
COLORADO SPRINGS CITY OF	RAY D. NIXON	1	200	COAL	10/77	10/79
PUBLIC SERVICE CO OF COLORADO	PAWNEE	2	500	COAL	4/81	4/81
COLORADO-UTE ELEC ASSOC	CRAIG	3	380	COAL	4/80	7/81
COLORADO-UTE ELEC ASSOC	CRAIG	4	380	COAL	4/82	7/82
PUBLIC SERVICE CO OF COLORADO	SOUTHEASTERN	1	500	COAL	4/78	4/83
PUBLIC SERVICE CO OF COLORADO	SOUTHEASTERN	2	500	COAL	4/85	4/85
COLORADO SPRINGS CITY OF	RAY D. NIXON	2	200	COAL	10/80	10/85
DELAWARE						
DELMARVA POWER & LIGHT	INDIAN RIVER	4	400	COAL	6/78	5/79
FLORIDA						
LAKELAND DEPT ELEC & WTR	MCINTOSH	3	336	COAL	5/78	5/81
GULF POWER (SC)	ELLIS	1	518	COAL	5/80	5/82
FLORIDA POWER	UNSITED	1	600	COAL	10/81	10/83
TAMPA ELECTRIC CO	BEACON KEY	1	425	COAL	4/81	3/85
FLORIDA POWER	UNSITED	3	600	COAL	10/85	10/85
FLORIDA POWER	UNSITED	2	600	COAL	10/84	10/85
GEORGIA						
GEORGIA POWER (SC)	WANSLEY	2	870	COAL	2/77	6/78
GEORGIA POWER (SC)	SCHERER	1	825	COAL	2/79	6/81
GEORGIA POWER (SC)	SCHERER	2	825	COAL	2/80	2/82
GEORGIA POWER (SC)	SCHERER	3	825	COAL	2/81	2/84

NEW COAL STEAM UNITS PROJECTED FOR 1977–1985

UTILITY	PLANT	UNIT NO	CAP (MW)	FUEL TYPE	COMPLETION DATE ORIG	COMPLETION DATE CURRENT
GEORGIA POWER (SC)	SCHERER	4	825	COAL	2/82	2/85
ILLINOIS						
CENTRAL ILLINOIS PUB SERV	NEWTON	1	550	COAL	4/77	12/77
SPRINGFIELD CITY OF	DALLMAN	3	175	COAL	1/77	6/78
SOUTHERN ILLINOIS PWR COOP	MARION	4	173	COAL	2/76	6/78
ILLINOIS POWER	HAVANA	6	450	COAL	6/78	6/78
CENTRAL ILLINOIS PUB SERV	NEWTON	2	550	COAL	4/80	4/81
CENTRAL ILLINOIS LIGHT	DUCK CREEK	2	400	COAL	1/79	1/82
CENTRAL ILLINOIS PUB SERV	NEWTON	3	550	COAL	4/82	4/84
INDIANA						
INDIANAPOLIS POWER & LIGHT	PETERSBURG	3	515	COAL	4/77	10/77
PUBLIC SERVICE CO OF INDIANA	GIBSON	3	650	COAL	1/78	4/78
SOUTHERN INDIANA GAS & ELEC	A. B. BROWN	1	255	COAL	4/78	4/79
PUBLIC SERVICE CO OF INDIANA	GIBSON	4	650	COAL	1/79	4/79
NORTHERN INDIANA PUB SERV	R. M. SCHAHFER	15	527	COAL	6/78	6/79
HOOSIER ENERGY DIV OF	MEROM	2	450	COAL	9/81	12/80
HOOSIER ENERGY DIV OF	MEROM	1	450	COAL	9/80	10/81
INDIANAPOLIS POWER & LIGHT	PETERSBURG	4	515	COAL	4/79	4/82
INDIANAPOLIS POWER & LIGHT	UNSITED	1	650	COAL	0/ 0	4/85
RICHMOND POWER & LIGHT	WHITEWATER VAL	3	100	COAL	1/80	7/85
IOWA						
IOWA STATE UNIVERSITY	IOWA STATE	6	11	COAL	5/77	5/77
INTERSTATE POWER	LANSING	4	260	COAL	5/77	5/77
IOWA POWER & LIGHT	COUNCIL BLUFFS	3	650	COAL	1/79	6/78
IOWA PUBLIC SERVICE	GEORGE NEAL	4	576	COAL	3/75	5/79
IOWA SOUTHERN UTILITIES	OTTUMWA	1	675	COAL	1/81	1/81
KANSAS						
KANSAS CITY PWR & LT	LA CYGNE	2	630	COAL	4/77	4/77
KANSAS POWER & LIGHT	JEFFREY	1	680	COAL	5/78	6/79
KANSAS CITY BRD PUB UTILS	NEARMAN CREEK	1	235	COAL	5/78	6/79
KANSAS POWER & LIGHT	JEFFREY	2	680	COAL	6/79	6/80
KANSAS POWER & LIGHT	JEFFREY	3	680	COAL	6/80	6/82
KANSAS CITY BRD PUB UTILS	NEARMAN CREEK	2	300	COAL	6/82	6/82
KANSAS POWER & LIGHT	JEFFREY	4	680	COAL	6/84	6/84
KENTUCKY						
KENTUCKY UTILITIES	GHENT	2	500	COAL	1/77	4/77
EAST KENTUCKY POWER COOP	H. L. SPURLOCK	1	330	COAL	4/76	5/77
LOUISVILLE GAS & ELECTRIC	MILL CREEK	3	425	COAL	6/77	12/77
BIG RIVERS ELECTRIC	REID	2	240	COAL	10/79	12/79
EAST KENTUCKY POWER COOP	H. L. SPURLOCK	2	550	COAL	4/80	4/80
LOUISVILLE GAS & ELECTRIC	MILL CREEK	4	495	COAL	6/79	6/80
CINCINNATI GAS & ELECTRIC	EAST BEND	2	600	COAL	1/81	0/81
KENTUCKY UTILITIES	UNSITED	1	500	COAL	4/81	4/81
KENTUCKY UTILITIES	UNSITED	2	500	COAL	4/82	4/83
CINCINNATI GAS & ELECTRIC	EAST BEND	1	600	COAL	1/79	0/84
CINCINNATI GAS & ELECTRIC	EAST BEND	3	800	COAL	1/84	1/84
KENTUCKY UTILITIES	GHENT	3	500	COAL	0/ 0	4/84
EAST KENTUCKY POWER COOP	UNSITED	2	500	COAL	4/82	4/84
EAST KENTUCKY POWER COOP	UNSITED	1	550	COAL	4/84	4/84
BIG RIVERS ELECTRIC	REID	3	240	COAL	0/ 0	4/84
KENTUCKY UTILITIES	UNSITED	4	650	COAL	0/ 0	4/85
LOUISIANA						
CAJUN ELECTRIC POWER COOP	BIG CAJUN 2	1	540	COAL	7/79	7/79

NEW COAL STEAM UNITS PROJECTED FOR 1977-1985

UTILITY	PLANT	UNIT NO	CAP (MW)	FUEL TYPE	COMPLETION DATE ORIG	COMPLETION DATE CURRENT
CENTRAL LOUISIANA ELECTRIC	RODEMACHER	2	530	COAL	1/79	4/80
CAJUN ELECTRIC POWER COOP	BIG CAJUN 2	2	540	COAL	7/80	7/80
LOUISIANA POWER & LIGHT (MSU)	UNSITED	1	700	COAL	1/83	1/83
LOUISIANA POWER & LIGHT (MSU)	UNSITED	2	700	COAL	1/84	1/84
LOUISIANA POWER & LIGHT (MSU)	UNSITED	3	700	COAL	1/85	1/85
CAJUN ELECTRIC POWER COOP	BIG CAJUN 2	3	540	COAL	7/85	7/85
GULF STATES UTILITIES	R. S. NELSON	5	540	COAL	2/78	9/85
	MARYLAND					
POTOMAC ELECTRIC POWER	DICKERSON	4	800	COAL	12/77	3/82
	MICHIGAN					
UPPER PENINSULA POWER	UNSITED	1	80	COAL	1/78	1/78
UPPER PENINSULA GENERATING	PRESQUE ISLE	7	80	COAL	0/ 0	1/78
UPPER PENINSULA POWER	UNSITED	2	80	COAL	1/79	4/78
UPPER PENINSULA GENERATING	PRESQUE ISLE	8	80	COAL	0/ 0	4/78
UPPER PENINSULA GENERATING	PRESQUE ISLE	9	80	COAL	0/ 0	1/79
UPPER PENINSULA POWER	UNSITED	3	80	COAL	1/80	1/80
CONSUMERS POWER	J. H. CAMPBELL	3	802	COAL	3/78	5/80
MARQUETTE BRD OF LT & PWR	SHIRAS	3	41	COAL	12/77	12/80
GRAND HAVEN BRD LT & PWR	ISLAND	3	20	COAL	5/78	5/81
UPPER PENINSULA POWER	UNSITED	1	90	COAL	0/ 0	1/82
DETROIT EDISON	BELLE RIVER	1	676	COAL	3/79	3/82
COLDWATER BRD OF PUB UTILS	COLDWATER	7	20	COAL	0/ 0	9/82
CONSUMERS POWER	J. H. CAMPBELL	4	802	COAL	0/ 0	0/83
DETROIT EDISON	BELLE RIVER	2	676	COAL	3/80	3/83
UPPER PENINSULA POWER	UNSITED	4	80	COAL	1/84	1/84
	MINNESOTA					
NORTHERN STATES POWER	SHERBURNE CTY	2	680	COAL	5/77	5/77
MINNESOTA POWER & LIGHT	CLAY BOSWELL	4	500	COAL	5/80	5/80
AUSTIN UTILITIES	NORTHEAST STA	2	44	COAL	5/80	5/80
NORTHERN STATES POWER	SHERBURNE CTY	3	800	COAL	5/82	5/81
NEW ULM PUB UTILS COMM	NEW ULM	6	40	COAL	0/ 0	0/83
NORTHERN STATES POWER	SHERBURNE CTY	4	680	COAL	5/84	5/83
	MISSISSIPPI					
MISSISSIPPI POWER (SC)	JACKSON COUNTY	1	502	COAL	6/76	6/77
SOUTHERN MISSISSIPPI ELEC PWR	MORROW	1	180	COAL	6/77	2/78
SOUTHERN MISSISSIPPI ELEC PWR	MORROW	2	180	COAL	6/78	9/78
MISSISSIPPI POWER (SC)	JACKSON COUNTY	2	502	COAL	5/78	6/80
MISSISSIPPI PWR & LT (MSU)	UNSITED	1	700	COAL	1/85	1/85
	MISSOURI					
UNION ELECTRIC	RUSH ISLAND	2	575	COAL	3/76	3/77
UNION ELECTRIC	RUSH ISLAND	1	575	COAL	6/75	3/77
ASSOCIATED ELECTRIC COOP	NEW MADRID	2	600	COAL	6/77	6/77
KANSAS CITY PWR & LT	IATAN	1	630	COAL	5/79	4/80
ASSOCIATED ELECTRIC COOP	THOMAS HILL	3	600	COAL	3/81	3/81
SPRINGFIELD UTILITIES	SOUTHWEST	2	200	COAL	4/80	0/82
EMPIRE DISTRICT ELECTRIC	ASBURY	2	300	COAL	5/82	6/84
MISSOURI PUBLIC SERVICE	UNSITED	1	100	COAL	6/85	6/85
	MONTANA					
MONTANA POWER	COLSTRIP	3	700	COAL	7/78	10/80
MONTANA POWER	COLSTRIP	4	700	COAL	7/79	8/81
	NEBRASKA					
NEBRASKA PUBLIC PWR DIST	GENTLEMAN	1	600	COAL	5/77	5/78

NEW COAL STEAM UNITS PROJECTED FOR 1977-1985

UTILITY	PLANT	UNIT NO	CAP (MW)	FUEL TYPE	COMPLETION DATE ORIG	COMPLETION DATE CURRENT
OMAHA PUBLIC POWER DISTRICT	NEBRASKA CITY	1	575	COAL	1/79	1/79
GRAND ISLAND WTR & LT DEPT	UNSITED	1	147	COAL	0/ 0	0/81
NEBRASKA PUBLIC POWER DIST	GENTLEMAN	2	600	COAL	5/80	5/81
	NEVADA					
SIERRA PACIFIC POWER	VALMY	1	250	COAL	10/80	0/82
SIERRA PACIFIC POWER	VALMY	2	250	COAL	10/83	10/83
NEVADA POWER	HARRY ALLEN	1	500	COAL	6/79	6/84
NEVADA POWER	HARRY ALLEN	2	500	COAL	6/80	6/85
	NEW MEXICO					
PUB SERV CO OF NEW MEXICO	SAN JUAN	3	466	COAL	5/78	5/79
PUB SERV CO OF NEW MEXICO	SAN JUAN	4	466	COAL	5/79	5/81
	NEW YORK					
POWER AUTH OF STATE OF N. Y.	MTA-ARTHUR KILL	1	700	COAL	5/80	9/82
NEW YORK STATE ELEC & GAS	CAYUGA	1	850	COAL	12/79	11/83
NIAGARA MOHAWK POWER	LAKE ERIE	1	850	COAL	11/82	11/85
	NORTH CAROLINA					
CAROLINA POWER & LIGHT	ROXBORO	4	720	COAL	3/76	3/80
CAROLINA POWER & LIGHT	MAYO	1	720	COAL	3/79	3/83
CAROLINA POWER & LIGHT	MAYO	2	720	COAL	3/**	3/85
	NORTH DAKOTA					
MINNKOTA POWER COOP	MILTON R. YOUNG	2	403	COAL	5/77	5/77
COOPERATIVE POWER ASSN	COAL CREEK	1	490	COAL	11/78	11/78
COOPERATIVE POWER ASSN	COAL CREEK	2	490	COAL	11/79	11/79
OTTER TAIL POWER	COYOTE	1	400	COAL	5/81	5/81
BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY	1	440	COAL	5/79	6/81
BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY	2	440	COAL	5/81	6/82
	OHIO					
CARDINAL OPERATING (AEP)	CARDINAL	3	615	COAL	10/76	6/77
COLUMBUS & S OHIO ELECTRIC	CONESVILLE	6	375	COAL	1/77	1/78
CINCINNATI GAS & ELECTRIC	MIAMI FORT	8	500	COAL	1/77	1/78
COLUMBUS & S OHIO ELECTRIC	POSTON	5	375	COAL	1/79	1/81
DAYTON POWER & LIGHT	KILLEN STATION	2	600	COAL	1/79	1/82
COLUMBUS & S OHIO ELECTRIC	POSTON	6	375	COAL	1/80	1/83
DAYTON POWER & LIGHT	KILLEN STATION	1	600	COAL	1/80	1/85
COLUMBUS & S OHIO ELECTRIC	SITE C	1	375	COAL	1/85	1/85
	OKLAHOMA					
OKLAHOMA GAS & ELECTRIC	MUSKOGEE	4	515	COAL	2/77	2/77
OKLAHOMA GAS & ELECTRIC	MUSKOGEE	5	515	COAL	2/78	2/78
OKLAHOMA GAS & ELECTRIC	SOONER	1	515	COAL	2/79	2/79
PUB SERV CO OF OKLAHOMA (CSW)	NORTHEASTERN	3	450	COAL	5/79	6/79
OKLAHOMA GAS & ELECTRIC	SOONER	2	515	COAL	2/80	2/80
WESTERN FARMERS ELECTRIC COOP	UNSITED	2	350	COAL	6/82	5/80
PUB SERV CO OF OKLAHOMA (CSW)	NORTHEASTERN	4	450	COAL	5/80	6/80
WESTERN FARMERS ELECTRIC COOP	UNSITED	3	350	COAL	0/ 0	5/82
OKLAHOMA GAS & ELECTRIC	SOONER	3	515	COAL	2/81	2/83
OKLAHOMA GAS & ELECTRIC	UNSITED	3	700	COAL	2/84	2/84
OKLAHOMA GAS & ELECTRIC	SOONER	4	515	COAL	2/82	2/84
PUB SERV CO OF OKLAHOMA (CSW)	CSR JOINT	1	240	COAL	5/82	5/84
	OREGON					
PORTLAND GENERAL ELECTRIC	BOARDMAN	1	500	COAL	7/80	7/80

NEW COAL STEAM UNITS PROJECTED FOR 1977-1985

UTILITY	PLANT	UNIT NO	CAP (MW)	FUEL TYPE	COMPLETION DATE ORIG	COMPLETION DATE CURRENT
PENNSYLVANIA						
PENNSYLVANIA ELECTRIC (GPU)	HOMER CITY	3	650	COAL	4/77	10/77
OHIO EDISON	MANSFIELD	2	825	COAL	4/76	10/77
OHIO EDISON	MANSFIELD	3	825	COAL	4/78	10/79
PENNSYLVANIA ELECTRIC (GPU)	SEWARD	7	800	COAL	12/78	5/84
SOUTH CAROLINA						
SOUTH CAROLINA PUB SERV AUTH	WINYAH	2	280	COAL	5/77	5/77
SOUTH CAROLINA ELECTRIC & GAS	UNSITED	2	500	COAL	0/ 0	5/84
SOUTH CAROLINA ELECTRIC & GAS	UNSITED	1	500	COAL	5/84	5/84
TEXAS						
SOUTHWESTERN ELEC PWR (CSW)	WELSH	1	528	COAL	2/77	2/77
SAN ANTONIO PUB SER BRD	J. T. DEELY	1	418	COAL	0/ 0	2/77
TEXAS POWER & LIGHT (TU)	MARTIN LAKE	1	750	COAL	12/76	3/77
SAN ANTONIO PUB SER BRD	J. T. DEELY	2	418	COAL	0/ 0	7/77
TEXAS POWER & LIGHT (TU)	MARTIN LAKE	2	750	COAL	12/77	2/78
TEXAS POWER & LIGHT (TU)	MONTICELLO	3	750	COAL	12/77	3/78
SOUTH TEXAS ELECTRIC COOP	TEXAS COOP	1	400	COAL	0/ 0	0/79
HOUSTON LIGHTING & POWER	W. A. PARISH	5	660	COAL	3/77	0/79
TEXAS POWER & LIGHT (TU)	MARTIN LAKE	3	750	COAL	12/78	2/79
SOUTHWESTERN PUB SERV	HARRINGTON	2	317	COAL	12/78	2/79
LOWER COLORADO RIVER AUTHORITY	FAYETTE	1	550	COAL	3/79	7/79
CENTRAL POWER & LIGHT (CSW)	COLETO CREEK	1	550	COAL	1/79	0/80
SOUTHWESTERN ELEC PWR (CSW)	WELSH	2	528	COAL	2/80	2/80
LOWER COLORADO RIVER AUTHORITY	FAYETTE	2	550	COAL	12/79	4/80
SOUTHWESTERN PUB SERV	HARRINGTON	3	317	COAL	6/80	6/80
TEXAS POWER POOL	SAN MIGUEL	1	400	COAL	6/79	7/80
TEXAS POWER POOL	SAN MIGUEL	2	400	COAL	6/81	12/80
HOUSTON LIGHTING & POWER	W. A. PARISH	6	660	COAL	3/78	0/81
TEXAS POWER POOL	BRYAN	1	400	COAL	6/82	1/81
TEXAS POWER & LIGHT (TU)	FOREST GROVE	1	750	COAL	12/78	1/81
TEXAS POWER & LIGHT (TU)	MARTIN LAKE	4	750	COAL	12/79	2/81
HOUSTON LIGHTING & POWER	W. A. PARISH	7	750	COAL	3/79	3/81
SOUTH TEXAS ELECTRIC COOP	TEXAS COOP	2	400	COAL	0/ 0	6/81
TEXAS POWER & LIGHT (TU)	TWIN OAK	1	750	COAL	1/81	1/82
SOUTHWESTERN ELEC PWR (CSW)	WELSH	3	528	COAL	2/82	2/82
HOUSTON LIGHTING & POWER	W. A. PARISH	8	750	COAL	3/80	3/82
SOUTHWESTERN PUB SERV	SOUTH PLAINS	1	475	COAL	0/ 0	6/82
TEXAS POWER POOL	BRYAN	2	400	COAL	6/83	1/83
TEXAS POWER & LIGHT (TU)	TWIN OAK	2	750	COAL	1/82	1/83
HOUSTON LIGHTING & POWER	UNSITED	1	750	COAL	3/83	3/83
SAN ANTONIO PUB SER BRD	UNSITED	1	375	COAL	3/81	6/83
TEXAS POWER POOL	BRYAN	3	400	COAL	1/84	1/84
SOUTHWESTERN PUB SERV	SOUTH PLAINS	2	475	COAL	0/ 0	6/84
TEXAS POWER & LIGHT (TU)	UNSITED	2	750	COAL	1/84	1/85
TEXAS POWER & LIGHT (TU)	UNSITED	1	400	COAL	1/83	1/85
HOUSTON LIGHTING & POWER	UNSITED	1	750	COAL	3/85	3/85
UTAH						
UTAH POWER & LIGHT	HUNTINGTON CYN	1	415	COAL	0/ 0	6/77
UTAH POWER & LIGHT	EMERGY	1	400	COAL	6/78	6/78
UTAH POWER & LIGHT	EMERGY	2	400	COAL	4/79	4/80
NEVADA POWER	WARNER VALLEY	1	250	COAL	6/78	6/81
NEVADA POWER	WARNER VALLEY	2	250	COAL	6/79	6/82
LOS ANGELES DEPT WTR & PWR	INTERMOUNTAIN	1	750	COAL	11/83	11/83
LOS ANGELES DEPT WTR & PWR	INTERMOUNTAIN	2	750	COAL	11/84	11/84

NEW COAL STEAM UNITS PROJECTED FOR 1977-1985

UTILITY	PLANT	UNIT NO	CAP (MW)	FUEL TYPE	COMPLETION DATE ORIG	CURRENT
LOS ANGELES DEPT WTR & PWR	INTERMOUNTAIN	3	750	COAL	11/85	11/85
WEST VIRGINIA						
MONONGAHELA POWER (APS)	PLEASANTS	1	626	COAL	3/78	3/79
APPALACHIAN POWER (AEP)	PROJECT 1301	1	1300	COAL	6/79	0/80
MONONGAHELA POWER (APS)	PLEASANTS	2	626	COAL	3/81	3/80
MONONGAHELA POWER (APS)	UNSITED	1	630	COAL	3/83	3/84
MONONGAHELA POWER (APS)	UNSITED	2	630	COAL	3/82	3/85
WISCONSIN						
WISCONSIN POWER & LIGHT	COLUMBIA	2	527	COAL	3/78	3/78
DAIRYLAND POWER COOP	ALMA	6	350	COAL	5/78	5/79
MARSHFIELD ELECTRIC & WTR DEPT	WILDWOOD	6	20	COAL	0/ 0	6/79
MANITOWOC PUBLIC UTILITIES	MANITOWOC	7	57	COAL	1/80	1/80
WISCONSIN ELECTRIC POWER	PLEASANT PR'RIE	1	580	COAL	6/79	4/80
WISCONSIN PUBLIC SERVICE	WESTON	3	300	COAL	0/ 0	3/81
WISCONSIN POWER & LIGHT	EDGEWATER	5	400	COAL	3/81	3/82
WISCONSIN ELECTRIC POWER	PLEASANT PR'RIE	2	580	COAL	6/80	4/82
WYOMING						
PACIFIC POWER & LIGHT	WYODAK	1	330	COAL	5/77	5/78
PACIFIC POWER & LIGHT	JIM BRIDGER	4	500	COAL	7/78	12/79
TRI STATE GEN & TRANS ASSN	LARAMIE RIVER	1	500	COAL	1/80	6/80
UTAH POWER & LIGHT	NAUGHTON	4	400	COAL	4/82	4/82
TRI STATE GEN & TRANS ASSN	LARAMIE RIVER	2	500	COAL	6/80	12/82
PACIFIC POWER & LIGHT	WYODAK	2	330	COAL	0/ 0	5/83
TRI STATE GEN & TRANS ASSN	LARAMIE RIVER	3	500	COAL	6/83	12/83
UTAH POWER & LIGHT	NAUGHTON	5	400	COAL	4/84	4/84

FACTS ABOUT THE FEA PROGRAM TO CONVERT EXISTING ELECTRIC GENERATING PLANS BACK TO COAL

1. Steps in the Process. Once FEA identifies promising candidates (after considering plant capacity and condition, coal and transportation availability, economics, etc.), the following steps are needed for each plant:
   - FEA issues a Notice of Intent (NOI) to issue an order prohibiting the use of fuel other than coal.
   - FEA holds public hearing on proposed order.
   - FEA issues the Prohibition Order (PO).
   - FEA begins an Environmental Assessment or Environmental Impact Statement (EIS) on each order.
   - EPA, if it so concludes, certifies that the ordered conversion can be accomplished within air quality requirements & standards.
   - When FEA's environmental analysis is completed (including hearings for EIS's), FEA can issue a Notice of Effectiveness (NOE) which defines the date and schedule for implementing the order.
   - FEA enforces order -- which should lead to burning of coal.

2. Elapse Time. FEA estimates that a period of 4 to 8 years is required to achieve forced conversion, depending on many factors including whether orders are challenged by the utility or others.

	Approx. No. of Units	Sites	Approx. Capacity (megawatts)
3. Potential Candidates for Conversion Back to Coal.			
. Boilers identified as potential candidates	680		62,600
. Rejects - considered too old (built before 1950) or too small (25 MGW or less)	425	80	21,700
4. FEA's First Round Orders.	74	32	11,296
EPA Conclusions on air quality on 1st round.			
. Eligible for immediate coal use	11		938
. Can convert only if additional pollution control equipment installed	51		7,705
. No conclusion yet reached	12		2,653
5. FEA's Second Round Orders (NOI's April 1977).	31		4,686
6. Potential Future Orders, if Authority Extended. (Identified by FEA contractor as of March 77)	148		25,000

7. No coal is being burned in reconverted plants as a result of an FEA order.

8. However, utilities -- especially those in round one that can meet environmental requirements -- voluntarily have increased their use of coal. Specifically:

	Units	Mega-watt Capacity	Tons of coal burned 1973	Tons of coal burned 1975	Coal as % of total fuel used 1973	Coal as % of total fuel used 1975
			(000 tons)			
1st Round (Totals)	(74)	(11,296)	(4,386)	(6,386)	(16%)	(29%)
. EPA-cleared units	11	938	899	1,253	36%	69%
. More pollution control needed	51	7,705	2,853	4,239	15%	29%
. No EPA decision	12	2,653	634	894	11%	18%
2nd Round-NOI's						
. Issued April 1977	31	4,686	568	1,205	5%	12%

FPC does not yet have available the unit by unit data for 1976, but overall plant data for those plants where the above units are located show that coal use increased substantially in 1976 over 1975 for all categories in the first round -- with percent of power generated by coal jumping from 29% in 1973 to 36% in 1975 and 48% in 1976.

9. Estimated 1978 Funding Required for FEA Program: $5.8 million.

10. More detailed summary of data for plants and units covered by FEA Orders and Notices of Intents is provided in the summary table on the next page. Plant by plant data are available in an NCA May 1977 analysis.

SUMMARY

Category Round One	Installed Capacity: Total Plant (MW)	Installed Capacity: Unit(s) Effected (MW)	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 Tons)	Total Plant: % Generation by Coal	Oil	Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons)	Unit: % Generation by Coal	Oil	Gas
11 units certified to burn coal immediately	1,893	938	1973	8,714	1,473	33	31	37	4,592	899	36	20	44
			1975	5,612	1,816	61	9	30	3,714	1,253	69	-	31
			1976	6,517	2,568	76	5	19					
51 units - can burn coal after equipment modification	11,340	7,705	1973	57,014	7,940	33	54	13	37,813	2,853	15	69	16
			1975	45,244	8,654	41	49	10	30,618	4,239	29	61	10
			1976	45,492	11,300	55	39	6					
12 units - no decision made	4,232	2,653	1973	16,755	655	10	89	1	14,249	634	11	87	2
			1975	17,035	1,218	16	80	4	11,526	894	18	79	3
			1976	18,871	1,583	20	80	1					
Total 74 Round One Units 1/	17,465	11,296	1973	82,483 1/	10,068 1/	29	59	12	56,654	4,386	16	70	14
			1975	67,891 1/	11,688 1/	36	53	11	45,858	6,386	29	61	10
			1976	70,880 1/	15,451 1/	48	47	5					
Round Two													
NOI's issued April, 1977 31 units	7,346	4,686	1973	37,021	599	4	82	14	27,733	568	5	87	8
			1975	33,660	1,494	10	79	11	23,937	1,205	12	82	6
			1976	31,449	789	5	84	11					

1/ Total plant statistics include some duplication of data.

COAL MINE DEVELOPMENT PLANS

Capacity (Expected Production) Increments by Years

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	Total Additions 1976-1985
					(Million Tons)						
N.C.A. 1/											
East	30.62	33.81	36.37	28.16	23.52	18.27	21.37	13.30	10.93	8.25	224.60
West	26.96	35.51	39.10	46.80	31.30	32.70	22.50	19.60	15.20	5.60	275.27
Total	57.58	69.32	75.49	74.96	54.82	50.97	43.87	32.90	26.13	13.85	499.87
McGraw Hill - Coal Age 2/											
East	34.15	41.36	41.96	30.73	17.45	9.68	7.69	6.53	6.17	6.30	202.02
West	19.60	50.86	53.95	56.95	104.40	54.40	43.50	26.80	23.80	34.80	469.06
Total	53.75	92.22	95.91	87.68	121.85	64.08	51.19	33.33	29.97	41.10	671.08
Federal Energy Adm. 3/											
West	21.60	37.90	50.30	56.80	61.40	89.80	56.40	33.10	55.00	69.00	531.30
Bureau of Mines 4/											
East	Detail not available by yearly increments.										242.60
West											472.10
Total											714.70

1/ "A Study of New Mine Additions and Major Expansion Plans of the Coal Industry," National Coal Association, August, 1976.

2/ "New Coal Mine Development Plans to 1985," February, 1977 Coal Age. These are Keystone's estimates of capacity (here projected output) of new and expansion projects through 1985.

3/ Spring Quarter Western Coal Development Monitoring System, Federal Energy Administration. Data are production projections as obtained from companies for each western mine now producing or expected to produce 200,000 tpy or more.

4/ Projects to Expand Fuel Sources in Eastern (Western) States. BOM Information Circular 8725 (8719). Estimates of new and expansion additions to production.

NOTE: All sources are gross production additions. Estimates of eastern capacity additions must be discounted by 12 - 15 million tons per year to reflect replacement tonnages.

Appendix E

NATIONAL COAL ASSOCIATION

Coal Building | 1130 Seventeenth Street, Northwest | Washington, D. C. 20036 | (202) 628-4322

CARL E. BAGGE
president

March 10, 1977

MEMORANDUM TO NCA MEMBERS

FROM: Carl E. Bagge

The Federal Power Commission has just completed the most extensive study ever undertaken by a federal agency on new coal supply for new electric generating units. The attached study, "Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985," was done by combining existing data with a phone survey to all of the power companies planning new coal-fired units. The base year is 1975 and the study covers a ten-year period. The major findings were:

1. The annual amount of coal required by the new units is 173.9 million tons in 1980 and 357.7 million tons in 1985. (The 1985 figure includes the 1980 amount.)

2. The amount of this coal already under contract is 85 percent in 1980 and 68 percent in 1985. See pages 34-37 for a unit by unit breakdown on the amount of coal contracted.

3. The average length of contracts signed was (by coal-producing area):

Appalachia	20 years
Texas	35 years
Western	26 years

4. The projected breakdown by mode of transport is as follows:

	1980	1985
Railroad	65%	61%
Barge	10	8
Truck & Conveyor Belt (Mine-mouth)	25	28
Pipeline	-	3

5. The percentage of coal with a transportation contract by mode of transport is as follows:

	1980	1985
Railroad	57%	33%
Barge	66	66
Truck & Conveyor Belt	92	78
Pipeline	-	-

6. The following general points were also indicated by the study:

   (a) The further you go into the future, the less coal is under contract.

   (b) The average length of transportation contracts is for the duration of the supply contracts.

   (c) 94 percent of the coal to be produced West of the Mississippi is projected to be used West of the Mississippi.

   (d) Contractual agreements for transportation are not always concluded simultaneously with supply contracts.

   (e) Only a relatively small share of the total projected rail shipments, particularly from Appalachia to geographic regions in the eastern United States, is committed to contract. The level of contracts is also low for rail shipments from the Northern Great Plains, although not as low as from Appalachia.

   (f) The bulk of the shipments by barge will be from Appalachia, and to a lesser extent from the Interior Basin, to various regions in the East.

NATIONAL COAL ASSOCIATION

Memorandum to NCA Members
March 10, 1977
Page 3

(g) Shipments by truck and belt, reflecting the extent of mine-mouth plant developments, will take place almost entirely in the West.

(h) Coal deliveries across the Great Lakes to new units in the East North Central Region will originate in the Northern Great Plains and the first leg of the shipments will be by rail.

(i) The pipeline deliveries are projected for proposed coal-slurry shipments from the Rockies to plants in the Mountain Region (from Utah to Utah and to Nevada).

Also attached are two tables NCA has constructed based on some of the report's most pertinent data.

I hope that this information will be helpful to you.

CEB:vh

TABLE 1.

ORIGIN AND AMOUNT OF COAL
UNDER CONTRACT FOR NEW UNITS

APPALACHIA		1980	Coal % Contract	1985	Coal % Contract
Dist.	State				
1	PA	1.3	100	3.2	41
4	OHIO	10.5	72	11.9	68
6	W VA	.4	100	.4	0
8	KY, VA, TN, W VA	9.5	36	30.1	32
13	AL, GA, TN	1.7	58	6.6	46
	APPALACHIA TOTAL	23.4	58	52.2	43
INTERIOR					
Dist.	State				
9	W KY	8.4	96	12.0	82
10	IL	11.7	99	15.9	95
11	IN	3.2	100	8.5	66
15	MO, OK	.4	100	2.2	21
	INTERIOR TOTAL	23.7	98	38.6	80
WESTERN					
Dist.	State				
15	TX	21.4	91	51.4	76
16	CO	3.8	97	4.3	97
18	NM	9.1	100	18.3	94
19	WY	55.6	90	92.6	78
20	UT	4.5	80	15.8	85
21	ND	8.7	100	18.1	100
22	MT	19.3	83	48.4	53
	WESTERN TOTAL	122.4	91	248.9	76
	UNKNOWN	4.4		17.8	
	US	173.9	85	357.7	68

TABLE 2.

PROJECTED DELIVERY MODE OF COAL TO NEW UNITS 1980
(Million Tons)

Mode/Region	Appalachian	Percent Regional Total	Interior	Percent Regional Total	Western	Percent Regional Total	U. S. Total	Percent of Total
Railroad	9.8	41.9	18.5	78.1	81.7	66.7	110.0	64.9
Barge	11.6	49.6	3.6	15.2	1.0	0.9	16.2	9.5
Truck & Conveyor Belt	2.0	8.5	1.6	6.7	39.7	32.4	43.3	25.6
	23.4	100.0	23.7	100.0	122.4	100.0	169.5	100.0

PROJECTED DELIVERY MODE OF COAL TO NEW UNITS - 1985
(Million Tons)

Mode/Region	Appalachian	Percent Regional Total	Interior	Percent Regional Total	Western	Percent Regional Total	U. S. Total	Percent of Total
Railroad	34.1	65.3	28.2	73.1	145.3	58.4	207.6	61.1
Barge	16.0	30.7	6.8	17.6	5.4	2.2	28.2	8.3
Truck & Conveyor Belt	2.1	4.0	3.6	9.3	88.4	35.5	94.1	27.7
Pipeline	-	-	-	-	9.8	3.9	9.8	2.9
	52.2	100.0	38.6	100.0	248.9	100.0	339.7	100.0

NATIONAL COAL ASSOCIATION

AN ANALYSIS OF

EXISTING ELECTRIC GENERATING UNITS COVERED
BY FEA'S ATTEMPTS TO FORCE USE OF COAL

National Coal Association
May 1977

ANALYSIS OF ELECTRIC GENERATING UNITS COVERED BY FEA'S ATTEMPTS TO FORCE CONVERSION TO COAL

This paper presents data and conclusions from an analysis of the 105 existing electric generating units covered by the Federal Energy Administration's(FEA's) attempts to force conversion from oil and natural gas to coal.

PRINCIPAL CONCLUSIONS

The principal conclusions from the analysis are that:

- Utilities are voluntarily using more coal in a number of existing electric generating units covered by the FEA efforts -- even though the government has not reached the stage in its complex process of ordering coal use.

- The existing units covered by FEA efforts tend to be small in size -- averaging about 150 megawatts -- compared to an average of about 500 megawatts for the 250 new coal-fired units that utilities are planning to bring on line between now and 1985.

- The units covered by FEA efforts are being used less than new base-load units and are being used even less frequently as time passes -- presumably because the units are older and less efficient than new base-load units that are available to the utilities.

- Even though the units are being used less, the use of coal was increased voluntarily from 1973 to 1975 -- both in absolute terms (from 5.0 million tons to 7.6 million tons) and as a percentage of total fuel used in the units. Increased coal use is probably due to its lower price relative to oil or natural gas and greater certainty of supply.

- The total potential for increased coal use in existing units covered by FEA efforts is small when compared to the potential for new base-load coal-fired plants.

SUMMARY OF DATA

- Units Covered by FEA Attempts.

  During 1975, FEA issued notices of intent(NOI's) to order conversion of 74 existing units. In April 1977, FEA issued NOI's covering 31 additional units. NOI's are the first step in a long process that could lead to an order (called a notice of effectiveness) requiring a utility to burn coal in designated units. One step in the process is a certification by the Environmental Protection Agency(EPA) that coal can be burned within air quality standards and requirements.

The following table, based on data from FEA and the Federal Power Commission(FPC), shows the number of units involved in FEA efforts, the status of EPA's certification decisions, the total capacity of units and the average capacity.

Table 1:

	Number of Units	Total Capacity (Megawatts)	Average Capacity Per Unit
. 1st Round			
-EPA cleared for coal use	11	938	85
-More pollution control required	51	7,705	151
-EPA not yet decided	12	2,653	221
(Subtotal)	74	11,296	153
. 2nd Round			
-Notices issued April 77	31	4,686	151
Total	105	15,982	152

Utilities have reported to the FPC plans to bring ~~250 bring~~ 250 new coal-fired units on line during the period from 1977 through 1985 with a total capacity of about 123,350 megawatts or 493 megawatts per unit. Utilities have also reported 125 new nuclear units for the same period with a capacity of 135,872 megawatts. The total for coal and nuclear is 259,222 megawatts.

The data above show:

- Units covered by FEA conversion efforts are, on the average, much smaller than planned new units.
- The total capacity of all units covered by FEA efforts is equal to about 6% of the capacity of the new coal and nuclear units planned.

However, utilities operating some of the units covered by FEA efforts believe it is not practicable, feasible or desirable to convert some of the units to coal and have announced their intention to fight FEA in the courts.

. Extent of Generating Unit Use

The following table shows for 1973 and 1975 estimates of the killowatt hours of electricity generated by units in each group and the average percentage of time units are producing electricity.

Table 2:

	Total Capacity (Megawatt)	Estimated Generation (million kwh) 1973	1975	Avg. % of Time in Use 1973	1975
. Round 1					
- 11 EPA cleared	938	4,592	3,714	56	45
- 51 More control	7,705	37,813	30,618	56	45
- 12 No decision	2,653	14,249	11,526	61	50
(Subtotal)	(11,296)	(56,654)	(45,858)	(57)	(46)
. Round 2					
- April 77 NOI's	4,686	27,793	23,937	67	58
	15,982	84,447	69,795	60	50

New base-load coal-fired plants are generally expected to be in use (generating electricity) about 65-70% of the time.

Data in the above table shows that units covered by FEA efforts:
- Are used less than new base-load plants.
- Are being used less as time passes.

Data for 1976 are not yet available from FPC but are expected soon. Those data are expected to show further declines in electricity generated by the units and time in use.

. Coal Use

The following table shows for 1973 and 1975 the tons of coal used and the percent of all fuel (i.e., coal, oil and gas) accounted for by coal.

Table 3:

	Tons of Coal Burned (000 tons) 1973	1975	Coal as % of total fuel used 1973	1975
. Round 1				
- 11 EPA cleared units	899	1,253	36%	69%
- 51 More control	2,853	4,239	15%	29%
- 12 No decision	634	894	11%	18%
(Subtotal)	(4,386)	(6,386)	(16%)	(29%)
. Round 2				
- April 77 NOI's	568	1,205	5%	12%
Totals	4,954	7,591		

For comparison, a new coal-fired base-load unit of 400 megawatts in capacity uses about 1 million tons of coal per year.

The above table shows that coal use is increasing in the units covered by FEA efforts:
- In absolute terms, from about 5 million tons to about 7.6 million tons per year.
- As a percentage of total fuel used.

Data are not yet available from FPC for 1976, but those data will be available soon and are expected to show significant increases in coal use over 1975.

* * *

Detailed information on the 105 units are shown in the tables on the following pages -- along with data for the total plants of which the units are a part. Plant sites often include more than 1 unit, including some units not covered by the FEA conversion efforts. In several cases, the other units located at the plant site were already using coal and are continuing to do so.

* * *

<u>Steps in the FEA Conversion Effort Process.</u> Once FEA identifies promising candidates (after considering plant capacity and condition, coal and transportation availability, economics, etc), the following steps are needed for each unit:

. FEA issues a Notice of Intent (NOI) to issue an order prohibiting the use of fuel other than coal.
. FEA holds public hearing on proposed order.
. FEA issues the Prohibition Order (PO).
. FEA begins an Environmental Assessment or Environmental Impact Statement(EIS) on each order.
. EPA, if it so concludes, certifies that the ordered conversion can be accomplished within air quality standards & requirements.
. When FEA's environmental analysis is completed (including hearings for EIS's), FEA can issue a Notice of Effectiveness(NOE) which defines the date and schedule for implementing the order.
. FEA enforces the order -- which should lead to burning of coal.

<u>Elapse time</u>. FEA estimates that a period of 4 to 8 years may be required to achieved forced conversion, depending on many factors including whether orders are challenged by the utility or others.

SUMMARY

Category Round One	Installed Capacity: Total Plant (MW)	Installed Capacity: Unit(s) Effected (MW)	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 Tons)	Total Plant Statistics: % Generation by Coal	Total Plant Statistics: % Generation by Oil	Total Plant Statistics: % Generation by Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons)	Unit Statistics: % Generation by Coal	Unit Statistics: % Generation by Oil	Unit Statistics: % Generation by Gas
11 units certified to burn coal immediately	1,893	938	1973	8,714	1,473	33	31	37	4,592	899	36	20	44
			1975	5,612	1,816	61	9	30	3,714	1,253	69	-	31
			1976	6,517	2,568	76	5	19					
51 units - can burn coal after equipment modification	11,340	7,705	1973	57,014	7,940	33	54	13	37,813	2,853	15	69	16
			1975	45,244	8,654	41	49	10	30,618	4,239	29	61	10
			1976	45,492	11,200	55	39	6					
12 units - no decision made	4,232	2,653	1973	16,755	655	10	89	1	14,249	634	11	87	2
			1975	17,035	1,218	16	80	4	11,526	894	18	79	3
			1976	18,871	1,583	20	80	1					
Total 74 Round One Units 1/	17,465	11,296	1973	82,483 1/	10,068 1/	29	59	12	56,654	4,386	16	70	14
			1975	67,891 1/	11,688 1/	36	53	11	45,858	6,386	29	61	10
			1976	70,880 1/	15,451 1/	48	47	5					
Round Two													
NOI's issued April, 1977 31 units	7,346	4,686	1973	37,021	599	4	82	14	27,733	568	5	87	8
			1975	33,660	1,494	10	79	11	23,937	1,205	12	82	6
			1976	31,449	789	5	84	11					

1/ Total plant statistics include some duplication of data.

ROUND ONE - PO's ISSUED 1975
ELEVEN UNITS CERTIFIED BY EPA
TO BURN COAL IMMEDIATELY

Company	Location	Installed Capacity: Total Plant MW	Installed Capacity: Unit(s) Effected MW	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 tons)	Total Plant Statistics: % Generation by Coal	Oil	Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 tons)	Unit Statistics: % Generation by Coal	Oil	Gas
Alabama Electric Coop. McWilliams 3	Ala.	40.0	25.0	1973	79	4	8	-	92	70	3	9	-	91
				1975	223	18	15	-	85	145	14	19	-	81
				1976	72	37	87	-	13					
Ames Municipal Unit 7	Iowa	60.2	33.0	1973	197	46	34	1	65	190	38	35	1	64
				1975	204	69	49	1	50	197	66	49	1	50
				1976	118	86	65	1	34					
Carolina Power & Light Sutton 1 & 2	N.C.	671.0	226.0	1973	2,984	150	11	89	-	1,004	21	6	94	-
				1975	1,197	546	97	3	-	726	324	100	-	-
				1976	2,247	869	88	12	-					
Iowa Power & Light Co. Des Moines 10, 11	Iowa	324.6	180.0	1973	1,636	480	44	-	56	959	363	58	-	42
				1975	1,115	367	45	1	54	654	278	70	-	30
				1976	940	496	75	3	22					
Iowa Public Service Co. Maynard 14	Iowa	107.4	50.0	1973	407	63	28	2	70	280	52	28	-	72
				1975	312	46	25	1	74	159	38	26	-	74
				1976	192	44	42	4	54					
Kansas City Bd. of Pub. Util. Quindaro 3 #1 & 2	Kans.	327.0	240.0	1973	1,138	120	25	-	75	863	120	25	-	75
				1975	1,107	335	60	-	40	942	295	73	-	27
				1976	1,301	407	67	-	33					
Nebraska Public Pwr. Dist. Sheldon 1	Neb.	227.8	109.0	1973	1,342	260	44	-	56	641	124	44	-	56
				1975	807	199	53	-	47	386	95	23	-	47
				1976	1,027	365	69	-	31					
Wisconsin Public Service Co. Weston 2	Wisc.	135.0	75.0	1973	931	350	79	-	21	585	178	65	-	35
				1975	647	236	71	-	29	505	143	61	-	39
				1976	620	264	79	-	21					
Total 11		1,893.0	938.0	1973	8,714	1,473	33	31	37	4,592	899	36	20	44
				1975	5,612	1,816	61	9	30	3,714	1,253	69	-	31
				1976	6,517	2,568	76	5	19					

ROUND ONE - PO's ISSUED 1975
51 Units Can Begin Burning Coal
Upon Necessary Equipment Upgrading or
Installation of New Pollution Control Apparatus

Company	Location	Installed Capacity: Total Plant MW	Installed Capacity: Units(s) Effected MW	Year	Total Plant Statistics: Generation (Mil. kwh)	Total Plant Statistics: Consumption (000 Tons)	Total Plant % Generation by Coal	Total Plant % Generation by Oil	Total Plant % Generation by Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons)	Unit % Generation by Coal	Unit % Generation by Oil	Unit % Generation by Gas
Delmarva Power & Light Edgemoor 1-4	Del.	390	357	1973	2,283	-	-	97	3	1,962	-	-	97	3
				1975	1,600	-	-	100	-	1,475	-	-	99	1
				1976	1,519	-	-	100	-					
Baltimore Gas & Electric Crane 1 & 2	Md.	399	391	1973	2,477	-	-	100	-	2,477	-	-	100	-
				1975	1,842	-	-	100	-	1,842	-	-	100	-
				1976	1,774	39	5	95	-					
Baltimore Gas & Electric Wagner 1 & 2	Md.	1,042	268	1973	5,141	774	39	61	-	1,400	-	-	100	-
				1975	3,390	502	37	63	-	1,129	-	-	100	-
				1976	3,653	605	48	52	-					
Baltimore Gas & Electric Riverside 4 & 5	Md.	333	153	1973	1,266	-	-	100	-	625	-	-	100	-
				1975	584	-	-	100	-	385	-	-	100	-
				1976	589	-	-	100	-					
Winnetka, Ill. Winnetka 5, 6, 7, 8	Ill.	25	28	1973	52	10	27	-	73	52	10	27	-	73
				1975	15	6	51	-	49	15	6	51	-	49
				1976	8	4	41	-	59					
Detroit Edison Co. St. Clair 5	Mich.	1,905	358	1973	10,510	3,560	87	13	-	1,114	172	31	69	-
				1975	8,610	2,989	80	20	-	1,091	-	-	100	-
				1976	8,653	3,277	82	18	-					
Kansas City Pwr. & Light Hawthorne, 3, 4, 5	Mo.	908	771	1973	3,311	1,149	64	-	36	2,701	1,142	67	-	33
				1975	2,971	1,298	84	-	16	2,400	1,255	95	-	5
				1976	2,782	1,182	82	-	18					
Nebraska Public Pwr. Dist. Sheldon 2	Neb.	227.8	120	1973	1,342	260	44	-	56	701	136	44	-	56
				1975	807	199	53	-	47	421	104	53	-	47
				1976	1,027	365	69	-	31					
Virginia Electric & Pwr. Co. Chesterfield 3, 4, 5, 6	Va.	1,484	1,354	1973	7,600	-	-	100	-	6,586	-	-	100	-
				1975	5,283	375	15	85	-	4,206	375	20	80	-
				1976	5,203	1,469	67	33	-					

51 units - Cont's.

		Installed Capacity			Total Plant Statistics					Unit Statistics				
Company	Location	Total Plant MW	Unit(s) Effected MW	Year	Net Generation (Mil. kwh)	Coal Consumption (000 Tons)	% Generation by Coal	Oil	Gas	Estimated Generation (Mil. kwh)	Coal Consumption (000 Tons)	% Generation by Coal	Oil	Gas
Potomac Elec. Pwr. Co. Morgantown 1, 2	Md.	1,251	1,251	1973	6,446	557	24	76	-	6,446	557	24	76	-
				1975	6,257	968	40	60	-	6,257	968	40	60	--
				1976	6,804	1,689	66	34	-					
Georgia Power Company McManus 1, 2	Ga.	143	144	1973	739	11	3	97	-	739	11	3	97	-
				1975	564	-	-	100	-	564	-	-	100	-
				1976	582	-	-	100	-					
Virginia Elec. & Pwr. Co. Portsmouth 1, 2, 3, 4	Va.	649	650	1973	3,328	-	-	100	-	3,328	-	-	100	-
				1975	2,271	-	-	100	-	2,271	-	-	100	-
				1976	2,601	--	-	100	-					
Niagra Mohawk Power Albany 1, 2, 3, 4	N.Y.	400	400	1973	2,617	-	-	100	-	2,617	-	-	100	-
				1975	2,149	-	-	100	-	2,149	-	-	100	-
				1976	2,080	-	-	100	-					
Kansas City Bd. of Pub. Util. Kaw 1, 2, 3	Kans	144	161	1973	668	37	11	-	89	668	37	11	-	89
				1975	700	157	45	-	55	700	157	45	-	55
				1976	530	187	73	-	27					
Iowa Elec. Light & Pwr. Sutherland 1, 2, 3	Iowa	156	158	1973	1,072	196	34	-	66	1,072	196	34	-	66
				1975	739	165	37	-	63	739	165	37	-	63
				1976	777	268	62	-	38					
Kansas Pwr. & Light Co. Lawrence 3, 4, 5	Kans.	613	566	1973	2,914	211	16	4	80	2,814	211	16	4	80
				1975	2,754	572	38	16	45	2,660	572	40	16	44
				1976	2,349	638	49	19	32					
Springfield Utilities James River 3, 4	Mo.	253	104	1973	1,028	94	19	-	81	420	26	13	-	87
				1975	849	197	47	-	53	290	65	41	-	59
				1976	919	271	60	-	40					

51 Units - Cont'd.

Company	Location	Installed Capacity: Total Plant MW	Installed Capacity: Unit(s) Effected MW	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 Tons)	Total Plant Statistics: % Generation by Coal	Total Plant Statistics: % Generation by Oil	Total Plant Statistics: % Generation by Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons)	Unit Statistics: % Generation by Coal	Unit Statistics: % Generation by Oil	Unit Statistics: % Generation by Gas
Public Service of N.H. Schiller 4, 5	N.H.	175	100	1973	904	-	-	100	-	596	-	-	100	-
				1975	504	-	-	100	-	310	-	-	100	-
				1976	439	-	-	100	-					
Kansas Pwr. & Light Co. Tecumseh 9, 10	Kans.	346	232	1973	840	98	21	2	77	669	98	31	2	67
				1975	1,015	332	52	9	39	943	332	68	3	29
				1976	961	294	48	18	34					
Iowa Public Service Co. Neal 1	Iowa	496	139	1973	2,506	983	80	-	20	826	257	57	-	43
				1975	2,340	894	78	-	30	771	240	57	-	43
				1976	2,242	1,012	91	-	9					
Total 51 units		11,340	7,705	1973	57,014	7,940	33	54	13	37,813	2,853	15	69	16
				1975	45,244	8,654	41	49	10	30,618	4,239	29	61	10
				1976	45,492	11,300	55	39	6					

ROUND ONE - PO's ISSUED 1975
TWELVE UNITS - NO EPA
DECISION

		Installed Capacity			Total Plant Statistics					Unit Statistics				
Company	Location	Total Plant MW	Unit(s) Effected MW	Year	Net Generation (Mil. kwh)	Coal Consumption (000 Tons)	% Generation by Coal	Oil	Gas	Estimated Generation (Mil. kwh)	Coal Consumption (000 Tons)	% Generation by Coal	Oil	Gas
Atlantic City Electric	N.J.	475	299	1973	1,947	37	4	96	-	1,947	37	4	96	-
B. L. England 1, 2				1975	2,312	672	70	30	-	1,663	672	100	-	-
				1976	2,586	701	69	31	-					
Central Hudson Gas & Elec.	N.Y.	531	386	1973	3,220	-	-	100	-	2,390	-	-	100	-
Danskammer 3, 4				1975	2,169	-	-	100	-	1,813	-	-	100	-
				1976	2,256	-	-	100	-					
Virginia Elec. & Pwr. Co.	Va.	1,257	376	1973	1,798	393	62	38	-	1,798	393	62	38	-
Yorktown 1, 2				1975	4,340	-	-	100	-	1,294	-	-	100	-
				1976	4,945	-	-	100	-					
Carolina Power & Light	N.C.	671	420	1973	2,984	150	11	89	-	1,980	129	14	86	-
Sutton 3				1975	1,197	546	97	3	-	471	222	97	3	-
				1976	2,247	869	88	12	-					
Florida Power Corp.	Fla.	965	965	1973	5,248	-	-	100	-	5,248	-	-	100	-
Crystal 1 & 2				1975	5,319	-	-	100	-	5,319	-	-	100	-
				1976	4,891	13	1	99	-					
Savannah Elec. & Pwr. Co.	Ga.	333	207	1973	1,558	75	10	75	15	886	75	18	57	25
Port Wentworth 1, 2, 3				1975	1,698	-	-	65	35	966	-	-	65	35
				1976	1,946	-	-	96	4					
Total 12 units		4,232	2,653	1973	16,755	655	10	89	1	14,249	634	11	87	2
				1975	17,035	1,218	16	80	4	11,526	894	18	79	3
				1976	18,871	1,583	20	80	-					

ROUND TWO - NOI's ISSUED 1975
31 UNITS

Company	Location	Installed Capacity: Total Plant MW	Installed Capacity: Unit(s) Effected MW	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 Tons)	Total Plant Statistics: % Generation by Coal	Oil	Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons)	Unit Statistics: % Generation by Coal	Oil	Gas
New England Electric	Mass.	1,600	1,125	1973	7,346	-	-	100	-	7,346	-	-	100	-
Brayton Point 1,2,3				1975	7,031	601	21	79	-	5,130	601	30	70	-
				1976	7,296	-	-	100	-					
Montaup Electric	Mass.	290	122	1973	1,728	-	-	100	-	660	-	-	100	-
Somerset 8				1975	1,154	121	22	78	-	855	-	-	100	-
				1976	767	-	-	100	-					
Hartford Electric Co.	Conn.	837	421	1973	3,587	20	1	99	-	2,240	20	2	98	-
Middletown 1,2,3				1975	3,421	-	-	100	-	2,056	-	-	100	-
				1976	2,418	-	-	100	-					
Northeast Utilities	Conn.	326	326	1973	2,039	-	-	100	-	2,039	-	-	100	-
Norwalk Harbor 1,2				1975	1,916	-	-	100	-	1,916	-	-	100	-
				1976	1,793	-	-	100	-					
United Illuminating	Conn.	653	660	1973	3,721	-	-	100	-	3,721	-	-	100	-
Bridgeport Harbor 1,2,3				1975	3,385	-	-	100	-	3,385	-	-	100	-
				1976	3,189	-	-	100	-					
New England Electric	Mass.	805	275	1973	3,340	-	-	100	-	1,746	-	-	100	-
Salem Harbor 1,2,3				1975	4,086	82	4	96	-	1,673	82	10	90	-
				1976	3,742	-	-	100	-					
Holyoke Water & Pwr.	Mass.	136	136	1973	873	13	4	96	-	873	13	4	96	-
Mt. Tom				1975	1,007	-	-	100	-	1,007	-	-	100	-
				1976	805	-	-	100	-					
Vineland, City of	N.J.	75	25	1973	310	-	-	100	-	165	-	-	100	-
Vineland (Down)				1975	290	-	-	100	-	157	-	-	100	-
				1976	156	-	-	100	-					

31 units - Cont'd.

		Installed Capacity			Total Plant Statistics					Unit Statistics				
		Total Plant	Unit(s) Effected		Net Generation	Coal Consumption	% Generation by			Estimated Generation	Coal Consumption	% Generation by		
Company	Location	MW	MW	Year	(Mil. kwh)	(000 Tons)	Coal	Oil	Gas	(Mil. kwh)	(000 Tons)	Coal	Oil	Gas
General Public Utilities Sayreville 7, 8	N.J.	347	247	1973	1,995	-	-	96	4	1,490	-	-	95	5
				1975	1,123	-	-	97	3	1,096	-	-	97	3
				1976	1,069	-	-	100	-					
Long Island Lighting E. F. Barrett 10	N.Y.	375	175	1973	2,060	-	-	82	18	920	-	-	80	20
				1975	1,848	-	-	96	4	935	-	-	92	8
				1976	1,828	-	-	96	4					
Long Island Lighting Port Jefferson 3, 4	N.Y.	467	350	1973	2,382	-	-	100	-	1,877	-	-	100	-
				1975	2,483	-	-	100	-	2,400	-	-	100	-
				1976	2,540	-	-	100	-					
Philadelphia Electric Co. Cromby 1, 2	Pa.	418	418	1973	2,268	396	46	54	-	2,268	396	46	54	-
				1975	1,594	340	53	47	-	1,594	340	53	47	-
				1976	1,752	391	55	45	-					
Interstate Power Co. Fox Lake 3	Minn.	105	82	1973	351	-	-	66	34	271	-	-	63	37
				1975	314	10	5	35	60	285	-	-	35	65
				1976	307	66	30	29	41					
Oklahoma Gas & Electric Mustang 3	Okla.	594	118	1973	3,215	0.6	-	-	100	860	0.6	-	-	100
				1975	2,882	-	-	-	100	730	-	-	-	100
				1976	2,549	-	-	-	100					
Corn Belt Power Coop. Wisdom	Iowa	37	38	1973	211	43	39	-	61	211	43	39	-	61
				1975	134	43	57	-	43	134	43	57	-	43
				1976	40	16	64	-	36					
Independence Pwr. & Light Blue Valley 3	Mo.	115	58	1973	478	37	15	1	84	216	14	12	1	87
				1975	474	131	50	1	49	232	17	15	-	85
				1976	435	112	49	9	42					

31 units - Cont'd.

Company	Location	Installed Capacity: Total Plant MW	Installed Capacity: Unit(s) Effected MW	Year	Total Plant Statistics: Net Generation (Mil. kwh)	Total Plant Statistics: Coal Consumption (000 Tons)	Total Plant Statistics: % Generation by Coal	Oil	Gas	Unit Statistics: Estimated Generation (Mil. kwh)	Unit Statistics: Coal Consumption (000 Tons	Unit Statistics: % Generation by Coal	Oil	Gas
St. Joseph Pwr. & Light Co.	Mo.	125	84	1973	936	64	10	2	88	707	59	14	1	85
Lake Rd. 5, 6	.			1975	338	104	49	4	47	250	102	60	-	39
				1976	547	143	47	3	50					
Fremont Dept. of Utilities	Neb.	41	26	1973	181	25	26	-	74	123	22	34	-	66
L. D. Wright 7				1975	180	49	41	-	59	102	20	35	-	65
				1976	216	91	70	-	30					
Total 31 units		7,346	4,686	1973	37,021	599	4	82	14	27,733	568	5	87	8
				1975	33,660	1,494	10	79	11	23,937	1,205	12	82	6
				1976	31,449	789	5	84	11					

Mr. Moffett. Thank you, Mr. Bagge.

Before Dr. Boyd begins his testimony, the Chair would like to announce we are going to continue through this recorded vote and hope that we won't have to interrupt if one of the members returns because this panel is scheduled to conclude at 11 o'clock and we want to make the best possible use of our time.

Dr. Boyd.

STATEMENT OF JAMES BOYD, PH.D.

Mr. Boyd. Thank you, Mr. Chairman, members of the committee. My name is James Boyd, president of Materials Associates, Inc. For the past 2 years I have served as chairman of the Energy Resources Group of the Committee on Nuclear and Alternative Energy Systems (CONAES), a major National Academy of Sciences/National Academy of Engineering study of solutions to this Nation's energy problem. The complete report of that study should be available in the next 2 or 3 months. This morning I would like to share with you some of the conclusions I have reached while being intimately associated with the Coal Sub-Panel during the time it was generating its advice to CONAES.

By 1985 the National Energy Act seeks, "an increase in annual coal production to at least 400 million tons over 1976 production." This calls for total coal production of 1.065 billion tons in 1985, since 1976 production was 665 million tons. Can we get to nearly 1.1 billion tons in 1985? Based upon 2 years of intensive study by some of the most knowledgeable academic and industrial coal experts, the answer has to be a qualified "yes."

There are two overriding qualifications which must be attached to that yes. The first caveat is that the market for this coal will develop. The bill addresses market stimulation. Others testifying here will speak to the point of whether the market will, in fact, develop under the provisions of this bill. The second overriding consideration is whether Federal production-related policies will permit coal to be produced at that rate.

PRESENT COAL RESERVES

The ability to meet coal production goals depends first on the size and nature of recoverable reserves of coal. They total 266.3 billion tons, as table I demonstrates. These numbers were derived by applying recovery rates of 50 percent for underground mining and 85 percent for surface mining to the coal reserve based estimated by the U.S. Bureau of Mines and confirmed by discussions with the various State geologists. Clearly, our reserve position will support mining 1.1 billion tons of coal for a long time.

TABLE I

RECOVERABLE RESERVES OF U.S. COAL BY TYPE OF MINING AND TYPE OF COAL

Type of Coal	Type of Mining		
	Underground	Surface	Total
	MM Tons	MM Tons	MM Tons
Anthracite	3,650	80	3,730
Bituminous	96,200	34,500	130,700
Subbituminous	50,100	57,860	107,960
Lignite		23,940	23,940
TOTAL	149,950	116,380	266.330

PRESENT PRODUCTION TRENDS

While the coal reserves will support production of 1.1 billion tons of coal, our estimates of present industry growth trends show that the industry will achieve only 995 million tons of production in 1985. Thus there will be a shortfall of about 70 to 100 million tons of coal in that year.

It take from 4 to 10 years to plan, get approval, buy equipment and open a coal mine, depending on its size and mining method. Any new mines not now well along in the planning stage cannot be expected to be producing in the 7 years remaining until 1985 without a major change in the policies under which coal is produced today.

The 995 million tons, however, represents increasing production by 330 million tons—about a 50 percent increase over present production. It means replacing nearly 300 million tons of present coal mining capacity, as all mines have a finite life, plus adding more capacity on top of that replacement. Under present plans, about 75 percent of the replacement plus expansion will come from western coal mines. Table II presents the present projects for 472 million tons of future western coal mining production, now either in planning or construction.

Table II. Future Western Coal Mines and Capacities by States

State	New mines		Expansions to existing mines		Totals	
	Number	Annual production increase[1]	Number	Annual production increase[1]	Number	Annual production increase[1]
Arizona.......	–	–	2	5.0	2	5.0
Arkansas......	–	–	1	.1	1	.1
Colorado......	[2] 37	38.8	8	6.8	45	45.6
Kansas........	1	.25	–	–	1	.25
Iowa..........	–	–	1	.1	1	.1
Montana.......	[3] 6	19.0	3	29.2	9	48.2
New Mexico....	3	34.0	5	43.7	8	77.7
North Dakota..	[4] 5	34.0	4	8.6	9	42.6
Oklahoma......	[5] 7	.25	–	–	7	.25
Texas.........	5	38.0	1	8.0	6	46.0
Utah..........	[6] 25	54.3	5	10.2	30	64.5
Washington....	2	2.0	–	–	2	2.0
Wyoming.......	[7] 23	118.4	10	21.4	33	139.8
Total....	114	339.0	40	133.1	154	472.1

[1]Annual production increase in million short tons per year.
[2]Includes 10 new mines with planned capacities unknown or unavailable.
[3]Includes 4 new mines with planned capacities unknown or unavailable.
[4]Includes 2 new mines with planned capacities unknown or unavailable.
[5]Includes 6 new mines with planned capacities unknown or unavailable.
[6]Includes 1 new mines with planned capacities unknown or unavailable.
[7]Includes 2 new mines with planned capacities unknown or unavailable.

Thus, under present policies there will be a shortage of coal in 1985, if demand develops for the utilization of 1.1 billion tons in that year.

REACHING 1.1 BILLION TONS

Closing the 70 to 100 million ton production gap will require more incentives than just creating a market. It is clear to me that there is agreement among the people I have been working with that 1.1 billion tons of coal could be produced. I would like to summarize those policy changes needed to permit this to happen.

H.R. 6831 deals with some of the issues involved, but as it is directed primarily to detailed regulation, it is too complicated to permit the removal of principal impediments to expansion.

A. Uncertainties should be removed from Federal land policies, including leasing of appropriate lands. The administration has to recognize and act to remove uncertainties.

B. Present environmental policies should be continued in substance, but not in the present form. The intent of each law would be fulfilled but with interpretations and actions which recognize "the need to produce goods as well as the need to protect the environment." The intensity of the adversary atmosphere, existing today, must be diminished significantly. This implies:

(1) The permitting process should continue to exist, but in streamlined form. The number of authorizing agencies at all levels of government should be materially reduced, then decisions made in reasonable, legally required, timeframes.

Mr. MOFFETT. I was hoping that one of my colleagues would get back but apparently that hasn't happened so we will stand in recess.

[Brief recess.]

Mr. SHARP. The subcommittee will come to order.

Dr. Boyd, will you continue?

Mr. BOYD. I was pointing out the particular items which need to be addressed which were not addressed by the bill and will be required of the Congress in order to assist in this program.

(2) Court challenges should continue to exist but the number and time duration of such challenges should be reduced, by specific legislation.

(3) Monitoring of energy production units should continue, but would proceed within the context of an overall energy policy which encourages development. Establishment of standards should not be waived, but the means of reducing pollutants which result in possible long-term health problems should be geared to realistical time frames.

(4) Health and safety laws must continue to be enforced, but the hostility presently existing between inspectors and industry has to be replaced by a cooperative effort to improve working conditions.

You may remember, Mr. Chairman, I was once director of the Bureau of Mines and we did this all on a voluntary basis.

C. Capital markets must afford more investment money to the expansion of energy conversion. This implies:

(1) That coal, at this juncture, is the primary alternative to the less abundant fuels. End users such as electric utilities will find more money available for coal-fired plants.

I think Mr. Bagge has explained that in detail.

(2) The elimination of uncertainties will make energy investments more attractive.

D. General public attitudes will have to reflect more of a sense of purpose. This will be reflected in worker attitudes within the energy industry.

MAGNITUDE OF THE TASK

To reach the 1.1 billion ton level by 1985, the coal industry will have to expand at an annual rate approaching 7.5 percent. That is a formidable task. It requires no slippage in production schedules, no delays—whatever the cause. Measures of the degree of difficulty can be found in estimates of related requirements. They are as follows:

(1) $27.9 billion of capital for opening and expanding coal mines (but not for related systems such as transportation and utilization);

(2) Raising the work force level from the current level of about 160,000 to approximately 250,000 workers; and

(3) Raising the engineering work force from a present level of 5,000 to 21,000 skilled professionals.

This is one of the most important things and was raised by the fact that previous testimony indicated that the technologies are perhaps lagging in coal, there aren't sufficient engineers to do these things.

These hurdles are not insurmountable. The task of accomplishing those requirements, however, is of Herculean proportions.

CONCLUSION

Yes, we can get the coal if there are Federal policies which encourage the flow of capital into the industry, recruit the workers, and train and hire the engineers. We can get the coal if consuming industries are encouraged or permitted to use coal and thus to provide firm markets on which the mining companies can have firm contracts. Those are big "ifs." Thus, in pursuing the goal of 1.1 billion tons of coal by 1985, the answer regarding our capability to produce that much can only be a qualified "yes." The complexities of H.R. 6831 make the qualification more emphatic. The act as written will take long periods of time to convert into regulation, the regulations promulgated and become effective; and it does not include some of the "musts" listed above.

Mr. Sharp. Thank you, Mr. Boyd.

Mr. Perry.

STATEMENT OF HARRY PERRY

Mr. Perry. Part F of title I of H.R. 6831 is directed at reducing oil imports and use of gas at major energy-consuming facilities by replacing or converting these facilities to coal as their fuel. These are very desirable objectives but the legislation as written is more complex than it should be. Several methods of simplifying the legislation are suggested. For new plants the legislation should be phrased so as to make plain Congress' intention that exceptions or exemptions be extremely difficult to obtain. As to existing plants, those who will administer the program should be given more leeway in making case-by-case decisions but under conditions clearly indicating the intent of Congress to make conversions as rapidly as possible subject to economic, environmental, regulatory, et cetera, considerations. The clearer the conditions are spelled out, the less time will be spent in time-consuming litigation.

If the phasing out of oil and gas use at those major energy-consuming installation is carried out as suggested, there should be little difficulty in obtaining ample coal supplies. This results because the timing of the phasing out of oil and gas would, in most instances, be long enough for the new coal mines that are needed to be constructed.

The President's National Energy Plan has among its major goals a reduction in the use of oil and gas in order to achieve two principal energy objectives. The first is to reduce the level of oil imports to 6 million barrels per day by 1985 so that the Nation's supply of energy will be more secure and less susceptible to interruptions. A subsidiary hoped-for benefit of a reduction in imports will be an improved balance of payments position for the Nation. The second objective of reducing oil and gas use will be to ensure a more orderly transition from the current dependence on the use of oil and gas to other domestic energy forms that are in greater abundance or are, for all practical purposes, inexhaustible.

Part F of title I of H.R. 6831 would prohibit new electric plants and major fuel-burning facilities from burning oil and gas and would require existing powerplants and major fuel-burning facilities using these fuels to convert to coal if they are capable of doing so. Existing oil- and gas-burning facilities not able to convert immediately would be phased our over time. Provisions are made for various exceptions and exemptions to these requirements. But it is unclear as to the extent to which customers of electricity in various regions may have to bear the extraordinary costs of conversion.

There can be little doubt that it is in that Nation's best interest to establish a more reliable and secure supply of fuels and to begin the very difficult and time-consuming process of making the transition from oil and gas to other energy forms. Under the very best of circumstances the transition will create a large number of extremely complex economic, social, institutional, and political problems. Part F of title I is an attempt to expedite the shift away from oil and gas in those kinds of facilities that are able to use coal as a fuel.

Unfortunately, the provisions of part F are extremely complex and the exceptions and exemptions so numerous that it will be extremely difficult to administer, particularly with respect to existing plants that now use oil and gas. The experience to date in enforcing the provisions of the Energy Supply and Environmental Coordination Act of 1974 has been very unsatisfactory. It is not obvious how the provisions of part F with respect to conversion of existing plants would be an improvement over the present regulations.

Much of the complexity in administering new legislation derives from the increasing frequency of incorporating detailed rules and regulations in the legislation in place of establishing clear-cut guidelines which administrators are directed to follow and allowing them to carry out the intent of the legislation in the most efficient manner. The problem in giving the administrators vague and subjective standards is that they promote endless litigation. With respect to part F of title I, this defect could best be avoided by requiring that:

All new installations—utility and major fuel-burning installations—use coal in an environmentally acceptable manner. Exceptions and exemptions would be determined by the administrator on a case-by-case basis, subject to the general congressional policy directive that primary ambient air quality standards would be met in every instance, and exceptions from more stringent regulations should be kept to a minimum.

All existing oil- and gas-burning installations be phased out within *x* years but, as any facility reached its 20th year of operation, it must be phased out. Existing facilities nearing their 20th year of life at the time of enactment of the legislation would be permitted to operate for a minimum of 5 more years. The extra costs to ratepayers of any of these early retirements should be reimbursed by the Federal Government.

Reconversion back to coal of existing facilities that were designed to burn coal would be on a case-by-case basis by the administrator, using such criteria as environmental considerations, physical ability to reconvert, and estimates of the economic implications of reconversion. This last criterion would depend, among other factors, on the age of the plant, the difficulty and costs of reconversion and the relative costs of coal compared to those of oil and gas currently being used.

The rationale for adopting these three principles is as follows: First, the times required for constructing new coal-burning plants and the new mines to serve them are such that new mines could be constructed in the time required to build the plant that would use the coal. Moreover, if the environmental standards the mine and the coal utilizing facility would have to meet were known, provisions could be made to mine and burn the coal in a way that would meet the environmental standards.

With respect to phasing out existing plants sufficent time should be allowed to do this in an orderly manner. This approach would also permit environmental standards to be met more promptly. Coal supply should not create any problems since sufficient time would be allowed so that new mines could be constructed to supply the new demand.

Reconversion of facilities that were once able to burn coal has received the most attention because of the provisions of the ESECA legislation passed in 1974. While it is probable that the reconversion of some plants is justified, and, in fact, some plants have been reconverted, it is unlikely that if the criteria suggested above are used many plants would qualify.

Estimates of the costs of reconversion for utility plants have been made by the FEA and recently estimates of costs for industrial facilities were released when a number of industrial plants were put on notice that they were expected to reconvert to coal. The costs of reconversion are very high, the physical difficulties to obtain satisfactory reconversion are often great, and the ability of these facilities to obtain coal quickly and have it delivered to the plants is limited. Until each individual installation is examined in detail and estimates are made of the costs of reconversion it is impossible to determine how much effort should be devoted to forcing these plants to use coal again. Based on the limited data available, it is unlikely that reconversion of the plants that meet reasonable criteria for shifting back to coal will result in large savings in the use of oil and gas—perhaps not even enough to be worth the effort except in unusual cases.

One particularly difficult problem in determining which plants should reconvert is establishing the availability and costs of compliance coal for the plant. When each individual plant is examined separately it usually appears that there is ample compliance coal available. However, if all the plants that are expected to convert are examined at the same time, the total coal available that will meet the environmental standards would be in short supply. This complex problem has not received sufficient attention to date by FEA or EPA.

Finally, the availability of compliance coal to meet the requirements for coal supply that would develop if part F were implemented immediately is very difficult to determine. Large increases in coal production capacity should be possible by 1985, given the large reserve base for coal, but whether the new mines will be constructed depends on the resolution of a number of still unsettled issues; with respect to the environment, the strip mine and air pollution regulations are the two most important. In the shorter term, 1980 for example, unless existing coal mines and those under construction are prohibited from producing coal for some reason, productive capacity should be able to meet demand for coal. But this conclusion is based on the limited reconversion to coal policies that are suggested above.

One final remark.

In the national energy plan, the coal requirement for 1985, without the Carter plan are proposed at just over 1 billion tons, with the Carter plan at 1.2 billion tons, and I see nothing in the plan that would account for the industry to be able to produce any incentives for the industry to be able to produce those extra 200 million tons of coal. It just isn't clear to me how that would fall out of the plan.

Mr. MOFFETT. Thank you, Mr. Perry.

The Chair now recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

I would first like to address a remark to Assistant Secretary Martin, simply saying that has nothing to do with this hearing directly. I am very distressed with the cancellation of the lease sales for offshore production off the South Atlantic Coast, Alaska and California. For the life of me I don't understand. We are trying to find an energy solution. We go about studying, restudying and reconsidering this problem. It has been studied to death. I can only say this must be a part of the administration's true plan to produce no more oil and natural gas in this country, or to encourage no more production, but in fact this must fit into a plan to force conversion to coal by denying one supplies of oil and natural gas.

People in Louisiana, my State, and I suppose Texas may be the same way, are getting a little piqued, justifiably, as to why we continue to produce oil and gas off our coastlines and share with the rest of the Nation and then are being forced to convert to coal, something we don't have, which is going to cause us grave expense. We don't understand that and I am having a hard time explaining it to them.

I think you are entirely correct, reading your statement, Mr. Bagge. I think you are next, if we continue this scheme of regulation which is producing less energy every day. Allocations and price control on coal is a sure thing, with some kind of Btu magic conversion formula such as we have seen in this bill. I commend you on your testimony and I assume you would favor decontrol of the entire energy industry in a step-by-step fashion.

Mr. BAGGE. We make that point explicitly, Congressman, in our prepared statement. We believe that with respect to that issue, that in lieu of taxes on oil and gas, as an incentive or a disincentive to use oil and gas, taxes don't provide incentives for more production, and we say explicitly in the statement, Congressman Moore, that between decontrol of oil and gas and taxes, we support the concept of decontrol as a more effective means of achieving both the shift to coal and incentives for new production.

Mr. MOORE. Let me ask you this question. I read your statement as to what your alternative solution is. I don't know that that would be acceptable to this committee. It certainly would be to me, but I am not sure it will be to this committee or the administration.

The 1990 forced conversion date to utilities seems to pose a problem to some in my area who have almost new oil or natural gas boilers; it being said that we are forced to convert by that date, and to scrap good equipment that is not worn out would cost something on the order of $3 million to the utility company in my hometown, and they are saying they are going to have to raise utility rates by some three times to get it back.

Could you give us a date if we have to have a date? Is there a more reasonable date we can put in this bill that would give us time to see that no new oil and natural gas burners are constructed, but also give us time to allow the wearing out of the ones we have so we don't force one into an inefficient and cost ineffective conversion? Is there a more opportune date you can give us?

Mr. BAGGE. I would think approaching that question with an arbitrary date is itself a ludicrous way of resolving the issue. If there is some capital cost in your part of the country, sunk in a gas-fired boiler, and it doesn't lend itself to retrofitting to coal, rather than an absolute arbitrary date, it would seem to me that the rational way for public policy to articulate what our goals are is to say that that sunk capital cost may continue to be utilized in the public interest for the benefit of those consumers.

We have attached as appendix A to the formal statement, a showing of what the utility plans are as reported to the Federal Power Commission, and we find there that gas is being phased out. The specific number of boilers and units are described in there, in the portion of my paper that I did read. I did point out that this is being phased out today.

It seems to be ludicrous to adopt as a matter of national policy an arbitrary date which will inure to the disadvantage of the consumers of that region in the country where we have been traditionally burning natural gas.

Mr. MOORE. If we don't use that approach then, I think to satisfy my colleagues, we are going to have to have some assurance in this bill, and to satisfy the administration, that there will be no more oil or natural gas boilers constructed for purposes of use in utility companies.

Could we in place of that simply just say that there shall be no more constructed after a certain date, and maybe give a carrot approach for those who can convert reasonably effectively?

Mr. BAGGE. That strikes me as a far more reasonable alternative than an arbitary date, which would scrap sunk capital costs, far more reasonable.

Mr. MOORE. Could you very briefly in the time we have left—this is the first panel of witnesses on this problem, and I am not a coal expert—explain just what are the problems. Let's assume you have got a natural gas-fired boiler that is relatively new. That is what we have now in our part of the country all over where gas is produced. What are the practical problems? Can you tick them off to require somebody by 1990 to scrap them and go to a coal-fired operation?

Mr. BAGGE. No, I am not technically qualified to describe in detail the circumstances that make that impossible in that part of the country. I do, however, have to rely on the opinion of my staff who are expert in that, and I would call on Mr. Mullan, who is a boiler engineer who can describe that, if Mr. Mullan would do so. He is qualified to describe the technical details.

Mr. MOFFET. Would you come forward, Mr. Mullan?

Mr. MOORE. Very briefly. My time is almost expired. I appreciate the Chair's leniency.

Just tell us what are the problems of storage, new kinds of boilers, transportation, size of plants, that sort of thing.

Mr. MOFFETT. Would you just give your full name?

Mr. MULLAN. Joseph W. Mullan, vice president, Government Relations, National Coal Association.

It starts in the boiler itself, sir. The furnace volume of the boiler, if it is designed for gas, does not lend itself to be used for coal.

Mr. MOORE. You have to have a new boiler.

Mr. MULLAN. That is right. That is for openers. Obviously they don't have coal handling equipment at such plants. They did not have that in mind. You don't have coal pulverizing equipment. They probably have no air pollution control equipment at the plant. You may not have the railroad facilities to deliver it to the plant so it is not just a simple pick up one fuel and put in another.

Mr. MOORE. What is a comparative size of a physical facility to house the storage of coal, the coal burners, as compared to a natural gas operation?

Mr. MULLAN. The basic land area involved?

Mr. MOORE. And building area, yes.

Mr. MULLAN. Land and building area I would say would be a minimum of three and as much as five times the area.

Mr. MOORE. Three to five times larger for coal than gas.

Mr. MULLAN. For coal. The boiler itself is not five times larger. I am just taking the land area that would be required for the burn facilities.

Mr. MOORE. Thank you, Mr. Chairman, and thank you for the answers.

Mr. MOFFETT. Thank you, Mr. Mullan.

We will now hear from the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. Yes, Mr. Chairman, I would like to ask this of the panel.

I believe, Mr. Bagge, you were advocating that we allow construction work in progress on the rate basis for any new plant; is that correct?

Mr. BAGGE. We are saying more than that, Congressman Sharp. We are saying that Congress has to look at the whole system. We think the key to unlocking and making a true national commitment to coal lies in the States, and the State regulatory policies, a whole host of policies, not just construction work in progress, but the fuel adjustment clause, which operates as an affirmative disincentive to capital investment in flue gas desulfurization, low gas Btu, and technologies that can burn coal cleanly. The accumulative thrust of a number of State regulatory policies are presently operating as a disincentive. It is broader than just the construction work in progress although we perceive that as an important element in a rational State regulatory policy which will provide for a shifting of this economy away from oil and gas to coal.

Mr. SHARP. You would like us to mandate those with utilities.

Mr. BAGGE. We are advocating that not only with respect to utility regulatory policies. We are also suggesting that you give consideration to an override by the Federal Government of the air quality requirements. To us the States are the key to this, Congressman Sharp. The States were affirmatively induced in 1970, it is our contention, by EPA, in their overzealous attempt to formulate air quality goals, that EPA itself found, when the State implementation plans were sent to them, cannot be implemented because of the lack of low sulfur oil and natural gas.

We respectfully contend that the Federal Government, having in 1970 affirmatively induced the States to set standards which they themselves explicitly found cannot be met, has a continuing responsibility to the people of this Nation, now that we have pereived the importance of coal, to override State air quality requirements that exceed the primary health standard established by the Federal Government. So it is not only in terms of State regulatory policy; it is not only in terms of construction work in progress, but it is the whole mechanism by which the States are creating affirmative constraints on the utilization side, and in the ability of the utilities to make capital investments. So we are urging you to take a serious look at this problem.

Mr. SHARP. All right, fine. I understand that is a broader issue. I want to narrow it for the moment just to CWIP.

I was going to ask the other panel members if there might not be another way of handling this. As I understand now, the Federal Power Commission allows for construction work in progress in terms of pollution equipment and conversion to coal and some suggestion has been made that, rather than give that across the board, expand it for only coal-fired plants as opposed to nuclear, as a way of emphasizing coal over nuclear.

I wonder if you have any particular approach to construction work in progress.

Mr. MARTIN. I am going to defer comment on that until one of your later panels. I think we have gone beyond the issue of supply. The administration is going to supply witnesses specifically qualified to talk about that issue in detail.

Mr. SHARP. Mr. McCormick, do you have any comment?

Mr. MCCORMICK. No.

Mr. SHARP. Do the other gentlemen?

We will await another panel on this issue. I would like to return then to the question of what is involved in follow-up, if you would like to bring the other gentleman from the National Coal Association back just to give us just a little more indication of what as a practical matter is involved.

Can you give us any cost estimate? I realize every plant is different, every situation is different. But what kind of sums of money are we perhaps talking about in an average size plant, assuming there is some transportation facility to get it there.

Mr. MULLAN. If for numbers' sake, we are talking now of a plant size of a 1,000 megawatts, which is a typical design for a new large electric utility installation. A thousand megawatts is a thousand-thousand kilowatts. It costs about $500 to $600 a kilowatt to construct a coal-fired plant. I would presume that the gas-fired plant could be built for something in the range of $300 to $400 per kilowatt.

I would really like to check that number. I have not looked at the price of gas-fired plants recently, I have been looking at coal-fired and nuclear plants.

Mr. SHARP. That is new plants?

Mr. MULLAN. Yes, new plants.

Mr. SHARP. I am trying to determine what it would cost to convert from an existing plant into a new plant.

Mr. MULLAN. That is a very difficult one to answer. It would have to be specific in nature. If you could convert the boiler, obviously you would not have the cost of building a new boiler, but you would still have the price of the pulverizers, and coal-handling equipment. You could pay as much for the conversion of the boiler as you could to build a new boiler unit, because you are retrofitting, putting things in the place of other equipment.

I guess you would compare it to adding a closet to an existing house; you tear the house apart putting the closet in. In a case of a gas-fired boiler, if in fact you could do it, you would spend as much as you would building a new coal-fired plant in the first place.

Mr. SHARP. I take it there is a radical variation among plants as to what would be needed.

Mr. MULLAN. That is right.

Mr. SHARP. Some could be retrofitted, others would be expensive, some would be old, close to getting new equipment anyway, with equipment wearing out and, as Mr. Moore indicated——

Mr. MULLAN. Your point is very well made. That is the reason these have to be looked at on a site-specific basis.

Mr. SHARP. Mr. Perry, were you going to comment?

Mr. PERRY. Yes. I think you have to think of an existing gas-fired plant, if it has to convert to coal, as being a replacement as far as the boiler, coal-handling facilities, everything but the turbine.

You are probably talking about $400 to $500 an installed kilowatt or $400 to $500 million for a 1,000-megawatt plant. I just do not think for a variety of physical and technical reasons that you would do other than to replace the boiler.

Mr. MULLAN. I agree.

Mr. SHARP. You said between $400 and $500 million?

Mr. PERRY. Per 1,000 megawatt plant, yes, sir.

Mr. SHARP. Anybody have any different——

Mr. MOORE. Will the gentleman yield one moment?

Mr. SHARP. Sure.

Mr. MOORE. What is the life of a gas-fired plant? How long will these boiler plants be expected to live?

Mr. SHARP. Yes, and can you tell us on the other kinds, coal, oil, gas?

Mr. MULLAN. I believe the Internal Revenue Service allows them to write it off in something like 25 years. That is one number. There are coal-fired boilers in the United States which are as old as 50 years. I would say the typical life of a coal-fired power plant is between 30 and 35 years. I am not sure it would be the same for gas-fired boilers.

Mr. MOORE. Does anybody know for gas?

Mr. PERRY. That is a close enough number. It depends on the plant obviously.

Mr. BROWN. Are you specific about that 25 years or is that an estimate?

Mr. MULLAN. The tax people could best answer that.

Mr. BROWN. The tax.

Mr. MULLAN. I would rather supply that number specifically, sir.

Mr. MOFFETT. The gentleman's time has expired.

The Chair recognizes the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Thank you, Mr. Chairman.

Mr. Martin, I find your testimony perhaps most fascinating of all, although it is sort of an aside. How can you rationalize the constraining of Federal leasing policy with the President's program of emphasis on coal?

On the top of page 11 you say the President has directed the Secretary of Interior to manage the Federal coal leasing program to be sure that it can respond to leasing goals by leasing only those areas where mining is environmentally acceptable and compatible with other land uses and with respect to the rights of private surface owners. Then you say all these conflicts have been resolved. We are in the process of working over on the floor right now on the Clean Air Act, which I assume will set up some additional conflicts.

How is that being rationalized, how are you making that determination? Somebody has to give, do they not?

Mr. Martin?

Mr. MARTIN. Right here, sir.

I am not sure exactly where you are going with the question. Let me say I think what we are talking about is specific land use and resource planning on a region-to-region and right down to local basis. So that the tenor of my remarks really go to the exact relationship between leasing and production, and in the past we have discovered that the amount of land that is leased is not directly related to that which is produced.

I think I am honestly recognizing that in my statement, trying to look at those things, making clear to you we are going to look at those things that will increase production, which is what the President wants, as opposed to simply putting more acres under lease.

Mr. BROWN. Does that mean in certain areas you will be very restrictive about the environmental impacts and in other areas you will be very relaxed about them, depending upon how much need there is for coal to be produced in those areas.

Mr. MARTIN. I do not think the way in which we approach the environmental balance is going to be different from area to area, but there are certainly going to be areas identified which are better for leasing for a variety of purposes, including the fact that the coal can be developed and will be marketed, including the fact it is a better place to develop the coal in terms of the environmental balance.

Mr. BROWN. Do I understand that you are not going to make a lease then until you know that it can be developed and that there is a contract for the marketing of it; is that right?

Mr. MARTIN. I would not agree to that specific formulation you just made, but that is right, we are going to tend in that direction, to lease in areas where we believe we can make a decision that it is right for a variety of purposes, including the ability to see it developed as quickly as possible.

Mr. BROWN. Mr. Bagge, do you want to comment on whether or not the miners are going to have to have a contract for all the coal they take out before they develop the lease?

Mr. BAGGE. Yes.

I would like to suggest respectfully, as I did to a member of the Department of Interior staff some months ago when the EMARS program was being formulated and the gentleman in charge of developing the EMARS program in Interior, in briefing my principals on the subject, said that they will not consider a nomination for a coal lease until they bring a contract, a written contract between the utility and the coal producer to Interior for a nomination.

That startled all of us, because obviously this young man at Interior did not know how the system works. My industry——

Mr. BROWN. Maybe we do not either. Maybe you ought to tell us.

Mr. BAGGE. Well, I was out in Wyoming last Friday for the opening, thank God, of a coal mine which was successfully opened in spite of the Government of the United States. We were told then that the utilities now are looking for coal reserves for plants beyond 1985. Since 70 percent of all the coal that will be used between now and 1985 is already contractually committed, unless my principals have a coal inventory in hand so that a utility looking now beyond 1985 to 1995 can determine with precision the kind, the quality of coal, its ash content, its burning capabilities, in order to build and design a boiler that accommodates that specific type of coal, it is impossible to do business. This must be understood.

Mr. BROWN. What does it take in terms of time from the point at which somebody decides that there is coal in "them thar hills" and we want to get it out and it is actually burned in a boiler suitable for that coal?

Mr. BAGGE. There is no general answer to that question.

Mr. BROWN. Could you give us a time reference?

Mr. BAGGE. Right now——

Mr. BROWN. Three months and 8 years, something like that?

Mr. BAGGE. Right now, unless we get additional coal leasing in the West, my principals are unable to deal with the utility industry in a rational and orderly manner for that increment of production which has to come on line to accommodate the next increment of expansion in the utility sector between 1985 and 1995.

Mr. BROWN. Does your study on the top of page 18 take into account the President's strip mining legislation and this policy by the Department of Interior on leasing?

Mr. BAGGE. The assumption of our production projections, Congressman Brown, are based upon a rational strip mine bill which will not have as its objective the curtailing of coal development in the West, but which will have as its objective the reclamation of land after mining.

Mr. BROWN. And the leasing policy?

Mr. BAGGE. It assumed rational leasing policies and not a leasing policy which, in a diagrammatic flow chart prepared by an interagency task force of the government in Denver, is 24.5 feet long, which visualizes now the cumbersome procedure by which we in the coal industry are forced, if we want to lease coal——

Mr. BROWN. You are telling us that you do not think that is particularly rational?

Mr. BAGGE. I am telling you I think it is not rational.

Mr. BROWN. Thank you.

Mr. BAGGE. "Rational" is all too mild——

Mr. BROWN. I wish I could get a strong view from you, Mr. Bagge.

Mr. MARTIN. I would like an opportunity to respond to that.

Mr. BROWN. I would be glad to have you respond. I want to ask one more question and then let you respond to that.

Mr. Bagge, in this—and maybe the rest of you could also answer this question—in this bill we have what is called Btu equivalency, that is natural gas as it comes from the well, the wellhead price, and oil as it goes to the refinery. I am not sure I know what that differential does.

I have the feeling that people who decide what fuel they are going to use, whether it is coal or oil, gas, buffalo chips, whatever it is, make the decision at the burner tip rather than at—and maybe even after the burner tip in the case of coal because of the costs that go into cleaning it up, and so forth and so on, it is an economic decision.

Does this bill address that economic decision soundly or is the Btu equivalency sort of fouled up?

I would like to ask you, Mr. Martin, to address that and then respond to Mr. Bagge, and also Mr. Bagge to address it and then anyone else who wishes.

My time is up I am sure.

Mr. MARTIN. I am going to defer answering that to other governmental witnesses that I think can answer it far more accurately than I can in terms of the pricing mechanism. I really do not think I am qualified.

Mr. BROWN. Do you want to comment on the other?

Mr. MARTIN. I certainly want to comment on the other because I think you should understand that it is very easy to generalize away the sort of leasing policy that you see represented in my statement.

Let me just reiterate that there are in excess of 17 billion tons of coal under lease, an additional 9 billion tons of coal under the preference leasing system, and that there is no evidence, despite certain contracts, that there are fixed plans for the development of that coal. All I am saying is this: That before we commit to additional leasing pursuant to the same kind of demands that led to the 17 plus 9 billion tons now leased, all of which were premised on the promise to develop and market—they were not invented by the Federal Government—before we do that we make sure we are not creating a system simply putting more coal under lease than can or will be realistically developed.

The EMARS program was misdescribed by Mr. Bagge. It is a system which contemplates nominations by industry after the time that areas appropriate for coal development are identified—and there are many such areas. There is going to be an active program in this regard but I do not think it should be one premised on a background of failure to develop literally billions of tons of coal in a country where we are producing less than 1 billion tons a year. That is our point.

There is no reason to have a massive additional leasing program at a time or in regions when there are no specific apparent plans to develop what is now under lease. There is much more to be said about it, but I am dealing with a general response to a very general assertion by Mr. Bagge.

Mr. BAGGE. I would like to say that I did not misdescribe the program. I accurately described the way it was presented to us by a representative of the Interior Department at a meeting with our people.

Mr. BROWN. If I cannot get the question answered by the panel here, could I get you to give me the answer in writing that I asked?

Mr. BAGGE. Yes, we will supply it for the record.

Mr. BROWN. The question was whether this bill addresses the rational Btu equivalency decision by the people who use the energy.

Mr. MOFFETT. The gentleman's time has expired.

The Chair would like to ask Mr. McCormick, and have Mr. Bagge comment as well, about Mr. Bagge's assertion that the sulfur oxide control requirements imposed by many States are much tighter than needed and how that relates to the problem we are discussing here. Do you have an opinion on that?

Mr. McCormick. I do. The standards imposed by the States have undergone considerable public hearing. The American Medical Association and health officials have provided ample testimony. I think that the facts are pretty well-grounded that sulfur oxides do represent considerable health hazards.

The question now is, putting that issue aside——

Mr. Moffett. Let me interrupt then.

You do not disagree with that, with the assertion that there are considerable health hazards posed by these emissions, right?

Mr. Bagge. No. As a matter of fact, we are asserting, Mr. Chairman, that a rational public policy response in the present posture would be to mandate only the enforcement of the primary health standards. But we are saying that anything beyond the primary health requirements that the States have adopted, is generally where the problem lies. This is one issue that has to be addressed and has to be met. There is a good deal of evidence on the other side about even how hard those figures were in establishing the primary health standards.

Politically, we are beyond that. We know we cannot get the Congress to change those requirements, but beyond that we are saying in the context of this clearly perceived need to create a market for coal, we do not understand, and we have addressed a letter to the Governors of each of the 50 States, and to the chairmen of all the PUCs throughout the Nation, pleading with them to help us because our analysis shows with nondegradation and nondeterioration and the tightening of the environmental screws by the Congress, that even the 250 plants that are now planned for, cannot meet the tightened environmental constraints. We have asked the President and the administration to show us, that we are wrong.

Mr. Moffett. That is a legitimate point. But when you talk about States that are engaging in overkill, I guess mine might be one, Mr. Ottinger's might be one. You are not in the dark about why, in fact, we might have States that impose tougher air quality requirements in the Northeaast, are you?

Mr. Bagge. No, I am not.

Mr. Moffett. It is not just that they are trying to indulge in seeing who can have the toughest air plan?

Mr. Bagge. No, that is not what I am suggesting. In my own State of Illinois, for example, coal production has gone down. We are sitting on Illinois basin coal, which are the largest indigenous bituminous coal reserves in the lower 48 States. Yet the utilities in my State are forced to turn to western coal, tragically, when, if we only applied the health standards and applied them rationally, we could be burning, at a considerably lower cost to consumers, indigenous Illinois coal.

Mr. Moffett. I do not know what you mean by rationally. I have some real questions about the coal conversion plan as it relates to the Northeast, for example, States like Conecticut, because of our air problems as well as other problems, transportation.

Mr. Bagge. I can appreciate that.

Mr. MOFFETT. Which have not been addressed. I think we both share those concerns.

Mr. BAGGE. We do share those concerns.

Mr. MOFFETT. I am looking at the administration plan and wondering how in the world it can be implemented in these places. But when you talk about health standards implemented or applied rationally, I am just not sure; that is where I get a little confused about what your testimony really is.

Mr. BAGGE. Maybe I have not articulated it well, Mr. Chairman.

We say that the Federal primary health standards which have been adopted by the Congress as the goal of the Clean Air Act, we say that that goal should be met. We are not compromising, we are not suggesting the Congress compromise with the primary health standards. But when you go beyond the primary standard and say we have to achieve the ameliorative, however it is characterized, the secondary standard, and then when you look at the States, such as my State of Illinois, where they have gone beyond the secondary——

Mr. MOFFETT. Why have they done that?

Mr. BAGGE. We contend respectfully that in their enthusiasm—I do not want to use the word "hysteria," but I will use it——

Mr. MOFFETT. You did.

Mr. BAGGE. I am trying to observe Congresman Brown's admonition not to overstate things. I will try to restrain myself.

Mr. MOFFETT. He never does that.

Mr. BAGGE. In the enthusiasm—and you know our society, the way we Americans are; the pendulum swings way over, if we are for something we are really for it like gangbusters.

What happened in 1970 was that the EPA and dedicated people who wanted to achieve these goals, it seems to us faster than the system could accommodate it, encouraged public interest groups, well-meaning, well-intentioned public interest groups to appear at these State hearings that you have mentioned and induced the States to adopt unrealistic and unattainable standards.

Remember in 1970 you did not have the degree of sophistication in State government that you have today with respect to air quality. As a result of that, there is the political problem with the Governors. It is very difficult because of the popularity of overkill, I say overkill, maybe I should say overly ambitious standards that exceed the Federal, such as the secondary standard in my own State of Illinois.

For example, it seems to me the Congress now has a responsibility, if you are serious about a meaningful shift of this economy away from oil and gas to coal, to take another serious look at what EPA induced the States to do.

Now one of the most tragic political documents that I have seen was the EPA document which addressed the various State air quality implementation plans in 1972. William Ruckelshaus and EPA expressly found in implementing the State plans, that there was no way, absolutely no way that these State implementation plans could in fact be implemented. Nevertheless, they went ahead and implemented the State plans in spite of an express finding by

EPA that there was not sufficient low-sulfur fuel in this country to achieve this goal in the timeframe contemplated by the State.

Mr. MOFFETT. A couple of questions come up. I do not want to push this into a debate on clean air. In my own area we do not have a choice. I mean the air is so bad. That is really not an overstatement. It really is. We do not have any place to go. It is not a matter of our having gone too far, and now we can pull back; it is a real health hazard, it is a matter of public health.

Mr. BAGGE. I would say coal cannot be burned in your State, if that, in fact, is the circumstance.

Mr. MOFFETT. That is a very real possibility. What about the technology question, though?

Mr. BAGGE. As a matter of fact, in New England we do not see a great shift to coal in these utility projections we have provided you.

Mr. MOFFETT. Let me ask Mr. McCormick.

Mr. MCCORMICK. I was going to continue my statement by saying that while we are aware that the primary standards are not going to be weakened, I think we have to be cognizant of the fact that EPA has given consideration to sulfate standards.

The only way to eliminate sulfate is to eliminate SO_2. I do not believe sscrubbers can eliminate SO_2, but it can certainly go a long way toward eliminating the sulfates. I think the utilities ought to be preparing for the eventuality when sulfates become part of the debate.

Mr. MOFFETT. Let me ask about the compliance coal for a moment.

As I understand it, we have a difference of opinion because Mr. Perry, as I heard him, said there are limited resources of compliance coal.

As I heard you, Mr. Bagge, you did not seem to share that view.

Mr. BAGGE. Well, that is a wrong impression.

Mr. MOFFETT. Is there enough compliance coal?

Mr. BAGGE. No, I agree with Mr. Perry's statement.

I have tried to direct your attention to that report by EPA. When they implemented the State plans they expressly said there is not enough compliance coal or gas or oil and we knew that in 1973.

Mr. MOFFETT. What about the question of technology in treating the problem?

Mr. BAGGE. We have a number of technologies on the horizon. But we are here talking about the here and now. If we are concerned about reducing our dependence on imported oil now, we simply cannot deceive the American public into thinking that technology is somehow going to save us in the short term, because it is not. It cannot.

Fluidized bed, the solvent refined methods, low Btu gasification, the lead time on these technologies, even if they are proved commercially feasible, are horrendous. If we are talking about solving the energy problem today, we have to bite the bullet, it seems to me, and squarely face reality. We cannot be talking about technology that is not now here.

Mr. MOFFETT. Let's have Mr. Perry respond to that and address the question also of scrubber technology which EPA says is quite improved.

Mr. PERRY. The kind of technologies you are talking about are scrubbing the flue gases to get the sulfur out after you have made SO_2 from the sulfur that was in the fuel, and there are still some unresolved questions.

I guess EPA has been saying for almost 10 years that the scrubber problem has been solved and yet we still have some problems with it. There are scrubbers that work well, some do not, a lot of things we still do not know about it, particularly how to dispose of the scrubber waste that we generate in an environmentally acceptable way.

The other technologies that you are talking about, either better coal preparation methods, the wider use of existing preparation methods, fluidized bed combustion, low Btu from which you can scrub the sulfur oxides, all of these technologies may prove to be beneficial. But if you are looking between now and let's say 1985, there will be no widespread deployment of any of these technologies in that time period.

Mr. MOFFETT. The Chair wants to recognize the gentleman from New York for 5 minutes.

Mr. OTTINGER. Fluidized bed is something that can be done now.

One of the things that bothers me—a lot bothers me—is what has the coal industry done to try and push this technology which is clearly capable of present use? It is not something that you have to wait——

Mr. BAGGE. Are you asking me that question, Congressman Ottinger?

Mr. OTTINGER. Why not?

Mr. BAGGE. Okay.

The coal producers, Congressman Ottinger, are not directly involved. Our challenge with the President's plan, with productivity having been cut in half in the last decade, with the overwhelming challenges that we have to try to meet with technological breakthroughs in mining technology.

The coal industry, which is on the production side, is not directly involved in conversion technology. We are not going to be the ones converting the coal to liquids and gases, fluidized bed, or any of these technologies. We have a big enough challenge in trying to return productivity to the mines, both underground and surface mines. We are involved in this effort directly.

We do support enthusiastically the research efforts by the utilities in this area, but we are simply not involved in these technologies directly.

Mr. OTTINGER. Well, I think maybe you ought to be, because the approach that you have taken I think is an untenable approach. I do not think it serves the objective of using our coal utilization well.

I think as long as you take the hard line that you are taking you are going to be running up against a solid wall here in Congress. You have resisted strip mining regulation, resisted strong mine safety regulation.

You have resisted scrubber technology, you are now resisting clean air standards. It seems to me that that is a public-be-damned attitude that does not serve the coal industry well because we obviously are not going to give carte blanche to the coal industry to subject unreasonable risks on either the people who mine the coal or the public that is going to have to suffer the consequences of unrestrained burning of coal.

Mr. BAGGE. I would like to say in response, Congressman Ottinger, that we supported the Mine Health and Safety Act of 1969.

We affirmatively supported the surface mining legislation for 5 years, until the issue became so polarized and the bill, as we perceived it at least, was not a reclamation bill but a land use bill. It was then, just a year and a half ago that we opposed that bill. But we supported affirmatively Federal land mine reclamation in order to provide standards which the States did provide in the interim period of time.

So I do not think we have been irresponsible in our posture with respect to these issues.

Mr. OTTINGER. From where I sit, your posture has been to support every measure to weaken the controls for the health and safety of the American public.

Mr. BAGGE. Well, as I said, that may be your perception of it, but I respectfully disagree with you, Congressman. I think we have been quite responsible.

Mr. OTTINGER. If you want to see more coal utilized, then why should you not get involved in the technologies, improvements of the technologies, of being able to utilize them?

Mr. BAGGE. Because, as I said before, our greatest challenge is in moving ahead in the coal extraction processes of this country. We are now utilizing a technique in mining which is 30 years old.

Our challenge 30 years ago was to mechanize the mines. Our challenge now is to automate the mines. We have a laboratory which we fund. We are working with the Bureau of Mines in projects now to introduce long-wall mining and short-wall mining in this country from the German technology; we have a host of—in fact we are involved in the utilization side. Our laboratory has developed a means of high Btu gasification of coal; we have a $23 million plant in Homer City, Pennsylvania, which our association funds, in order to demonstrate the feasibility, the economic feasibility in a pilot plant of high Btu coal gasification. We have, in fact, been involved in a number of these projects ourselves.

As we see it, with the decline in productivity of 50 percent, we have to focus the limited financial resources of our industry and keep in mind the coal industry has been a marginal industry. It is only since 1973 that the political leadership discovered us, during the oil embargo. Until then we were a marginal industry.

So our earnings have not been that of our more respectable energy peers. We are taking the money we have now and are putting it into the area where we have the greatest challenge, i.e., in the extraction of coal which is our part of the President's energy plan and our contribution that we could make to this country as part of the President's energy program. This is our challenge. This is where we are voting our dollars, to try to make major breakthroughs in mining technology.

Mr. OTTINGER. I think it is part of the challenge of the industry and before the country, I think there are tremendous dangers in going to great utilization of coal under the technologies that presently exist. If we are going to see coal used as a major energy resource in the country, then every aspect of the industry has to work not on lowering the standards, subject the people to more health hazards, but whether we must try to find ways to utilize the coal in ways that will not endanger people's lives.

Mr. BAGGE. I said we are not suggesting you compromise the health standards one iota, I tried to make that clear.

Mr. OTTINGER. We come apart on that, because the efforts amount to that result as far as I can see.

Mr. BAGGE. Well, I respectfully disagree, because I could not stand before this committee and suggest that we are suggesting to you gentlemen to compromise the health standards of the people of this country at a time when we are making a commitment to coal.

I respectfully disagree with your perception of our position. I have tried to express it as clearly as I can.

Mr. MOFFETT. The gentleman's time has expired.

Does the gentleman from Ohio have additional questions?

Mr. BROWN. Yes.

I would like to ask each of the gentleman to submit for the record their view of the technologies that exist in this field. If you want to add something to the list, I would be glad to take your recommendation, but I am interested in particular in fluidized beds, coal liquefaction, coal gasification—I notice Mr. Bagge keeps talking about high Btu gasification and does not speak of low Btu gasification—but I would like to have both discussed. One is pipeline quality, the other one is not, and sulfurization.

Are there other technologies in terms of the utilization of coal?

Mr. BAGGE. Solvent refining, which is a unique technology, different than any of those others you have enumerated.

Mr. BROWN. All right. Mr. Perry.

Mr. PERRY. You ought to add coal cleaning, both physical and chemical coal cleaning.

Mr. BROWN. Now I would like to have these discussed in two ways, several ways.

The first is, how soon does the technology become available?

How much is it going to add to the cost of the conversion of coal into energy per ton, and how much energy loss is there in the process, Btu loss?

Then finally, how long does it take, wherever it is used, to be installed? In other words, if it is installed at the burning site, if it is installed at some other site, and so forth?

Then with reference to scrubbers, I would like to ask how energy-intensive the scrubber cleaning system is. I understand that you need 10 percent of the power generated by a new utility to scrub the effluent or whatever you call it, the discharge.

Where are we on sludge disposal? In other words, where does a city like New York put its sludge, in Connecticut, or what are we talking about here? Does Connecticut mail it to New York, get a contract out by somebody to dispose of it?

The next question is the reliability of the scrubber system. I understand there is 10 percent down factor. In other words, if you run your scrubber for 10 days, one day the utility will be closed down for upkeep and maintenance. I do not know what that does to the necessity of building additional new utility plants around the country, but I assume it means that you have to build about 10 percent more than you otherwise would have to build. So if you could address that, I would appreciate it.

Finally, Mr. Bagge, you have referred to declining productivity in the coal field. I am hard-pressed to understand that, quite, because it seems to me that if there is a need for more coal, if we are opening new mines, rather than just plugging along on old lines with old processes, and if the price of coal has gone up, which I understand it has, it seems to me the productivity would be higher, that you would be using more modern processes and bigger and better mines, and so forth and so on.

I do not understand the reason for the declining coal productivity.

Mr. BAGGE. Well, the decline——

Mr. BROWN. There is one other—I am sorry, really two others.

In my district I have a company that makes those shuffles that strip-mine coal. A few years ago they had a little problem with plate steel, could not get it, made in steel mills fired by coal, which indicates that there is something of a circle of problems here.

I understand railroad cars also require plate steel in order to build the car to move the coal. I guess we have a panel later that has some steel people on it that will tell us how much problem the plate steel is.

I want to know about the capacity of the industry that makes the stuff to mine the coal, first. Then secondly, the capacity of the industry that makes the stuff to move the coal; what is their capacity?

It is wonderful if we can dig all this coal and put it in a big pile out in Colorado where they do not have the industry to burn it and cannot get it east where it is to be burned; what are we going to do? I would like to have that addressed.

Mr. MOFFETT. I might say to the gentleman from Ohio, not only are we running short of time, but future panels are going to address these points.

Mr. BROWN. These people will not be on future panels unless they have a friend on the staff. So I want to be sure that they get the question in here.

Mr. MOFFETT. Without objection we would like to see those things submitted for the record.

I have one more question——

Mr. BROWN. Remind them of the necessity of getting them in promptly so that we will have the benefit of it before we come to the conclusion, otherwise we will come to the conclusion and probably not get a chance to look at what you have said about the facts.

Mr. MOFFETT. Yes. One more question on western coal. I suppose it is obvious, but in addition to being low sulfur, it is aLso lower Btu, right, so you hve to burn more of it? So to talk about its being great in terms of compliance coal is not necessarily that accurate, is it?

Mr. Bagge, I guess in terms of overall compliance it might not be——

Mr. BAGGE. It is true, notwithstanding its lower sulfur characteristics than bituminous coal, that because you have to burn more of it, and the way our system works, as we identify the pollution, scrubbers are required even with what otherwise might be perceived as compliance coal.

So what you say is absolutely correct, Mr. Chairman.

Mr. MARTIN. Could I respond?

Mr. MOFFETT. Please.

Mr. MARTIN. I think it is important when you think conceptually of the President's program on this issue to recognize that there really has been a distinction made. In the past the sort of issue you raise, that is looking around for the specific coal that is by its character "compliance coal," was the focus of our activities. By the President's action he has provided a structure by which other coal can become compliance coal, and this has broadened our alternatives for areas like yours, for instance, to look at other types of coal that can be used, rather than making all the trade-offs in terms of land, resources, transportation costs, for instance.

Mr. MOFFETT. Thank you.

The Chair would like, on behalf of the subcommittee, to thank the panel. I think you have given us a very good start.

Mr. BROWN. Could we still reserve the right to ask a couple of more questions in writing because the staff has some questions it would like to ask also?

Mr. MOFFETT. Certainly.

Thank you very much.

[The following letter and material were received for the record:]

Identical letter to
Congressman Clarence Brown

NATIONAL COAL ASSOCIATION

Coal Building | 1130 Seventeenth Street, Northwest | Washington, D. C. 20036 | (202) 628-4322

CARL E. BAGGE
president

June 6, 1977

Honorable John D. Dingell
Chairman
Subcommittee on Energy and Power
Committee on Interstate and Foreign
Commerce
U. S. House of Representatives
Washington, D. C. 20515

Dear Mr. Chairman:

This letter and its enclosure respond to questions posed by members of your Subcommittee when I appeared on May 25, 1977. The questions dealt with:

. The status of coal gasification, liquefaction, fluidized bed combustion and coal cleaning technologies.
. The status of flue gas desulfurization (scrubber) technology.
. The concept of Btu equivalence, as reflected in the Administration's energy plan and legislative proposals.

Alternative Technologies for Using Coal

The coal industry, principally through its research affiliate, Bituminous Coal Research, Incorporated, has conducted research and development on several processes for using coal which do not involve direct burning. However, a much greater effort has been undertaken by the Federal Government and by a number of firms that either use or supply liquid and gaseous fuel or sell equipment and facilities to firms using such fuel. The Federal Government effort relating to coal utilization technologies would be in excess of $500 million in fiscal year 1978 under the President's budget request to the Congress.

Even though we cannot provide a detailed technical and economic evaluation of the various coal utilization technologies, we have completed an analysis that we believe will be useful to the Subcommittee and its staff.

Briefly, the analysis which is enclosed:

. Describes each of the principal technologies that are being pursued, including:

- High-Btu coal gasification
- Low-Btu coal gasification
- Coal liquefaction, including solvent refining of coal
- Fluidized bed combustion
- Physical and chemical coal cleaning

. Lists, according to the above categories, 45 processes that have been or are being developed -- showing the developing organization and where available, the dates for initial development, laboratory scale, process development unit scale, pilot plant, demonstration plant and availability of a commercial scale plant.

Our analysis has reaffirmed our conclusions that (a) considerable additional time will be required before technical, economic and environmental obstacles are overcome and significant commercial application of these processes is feasible and practicable, and (b) the Nation must proceed on the assumption that direct burning will be the principal use of coal for many years.

Scrubber Technology

Since the coal industry is a producer and not a major user of coal, the development of flue gas desulfurization technology (scrubbers) has been pursued primarily by the Government, by utility and major industrial users of coal, and by firms that sell equipment and facilities to utility and industrial users of coal. The coal industry conducted some R&D on selected desulfurization processes, but discontinued the work when much larger efforts were undertaken by others.

The coal industry, therefore, is not in a good position to evaluate scrubbers and respond to the questions about availability, performance, energy impact, cost and environmental side effects posed by members of the Subcommittee. However, we understand that the Federal Power Commission staff has recently completed a very thorough year-long assessment of flue gas desulfurization applications in the U.S. While we do not know the results of this study, we understand that an extensive report on it will be available soon. Apparently the study and report deal with a number of sulfur control approaches in addition to scrubbers.

Several other studies of "scrubbers" have been undertaken over the past few years -- e.g., by EPA, the Commerce Technical Advisory Committee (CTAB), and the National Academies, but we are not aware of any that have been as extensive as the one that FPC apparently has completed.

BTU Equivalence

We assume this question relates to the concept of Btu equivalence as proposed and discussed by the Administration in:

. The discussion of natural gas pricing wherein it is proposed that the price of "new" natural gas be set at a "Btu equivalent" level comparable to the refiner acquisition cost of all domestic crude oil (pp xvii-xviii, and 53 of the National Energy Plan) and

. The discussion of the oil and natural gas user taxes wherein it is proposed that a tax be placed on industrial and utility use of natural gas for certain purposes at an amount determined on the basis of Btu equivalence when compared to distillate oil (pp 65-66 of the National Energy Plan and Sec. 1501 of the Administration's bill - H.R. 6831).

We have not analyzed these BTU equivalence concepts thoroughly, particularly because they are not being applied directly to coal. However, our cursory review suggests that neither proposed application of the concept takes into account the far different value of the natural gas at the point of Btu equivalence comparison. Specifically:

. Natural gas sold from new reservoirs would appear to have a much greater value than the acquisition cost of domestic crude oil to refiners because of such factors as (a) the fact that natural gas is one of our most desirable fuels; e.g., because of its cleanliness and environmental acceptability, (b) there is no need for or cost of refining to remove sulfur, and (c) the handling and transportation costs -- on the way to consumers -- are undoubtedly different.

. Natural gas sold to utility and industrial users would appear to have a different and often greater value than distillate oil because of such factors as (a) environmental desirability, (b) storage and handling costs, and (c) potential applications which, in some cases, would not permit use of distillate.

* * *

We appreciate the opportunity to respond to the Subcommittee's questions and hope that the information provided will be useful to you.

Sincerely,

Carl Bagge

Carl E. Bagge

CEB:bls
Encl.

NATIONAL COAL ASSOCIATION
COAL BUILDING
WASHINGTON, D. C. 20036

AN ANALYSIS OF COAL GASIFICATION, LIQUEFACTION, FLUIDIZED BED COMBUSTION AND COAL CLEANING

By: Staff
Bituminous Coal Research
National Coal Association
June 1977

An Analysis of
Coal Gasification, Liquefaction, Fluidized
Bed Combustion and Coal Cleaning

- Contents -

An Analysis of Coal Gasification, Liquefaction, Fluidized Bed Combustion and Coal Cleaning

This brief analysis presents a short description of the processes under active consideration and a summary table showing their historical development timetable.

Principal Conclusions

The conclusions drawn from this analysis are based on the development timetables and past experiences of industry in the widespread adoption of new industrial processes. Conclusions regarding the prospects for commercialization are that:

. First generation low-Btu process plants are available in commercial size units. The constraints to commercialization are economic uncertainties, environmental restrictions, and the multitudinous regulatory requirements and permits.

. High-Btu or SNG technology has not been validated at the demonstration plant scale size. Process technology for commercial plants will probably be available in the mid 1990's. Widespread use beyond that will again be dictated by economic, environmental and regulatory constraints.

. Liquefaction and solvent refining processes still face some technological barriers that must be resolved before their economic feasibilities can be determined.

. Fluidized bed combustion appears to be an attractive option compared to a conventional coal burning system employing a stack gas clean up system. The commercialization timetable in the United States is difficult to predict because no demonstration plants have been built and tested.

. Advanced processes for coal cleaning should be generally available in the mid 1980's. However, their use will be dependent upon the permissible sulfur content in the coals or the clean air requirements. For example, if a midwestern coal with 5 percent sulfur, evenly divided between pyritic and organic sulfur, was chemically cleaned, the process would have to remove 95 percent of the pyritic sulfur and 77 percent of the organic sulfur to meet present EPA requirements for new power plants. None of the chemical processes under investigation can clean coal to these specifications.

HIGH-Btu GAS PROCESSES

The development timetable for the ten most active processes are summarized in Table 1. High-Btu gasification produces gas which may be used as a substitute natural gas (SNG). This methane-rich gas generally has a heating value of 900 to 1000 Btu per cubic foot, and can be fed directly into existing pipeline systems with no modification. Gas can be produced from three basic types of reactors. The entrained bed reactor is one in which solid particles are suspended in a moving fluid and are progressively carried out of the vessel in the effluent stream. The fluidized bed reactor is a bed through which a fluid is passed with a velocity high enough for the solid particles to become freely supported in the fluid, but not entrained. The fixed bed reactor is one in which gases pass at a relatively low velocity so the particles remain stationary within the vessel or slowly move downward for bottom removal.

Medium-Btu gas is used generally for feedstock to a catalytic reactor for conversion to SNG, oils, gasoline or other chemical products. The heating value ranges from 250 to 500 Btu per cubic foot and is generally produced by reacting coal with oxygen and/or steam.

Process efficiencies for high- and medium-Btu gasification processes range from 65 to 80 percent. Efficiencies are based on Btu's available in the product gas versus Btu's in the coal feed.

A gasification plant producing 250 million cubic feet per day of SNG has been estimated to cost between $850 and $1300 million. The cost for gas produced from a plant of this type would range from $2.70 to $6.75 per million Btu depending on the type of financing used.(1)

Construction of a typical installation would take three to five years from order placement to plant startup.

Of the ten most recognized high-Btu gasification processes only two have been commercialized. All of these plants are outside of the U.S. and their designs are based on technology developed in the 1940's. The other, "second generation" processes, intended to bring forward new, more efficient technologies, are still in the mid-stages of development. The prospect that these second-generation processes will prove to be efficient, economical and environmentally acceptable will depend upon their demonstration, as yet un-scheduled, at the semi-commercial or commercial scale.

(1) "Preliminary Economic Comparison of Six Processes for Pipeline Gas from Coal", Roger F. Detman, C. F. Braun & Co., published in the proceedings of the 8th Synthetic Pipeline Gas Symposium, Chicago, Ill., October 18-20, 1976.

TABLE 1

Gasification - Medium to High Btu: Process Development Timetable

Process	Type	Initial Development	Developed By	Present Status of the Process In Operation or Planned: Lab Scale	PDU	Pilot Plant	Demonstration Plant	Commercial Scale Plant
Babcock & Wilcox - Dupont	E.	Late 1940's	U.S. Bureau of Mines			1950's and 1960's	1955	About 1960
HYGAS	Fl.	1945	Institute of Gas Technology	1964	1964-1967	1971-1977	Planning NS	NS
Koppers-Totzek	E.	1948	Koppers-Totzek	Unknown	Unknown	Unknown	1948	1949
Texaco	E.	Early 1950's	Texaco			1956-1958	NS	NS
Hydrane	Fl.	1955	U.S. Bureau of Mines PERC	1955-mid 1960's	1979-	Prelim. Design	NS	NS
Synthane	Fl.	1961	U.S. Bureau of Mines PERC	1961	Early 1970's	1976-1979	NS	NS
COGAS	Fl.	1962	FMC Corp.		1962	1974-1975	Planning NS	Est'd 1980
BI-GAS	E.	1963	Bituminous Coal Res.	1963-1969	1969-1971	1976-1979	NS	NS
CO_2 Acceptor	Fl.	Prior to 1964	Consolidation Coal (CONOCO)	1964-1968		1971-1977	NS	NS
Catalytic		1968	Exxon Research & Engineering	1968-1977	1978-1980	1981-	NS	NS

E. = Entrained
Fl. = Fluidized
F. = Fixed

NS = None Scheduled; i.e., no firm date set for proceeding to this stage.

LOW-Btu GAS PROCESSES

The present status and projected timetable for 13 low-Btu gasification processes are presented in Table 2. Low-Btu gas refers to that gas with a heating value from 100 to 200 Btu's per cubic foot. This gas is generally produced by reaction of coal, steam and air. As in the case of high-Btu gases, the reactors used can be of the entrained, fluidized, or fixed types. This gas is intended primarily for direct use as a fuel gas in a plant or power station near the gasifier itself. The low heating value of the gas generally makes transportation of the gas over any appreciable distance economically unattractive. The gas may also be used as fuel for a gas turbine.

Process efficiencies for low-Btu gasificiation plants are difficult to estimate due to the wide variance in plant size; however, most projections indicate that gas costs would range from $2.00 to $5.00 per million Btu depending on financing method, plant size, and type of coal feedstock and its cost.

Five low-Btu gasification processes are currently available for industrial application. They were used for in-plant generation of fuel gas or process gas prior to the advent of abundent natural gas. R&D effort on the newer processes is directed toward improving process efficiency and environmental compatibility. Application of new concepts for improved gasification techniques can make the low-Btu processes attractive for industrial or utility use.

TABLE 2

Gasification - Low Btu: Process Development Timetable

Process	Type	Initial Development	Developed By	Lab Scale	PDU	Pilot Plant	Demonstration Plant	Commercial Scale Plant
Winkler	Fl.	1920's	Davy Powergas	Unknown	Unknown	Unknown	Unknown	1926
Lurgi	F.	Prior to 1936	Lurgi	Unknown	Unknown	Unknown	Unknown	1936
Wellman-Galusha	F.	Prior to 1940	McDowell-Wellman	Unknown	Unknown	Unknown	Unknown	About 1940
I.G.I. Two-Stage	F.	1940's	Il Gas Integrale	Unknown	Unknown	Unknown	Unknown	About 1946
U-Gas	Fl.	1945	Institute of Gas Technology		1947	1951-53; 1977-78	NS	NS
Otto-Rummel	Slag Bath	Prior to 1950	Dr. C. Otto & Co. G.M.B.H.	Unknown	Unknown	1950	Unknown	About 1950
Agglomerating Ash	Fl.	1960's	Union Carbide/ Battelle	1960's	1976-1979		NS	NS
ERDA-MERC	F.	1968	ERDA-MERC			1968-	NS	NS
TRI-GAS	Fl.	1969	Bituminous	1970	1975-1977		NS	NS
Combustion Engineering	E.	1972	Combustion Engineering	1972		1977	1980	NS
Foster Wheeler	E.	1972	Foster Wheeler			1977	NS	NS
Westinghouse	Fl.	1972	Westinghouse			1974-78	NS	NS

E. = Entrained   Fl. = Fluidized   F. = Fixed   M.S. = Molten Salt
NS = None Scheduled: i.e., no firm date set for proceeding to this stage.

LIQUEFACTION AND SOLVENT REFINING

The seven most actively pursued liquefaction processes are summarized in Table 3 and the four solvent refining processes are listed in Table 4. None of these processes has been developed to the point where technical and economic viability of commercial scale plants are ensured.

Liquefaction and solvent refining of coal are similar processes. Liquefaction produces a liquid, oil-like product suitable for chemical feedstock or direct fuel use. Solvent refining produces a solid fuel similar to the parent coal but with greatly reduced levels of impurities, such as sulfur and ash.

TABLE 3

Liquefaction: Process Development Timetable

Process	Initial Development	Developed By	Present Status of the Process In Operation or Planned				
			Lab Scale	PDU	Pilot Plant	Demonstration Plant	Commercial Scale Plant
COED	1962	FMC Corporation			1970-1975	Planning (COGAS)	Est'd 1980
Zinc Chloride Catalyst	1963	Consolidation Coal	1976	1977-1980	NS	NS	NS
H-Coal	1964	Hydrocarbon Res. Inc.	1973-1976	1973-1976	1978	NS	NS
C.C.L. (Catalytic Coal Liquefaction)	1968	Gulf R&D Co.	Through 1974		1975	NS	NS
Synthoil	1969	U.S. BuMines(PERC)		1978-1980	NS	NS	NS
Multi-stage	1972	Lummus Co.		1977-1978	1981-	NS	NS
Clean-Coke	1972	U.S. Steel Corp.			1974-1978		

NS = None Scheduled; i.e., no firm date set for proceeding to this stage.

TABLE 4

Solvent Extraction Processes

Process	Initial Development	Developed By	Present Status of the Process In Operation or Planned				
			Lab Scale	PDU	Pilot Plant	Demonstration Plant	Commercial Scale Plant
SRC (Solvent Refined Coal)	1950's	Spencer Chemical (Gulf Oil)	-1969	1976-1979	1975-1981	NS	NS
SRL (Solvent Refined Lignite)	1960's	U. of North Dakota	-1976	1975-1978	NS	NS	NS
Donor-Solvent	1966	Exxon	-1975	1976-1981	1980-1982	NS	NS
CO-Steam	1976	U.S. BuMines(PERC)	-1981	NS	NS	NS	NS

NS = None Scheduled; i.e., no firm date set for proceeding to this stage.

FLUIDIZED-BED COMBUSTION

In fluidized-bed combustion, combustion air passes through a bed of coal particles at a velocity high enough for the particles to separate and become freely supported in the gas. A bubbling action gives rise to a high degree of particles mixing.

Potential advantages of the system over conventional combusion include:

1. High heat transfer rates should permit steam raising with fewer tubes, thus reducing the capital costs;
2. Lower combustion temperatures minimize production of NO_x, and should reduce fouling and corrosion problems;
3. Addition of limestone or dolomite to the bed traps a large portion of the sulfur of the coal, reducing the amount of sulfur oxides emitted into the atmosphere.
4. The fluidized bed can accept coals having a wide range of sulfur and ash content.

Fluidized-bed combustors can be designed to serve a wide range of capacities, from small industrial units to those having the capacity of a central station utility boiler. The Rivesville unit, now in operation as a demonstration, is sized at 30 megawatts (electrical) and is a building block for scale-up to larger (200-800 MW_e) plant sizes.

Based upon early research and development, particularly that done in the United Kingdom during the 1960's, the estimated efficiency of a fluidized-bed boiler power plant is projected to be 39 percent compared to approximately 32 percent for a conventional coal-fired plant operating on the same coal and employing stack gas cleanup.

Capital cost of a grass roots fluidized-bed boiler system has been estimated to be approximately 20 percent less than for a conventional system using the same coal and employing a stack gas cleanup system.

Fluidized-bed combustion appears to be a viable approach to the acceptable use of high-sulfur coals. Experience with the Rivesville unit should help confirm the potential advantages of the system.

TABLE 5

Fluidized-bed Combustion: Process Development Timetable

Process	Initial Development	Developed By	Present Status of the Process In Operation or Planned				Commercial Scale Plant
			Lab Scale	PDU	Pilot Plant	Demonstration Plant	
AFB Multi-cell	1963	Pope, Evans & Robbins		1965	Rivesville, WV, 1977-78	NS	Est'd. 1981
PFB Combined Cycle	1976	Curtis-Wright Corp.			1979	NS	Est'd. 1986

AFB = Atmospheric Fluidized Bed
PFB = Pressurized Fluidized Bed

NS = None Scheduled; i.e., no firm date set for proceeding to this stage.

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COAL CLEANING PROCESSES

The following is a summary of ten of the most advanced processes for removing sulfur from coal. Table 6 shows their timetable for development. Some of the processes attack only the removal of the pyritic sulfur in the coal while others remove the majority of the pyritic sulfur and a significant portion of the organic sulfur. Coal cleaning methods in use today are mechanical and remove 50 percent of the pyritic sulfur and none of the organic sulfur.

Despite the fact that these processes are the most advanced, few can expect to be developed to the commercial scale prior to 1985. Processes proven to be technically sound and economically attractive at the commercial size would probably not see widespread use prior to the early 90's.

Some cost estimates have been made and were presented in a paper entitled "Technical and Cost Comparisons for Chemical Coal Cleaning Processes" at the American Mining Congress meeting held in Pittsburgh in May 1977. From the six processes reviewed, the cost of those processes removing only pyritic sulfur range from \$14 to \$20 per ton of clean coal. Processes removing both pyritic and organic sulfur range from \$19 to \$22 per ton of clean coal. Due to the many uncertainties facing the successful development of these processes these cost data should only be considered as preliminary.

A brief description of the ten processes reviewed follows.

1. Battelle Hydrothermal Process - In the hydrothermal process, raw coal is crushed and mixed with a leaching fluid to form a slurry. The slurry is pumped into pressure vessels where it is held for up to 30 minutes at pressures between 350 and 2,500 psi and temperatures between 225° and 350° C. The chemicals are then filtered off, regenerated and recycled. The coal, after washing and drying, emerges low in sulfur and impregnated with alkali which captures additional sulfur during combustion. According to Battelle, this treatment is sufficient to remove nearly all inorganic sulfur. In addition, roughly half of the organic sulfur is also removed.

2. TRW Meyers Process - Chemical leaching with aqueous ferric sulfate solutions at temperature of 90° to 130° C. is employed in this process to remove 90 to 95 percent of the pyritic sulfur contained in the coal matrix. The ferrous sulfate content of the leachate is regenerated at similar temperatures using air or oxygen, and elemental sulfur and iron sulfates are recovered as reaction products. The process does not reduce the organic sulfur content of the coal.

3. BOM/ERDA Oxidesulfurization Process - Similar to the Ledgemont process except air is used in place of oxygen. It operates at higher temperatures and pressures. Unlike the Ledgemont process it is claimed that up to 40% of the organic sulfur in the coal can also be removed.

4. USBM Froth Flotation Process - A two-stage froth flotation process developed to remove pyritic sulfur from fine-size coals. The process involves a first-stage standard coal flotation step to remove high-ash refuse and some of the coarser pyrite as tailings. The first-stage concentrate is then retreated in a second bank of flotation cells in the presence of a coal depressant and a flotation collector to selectivity float the remaining pyrite. The process can remove up to 90 percent of the pyritic sulfur with certain select coals. It does not reduce the organic sulfur content of the coal.

5. Ledgemont Oxygen Leaching (LOL) - This process was developed at the Ledgemont Laboratories of Kennecott Copper Corporation. The process is based on the oxidation of pyrite with oxygen and water to form sulfuric acid and soluble sulfates, commonly known as acid mine drainage. The process will remove a high percentage of the pyritic sulfur in the coal but will not reduce the organic sulfur.

6. KVB Clean Coal Process - Patented by KVB Engineering, Tustin, California. In the process the dry, pulverized coal is exposed to an atmosphere containing NO, O_2, NO_2, and N_2 at 250°F and 35 psia. It is claimed that pyrite is converted to iron sulfate and SO_2 and SO_3, and part of the organic sulfur is converted to SO_2 and SO_3 by reacting with NO_2 in the gas phase. Only NO, O_2, and N_2 are supplied to the reactor. It is claimed that NO_2 is generated in the reactor by the reaction of NO with O_2. This dry step is optionally followed by a caustic washing step to remove the soluble sulfates formed in the process. There is no published information on the process other than the patent.

7. Microwave Desulfurization Process - developed by General Electric. Can be used as a dry process for removing pyritic sulfur or as a wet process for removing both pyritic and organic sulfur. The dry coal or the slurry which has had sodium hydroxide added to it is heated to 150°- 250°C. in a reactor for 30 seconds to one minute at low pressures. It is claimed that up to 90 percent of both the pyritic and organic sulfur can be removed in the wet process with certain coals.

8. Magnex Process - Developed by Hazen Research. Renders the mineral matter and pyritic sulfur in coal magnetic, thereby making possible their removal by conventional magnetic separation. In this process, which is an outgrowth of chemical vapor deposition technology, raw coal is treated with iron carbonyl vapor which puts a thin skin of magnetic material on the pyrite and mineral matter but does not affect the coal. The dry process has been applied to one coal at temperatures of approximately 200°C. Up to 90 percent of the pyritic sulfur was removed and Btu's were increased about 25 percent. The ash was reduced from 25 percent in the feed to 9 percent in the clean coal. The process does not reduce the organic sulfur content of the coal.

9. Arco Process - This proprietary process was developed by Atlantic-Richfield. Fine ground coal in a slurry is treated with specific propieitary oxidation chemicals. The process is claimed to remove up to 95 percent of the pyritic sulfur and approximately 50 percent of the organic sulfur on certain coals.

10. JPL Process - developed by the Jet Propulsion Laboratory. Treats finely ground coal with methol chloroform and chlorine gas. The chlorine gas cleans the carbon and sulfur bonds. The sulfur in the pyrite comes off as water soluable sulfates and sulpheric acid. One coal has been tested to date, an Illinois coal with equal portions of pyritic and organic sulfur. A 76 percent reduction in pyritic sulfur and a 70 percent reduction in organic sulfur was obtained.

TABLE 6

Coal Cleaning: Process Development Timetable

Process	Initial Development	Developed By	Present Status of the Process In Operation or Planned: Lab Scale	PDU	Pilot Plant	Demonstration Plant	Commercial Scale Plant
Battelle Hydro-thermal Coal Process	1969	Battelle Memorial Institute	1969 to Date	1974 to Date	NS		Est'd 1985-88
TRW Myers Process	1970	TRW, Inc. EPA sponsorship	1970 to Date		1977	1980	Est'd 1981
BOM/ERDA Oxidesulfurization of Coal	1971	BOM - transferred to ERDA	1971 to Date	1977	Planned; No Date		Est'd Mid 80's
USBM 2-stage froth flotation	1971	US Bureau of Mines	1971-1972		1972-1976	1977	Est'd 1978
Ledgemont Oxident Leaching Process	1973	Ledgemont Laboratory, Kennecott Copper Company	1973-1976	NS	NS	NS	Est'd 1983
KVB Coal Clean-Up Process	1973	KVB, Inc.	1973 to Date	1978	1980	1983	Est'd 1985
Microwave Desulfurization Process	1974	General Electric	1/1/76 to Date	Planned 1980	Planned 1981		Est'd 1982-85
Magnex Process	1974	Hazen Research	1974-1976		1976-1977	Planned 1978; NS	Est'd 1980
ARCO	1975	Atlantic-Richfield	1975 to Date	10/1/76 to Date	NS	NS	Est'd 1983-85
JPL Process	1976	Jet Propulsion Laboratory	1976 to Date	NS	NS	NS	Est'd 1987

NS = None Scheduled; i.e., no firm date set for proceeding to this stage.

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Noyes Data Corporation
Park Ridge, New Jersey
1976

FOSSIL ENERGY RESEARCH PROGRAM, FY-1978

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HANDBOOK OF GASIFIERS & GAS TREATMENT SYSTEMS

FE-1772-11 (ERDA Contract No. E(49-18)1772)
Dravo Corporation
Pittsburgh, Pennsylvania
February 1976

ENERGY TECHNOLOGY HANDBOOK

Douglas M. Considine, Editor-in-chief
McGraw-Hill Book Company
1977

BCR Staff

"Technical and Cost Comparisons for Chemical Coal Cleaning Processes"

The Bechtel Corporation
San Francisco, California
AMC Meeting, Pittsburgh, May 1977

Submission for the record from Harry Perry; NERA, in reference to questions which were asked by Congressman Brown on May 25, 1977 before the House Energy and Power Subcommittee in reference to Coal Conversion and other related topics.

Fluidized Beds

Research has been carried on in the field for the last ten to 15 years with to date the only practical results being at a plant in Reedsiville, W. Va. The test plant at Reedsville is relatively small with only a 30 MW capacity.

Experts feel that there are still too many unaswered problems in the area for it to be productive before the post 1985 period. This is based on technological as well as the logistical problems of coal supply to the numerous new and small plants which would use the method.

As far as cost is concern the fluidized method is less costly than any of the other methods of Coal liquefaction, solvent refining, or coal cleaning.

In the area of energy loss occassioned by the process fluidized bed also appears head and shoulders above any alternative method.

Coal Liquefaction

Coal liquefaction has been researched for the last fifty years with the most extensive practical experience in World War 11 when the Germans fueled aircraft by this means. There is currently a working coal liquefaction plant in South Africa which was built in the early fifties and for that reason may now be liquifying coal at an economically feasible rate because of the difference in building costs between that time and now. It however is probably the only such plant.

One of the main drawbacks seen in this nethod is the lack of any practical experence in the area. Thus it would be necessary to build a series of experimental plants with a small capacity and later expand to larger capacity plants. Because of that problem it is estimated that large scale production could not begin until approximately 1990.

On the cost end of the picture the cost is estimated as being high compared to other alternative means and at approximately \$30 to \$40 per barrel.

Energy Loss would range from 30 to 55% in the process of liquefaction.

Solvent Refining Coal

This is another area which has been researched in the United States for the last fifty years with government support for the reasearch since the early 1960's. There are currently two operational and experimental plants in the United States with one subsidized by the federal government and the other a product of private industry.

It is certain that to make this method practicable there will be a need for the construction of larger scale plants than the two currently in operation.

The cost that the solvent refining method would incur, would be less than liquefaction but more than the Fluidized bed method.

Coal Cleaning

Of all the coal used in the United States at the present time approximately sixty-five percent is cleaned by physical means. I doubt that chemical means of cleaning coal would ever be available in a commercially feasible manner.

The cost of physically cleaning the coal currently adds $3 to $4 to the cost of a ton of coal and it is estimated that when and if a chemical means is developed it would add approximately $10 to $15 to the cost of a ton.

A large advantage of this process is the relatively small energy loss occassioned by the process of only 5%. Agian the ever present drawback which can't be denied is the expressed doubt that it will ever be sufficiently developed.

Scrubbers

It appears that the Utility companies are finally beginning to accept the eventuality of scrubbers and are investing heavily in them, although there are still numerous problems which have not been worked out.

Amoung the problems is the fact that scrubbers work differently with different types of coal and their effectivness varies accordingly. Linked with this is the problem of disposal of the waste product. In its original state as the waste comes from the scrubber it is liquid and is usually stored on the cite in large outdoor open tanks. The problem with this type of disposal is in the leaching into the underground and possible contamination of water resources. Currently there is experimentation being carried on with two processes which will purportedly solidify the waste material and allow an alternative means of disposal.

Mr. MOFFETT. The subcommittee will now focus on the impact of conversion on industry.

The Chair would call to the table Mr. James Riddell, U.S. Brewers Association; Mr. O. S. Andras, Director of Hydrocarbons for Dow Chemical; Donald Lutken, president of the Mississippi Power and Light; George Oprea, executive vice president, Houston Lighting and Power, and Donald Allen, vice president, New England Electric Supply System.

We would like to have order in this hearing room if we might.

We will ask you to begin, identify yourself for the record, and your affiliation.

STATEMENTS OF DONALD G. ALLEN, VICE PRESIDENT, NEW ENGLAND ELECTRIC SYSTEM; O. S. ANDRAS, DIRECTOR OF HYDROCARBONS, DOW CHEMICAL COMPANY; GEORGE W. OPREA, JR., EXECUTIVE VICE PRESIDENT, HOUSTON LIGHTING & POWER COMPANY; DONALD C. LUTKEN, PRESIDENT, MISSISSIPPI POWER & LIGHT COMPANY; AND JAMES W. RIDDELL, U.S. BREWERS ASSOCIATION, INC.

Mr. ALLEN. I am Donald G. Allen, vice president of New England Electric System.

I would like to correct the record; there is no "supply' in our name.

Mr. ANDRAS. I am O. S. Andras, Director of Hydrocarbons for Dow Chemical.

Mr. OPREA. I am George Oprea, executive vice president of Houston Lighting and Power Company.

Mr. LUTLEN. I am Donald Lutken, president of Mississippi Power and Light Company.

Mr. RIDDELL. I am Dick Riddell; I represent the U.S. Brewers Association.

Mr. MOFFETT. Thank you.

The Chair would like to call first on Mr. Allen. You may, of course, paraphrase your statement if that is possible, and in the interest of time it would be beneficial to the committee.

Mr. ALLEN. I would be happy if my full statement could be included in the record, and I do intend to summarize it.

Mr. MOFFETT. Without objection.

STATEMENT OF DONALD G. ALLEN

Mr. ALLEN. Today I think I can give you a case example of the problems of coal conversion faced by an East Coast utility which has oil-burning plants which can be converted to coal. Others on the panel are going to address the other subjects of importance here.

At our Brayton Point station in Massachusetts, we have two units which clearly can be converted to coal at savings to our customers. We have a third unit which it may well be possible to convert economically, depending on the expense of retrofitting and the environmental requirements involved.

To put this in setting, our Brayton Point station of the three units I have mentioned involves 1100 megawatts, and has an oil requirement of roughly 11 million barrels per year. Again I think this is about 5 percent of what people have identified as the probable candidates for conversion from oil to coal.

To convert economically, we need two things.

First we need coal with characteristics as close to the original design specifications as we can get, and at a price which will represent savings over OPEC-priced oil, savings enough to offset our capital costs of converting. We believe that eastern coal is available which would meet this test.

Second, we need a modification of the Massachusetts clean air State implementation plan which would permit burning this coal without installing scrubbers. Specifically, we need to be able to burn something like 1.5 percent sulfur coal and have that a conforming fuel.

We believe this can be done without exceeding national standards, since the Massachusetts plan as it was originally adopted includes a very considerable margin of safety before the national sulfur dioxide standard is met. The Massachusetts authorities have already proposed such a change, but it has not yet been approved by the regional EPA office. If this change is made, and we are publicly committed to this, we are prepared to go ahead voluntarily with coal conversions which we believe will reduce the cost of power to our customers.

In the past month, all of our Brayton Point units and three of our older units at Salem Harbor in Salem, Massachusetts, have been issued notices of intention by FEA under ESECA. The additional capacity at our Salem Harbor plant is about 300 megawatts, or less than a third of that at Brayton Point.

Our experience under the mandatory ESECA program to date has been total frustration. FEA apparently has specified a coal that does not conform with Massachusetts requirements but, nevertheless, tells us we can go ahead without scrubbers and at savings.

Second, we have been totally unable to establish any kind of a dialogue with FEA to find out what their basic analyses are. We have their conclusions but not how they got to them.

We would like to have a chance, in the name of our customers, if it is going to be expensive, to test their estimates of feasibility and cost. Most importantly, neither FEA, so far as we know, and certainly not we, have had any definitive reading from EPA as to what EPA believes will be necessary to maintain Clean Air Act standards. We do not know whether EPA, specifically, will approve the proposed modification of the Massachusetts State implementation plan. As a result we feel that the mandatory coal conversion process under the old ESECA puts us pretty much in the position of having FEA and EPA ask our customers for a blank check on their pocketbooks. We feel we have an obligation to make sure that we know at least the dimensions of that check.

We do not think that this is what Congress intended to happen under ESECA.

We think that a coal conversion program can result in some tangible short-term savings of oil imports if two common-sense principles are adhered to.

First of all, we need a clearer reading and in advance of commitments, as to what the Clean Air Act requirements will be for plants that are going to convert to coal.

We think this can best be done by setting specific emission limitations, the best we can do, if you like, of emissions per million Btu of fuel; and say that if you can do that, that is a fixed target, not a moving target. We need to have a fixed point of reference in order to enter into the long-term coal contracts which, as other speakers on the previous panel have told you, in other words, are an absolute prerequisite to getting the coal out of the ground. The words used were "coal supply is demand-limited." Basically this means that there must be long-term utility contracts that are financible for the coal industry or there is not any coal. We in turn cannot enter into justifiable long-term coal contracts if two years from now it is going to be nonconforming coal. We need a fixed target.

We think this can be done, as I have indicated in my written testimony, by looking at the new source performance standards, recognizing that a new plant can be designed cleaner than an old one, and scaling up to get an emission standard for coal converted plants.

Second, we need a much better system for getting at the costs involved in coal conversion. Where a coal conversion will result in savings to consumers, we think other utilities, like ourselves, will be ready to go ahead voluntarily, with just the economic pressures involved.

In the rare case that this would not be so, an FEA prohibition order might make some sense. On the other hand, we think it is very important to determine whether there are savings to consumers or not.

The impact of what I call "net cost" conversions, where the consumer has to pay something in the national interest, is going to fall very clearly on two regions of the country, the East Coast and the Gulf Coast and the Southwest. We do not think it is fair in the name of a national goal to impose a very large burden on regional consumers. I suggest in my written testimony that if you want to go to something which fulfills this national interest, it should not be at the expense of regional consumers but the excess costs should be shared by some sort of Federal payment.

Looking at the new coal conversion procedures set up by the bill before us, we do not think this meets either of our tests, of giving us a fixed target or giving us any way of finding out what the costs really will be and where the consumers stand.

First of all, it does nothing with respect to Clean Air Act requirements, it ignores EPA's role in the process almost entirely, and therefore the Clean Air Act requirements, instead of being fixed, remain totally open-ended and a moving target.

Second, as we read it, instead of having just the single ESECA method, we have a new track that can be used. I shall call it track 1, and it is found in section 105(a)(2)(a).

Under track 1, FEA is given almost unlimited power to issue plant conversion orders to categories of powerplants. When that happens, the powerplants are simply forbidden to use oil and it is up to them to find out how to get out of this terrible problem. They can apply for exemptions, which turn out to be catch 22s, and you wind up with a situation, instead of having a sensible administrative process, of leaving the total burden on the utilities to find out what the score is, specifically, what EPA requires, and to take as long as may be necessary to do this.

I think this is unpardonable. I have no doubt but what FEA, when it gets around to issuing some rules and regulations and some conversion orders, will act with some restraint, but there is nothing in the act which guarantees us that that will happen. Nor is there anything in either track, either track 1 which is the category procedure, or the modified ESECA track 2, which is plant-by-plant, which assures any kind of public dialogue and third-party scrutiny of the statements that FEA makes of the costs involved.

If I am right that the cost should be limited to economic coal conversions, or if otherwise the excess costs should be borne in some fashion by the government, we need to know what that figure is.

We do believe that the bill as presently drafted can readily be converted into a more effective coal conversion procedure, first by combining tracks 1 and 2 as suggested in the latter part of my testimony; second by considering a government contribution to excess costs, and third, by finding, as I have already indicated, some means of fixing the clean air contribution of coal-converted plants and leaving us able to contract for long-term coal without looking at a moving target.

If these changes are made, I think we will have coal conversions that ought to be made in the national interest. I would echo what some of the earlier panelists have stated; this is not the major way of limiting our oil imports. The major way is to get new coal and nuclear power on line whch will push the older plants up the load curve and eventually retire them.

We could spent a great deal of money pursuing a short-term objective if we proceed too rapidly in the coal conversion program, beyond what is economically justified. We could, in the course of this, compromise our ability to get on with the main show, which is to get new, nonoil, nonnatural gas plants on line to take the burden for the eighties and nineties.

I would be happy to answer questions and hope that my short summary will be explained by my longer testimony.

[Mr. Allen's prepared statement follows:]

BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
OF THE
HOUSE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

Statement of Donald G. Allen

Vice President of New England Electric System and New England Power Company

on

Coal conversion provisions of the proposed National Energy Act
(Title I, Part F of H.R. 6831)
May 25, 1977

I believe that the experience of my company may offer a useful case example of the complex problems involved in converting oil-burning generating units to coal. We have generating units we would like to convert to coal. We believe we can burn coal cleanly. And we believe we can save our consumers money by doing so.

In my testimony, I plan to summarize briefly (1) our basic philosophy on coal conversion; (2) our experience to date with the conflicting demands of ESECA* and the Clean Air Act; (3) our analysis of the coal conversion provisions of H.R. 6831; and (4) our recommendations for change which we believe will move more realistically to an effective coal conversion program.

(1) Basic philosophy.

New England Electric System wholeheartedly supports the broad objectives of the National Energy Act: to limit our increasingly dangerous over-dependence on imported oil, and to rely more heavily on the efficient use of our domestic energy resources. In the near term, these objectives require us to reserve our domestic supplies of oil and natural gas for priority uses, and to rely increasingly for the balance of our energy supply on coal and nuclear power.

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* Energy Supply and Environmental Coordination Act of 1974, as amended.

A program for converting existing electric generating units from natural gas and oil to coal can contribute to these objectives, with tangible results by 1985. But there are important cross-cutting considerations involved:

. For the longer term, the most effective program for limiting our oil imports is to bring new coal and nuclear power plants on line as promptly as possible, and thus to limit the use of our older generating plants which require oil and natural gas as fuels. Thus the investments to be made in converting existing plants to coal should not be so large as to force a postponement of these longer range plants.

. The Clean Air Act, and the state implementation plans through which it is administered, are a major impediment to a coal conversion program. In some cases, particularly in non-attainment areas where a national ambient air standard is exceeded, the Clean Air Act may be a complete road-block to coal conversion. In many other cases, the Clean Air Act will require additional capital investments and increased operating costs out of all proportion to the gains in reducing oil imports.

. If coal conversions result in increased electric rates, the national bill for reducing our dependence on oil and natural gas for electric generation will be paid in major part by consumers in two regions: the Northeast and Mid-Atlantic states, which rely heavily on oil, and the Gulf Coast and Southwest states which rely heavily on natural gas.

It is our strong belief that coal conversions should not be forced to the point where consumers in these regions are asked to foot the national bill; and that an effective coal conversion program can be carried out by seeking accommodations in the administration of the Clean Air Act which will not result in "gutting" that legislation or abandoning our national commitment of environmental concern.

(2) The New England Electric System experience.

New England Electric System is an integrated holding-company system, whose operating subsidiaries serve over 1,000,000 customers in the states of Massachusetts, Rhode Island and New Hampshire. Electric supply for the system is provided by a separate generating and transmission subsidiary, New England Power Company.

New England Power Company's principal fossil-fueled generating plants are its Salem Harbor plant, located at Salem, Massachusetts, and its Brayton Point plant, located at Somerset, Massachusetts.

Both plants include three units which were originally designed for coal-firing. The three Salem Harbor units were built in the 1950's and represent 314 MW of capacity; the three Brayton Point units were built in the 1960's and represent 1,147 MW of capacity.

All six units were converted to oil-firing in the late 1960's. As with other East Coast utilities, there was a two-fold reason for this conversion: the savings in fuel cost available through the use of imported residual oil under then-current governmental policies; and the greater acceptability of oil-firing in terms of clean air requirements under predecessor legislation to the present Clean Air Act.

With the onset of the Arab oil embargo in the fall of 1973, New England Power Company undertook a major effort to reconvert these units to coal. Plant modifications were made on an emergency basis, coal supplies and transportation were arranged, variances and a suspension order under ESECA were obtained, and a total of 1.5 million tons of coal were burned during 1974 and 1975. This program provided a much-needed secure source of fossil generation for the New England grid, and resulted in fuel-cost savings to our customers of over $18,000,000. The coal-burning program terminated on June 30, 1975, the final date permitted by ESECA for an EPA suspension order.

Since that time, we have made every effort to thread our way through Clean Air Act requirements in order to establish a coal-burning program which would provide permanent savings to our customers. We believe that this is possible at Brayton Point, but not with the older units at Salem Harbor. We have been encouraged in our efforts by the "clean fuels policy" incorporated in the 1975 amendments of ESECA*, and by the action of the Massachusetts legislature** in requiring a re-examination of the Massachusetts state implementation plan to eliminate "overkill" requirements beyond those necessary to conform to national ambient air quality standards. A state agency proposal responsive to the Massachusetts legislation has been pending before EPA since December 1975, which would make 1.5% sulfur coal a conforming fuel for Brayton Point -- i.e. coal we could safely burn without infringing national standards. We believe that Eastern coal of this sulfur content is available at a price which would represent savings to our customers. We are prepared to go forward voluntarily with a permanent reconversion of our Brayton Point units if our right to burn this coal can be established over the period required for a long-term coal contract.

With their demonstrated ability to reconvert to coal, our Salem Harbor and Brayton Point units are obvious candidates for mandatory reconversion orders under ESECA. Over the past two years, we have provided a large volume of detailed information on these units to FEA and its contractors, and at the same time have made our own independent analysis on a number of alternative scenarios.

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* ESECA, section 4, amending Clean Air Act, section 110(a).

** 1974 amendment to Mass. G.L. ch. 111 section 142D.

On April 25, 1977 FEA issued its Round II notice of intention to issue prohibition orders. Fifteen New England oil-burning units were included, including our three units at Salem Harbor and our three units at Brayton Point. The notice of intention includes an appendix summarizing FEA's tentative findings, and comments were accepted at public hearings on May 10-12. The forward schedule calls for FEA to issue its prohibition orders before expiration of its ESECA authority on June 30, followed by an EPA investigation and advice to FEA as to the earliest date when the units can be retrofitted to meet Clean Air Act requirements. The final step is then the issuance by FEA of an environmental impact statement and a final notice of effectiveness.

FEA estimates differ markedly from New England Power Company's estimates. FEA predicts capital costs of $119.3 million and net annual savings of $19.8 million. Our estimates predict capital costs of $340.8 million and net annual increased costs to our customers of $138.0 million. The only point of general agreement is that both FEA and New England Power Company analyses find it uneconomic to convert the Salem Harbor units.

The differences in the two estimates involve virtually all major variables: the physical requirements for new equipment and the capital cost to re-establish coal-burning capability on a permanent basis; the equipment and capital costs required to meet Clean Air Act requirements; the relative future costs of imported oil and conforming coal; the remaining useful life of the units, over which capital costs must be amortized; the expected capacity factors of the units when burning coal; and the financial risks involved in future changes in Clean Air Act requirements.

Without attempting to resolve these differences here, three major comments can be made:

1. A major unknown in both sets of estimates is whether EPA will permit coal conversion at all, and if so on what terms. FEA appears to have specified a coal which does not conform to the present Massachusetts state implementation plan, and has assumed that scrubbers will not be required. In the light of our experience to date, we have necessarily assumed that scrubbers will be required for any coal that can be economically delivered on-site.

2. Although we have responded to all requests for information and have presented our estimates for FEA review, FEA has refused to make its detailed analysis available to us. As a result, we have had no real dialogue with FEA which might reconcile our differences. Indeed, since ESECA requires only a legislative-type hearing before issuing a prohibition order (and makes no provision for any meaningful review of EPA's findings prior to issuance of a notice of effectiveness), we have been forced to take court action in order to obtain the basis for FEA's estimates and, hopefully, to precipitate a meaningful dialogue before we are told to pass on what we believe may be very substantial rate increases to our customers.

3. The FEA Administrator has publicly stated that utilities have an economic bias to avoid the capital investments required for coal conversion, and to prefer to pass on higher oil costs through their fuel adjustment clauses. Our own public commitment is quite to the contrary: if there are net savings to our customers, we are prepared to convert to coal, remit the fuel savings to our customers immediately through the fuel clause, and seek to recover our capital costs through subsequent rate cases. This is precisely what we did at the time of the Arab oil embargo, and what we are prepared to do again. Our commitment to achieve lowest overall costs reflects not only what we believe is required of responsible utility management; it also reflects an economic pressure which the FEA Administrator has temporarily overlooked: our ability to finance the future capacity requirements of our service area depends critically on investor acceptance of our securities; this in turn requires rate increases which will fully reflect the increasing cost of new equipment and current operations;

and we know from experience that such rate increases are possible only when our customers and our regulatory agencies believe that we have made every effort to minimize our total costs of service.

(3) The coal conversion provisions of H.R. 6831.

Section 601 of the bill rewrites and broadens the coal-conversion provisions of ESECA. Section 603 provides that the new regime will become effective six months after enactment. Although FEA's authority is greatly changed, EPA's role is not addressed by any change in section 119 of the Clean Air Act, which was originally enacted as section 3 of ESECA and which relates solely to the mandatory coal conversion program.

I plan to limit my comments to proposed section 105* of the revised ESECA; and to focus my remarks on the problems of the electric utilities which own oil-burning units that may be candidates for conversion to coal. I understand that others on today's panel will address the problems of the electric utilities which own natural gas-fired units; and the problems of industrial firms which may be required to convert "major fuel-burning installations".

Section 105(a) appears to set up a two-track system, with the choice left wholly to the discretion of the FEA Administrator.

1. Track I is outlined, with elegant simplicity, in section 105(a)(2)(A). FEA may identify categories of power plants, which are then forbidden to use natural gas or oil. That is all there is to it: Track I does not "shift the burden of proof", it dispenses with the need for proof entirely.

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* Pages 99-107 of the bill.

The only category specifically mentioned for Track I treatment consists of power plants which have been listed by FEA as coal conversion candidates under the old ESECA -- whether or not FEA and EPA have completed their review of the feasibility and cost of conversion.

If a utility feels a need to plead for further consideration, it may apply to the Administrator for a 5-year temporary exception under section 105(d), or for a permanent exemption under section 105(e). However, both sections raise almost impossible burdens of proof, and relief in any event is wholly in the discretion of the Administrator.

Thus, unless FEA provides a period of grace in its categorization order, the utility will have no choice but to shut down its power plant, find out what EPA's requirements may be, and then set about the job of retrofitting and lining up an acceptable supply of coal.

It should be noted that if FEA follows Track I it may, if it chooses, disregard all the criteria thought to be relevant for a mandatory coal conversion under ESECA: the capability of the unit to burn coal; the practicability of conversion; the availability of a coal supply and coal transportation; the effect on reliability of service; and the interface with EPA in determining the Clean Air Act requirements to be observed. Admittedly, FEA may act with self-restraint, either through regulations to be promulgated in the future, or in the detailed provisions of a categorization order. But the grant of virtually imperial power requested in section 105(a)(2)(A) is unlimited in scope and a potential disaster for consumers.

2. Track II is outlined in sections 105(a)(2)(B) and (C), with an addendum in section 105(b)(3). If FEA elects to use this track, it will issue prohibition orders to individual power plants, following criteria which require findings as to coal burning capability, financial feasibility, reliability and coal supply which are reminiscent of ESECA. In addition, FEA

will not issue a notice of effectiveness until EPA has certified "the earliest date that the power plant will be able to comply with all applicable requirements of section 119 (of the Clean Air Act)". Section 105(b)(2) carries forward the ESECA precedent, of permitting FEA to issue a prohibition order after a legislative-type hearing, but without any meaningful dialogue to resolve factual or estimating differences. And EPA remains, as under ESECA, in the role of private advisor to FEA.

To summarize: We fully recognize the national interest in limiting our national dependence on imported oil; and we believe that a program to convert existing power plants from oil to coal can make an appreciable contribution by the early 1980's. But even the Department of Defense is required to count the cost of military preparedness programs. Here, neither Track I nor Track II imposes any real fiscal accountability on FEA -- perhaps because the cost will not be borne by the general treasury, but rather by the electric consumers involved. We continue to believe that needless expense should be avoided in coal conversions and that "net cost" coal conversions should not be ordered at the expense of a regional minority; and in any event that they should not be ordered without a conscientious attempt to estimate the costs, whatever they may be. Neither Track I nor Track II, nor ESECA in its present form, imposes this requirement on FEA in any meaningful way.

(4) Recommendations.

(A) Section 105 as presently drafted can readily be converted into a more effective coal conversion procedure by combining Tracks I and II.

As revised, the Track I categorization procedure would be recast as agency rulemaking, with the result that power plants falling within a category would become presumptive candidates for coal conversion. A definitive prohibition order would then be issued only after a Track II proceeding in which the individual characteristics of the plant were considered and FEA had found that all statutory criteria for conversion were met.

The Track II procedures for issuing definitive individual prohibition orders would then be revised as follows:

1. EPA's advice as to what emission control equipment and procedures are necessary to meet Clean Air Act requirements would be provided to FEA and the power plant owner at an earlier stage of the proceeding, and before FEA makes its final decision on the financial feasibility of conversion.

2. FEA and EPA would both be required to enter into a meaningful dialogue with the power plant owner to resolve disputed issues of fact and estimates. This could be accomplished by revising section 105(b)(2) to provide a limited opportunity for discovery and cross-examination of FEA and EPA witnesses before an FEA hearing board, and requiring the board's recommendations to be reviewed by the Administrator before issuing a final prohibition order. FEA's Office of Exceptions and Appeals provides an existing vehicle for such an independent review.

3. A prohibition order would not be issued if FEA concludes, on the basis of its most probable estimate, that coal conversion will result in a rate increase to consumers. In its consideration of this question, FEA would factor in any government contribution which might be authorized in order to permit "net cost" coal conversions in the national interest.

This suggestion would involve a revision of section 105(a)(2)(C) to define "financial feasibility" more specifically. In the course of this revision, consideration should be given to the definition of "cost" which appears in proposed section 102(14), and which differs from the calculus now in use by FEA under ESECA.

(B) Consideration should be given to a government contribution to the costs of coal conversions which result in a net cost to electric consumers, but which are nevertheless deemed to be in the national interest. To expedite coal conversions, and to deal fairly with all parties, it would be preferable to base this contribution on after-the-fact information rather than preliminary estimates. Thus, the amount of the government contribution might be determined after coal conversion had been completed, a permanent coal supply had been assured, and a one-year test period had elapsed from which operating and maintenance expense and capacity factor could be more accurately estimated.

(C) Consideration should be given to minimizing the cost of coal conversions by re-examining Clean Air Act policies now in place under EPA regulations and state implementation plans. We make this suggestion for the following reasons:

1. The Clean Air Act standards which most directly relate to fossil-fired electric generating plants involve the "criteria pollutants", sulfur dioxide and particulates. The national ambient standards for these pollutants were based on criteria published by EPA's predecessor agency in 1969. The criteria reflected a working scientific hypothesis that by controlling these two pollutants, we would reduce their transformation products (aerosol sulfates, for example) which were believed to have a direct relationship to respiratory disease.

Analysis of the greatly expanded data base resulting from EPA's administration of the Clean Air Act now suggests that the basic problem is far more complex, and that by about 1980 research now in progress may indicate the need for revising clean air standards to control a sub-set of specific pollutants more directly. Under these circumstances, it would seem prudent to adopt a "hold the line" policy, to keep the present standards in effect, but not to tighten present control regulations so as to require additional investments which may be made obsolete by new developments.

2. In directing EPA to set national ambient air quality standards, Congress in 1970 required EPA to base its findings on the criteria documents and to allow "an adequate margin of safety" to protect public health.* In fact an excessive margin of safety has resulted, first in setting the national ambient standards themselves, second in interpreting the results of air quality monitoring, and third in modelling air quality conditions to determine the specific control strategies for state implementation plans.

3. Given this redundant margin of safety and the fragmentary data base on which the original criteria were set, it would seem prudent now to inquire whether the national interest in reducing our dependence on imported oil cannot be accommodated by setting reasonable standards to be met by power plants to be converted to coal. We believe that this can be done without wholesale revision of the Clean Air Act, and without abandoning our national commitment to air quality.

In devising the standards to be met by converted power plants, we believe that specific emission limitations should be fixed which will remain valid for twenty years or expected plant life. Only with this assurance will it be possible to enter into long-term contracts for coal and pollution control equipment, since current Clean Air Act policies otherwise present a moving target as EPA and the Congress consider new initiatives to deal with new pollutants, with non-attainment problems, and with the thorny issue of "no significant deterioration" of pristine areas. And it is clear that the new coal supply necessary to support coal conversions will not be forthcoming in the absence of long-term utility contracts.

Analogies are readily available to carry out this suggestion. First, the new source performance standards set by EPA under section 111 of the Clean Air Act specify precise

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* Clean Air Act, section 109(b)(1).

emission limitations to be met by new plants. Given the fact that new plants can be designed to meet a higher standard than existing plants, it should be possible to set emission limits for a category of converted plants by an appropriate scaling-up of EPA's new source performance standards. Second, a precedent for maintaining emission standards unchanged over an appropriate amortization period already exists in section 306(d) of the Federal Water Pollution Control Act, as amended in 1972.

We therefore urge the Subcommittee to solicit the advice of FEA and EPA in devising fixed emission standards for converted power plants which will carry out this suggestion.

In summary, we believe that an effective coal conversion program should meet three common-sense tests:

1. It should avoid needless expense to electric consumers.

2. It should encourage coal conversions wherever there are net savings to consumers; and should not force "net cost" conversions unless the government is willing to foot the excess costs.

3. It should be carried out under procedures which do not hand FEA and EPA a blank check.

If the bill is revised in line with our suggestions, we believe these three common-sense tests will be met.

5/25/77

H.R. 6831: COAL CONVERSION

Donald G. Allen (New England Electric System/New England Power Company)

New England Power Company has oil-burning generating units which can be converted to coal at net savings to consumers. This will require a revision of the Massachusetts state implementation plan under the Clean Air Act. Conversion plans are stalled pending EPA review.

(1) Basic philosophy.

Coal conversions can contribute to reduced oil imports. Clean Air Act requirements are a major road-block. Coal conversions should not be forced when they are uneconomic; otherwise the national interest in reducing use of oil and natural gas will be financed on a narrow regional basis.

(2) The New England Electric System experience.

New England Power Company has generating units originally designed to burn coal. They were converted to oil-firing in the late 1960's. They burned coal on a temporary basis following the Arab oil embargo. Some units could burn coal permanently if a pending revision of the Massachusetts state implementation plan were approved by EPA. All units are candidates for mandatory coal conversion under FEA's Round II. FEA says coal conversion would result in savings to consumers. The Company says coal conversion would result in rate increases to consumers. A major source of difference between the two estimates is that neither FEA nor the Company knows what EPA's requirements will be.

(3) The coal conversion provisions of H.R. 6831.

Conversion of *existing* electric generating units to coal is covered by proposed new ESECA section 105. This appears to set up a two-track system. Track I gives FEA the option of forcing coal conversion by listing categories of power plants which have to be converted. Track II calls for individual coal conversion orders. Track I appears to give FEA uncontrolled authority to order coal conversions, without considering the cost to consumers.

(4) Recommendations.

1. Combine Track I and Track II and revise the ESECA procedure to get EPA's advice on the table at an earlier date.

2. Authorize a government contribution to any excess costs of conversions ordered by FEA in the national interest, where coal conversion orders will result in added costs to regional consumers.

3. Set fixed emission limits to be met by power plants to be converted to coal. These limits should remain valid for the remaining life of the plant. Otherwise it will be impossible to obtain the necessary coal under long-term contracts.

Mr. MOFFETT. Thank you very much.
We will proceeed to Mr. Andras.

STATEMENT OF O. S. ANDRAS

Mr. ANDRAS. Good morning. We appreciate this opportunity to give our support to the objectives of the President's national energy plan as they relate to the increased use of coal as a substitute for more valuable and scarce oil and gas. We have long recognized the need and desirability to preserve oil and gas for their highest priority use.

The details of the National Energy Act, however, present us with some real problems as we evaluate our future options. It must be noted at the outset that conversion is a misnomer when applied to most facilities which burn oil and gas and will eventually be required to switch to coal combustion. In almost all cases, these units must be completely replaced, including the turbines and electrical switch gear. And, as this replacement takes place, the existing units must continue to function.

In the short range, however, we can see no reason why some gas-fired facilities should not be converted to burn oil. A gas-to-oil conversion can be made rapidly and with much less expense and would not preclude the longer-range replacement with coal-fired units. We recognize the desirability of reducing our dependency on oil imports, but the short-term problem which our Nation faces is a shortage of natural gas, not residual oil. Such interim conversions would minimize the negative impact of requiring massive capital investments for nonproductive projects.

The most serious aspects of coal utilization for industry, as developed in the National Energy Act, is one of timing. The energy use taxes on gas and oil which are used as the means to force replacement, begin in 1979. On utilities the schedule of use taxes begins in 1983 and continues at a lower rate than the industrial tax. This discrepancy in timing would imply that the administration believes industrial boilers can make the switch to coal more quickly than utility boilers. This is not true. Large industrial boilers are every bit as difficult, time-consuming, and expensive to replace as are utility boilers. We currently are planning a coal-fired plant for our Texas operations, and we estimate it will take over 6 years to complete.

The administration plan has provisions for recapturing part of the use tax by applying it against the capital spent to switch to coal. While this approach in theory would tend to minimize the financial impact of replacement, in practice the use tax will be paid for several years before capital expenditures can start. Once it is paid, if an offsetting capital expenditure is not made in that year, the tax payment cannot be recaptured.

In order to build a major coal-burning facility, many operating factors must happen simultaneously. Permits to mine and burn the coal must be otained from local, State, and Federal authorities. The current morass of uncertainty surrounding air quality standards and the proposed strip-mining regulations make it unlikely that significant increased use of coal will be allowed or planned until someone takes a firm hand in resolving what appears to be contradictory goals within the administration. In addition, there will be certain areas of the country where coal-burning never will be allowed, even with the best available technology. Meanwhile, the use taxes would continue, penalizing the energy user through no fault of his own.

Even if the environmental issues are resolved in such a way as to allow rapid increases in coal utilization, the capacity of the transportation industry, boiler and other equipment manufacturers, the engineering and construction companies will be severely strained to meet the proposed timetable. Again, if any one of these necessary operations is unable to respond quickly, the industrial user is unfairly penalized.

The FEA currently has the authority under ESECA to issue construction orders forbidding new oil- and gas-burning facilities and to mandate burning of coal in existing dual-fired facilities.

We recommend that approach. That, coupled with the time deadline of perhaps 1990, when penalties could be applied to those who have not switched to coal but have had the opportunity to do so, is a more reasonable and less disruptive means to coal utilization than is a discriminatory and unrealistically rapid application of punitive user taxes. If we are to have a tax on gas and oil, we think it should be equally applied to all those who have to replace facilities, and a reasonable time schedule should be permitted.

[The attachment to Mr. Andras' prepared statement follows:]

Additional Written Comments Presented by O.S. Andras, Dow Chemical U.S.A.

BASIC OBJECTIVES AND APPROACH

We strongly support the Administration's objectives of conserving natural gas and petroleum for essential end-uses by construction of new boilers to use fuel other than gas and petroleum and the orderly replacement of existing gas or oil fired boilers with coal combustors.

We believe free market processes can best achieve these goals. But we recognize that government regulation has artificially stimulated demand for natural gas, and to a lesser extent for oil, while artificially restricting the supply of gas, oil and coal. Deregulation of new natural gas and of U.S. petroleum would result in price incentives to convert boilers to alternate fuels without adding to the federal regulatory bureaucracy. This approach would avoid the administrative complexity, expense and delays (a goal that the President as well as many members of this Committee have vigorously supported) which would result from a newly designed mandatory conversion program.

Under present circumstances, however, we are faced with a dilemma: how to return to a free market as the primary mechanism to allocate resources in the face of continuing regulatory incentives which would bias the market response.

For example, on a nationwide basis, coal is now the cheapest source of fossil fuel energy for electric utilities.1/ Why, then, are we not using more of it? Is it not largely because regulatory constraints still make gas and oil more economical?

In fact, the problem is even more difficult. Boilers with dual-fired capability are still burning gas supplied by interstate pipelines, even under interruptible contracts, while higher priority users are being curtailed, even under firm contracts.

1/ Federal Power Commission, News Release No. 22995, Monthly Fuel Cost and Quality Information, March 14, 1977, p. iii. The costs of coal transport and coal handling equipment would also affect fuel use decisions to some degree.

Why is this happening?

Perhaps it is because federal regulation of energy end-use (demand factors) and federal regulation of energy supply have been considered as separate issues.

Isolating federal regulation affecting demand for energy resources, we find in place today controls which can, in whole or in part, :

- allocate natural gas to, or away from, boilers
- allocate petroleum to, or away from, boilers
- mandate conversion to coal or construction of coal fired boilers
- prohibit burning of gas and oil in boilers
- allocate coal to boilers.

With such federal controls in place, it is probably academic to judge the Administration's proposals on the basis of their relation to a free market energy management approach. It is, however, meaningful to determine, if possible,

- what this bill will do that present laws will not do, if properly administered?
- what this bill does not do?
- what measures should be taken to achieve the results desired in this bill?

We wish to concentrate on the last question.

REMOVE FEDERAL DISINCENTIVES

To achieve the coal utilization benefits desired, we would suggest that federal disincentives to use a potentially cheaper boiler fuel, coal, be removed, thereby allowing natural market demand forces to operate. At the same time, remove constraints on supply, so that the federal government will not believe itself required to ration limited supplies.

Federal disincentives to burn coal include:

- the high cost of pollution abatement equipment required to burn coal legally,
- the uncertainty of whether future air quality standards will allow coal use over the economic life of the boiler,
- the uncertainty of an assured supply at a reasonable price due to federal and state policies on leasing, mining and transportation.

Additionally, a powerful disincentive is the high, non-productive expenditure required to replace existing gas and oil fired boilers which have a long remaining economic life.

One of the most effective mechanisms to remove or mitigate the adverse impact of non-productive costs unrelated to the economics of boiler operation is to permit an acceleration of the federal income tax consequences of conversion or construction of coal-fired boilers.

Equally significant are the disincentives within the scope of Clean Air and Surface Mining legislation, not this bill. Perhaps it is enough to say that adverse provisions in such legislation will frustrate effective implementation of this Bill and that the first order of business must be to remove such constraints.

As an example, one company in our industry has, on orders from EPA, just recently completed expensive construction of oil-fired facilities to replace its existing coal-fired boilers. Under the Administration plan, this company would face reconversion at additional cost, or pay the puitive and unequitable user taxes which are part of the proposal. This bill does not address the clear conflict its provisions will produce between coal utilization deadlines or user tax penalties and compliance with environmental standards. The resolution of these conflicts must come first before industries or utilities are penalized by user taxes which they must pay in the interim, while through no fault of their own they are not allowed to burn coal.

EMPHASIZE EFFICIENT MEASURES

Ending boiler fuel use of natural gas and petroleum will impose significant economic costs on the nation. Consequently, each legislative provision should seek the maximum energy saving for every dollar of conversion expenditure made. To do this the program should :

- distinguish between new and existing boilers;
- prohibit construction of new gas-fired boilers and, subject to reasonable exceptions, new petroleum-fired boilers;
- order existing dual-fired boilers capable of burning coal to do so;
- convert large boilers first.

NEW FACILITIES

The Administration plan very properly recognizes that new boilers should not be constructed to use natural gas fuel, and we endorse the HR 6831 policy of allowing exceptions and exemptions in some cases for petroleum fuel. Leaving flexibility and a reasonable exception process for petroleum-fired boilers will serve to soften the economic dislocation imposed by mandated conversion schedules and consequent pressure on coal and coal transportation resources. However, even though an industrial consumer might be allowed to use oil, the punitive user's tax would continue. Such industrials would be at a definite disadvantage if they produce their own power in relation to a company who purchases power from a utility.

EXISTING BOILERS

Requiring existing dual-fired boilers to use coal is the cheapest and quickest means of reducing boiler fuel use of natural gas and oil. Even during this winter, when we experienced the worst gas shortages in our history, a large amount of natural gas under interruptible contracts was being used by electric utilities.2/ Tremendous gas savings could be realized immediately, even during the coming summer, by requiring such facilities to use coal rather than gas.

DEAL WITH LARGE BOILERS FIRST

With respect to both new and existing boilers, substantial cost savings can be made by recognizing that large volume boilers consume the greatest proportion of total oil and gas. Thus, to maximize efficiency of coal utilization expenditures, they should be the initial focus of a replacement program.

- HR 6831 defines major fuel burning installations as including units with a fuel heat input of 100 million BTU/hr or greater, a lower limit far too low to be economically efficient. The program should exclude smaller sized boilers or extend the timetable for conversion of smaller sized boilers. A sound lower limit would be 300 MMBtu/hr and above. The American Boiler Manufacturers Association (ABMA) states that most existing boilers cannot, for technical design reasons, be converted from gas to coal firing, but must be replace entirely.3/ In its

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2/ This past September - November alone, electric utilites burned more than 231 Bcf of gas purchased under interruptible contracts. Federal Power Commission News Release, supra, pp. 16-17.

3/ ABMA Statement before the Subcommittee on Energy Production and Supply, Committee on Energy and Natural Resources, U.S. Senate, March 29, 1977, p.2

Comments last year on S. 1777, the ABMA estimated that total replacement costs for units at the 120 MMBtu/hr and above level would be $49 billion exclusive of the cost of required pollution control equipment.4/ If the minimum level is raised to 300 MMBtu/hr, the total replacement cost figure drops to $24 billion.5/ Yet boilers in the 101-300 million Btu/hr range use only about 8.6% of the total industrial and utility boiler fuel gas and oil consumed.6/

- Taking this data into account, it is inefficient to target either new or existing facilities in some order of priority based on selections from the SIC industry category list. The focus should be on boiler size and age. The particular type of industry or its overall rate of fuel consumption is not relevant to efficient gas and petroleum conservation.
- Since boiler size is the most significant factor bearing on cost and feasibility of conversion, the Committee should consider including commercial boilers in the HR 6831 program.

Equally significant in considering HR 6831 is recognizing that reasonable deadlines or timetables for replacement of existing boilers must be granted. Applying a user's tax on industrials starting in 1979 with rebate provisions implies that replacement of existing industrial boilers can begin immediately. Under current environmental regulations this is almost impossible to do. Yet the user's tax

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4/ Comments of the American Boiler Manufacturers Association for the Senate Committee on Public Works, June 30, 1975 (revised July 17, 1975), Table 1. These comments also reveal that some 17,000 units would have to be replaced if the input level is 120 MMBtu/hr and above. If the input level is raised to 300 MMBtu/hr, the number of units needing replacement drops to 4,000.

5/ Id.

6/ ABMA Statement, March 29, 1977, supra at pp. 3-4.

would continue, placing U.S. industry at a sever disadvantage relative to a world market. Such punitive user's taxes appear to have been suggested without careful consideration of equipment, coal, and coal transport availability.

- The ABMA comments suggest some question as to adequate manufacturing capacity to provide the number of new boilers that would be required by S. 977.7/
- We estimate that if all electric utilities using oil and gas as boiler fuel in 1975 were required to use coal, total coal demand would have been 45.7% greater than the amount of coal used for all uses in 1975.8/
- A free market approach, allowing replacement to take place in an orderly fashion would minimize the adverse impact of an overzealous tax program and permit time for analysis. If necessary, user taxes could be applied at a much later date to entice those who have not yet switched to coal but would have been allowed to.

7/ ABMA Statement, March 29, 1977, supra at pp. 2-3.

8/ See American Petroleum Institute, Basic Petroleum Data Book, 1976, Section 1, Tables 12a, 15a, 17a, 18a, 19a.

Mr. MOFFETT. Thank you very much.
Mr. Oprea.

STATEMENT OF GEORGE W. OPREA, JR.

Mr. OPREA. Mr. Chairman, we have submitted our testimony to the subcommittee and, if I may, I would like to submit an oral summary in regard to that written testimony.

We wholeheartedly support the President's conservation objectives. As a matter of fact, Houston Lighting and Power started supporting that program back in the early seventies more permanently, starting in the latter part of the 1960s. At that time we embarked upon a policy of no further installation of gas-fired units, using oil as stop-gap measure, as a prelude to moving fully into a coal and nuclear option. As a result, at the close of 1976 where we had been 99 percent on natural gas, by 1985 our dependency will be 15 percent. Our coal dependency will be somewhere around 30 to 35 percent.

I think it is significant to note that as a whole in the State of Texas, the whole State of Texas had taken similar courses of action, and by 1985 we expect the whole State of Texas to have a dependency of no more than 18 percent on natural gas. We wholeheartedly urge the committee to have regulatory requirements in the bill that are realistic and efficient, that indeed take into account specific situations at various electric utilities in different regions of the United States. We feel a rigid plan could create planning uncertainty, provide for delays in needed construction, and the end result would be undue difficulties in financing our projects.

Houston Lighting and Power Company is in an oil-gas producing region. The fuel we have used for all of our facilities is per the gas route. Everything we have installed can only burn gas, although we embarked upon a conversion program 3 years ago to put roughly 50 percent of our plant capacity on oil should the desire and the necessity so deem it.

However, there are parts of the country, utilities and industries that have switched from coal to oil and to gas, and possess facilities that allow them to go back to coal. We cannot convert to coal. We have to replace our facilities with coal facilities, without any conversion whatsoever possible.

Although we are looking at various ways to provide some degree of conversion, for the most part we cannot do anything but replace the existing facilities with coal facilities, and that replacement would have to take place at another one or two new powerplant sites.

We feel the bill really provides no distinction of the ease or difficulty associated with the switch to coal as related to the different regions of the United States.

The single arbitrary deadline of January 1990 to end use of gas- and oil-powered plants, as well as the arbitrary deadline relative to the energy use tax of 1983, that says "Unless you end your use of gas by 1983, you will be penalized," is a very, very heavy financial burden for all of us.

In the case of Houston Lighting and Power Company, starting in 1983 through 1990, the tax on the use of gas would amount to roughly $1.7 billion, almost equivalent to the cost for the installation of 3 million kilowatts of coal-fired facilities.

We feel that certain incentives in H.R. 6831 do not give the extensive support necessary for companies like Houston Lighting and Power Company that will be subjected to very, very horrendous expenditures because they cannot convert but, instead, they have to replace and rebuild in other locations.

We feel that there should be a reasonable deadline and timetable which provides for the replacement of existing boilers, that distinction should be made between facilities that can be converted versus those that should be replaced in toto, and there should be clear recognition of that difference.

We feel also that careful studies and evaluation should be made of the availability of boiler equipment, coal transportation facilities, coal suppliers and production facilities, as well as labor necessary to build those facilities.

We feel our present coal utilization plans are completely compatible with efficiently designed legislative timetables that hopefully will come out of this committee and others per bill 6831.

As you know, the Texas Railroad Commission has initiated a very rigorous program whereby they are making it mandatory upon all Texas utilities to minimize their dependency on gas. We are following those mandatory requirements and our corporate plans support that requirement, plus other severe measures that we feel are fully supportive of the requirements of the State of Texas, and are a prelude to the issuance of the President's national energy policy.

We feel there are inconsistent Federal demands that take place relative to utilities and their conversion and replacement to coal faciliteis. We feel Federal programs can impact our present and planned activities and feel that realistic appraisals must be made and a balance struck between the Clean Air Act, the need for coal transportation, Strip Mining Act, and also the Coal Leasing Act.

As a matter of reference to cost, if Houston Lighting and Power Company had to replace all of its existing gas-fired facilities within the next 10- to 15-year period, it would increase the capital investment in plant—which at year end 1976 was $2.5 billion—fivefold, in excess of $11 billion.

That, gentlemen, is over and above the $5 bilion we now have in our budget to take care of the normal development, incremental capacity needs that are now projected via our corporate plans. Added on top of that would be the gas user and oil taxes that would impose an additional $2.2 billion on very, very tough budgets that we are experiencing this year and through the next 15 years.

What this means is that we today and for the next 15 years, prior to the issuance of the Carter policy statement—have that range from $425 million, upwards to about $600 million per annum; with the overload of the additional conversion and replacement of facilities, and also the user taxes, we would have budgets that would range somewhere between $750 million to $1 billion per annum. We feel it a near impossibility to finance projects that require dollars of that magnitude.

In closing, I would like to recommend four items:

I would like to recommend that the coal conversion provisions clearly recognize special regional conditions that do not give all utilities the same ability to utilize coal, and also the same identical conversion timetables.

Secondarily, I would like to suggest that the investment tax credit should be provided for the required new facilities for the coal conversion factors in H.R. 6831.

Thirdly, we feel accelerated depreciation of useful plant should be allowed because the bill will indeed require us to abandon certain plant facilities.

Fourth, we feel a credit of oil and gas use tax should be allowed simultaneously with replacement expenditures for qualified replacement and conversion facilities in order to ease the financing requirements of the many utilities.

Thank you very much.

[Mr. Oprea's prepared statement follows:]

COAL CONVERSION PROVISIONS
OF THE NATIONAL ENERGY ACT

Testimony by

George W. Oprea, Jr.
Executive Vice President
Houston Lighting and Power Company

Committee on Interstate and Foreign Commerce
Subcommittee on Energy and Power — May 25, 1977
U. S. House of Representatives — Washington, D. C.

Mr. Chairman, members of the Committee, my name is George W. Oprea, Jr. I am Executive Vice President of the Houston Lighting and Power Company.

We appreciate today's opportunity to present our views on the coal conversion sections of the National Energy Act, Part F, Title I, of H.R. 6831.

We support the conservation objectives advocated by the President. Recognizing how vital energy conservation is, we began our own effort some time ago. In fact, we have not begun construction of a new gas-fired boiler since 1968, six years before the ESECA legislation was enacted. And we have no plans to construct additional gas-fired utility boilers. As we read the President's National Energy Plan, we believe our own planning efforts respond to the objectives he has expressed. And we will continue to press ahead along these lines, not only because we believe that our future lies in coal and nuclear, but because our own State government requires it.

Realistic and Efficient Legislation

We urge the Committee, however, to insure that the regulatory requirements established by the Bill are realistic and efficient. Too rapid a conversion timetable would simply result in a landslide of exception and exemption proceedings in order to maintain reliable electric service. A program too rigid will only create further planning uncertainity and delay needed construction while increasing our difficulties in the capital market. The conversion program must take account of the specific situation electric utilities face.

For example, HL&P now uses gas for virtually all power generation. Section 401 of the National Energy Act notes that natural gas originally was considered as a useless by-product of crude oil production, which in turn produced dependence on gas in our region.

At the same time, because federally regulated interstate gas was held at low prices, many utilities with alternate fuel capability have used large quantities. Last October through December, for example, 112.5 Bcf of interstate gas under interruptible contracts was burned under utility boilers outside of the gas producing states.

Many utilities and industries in other regions of the country have in past years switched coal-burning facilities to gas and oil, but still possess the necessary sites or facilities for burning coal, such as railroad spurs, loading docks and storage capacity. However, we constructed our facilities to burn gas. They cannot be converted to coal; they must be replaced.

Unfortunately, this is a distinction the Bill fails to recognize in a number of its key provisions. For example, a single, arbitrary deadline (January 1, 1990) for ending utility use of gas is established for all existing powerplants. And the energy use tax beginning in 1983 for all utilities constitutes another such arbitrary deadline beyond which all utilities must end gas use or be penalized. Certain incentives proposed in the Bill do not clearly include the type of extensive expenditures required of a company like HL&P which cannot convert but must build new facilities.

Timing

We feel that reasonable deadlines or timetables for replacement of existing boilers can be established if the distinction between those facilities that can be converted to coal and those that would have to be completely replaced is clearly recognized. We also feel that careful study of boiler equipment, coal and coal transport availability, and the impact of conversion on coal mines should be made. We are pleased that the Chairman posed specific questions on these latter issues to each witness appearing here today.

- The American Boilers Manufacturers Association (ABMA) has questioned whether adequate manufacturing capacity currently exists to provide the number of new boilers required by the Bill.

- We estimate that if all electric utilities using oil and gas as boiler fuel in 1975 were required to use coal, total coal demand would have been 45.7% greater than the amount of coal used for <u>all</u> uses in 1975.

A 1983 date for completion of coal utilization preparations may fit some, but not all utilities' feasible timetables. The National Energy Plan recognizes that in 1985, approximately 1 Tcf of natural gas will be needed for electric utilities. This legislation must insure that the initial changeover to coal utilization is made by those who are already equipped to do so most efficiently with the lowest capital expenditure.

We believe our existing coal utilization plans would be compatible with efficiently designed legislative timetables planned to allow for such factors. As I'm sure you know, the Texas Railroad Commission, in Docket 600, has already initiated a rigorous conversion program.

Inconsistent Federal Demands

We hope the Committee will keep in mind that an electric utility such as HL&P is faced not just with the conversion program envisioned in Part F of H.R. 6831, but with other federal programs and proposed programs that will each have a major impact on our present and planned activities. These programs and federal policies, regulations, and orders can whipsaw industry between conflicting demands. Greater use of coal will conflict directly with federal Clean Air standards, an issue apparently not resolved by the National Energy Act. Greater burning of coal will strain the existing coal transportation system, an issue that the Administration plans to study sometime in the future.

A comprehensive coal conversion program cannot be considered in isolation. We suggest that realistic appraisals of the existing situation be made.

Cost

Replacement of HL&P's gas-fired plants will cost roughly five times the company's existing capital. This is in addition to the $5 billion we have budgeted through 1985 to provide the incremental capacity that increased energy demands of our service area will require. Moreover, we face in the interim, higher costs from the user taxes on oil and gas and wellhead taxes on crude oil; other direct expenditures are also mandated by the Act. Mandatory interconnection, for example, which is possible under proposed Section 521, could cost HL&P $300 million. Such expenditures will obviously make it more difficult to find the capital to fund the mandated replacement projects.

We would propose that the coal conversion provisions clearly recognize the special situation of utilities which, like ourselves, do not have the conversion option. Investment tax credits should be provided for the required new facilities, and accelerated depreciation of useful equipment which the Bill will require us to abandon should be allowed. The credit against oil and gas consumption taxes for qualified replacement investments should be simultaneous with the replacement expenditures.

We appreciate this opportunity to appear today to voice concerns about the programs proposed, for if the conversion program and other regulatory requirements cause our construction program to lag behind the energy needs of our service area, the economic impact would spread far beyond my own company.

We hope an efficient and realistic conversion program will be developed as a result of this Committee's efforts for we share your concern and that of the President for insuring the energy supplies our nation will need in the coming decades.

Mr. MOFFETT. Mr. Lutken.

Mr. LUTKEN. Mr. Chairman, I previously submitted my testimony to the subcommittee, and I will summarize it.

Mr. MOFFETT. Thank you.

STATEMENT OF DONALD C. LUTKEN

Mr. LUTKEN. First, I would like to say electric energy is essential to every home, every commercial establishment and every industry. It is a necessity which should take precedence over lesser energy forms and intangible environmental objectives in the national energy plan.

Part F of the proposed legislation is unneeded, as we see it, because of, one, the electric industry has already embarked on a program to supplant baseload oil and gas-fired generation equipment using coal and uranium; two, part F, if enacted, would require a substantial misallocation of capital, and, three, part F would impose disproportionate costs on certain regions of the country in contravention to the announced policy of equity for all.

Our company has been down that road, Mr. Chairman. In 1970, when the Federal Power Commission took our gas away from us for which we had long-term firm contracts, we had to convert to oil. Our gas went to the benefit of others in the country, and our customers, as a consequence, have paid something in the neighborhood of $260 million in added fuel cost, not to mention the carrying charges of $100 million for conversion. So I seriously doubt that this policy will be equitable throughout the United States.

The electric industry pioneered in halting the massive waste of natural gas which formerly was flared, and has utilized this heat source effectively and efficiently since that time.

The conversions contemplated in part F would legislate extensive waste of capital, fuel and capacity.

Natural gas supply, like any other commodity, responds quickly to market constraints, even in exceptional peak demand periods such as the 100-year winter just experienced. Billions of cubic feet of gas offered for sale under the Emergency Act went unsold; and the shortage vanished.

Residual oil is, as its name indicates, a waste product which is best disposed of as boiler fuel. Prohibiting its use would be a tragic waste.

The electric industry has the experience, the trained personnel and the technology to meet the electric energy requirements of an expanding economy if it is given relief from unnecessarily restrictive and unproductive governmental policies that have intangible, or at best, marginal benefits.

The industry needs the understanding and the help of the Congress.

Thank you, sir.

[Mr. Lutken's prepared statement follows:]

STATEMENT OF
DONALD C. LUTKEN, PRESIDENT & CHIEF EXECUTIVE OFFICER
MISSISSIPPI POWER & LIGHT COMPANY
ON BEHALF OF
EDISON ELECTRIC INSTITUTE

Hearing Before the
Subcommittee on Energy and Power
Interstate and Foreign Commerce Committee
United States House of Representatives

May 25, 1977

I am pleased to speak on behalf of the investor-owned electric companies of this country. The service we supply is unique. It has become regarded as a necessity for every home, every commercial establishment and every industry. No other energy source has such a universal demand. In fact, many people are now taking the position that there is an inherent right to basic increments of electric energy. In any event, it is a modern necessity.

During the summer of 1976 the California Public Utility Commission adopted a plan for electric service curtailment after a series of public hearings on that subject.

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The California Commission heard 117 witnesses and took 1952 pages of testimony. Based on the evidence taken at these hearings the Commission said in part: "It is clear that any shortage of electricity will be so disruptive to both the economy and to individuals that every possible measure should be taken to avoid it. We must ensure that electric utility operating margins are maintained at a safe level."

The Commission indicated that "electricity is a replenishable energy medium, in sharp contrast to our ultimately finite and limited natural gas resources." It said that the masses of data it compiled "stress the importance electricity plays in every day life and the severe hardship that interruption of service would cause."

Mr. Chairman, your Committee may be interested in the full report of the California Commission, which I do not have, but the excerpts I have read indicate that the people of California set the highest priority on need for electric energy above other energy forms. (See Attachment #2)

If we accept the premise that the need for electric energy is universal, then the priorities of The National Energy Plan need to be restructured so that appropriate emphasis is given to meeting the universal need for electricity rather than the priorities being placed in the Plan on other energy forms, and on environmental matters.

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Part F amends the Energy Supply and Environmental Coordination Act so as to require the conversion of electric generating capacity now using oil and natural gas as boiler fuel to a capability to burn coal or some other fuel.

Because of the time constraints of today's hearings, a full discussion of the provisions in Part F is impossible, but with the permission of the Committee, I am filing additional testimony and supporting documents to be made a part of the record.

I do have the following specific comments:

(1) Part F is unnecessary because the electric industry has already embarked on a nationwide program to replace oil and gas-fired boilers for base load generation. (See Attachment #1)

(2) Part F, if enacted, would require a substantial misallocation of capital at a point in time when the industry is having difficulty financing new units needed to meet present and projected load growth requirements.

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(3) Part F, if enacted, would impose intolerable energy costs on certain regions of the country, thus countervening the President's "fifth" principle -- "that the United States must solve its energy problems in a manner that is equitable to all regions, sectors and income groups".

Much concern has been expressed about the use of natural gas as fuel for the generation of electricity. It has been termed "wasteful" by those who would like to divert this fuel to other applications.

However, in the infancy of the natural gas industry, gas was being flared in tremendous quantities in the oil fields of South Louisiana and West Texas.

The first major effort to gather this gas, and transport it to prospective markets outside the producing region was made by an investor-owned electric utility holding company in the years of the Great Depression.

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Another electric utility helped finance and develop the Cut Bank Montana gas discovery in the early 30's, and this is all a matter of record in testimony filed with this Committee in March 1935, 42 years ago. 1/

It made good economic sense then to find markets for residential and commercial use of natural gas and balance the cost to the consumer by utilizing excess seasonal pipeline capacity for electric generation. It still makes good sense to those of us who supply energy to areas of these United States where a disproportionate number of our customers are on the bottom of the economic ladder.

Yet, this bill, if enacted, would take away from us and our customers a fuel native to our area and require us to reach out thousands of miles for substitute fuel. Our customers would ultimately have to bear the expense of conversion and the cost of substitute fuel.

Perhaps, the most ironic feature of the proposed conversion program is that it is being advocated in the name of the conservation of energy.

1/ A Presentation on Behalf of Electric Bond and Share Company to the Committee on Interstate and Foreign Commerce of the House of Representatives in Public Hearings on the Proposed Public Utility Act of 1935 (H. R. 5423). March, 1935

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Nothing could be more wasteful of both money and energy than the conversion of existing plants.

The Act would require that all "converted" units be equipped with scrubbers, even though low-sulfur coal is used.

Scrubbers would reduce the net output of the plant by seven to ten per cent. This is a substantial waste of energy. Scrubbers also would require the mining and transportation of large quantities of limestone, another net waste of energy. Scrubbers create a sludge disposal problem which wastes land and poses unknown environmental problems.

In short, if we are concerned with a net savings of energy, the rejection of Part F is a substantial step in that direction.

I would like to address two other points in the time remaining.

One is the availability of natural gas for electric generation. If the weather-related supply shortages of January 1977 told us anything, it proved that when the price is right, shortages disappear.

This is confirmed in the testimony given this Committee on April 5 by Mr. Dunham, Chairman of the Federal Power Commission, with reference to his administration of the Emergency Natural Gas Act.

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You will recall that he testified that the total sale volume under the Emergency Act will approximate 200 Bcf and that the average weighted priceof this emergency gas is $2.24 per million Btu.

He also testified that much more gas was offered for sale by electric utilities in this price range and that there were no buyers.

This demonstrates that where a free market exists, the use of natural gas as boiler fuel is not a problem, even in critical supply situations such as the severe winter created in January.

The second point is that most oil burning boilers in the South and Southwest use residual oil rather than No. 2 distillate.

The banning of the use of residual oil as a conservation tool makes very little sense. Why not ban the use of asphalt for roads, streets and roofing compounds? Both residual oil and asphalt are by-products of the refining of crude oil; and it seems odd that the Congress would want to ban this very practical use of a waste product.

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In conclusion, let me urge the Committee to give all the aid and comfort it can to the electric utility industry, because we have the responsibility to provide an ample, reasonably priced, essential service to the public.

We believe the investor-owned electric companies along with those in the public sector have the trained personnel, the experience, and the technology to meet the electric energy requirements of a healthy, expansive American economy. We know that the proved reserves of coal and uranium are adequate for the needs of this generation and many to follow.

It is depressing to have this knowledge, capability and technology to meet expected demands for electric energy and to be restrained from doing so by unnecessarily restrictive government policies that have intangible, or at best, marginal benefits.

I respectfully suggest to the Congress that rather than restraint, we need relief.

With help and understanding from the Congress, our industry will show you some positive results that will benefit the people of the United States.

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I am attaching to this statement pertinent data on coal conversion, some of which is testimony presented last month to the Senate Committee on Energy and Power, (See Attachment #3 and Attachment #4) and a statement made to this Commission on March 28, 1977 by Mr. Bernard Chew of the Federal Power Commission Bureau of Power. (See Attachment #5)

I would be pleased to respond to any questions from the Committee.

Thank you.

# # # # # # #

Attachments (5)

1. The Phasing out of Oil and Gas Used for Boiler Fuel - Constraints and Incentives - March 7, 1977

2. Excerpts from NARUC Bulletin No. 29-1976, dated July 19, 1976

3. Statement of Middle South Utilities, Inc., dated April 1977

4. Statement of Southwest Power Pool, dated April 1977

5. Statement of Bernard Chew, Federal Power Commission Bureau of Power, dated March 28, 1977

(Attachment #1)

The Phasing Out of Oil and Gas Used for Boiler Fuel
(The Cost of Converting to Coal)

-- Constraints and Incentives --

Economics and Statistics Division
Edison Electric Institute
March 7, 1977

The Phasing Out of Oil and Gas Used for Boiler Fuel

I. Summary

Shifting the nation's dependence from oil and gas to coal and uranium is the key to solving the energy crisis. American industry recognizes that as part of this necessary transition, its own use of oil and gas in boilers must eventually be minimized. However, the phasing out of oil and gas is an objective which must be reached taking into account numerous economic, physical, and other elements involved in the maintenance of a healthy economy served by reliable energy supplies. This objective can best be attained by facilitating the construction of new coal and nuclear steam electric generating capacity and by allowing those oil and gas burning industrial and utility facilities which were originally designed to burn coal to convert or reconvert to this fuel. Emphasis should be placed on expediting the construction of new steam electric generation plant because the long-term substitution of coal and uranium in most end-use applications will require the conversion of these fuels to electricity.

Assuring the timely installation of new capacity will require the removal of regulatory obstacles to its construction and operation. It will also require Federal and state actions in the realms of tax policy and rate regulation designed to enable the electric utility industry to mobilize the necessary capital resources. Switching existing industrial and utility convertible capacity back to coal will require a realistic implementation of air quality regulations including recognition that alternative methods of SO_2 control are preferable to the retrofitting of scrubbers. This recognition is especially critical for those convertible boilers whose age and size preclude such retrofitting.

II. Incentives for Phasing Out Oil and Gas

Construction of New Nuclear and Coal Facilities

Measures required to accelerate use of coal and nuclear fuels for boilers relate primarily to the removal of existing regulatory obstacles. Government efforts to shorten lead times by eliminating regulatory delays in the construction and operation of both nuclear and coal-fired generating units would have a significant impact on oil and gas use and would serve to reduce the heavy cost burden on utilities and their customers by minimizing the effects of cost escalation during construction.

Besides reforming regulatory procedures for the approval of new plant construction and operation, a number of other incentives are needed to hasten the building of these facilities. These include:

(1) Prompt and adequate rate relief by state and Federal regulatory agencies to permit building necessary nuclear and coal facilities while maintaining the financial integrity of the industry and minimizing the cost of capital needed to serve the electricity consumer.

(2) Modification of the Clean Air Act to: recognize alternative strategies in meeting health-related, primary ambient sulphur oxide standards (i.e., tall stacks and intermittent controls) and require cost-benefit justification of stringent state implementation plans, no significant deterioration and non-attainment interpretations.

(3) Governmental commitment to the immediate additional leasing, development, transportation and utilization of western coal in those areas now primarily dependent on natural gas, including the possible conversion of coal to low Btu gas for boiler fuel use.

(4) Resolving the major issues relating to the nuclear fuel cycle to keep this energy option viable.

(5) Resolving the continuing uncertainty over nuclear plant design and safety standards which risks driving both utilities and equipment fabricators away from nuclear power.

(6) Requiring the users of natural gas to pay for the scarcity value of this fuel and permitting electric utilities obliged to surrender rights to gas supplies to sell these rights at prices which cover the full cost to electric consumers of any forced conversions.

(7) Enacting legislation to permit the construction and use of coal slurry pipelines where feasible.

(8) Establishing a permanent investment tax credit at 12 percent and permitting the credit to be offset against the full tax liability, as in 1976, rather than reducing it at the rate of 10 percent per year until only 50 percent of the liability is usable.

(9) Eliminating the double taxation of dividends. If this cannot be achieved, at a minimum, dividends reinvested should be exempt from taxation until the stock is sold.

(10) Encouraging the inclusion of construction work in progress (CWIP) in the rate base with a commensurate rate of return.

(11) Allowing higher book depreciation rates.

(12) Normalizing the tax benefits resulting from accelerated depreciation.

Conversion of Existing Convertible Capacity

Measures which could hasten the reconversion to coal of industrial and utility boilers originally designed for its use must deal essentially with existing air quality control regulations which effectively preclude many reconversions. Necessary modifications include allowing the use of:

- tall stacks for SO_2 emission dispersal
- intermittent control as a means of maintaining ambient air standards
- natural gas when available as part of an intermittent control technique.

III. The Impracticality of Attempting an Oil and Gas Phase Out Through the Reconstruction of Boilers Not Originally Designed to Burn Coal

Discussions of phase-out strategies frequently include reference to the possibility of converting to coal those oil and gas fired boilers which were not originally designed and constructed for use of this fuel. In order to achieve any such accelerated conversion of industrial and utility boilers, a number of significant problem areas would have to be dealt with and various incentives considered which are at the heart of national energy policy decisions and which potentially conflict with policy options in the environmental, economic and Federal-state political areas. In addition, several threshold factors require recognition: (1) almost no new base-load oil or gas electric generating capacity has been planned since 1973; (2) existing oil and gas generating capacity represents substantial investment being paid for by electric consumers, based on government energy policy existing at the time of construction; (3) much of the industrial and utility boiler capacity is impractical to convert to coal and has substantial economic life remaining; (4) electricity is supplied to consumers on a "cost of service" basis and the full economic costs of forced conversion from oil and gas will have to be borne by those served by systems now using these fuels, including the cost of: forced conversion and associated pollution control, replacement power during conversion, and the loss of efficiency or reliability resulting from conversion; (5) conservation of energy to be effective and accepted must be accomplished on an economy-wide basis and not solely through an individual fuel, energy source or industry, with its economic costs and benefits carefully studied beforehand; and (6) the role of state governments and Federal pre-emption will have to be resolved.

All of these factors must be considered against the background of the massive physical and financial undertaking which a forced draft conversion to coal would represent for the American economy. The dimensions of such an undertaking for the electric utility industry are outlined in the following discussion.

A. Steam Electric Generating Capacity Using Oil and Gas Existing Installations

In 1976 some 93,000 MW of steam electric generating capacity in the United States was oil-fired. This total included approximately 20,000 MW in units capable of burning coal without complete reconstruction of boilers and fuel handling facilities. Gas-fired steam capacity amounted to nearly 59,000 MW of which only 2,000 MW was convertible to coal without major rebuilding.[(1)]

Planned Additions

Between 1977 and 1985, utilities have scheduled for commercial operation a further 16,500 MW of oil burning steam electric facilities and 1,000 MW of gas-fired steam plant. Virtually all of this capacity will be in service by 1980, reflecting the fact that since 1973, the uncertainty of future oil and gas supplies plus government restrictions have effectively excluded these fuels as planning options for steam electric generation.

B. Coal Requirements for Total Conversion

If it were possible to convert existing oil and gas burning steam capacity which will still be in service in 1985 to coal utilitzation, the incremental coal requirement would be on the order of 275 million tons by 1985. Were the planned 17,500 MW of gas and oil using capacity also converted to coal, an additional increment of coal supply of approximately 40 million tons would be required. These estimates are based on the following assumptions:

(1) Total capacity figures from "Fossil and Nuclear Fuel for Electric Utility Generation - Requirements and Constraints" 1976-1985, NERC June 1976.

Convertible Capacity data from "The Potential for Conversion of Oil-Fired and Gas-Fired Electric Generating Units to Use of Coal" - Staff Report, Bureau of Power, FPC November 1973.

Capacity Existing in 1976 and
Still in Service in 1985

- 137,500 MW to be converted
- Utilization of 3,800 hours per year in 1985
- Average effective heat rate of 10,500 Btu/Kwhr
- Coal with an average heat content of 20 million Btu/ton

Additional Capacity Planned as of 1976

- 17,500 MW to be converted
- Utilization of 5,000 hours per year in 1985
- Average effective heat rate of 9,500 Btu/Kwhr
- Coal with an average heat content of 20 million Btu/ton

Of the existing 152,000 MW operating on oil and gas, only 22,000 MW are convertible to coal without major reconstruction. The coal requirement of these "easily" converted facilities could total about 30 million tons in 1985 if the following were assumed:

- Utilization of 3,000 hours per year in 1985
- Average effective heat rate of 11,000 Btu/Kwhr
- Eastern coal with an average heat content of 24 million Btu/ton

The total coal requirement implied by complete conversion is thus some 315 million tons of which only 30 million tons would be for use in plants subject to conversion without major reconstruction.

C. Coal Requirements for Planned New Coal Burning Capacity

Any incremental coal requirements resulting from conversion of existing or planned gas and oil burning facilities would have to be supplied by a mining industry already straining to expand production necessary to fuel some 111,000 MW of new coal-fired capacity planned for operation by 1985.(2) This new capacity will have an annual need of nearly 358 million tons of fuel by year-end 1985. Thus, presently projected coal output from new and expanded mines supplying utility fuel would have to be augmented by 88 percent if the 315 million tons of "conversion" coal requirements were to be satisfied.

D. Mining Industry Requirements to Handle Total Conversion

The additional 315 million tons of coal required by total conversion of existing and planned gas and oil capacity would necessitate the development of some 40 new surface mines of 5 million tons annual output and some 75 underground mines of 1.5 million tons of yearly production. These estimates are premised on an incremental expansion pattern similar to the coal industry's present expansion profile which calls for 65 percent of all new capacity in the form of surface operations.(3)

(2) Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985 - Staff Report by the Bureau of Power, FPC, January, 1977.

(3) "Coal Mine Development and Expansion Survey" - Coal Market Commentary and Research Service, Appalachian Coals, Inc, February 10, 1977, Vol XXXVII, No. 6.

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Capital costs for such an incremental expansion would approximate $12 per ton of annual surface production and $35 per ton of underground annual capacity.[4] The total capital burden on the coal industry would approximate some $6.3 billion of which:

- $2.45 billion for surface mines ($12/ton x 205 million tons of annual capacity)
- $3.85 billion for underground mines ($35/ton x 110 million tons of annual capacity).

Labor requirements in 1985 to man the "conversion" coal production could approximate 73,000 men (50,000 underground -- 23,000 surface) based on the following assumptions:

Underground

- 220 work days/year x 10 tons/man day
- 110 million tons annual production

Surface

- 220 work days/year x 40 tons/man day
- 205 million tons annual production

E. Transportation

Moving the incremental coal supplies necessary for a total conversion program would present economic and physical

(4) "Project Financing" - J A Self, Vice President, Chase Manhattan Bank, Southern Coals Conference, Cincinnati, October 21, 1976.

problems as great or greater than those associated with increasing coal output. The bulk of these problems would rest on the railroads. Since most of the additional fuel would come from Western sources, the capacity of rail lines linking the coal regions of the West to the Northeast, Southwest and Pacific Coast would have to be increased considerably. Quantifying the cost of the incremental expansion needed is difficult because these rail arteries are already in need of considerable rebuilding simply to handle presently projected coal, grain, and other goods movement. To these costs, however large, would also have to be added a sizeable investment in rolling stock and power units.

F. Electric Utility Financial Requirements to Handle Total Conversion

The additional financial burden placed on the coal industry to meet a total conversion of utility gas and oil use would be dwarfed by the capital requirements which the electric industry would have to face. To convert the 155,000 MW of existing and planned oil and gas burning capacity expected to be still in service in 1985 would necessitate an expenditure of $50 billion in 1976 dollars. Of this total approximately $28 billion would represent conversion of oil facilities to coal and $22 billion would be accounted for by gas to coal conversion. These expenditure requirements are based on the following assumptions:

Oil to Coal

Reconstruction[5]	
89,500 MW x $300/KW =	$26.9 billion
Easily Converted[5]	
20,000 MW x $ 80/KW =	$ 1.6 billion
Subtotal Oil to Coal	$28.5 billion

Gas to Coal

Reconstruction - Units of 150 MW or Smaller[6]	
10,000 MW x $600/KW =	$ 6.00 billion
Reconstruction - Units of More Than 150 MW[6]	
33,500 MW x $475/KW =	$15.90 billion
Easily Converted[5]	
2,000 MW x $ 80/KW =	$ 0.16 billion
Subtotal Gas to Coal	$22.06 billion
Total Cost of Conversion - Oil and Gas to Coal	$50.56 billion

(5) EEI estimates based on cost figures appearing in the Preliminary Report of the FPC Technical Advisory Committee on Fuels on the "Fuel Oil Conservation Targets for the Electric Utility Industry Outlined in the President's October 8, 1974 Economic Message and the Accompanying Fact Sheet", October 18, 1974. Scrubbers are assumed needed on one third of reconstructed capacity and half of convertible capacity.

(6) EEI estimates based on unit cost figures for use of low sulfur coal appearing in the submission by "The Utilities of the State of Texas pursuant to Texas Railroad Commission Docket No. 600 - Reducing or Eliminating Natural Gas as a Boiler Fuel in Texas," EBASCO Services Incorporated, May 1975. If scrubbers were required on reconstructed gas-fired boilers, unit costs could equal or exceed $700/KW.

If an annual inflation rate of 7 percent were assumed and conversion expenditures were staged uniformly over the nine years, 1977-1985, the $50 billion constant dollar capital requirement would equate to a current dollar outlay of $71 billion. Present estimates of electric utility current dollar expenditures on electric plant and equipment over the same period total some $345 billion. Thus a total conversion program would increase presently projected capital requirements by more than 20 percent. Virtually all of the additional funds would have to be raised externally if present rate and regulatory practices were maintained. In the case of investor-owned electric utilities, an external financing rate of 60 percent is presently being envisioned based on existing expansion plans. This rate would probably increase to nearly 70 percent if a total conversion program were undertaken.

A dependence on money markets for up to 70 percent of total construction expenditures would produce extremely serious financing problems for an industry still burdened with financial difficulties engendered by the inflation of recent years and the effects of inadequate rate relief. Maintaining such an external financing rate for any length of time would likely prove to be impossible. At some point companies with inferior credit would just not be able to obtain funds. At any rate, coverage ratios would drop precipitously and the cost of all new financing increased significantly with a concomitant impact on the prices ultimately paid by electricity users. Moreover, these burdens would be concentrated essentially on utilities and electricity users in the Northeast, Southwest, and Pacific Coast regions of the country.

G. Constraints on Conversion Through Reconstruction

A number of constraints in addition to financial limitations would tend to hinder any accelerated phasing out of oil and gas as boiler fuel through reconstruction. These include:

- Sites and plants restricted from the standpoint of zoning requirements and the availability of land for fuel delivery, storage and handling facilities as well as the storage and handling of wastes.
- Present system designs and operational reliability which will not tolerate the 2 to 3 years of outage time required for the conversion of an existing steam generator to burn coal. Insufficient capacity would be available to meet peak obligations and many utilities would be obliged to install additional combustion turbines and/or reinforce transmission interties in order to maintain reliable service. The cost of these interim measures would only aggravate the financial problems posed by the first order costs of conversion itself.
- The limited ability of boiler manufacturers and the fabricators of the necessary auxiliary equipment to produce equipment, of coal suppliers to mine and transport coal, of engineers to plan and design, and of craft manpower to do construction work.

- Air quality controls by Federal, state and local regulations for both primary and secondary standards which could require use of SO_2 scrubbers which are characterized by reduced reliability, high operation and maintenance costs, and waste disposal problems.
- Regulatory lag due to proliferation and division of responsibility for approving utility construction projects.
- Environmental and regulatory limits on access to coal supplies for future power generation.
- Federal and state environmental restrictions on the construction of transmission interconnections needed to assure reliability during conversion or to implement any coal-substitution-by-transmission policy.
- The age of many plants which would have been reduced to only peaking service before their conversion could be completed.

IV. Electric Utility Plans for Phasing Out Oil and Gas by the Construction of New Nuclear and Coal Facilities

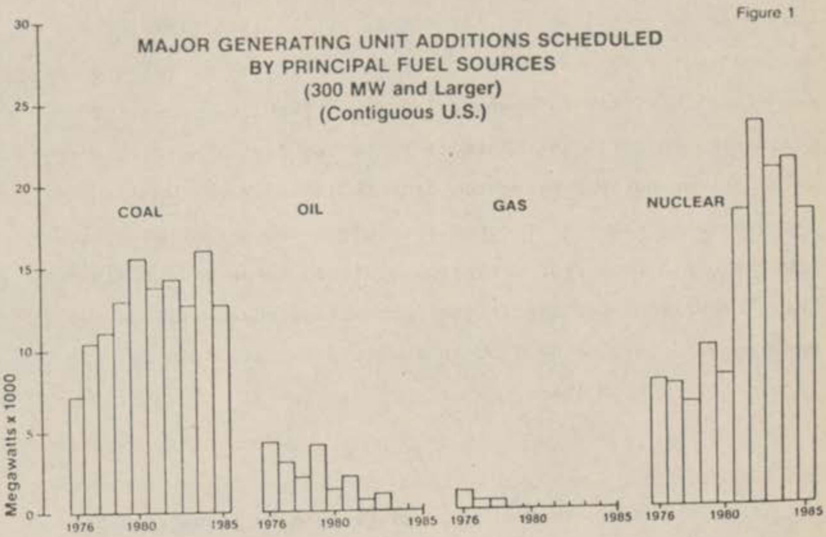
The magnitude of the physical and financial prerequisites for a total "forced draft" conversion to coal by reconstructing existing utility oil and gas-fired generating facilities clearly indicate that such a course of action is not to be recommended. Phasing out of even half of the present oil and gas use through reconstruction would entail a reallocation of capital and other resources in the economy which cannot be justified. Instead, the optimum way to reduce oil and gas as rapidly as possible lies in expediting the electric utilities' planned expansion program which is focused on the construction of new coal and nuclear facilities.

National Electric Reliability Council (NERC) studies conducted in response to questions posed in the Joint Hearings on Greater Coal Utilization before the Committee on Interior and Insular Affairs and Public Works of the United State Senate, pursuant to S. Res. 45, 94th Congress, National Fuels and Energy Policy Study on S. 1777, indicate that the electric utility industry is already phasing out installation of new oil-fired and gas-fired generating units. No new major generating units are planned for natural gas-firing in the years ahead and installation of oil-fired units is essentially phased out by the early 1980's. The bulk of this capacity is already committed and under construction. The following charts indicating the substitution of coal and nuclear planned by utilities are taken from the NERC "Review of Overall Adequacy and Reliability of the North American Bulk Power Systems (Sixth Annual Review - July 1976)."

Figure 1 reveals that next year will mark the installation of the last gas-fired unit of more than 300 MW. The last unit of

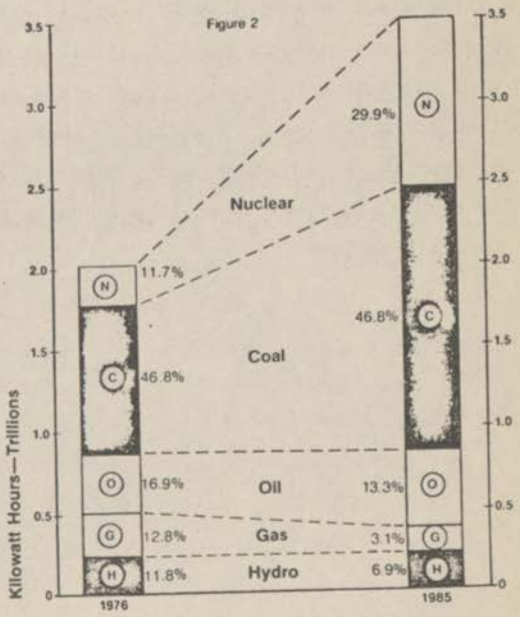
Figure 1

MAJOR GENERATING UNIT ADDITIONS SCHEDULED BY PRINCIPAL FUEL SOURCES (300 MW and Larger) (Contiguous U.S.)



ELECTRIC GENERATION by PRINCIPAL ENERGY SOURCES (Contiguous U.S.)

Figure 2



this size using oil is due for completion in 1983. Figure 2 delineates the shifts in the relative importance of oil and gas in the electric utilities' generation mix. From 30 percent of generation in 1976, the share of these two fuels in total output is projected to fall by nearly half by 1985. More importantly, gas use is forecast to account for only 3 percent of electricity production in that year compared to almost 13 percent in 1976. This draconian reduction in gas' percentage share will be due in part to a 60 percent decline in absolute gas use from 2.9 TCF in 1976 to 1.1 TCF in 1985.

V. Conclusion

The minimizing of oil and gas use in industrial and utility boilers is a desirable objective for a national energy policy. This objective can best be attained by facilitating the construction of new coal and nuclear capacity sufficient to cover load growth requirements while permitting a steady and rational withdrawal from base load service of existing oil and gas burning plants. Assuring the timely installation of this new capacity will require the removal of regulatory obstacles to its construction and operation. It will also require Federal and state actions in the realms of tax policy and rate regulation designed to enable the electric utility industry to mobilize the necessary capital resources.

(Attachment #2)

Excerpt from National Association of Regulatory Utility Commissioners Bulletin No. 29-1976, dated July 19, 1976

"CALIFORNIA PUC ADOPTS ELECTRIC CURTAILMENT PRIORITIES"

"The California Public Utilities Commission adopted a system of priorities for Statewide curtailment of electric service.

"Establishing five priority groups, the PUC categorized the uses of electricity in descending order as follows:

"--Priority 1 - Essential or protected customers or uses.

"These include governmental agencies to provide essential service to fire, police, prison facilities and to provide essential lighting for streets, highways, and other public areas; activities related to national defense; hospitals and convalescent homes for critical facilities such as operating rooms, emergency rooms, life support machines, diagnostic machines, refrigeration for medicines, communications and minimal lighting.

"Also included under Priority 1 are private and public utilities' system use in providing electric, gas, water, communications and sewage disposal services to the extent that those services could not be reduced without seriously affecting public health and safety and public transportation and associated customers (rail, air, bus and trucking), in their use in operation of the conveyances and in providing guidance control, communication and navigation services, as well as the maintenance of essential lighting at passenger or freight gathering and dispersing areas.

"Other end use categories under the Priority 1 group are those dealing with the production, refining and transmission of fossil fuel, nuclear fuel or steam, radio and television broadcasting stations for the transmittal of emergency messages and public information broadcasts related to those procedures, and residential customers for the use of life-support equipment such as an iron lung or kidney machine.

"--Priority 2 - Customers and their usage other than in Priority 1, susceptible to exceptional or irreparable loss in the event of curtailment or interruption of electric supply.

More

"These would include agricultural customers where the usage of electricity is directly necessary for the production, processing and storage of food products; commercial/industrial customers, where curtailment of electricity would cause an unemployment crisis in the locality, or where a prolonged shutdown of equipment using electricity would cause major irreparable damage to that equipment or its product.

"Priority 3 - Residential customers to the extent that their usage is confined to minimal essential lighting and heating in occupied portions of the residence; to minimal water heating at the minimum temperature needed; to provide use of electric appliances but to exclude partial use of washing machines, dryers, etc. and to provide use of cooking facilities.

"Priority 4 - Customers and their usage of a customary nature not qualifying under Priority 1, 2, or 3 and not excluded under Priority 5, and all customers at their general level of usage in the year preceding the subject energy crisis.

"Priority 5 - Customers and usage to be curtailed first in the event of a generating capacity or fuel shortage crisis.

"Uses under this category would include that by residential customers in any luxurious or wasteful usage. This would include heating or circulating water in a swimming pool unless prescribed by a physician for therapy. It would also include heating or cooling of unused space, the use of grossly inefficient appliances, or the space conditioning of poorly insulated rooms. Ornamental lighting or display when such use does not contribute to essential use would also be among the first uses to be curtailed.

"The curtailment priorities established by the PUC in its interim opinion are the result of extensive hearings on electricial priorities which began in Los Angeles September 29, 1975, and continued in various cities to February 27, 1976.

"During the course of the public hearings some 117 witnesses testified, there were more than 60 exhibits and 1,952 pages of transcript.

"'The consolidated record in this case consists of masses of data, all of which stress the importance electricity plays in everyday life and the severe hardship that interruption of service would cause' the Commission said.

"It noted also that with respect to the establishment of electric priorities, the parties could agree 'on little except the difficulty of establishing an equitable plan and the complexity of the problems for the utilities who must implement such a plan.

" 'It is clear than any shortage of electricity will be so disruptive to both the economy and to individuals that every possible measure should be taken to avoid it. We must ensure that electric utility operating margins are maintained at safe levels. The concept that it is economically more sensible to risk an occasional capacity shortage than to pay the ever-increasing cost of plant additions must be rejected. Plant additions cannot be forestalled indefinitely by increasing utility interconnection capacities.'

"The PUC said it must consider fully the impact of natural gas customers switching to electricity and of new customers fore-going natural gas for electricity.

"The problems posed by an electricity shortage are different than those associated with shortages in natural gas, the PUC said, and different considerations were given toward establishing the electrical priorities than those for gas.

"The Commission, in discussing the rationale for this decision, indicated that 'electricity is a replenishable energy medium, in sharp contrast to our ultimately finite and limited natural gas resources.

" 'Virtually all sectors of California's society and economy are substantially dependent upon a continued supply of electricity within the framework of the presently available energy resources.

" '. . . As to a multiplicity of end-use applications, particularly in the industrial sector, there are no known or proven alternative energy sources.'

"Because the different characteristics of electrical energy usage do not permit the PUC to make the same fundamental distinction made in establishing gas curtailment priorities, the Commission said it can't establish priorities between residential and non-residential electric use in the same way it did for gas.

" 'Standing in the way of such a distinction,' the PUC said, 'is the central fact of widespread dependence upon electricity of innumerable industrial processes, in terms of existing, immediate power needs, as well as those requirements essential to society's capacity for future growth. These factors plus the evidence in the records support the concept that all sectors should bear the burden of future electrical energy shortages.' "

(Attachment # 3)

STATEMENT OF MIDDLE SOUTH UTILITIES, INC.

1. Introduction

Hearings were held on the proposed "Coal Utilization Act of 1977" (S.977) by the Senate Energy Subcommittee on Energy Production and Supply, on March 21, 29, 30 and April 5, 1977. S.977 substantially amends and enlarges the Energy Supply and Environmental Coordination Act of 1974 (ESECA), incorporating it as title one, and adding two additional titles relating to conservation of natural gas and petroleum, and to coal substitution incentives, respectively. The stated purposes of the bill include the furtherence of energy self-sufficiency, the use of indigeneous energy resources, the conservation of natural gas and petroleum products, and the mandatory conversion to coal-firing of major steam electric power plants, insofar as practicable. It mandates conversion from natural gas to oil or coal by 1979 and from oil to coal by 1990, subject to exemptions.

2. Historical Background of the Middle South Utilities System

Middle South Utilities, Inc. is a holding company registered under the Public Utility Holding Company Act of 1935 and is comprised of five operating subsidiary companies; i.e., Arkansas Power & Light Company, Arkansas-Missouri Power Company, Louisiana Power & Light Company, Mississippi Power & Light Company, and New Orleans Public Service Inc. These Middle South Utilities operating companies are operated as a single integrated electric system.

All major generating units in the Middle South Utilities System were designed for burning natural gas as the primary fuel until about 1969 when evidence of the impending shortage of natural gas became apparent. Since then, with the exception of three units which were committed for in 1969-1970 and were designed for continuous firing of fuel oil, its expansion plans have been based on having all future base load units in the form of nuclear and coal units. While the System's generating units were historically designed to burn only natural gas on a continuous basis, to handle emergency situations involving loss of gas fuel for short periods of time, the boilers were equiped to be able to burn fuel oil intermittently, for very limited periods.

Under orders of the Federal Power Commission, delivery of natural gas to Middle South power plants by interstate pipelines already has been greatly curtailed. The System's natural gas usage as a boiler fuel has dropped by 31 percent in the period from 1970 to 1976, representing a total reduction estimated at 667,000,000 MCF of boiler fuel gas for the six-year period. Our present projections plan for an additional 61 percent reduction between now and 1986 in use of natural gas as a boiler fuel by the System. Concurrently, the System's oil usage increased from 975,120 barrels in 1970 to 25,130,000 barrels in 1976. Substitution of fuel oil and purchased energy for this gas (which was contracted for on a fixed-price, firm-delivery basis but not delivered) has increased the fuel costs to our customers by an estimated $610,000,000 over this six-year period. These costs, together with associated boiler conversion costs, represent a burden already thrust upon the consumers in our service area by virtue of federal governmental action. At the same time, curtailments by the interstate pipeline supplying the greater portion of the

System's boiler fuel, United Gas Pipe Line Company, have been about double those of the next largest pipeline curtailments (Schedule I, FPC Curtailment Report, November, 1976). Additionally, the Middle South Utilities System operating companies have expended approximately $180,000,000 to convert their major boilers in order to permit burning oil as the primary fuel. None of these modifications were done with the contemplation of eventually converting to coal-firing; therefore, all of the modified facilities would have to be prematurely retired and replaced with new coal burning facilities. Furthermore, the System companies have experienced greatly increased operating and maintenance problems and expense as a consequence of the increased use of fuel oil in boilers not designed to burn oil on a continuous basis.

Already, delivery of natural gas under firm contract to three of the operating companies has been curtailed by FPC order to the point that there is practically no use of natural gas in their power plants, with the insignificant amounts received being used for boiler start-up purposes. The remaining two operating companies have varying quantities of intrastate gas, but not amounts sufficient to meet all of their customer requirements.

It is anticipated that the Middle South Utilities System will consume about 40,000,000 barrels of oil in 1977 (60% more than in 1976) to supplant the natural gas shortfall and meet our customers' energy requirements. We feel that it is obvious from the foregoing facts that the Middle South Utilities System and its customers are already bearing a heavy financial burden as a result of shifting its primary boiler fuel from natural gas to oil.

3. Practicability and Estimated Capital Cost of Coal Conversion Program

By report dated March 7, 1977 entitled "The Phasing Out of Oil and Gas Used for Boiler Fuel -- Constraints and Incentives" (a copy of which is attached as Appendix "A"), the Edison Electric Institute outlined many of the technical, legal and economic problems involved in a massive, sudden, forced conversion program as is proposed in S.977.

We have prepared an estimate of capital costs which would be incurred by the Middle South Utilities System in such a conversion program using the average cost per kilowatt quoted in the above referenced Edison Electric Institute report. This estimated cost, expressed in 1976 dollars, is $4,913,825,000.

However, considering only the estimated capital costs for conversion to coal and assuming that these costs would be spread uniformly over the eight-year period, 1978-1985, with an average annual inflation rate of seven percent, the total estimated expenditures would be $7,215,336,000. Conversion costs by state are as follows:

Arkansas	$1,349,125,000
Louisiana	5,366,600,000
Mississippi	1,550,200,000

Assuming further that seventy percent of the cost would be financed with bonds at a 10 percent interest rate, with the balance being equity capital at 14 percent and a 20-year amortization period, the annual fixed charge rate would be about 15 percent. Based on these assumptions, the levelized annual cost would be $1,082,300,000. Applying this levelized annual cost to our total estimated energy sales for 1986 would result in an average increase of 12.58 mills per KWH. Assuming that this cost would be passed on to all customer classes ratably, the average residential customer's 1986 bill would amount to about $925, an increase of 27.6 percent. On the other hand, it could be assumed that the total incremental cost would ultimately be borne by residential customers, since the incremental electric cost component of goods and services are passed on to the ultimate consumer. The effect would then be to virtually double the homeowner's yearly energy cost to about $1,450 by 1986. To the extent that industrial energy costs are not borne by local customers using goods and services, this figure would be reduced, although they would bear the additional costs of goods and services produced elsewhere and consumed locally.

Although S.977 provides for certain exemptions, we have not included the effect of such exemptions, since there are several bills under consideration that may be consolidated into a single bill, which may or may not provide automatic exemptions, and since exemptions which are discretionary with regulators have proven to be risky bases for investment decisions with a 10-year lead time and involving billions of dollars.

It should be noted that, in using the EEI average conversion costs, certain basic assumptions were made which, in our opinion, make these costs extremely conservative. Among these assumptions are:

1. It has been assumed that "if compliance coal" were used, no sulfur removal equipment would be required. We understand that the Congress and the Environmental Protection Agency are studying various proposals, which could result in more stringent regulations

concerning sulfur dioxide. Enactment of such regulations could well result in mandating the installation of sulfur removal equipment, even for "compliance coal", greatly increasing the cost of the coal conversion program.

2. Many technical and/or legal constraints make it impracticable to convert many of our existing units to coal-firing. Included among these constraints are such factors as:

   a. Lack of physical space for new boilers, coal storage, handling facilities, ash and sludge disposal areas. Some of our major generating stations are located in heavily populated metropolitan areas and it would be literally impossible to acquire the necessary land, which we understand would require about 2,000 acres for a 1,000 MW plant.

   b. Height limitations imposed by local, regional, state and/or federal regulations such as, proximity to commercial or private airports. Such limitations would preclude the possibility of contructing tall stacks (400-800 feet).

   c. The lack of adequate manufacturing capability for boilers and associated equipment, which would be required if the proposed legislation were enacted.

   d. The lack of adequate manufacturing capability for combustion turbines or other capacity, which would have to be constructed to provide replacement power for the existing facilities during the conversion period.

e. The problems associated with mining and transportation of the additional coal which would be required in the event of passage of such legislation. There is a serious question whether or not there are adequate mining and transportation facilities to accommodate coal units currently in the planning and/or construction period. Legislation authorizing the construction of coal slurry pipelines appears essential in order to supplement the capability of railroads for transporting coal.

Many of the technical and legal constraints are described in greater detail in various documents such as:

a. The record of the testimony held in 1975 before the Committee on Interior and Insular Affairs and Public Works of the U.S. Senate relative to proposed bill S.1777 (specifically, Texas Railroad Commission - Docket No. 600 (pages 1903-1950); Statement of Mr. William McCollam, Jr. (pages 929-952); Statement of Walter D. Brown (pages 952-954); and Statement of Walter J. Matthews (pages 955-1000).

b. Part II of the FPC Fort Worth Regional Office's Report on "The Phasing Out of Natural Gas and Oil for Electric Power Generation - Southwest Power Pool and Electric Reliability Council of Texas"-- March 1976.

c. The attached EEI report entitled "The Phasing Out of Oil and Gas Used for Boiler Fuel--Constraints and Incentives" dated March 7, 1977.

The estimated conversion cost of $4,913,825,000 enumerated hereinabove represents capital cost only (in 1976 dollars); we have not attempted to quantify other obvious costs, such as cost of replacement energy and loss of capacity from conversion.

The System's present plans call for substantial expenditures for electric production facilities during the period 1978-1985. The proposed legislation, if enacted, would approximately double these expenditures, making it almost impossible for our System to finance such a program when we are still burdened with financial difficulties brought about by factors beyond our control, such as inflation of recent years, the effects of inadequate rate relief and higher fuel costs resulting from curtailments of firm contracts.

4. Estimated Increase in Fuel Cost

Using data from the report entitled, "1976 National Energy Outlook", Federal Energy Administration, February 1976 (Table IV-10, page 179 and Table IV-28, page 199), the weighted average cost of low sulfur western coal, including transportation to our System's service area, was computed to be $2.16 per million BTU's. This estimate was based on the following assumptions: high coal production scenario, average annual escalation of 7%, and 19,000,000 BTU's per ton. It was further assumed that this weighted average coal cost would apply to all future coal units (new and/or converted) with the exception of White Bluff Units 1 and 2, for which units coal costs were assumed to be as stipulated in the coal contract for this station.

In order to determine the change in fuel costs associated with conversion to coal of the generating units on the Middle South System, the above-described coal costs were compared to our latest estimated costs for natural gas, fuel oil, and coal, assuming appropriate substitution by fuel type for the estimated generation for the year 1986. The results of our calculations indicate fuel cost increases of $134,527,000 to our sales in 1986, resulting in an average increase of 1.56 mills per KWH.

Assuming that this cost would be passed onto all customer classes ratably, the average residential customer's 1986 electric bill would increase by about $25 for a total, with conversion costs, of $950 per year. Assuming that the total cost would ultimately be borne by residential customers, the average residential customer's energy cost would be increased by $90 in 1976 to about $1,540. Any additional costs such as scrubbers on "compliance coal" and replacement energy would have to be added to these figures. If forced conversion were ordered prior to 1986, the costs would be even higher for the intervening years, possibly doubling or tripling the added amounts for fuel.

On the other hand, our present plans to phase out the use of oil and gas from generating units as quickly as replacement coal and nuclear facilities are available would result in an overall 73 percent reduction in our use of gas from our 1970 base by 1986.

5. Summary

In summary, we are of the considered opinion that it is not feasible, technically or economically, to convert any of our existing gas or oil-fired boilers to permit burning coal. Conversion to coal-burning would involve (1) completely replacing the existing boilers with new boilers; (2) constructing new boilers remote from the existing boilers and, upon completion, reconnecting the steam lines to the new boilers; or (3) installing a coal gasification plant on the plant site and modifying the existing boilers to permit burning low Btu gas. None of these alternatives could be accomplished for a number of years because of the lead times involved in the design and construction of such facilities. The third option has not yet been proven as being viable for large scale, commercial application, with the degree of reliability required by the electric power industry. If we were forced to convert to coal-firing, the inevitable result, in our opinion, would be that electric service to our customers would be greatly jeopardized during the conversion period.

6. Alternative Program

The estimated conversion cost of $4,913,825,000 (in 1976 dollars) would be equivalent to a levelized annual cost of $737,074,000, again assuming a 15 percent fixed charge rate. Relating this levelized cost to our total actual 1976 energy sales (excluding sales to other utilities) would represent an average incremental cost of 19.48 mills per KWH. This cost is equivalent to $11.66 per barrel, based on our actual 1976 oil-fired generation and oil consumption. Our average oil cost in 1976 was about $11.40; therefore, the incremental cost represents an increase of over 100%. It appears to us that, in view of the above described constraints and other major problems concerning the national energy situation, it would be much more appropriate and logical to use the $11.66 per barrel equivalent for securing fuels through the use of more advanced technologies. It is possible that such a program could advance commercial development of such fuels which would be more compatible with our existing boilers.

(Attachment #4)

SOUTHWEST POWER POOL STATEMENT

Southwest Power Pool is one of nine reliability councils that make up the National Electric Reliability Council (NERC) - The primary function of Southwest Power Pool is "...to augment the reliability and adequacy of bulk power supply in Kansas, Oklahoma, Arkansas, Louisiana and parts of Texas, Missouri and Mississippi in co-ordination with other regional reliability councils.

At the present time, Southwest Power Pool (SPP) has 37 members as follows:

Investor-Owned --------------------	23 Systems
Municipalities ---------------------	7 Systems
G & T Cooperatives ----------------	5 Systems
Federal Agencies ------------------	1 System
State Agencies ---------------------	1 System

These members have joined together to:

1. Adopt practices for system operation that will help to assure a reliable bulk power supply among the systems in the SPP.

2. Study the reliability of the bulk electric power supply of the SPP region. /1

Historically, these systems relied on natural gas for boiler fuel until it became obvious in the late 60's and early 70's that long-term supplies of natural gas for new base load units were unavailable.

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As reflected in the March 1976 study by the Federal Power Commission's Fort Worth Regional Office, electric utilities in the SPP 'ad already initiated a program to phase out the use of natural gas as boiler fuel leading to a 73% reduction in the use of gas for generation in the SPP by 1990. The report points out that this is being accomplished primarily by constructing new base load plants utilizing coal and uranium.

The requirements in S. 977 would completely disrupt this orderly planning already being implemented, and, in effect, be self-defeating, actually delaying the achievement of the obvious meritorious objectives of the authors of S. 977. The objectionable features of S. 977 are discussed in the body of this statement.

The timely conversion of base load generation in the SPP -- and the remainder of this Nation -- to dependence on domestic supplies of coal and uranium needs to be encouraged and, to the maximum extent possible, accelerated.

The attempt to accomplish this through passage of S. 977 would disrupt the economy, and would require a massive mis-allocation of capital funds.

S. 977 appears to offer relief to hard-pressed gas pipelines in meeting "human needs" and prevent a recurrence of the hardships of the past winter. Substituting therefore a more severe hardship on the population in Oklahoma, Texas, New Mexico, California, Kansas, Louisiana, Mississippi, Arkansas, and Alaska.

Realistically, the bill will not provide significant relief to the customers of the interstate pipelines.

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The disruption of the power supply system of the SPP region and other regions and the resultant national repercussion hardly justifies this radical approach to the energy supply problem.

During the calendar year of 1976, about 19 Tcf of natural gas was used in the United States, including 2.8 Tcf for electric generation. If 210 Tcf is a reasonable estimate of proved reserves, then, at this rate of consumption the life of proved reserves is 11.05 years. If all the 2.8 Tcf used for electric generation were subtracted from the 19 Tcf/year usage, this would extend the life of proven reserves by less than two years.

PHASING OUT OF NATURAL GAS/OIL

In March 1976, the Federal Power Commission's Fort Worth Regional Office issued a report entitled "The Phasing Out of Natural Gas and Oil for Electric Power Generation - Southwest Power Pool and Electric Reliability Council of Texas". /3

In this report, FPC found that in 1975, 86.7 percent of the electricity produced in a five-state area was produced by gas. The report goes on to say "...utilities in this area have already initiated a program which would lead to a 40 percent reduction in electric utilities gas usage by 1985 and a 73 percent reduction by 1990." /4

The Federal Power Commission concluded that,

"Electric utilities in the Southwest Power Pool and the Electric Reliability Council of Texas have made plans which, in the next 15 years,

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will result in a 73 percent decline in the annual rate of gas usage for electric power production in these regions. The reduction would be achieved through a balanced program of new power plant additions using coal and nuclear fuel and, where practicable and technically feasible, by converting some existing generating capacity to oil and coal." /5

S. 977

Senate Bill 977 provides that all new fossil-fired plants would have to burn coal; all existing fossil plants with coal or oil-burning capability would be barred from using gas by January 1, 1979 (with limited exceptions); existing gas-fired plants would have to burn coal or oil by January 1, 1979. /6

The members, and seven non members included in the April 1, 1977 report to the Federal Power Commission shows the systems plan the following generating capacity additions during the period 1977-1986: /1

Primary Fuel	Units	Megawatts	Percent of Total
Nuclear	9	9,907	24.58%
Natural Gas*	6	591	1.47
Heavy Oil	1	480	1.19
Middle Distillates	23	2,931	7.27
Hydro	8	214	0.53
Coal	52	26,183	64.93
	99	40,306	100.00%

*5 units totaling 491 MW under construction for service in 1977.

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The following generating capacity was in service January 1, 1977: /2

Primary Fuel*	Units	Megawatts	Percent
Nuclear	1	836	2.0
Natural Gas	345	30,550	72.0
Heavy Oil	13	3,009	7.0
Middle Distillates	76	1,481	3.5
Hydro	69	2,472	6.0
Coal	19	4,012	9.5
Total	523	42,360	100.0

*For which units were originally designed.

EFFECT ON BULK POWER RELIABILITY IN SPP

The SPP has found the following constraints to be common to most member systems:

1. Huge capital requirements; $4.9 billion conversion costs - in 1976 dollars was reported by our largest system. The systems in Oklahoma estimate $1.8 billion. Funds of this magnitude for the purpose of retro-construction simply are not available, and would increase rates paid by $700 per annum per customer.

2. Shortages of material/manpower would delay the massive conversion of boilers. Boiler manufacturers and fabricators could not produce the needed equipment, in addition equipment needed for forecast load growth, since all systems would be trying to comply simultaneously.

3. Many systems would be unable to meet their load obligations and at the same time convert to coal, plus carry on normal maintenance and

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fulfill existing long-term contracts for sales of power and energy. Sufficient emergency power is not known to be available once the conversions to coal begin.

4. Few, if any, existing gas-fired electric plants have enough land to permit conversion to coal. It normally requires about 1,000 acres for a coal plant as opposed to 40-60 acres for a gas-fired plant.

5. It is assumed that if low-sulfur coal is used, no sulfur removal equipment would be required. Obviously, there would be a dramatic increase in costs if sulfur removal were mandated even for "compliance coal".

6. Height limitations imposed by local, regional, state and/or federal regulations such as proximity to airports would preclude the possibility of constructing tall stacks (400-800 feet).

7. Manufacturing capability for combustion turbines or other capacity would not supply the requirements over and above that presently planned to replace capacity out for modification, re-building, or forced retirement.

8. Systems that have already experienced gas curtailment and have been forced to burn oil in boilers designed to burn natural gas have been faced with (1) increased boiler down-time (2) ever-increasing maintenance problems (3) increased likelihood of forced outages and (4) loss of capability ranging from 8-10 percent. If all SPP's fossil-fired capacity was forced to burn oil, the loss in capability might well exceed 2,500 Megawatts, which must be replaced in addition to presently projected capacity additions.

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COMMENTS

With reference to the specific provisions of S. 977, the following observations are presented for consideration:

In Section 202 FINDINGS, it appears that the net impact of S. 977 as written will be inimical to the protection of public welfare and the preservation of national security because it will jeopardize the continuity and reliability of electric service to a substantial segment of the country.

In Section 205(b) NATURAL GAS RESTRICTION, the requirement to convert a unit designed primarily to burn natural gas to the capability to burn something else by 1979 is not realistic, even with the exceptions provided for in Section 207, 208, 209 and 213. It has been the experience of member systems that conversion of a gas-fired boiler to the capability to burn No. 6 residual oil takes several years under optimum conditions. Conversion to coal would require the construction of the entire steam supply system and is therefore completely impractical in time provided in all but a few sites.

Section 207 provides for "temporary" exceptions of up to 5 years if the owner submits a compliance plan and schedule to the Administrator which apparently contemplates the conversion of the unit to coal. This section offers no relief to members of SPP because of the infeasibility of conversion to coal.

Section 208(a) deals with exemption to plants contemplating the use of oil beyond the January 1, 1979 deadline set out in Sections 204 and 205.

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It requires a "demonstration" of "good faith efforts" to find coal and to overcome legal and other impediments plus a demonstration that coal will cost more than oil. This appears to raise enough bureaucratic barriers to make Section 208 of no effect whatever for an existing plant; and the remaining language dealing with new plants effectively rules out any practical application of this sub-section.

Section 208(b) sets an upper limit of 9,500 as the heat rate for peaking and intermediate facilities using oil as a condition of the exemption and will eliminate the use of simple cycle combustion turbines, as well as steam units operating in intermediate, or peaking mode.

Section 208(c) covering exemptions for intermediate load facilities and requires the simultaneous application of eight specific conditions before the exemption can be granted. There is no possible way to qualify any existing unit to meet these eight requirements.

Section 208(d) provides for exemptions under certain conditions for units burning oil only if the cost of conversion to coal exceeds 100% of the replacement cost of the unit. The language of this sub-section is confusing in that it appears to include natural gas as well as oil-fired units in Section 208(d) (1) (A). If this section means that the useful life of gas-fired units beyond 1985 and oil-fired units beyond 1990 must be abandoned, then these dates need to be extended to cover the entire life of these units.

The PUBLIC INTEREST EXEMPTION appearing on page 27 and beginning at line 21 does not waive the penalties in Section 212 and therefore no system could afford to operate a unit granted an exemption under this section.

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Section 211 DISRUPTION OF NATURAL GAS SUPPLY CONTRACTS, appears to exceed the Constitutional authority given to the Congress. Article I, Section 10 prohibits the states from passing laws impairing the obligation of contracts. Under the specific powers granted the Congress there is no power conferred to impair contracts.

Even though the language of Section 211(b) COMPENSATION makes an attempt at redress for intrastate gas only, it still strikes at a basic American right of contract sanctity, the right to due process, and the right to just compensation for property taken for public use.

This section, if enacted, is certain to result in prolonged litigation. It would be more in keeping with American tradition for the Congress to re-affirm these basic rights by writing them into law.

CONCLUSIONS AND RECOMMENDATIONS

The Congress must enact a program to accomplish acceleration of conversion, reduction of consumer costs, wise use of domestic resources and strengthening of national economy, security and defense of the nation.

1. SPP suggests legislation which would accomplish and encourage the orderly phase-out of the use of natural gas as boiler fuel. Rather than the abrupt prohibition of the use of boiler fuel for electric generation, legislation should be drafted requiring each system to reduce the percentage of Kwh generated by gas over a reasonable time period. The percentage reduction should continue until 20% of 1976 base period amount is reached and then maintained at that level for intermediate and peaking load requirements.

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2. Oil-fueled electric generation should be permitted without restriction in existing plants designed for oil or gas.

3. It is timely now that the public be given the full benefit of commonly held resources of coal and uranium, while conserving natural gas and petroleum. Such a program could include:

Favorable leasing rights on a priority basis of federally owned proven coal or uranium reserves be made to electric utilities or major fuel burning installations sufficient to provide all the fuel requirements of all units constructed to replace present gas-fired or oil-fired generation or major fuel burning installations.

Federal and state regulatory authorities be mandated to allow construction work in progress for the full cost of the replacement units.

Limit the application of environmental regulations to such plants to only those requirements which prohibit the endangerment of public health, and grandfather these requirements for the useful life of these plants.

Grant easements at no cost to coal slurry pipelines across all federal lands, and the right of eminent domain across private lands.

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/1 Southwest Power Pool Coordination Agrement, Dec. 17, 1969, Art. VIII.

/2 Southwest Power Pool, Reliability and Adequacy of Electric Power, 1977-1996, April 1, 1977.

/3 Technical and Economic Evaluation of Various Possible Electric Utility Natural Gas Reduction Programs, 1975-1990, FPC, Fort Worth Regional Office, March, 1976.

/4 Ibid.

/5 Ibid.

/6 Congressional Record - Senate, pg S.3944-S.3941, March 10, 1977.

(Attachment #5)

STATEMENT OF
BERNARD B. CHEW, CHIEF,
DIVISION OF POWER SURVEYS AND ANALYSES
BUREAU OF POWER
FEDERAL POWER COMMISSION

Hearings Before the
Subcommittee on Energy and Power
Interstate and Foreign Commerce Committee
United States House of Representatives

March 28, 1977

Mr. Chairman and Members of the Subcommittee on Energy and Power:

My testimony* is concerned with the burning of natural gas in electric power plants, specifically the characteristics and trends of such use. It reviews the prospects and problems of phasing out the use of natural gas in the Southwest over the long term and also discusses the short term potential for reducing gas use by the import of electricity from coal-burning utilities outside the Southwest and by the burning of oil-gas mixtures.

As indicated in the following table, the national consumption of gas for electricity generation has been declining since 1971-1972 and by 1976 was down by almost a fourth from the peak usage. However, almost all the reduction has been achieved by curtailments in the use of interstate gas, under the FPC system of priorities for pipelines in curtailment. In Texas, Louisiana, and Oklahoma, where practically all the power plant gas is intrastate gas, the consumption has continued to grow although at a declining rate. The 1976 usage in those states was two-thirds of the total national consumption of gas in power plants. In December 1976, when the interstate pipelines were experiencing heavy demands because of cold weather, 82 percent of the national gas usage in power plants was accounted for by the three states. Overall, natural gas usage in power plants is about 15 percent of the natural gas consumption for all purposes.

*The views expressed are those of the witness and not necessarily those of the Commission.

ELECTRIC UTILITY CONSUMPTION OF NATURAL GAS
(Billions of Cubic Feet)

Year	U.S. Total	West South Central Region (Texas, Louisiana, Oklahoma, Arkansas)	W.S.C. Region as Percent of U.S. Total
1965	2321.1	1009.9	43.5
1970	3931.9	1735.5	44.1
1971	3976.7	1856.4	46.7
1972	3976.6	1999.8	50.3
1973	3643.7	1949.9	53.5
1974	3429.0	2011.9	58.7
1975	3146.8	2042.9	64.9
1976	3078.1	2091.1	67.7

Before discussing the outlook for reductions in power plant use of natural gas, I would like to review some of the basic characteristics of gas use for electricity generation.

About 95 percent of the gas is burned in steam generating plants, with the remaining 5 percent used in peaking gas turbines and internal combustion engine generators which are primarily used by small communities.

Interstate gas has been supplied to power plants almost always on an interruptible basis. Thus, the power plants which have used interstate gas have usually had a full time capability to burn either coal or oil as alternate fuels. Traditionally, gas was supplied to the power plants in the summer months when other consumers did not need the gas and the pipelines were anxious to maintain deliveries. Such deliveries are sometimes termed 'dump gas.' However, the gas industry now has increased its storage capacity, which must be filled in the summertime, and with declining interstate pipeline supplies and greater reservoir drawdowns, deliveries of interstate gas to power plants have been reduced. In general, such deliveries are now made only when the pipeline or distributor has gas available beyond the needs of storage or other gas customers. Because the power plants using interstate gas were designed to burn other fuels for extended periods, there is generally not a significant adverse effect on electricity supply reliability when the gas is withdrawn. This does not mean that the loss of gas is without problems for the utilities; they have to firm up additional supplies of oil or coal with the needed transportation, and in many cases additional fuel storage facilities are required. Also, the burning of oil or coal increases boiler maintenance work. The net effect of the loss of natural gas to the power plants using interstate gas, however, is primarily economic, with the extra costs of the substitute fuel, the fuel inventory charges, and increasing operating expenses being passed on to the ratepayers.

There is one instance where withdrawal of interstate gas may have significant environmental effects, in addition to economic effects. Because of the severe air pollution problems in southern California, electric utilities there are required to burn gas whenever it is available, particularly in the summer and fall months when air temperature inversions are most prevalent. The state has requested that the FPC grant a higher priority for power plant gas use as an air pollution control measure. In 1976, California was fourth in consumption of natural gas in power plants, behind Texas, Oklahoma, and Louisiana, using about 10 percent as much as the other three states combined. However, California's use of natural gas for electricity generation is now less than half what it was in 1972.

Gas burning power plants using intrastate gas, chiefly in Texas, Oklahoma, Louisiana, and Kansas*, were for the most part designed and built to burn only gas as the primary fuel because of the abundant gas supplies. This allowed the boilers to be smaller and less costly. The boilers do have a limited capability to burn oil, in order to provide protection against temporary gas supply interruptions, such as could result from a pipeline compressor failure. However, oil burning quickly builds up soot on the boiler tubes, since the boilers do not have soot removal equipment, and the power output degrades quite rapidly. After about a week, it becomes necessary to shut down the boiler in order to accomplish manual cleaning of the tubes. However, if gas use can be reinstated in several days, the soot can be burned away allowing the boiler to return to full power.

Because of the limited oil burning capability, oil stocks maintained at plants using gas as the primary fuel are sufficient for only a few days. Also, the oil transport capabilities are in many cases inadequate to support full time oil operation, even if the boilers had such a capability. Large oil burning plants require very large volumes of oil, which generally must be supplied by tanker, barge, or pipeline. Rail tank cars or trucks are simply not feasible for the large plants, although they are used for small units. In some cases, then, the absence of water transport or pipelines can make the delivery of large oil volumes impractical, although in other cases the transportation capabilities can be upgraded.

Generally, plants only able to use gas as the primary fuel can operate satisfactorily for extended periods on a fuel mixture of 80-85 percent gas and 15-20 percent oil, although some increase in maintenance costs may be

*Kansas is included in this discussion because it has significant natural gas production and uses more than 7 times as much gas in electricity generation as does Arkansas.

involved. This mixed-firing capability was the basis, in part, for the Chairman's appeal to electric utilities in the West South Central States to release gas to the interstate pipelines during the present gas emergency.

With respect to modifications of boilers to use other fuels, it is generally possible to convert boilers only capable of full time operation on natural gas so that they can operate full time on oil. The modifications include installation of soot removal equipment, expansion of oil storage capacity, and modification of control systems, assuming that oil transportation problems can be solved. However, there is a loss of power output of up to 20 percent because of the inadequate size of the boiler for oil firing.

However, it is generally not feasible to convert gas-only boilers to coal firing. The boilers must be totally replaced with larger boilers with ash handling equipment, coal bunkers, pulverizers, new controls, soot blowers, precipitators, and in many cases sulfur removal systems. The larger boilers and more extensive auxiliary equipment require a much heavier foundation, and, of course, there must be large areas of land immediately adjacent for coal storage. Either rail or water transportation to the plant also must be available. The difficulty of meeting all these requirements has resulted in a determination in most cases that construction of an entirely new coal fired plant is economically and technically superior to conversion of the existing gas-fired plants to coal.

With these general characteristics in mind, I will now review the prospects for reducing the use of natural gas for electricity generation in the Southwest.

It has become clear to utilities in the Southwest over the past 4 or 5 years that natural gas will be increasingly unavailable for electric power.

There have been no commitments to new gas-fired steam plants in that time and the new construction plans of the utilities in Texas, Oklahoma, and Louisiana have been principally for base-load coal and nuclear plants. Although electricity generation in the three states was about 88 percent from gas in 1976, and, therefore, consumption of natural gas in power plants essentially is presently dictated by the electric load in the area, the utilities' construction plans, if completed on schedule, will reduce gas consumption in those states by about one-half over the next decade. Because of the high proportion of national consumption represented by the three states, the national consumption by power plants should also fall by about one-half.

The Southwestern areas of large-scale gas use for electricity generation are covered by two Regional Reliability Councils, the Southwest Power Pool (SWPP) and the Electric Reliability Council of Texas (ERCOT). While these Councils include the states of Kansas and Arkansas, as well as portions of Missouri, New Mexico, and Mississippi, the interconnected nature of each Council's operations makes it desirable to analyze electric reliability and capacity on a Council basis. As of 1976, more than 60 percent of the Southwest Power Pool's total capacity of 42,000 megawatts was represented by gas-fired steam plants. Coal-fired capacity was about 11 percent, and it had 1 nuclear plant in operation, representing 2 percent of total capacity. By 1985, SWPP's gas-fired capacity is scheduled to decline to 28 percent of the total, with coal capacity increasing to 36 percent and nuclear capacity to 1[illegible] percent. The gas-fired plants would be used principally for cycling and peaking, so that energy generated by gas would fall from about 65 percent of the total in 1976 to 19 percent in 1985. In absolute terms, the SWPP consumption of natural gas is expected to decline by 45 percent, from about 1.1 trillion cubic feet in 1976 to .6 trillion cubic feet in 1985. Some 22,000 megawatts of coal capacity and 10,000 megawatts of nuclear capacity will have been added at a cost of approximately $18 billion.

Similarly, the Electric Reliability Council of Texas will reduce its gas-fired steam capacity from about 85 percent of total capacity in 1976 to 38 percent in 1985, with a corresponding reduction in gas generation from 88 percent to 15 percent of total generation. Gas used is projected to decline from about 1.1 trillion cubic feet in 1976 to .4 trillion cubic feet in 1985. Approximately 16,000 megawatts of coal-fired capacity and 5,000 megawatts of nuclear capacity will have been added at a cost of about $12 billion.

The projected construction schedule may not be met because of slower load growth, financing problems, difficulties in securing permits for nuclear plants, problems in mining and transporting coal, construction delays, and similar factors. Slippage of the construction schedule would require increased use of gas and/or oil to meet electricity demands, but it seems unlikely that new capacity needs could be deferred by more than a few years. Thus, it appears reasonably certain that present plans will reduce use of intrastate gas for electricity in the Southwest by one-half or more over the next decade.

The 5 percent of natural gas used in combustion turbines and internal combustion engines is not a significant factor in the overall consumption of natural gas for electricity generation. Further, generally speaking, the combustion turbines can be modified to burn oil and oil supply is not a problem because of the low utilization of combustion turbines in the usual peaking applications. However, internal combustion engines are mostly used by small municipal electric systems, along with a few combustion turbines, and the substitution of high-cost oil fuel in such systems results in large increases in system costs and can threaten the viability of the municipal systems. The withdrawal of natural gas from small systems, while not significantly aiding the total gas supply picture, thus can have serious economic consequences for some municipalities, until they can arrange for the purchase of coal or nuclear generated electricity from larger systems.

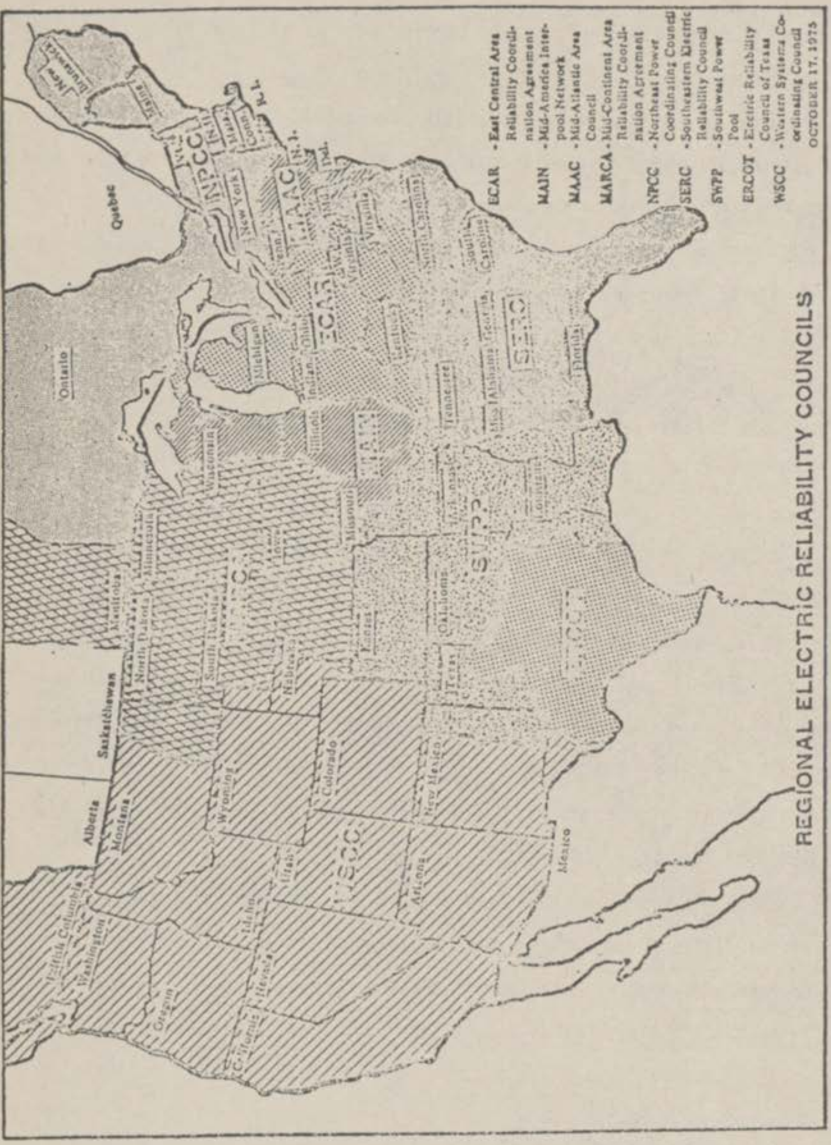
Accelerating the phase out of natural gas use by electric utilities in the Southwest, beyond present plans, is technically possible but would impose heavy additional costs on the area's ratepayers. Where conversion of plants to use of oil is feasible, there will be substantial capital charges associated with the conversions and the associated plant deratings, as well as the higher costs of the oil fuel. Where additional coal and nuclear plants are built, ratepayers would have to bear the costs of new expensive facilities to replace facilities with many years of useful life left. There would also be increased pressure on coal production and transportation capabilities, which will have to double over the next decade, even with present utility industry plans. If it were feasible to convert all existing gas-fired plants in the Southwest to oil, demand would increase by 1 million barrels a day, which is beyond the capabilities of the present oil supply system in that area.

Because of the extensive engineering, construction, and equipment requirements to accelerate the phase out of natural gas use in Southwestern power plants, there may be a number of limiting factors encountered. Shortages of skilled personnel and equipment, and the fact that only a few units can be cut of service for conversion at any one time, are obvious ones.

Because of the complexity of the considerations, it is difficult to predict the degree of acceleration of gas use phase-out that would prove to be technically possible and economically acceptable. My personal estimate is that the long term rate of reduction of gas use by Southwestern power plants cannot be greatly increased over present utility plans.

For the short term, it is possible to somewhat reduce the consumption of natural gas by burning a mixture of 15-20 percent oil and 80-85 percent gas, which as noted earlier, is feasible in many cases on a more-or-less continuous basis. However, boilers vary in their characteristics and estimates of the aggregate mixed firing capability are not reliable. If it is assumed that a 15 percent oil substitution is an average capability, gas consumption in Texas, Louisiana, Oklahoma, and Kansas could be reduced by about 160 billion cubic feet over the 6-month period from April through September. The replacement oil would aggregate about 25 million barrels, or 150,000 barrels of oil per day. Indications are that this supply of No. 2 fuel oil could be available in the Southwest during the summer months when heating oil demands are low, but the ability of the transportation system to deliver the oil has not been determined. It is also not clear whether the supplemental oil would be available and deliverable during the winter months, when the heating oil demand is high.

Another possible short term measure for reducing the consumption of natural gas is the import of electricity, generated by other than gas, into the Southwest area. At the request of the Bureau of Power, the National Electric Reliability Council (NERC) has made evaluations of the electric energy transfer capabilities between Regional Reliability Council regions. (A map of the Council regions is shown for reference.) This is a highly



REGIONAL ELECTRIC RELIABILITY COUNCILS

complex analysis which must consider the transmission system characteristics, the operating practices of the utilities, the ability of the sending region to provide surplus energy and at what times, the ability of the receiving region to take the energy, and at what times, the stability of the interconnected systems, assurance of adequate protection to deal with unscheduled equipment outages, and other factors. The results are dependent on the current operating reserve margins and vary over time. Consequently, the energy transfer capabilities are estimated for specific periods and the estimates cannot be safely used for other periods without evaluation.

The following diagram, taken from a NERC publication[1/], shows the 1976 and 1980 projected transmission capabilities for power transfers under heavy load conditions into and out of the Southwest Power Pool. There is no significant capability for power and energy transfers into or out of the Electric Reliability Council of Texas region, since it does not maintain interconnections across state lines. While the transmission capabilities are limiting, the power and energy transfer capabilities depend also on the status of generating equipment and the characteristics of the load. Thus, the diagram is not a sufficient basis for estimating energy transfers.

A 1975 NERC study, made at the request of the Bureau of Power, examined the capabilities for interregional energy transfers in the winter of 1975-76[2/]. Considering available capacity, the operating requirements of the utilities and the characteristics of the transmission systems, it concluded that the Southwest Power Pool could import an average of 343,000 megawatt-hours a

1/ National Electric Reliability Council, _6th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems_, July 1976.

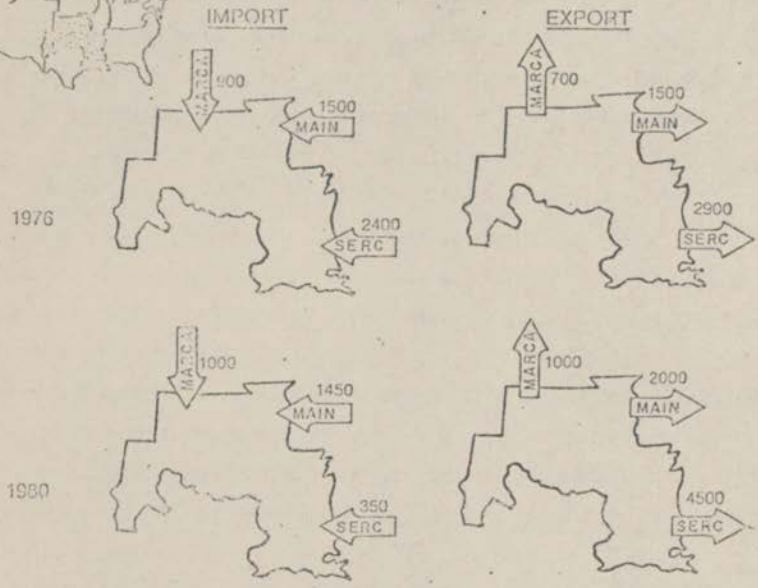
2/ National Electric Reliability Council, _A Study of Interregional Energy Transfers 1975-76 Winter_, October 1975.

SPP

Appendix E-3

NON-SIMULTANEOUS EMERGENCY TRANSFER CAPABILITIES — MW

Interregional (Incremental)



Intraregional (Incremental)

	1980 Imports	1980 Exports
ARKANSAS/LA./MISS./E. TEXAS	2000	2000
OKLA./W. ARKANSAS	2000	2000
KANSAS/W. MISSOURI	1700	2100
MISSOURI	500	500

week, principally from the Southeast Electric Reliability Council (SERC). The energy transfer would not be at a uniform rate, varying with time of day and from weekdays to weekends. This transfer capability is equivalent to about 3.5 billion cubic feet of gas a week. Although conditions change from year to year, it was concluded in the autumn of 1976 that the year-earlier estimate of energy transfer capabilities to SWPP during the winter was still valid.

In fact, however, there was not as much excess capacity available last winter in SERC as projected, because of various problems and the effect of the cold weather in increasing electric demands in the SERC region. Consequently, the full projected three-month capability, December through February, for transferring electric energy equivalent to 45 billion cubic feet of gas did not exist. However, it is believed that a substantial portion of the estimated energy transfer could have been effected, although at high cost.

During the spring and autumn, electric loads tend to be lower than in summer or winter and electric utilities take generating units out of service for maintenance. Consequently, it is not certain that more, or even as much, energy could be transferred at these times as in the winter. During the high peak load periods of summer, the transfer capability is uncertain and most of any transferred energy would be derived from oil generation, since the lower cost coal and nuclear generation would be used to serve SERC's own loads.

It appears then that electric energy transfers to SWPP have some capability for reducing gas consumption in generating plants, but the extent of the saving is uncertain and varies with the time of year. Much of the transferred energy will be oil-generated, at costs to the receiving utility in the range of 30 or 40 mills per kilowatt-hour, roughly equivalent to a cost of $3 to $4 per million Btu for generating fuel.

This concludes my testimony. I will be pleased to respond to any questions.

Mr. MOFFETT. Thank you.
Mr. Riddell?

STATEMENT OF JAMES W. RIDDELL

Mr. RIDDELL. Mr. Chairman, I regret I am an expert in nothing, but I am a practical lawyer who is called upon by his clients to give real-life advice.

Before I came up here, I reviewed the last report that my industry submitted to the FEA, and that report indicates that since 1972 that we are using 28 percent less energy. Now governmental policy didn't have anything to do with that. Cost had everything to do with it. We are not patting ourselves on the back because we use less energy. If we use less energy, we expend fewer dollars, and that is a powerful incentive to utilize our resources in the most efficient way that we can.

Now I come before you today to address myself to the subject of this panel, that is, the impact of this proposal that you are considering on industry.

Let me take one brewery for you. It is the largest one in the country. Prior to the submission of the proposal by the President, we reviewed the cost to that brewery. We determined that coal conversion would cost it $200 million, and that the most modern plant that we have would be operated, given a 12 percent investment credit, would operate for 12 years without showing a profit. Twelve years without showing a profit.

Now, I suppose that I can best address myself to this problem by telling you a few tales of a few cities. Let me start with Moorhead City, Minnesota, and a malting plant. Plans and contracts were let for that plant more than a year ago. At the time that we let the contracts for construction, we were advised by our suppliers that leadtime for a coal-burning combustor was 3-1/2 years. Naturally enough, if we had to wait 3-1/2 years to get a coal-burning combustor, there was no point in building a plant. We would buy the malting from some other place, and since malting facilities in the United States are limited, we would have to buy it abroad. It was a cold winter. And we weren't able, because of the cold, to put our footings into place by December 31, 1976. So I was faced with a $14 million hole in the ground, and I crawled to FEA on my hands and knees and asked them to give me advice about whether or not we should pursue the construction of that plant or abandon the $14 million.

I was given no answer. As a matter of fact, I got my answer by reading the Wall Street Journal. The Wall Street Journal informed me that plant, together with four other facilities which I have an interest in, was going to be required through public hearings to address themselves to the question of why they should not be required to convert instantly to coal.

Now, as I said, I am a practical man. I went back to our suppliers and said if your leadtime on supplying a coal-burning combustor as of May 1976, was 3-1/2 years, what is it now? They said it was 7 years.

Now I am confronted with a practical dilemma and bearing in mind your admonition to the previous panel, I am not here to express my anger and frustration. I am, in the terms of one of our better slogans, here to make love, not war.

We have another problem. In Fulton, New York, there is a brewery owned by the Miller Brewing Company. In Auburn, New York, there is a limited supply of natural gas which is not—and I regret so much Mr. Ottinger is not here—which is not in the view of the industry commercially exploitable. But there is a distance of 34 miles between Auburn and Fulton.

Now the President, when he sent his proposal to you, exempted or prayed that you exempt from the impact of this bill the use of natural gas on the site of the user. Well obviously 34 miles is not on the site. And what is commercially exploitable source of natural gas?

Sir, my problem is a $30 million profit. Do I advise my client to continue with his plans to construct the pipeline from Auburn to Fulton, New York? Only you gentlemen can tell me. But it is still $30 million.

Nobody needs my profit. Unlike the gentlemen here who are representing utilities, I represent brewers, and we serve a market of no necessity. If we cannot produce a profit, there is no point in us being in business. Now, how are we going to cope with the sort of problems that I am addressing to you?

Let me give you another problem. There is no way for the food-processing industry to dry the liners on the cans we use, whether a beverage such as beer or a can of peas, without the use of natural gas. Technology is not here for the utilization of steam. Ultraviolet processes are far more energy-insensitive, and no other fuel will permit us to dry the liner in a can without leaving a residual taste, except natural gas.

The President did not propose that such a use be exempt, but I pray he wouldn't. In my written statement I will set forth the facts to support it, to exempt such a use of natural gas.

We also need it for the drying of spent grains. If we don't have it for the use of spent grains, then there is a residual taste problem which makes it even unpalatable to the animals to whom it will be fed.

But, as I said, I would hope that you would begin anew, that you would instruct FEA to bring to its administration of existing law and any law that you propose those real world considerations that I have laid before you.

Sir, you addressed a problem to the previous panel. You said how is it that the people in my State are going to endure with their problems with polluted air, energy- insensitive industries with a restricted source of supply. I don't know the extent to which you or the other members of this committee have addressed yourself to demographics recently, but I suggest you do so, because they demonstrate one thing, that people are going to leave those areas where there is not employment, and if public policy makes it difficult for a practical man such as myself to give advice on how to exist with respect to real-world problems, I suggest to you that you are going to see population shifts in this country that are going to be very surprising to you, and that the Northeast, where you and Mr. Ottinger represent a large constituency, are going to see a population loss that is going to be appalling, and it is taking place now.

Now, we are trying as honest people to give honest advice, and we are given no help. Indeed, we are obstructed. As I say, it has taken me almost a year to get the permission of the State of New York to construct that pipeline, but now I can tell you this; unless you exempt that use, there is $30 million that I can't advise my client to expend.

I apologize for the length of my summary, but you were interested, if I understood, in the impact of these proposals in real-life terms.

Thank you.

Mr. MOFFETT. Thank you.

The Chair recognizes the gentleman from Louisiana.

Mr. MOORE. Thank you, Mr. Chairman.

I am particularly interested, of course, in Mr. Riddell's problems.

I think one thing I would like to ask the gentleman from Dow, I have a plant across the river from my district, and I am concerned about future Dow plants. Would it not be a fair statement to say that in the future, if Dow builds a plant or anybody else builds one, they might determine, all other things being equal, to locate near a coal source of supply as opposed to a supply of oil and natural gas?

Mr. ANDRAS. We in Louisiana and in Texas have operated for many years in a decontrolled situation on oil and gas prices. My company, for years being a large consumer, has supported decontrol. We believe that this is the most effective way to get priority end use to oil and gas. Over the last 2 or 3 years in Louisiana and Texas, there has been a shift to plan for future facilities burning coal. Most of the utilities already have under construction coal-burning facilities. Our plans are to replace our gas-fired equipment with coal-burning facilities in the Louisiana division of which you speak.

The situation in Louisiana is an environment in which we have enjoyed an abundant raw material situation, primarily hydrocarbons, but there are also major other raw materials in Louisiana that we feel would continue to stimulate industrial growth in that state.

We are in the business of making chlorine and chlorinated hydrocarbons, and we need brine to do that. Large brine deposits in Louisiana, of course, are a major raw material to us. Also the fresh water situation of the Mississippi River will induce industry to come to the State of Louisiana without a major coal supply.

We have for some time been interested in trying to develop the lignite reserves in North Louisiana, and we have made substantial investment to get a reserve position there. We currently have approximately 100 million tons of lignite reserves in North Louisiana. We plan to use that in our facilities in the future.

Mr. MOORE. Dow is a quality employer. I hope the others feel the same way you do and do not abandon our State and Texas for other parts of the country that have coal.

I would like to talk now with the gentlemen representing the power and light companies. I think the gentleman from the Houston Power & Light Company came the closer to giving us a figure of what the consumers can expect to pay.

Let's assume for a moment that you are not going to get anything more of this investment tax credit which is in existence now to help you defray the cost of building the plants. There is not going to be rapid depreciation or any kind of government gifts or what-have-you. What can you expect to pay by 1990 converting your oil and gas-fired plants, or more practically speaking, replacing them, because those that are worn out, you would be replacing anyway?

What will happen to the rate structure for electricity? That is what the consumers and we are interested in. You came close to telling us what the capital outlays would be and how much more it would go up, and where you are going to get the money from. I think the answer is you are going to get it from the consumers. The government isn't going to give it to you.

How much more is the consumer going to pay for electricity? I would like the three of you to reply.

Mr. OPREA. If you will bear with me, I have a throat problem and am having a hard time trying to talk.

We anticipate with full replacement of existing gas-fired and oil-fired facilities with coal by 1990, should that come to pass, and let's just assume that we get none of these financial or tax-incentive reliefs that we have recommended be considered by your subcommittee, we talk about budgets above $1 billion, equal to or above $1 billion per annum.

First, you would have a financial impossibility to acquire the funds necessary through the security market, and I think also through rate relief, through the Public Utilities Commission. But assuming all this comes to pass, we feel that the price of electricity over what we see today will increase at least three to five times.

Mr. MOORE. That is the figure I have heard from other utility companies in my area.

What about the other two gentlemen from Mississippi and the Northwest?

Mr. LUTKEN. As you know, Congressman Moore, we are a part of the Middle South system, and we have in my prepared statement some figures that would bear out the actual cost as we see it to our consumer which would just about triple, or maybe a little more, the annual residential bill to our customers. In my particular company, the average residential customer pays us about $377 per year, and this would mean, as I said earlier, in the poorest State in the Union that bill would go up to better than $1,000 a year.

Mr. MOORE. Thank you.

Mr. Allen?

Mr. ALLEN. First, let me start with two observations. One, we have enjoyed much higher rates in New England and on the East Coast for years than you have enjoyed in the Gulf. Second, we are not talking about complete replacement; we are talking about converting things that were originally designed for coal. So, in two steps, if we can convert on the program which we have outlined, we can save money for our consumers. If, on the other hand, we have to convert to a moving target, and a very overly strict one with respect to environmental protection, we estimate that the cost to our consumers when you put it all the way through to the retail rates could be on the order of 10-15 percent.

Mr. MOORE. Let me follow up on that now. Let's assume that we take a more reasonable approach, and we allow those units which cannot be readily converted such as the gas-fired ones, according to the previous testimony, allow them to be worn out or replaced when it becomes financially feasible to do so through rapid rates of depreciation and what-have-you. As I understand the rate structures, there should be enough money put aside for eventual replacement of existing facilities without increasing rates, so would it be fair to say if we didn't put you on a 1990 deadline, simply said you can't build any more and give you incentives to convert where you can, when you can, would it be fair to say that the electric rates would not go up?

I would like each one of you to answer.

Mr. LUTKEN. If we can get the economic use of the life of our existing plants without further expenditures for conversion and develop our plans on the drawing board to go completely to coal and nuclear for new base load requirements, I think our ratios in our area would probably go up at the same rate as the cost of living.

Mr. MOORE. Houston?

Mr. OPREA. Assuming again that we can pursue developing our system and putting in the replacement plant as this plant gets totally worn out, that would extend the useful life in many of our plants to about the turn of the century, some well beyond that. Assuming we can pursue that course, I would think, based on what fuel costs, and these are the major parts of the rates that our customers pay today, I would say if such is the case, we can expect that we will have more normalized type of rate increases, similar to what Mr. Lutken mentioned. Of course, that is a lot to assume.

Mr. MOORE. I am with you.

Mr. Allen?

Mr. ALLEN. I think what you said, if you can make the conversions on a cost-effective basis, then you should be able to keep the rates steady, yes. But you have put in an assumption there that I think is unwarranted. If you look to the future, and we are going to build new capacity, as we certainly hope we can, and get more oil savings, we are faced with the fact that the plants we are retiring are going out at very low cost. We are an original cost industry, and I think in round figures there is no way you can replace kilowatts that were built for around $100 with kilowatts built at $500, $600, or $700, and keep the rates steady. That is a fact of life of the industry. We have had major inflation in construction costs. Given that situation, if you can convert and save your customers money; you are ahead of the game. It is good.

Mr. MOORE. Thank you.

Mr. MOFFETT. The Chair recognizes the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Thank you, Mr. Chairman.

Mr. Allen, you suggested you were going to have to suffer more in this situation than other parts of the country, New England and the South. I would submit maybe that is Biblical judgment for all of those years you had cheap oil from Arabians and all the years that the South had gas to heat its boilers. No response is really necessary.

Mr. ALLEN. Speaking only in Biblical terms, we wish all else in the supply of electricity in New England had been as cheap as imported oil for a brief period.

Mr. BROWN. Indeed. First, I have to say I have a conflict of interest. I don't have the same conflict of interest that the gentleman from Louisiana has. I don't have a Dow plant in my district. I do have people who use Dow products and people who use electric energy. I am sorry I don't have any consumers of your product, Mr. Riddell, in my district.

Mr. Riddell, how many people would work in those $30 million worth of plants that you spoke of?

Mr. RIDDELL. I spoke only of a pipeline in terms of $30 million.

Mr. BROWN. If you don't have the pipeline, you won't have the plants; is that the idea?

Mr. RIDDELL. That is right. We already have a plant in being. With utilization of gas, the malting can plant and brewery that it will serve would employ an additional 700 people. The plant that I referred to in Moorhead City, my $14 million hole in the ground, that is 600 permanent jobs. My brewery down in Eden, North Carolina, that is 1,000 jobs. The addition to the Williamsburg brewery, 400 jobs. Those are permanent high-paying jobs.

This is not an adversary proceeding, Mr. Brown, as you know better than I. I have already made plain the point that we sitting on this side of the table, the function of cost, I mean, we have to bear the burden one way or another.

Mr. BROWN. Well, I want to make one observation. "We," I gather, is a collective noun for the consumers?

Mr. RIDDELL. Yes.

Mr. BROWN. Because obviously you are not producing the beer for charity.

Mr. RIDDELL. Right. And if we translate cost into a 6-pack of beer, it is frightening.

Mr. BROWN. I wonder if you could try to do that for me when you submit your testimony?

Mr. RIDDELL. I am prepared to do it now.

Mr. BROWN. I do have some people, I have to tell you, in my district that drink a little beer, and I talk to them occasionally, and I would like to be able to tell them something about what the government has done for them.

Mr. Lutken, on page 2 of your appendix, you say that you have decided to switch all future plants to nuclear and coal. Why has that decision been made?

Mr. LUTKEN. Page 2 of what?

Mr. BROWN. Attachment No. 3. If the government does collapse, it is all going to be covered with paper. I think this is page 2 of attachment 3 of this number here.

Mr. LUTKEN. I have it.

Why do we make the decision to go from gas and oil to nuclear and coal? That is what the hearing is all about, as I understand it. We have lost our natural gas primarily in the Middle South system with the exception of some intrastate gas in Louisiana.

Mr. BROWN. So it is the anticipation this will be prohibited in the first instance?

Mr. LUTKEN. That is right, and the oil embargo, having gone through that with the cost involved in that, we took the only expedient step we could, and that was to convert from gas to oil. We couldn't convert to coal. There is no way. It was impossible.

Mr. BROWN. Why?

Mr. LUTKEN. As I said earlier, we might as well build a new plant, shut down the existing plants that are relatively new. The oldest one we have came on the system in 1948.

Mr. BROWN. You make your decision on cost based on what? Based on the Btu equivalent cost to coal as this legislation is drawn?

Mr. LUTKEN. Fuel cost plus capital cost outlay as far as the plant is concerned.

Mr. BROWN. I guess I don't want to ask the question indirectly. I want to say it and get you to agree with me. Maybe you all would.

I gather the decision on whether you use coal, oil or wastepaper, whatever it is, nuclear, is based on, in the case of Mr. Riddell, process to some extent, but in terms of the heating requirements, the Btu requirement, it is based on not any arbitrary Btu equivalency price of the product as it comes out of the ground, but rather the product as used in the plant.

Mr. LUTKEN. As burned and the equivalent it takes to burn it.

Mr. BROWN. Part of the cost of burning coal is cleaning up after it?

Mr. LUTKEN. That is right.

Mr. BROWN. And part of the cost of burning oil or coal or gas is its transportation and those have different relative costs, certainly for the South they do, I assume. Is that right?

Mr. LUTKEN. Yes, sir, and, of course, of availability of the fuel you are looking at. It is readily available.

Mr. BROWN. Of course, the government restricts, if those are part of the pattern. But I am trying to establish the point that this bill has what I consider to be a foolish Btu equivalency pricing plan which I think results for every one of you, if you could get it, in gas being the cheapest fuel available to use; isn't that right?

You may be an exception, Mr. Allen.

Mr. ALLEN. We don't use natural gas, but have been trying to find out what this bill holds. Let me tell you my confusion. I think the Btu equivalency in fixing natural gas prices is one thing, and the Btu equivalency in imposing a tax is based on another. The first I believe is based at the refinery; the second is based at the wholesaler, in the regional wholesaler price. I have gotten that far, and I don't understand it. Your basic proposition——

Mr. BROWN. Welcome to the group.

Mr. ALLEN. If your basic proposition is "When you get all through, you try to do the most economical thing, whether you are in regulated or unregulated industry," of course you are right.

Mr. BROWN. Mr. Dow?

Mr. ANDRAS. We also look for the more economical alternative in our business decisions. We have for some period of time been low-priority end use on natural gas, and even though the interstate gas prices have been regulated artificially low, we haven't been expanding our facilities with the plan of using natural gas as a fuel.

Mr. BROWN. Because you couldn't get it.

Mr. ANDRAS. Because we didn't think it would be available; that is correct.

Mr. BROWN. Mr. Allen, could you provide for the record an explicit comparison of your estimate and the FEA estimates mentioned on page 5 of your testimony?

Mr. ALLEN. A comparison line by line, in what detail?

Mr. BROWN. More explicit, if you can do it, than the aggregate figures you gave us, and I don't know——

Mr. ALLEN. Yes, we can. To the extent we can find out what FEA's estimates are line by line, we will.

Mr. BROWN. What happens if EPA refuses to go along with those things specified by FEA in your conversion in Massachusetts?

Mr. ALLEN. I assume one of three things: Either we don't convert, or we find out what the additional cost will be for converting and meeting EPA's requirements, or possibly, three, we are told to shut down and forget it. Those seem to me to be the alternatives.

Mr. BROWN. One other question for the record, if I may, Mr. Chairman, and one other general question I would like to ask the gentlemen from the South, in particular.

Would the utility operators compare on a per kilowatt hour basis and provide this for us as soon as you can, the cost of construction of a coal-fired plant, a gas-fired plant, and a nuclear plant, as if you were going to build one tomorrow, including the timeframes that you have to consider, and so forth, and the cost of the money to cover those time frames?

What are the differing operating costs for each of these plants, and what the percentage of the costs of a coal-fired plant are for pollution control facilities? In other words, out of that total cost what are you obliged to do with reference to that necessity for cleanup.

Now, I would also like to ask you, we have had some discussion about, and you may have seen in the Wall Street Journal an article or two about the question of geothermal methane gas trapped in water solution. I am fascinated by that with reference to this whole area of coal conversion, and at this point, Mr. Bagge may get up in a huff and walk out of the room, but we are obliging you to convert to coal at a time when Dr. Barnea of the United Nations says we have a several-hundred-years supply of methane gas under the territory that at least the southern utilities attempt to heat, and this guy is no fly-by-night because he has been the head of the international geothermal study or whatever the association is called, and he says that possibly could come in for as low as $2.50 a thousand cubic feet. If that is true, that isn't very far from what I understand has recently been requested of the Federal Power Commission by producers of conventional natural gas.

I understand those two prices asked in February of the FPC were $2.36 and $2.45 in relation, of course, to $1.75 or $1.42, but we are past that point.

Are we making sense here by overlooking that possibility as we now demand that you convert to some other source of electric generation than gas? Have any of you thought about this, or could you comment?

I might say the thing it is trapped in, of course, is hot water, and I don't know whether you run your plants on hot water or not, but if you get the pipe to the hot water, maybe you wouldn't have to mess around with the gas.

Mr. OPREA. Mr. Chairman, as you identified, in the southwestern part of the United States, there is a geopressure, geothermal zone, that reaches a couple hundred miles inland of the coast and a couple hundred miles out into the Gulf of Mexico. Part of that zone is in our service area.

Mr. BROWN. This is not questioned? This is fact? We know it is there; right?

Mr. OPREA. This is a fact. We presently are involved with three other electric utilities in the State of Texas and also the University of Texas in a project whereby we are going to drill in our service area to attempt to make the determination as to what the geopressure zone holds for the State of Texas relative to producing methane that has been identified as a highly potential end product, along with hot water, to be able to turn turbines.

But the big problem is what percentage of methane. We have heard varying values that range anywhere from several hundred trillion cubic feet up to several thousand, and the people involved in this project felt that before you talk about cost and recoverability of methane gas from hot water, what you have to do is drill the shafts, go down and do the necessary experimental work and even put in a small prototype system to see what type of recovery you can expect. But the potential is there.

Mr. BROWN. What do you think of our requirement for convection? Are we doing the right thing or wrong thing?

Mr. LUTKEN. We, too, in the Middle South system have made a study of this geopressure geothermal area which starts about Louisiana and extends down into Texas on the Gulf Coast area, and we will be glad to submit that study to this committee if you want it, if you would like to have our findings in the geopressure area.

Additionally, we are about to enter into a project to recover methane from this geopressure thermal area, and we understand from talking to I think one of the renowned people in this field, Dr. Vise up at LSU, and we are working with him and will be drilling some test wells if we can come up with the money to develop this program with him.

We understand that the big problem is getting rid of the salt water once you bring this water to the surface, extract the methane gas, and, here again, that would affect the cost tremendously. If you can dump it back into the river—this area we are looking at is along the Mississippi River. Of course, out in the ocean you can dump it back in the ocean with no problem. But if we have to put it back in the ground, this will raise the cost of the methane, if we find any. But we would be delighted to give you that report we have on geopressure.

Mr. MOFFETT. We would like very much to have it, if you would submit it for the record.

Mr. BROWN. I ask unanimous consent that it be received.

Mr. MOFFETT. Yes. Without objection, it is so ordered.

[The following letter and attachments were received for the record:]

MISSISSIPPI POWER & LIGHT COMPANY
Helping Build Mississippi
P. O. BOX 1640, JACKSON, MISSISSIPPI 39205

DONALD C. LUTKEN
PRESIDENT

May 26, 1977

Mr. Jan B. Vlcek
Acting Minority Counsel
Interstate and Foreign Commerce Committee
Subcommittee on Energy and Power
Room 2125
Rayburn House Office Building
Washington, D. C. 20515

Dear Mr. Vlcek:

As requested by the Committee after my testimony on May 25 on Part F of HR1863, I am attaching a tabulation of estimates given us by architects-engineers for new steam generating plants to come on line in the 1985-87 time frame.

I am also attaching a tabulation of the original cost of our Baxter Wilson Steam Electric Station at Vicksburg, Ms., the actual costs of conversion of these two units from gas to oil, and a current estimate of the cost to convert these units from oil to coal.

With reference to the request for information on the potential for electric generation from geopressured brine thought to exist near the Gulf Coast, a copy of a study made in 1974 for Middle South Utilities System by the engineering firm of Hise and Hise, Baton Rouge, entitled, "Geopressured Water, a Potential Source of Electric Power for South Louisiana" is being mailed to you today.

Also, as requested, I am attaching a tabulation of estimated operating costs expressed in mills per KWH for 1985 nuclear and coal-fired plants in comparison with MP&L operating costs in February 1976.

Please advise if I can supply you with additional information.

Sincerely,

Donald C. Lutken, President

DCL:jh
Encl: (3)
cc - Mr. Dave Cantor
National Association of Electric Companies
Mr. N. L. Stampley

Member Middle South Utilities System

FIRM	Time Frame	$/KWe Nuclear	Coal W/FGD	Coal W/Out
Collieries Management Corp. 2-77	1985-7	1150	980	
Ebasco 11-76	1988	1190	1094	901
Gibbs & Hill 4-77	1987	1106	951	743
Boyer Philadelphia Electric 6-76	1985	1050	796	692
Sargent & Lundy 9-76	1985	1047	906	
AVERAGE		1108	959	793

May 26, 1977

BAXTER WILSON STEAM ELECTRIC STATION
VICKSBURG, MS

The Baxter Wilson Steam Electric Station at Vicksburg consists of two units, both of which were designed to burn natural gas, with No. 2 oil as emergency stand-by fuel.

These units were constructed after long-term, firm fuel contracts had been negotiated. These contracts expire in 1993.

In 1970, the Federal Power Commission authorized the fuel supplier to abrogate these firm fuel supply contracts, necessitating the conversion of these two units to a capability of firing with oil on a sustained basis.

The design, engineering and construction work necessary to effectuate this capability have just been completed at great expense to the company and its customers and at a loss of more than 10% of the original capability of the station, as the tabulation below indicates:

	Date of Completion	Capacity KW	Original Cost	Cost in KW
Unit #1	1967	550,000	$44,000,000	$80
Unit #2	1971	750,000	66,000,000	$88
Station	1971	1,300,000	$110,000,000	$85
Conversion Cost	1977	1,150,000	70,000,000	$61
			Replacement Cost/ Coal	
Lost Capacity	1977	150,000	$120,000,000	$800
Station Conversion to Coal	1985	1,300,000 KW	$400,000,000	$300

This tabulation shows a station with an original cost of $110,000,000 required an investment of $70,000,000 for conversion from gas to oil, along with a loss of station capability of more than 10%. The cost of replacing this lost capability with a 150 MW coal plant exceeds the original cost of the entire station. Reconverting the unit from oil to coal would cost nearly four time s the cost of the original station.

May 26, 1977

GENERATION COSTS

1985 - MILLS/KWH

	MP&L Feb. 1976	Eastern Coal 800 MWe Avg. Haul SO_2 Removal	Western Coal 800 MWe 1000 Mile Haul No SO_2 Removal	Nuclear 1150 MWe
Operation & Maintenance	1.4	4.0	2.0	2.0
Fuel	19.3	17.3	15.0	7.9*
Capital Charges 18%	3.3	22.9	19.1	27.1
Total	24.0	44.2	36.1	37.0

*$50/lb. Fuel

Mr. MOFFETT. I would like to ask a question about transportation here. Is anyone on the panel aware of any analysis of any substance having been done by the administration with regard to transportation of coal under the proposed plan?

Mr. RIDDELL. I am a practical man, and one of the problems I have to answer is what is the availability, (a) of the coal, and (b), how am I going to transport it to Eden, North Carolina.

Mr. MOFFETT. You haven't seen anything——

Mr. RIDDELL. No, sir, but I find this. I find extreme difficulty on behalf of contractors to assure supply of coal or to assure the transportation with which to deliver it.

Mr. MOFFETT. I don't think that conflicts in any way, does it, with the earlier testimony that we had.

I know Mr. Bagge is still here. You perhaps heard the gentleman's comment. Would you come forward for a moment?

Mr. BAGGE. In answer to your question, Mr. Chairman, the President's plan, that is, the statement accompanying the energy plan, does call for a transportation study to be completed by the end of the year on the implications to the transportation network of all of the forms of fuel, including coal.

Mr. MOFFETT. We are being asked, as Mr. Brown pointed out, to approve something very soon, perhaps well before the end of the year without knowing what the transportation implications are.

Mr. BAGGE. The transportation implications, I can testify the constraints on the coal industry today in Appalachia are quite severe. The efforts to convert the utility plants of the East Coast have been frustrated largely because when the utility industry converted to imported oil that transportation network was abandoned. Indeed the loss of that tonnage was the largest single contributor to the demise of the Penn Central system.

Mr. MOFFETT. What about Mr. Riddell's comments before you came to the table, of the lack of availability of coal, and in terms of leadtime he can't count on it?

Mr. BAGGE. I would respectfully disagree with the articulate gentleman appearing for the brewers' association because in terms of supply the other panel, I think, certainly testified there is no problem with respect to coal availability.

Mr. RIDDELL. May I address myself to that point? The gentleman, of course, is about to appreciate and enjoy a governmentally imposed monopoly. Now that is to say he supplies coal. I am trying to buy coal in competition with all those other industries who need coal.

Now, let me address the problem of Anheuser-Busch in attempting to retain a contract for coal at Williamsburg in competition with Vepco Virginia Electric Company. And let me address myself to the contractor who is going to supply the coal.

Obviously Vepco is going to be the customer of preference. Now, I am competing——

Mr. BROWN. Why?

Mr. RIDDELL. Because there is a limited supply of coal in spite of the fact that this gentleman says it is infinite, and he didn't say that. I listened to all of his testimony, and he addressed to you the same sort of real-life problems I have.

Now he has to get it out of the ground; he has to ship it. And he has a bunch of hungry customers who, by governmental fiat, must buy coal. Now, again, I am that poor little country boy who is trying to buy coal, and there are 100 customers out there, and if they don't get the coal, guess what happens to the plant? It shuts down, assuming, mind you, that he and I can live with EPA, which is yet to be determined.

It is pure competition for a product. Now, these gentlemen over here, their cost is subject to public review. You know what theirs are. And when he sits there and tells you that he anticipates rates that are going to climb three to five times, look at me. I am out there trying to buy a product, coal, in competition with him, with U.S. Steel, with heavy industry, with light industry, and he tells me that I am not going to have a problem. I already have a problem.

Mr. MOFFETT. I wonder how serious that competition is at this point.

Mr. RIDDELL. It is damn serious.

Mr. MOFFETT. Very serious?

Mr. RIDDELL. Yes.

Mr. MOFFETT. If you could respond briefly, Mr. Bagge.

Mr. BAGGE. I would just like to put your mind at ease, if I could.

Mr. RIDDELL. How about putting my pocketbook at ease?

Mr. BAGGE. First of all, I want you to be aware of the fact that the coal industry is not looking for the role of the regulated monopoly. We are opposing this bill because we think it is going in entirely the wrong direction for reasons all of you have articulated here.

But we have today, Mr. Chairman, an unutilized capacity. We have mines able to produce right now, a conservatively estimated 70 million to 80 million tons of coal today that we can produce, but for which the market is not there. There is no question about our capacity to produce not only the 70 million tons that we could turn on line overnight if EPA would permit a market to be there, but we indeed, and in our documents in the earlier panel have described, the commitment we have made in terms of our plannings of building an incremental capacity of 560 million tons by 1985.

I don't think unless government intervenes by this bill, particularly the section you are looking at now, through allocation, and fouls the system up further—I think that your needs can be met if the government will take a hands-off policy and let the market forces determine rationally and orderly the substitution of coal for natural gas and oil.

Mr. MOFFETT. Okay. I do want to move on, if we can.

I would like to ask Mr. Allen specifically on the transportation question. We obviously in the Northeast have some very special problems transportationwise. What thought have you given to that, and would you respond individually?

Mr. ALLEN. I have to speak from my experience. As you know, there are a few plants in New England which have gotten coal by unit train, but they are in the minority. New England does happen to face on the Atlantic Ocean, and most of the fossil-fired plants have been at tidewater in very major part—I would think 95 percent of the coal that arrives in New England has come by barge or coastal transports. The only rail transportation that we have ever traditionally been worried about is how do you get coal from the Kentucky or West Virginia mines to Norfolk. That, I take it, is not part of Penn Central and still operates.

Mr. MOFFETT. Do you see a future with all the money we are spending on ConRail, for example? Are you looking to that for any assistance or not?

Mr. ALLEN. I would have to go back and ask my transportation expert. I think the answer is no, but I am not quite sure who is in ConRail in Appalachia.

Mr. MOFFETT. Okay. With regard to the prohibition in the plan on construction of new factories, this does not relate to utilities, but in construction of new factories that burn oil and gas. I don't have anyone else on the panel, I think, who can address this, and maybe you are not even the right person. It would probably be an industrial person from the Northeast, but what kind of a problem do you see here in terms of the kind of thing that Mr. Riddell was talking about, the shift and the possible relocation of plants, and so forth.

Mr. ALLEN. Let me respond as best I can. It seems to me that one of the problems we are facing not just in the Northeast but in Representative Brown's Ohio, in the Gulf Coast, anywhere we have any major industry, we are now facing nonattainment problems under the Clean Air Act increasingly across the country.

If you are talking about putting additional industry into Connecticut or Massachusetts or any other urban area, and if you say that for their process heat, they should burn coal, I can't think of a place in your State or mine, and I doubt if I could find one in Ohio, where you could accommodate additional coal-burning within the State implementation plan requirements you now have.

Mr. MOFFETT. And yet we have what, eight plants in Massachusetts, in terms of utilities, now? We have eight utility plants in Massachusetts and eight in Connecticut that have been ordered to switch.

Mr. ALLEN. It is a total of 15; I have forgotten the breakdown.

Mr. MOFFETT. It seems in terms of the administration's thrust both with regard to new factories and with regard to utility conversions that despite this air problem, they seem to be going ahead with the plans to have us convert, and I wonder when we get into the question of the exception and exemption process whether we are not going to see this just drag on ad infinitum. I know Northeast utilities and others are opposing——

Mr. ALLEN. As are we.

Mr. MOFFETT. As are you; there is no time limit on this. This could go on forever; right?

Mr. ALLEN. You may be writing a new set of rules in this act which will supersede ESECA, in which case we will have to reorganize ourselves to see whether we can do this on an economical basis, as we can, and I think Northeast cannot, or whether we have something which is so completely thrust down our consumers' throat, we feel we have to fight it. Where the battle lines are, we won't know until you finish writing this bill.

Mr. BROWN. There is another bill that will impact on this, and that is the Clean Air bill on the floor, and the problem is if those folks are going to move out of Connecticut or Ohio because they can't get jobs or build plants, the present bill, as I understand the way it is written, means that they don't have any place to go, at least in this country, because they can't go into the Southwest because of the nondeterioration standards. Even though the air may be cleaner, you can't build plants there, and you have the problem, that wonderful plant out in Utah some place.

Mr. BAGGE. Kaiparowitz.

Mr. BROWN. The one they can't build because 12 months out of the year it blows into the State park.

Mr. BAGGE. Kaiparowitz.

Mr. BROWN. Is that a description or the name of the plant?

Mr. BAGGE. It is the name of the plant.

Mr. BROWN. I am getting Four Corners up here and Kaiparowitz?

Mr. ALLEN. I think your analysis is absolutely right. If you can't do anything in the dirty area or in the clean area, maybe we better stop having new plants. In that case, I have in mind that my grandmother knew how to tat, and maybe I am going to take that up.

Mr. BROWN. To tat?

Mr. ALLEN. Tat. A cottage industry.

Mr. MOFFETT. Does anybody here see anything really good coming out of the coal conversion forces that the administration plans? Let me ask it more specifically; in terms of, let's say, in our area, there is more of a push to get involved not even so much in burning coal, but using more hydro wind power, and so forth?

Mr. ALLEN. Let me answer the first question. Yes, we see very definite savings for our consumers, which we think we should get for them by burning coal where we can. And we see a national interest, wanted in the short-term by 1985, and getting at least that many barrels of oil off the import list.

Long-term, without going to wind power, we feel very strongly that the future of New England for many reasons, both what it costs our consumers and what it costs the environment, is nuclear, as you are well aware.

Mr. OPREA. I would like to make a comment to that.

Mr. BROWN. What about all those folks in New Hampshire, or whatever it was, Seabrook, that I was told by the administration, were going to be a party to a social compact if we didn't go ahead and develop the fast breeder nuclear reactor; they would be a party to the social compact that would allow these light water reactors to go ahead and be built?

Mr. ALLEN. Two things, Mr. Brown: First, we have seven plants in New England which are now operating very successfully and well in supplying between 25 and 30 percent of our kilowatt hours. Second, the Seabrook problem is an extraordinary problem, both on the public demonstration front and also on the administrative front where we have the spectacle of the complete fouling up of the Federal Government in its collective underwear as to who is giving what permit.

But, we feel very strongly, first, that Seabrook and the successor plants are needed, are rational and make sense on both environmental and cost accounts. Second, we think that if we are patient

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and have the endurance, we can straighten out the administrative agency tangle, and third, I think I am hearing from some people, Mr. McCormick this morning, for instance, that there may well be more difficult problems for an environmentalist or for somebody who is concerned about pollution with burning additional coal than there are with nuclear when we finally have the pieces all sorted out.

Mr. Brown. Could you quantify the cost? Incidentally, you said after you work out the foul ups, the Federal licensing, and so forth, can you quantify that in any way in cost for us?

Mr. Allen. I think I can quantify the cost when I am sure what I am quantifying.

Mr. Brown. You said the problem with Seabrook——

Mr. Allen. The Seabrook problem of an NRC construction permit being issued and then being vetoed by a late order by EPA on the water discharge. So that we have a situation where two agencies have come down parallel roads and on different time schedules and have come out with opposite answers. We are now awaiting Mr. Costle's final review of the EPA position.

All I can tell you now is that we have suffered five months of flat down period and total uncertainty in the project.

Mr. Brown. The quantification of the cost is the question of that delay.

Mr. Allen. That can easily be done.

Mr. Oprea. Mr. Moffett, we in the Southwestern States went ahead on our own and commenced our replacement and also type of conversion in our respective companies. We didn't need the bill. We were doing things before the bill was set up.

Mr. Moffett. So the bill brings——

Mr. Oprea. It means nothing except that it does have a real threat to all of us.

Mr. Moffett. We are talking about good things now. Nothing good?

Mr. Oprea. If the good things represent an efficient, reasonable, legislative package that has a good timetable, that allows us to do it in an orderly way, whereby we are not going to cause economic chaos in our areas to the consumers, the same that we talk about as being the general public. If we have that type of rational, reasonable approach whereby you look at the regional situation instead of just carte blanche treating the entire country as one package and subject all the same rules on every one of the utilities—then you have problems. And I think then the bill is onerous, and it is going to be a horrendous thing for the utilities to implement of the plans that will materialize to the point of being fully on coal.

Mr. Moffett. Are they really doing that? Are they really treating the country as one? Aren't they also saying they are going to take special circumstances?

Mr. Oprea. The wording is so generalized we don't know what the bureaucracy's interpretation will be of the generalized wording.

Mr. Riddell. I can disagree with that to some extent. I speak with respect to existing law. I join in every comment that the gentleman said that this package can do great good for the country because it frees us from a dependence and gives us an additional option, but only if you permit us a timetable with which we can live.

But let's take existing law and FEA's administration of that law. There were orders, and they are being contested all over the country today, with respect to plants in progress. Now, there is no way if FEA issues orders that we can comply with those orders, and I tell you my hole in the ground will stay a hole in the ground.

If I cannot get a combustor in 7 years, what is the point of telling me I have to burn coal? We will abandon the project and walk away from it.

Mr. MOFFETT. Before we close, I want to get to this question of FEA and its relationship to industries such as yours, just for a moment.

You have given us some very useful anecdotes relating to problems with FEA. I have many of them from my own area, with my own industries having problems with FEA. What should we be doing to improve that situation?

I know generally we should get the government off our backs, let's not have so much bureaucracy. We hear that all the time. We do pay some attention to that. I am talking in terms of your relationship directly and the utility's relationship with FEA. How can that be improved so you will have more predictability, access, and more certainty in terms of what you can and cannot do, more responsiveness from them?

Mr. RIDDELL. Again, only a practical suggestion; that is to say, that FEA be instructed as a matter of policy, not legislation, that it take into account facts; that is to say, the availability of materials and sources of supply in the issuance of its orders.

All of us wish to do right by our customers. We want to produce a product at the lowest available price. But, we know that natural gas is a thing of the past. We are gravely concerned about our dependence upon oil. We want the additional option that coal will provide. But, it cannot be accomplished by fiat.

We have to convert in real world terms, in a timetable that permits us to do it. But, let me ask you a question. What sense does a tax and rebate system mean? It simply impairs the working capital position of every one of the utilities in the United States, and every other business. You take away as a disincentive from the airline industry in the form of tax, and my industry in the form of a tax, and you say you are going to rebate it to us.

All right. How many dollars is that and what is the function of the multiplier of the going rate on that sum, and how much working capital does that take out of the country? It makes no sense. You can by fiat say that the American people will live with a system of coal conversion. You simply issue orders and say that by a certain reasonable timeframe it will be done.

Please, sir, don't enforce it by a meaningless tax that is going to force interest rates up and impair the working capital of every business in the country. If you boil the money out of us, put it in the public, we have to go to the banks and borrow the money. I mean you have impaired the working capital at the time we can least afford to do it.

You are telling us, do the job. Do the job means spend money. At the same time, you are taking the money away as a tax and forcing me to go to the bank and borrow the money. It doesn't make any sense.

Mr. MOFFETT. Let me ask this question. Does the new energy reorganization hold any promise of having a better system as far as you are concerned in your relationship with the government? Yes or no?

Mr. BAGGE. I would like to say organization is not going to contribute substantially to the resolution of this problem one iota. We heap reorganization on top of reorganization. Yet, we don't deal with the root causes. If I may say so, sir, as I tried to say before on behalf of the coal industry, this bill does not begin to deal with the root causes which are the constraints of both production and the utilization of coal in this Nation today. We are trying to mandate it under a system, when at the same time we are asking for both guns and butter.

Everybody was asked to make a sacrifice. The President called for sacrifices from the coal industry, from industry generally, the utilities, the American public. But the environmentalists of this Nation have not been asked to sacrifice one inch to make the system go. That is what I find to be the real tragedy.

If we are telling you anything, we are telling you not to pass section F of this bill because it is not going to work.

Mr. MOFFETT. I don't know. Mr. Bagge, I am not sure I agree with your comments about the environmentalists not being asked to sacrifice. You make it sound as if they are running a company and have an economic interest. There are billions of dollars of health costs every year where things involve some sacrifice for some people.

Mr. BAGGE. We are not arguing the health costs.

Mr. MOFFETT. I understand. The Department of Energy, on the reorganization——

Mr. ALLEN. Could I respond. I think as an ex-lawyer and also old enough to be something of a philosopher, I can add one paragraph that would help.

I think you have a similar problem in the ESECA program and in the whole Department of Energy program. You start off with the proposition that here is something required in the national interest, we should give some strong administrator the powers to get the job done and order him to get it done, and call him to account if he doesn't. He responds and says, "Give me full powers and I will get it done for you." Then it turns out some of the things you ask him to get done are going to cost somebody a great deal of money.

There must be some kind of dialogue here. If I am going to be asked to pay a lot of money, I want to know at least that the person who is ordering me to do this is aware of what he is ordering, and that my sacrifice is worthwhile in the national interest.

This is the crucial problem of administrative law. I know Mr. Bagge from his FPC days is aware of it. We can get terribly bogged down in administrative trials, endless hearings. This happens all over the lot. So here we have taken the rulemaking route, the strong man route, and we have said in ESECA, the only hearings you will have will be legislative type—no criticism implied—but basically that is a chance to "crawl on your knees," as Mr. Riddell says, and be heard, but not find out really what goes on in agency thinking.

We saw a huge multiplication of the agency form of administration under the New Deal. Some of yesterday's liberals put a great deal of effort into this problem. Out of the Administrative Procedure Act we got the one principle that he who has the commitment to do and to order, the programmatic commitment, should not also try to sit in judgment. We must separate these roles within the agency.

Second, in more recent times the District of Columbia Circuit Court has done very important thinking in this area, saying there are some rulemaking proceedings which have such an immediate impact that if somebody can really narrow down an issue that ought to be looked at, he ought to have a chance to have the programmatic fellow, the doer, and his bureaucracy stop, look, listen, and pay attention to him.

We are beginning to see this hybrid rulemaking develop, where in certain limited cases you are entitled to cross-examine the guy who is carrying out the program, ask that somebody who is detached on his staff take a really careful look and advise him before he moves. That is where we ought to go in ESECA; that is what I have been trying to suggest written in my testimony.

It is the same very broad problem that has to be faced with the Department of Energy. The compromise is never clear, but clearly when you set up a new program—I don't care what it is, whether it is to get buttons made or get energy out there—you must also build in some restraint, some chance for the citizen to speak up before the man who is told to do the job at any cost is cut loose and can ask everybody for unknown sacrifices without their having their day in court.

The problem doesn't solve easily, but we have to keep working on it.

Mr. BROWN. If the gentleman will yield, even the Congress has come very close on a couple of votes recently, and I think maybe subsided on a couple of them, in wanting that opportunity with the bureaucracies. It was sort of an outgrowth of a guy who decided there should be no more mother and daughter banquets. We just felt maybe they had gone one step too far, and we ought to get a chance to look at some of those things.

But when we had our hearing last night, I think it became clear that the DOE would like the Congress to keep its nose out of this.

Mr. RIDDELL. Mr. Brown, I go back to your father's day. Oversight was oversight. It wasn't a partnership. If you are going to pass laws, and you are going to pass them, then you owe a real responsibility to oversee their administration.

Now, the problems that I brought to you this morning, I am without voice in. When I say that I crawled, I mean literally I crawled. When I found the man who had it upon his desk, he was frank with me. He said, "Mr. Riddell, I would like to solve your problem, I would like to take it up. But, you have to go find a boss of mine who will give me permission to do so."

Now, I spent 5 days trying to talk to one of those bosses. You know what? They were out to lunch, they were in a conference. And no one will deny the tale that I am telling you, because it is documented.

Mr. MOFFETT. On that note, we are going to recess until 2 o'clock. We want to thank you gentlemen. I think you have added a great deal to our considerations. Thank you very much for being here.

The committee stands in recess until two o'clock.

[The following letter was received for the record:]

NEW ENGLAND ELECTRIC SYSTEM
20 TURNPIKE ROAD
WESTBORO, MASSACHUSETTS 01581
TELEPHONE 617-366-9011

RECEIVED
MAY 31 1977
Energy & Power Subcommittee

May 27, 1977

Subcommittee on Energy and Power
House Committee on Interstate and Foreign Commerce
Washington, D. C. 20515

H.R. 6831: coal conversion provisions

Dear Sirs:

The following information is submitted in response to requests by Representative Brown, supplementing my testimony on May 25, 1977.

A. A comparison of FEA and Company estimates for coal conversion of New England Power Company generating units.

As pointed out at page 5 of my written statement, differences between the two estimates involve virtually all major variables. FEA appears to assume that the non-conforming coal can be burned without use of scrubbers. The Company estimates shown are for a scenario which assumes no change in the Massachusetts state implementation plan, in which case scrubbers would be required.

Brayton Point (3 units, 1147 MW)	FEA estimate	Company estimate
A. Additional capital costs	$76,275,000	$246,000,000
B. Additional annual carrying charge	16,675,000	68, 654,000
Additional annual operating expense (ex fuel)	12,365,000	38,285,000
Fuel savings	[52,361,000]	[9,239,000]
Net gain (cost) to consumer	$23,321,000	($ 97,700,000)

Salem Harbor (3 units, 314 MW)	FEA estimate	Company estimate
A. Additional capital costs	$39,997,000	$92,000,000
B. Additional annual carrying charge	9,687,000	37,038,000
Additional annual operating expense (ex fuel)	3,813,000	7,234,000
Fuel savings	[10,022,000]	[3,072,000]
Net gain (cost) to consumer	($ 3,478,000)	($41,200,000)

B. A caomparison of total capital cost and annual operating expense for "typical" new generating units using gas, oil, coal and nuclear fuels.

The figures below are current New England estimates for generating units to go on line in 1985. Estimates for particular sites and plant designs would, of course, vary from these normalized figures. We do not have estimates for gas-fired units, but understand that no new gas-fired units have been ordered by the utility industry for service in this time frame.

	Capital costs/KW	Total costs/KWH
Nuclear	$ 1150	55 mills
Coal (with scrubbers)	$ 975	82 mills
Oil (without scrubbers)	$ 800	82 mills

The difference in capital costs between the coal and oil plants is a good approximation of the cost of pollution control equipment.

C. Costs of delay of Seabrook nuclear project resulting from conflicing decisions of NRC and EPA Regional Office on water discharge requirements.

Public Service Company of New Hampshire estimates that the six-month delay to date will add $90,000,000 to the capital costs of the project.

Yours very truly,

DGAllen

D. G. Allen

DGA:paj

cc Hon. Clarence J. Brown

[Whereupon at 12:55 p.m. the hearing was adjourned to reconvene at 2:00 p.m.]

AFTER RECESS

[The subcommittee reconvened at 2 p.m., Chairman Staggers presiding.]

Chairman STAGGERS. The committee will come to order. We will start with our witnesses. I am sure we will have some other members of the committee here momentarily because the second bells have rung. They promised they would be over here right away.

We have two very distinguished witnesses before us today, two young Governors of our States. I would like to compliment both of them for taking the time to come and be with us today on one of the most important issues that face America today, and that has to do with energy. They are dealing with something that we have plenty of in both the States.

I would like to say that they have both been bright stars on the political horizon, too. Not only that, but they are intellectually two of our fine young intellectuals in the United States that are certainly capable of going further than they are now. You may say they don't have much further to go. But there are further places to go. I am not speaking politically. I remember introducing a young man in Morgantown, West Virginia, one time, saying that he had all of the qualifications and all of the things needed to be President of these United States. And I am saying the same thing today.

I would just like to say that I welcome Governor Carroll of Kentucky to the meeting and to say that we are honored to have him as the Governor here to give us his views. I wish more Governors of the United States would come in to take the time to give us their views.

In all the years I have been chairman and served on the committee, very few Governors have taken the time or have shown the interest to come here and give us their views from the States. For that reason, I am especially appreciative to both of you for being here.

Governor Carroll is the Governor of Kentucky. He will be the first witness.

I would like to introduce my own Governor here, sitting on the right of Governor Carroll—Governor John D. Rockefeller IV. I think we have heard that name in America a few times. We call him Jay over in West Virginia. Jay came to West Virginia, working as a VISTA worker, working with the poorer groups of people. He worked hard at the job. He saw some of the problems that had to be done and he helped to do that job. He ran for Member of the House of Delegates, was elected Secretary of State and now is our Governor.

Governor Rockefeller, it is a pleasure and honor for me to introduce you and Governor Carroll both, and to have you here as our witnesses today.

As I say, I wish more Governors would come to give us the benefit of their views.

At this time, if you don't mind, I will turn this over to Mr. Moffett of Connecticut, who will preside while I go over and vote and I will try to get back and be with you then.

Thank you.

Mr. MOFFETT [presiding]. I would like to also welcome you and say how pleased we are to have both of you here today.

Governor Carroll, would you like to begin.

STATEMENTS OF HON. JULIAN CARROLL, GOVERNOR, STATE OF KENTUCKY, AND CHAIRMAN, COMMITTEE ON NATURAL RESOURCES AND ENVIRONMENTAL MANAGEMENT, NATIONAL GOVERNORS' CONFERENCE AND HON. JOHN D. ROCKEFELLER IV, GOVERNOR, STATE OF WEST VIRGINIA, AND CHAIRMAN, COAL SUBCOMMITTEE, NATIONAL GOVERNORS' CONFERENCE

Governor CARROLL. Thank you very much, Mr. Chairman. We deeply appreciate the comments of the chairman of the parent committee upon his retiring from the room. As a matter of fact, I believe on count of my staff this is the ninth time that I have testified in the current year. At the rate I'm going, I am going to probably set some kind of record for myself as well as maybe the other Governors in the number of times I get to the Hill this year to testify.

Of course, there are so many subject matters that relate to the jurisdiction that I have in the National Governors' Conference it dictates that I come quite often, particularly in the formulation of the President's national energy policy.

Mr. Chairman, I served as the Chairman of the National Governors Conference Committee on Natural Resources and Environmental Management, and the distinguished Governor of West Virginia to my right, Governor Jay Rockefeller, serves as my lead Governor and Chairman of my Subcommittee on Coal.

We both come today really in two capacities—not only in our capacities as spokesmen for the National Governors, but we also come in the capacity of being the Governors of the two leading coal States in the United States. My own State of Kentucky produces about one-fifth of the coal consumed in the United States, and thus we are extremely interested in the subject matter before the committee today.

Mr. Chairman, I think it might do well for the record for me to summarize my testimony very quickly and file it for the record. I don't like to read testimony. It is something that is easy for anybody to do, to read. That is something you and your staff can do at your pleasure. I really prefer to generally touch on my testimony and hopefully not make it extended, but point out some various aspects of it that I think the committee would be interested in.

I think a good start would be for me to give you a concise statement of the policy of the National Governors' Conference with respect to utilization of coal.

At the last meeting of our Conference, we adopted a position statement that provided for a phase out as rapidly as possible of those existing natural gas facilities which do not represent the wisest and best use of natural gas under current circumstances.

Thus, we strongly support, in the National Governors Conference, the conversion to the use of coal where we are now using gas and oil so that we can utilize our natural gas, our butane gas, and our other oil resources for higher and wiser use.

In talking really about some of the problems that we have in the coal industry that relate very much to the subject matter that you have before you now on the Coal Utilization Act, I guess one of the major problems that we have to start with is the market itself. After all, in the whole atmosphere of discussion of whether or not you can take a product and properly utilize it relates primarily to the question of whether or not the product is available.

Well, we have plenty of coal in the United States. That coal, of course, is primarily in the ground with a little of it in stockpiles at the moment.

A lot of our coal, of course, is deep mined. A lot of our coal is strip-mined. But the major problem that we need to touch upon first is what we call primarily the production of that coal. We will later touch on the question of transportation of the product.

In 1975 we had what might be called a very tight market for coal. Spot prices were high and the coal was moving rapidly in the marketplace, because of a great demand that year for coal. It didn't take long for that demand, though, to subside, and we came to 1976, in which we had a great oversupply of coal.

Certainly the committee would appreciate the fact that in an industry such as the coal industry, you have a substantial amount of lead time involved, not only in establishing the locations of your mining activity, but you also have the problems of investing in major expensive, highly technical equipment that performs the production functions.

It is not easy to get in and get out of the coal business unless you are interested in going broke. I guess that is the easiest way to get out of it, simply go broke and let somebody else have all your equipment.

Most often this equipment is bought as a result of borrowing and then with some anticipation of long production records that will help make the payments on that equipment.

So we have major problems associated with a proper planning of production schedules.

I say to you in all honesty that one of the major problems that we will face in the whole field of coal utilization is trying to make a proper estimate, a realistic estimate, of the magnitude of the coal that will be demanded by the nation so as to prepare our market for that production and then, of course, the transportation of that coal into the marketplace.

You are well aware, of course, of the 1974 act that is designated the National Energy Supply and Environmental Coordination Act, that supposedly was to do exactly what we are primarily concerning ourselves with right now. But the committee is, of course, more aware than I am that that act really was very burdensome and complicated and quite honestly did not stimulate the utilities or the industrialists to convert to the use of coal.

When you start talking about that conversion, as they found out under the ESECA, you run into a substantial amount of difficulties, and those difficulties are the primary points that I want to touch upon today.

I guess one of the major points to start with respect to coal conversion comes from a subject that is very much in discussion on the floor of the House today, and that is, of course, the clean air amendments.

It is our effort, particularly my personal effort, to support a concept that we call, and I am sure the administration and the committee equally call it, the best available control technology. We believe that to be a sound principle, a principle that can be supported, not only in fact, but can be supported philosophically. If we are to maintain clean air standards throughout the United States, then obviously we have got to use the best technology available in order to achieve those results.

Quite honestly, when you talk about the coal of the United States, you primarily divide your coal into two major regions of eastern and western coal, the eastern coal having a sulfur content of approximately three times as much as the sulfur content of western coal. On the other hand, the western coal has a Btu content of only about half that of the eastern coal. Therefore, a nationwide policy that relates to utilization of coal with respect to the clean air amendments will indeed make both of those markets equally competitive, whereas at the moment, quite honestly, there is an amount of favoritism shown the western coal market that is causing and will continue to cause the eastern coal market some problems with respect to production of our coal and the use of our coal.

Approximately 73 percent now of all the natural gas utilized as boiler fuel or fuel for generation of electricity is being used by four States—the States of California, Louisiana, Oklahoma and Texas. Therefore, the capital investment demands that will be required in those four States for the conversion of their present gas and oil burning facilities over to coal will be a major one.

We know that additionally many of those facilities will have some problems totally converting to coal. Some consideration should be given, therefore, even to those utilities for some use of gas, particularly for peaking and particularly for other technical support in order for them to maintain their high level of efficiency.

With respect to some of the other problems associated with that conversion, obviously the committee is well aware and has heard testimony on and will continue to hear testimony on the problems of incentives to try to get these various companies to convert from their present gas and oil usage over to coal.

I might share with you just one major problem that I would estimate the committee will have in trying to formulate a policy, an effective policy, and that the industry will have in trying to follow that policy.

In the whole public utility business, you have to clearly understand that there are two competing motives involved in pricing. One of those motives, of course, is involved in what we generally call simply a net profit, in the operation of a private enterprise, which net profit is paid to the stockholders.

Another principle involved in that whole process is the pricing of the product that simply does nothing more than flow through the cost of furnishing the product. Therein lies a somewhat sharp difference of opinion that you probably are going to find when you start talking about incentives on the one hand and then on the other hand penalties in the nature of tax principles that are imposed on those who do not follow out the policies of the act.

Now, permit me very quickly to follow through with you what I estimate is going to happen.

With the principle of tax incentives you are going to find the utilities willing to convert using tax incentives, write-offs, accelerated depreciation, simply because that is most advantageous to the stockholder. They will be making a greater net profit in the operation of their business, using accelerated write-off and depreciation; whereas on the other hand the payment of a tax penalty is a flow-through which is finally paid by the consumer. In most of the regulated utilities throughout the United States they will have no problem at all taking that tax and flowing it through their rate structure and simply getting it returned to them in the form of a consumer payment.

Therefore, I suggest to you that when you look upon the whole problem of getting utilities, particularly regulated utilities, to convert from gas and oil over to the use of coal, that the whole problem of tax penalties is one that if it is not handled carefully and considerately, will end up in substantial increase in prices, and that is in the cost of fuel to the consumer.

On the other hand, incentives is a proper incentive on the part of the utility that will encourage them on that end to go on and make the transfer and then write it off, increasing the net profit to their stockholders.

The other major area that I should comment on that particularly relates to our State, and I am aware of some other States that have similar transportation problems, and that is getting the coal from the mine mouth to the market. That is not a simple task. It is a major problem in our State, and one of the major difficulties I have had in Kentucky is trying to maintain our roads sufficiently to get the coal from the mine mouth to the market.

In most States, particularly in the mountainous regions, road construction at its best is expensive and difficult. Most roads are built as a result of cuts and fills, and if you know anything about the whole principle of cuts and fills you know in the process of road building when you make a cut you leave the potential for a slide, and when you make a fill you have potential for settlement, and then when you start putting a considerable amount of weight on it, as a result of increased traffic, you have all kinds of problems, and then you have a severe winter with freeze and thawing, like we have just gone through this particular winter, you have a disastrous situation in your State, and we have that in Kentucky. I know a lot of the other States have it as a result of the same kind of freezing and thawing problems in their particular States.

We have done our best in Kentucky to control the amount of weight of those trucks on those roads, and quite frankly this coming January we are implementing a new court system in our State, that is a State system and no longer a county system, that will help us increase the control and activity over the problem of too much weight on those roads, but that still doesn't solve our problem of getting the coal from the mine mouth to the market, and so we have suggested very strongly that we feel like a part of the cost of supplying that coal to the marketplace includes the cost of transportation, and to that extent we should have some assistance in building the necessary roads to get it to the marketplace.

Quite frankly, the State of Kentucky at this very moment has already authorized this year alone bond issues in the amount of $200 million to build such roads in our State, and we simply do not have the financial capability to continue that kind of funding for coal transportation in our State, and I am sure the same thing is true in every other State. So coal transportation is a serious problem not only from the mine mouth to the marketplace, additionally it is a problem by rail. It is particularly by rail as the committee is well aware as it relates of course to cars.

Mr. Chairman, I have only one other quick area that I want to mention because I want to certainly leave a good amount of time for my fellow Governor from West Virginia to discuss some of the problems that relate to his particular subcommittee in his own State.

The last area that I would like to mention very quickly is one that we additionally call coal conversion, but in this instance we are speaking primarily of liquefaction or gasification, solidification, which means changing the texture of the coal into some other texture that might be utilized in some form other than its raw form as a coal product.

We now have under construction in Kentucky the first liquefaction plant in America to convert coal from its present form into liquid. We have a plant authorized already in Kentucky, and I hope to be breaking ground for that plant within the next month that will convert coal from its present form into gas.

I must say to you in all honesty we have had an extreme amount of difficulty in our relations with ERDA, in getting them to support our projects, and them changing signals just about as fast as we draft proposals, but I can suggest to you that it is our judgment that one of the best means by which coal can be utilized and can be utilized with full protection to the environment as well as utilized without all of the difficulties of transportation of the heavy product to the marketplace is the system of converting coal by way of liquefaction, gasification or solidification into some other form of energy.

We are proceeding well with that in Kentucky and to the extent that the committee can address that portion of the problem it would be extremely beneficial not only to us in supplying the marketplace with energy, but certainly convenient for the rest of the Nation.

Mr. Chairman, it now gives me great pleasure to offer to the committee a distinguished young Governor, who has already been introduced by the previous chairman of the parent committee, who is, of course, a member of the congressional delegation from his home State.

Mr. Chairman, it is my pleasure to present my very good friend, Governor Jay Rockefeller of West Virginia.

[Governor Carroll's prepared statement follows:]

STATEMENT OF GOVERNOR JULIAN M. CARROLL

I AM PLEASED TO BE HERE TODAY. MY REMARKS TODAY REFLECT BOTH MY INTERESTS AS GOVERNOR OF A MAJOR COAL-PRODUCING STATE AND AS A REPRESENTATIVE OF THE NATIONAL GOVERNORS' CONFERENCE. I AM HONORED TO SERVE AS CHAIRMAN OF THE CONFERENCE'S COMMITTEE ON NATURAL RESOURCES AND ENVIRONMENTAL MANAGEMENT WHICH, AS YOU MAY KNOW, HAS NGC JURISDICTION OVER ALL ENERGY-RELATED MATTERS, JAY ROCKEFELLER SERVES WITH ME ON THIS COMMITTEE AND I HAVE ASKED HIM TO BE LEAD GOVERNOR OF OUR SUBCOMMITTEE ON COAL.

THE ISSUE OF COAL AS A MAJOR RESOURCE IN OUR ENERGY MIX OF THE FUTURE IS ONE THAT WILL COMMAND OUR FULL ATTENTION AND HAS OUR ENTHUSIASTIC SUPPORT. THERE ARE OBVIOUS CONDITIONS THAT DICTATE THIS HIGH PRIORITY FOR COAL. I WILL NOT ELABORATE ON THEM AT THIS TIME AS THEY ARE WELL KNOWN TO US ALL.

HOWEVER, I WOULD SUGGEST THAT WE MUST PROCEED ON A COURSE THAT ENABLES US TO TAKE OPTIMUM ADVANTAGE OF THIS VITAL ENERGY RESOURCE AND FUEL IN SUCH A WAY THAT HAS A LASTING POSITIVE IMPACT UPON THIS NATION -- IN BOTH ITS COAL-PRODUCING AND COAL-CONSUMING REGIONS. WE CANNOT AFFORD A REPEAT OF THE NONE-TOO-WELL THOUGHT-OUT POLICIES AND HAPLESS MOMENTUM OF THE PAST IN DEALING WITH THE UTILIZATION OF OUR INDIGENOUS ENERGY RESOURCES. THIS PORTION OF THE LEGISLATION AND IMPLEMENTING THIS ADMINISTRATION'S PLAN AND THE CONCEPT BEHIND IT GIVES US GREAT HOPE FOR THE FUTURE. CERTAINLY, MUCH DISCUSSION IS AHEAD, LEADING TO THE BEST BILL POSSIBLE.

THE NATIONAL GOVERNORS' CONFERENCE AND OUR COMMITTEE HAVE ADOPTED POLICY POSITIONS CALLING FOR A NATIONAL PROGRAM TO "PHASE OUT AS RAPIDLY AS POSSIBLE THOSE EXISTING NATURAL GAS FACILITIES WHICH DO NOT REPPESENT THE WISEST AND BEST USE OF NATURAL GAS UNDER CURRENT CIRCUMSTANCES."

THEREFORE, WE COLLECTIVELY ENDORSE THE MOVEMENT TOWARD CONVERSION TO INCREASED COAL UTILIZATION IN THIS LEGISLATION AND ARE MORE THAN WILLING TO COOPERATE WITH THIS COMMITTEE AND THE ADMINISTRATION TO WORK OUT ANY SPECIFIC PROBLEM AREAS THAT MAY NEED TO BE ADDRESSED IN ORDER TO INSURE THAT THE CONVERSION TO COAL IN BOTH ELECTRICAL UTILITIES AND MAJOR FUEL-BURNING INSTALLATIONS WILL BE CARRIED OUT IN AN EQUITABLE AND RESPONSIBLE MANNER.

AS THE MEMBERS OF THIS COMMITTEE ARE WELL AWARE, ONE OF THE MAJOR FACTORS THAT IS INHIBITING DEVELOPMENT OF COAL RESOURCES IS THE LACK OF CONSISTENT AND PREDICTABLE MARKET DEMAND AND STABILITY. THE COAL INDUSTRY IS UNABLE TO FORECAST WITH ANY CERTAINTY A LONG-RANGE MARKET DEMAND. THEREFORE, IT CANNOT ATTRACT THE INVESTMENT NECESSARY TO INCREASE SUPPLY. MARKET FORECASTS THAT HAVE BEEN MADE IN THE PAST HAVE NOT BEEN FULFILLED, DUE TO THE VACILLATING NATURE OF ENVIRONMENTAL REGULATIONS AND THE LACK OF A CONSISTENT NATIONAL COMMITMENT TO CONVERT EXISTING ENERGY SYSTEMS AND TO CONSTRUCT NEW ENERGY-BURNING FACILITIES TO UTILIZE COAL OR COAL DERIVATIVE FUELS.

IN EARLY 1975, THE COAL INDUSTRY WAS EXPERIENCING A DRAMATIC TURNAROUND. AT THAT TIME, THERE EXISTED A TIGHT MARKET, EXEMPLIFIED BY VERY HIGH SPOT MARKET PRICES, RAPID DROPS IN STOCKPILE LEVELS, AND INCREASED SURGE TYPE PRODUCTION CYCLES. SEVERE CONSTRAINTS WERE FACING THE INDUSTRY, INCLUDING LONG LEAD TIMES ON EQUIPMENT, LABOR SHORTAGES, AND A MORATORIUM ON FEDERAL COAL LEASING.

SUBSEQUENTLY, THE TIGHT MARKET SITUATION MOVED TO AN OVER-SUPPLY SITUATION, DUE TO A LARGE QUANTITY OF SURGE PRODUCTION AND NEW MINE CAPACITY, AND LOWER THAN EXPECTED CONSUMPTION BY ELECTRIC UTILITIES AND COKING PLANTS.

SPOT MARKET PRICES HAVE FALLEN TO LOW LEVELS; STOCK LEVELS ARE HIGH THE MARGINAL MINES HAVE BEEN CLOSING. THESE IN SUMMARY, ARE THE KINDS OF PROBLEMS THAT WE MUST DEAL WITH IN ATTAINING THE LOFTY GOALS OF THIS LEGISLATION.

THE MANDATE THAT WAS GIVEN FEA IN 1974 UNDER THE ENERGY SUPPLY AND ENVIRONMENTAL COORDINATION ACT (ESECA) THAT REQUIRES THOSE INSITUTIONS CAPABLE OF CONVERTING TO COAL TO DO SO, AND TO INSURE THAT NEW FACILITIES HAD THE ABILITY TO DO SO, WAS THE PRECEDENT TO THE ACT NOW PROPOSED. ESECA, AS WAS NOTED BY FEA ADMINISTRATOR O'LEARY, "REQUIRED FEA TO SELECT EXISTING FACILITY CANDIDATES WITH THE BURDEN OF PROOF RESTING ON THE FEA TO MAKE A SERIES OF STATUTORY FINDINGS IN EACH CASE."

THE RESULTING PROCEDURES THAT WERE DEVELOPED TO IMPLEMENT THE EARLIER LEGISLATION WERE INDEED BURDENSOME AND COMPLICATED AND DID NOT STIUMULATE THE UTILITIES TO TAKE POSITIVE ACTION. THE PRESIDENT'S PROPOSAL CORRECTS SOME OF THE PRINCIPAL ADMINISTRATIVE PROBLEMS. IT PROVIDES THE OPPORTUNITY TO THE COAL INDUSTRY AND THE COAL-PRODUCING STATES TO BETTER FORECAST COAL DEMAND.

COAL IS AVAILABLE, AND ANY MOVE TO CONVERT TO COAL MUST BE VIEWED AS A POSITIVE STEP. THE USE OF COAL AS A BOILER FUEL IN INDUSTRY AND UTILITIES IS A VERY LOGICAL CONCEPT. THERE ARE DIFFICULTIES IN ACHIEVING A SMOOTH TRANSITION, HOWEVER, AND THOSE ARE THE ISSUES WE MUST ADDRESS. AS I HAVE PREVIOUSLY STATED, WE MUST PROVIDE FINANCIAL INCENTIVES THAT PERMIT WORKABLE AND ACCEPTABLE MEANS TO ENCOURAGE THE CONVERSION AS EXPEDITIOUSLY AS PRACTICABLE WITHOUT UNDUE HARDSHIP TO CONSUMER AND INDUSTRY ALIKE. THE TIME FRAMES FOR THE CONVERSION ENVISIONED ARE MOST REALISTIC AND THE CONCEPT OF TAX CREDITS FOR OFFSETTING INVESTMENT LEVELS IS PREFERABLE TO OTHER FORMS OF INCENTIVES HERETOFORE MENTIONED SUCH AS LOAN GUARANTEES.

ANOTHER MAJOR FACET THAT THIS BILL ADDRESSED, OF COURSE, IS THE IMPACT OF THE PROPOSED CLEAN AIR ACT AMENDMENTS ON THE FUTURE INCREASED USE OF COAL. THIS COMMITTEE, I AM SURE, WILL BE WORKING HAND-IN-HAND WITH THE OTHER COMMITTEES OF THE CONGRESS NOW DELIBERATING CLEAN AIR LEGISLATION, TO INSURE THAT THE INTENT OF THE BILL PRESENTLY BEFORE YOU WILL NOT BE CONTRADICTED BY COMMITTEE ACTION ON THE PROPOSED CLEAN AIR ACT AMENDMENTS AND VICE VERSA. THESE TWO IMPORTANT LEGISLATIVE INITIATIVES MUST BE COMPATIBLE, AS I AM CERTAIN YOU ARE AWARE. WE HAVE AT THE NGC LEVEL TAKEN ACTION ON THE CLEAN AIR ACT AMENDMENTS. I WILL LEAVE WITH YOU TODAY, FOR THE RECORD, A COPY OF THAT POLICY.

WE GENERALLY SUPPORT THE BEST AVAILABLE CONTROL TECHNOLOGY REQUIREMENT FOR ALL NEW POWER PLANTS. THIS PROVISION WILL REDUCE THE TREMENDOUS ADVANTAGE CURRENTLY ENJOYED BY WESTERN COAL, BECAUSE OF ITS LOW SULFUR CONTENT. CONSIDERATION MUST BE GIVEN TO THE ENVIRONMENTAL PROBLEMS ASSOCIATED WITH THE RAPID DEVELOPMENT OF WESTERN COAL AND THE ECONOMIC REPERCUSSIONS THAT WILL ACCOMPANY ANY DECLINE IN PRODUCTION OF EASTERN HIGH SULFUR COAL. PERHAPS SOME ACCEPTABLE FORM OF INCENTIVE OR ECONOMIC EQUALIZATION SUCH AS THE UNIFORM NATIONAL SEVERENCE TAX ON COAL, WHICH I HAVE MENTIONED ON OTHER OCCASIONS, COULD BE PART OF THE ANSWER IN THIS RECORD.

WEARING MY HAT AS CHAIRMAN OF THE NATIONAL GOVERNORS' CONFERENCE NATURAL RESOURCES AND ENVIRONMENTAL MANAGEMENT COMMITTEE, I WANT TO BRING TO YOUR ATTENTION A FEW SPECIFIC PROBLEMS THAT INDIVIDUAL STATES MIGHT ENCOUNTER AS A RESULT OF THE PASSAGE OF THIS LEGISLATION.

APPROXIMATELY 73% OF ALL NATURAL GAS NOW UTILIZED AS BOILER FUEL FOR THE GENERATION OF ELECTRICITY IS BEING USED BY FOUR STATES: CALIFORNIA, LOUISIANA, OKLAHOMA AND TEXAS.

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THE CAPITAL INVESTMENT DEMANDS, THEREFORE, THAT WILL BE REQUIRED TO HAVE THESE FACILITIES CONVERT COAL WILL BE CONCENTRATED IN THESE STATES. MOREOVER, THE REQUIREMENT THAT CONVERSION FROM GAS BE 100% BY 1990 WILL WORK AN ECONOMIC HARDSHIP ON THESE STATES. THE COST OF CONVERSION OF THE LAST 10% OF GAS, USED FOR PEAKING, FAR EXCEEDS THE PER BTU COST OF CONVERTING BASE AND INTERMEDIATE LOAD GAS FACILITIES. CONSIDERATION SHOULD BE GIVEN TO ALLOWING EXEMPTIONS FROM THE PROHIBITION ON BURNING AS IN THE CASE OF GAS-FIRED PEAKING FACILITIES.

GIVEN THESE AND OTHER CONCERNS OF THE STATES THAT WILL BEAR THE IMMEDIATE IMPACT OF THIS LEGISLATION, THE COMMITTEE SHOULD ENDEAVOR TO SEEK SPECIFIC COUNSEL FROM THE GOVERNORS OF THOSE STATES.

AS CHAIRMAN OF THE NGC NATURAL RESOURCES AND ENVIRONMENTAL MANAGEMENT COMMITTEE, I AM WILLING TO ASSIST THE COMMITTEE ON THESE MATTERS.

ALTHOUGH WE ARE IN AGREEMENT WITH BOTH THE STATED PURPOSE AND THE GENERAL APPROACH OF THE LEGISLATION, WE DO HAVE SOME RESERVATIONS. FIRST, IT IS UNCLEAR AS TO HOW THIS BILL WILL IMPACT THE DEVELOPMENT OF SYNTHETIC FUELS SUCH AS THE GASIFICATION, LIQUEFACTION, AND SOLIFACTION OF COAL. A STRONG AND EARLY PROGRAM OF CONVERTING TO COAL COULD CONCEIVABLY FORCE MANY UTILITIES INTO DECISIONS FOR WHICH NEAR-TERM RESEARCH AND DEVELOPMENT MIGHT PROVIDE A BETTER ANSWER.

WE WOULD LIKE TO ENCOURAGE THE CONTINUED DEVELOPMENT AND, IN FACT, SUGGEST THE ACCELERATED DEVELOPMENT, OF NEW TECHNOLOGIES SUCH AS FLUIDIZED BED COMBUSTION, SYNTHETIC FUELS AND THE SOLVENT REFINING OF COAL. ALTHOUGH THERE IS NO STATED OR IMPLIED INTENT IN THE LEGISLATION TO DETER THE DEVELOPMENT OF THE SYNTHETIC FUEL INDUSTRY, OUR CONCERN IS THAT EARLY EMPHASIS ON CONVERSION MAY CAUSE LONG-RANGE DECISIONS TO BE MADE WITHOUT ALL OF THE POTENTIAL OPTIONS BEING INVESTIGATED.

A BASIC QUESTION RELATED TO THE CONVERSION TO COAL AS THE PREDOMINANT FUEL IN BOILERS IS THE QUESTION OF THE REMOVAL OF THE ENVIRONMENTALLY UNDESIRABLE ASPECTS OF COAL COMBUSTION. WE BELIEVE THAT THE REMOVAL OF THE SULFUR AND ASH IN COAL IS BEST ACCOMPLISHED, AND MOST EFFICIENTLY ACCOMPLISHED, IN PRE-COMBUSTION AS OPPOSED TO POST-COMBUSTION. WE, THEREFORE, CONTINUE TO ENCOURAGE THE ACCELERATED DEVELOPMENT OF NEW TECHNOLOGIES WHICH WILL MINIMIZE THE NEED FOR POST-COMBUSTION CLEANUP.

AS A COAL-PRODUCTING STATE, WE HAVE SEEN THE NEED TO PURSUE THESE TECHNOLOGIES, EVEN FROM A SMALLER PERSPECTIVE.

OUR ACTIVITIES INCLUDE THE FOLLOWING:

* WE WILL HAVE COMPLETED THE DETAILED ENGINEERING DESIGN OF A SOLVENT REFINED COAL PLANT AT A COST OF $5 MILLION TO THE TAXPAYERS OF KENTUCKY AND WILL BE SEEKING SUPPORT FROM THE FEDERAL GOVERNMENT TO CONSTRUCT A 2,000-TON-PER-DAY DEMONSTRATION PLANT THAT WILL BE EASILY EXPANDABLE TO A FULL SCALE COMMERCIAL ENTITY.
* THE KENTUCKY CENTER FOR ENERGY RESEARCH IS PARTICIPATING WITH TVA IN THE DESIGN OF A 200 MEGAWATT FLUIDIZED BED COMBUSTION DEMONSTRATION FACILITY SCHEDULED FOR OPERATION IN 1983. THIS DEMONSTRATION PROJECT COULD BE ACCELERATED BY TWO YEARS AND ALLOW THE FIRST LARGE-SCALE COMMERCIAL FLUIDIZED BED COMBUSTION FACILITY TO BE IN OPERATION BY 1986.
* AS A STRONG SUPPORTER OF THE DEVELOPMENT OF NEW TECHNOLOGIES TO ENHANCE THE UTILIZATION OF COAL, SINCE 1971 WE HAVE EXPENDED OR COMMITTED MORE THAN $66 MILLION IN THIS AREA AND WILL NEXT MONTH OPEN A NEW ENERGY RESEARCH LABORATORY AT THE KENTUCKY CENTER FOR ENERGY RESEARCH IN LEXINGTON.

WE THINK IT IS IMPERATIVE THAT OUR NATIONAL PROGRAM TO DEVELOP TECHNOLOGIES TO ENHANCE THE UTILIZATION OF COAL BE ACCELERATED IF WE ARE TO ACHIEVE THE INCREASED RELIANCE ON COAL SOUGHT BY THIS BILL.

IN ORDER FOR THE PROVISIONS OF THIS LEGISLATION TO BE IMPLEMENTED RESPONSIBLY, A NATIONAL PROGRAM MUST BE PLANNED TO TRANSPORT COAL IN AN ENVIRONMENTALLY COMPATIBLE MANNER THROUGH ALL PHASES OF COAL PRODUCTION SYSTEMS. THERE IS A NEED FOR A COHESIVE FEDERAL EFFORT TO ASSIST THE COAL-PRODUCING STATES IN MAINTAINING AND IMPROVING THE ROADS AND HIGHWAYS THAT ARE UTILIZED TO DELIVER COAL TO MAJOR RAILWAY TRANSPORTATION CENTERS, AND TO DEVELOP A NATIONAL DELIVERY SYSTEM, INCORPORATING ECONOMICALLY BENEFICIAL AND ENVIRONMENTALLY COMPATIBLE HIGHWAYS, RAILROAD LINES AND WATERWAY SYSTEMS. IN OUR STATE, WE BELIEVE ENERGY AND TRANSPORTATION ARE SYNONYMOUS AND MUST OF NECESSITY GO HAND-IN-HAND.

LET ME ELABORATE. KENTUCKY'S ROADS ARE INADEQUATE TO MEET THE PRESENT DEMANDS PLACED ON THEM BY COAL TRAFFIC, MUCH LESS THE INCREASED DEMAND THAT OUR FEDERAL GOVERNMENT HAS ESTIMATED WE WILL HAVE TO TRANSPORT TO SUPPLY OUR SHARE OF THE NATION'S ENERGY REQUIREMENTS. KENTUCKY'S FINANCIAL RESOURCES ARE SIMPLY INSUFFICIENT TO SUPPORT THE KIND OF PROGRAM THAT WOULD BE REQUIRED TO MEET THESE DEMANDS.

ANY NATIONAL COAL CONVERSION PROGRAM WILL NOT BE ENFORCEABLE OR ACHIEVABLE WITHOUT PROVISION OF ADEQUATE TRANSPORTATION. UTILITIES CANNOT BE REQUIRED TO INVEST IN FACILITIES TO ENABLE THEM TO BURN COAL AND THEN BE UNABLE TO OBTAIN IT BECAUSE OF A LACK OF A DELIVERY SYSTEM.

FINALLY, THE GOVERNORS OF THOSE STATES IN THE EAST AND WEST THAT WILL BE CALLED UPON TO DEVELOP OUR STATES' COAL RESOURCES TO SERVE THE NATIONAL DEMAND ARE CONCERNED ABOUT THE SOCIAL, ENVIRONMENTAL AND ECONOMIC IMPACTS THAT WILL NECESSARILY RESULT AS WE INCREASE DEVELOPMENT. I HAVE STATED HERE AGAIN TODAY MY INTEREST IN CONSIDERATION

OF A NATIONAL SEVERANCE TAX ON COAL TO HELP ALLEVIATE DISPARITIES BETWEEN COALS FROM VARIOUS REGIONS OF THE COUNTRY AND THE DIFFERING QUANTITIES OF THOSE COALS. THIS LEVY COULD WELL PROVIDE SOME EQUALIZATION OF REGIONAL AND DEVELOPMENTAL IMPACTS.

THIS PROBLEM MUST BE FACED. THERE IS NO INTERAGENCY MECHANISM DESIGNED TO COORDINATE ANY NEW OR EXISTING FEDERAL PROGRAMS WHICH WOULD BE USED TO DEAL WITH IMPACT SITUATIONS. BY COMBINING A BETTER COORDINATED EFFORT OF IMPACT ASSISTANCE PROGRAMS AND THE FUNDING THAT WOULD BECOME AVAILABLE AS A RESULT OF THE NATIONAL SEVERANCE TAX, WE COULD VERY ADEQUATELY ADDRESS THAT PROBLEM. A REAL LOOK AT THIS SHOULD BE TAKEN AS YOU DEVELOP THIS BILL.

IN CLOSING, I WOULD AGAIN ENDORSE THE INTENT OF THIS LEGISLATION AS REGARDS COAL CONVERSION. I WOULD ALSO STRESS THE IMPORTANCE OF THIS COMMITTEE'S WORKING HAND-IN-HAND WITH THOSE OTHER CONGRESSIONAL COMMITTEES DEVELOPING ENVIRONMENTAL, HIGHWAY AND OTHER POTENTIAL TRANSPORTATION LEGISLATION, AND WITH THE ADMINISTRATION IN ITS ENERGY POLICY PROPOSALS TO INSURE THAT THE LAUDABLE INITIATIVE CONTAINED IN THIS BILL IS NOT OFFSET BY OTHER ACTIONS. FURTHER, WE HAVE A VERY AGGRESSIVE PROGRAM ONGOING WITHIN OUR NGC NATURAL RESOURCES AND ENVIRONMENTAL MANAGEMENT COMMITTEE AND WE ARE READY, WILLING AND ABLE TO ASSIST YOU IN YOUR EFFORTS. OUR COAL SUBCOMMITTEE WILL BE LOOKING AT VARIOUS FACTORS INVOLVED IN INCREASING OUR DEVELOPMENT OF COAL AND OTHER ENERGY RESOURCES. HOPEFULLY, WE WILL BE ABLE TO PROVIDE NECESSARY DETAILS TO QUESTIONS YOU MIGHT HAVE AS YOU DELIBERATE THIS BILL AND OTHERS OVER THE WEEKS TO COME.

I TRULY APPRECIATE THIS CHANCE TO DISCUSS MY VIEWS ON THIS VERY FAR-REACHING AND NEEDED ENERGY INITIATIVE AND I ENCOURAGE THE COMMITTEE TO PURSUE IT AGGRESSIVELY WITH THE GOVERNORS OF THOSE STATES MOST AFFECTED AND THOSE EXPERTS IN INDUSTRY AND CONSUMER AFFAIRS WHO WILL HAVE MUCH TO OFFER. THANK YOU FOR ALLOWING ME TO COME AND BE HERE WITH YOU TODAY. I WILL BE DELIGHTED TO RESPOND TO ANY QUESTIONS THE COMMITTEE MAY HAVE.

NGC POLICY POSITION

AMENDMENTS TO THE CLEAN AIR ACT

The 1970 amendments to the Clean Air Act reaffirmed that States have the primary responsibility for control and abatement of air pollution. This role must be continued and further strengthened if the States are to solve successfully the complex air-pollution problems that exist throughout the nation. The nation's Governors believe that Congress must pass comprehensive Clean Air Act Amendments legislation which includes the following provisions:

1. Congress—and not the courts—must establish national policy on the vitally important issue of prevention of significant deterioration. Any significant deterioration policy established by Congress must provide for protection of air quality over lands of prime national interest. On all other lands, the Governors must have the exclusive authority to designate air-quality classifications and the responsibility for implementing the prevention of significant deterioration programs. As a component of any prevention of significant deterioration policy relating to new major emitting facilities, Congress should require the Environmental Protection Agency to determine the best available control technology, with state discretion, to establish more stringent requirements. The Environmental Protection Agency shall involve the States in BACT development prior to publication in the Federal Register of proposed rulemaking. Further, EPA shall review BACT regularly—with full opportunity for state participation—to incorporate subsequent improvements in control technology.

2. Accommodating growth in the nation's non-attainment areas, while at the same time maintaining a vigorous program to attain ambient standards, is one of the most challenging demands of the Clean Air Act. This can be accommodated within the current provisions of the Clean Air Act provided the deadlines for meeting ambient air-quality standards in non-attainment areas are extended beyond July 1977.

A revision to a state implementation plan which allows a new or modified air pollution source in a non-attainment area must be approved by the Administrator provided such revision insures orderly and significant progress toward overall emission reductions. A national policy which limits expansion to existing facilities in non-attainment areas may be detrimental to the economic well-being of many areas of the nation. In addition, EPA'S new "off-set" policy has certain flaws which may reduce its effectiveness. States should have the flexibility to select the strategy most appropriate to their circumstances, including but not limited to those above, in seeking to reduce pollution in areas not attaining national standards. If the sources of emission causing or contributing to a non-attainment problem are outside the jurisdiction of the affected area, EPA must require the necessary emission reductions in the source areas so as to effect achievement and maintenance of the air quality standards in the affected receptor area.

3. More time and additional federal funding are needed to solve the transportation-related pollution problems that exist in our cities. A federally funded planning effort and reasonable deadline extensions must be granted by Congress to insure that this complex problem is solved in a rational and coordinated manner.

4. The automobile industry should be required to meet existing emission standards as expeditiously as is practical. Vehicle warranties on emissions-related components should be of sufficient duration so as to not impose burdensome costs and responsibilities on motorists for maintenance and repairs. Further, any decision to postpone current statutory auto-emission standards should be accompanied by a concurrent postponement of deadlines for meeting ambient standards in order to avoid increasing the restrictiveness of state implementation plans.

5. Federal facilities must be required to comply with all state and local substantive and procedural requirements on control and abatement of air pollution.

6. The EPA Administrator should be required to notify a State before contacting an air-pollution source within that State concerning an implementation plan deficiency. States should be provided a reasonable opportunity to correct any deficiencies prior to any federal action.

7. Upon petition of a State, or upon his own motion after consultation with a State, the Administrator should be permitted to alter the boundaries of air-quality control regions to provide greater flexibility in developing control strategies tailored to local problems.

8. If a National Commission on Air Quality is established to review implementation of the 1977 Amendments to the Clean Air Act and recommend to the Congress future changes in the law, the Commission should have representation from the public, the nation's Governors and members of the congressional committees which have jurisdiction over Clean Air Act matters.

9. The law should be amended to prevent state agencies from losing federal program funds by providing for a waiver of the "maintenance-of-effort" provision where state funds are reduced as a result of an overall or "across-the-board" state budget reduction.

The 95th Congress should move swiftly to pass the 1977 Amendments to the Clean Air Act. Clear direction from Congress is necessary for the States to carry out their proper roles in air-pollution control without having to face continuing litigation based on uncertainties as to congressional intent.

STATEMENT OF THE HONORABLE JOHN D. ROCKEFELLER IV

Governor ROCKEFELLER. Thank you, Governor Carroll, and Mr. Chairman.

I want to introduce on my right, West Virginia State Tax Commissioner, Tom Goodwin, who has been helping me with many of these matters, and I want to introduce into the record also the testimony from which I will speak rather than read.

I want to touch really on just one area, which in the testimony that I listened to this morning, and the testimony that I have read in the past, the testimony that I have watched on TV and listened to on the radio, has not been addressed, and which I consider essentially to be the nub of the whole problem of production of coal for the United States of America.

One can argue as to incentives as opposed to penalties, as opposed to loans and grants as between the President's bill, Senator Jackson's bill. I happen to agree with what Governor Carroll has said. That is primarily a matter of economics, and with the proper tinkering and arrangement, those kinds can be worked out most advantageously.

The environmental questions are fundamental, but I think they will resolve themselves, or at least ought to resolve themselves in such a way that there will not be environmental compromise, but nevertheless protecting the environment does not produce coal. It protects the environment but it does not produce coal.

There can be discussions about technology for taking sulfur out of coal, various ERDA type technological experiments that are going on, but even that at this point is not producing coal.

The question to me then is not whether we can accommodate in the United States both the energy needs and the environmental goals. Instead, to me the real question is whether nonenvironmental, nontechnological, noneconomic restraints will prevent us from expanding coal production to meet the President's mandate of 1.1 billion tons by 1985.

It is my own feeling that the problem of productivity, the problem of incentive, and the problem of attitude of the worker, state of the worker in the future, of the miner, is at the crux of the problem. Let me give you the example in West Virginia.

Coal production in West Virginia has dropped on a per man per day basis from 17 tons per day per man 10 years ago to 9 tons per day per man today, or last year. That is a drop of nearly 45 percent productivity per man in 10 years.

In 1967, or 10 years ago, West Virginia produced 152 million tons of coal a year. Today we produce 109 million tons of coal per year. In 1967 we had 43,000 mines producing more coal than the 57,000 that we have producing less coal today.

How can that be? How can you possibly, at a time when the Nation is talking about more coal production, how can you look at the second major coal producing State in the Nation, Kentucky and West Virginia probably together having more, definitely together having more high Btu coal for the purposes of the Nation not only for the coming 5 years but for the coming 50 years, than any other two States in the Nation, and here is West Virginia's coal production going straight downhill even as our miners increase and the technology increases.

If you can answer the question, then it seems to me you come to precisely the problem. In fact, West Virginia would have met, or will meet, the President's national mandate for 1985 if we could only return to where we were 10 years ago.

People say it is impossible to produce 1.1 billion tons. We could be at that point today if we were where we were 10 years ago in West Virginia. Where do you look? Let's do some frank talking.

Extraordinary disharmony between management and labor in the coal industry, more so than any other industry, and those who are taking up coal mining better look to the example, to the history and to the words of those of us in Appalachia that have been dealing with this for a while.

There is, in my judgment, and the blame to be placed both on the union and on management, a total absence of mutual respect between the producer of coal and the miner of coal, and there are classic labor confrontations throughout America's history, but none which I think makes such impact on what is now held out to be the Nation's major domestic agenda, which is the production of energy for our future.

We are going to have contract discussions coming up in December. The coal miner making quite a lot of money today, I don't think economics is going to be the discussion. I don't think safety in the mines is even going to be the main thing. It is going to be something called the right to strike, the right to strike over a local grievance issue. I predict to you that the unions and the companies are going to hold to traditional, rigid, ideological, noncommunicating, bitter habits of treating each other across a bargaining table, which will bring this Nation to a strike of considerable length, and all the rest of us discussing the future of America and the production of coal and tinkering around with incentives and loans aren't addressing what is this fundamental block.

Therefore it comes down to me to being the key to finding what it is will properly bring the right incentive to the miner as expressed through the company and the union, to produce more coal each day.

Both labor and management must pursue that goal in harmony, which they have never showed before, and I might say that the courts are going to have to participate in this process also. If both sides are willing to cooperate, the production can go up, and rather than worrying about billions of dollars to be spent here, there, in new technologies, we could probably do a great deal, Governor Carroll, by simply taking the mines which are already in place and producing better productivity.

Miners wages have doubled in the last 10 years, so then why is it, you say, that the miner can't react to the classic American economic incentive? The miners average $290 a week. I have met people, a lot of people with master's degrees, and a number of people with Ph.D. degrees who work in the mines because they can make a lot more money in the mines 300 feet underground than they can make in a university or a college. That is smart, so it is not necessarily economic incentive.

Why doesn't that work? Well, let's look at where a lot of our coal miners have to live in terms of some of the problems they face. The housing, for example. In southern West Virginia where about 1 percent of the land is flat, what do people have to return to in the way of housing after they work all day in dangerous and difficult circumstances? Sure they are paid well, but what do they have to return to in the way of housing? What do they have to return to in the way of recreation? Governor Carrroll talked about roads. Nobody can understand, until they have been on roads that coal trucks, 45-ton coal trucks have worked, been over what those roads are like. Nobody can understand, until they have been into a coal mining community where there are so many trailers or mobile homes or coal company houses or former coal company houses which have been patched up and repaired, sometimes painted, and owned, understand the lack of recreational opportunities, the lack of fishing opportunities, the lack of health opportunities, the lack of transportation opportunities, all of these things.

If we intend to seriously, as a Nation, as makers of public policy at the national level, to address ourselves to energy in the United States of America, then we had better address ourselves to putting into those places from which the coal is mined the kind of money which is going to produce a right incentive for the miner to be able to say not only "Yes, I get paid a good wage" but "This is a good life. This is a life that gives me incentive for something more."

It is cultural. It is expensive. It is needed. Our basic coal producing States have not been able to do it yet, and as Governor Carroll says, we don't have the money. It is not a question of wages. It is a question of quality of life in coal mining communities.

You explain to me how you can take a couple of mines, I know, for example, in Kentucky, where miners on salary are mining 30 tons per day, nonunion. Then go across into, let's say, a State mine in West Virginia, where they are producing 9 tons per day union, and then go to England where everybody gave up and nationalized it, and miners who have been mining for years are producing 3 tons per day with the same technology 39-3. What it talks about is incentive.

It used to be that United Mine Workers of America had almost 80 percent of the production of the working miners of the country. Now they are down to 54 percent. They have so much to lose, they have so much to gain. The coal operators who have been bargaining as a unit all of these years, in my judgment, if we go into an extended strike this year they could break up and start negotiating on an independent basis and you will have the situation where a small group of miners in one of these States will shut down coal production for the United States of America, and it all goes down to the perception of the miner about his stake in America.

He feels he has been taken for granted. He has been taken for granted. He has been taken for granted in Appalachia and other parts of this country, and we, you of the Congress, and we in the State, are going to have to face up to the miner as a full person of pride, with full rights and with the full right to a better economic life for which the price of coal and we in government are going to have to pay.

[Governor Rockfeller's prepared statement follows:]

STATEMENT OF GOVERNOR JOHN D. ROCKEFELLER IV

Mr. Chairman, I appreciate the opportunity to appear before you to discuss coal and its increasing importance as an energy source.

I speak as the Governor of a major coal-producing state and as a representative of the National Governors' Conference.

The President's national energy plan presents utility and industrial fuel purchasers with price prospects which clearly favor coal, even with the added costs of meeting the best available control technology requirements of the Clean Air Act Amendments.

The resulting increase in demand for coal should result in a sound price base for coal producers. Coal prices which bring a fair investment return to the producer will enable this nation to meet coal conversion goals and at the same time meet clean air requirements through the use of scrubbers and coal pretreatment technologies.

A fair price to the producer will also insure surface mining reclamation programs which adequately protect the environment.

The question, then, is not whether we can accommodate both energy needs and environmental goals. Instead, the <u>real</u> question is whether non-environmental restraints will prevent us from expanding coal production to meet the President's goal of 1.1 billion tons annually by 1985.

Much attention has been focused on the shortages of transportation and capital. These problems, just as the environmental ones, can be solved as coal prices reach adequate levels through increased demand. And this can be done without injury to the individual consumer because of the comparatively inexpensive cost of coal energy today.

I am convinced that the major impediment to the President's 1985 goal of one billion tons is neither an economic nor a technological problem; it is more subtle and more complex.

In examining the problem, let us begin by looking at what has happened to coal production in West Virginia in the past ten years.

On an individual level, coal production in West Virginia has dropped from seventeen tons per man day in 1967 to nine tons per man day in 1976, a drop of nearly 45 percent in just a decade.

In 1967, West Virginia produced 152 million tons of coal with 43,000 miners. In 1976, we produced 109 million tons with 57,000 miners.

The President's plan simply requires West Virginia to return to 1967 production levels.

In looking beyond production figures, let us first examine the extreme disharmony between management and labor in the coal industry. There is simply a total absence of mutual respect between producer and miner.

This lack of respect leads to frustration and ineffectiveness on both sides. And, the end result is decreasing production.

Many of the difficulties in raising production levels will come to light when negotiations on a new UMWA contract begin later this year. Both sides will gather, and each will mouth the divisive rhetoric of the past.

And despite all the talk, I predict that agreement on the economic issues, such as wages, will come quickly. Negotiations are likely to break down, however, when more basic questions are reached, such as the right to strike over local issues.

Traditional principles about local work stoppage or wildcat strike situations must be analyzed. In these situations, the companies refuse to negotiate as long as the miners are on strike. On the other hand, the miners--dominated by the vocal few--refuse to go back to work until the companies agree to start negotiations.

Battles over wildcat strikes and resulting federal court injunctions have not served either side well. Both sides need to rethink their positions.

Increasing individual productivity is the basic goal. Both labor and management must pursue the goal in harmony. For if it is reached, both sides will surely benefit.

I now turn to another fundamental issue--the individual miner and his quality of life.

Miners' wages have nearly doubled in the past ten years. Today, the average miner earns around 290 dollars a week. Yet absenteeism and wildcat strikes are increasing.

Why isn't the traditional economic incentive of higher wages working?

Let's look at what the typical coal miner finds in his community. Where does he live?

In many places, the only housing available is a trailer or an old company house.

In West Virginia, for example, there are very few good housing sites available for the miner because of land ownership patterns and the steep terrain.

It is not enough to offer a man high wages if he cannot find a decent place to live.

If we are to expand coal production in West Virginia and in this nation, we must motivate the coal miner with an incentive; he must be given a stake in expanding production.

We must begin by providing the miner opportunities to improve his quality of life.

Government must assist in providing opportunities for good housing. At the state level in particular, government must develop more creative techniques to provide sites for housing and community development.

Government at all levels must help local communities develop the water and sewer systems, the health facilities, the recreation centers, and the other basic services which the miner and the coal industry need in today's world.

My point is this: America's coal conversion plan must also include programs to improve life in the coalfields.

If we act now, perhaps the miner will come to feel that he has a stake in all of America. For if he does, we can convert to coal without the fear of America's coalfields ever holding our country captive through strikes or embargo-type action.

In closing, I believe that coal production can expand immediately to meet the increased demand of a national energy plan.

I firmly believe that the people of West Virginia will do their share--and more--to meet the necessary production levels.

Coal miners and producers alike must, and will, rise to meet this national energy emergency which we have finally recognized.

But, in addition, our state and federal governments must turn their resources to the human problems which are encountered daily by both miners and industry.

Thank you.

John D. Rockefeller IV

SUMMARY
Subcommittee on Energy and Power
United States House of Representatives

The President's national energy plan presents utility and industrial fuel purchasers with price prospects which clearly favor coal, even with the added costs of environmental protection.

The question is not whether we can accommodate both energy needs and environmental goals. Coal prices which bring a fair investment return will solve that problem.

The real question is whether non-environmental restraints will prevent us from expanding coal production to meet the President's goal of 1.1 billion tons annually by 1985.

Much attention has been focused on the shortages of transportation and capital. These problems, just as the environmental ones, can be solved as coal prices reach adequate levels through increased demand.

Increasing the productivity of the individual miner is the key to reaching the President's 1985 production goal. West Virginia production figures illustrate this.

On an individual level, coal production in West Virginia has dropped from seventeen tons per man day in 1967 to nine tons per man day in 1976, a drop of nearly 45 percent in just a decade. In 1967, West Virginia produced 152 million tons with 43,000 miners. In 1976, we produced 109 million tons with 57,000 miners.

The extreme disharmony between labor and management in the coal industry has contributed to decreasing production levels. Both sides need to rethink their relationship.

Part of the productivity problem centers around a very fundamental issue--the quality of life of the individual miner.

Miners' wages have doubled in the past ten years, but why isn't the traditional economic incentive of higher wages working? Perhaps it is because of what the miner finds in his community.

In many mining communities, the only housing available is a trailer or an old company house. It is not enough to offer a man high wages if he cannot find a decent place to live.

Government must assist in providing opportunities for good housing. All levels of government must help local communities develop the water and sewer systems, the health facilities, the recreation centers, and the other basic services which the miners and the coal industry need in today's world.

In sum, America's coal conversion plan must also include programs to improve life in the coalfields.

Mr. MOFFET. Thank you very much, Governor.

I would like to begin by asking this. First of all, both of your statements were excellent I think, and very helpful to the subcommittee because they did raise several points that had not been raised by the panelists to date. I would like to ask Governor Carroll something about the administration's development of this plan and the Governor's role in that process.

Has there been adequate consultation with the Governors in the development of the plan as far as you are concerned?

Governor CARROLL. Mr. Chairman, really the consultation I must say, in all honesty, has come since the announcement of the plan primarily, but there has been substantial involvement with the National Governors' Conference in working with the administration since the President announced his plan, and I am not at all surprised at the manner in which it was done because I assume that they played it pretty close to their chest within the administration prior to making their announcement of their policy, and once they did, then they started exploring all aspects of their policy with our committee.

As a matter of fact, Mr. Frank Harcher, whom I failed to recognize, and is at the table with me, heads our staff, and I believe he told me that only yesterday they spent 6 hours with some of the administration staff in working on one aspect of the coal policy.

Mr. MOFFETT. That is encouraging, because I had heard, up to the time that the plan was announced, that there has been virtually no contact.

Governor CARROLL. I think that is probably accurate up until the time the policy was announced.

Mr. MOFFETT. That has changed.

Governor CARROLL. Yes.

Mr. MOFFETT. And that is good. On the transportation question, we have been concerned about transportation of the coal to various regions, but we haven't really discussed the mine mouth to, say, rail problem.

Governor CARROLL. Right.

Mr. MOFFETT. Are you aware of any administration analysis of that problem up to this point?

Governor CARROLL. A couple of years ago our State made a study, at the request of the Department of Transportation, on the transporting of coal from the mine mouth to the market point, and we gave that report to the administration a couple of years ago, and it has been lying rather dormant since then, but recently there has been some increased interest in that report, and as a matter of fact I believe the Secretary of Transportation commented on it in some testimony approximately a week ago before one of the committees. I remember reading the fact that he did in a news report, so apparently the Department of Transportation is again interested, and may I also say that I am fortunate enough in the fact that the new head of the Federal Highway Administration is a former assistant in my office, and so I am making absolutely sure that he is fully aware of the problem in the whole Department of Transportation, and indeed, it is a major problem throughout the Nation.

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Mr. MOFFETT. I thank you. I have some more questions, but before I pose those, I would like to recognize the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. I thank the gentleman. I certainly thank both Governors. We saw these problems in the production of natural gas. We understand your problems. We appreciate your alluding to those States that have special problems. Thank you both for being here. I yield back the balance of my time, Mr. Chairman.

Mr. MOFFETT. The Chair recognizes the gentleman from New York, Mr. Ottinger.

Mr. OTTINGER. Thank you, Mr. Chairman.

I too would like to welcome the two Governors. I have the pleasure of having a wife that comes from Kentucky.

Governor CARROLL. Great.

Mr. OTTINGER. We have a close association with your State, and I worked with Governor Rockefeller in the Peace Corps some years back. I would like to ask Governor Rockefeller something which concerns me a little bit, and that is you say that the wages of miners have nearly doubled in the past 10 years, and that doesn't sound like a very good deal to me for the average miner. I wonder what the cost of living in West Virgina has done in the last 10 years.

Governor ROCKEFELLER. It has gone up obviously as it has across the Nation, but a high school graduate, or let's say anybody of 18 or 19 years old can go into the mines, and within a couple of months can clearly expect to be getting $16-, $17-, or $18,000 a year, which is not bad starting pay, and that goes up. Miners are averaging almost $60 per day, so that the increase in the wages does not necessarily put them where they are, where they ought to be, but the point is that with those wages, the miners can't purchase what it is that is really important to them, to evidently feel good about the way they are living.

Mr. OTTINGER. Have you specific suggestions for ways that we can assist in overcoming the living problems that you described so aptly in your statement? Is there specific help that you think the Federal Government ought to be giving?

Governor ROCKEFELLER. Yes, and it is a shopping list of considerable length. Again if you take where a lot of this coal comes from, which is remote and which is rural, which is far away from established urban centers, and if it is our purpose to really get coal out of the ground, then I think we are going to have to make a major investment at the Federal level and at the State level, in terms of housing, in terms of roads, in terms of health facilities, in terms of cultural facilities, for example, libraries, arts, so that miners begin to feel that they, as other workers, are part of the ordinary community life which exists across the rest of our State and across the rest of the Nation, and you can't just simply will it. It has got to be paid for, and the money isn't going in there now.

In southern West Virginia in housing in two counties where we have just had a lot of flooding, in one particular county, which is one of the richest coal counties in the United States, three are only 50 acres of current land available for housing which is above the floodplain, 50 acres in the whole county, with many, many thousands of people living in the county, so that tells me that creative new thinking about housing structures built into the sides of mountains or on the tops of mountains or in some other way, that this has to go on. We can't do that at the State level. We can't afford that.

Mr. OTTINGER. I am for nationally concentrating on the areas of greatest need which I think West Virginia certainly qualifies for, assisting in housing and in the areas which you mentioned, but I wonder if this is a prerequisite for getting our coal increase, whether we ought to provide some specified assistance in this legislation.

When we considered synthetic fuels legislation in the Science Committee some time back we provided impact assistance to the communities that would be affected rather drastically by development of Western lands in order to achieve that particular technology. I wondered whether we ought to consider some such special impact assistance in connection with this particular legislation.

Governor ROCKEFELLER. I strongly recommend it, because what I am really saying, Congressman, is that while the Nation is saying "We need coal," miners and miners' sons are saying "We would rather do something else," and if that works out to be true, then we are not going to get the coal.

Mr. OTTINGER. If we provided impact assistance, which is something I think we might consider, would that interfere with the negotiations between the companies and the unions which you referred to as being particularly difficult? I know historically they have been.

Do you think if the Federal Government provided some kind of special assistance that that would make the mine owners more intractable?

Governor ROCKEFELLER. Both sides, sir. Jawboning is going to be effective, and I will tell you quite frankly traditionally Governors for perfectly prudent political, economic and other reasons have remained aside from the whole process. As Governor of West Virginia, Governor of the whole State, I am going to choose not to do that. I place blame across the board, and I am not going to stand idly by and watch this opportunity for West Virginia, which is enormous and positive and creative and productive for the national purpose, fall by the wayside because of bickering, because of lack of communication, or because of the quality of life which, as a State and a Nation, we don't recognize and support. I am going to be what you would say is a moderate interventionist, in a tradition where Governors stay as far away as they can.

Mr. OTTINGER. I think both of you have exhibited a very constructive point of view with respect to this legislation, much more constructive, I might add, than the representatives of the industry have, and we are very appreciative.

Governor ROCKEFELLER. Thank you, sir.

Mr. MOFFETT. Governor Carroll, we heard testimony this morning from Carl Bagge, whom I am sure you know, that existing State implementation, air implementation plans, are too strict. Perhaps you know that he testified in that regard.

Do you think the States have been too harsh, and what changes would you make, if any, in the way in which the States are allowed to implement the Clean Air Act?

Governor CARROLL. Well, there have been some rather ridiculous, I might suggest, results. I don't know that they have necessarily come from legislation, but they often come from the interpretation of that legislation by some of the bureacrats. One comes particularly to my mind, as a matter of fact two quickly do, and I guess I should mention them for the record because of the kinds of things that cause us severe problems in carrying out the intent of your legislation.

In one particular instance I can remember that under the old act there were some powerplants built, of course, that utilized coal with sulfur content up to about 3.5 percent, and then of course under the new act they are prohibited from using coal with a sulfur content of approximately 0.7 percent.

In this particular instance it was brought to my attention a few weeks ago. The operator of the utility was trying to get the EPA people to let him burn western coal with a sulfur content of 1.4 percent, which was nothing more than an averaging of the emission of the two stacks, and they said "No, you have got to burn 0.7 percent in one stack while you can burn 3.5 percent coal in the other stack," which doesn't make any sense to me, but that was the result that he was getting out of EPA.

One other instance as a result of legislation previously passed. The industry was setting out to make some repairs on one of their boilers, and in the process of making the repairs, they finally found out that it would be in the best interests of the company as well as in the emission in the area for them to go on and install a new boiler. So by that point, when they made that decision, they went back to EPA and said "Look, we have decided to go whole hog, so to speak, and go on and do the right thing, and that is install a complete new boiler and stack and all while we are at it."

EPA said "That is fine. You now have to apply for a new permit, stop construction, and it will take us about 10 months to process it," which again I think is a ridiculous result.

We have those kinds of problems, yes. We don't have problems complying with reasonable standards, rules and regulations, the utilization of the best technology when sufficient lead time is given to install it and so on.

I don't totally disagree with Mr. Bagge nor totally agree with him. I just say to put it in its proper context, when you apply common sense to standards, and get into a particular problem, and certainly as the Congressman knows in dealing with numerous problems every day with your constituents, you find that legislation somehow or another works out slightly different than what you ever thought it would when you voted for it on the floor of the House, because I used to be a legislator, and I was often amazed when something finally got back home and they applied it to a particular business or particular instance somehow or another it didn't work out exactly like we hoped it would when we drafted the legislation. To that extent yes, we have those kinds of problems.

Mr. MOFFETT. Does the conference have a position on whether or not the Governors have too much flexibility, for example, over primary standards?

Governor CARROLL. No, we do not have enough flexibility in our judgment, just the opposite. The Governors need more flexibility.

Mr. MOFFETT. In that regard you do disagree.

Governor CARROLL. Yes. I do.

Mr. MOFFETT. And, Governor Rockefller, you would apparently disagree as well, from what you said. You seem to be saying that a fair price is going to allow the Nation to meet clean air standards with scrubbers and other technology; is that correct?

Governor ROCKEFELLER. It is. I might give one example in the area of strip mining, which I think is interesting. We passed just recently in West Virginia, strip mining legislation which would put us at the level of the Federal strip mine bill, which is my hope will pass at a tough level and I hope the House will hold firm on it.

The bill, however, was not effective until July 1, so that meant that for a period of another 3 months there could be a deluge of permits. I just simply told our director of the Department of Natural Resources to make the July 1 legal requirements in effect immediately, and since that time we have received 21 applications for permits, 18 of which, because I said so, were already in compliance with the tougher, upcoming law and the three that weren't, we sent back and they returned them to us in compliance, which says to me essentially if you say this is the public purpose, this is what we are going to do, you can get it done. I don't think we have to back down environmentally.

Mr. OTTINGER. Would the gentleman yield?

Mr. MOFFETT. Yes.

Mr. OTTINGER. I note, Governor Carroll, that in the statement that you submitted to us, you submitted an addendum which was addressed to the amendments to the Clean Air Act, and I take it is the position of the National Governors' Conference, and those positions come out very strongly in favor of maintaining the standards and the schedules that are established in the Clean Air Act. I take it that is your position as well.

Governor CARROLL. Yes, that is correct. Primarily I think you are talking about the various deadlines that the Congress has established, and we find no major disagreement with those.

Mr. MOFFETT. Governor Carroll, if we can go back just a moment to your question about the problem of bringing coal from the mine to the market, have you had any discussions with the administration or has there been any analysis on your part of the way in which the administration plan and its various measures, such as the gasoline tax, the gas guzzler tax, for example, to reduce gasoline consumption, would affect your State's financial ability to maintain those road systems?

Governor CARROLL. As a matter of fact, yes, there has been, and again it has been primarily through the fact that I have had the ability, both as chairman of the committee and as a Governor, who has a former employee who is now a member of the administration, I had an opportunity to clearly express myself that the gas guzzler tax as such would be rather disastrous to us financially in Kentucky, and that is true in our judgment in most of the other States, if some plan is not devised to offset that cost to the States by return of the tax collected to the States for proper expenditures for public purposes, which again I believe the Secretary of Transportation suggested before the Congress last week, which is a principle that we would support very strongly. I say "we." In my instance particularly as Governor of Kentucky. I would say the Governors nationally have not yet thoroughly discussed the principle, but it is my judgment, should they do so, that they would support it.

By the way, Mr. Chairman, in one other aspect of the whole transportation problem, we in Kentucky now are exploring a cooperative system through which we might make bonding available for the purpose of purchasing railroad cars to be utilized for the transportation of coal. I considered it during the last session of our general assembly and ran into some legal problems with it, and a timing problem additionally, and we now have under consideration and discussion with the railroad industry the possibility of us cooperatively buying those cars and making them available to the industry for the purpose of transporting our coal, so we are doing our best to get at the problem, but additionally it is not one that we can handle by our financial resources alone.

If you will permit me very quickly to say, I have suggested at least three times to the Congress that there is a method through which you can respond to our financial needs for transportation as well as, Mr. Ottinger, the response to the need for impact assistance, and that is through a national severance tax on coal.

We have such a tax on coal in Kentucky. It produces for us $100 million annually, which is of tremendous value to our general fund, and I have suggested more than once that that national severance tax with a credit to the States that have the tax be imposed, and that that fund then create some surplus money for the purpose of helping us with our transportation problems, and equally, of course, could be utilized for impact assistance.

By the way, with respect to impact assistance, I wrote the President just a few weeks ago suggesting that he might have his administration bring together all the multitude of impact assistance legislation that has been enacted by the Congress over a number of years now, somewhat like we have handled the Energy Act so that we can have a coordinated impact assistance program that particularly relates to this area now with which we are dealing.

There are some other impact assistance programs that would have some indirect relationship, and we have got to have one here, but I would suggest very strongly there is a sound means by which it could be financed. I happen to be sympathetic with the Congress when it comes to financing programs. We Governors particularly are, and I don't think we can hardly come up here and suggest to you that we need financial aid without suggesting to you some means by which you might furnish it.

Mr. MOFFETT. How about the sludge problem with coal? Let me just tell you that back home where I come from, we have notices of intent to order Northwest Utilities, for example, to convert some of its oil-fired generating units to coal, and that utility is telling us as well as, I assume, the FEA that the cost of sludge disposal is enormous, and the sludge from just a few units covers quite a large number of areas, and that they know of no site suitable for sludge disposal in our State, or perhaps not even in New England.

How do you address that problem or how does the Governors' Conference look upon that problem?

Governor CARROLL. Well, it is very much the subject of one of our discussions in our committees now. We are well aware that one of the major problems with the whole washing process, that it produces tons and tons and tons of sludge that we don't have any means to dispose of.

Now it is our understanding that the newer technology is producing less sludge. I would suggest to you though that as comparing technologies, we happen to think that the conversion technology of converting the coal into a usable energy precombustion system is a much better system of utilization of coal than it is of dealing with the postcombustion problems that come from the burning of coal, so we strongly support the precombustion and technology, rather than the postcombustion utilization.

Mr. MOFFETT. One more thing. You mentioned the problems of financing new coal operations. At least one of our witnesses this morning proposed a $750 million loan guarantee program directed at production.

Governor CARROLL. Yes.

Mr. MOFFETT. Do you have any specific suggestions for stimulating financing an investment, including loan guarantees, tax credits?

Governor CARROLL. Yes. I do. As a matter of fact, let me suggest to you very strongly that I think one portion of the 1974 ESECA that could have been utilized that has not been is that guarantee fund. I am astounded to find that it has not been utilized by the administration, and it could have been in my judgment, but it has not been, and I think it would be a major assistance to the industry if they would work out technical problems and start utilizing that act. It is my judgment that it would cost a very small sum of money to the administration's cash flow to utilize that act, and I am not criticizing the current administration because obviously they haven't had the opportunity to do so.

Mr. MOFFETT. Governor Rockefeller, do you have a comment on that?

Governor ROCKEFELLER. Yes, I would associate myself with that comment, particularly for small mines and smaller operators, but it is my general view that where you have, over a period of years, a reasonably firm demand, and where you have a profitability level, which in the State of West Virginia for coal operators is at about 16 percent, that you are going to have capital, that demand is the need and the capital is going to become available.

Mr. MOFFETT. Gentlemen, thank you.

Mr. OTTINGER. May I ask one more question?

Mr. MOFFETT. You may.

Mr. OTTINGER. Thank you, Mr. Chairman.

How do you feel—you say you think some incentives are proper, particularly for small mines. How do you gentlemen feel about the ownership of coal by the oil industry?

Governor ROCKEFELLER. I will put that one on Governor Carroll.

Governor CARROLL. As a matter of fact, we have done something about it in Kentucky. I suggest there is something any State can do about it, and that is tax coal in the ground. After a while they get tired paying the tax on it and they will go on and start mining. So that is one way we have gotten at it in Kentucky.

Let me suggest to you that if you are talking about divestiture, that I would strongly say that I have no problem as relates to divestiture, particularly in this area, as long as we do not get ourselves to the point that we have so purified a system of business interests that somebody cannot any longer research, develop, and then explore for a product, because I really think that we will lose the private incentive advantage of research and development if we do not go so far in divestiture that we divest anybody of any other kind of business activity.

Mr. OTTINGER. I think divestiture would be a good thing, but I do not see it happening in the near future. I did want to express a concern that I do not think with your major oil companies that own so much of the coal that really a financial incentive is appropriate.

I have no problem with giving incentives to people who genuinely cannot raise the capital, but to give Exxon loan guarantees has always seemed to me a little bit ludicrous.

Governor CARROLL. I believe under the ESECA, they would not be qualified under that act. It has been some time since I have looked at it, but I believe you will find it available only to the very small coal mines.

Mr. MOFFETT. Thank you very much.

Governor CARROLL. Thank you very much.

Mr. MOFFETT. You have made a very important contribution to our hearings today and we are very appreciative.

If we might have order in the hearing room, the next panel will focus on equipment and capital.

Our witnesses, and I would ask them to come to the table at this time, are Mr. William Gray, Mr. Joel Price, Mr. Richard Norton and Mr. A. M. Frendberg.

The Chair would request that the witnesses identify themselves from the Chair's right, please, and your affiliation, for the record.

STATEMENTS OF RICHARD C. NORTON, ASSISTANT MANAGER, CORPORATE DEVELOPMENT, STONE & WEBSTER ENGINEERING CORPORATION; A. M. FRENDBERG, CONTRACT MANAGER, ENGINEERING SERVICES, BABCOCK & WILCOX COMPANY; JOEL PRICE, VICE PRESIDENT, RESEARCH, DEAN WITTER AND COMPANY; AND WILLIAM R. GRAY, GENERAL MANAGER, CORPORATE PLANNING, INLAND STEEL COMPANY, FOR AMERICAN IRON AND STEEL INSTITUTE, ACCOMPANIED BY FRED CORBIN, ASSISTANT SUPERINTENDENT, FACILITIES PLANNING, AND JAMES HANEY, DIRECTOR OF TAXES

Mr. NORTON. I am Richard Norton of Stone & Webster Engineering Corporation in Boston, Massachusetts.

Mr. FRENDBERG. I am A. M. Frendberg, Babcock & Wilcox Company, Barberton, Ohio.

Mr. PRICE. I am Joel Price of Dean Witter and Company, New York.

Mr. GRAY. I am Bill Gray, general manager, Corporate Planning, Inland Steel Company.

I have accompanying me Mr. Fred Corbin, Assistant Superintendent of Facilities Planning, and Jim Haney, Director of Taxes, both of Inland Steel Company.

Mr. MOFFETT. Will Mr. Haney be testifying?

Mr. GRAY. Only in assisting me.

Mr. MOFFETT. Thank you.

It would be helpful to the subcommittee, if possible, if the witnesses could paraphrase their testimony. Of course your prepared statements will be made part of the record.

Mr. Norton, would you like to begin?

STATEMENT OF RICHARD C. NORTON

Mr. NORTON. All right.

I have copies of the statement if it would be helpful to have those up there.

Mr. MOFFETT. Yes, thank you.

Mr. NORTON. I have been asked to respond on what the problems are converting oil-burning and gas-burning powerplants to coal-burning.

First of all, there are really three different powerplant situations that present successively more difficult problems in converting from their present petroleum fuel burning process to burning coal.

The first is the powerplant that was designed for coal but, say, 5 or 10 years ago has been converted to burning oil.

The second is a powerplant where the boiler was originally designed and contemplated to run burning oil or natural gas, but that at some time in the future it may be necessary to change to coal and hence minimum provisions were made for the possible future conversion to coal.

Then there is the third case where the boiler was designed originally just for gas and oil, period, with no consideration for possible changes to coal.

I would plan to talk about each of those three in succession.

Many of the plants in New England are examples of this first case, but even the latest of those to be converted from coal to oil would require very difficult undertakings in order to accomplish the changes and the additions that are necessary now to resume the burning of coal; aside from the problems of securing a supply and delivery of coal to the site. The problem might be segregated into five aspects.

The first is particulate emission; the second is sulfur oxide emission; the third is nitrogen oxide emission; the fourth is storage and other space requirements, and the fifth is the economic reconciliation of the cost of doing all these things.

Briefly touching on each of the these:

The precipitators, though they were originally installed for the contemporary standards when the plant was burning coal, would probably have to be doubled or quadrupled in size now in order to conform with the current requirements.

Similarly for sulfur oxide. At the time that these boilers were burning coal, there were no stringent restrictions on that type of emission. Unless coal of sufficiently low sulfur content could be obtained for the plant, there would have to be the addition of a flue gas desulfurization system.

In the same sense, the original nitrogen oxide production from the boilers, in burning coal, was acceptable for the standards that were current at that time. Inherently the formation of these oxides in burning coal is greater because two to three times as much air is required to burn the coal than oil and gas, and there is, of course, the 80 percent nitrogen in the air.

Consequently, special physical changes are now required to these coal-burning boilers in order to burn the fuel with an acceptable limit of nitrous oxide production.

Fourth, the available space at the existing plant may no longer be available for coal storage. Perhaps it was taken over for putting in the fuel oil storage tanks or perhaps even a subsequent unit in the station encroached upon those areas.

Additionally, sufficient space may now be lacking for the enlarged precipitator. There is room for the original one, but if you have to quadruple its size it may be difficult to accommodate. The scrubber and its ancillary systems, the storage of the limestone to go along with the scrubber, and the disposal of the sludge that is created by the flue gas desulfurization system, all require much space that may not be available.

Lastly, there is the problem of reconciling the large capital investment that is required to make these changes. This is particularly hard to reconcile if the powerplant has lived out two-thirds of its economic life. It is very difficult to put a new investment on top of an investment that has matured for many years. In addition, there is also the loss of the availability of the unit while the changes are being undertaken. So much for perhaps the simplest case where the plant was designed to burn coal in the first place.

Take the second situation, where a plant was designed for the future burning of coal but was not originally installed with that equipment. That presents all of the problems of the first situation plus the burden of completing the equipment to outfit it for burning coal.

The magnitude of that problem is increased by the degree to which the original provisions for this possibly future addition of coal-burning may have been compromised.

The first likely to be compromised is the need for coal receiving, storage, handling systems, and processing equipment. This includes docks or rail for receiving, an area for the coal pile, a clear route for the conveyors, suitably located space for crushers, bunkers, pulverizers, coal pipes, precipitators and scrubbers.

The second provision that would be likely to have been compromised is an allowance for enlarging the furnace to make it sufficient for burning coal. A furnace for burning coal has to be practically twice as big as for burning oil and gas.

At a minimum, in contemplating this possible future change, the whole assembly would have been originally installed maybe 15 to 20 feet higher off the ground than needed for the gas or oil burning furnace.

To make that provision, the owner would have to reconcile the added cost for additional structural steel, not only for supporting the boiler but also for all the associated systems that connect to it. He gets nothing back in return for that additional investment unless and until it is needed to convert over to coal.

So it is a great temptation to make the minimum provisions possible, even to the point of saying, well, maybe we could dig a pit in the ground and put some extension of the boiler below.

Another feature which would be planned originally would be the recognition that for burning coal the tube spacing in the convection section would have to be more generous in order to accommodate the tendency for fouling.

This spacing might have been provided initially even though it were planned to burn oil. On the other hand, it may have been decided to lay out the duct work with sufficient space only, planning to cut out all of the original tube banks and put in tube banks that are adequately spaced for the coal when needed.

Then there is the economizer, which for gas-burning particularly might have been installed with extended surface in order to have greatest economy initially. However, such extended surface would be completely unacceptable for coal and would have to be removed completely and replaced with smooth tubes.

So much for those first two.

The third is where the original design is only for oil and gas, there being no contemplation of future conversion to coal. That situation presents almost insurmountable problems in conversion to coal-firing. At this point I should probably ask if you have really considered that as a viable possibility. In the paper that I presented I have detailed the problems but I will not go through it unless you think this is something that you will want to seriously entertain.

Mr. MOFFETT. I do not think so, I do not think it is something we want to entertain at this point.

Mr. NORTON. I think it can be recognized that the furnace has to be so much larger and the modifications are so great.

Mr. MOFFETT. Okay.

Mr. NORTON. Then that completes the statement.

Mr. MOFFETT. Thank you.

[Mr. Norton's prepared statement follows:]

PROBLEMS INVOLVED IN CONVERSION OF OIL-BURNING AND GAS-BURNING POWER PLANTS TO COAL-BURNING PLANTS

There are three different power plant situations that present successively more difficult problems in converting to coal-burning, as follows:

- o Designed for coal but converted to oil/gas
- o Designed for future coal
- o Designed only for oil/gas

Many of the plants in New England, for example, are of the first situation. But even the latest to be converted to oil from coal would require difficult to accomplish changes and additions in order to resume the burning of coal, aside from the problem of securing the supply and delivery of the coal to the site. The problem might be segregated in five groups, (1) particulate emission, (2) sulfur oxide emission (3) nitrogen oxide emission, (4) storage and other space requirements, and (5) economic reconciliation.

Briefly touching on each; the precipitators, though originally of contemporary standards when installed may have to be doubled or quadrupled in size in order to conform to current requirements. Similarly, for particulate emission, unless coal with sufficiently low sulfur content can be procured, the addition of a flue gas desulfurization system must be incorporated into the system. In the same sense, the original nitrogen oxide production when burning coal may have been acceptable at that time but not with current standards. Inherently, their formation is more of a problem burning coal than with oil or gas because 2 to 3 times as much excess air (including nitrogen) is required to burn coal. Consequently, special physical changes are now required to the firing system in order to burn the coal in an acceptable way.

Fourthly, the available space at the existing plant may no longer be available for coal storage, perhaps taken over for fuel oil tanks or subsequent units of the station. Additionally, sufficient space may be lacking for a greatly enlarged precipitator and for the scrubber with all its ancillary systems. Additional space would be required for storage of the limestone and also means for disposal of the spent reactant from the scrubber. Lastly, there is the problem of reconciling large capital investment in additions and changes to a plant that may have lived out more than half of its economic life. Also loss of the avaialbility of the power generating facility must be accomodated during the year or more that may be required for the conversion.

The second situation, a plant designed for future coal (but not originally equipped) presents all of the problems of the first situation plus the burden of completion of the equipment outfitting and changes. The magnitude of this latter problem is increased by the degree to which the original provisions were made or compromised. The first likely to be compromised is the needed space for the coal receiving, storage, handling system and processing equipment. These include docks or rail for receiving, area for a coal pile, clear route for conveyor and suitably located space for crushers, bunkers, pulverizers, coal pipes, precipitators and scrubbers.

The second provision likely to have been compromised is the allowance for enlarging the furnace and providing for bottom ash as may have been incorporated in the original design. At minimum, the total boiler assembly would have been raised 15-20 feet above the elevation required for the gas/oil design in order to provide for future increase in furnace volume and provision of a hopper bottom. This would have required an initial additional investment in boiler supporting steel which would have no value until the coal conversion materialized. A second feature, either planned only or encorporated partially in the original design would be the spacing of tube banks in the flue gas passage to avoid the plugging tendency when firing coal.

The third situation, an original design only for oil/gas poses almost insurmountable problems in conversion to coal firing. The fundamental reason for the problems is the existance of ash in coal fuel in quantities generally ranging 5 to 10 percent of the total coal weight burned compared to less than 0.1 percent for oil and none for natural gas. Problems relating to air polution are serious but not as fundamentally limiting as those relating directly to ash. It is absolutely necessary to accomodate the ash properly in order to achieve acceptable operation of the boiler. The problems that are most apparent are encountered in developing workable ways to satisfy that accomodation regardless of consideration of costs.

Consider the boiler that is designed exclusively for burning gas. Typically, it would consist of a rectangular box-shaped furnace with flat bottom, constructed of water cooled surface, with a gaseous combustion product outlet near the top of one wall leading to and through steam cooled tube bundles, thence through a water cooled economizer and/or combustion inlet air heater and finally to stack discharge via an induced draft fan. The walls and roof of the hot gas passages leading to and containing the aforementioned tube bundles are also water cooled like the furnace walls. Simplestically stated, the steam is typically generated in the water cooled wall system, separated from the water in a drum and passed through the tube bundles in the gas passage for drying and superheating to the desired final temperature. On the heating side, the gas fuel is burned in the water cooled furnace, imparting heat to the walls which results in some cooling of the burned gases to below the combustion temperature by the time it enters the tube bundles, called the convection section of the boiler. In this gas fuel case, there is no upper limit of burned gas temperature entering the tube bundles dictated by consideration of ash. This is where the situation becomes so different with coal fuel.

Consider next that means have been arranged to introduce and burn coal in suspension in the furnace just described. If the boiler is of contemporary size, the rate of coal introduction could be in the order of 200 tons per hour. If to illustrate, the coal is of ash content of say 10 percent, 20 tons per hour of ash would evolve as a sticky molten residue of the burning process. Roughly, 20 percent of this molten ash (4 tons per hour) will deposit on the walls of the furnace enclosure and run down towards the bottom. Hence, the first change to be faced in the gas fuel furnace is to replace the flat bottom with a slopping hopper, shaped to draw the molten ash to a bottom discharge opening. The remaining 80 percent of the total ash is destined to pass out of the furnace into the convection or tube bundle part of the assembly.

The furnace for burning coal must be almost twice as large as that needed for the same rating with gas/oil. Two reasons apply; the first is that the coal takes longer to burn than oil or gas even though it may be finely pulverized particles. Secondly, the 80 percent of the ash carried out of the furnace must be cooled sufficiently to loose its stickness, lest it solidly plug up the tube passages. Finally, a precipitator and flue gas scrubber would have to be added to avoid atmospheric polution.

The foregoing, in brief summary, are the problems that come to mind in contemplating conversion for gas/oil to burning coal.

Richard C. Norton
Stone & Webster Engineering Corporation
Boston, Massachusetts

Mr. MOFFETT. Mr. Frendberg, please.

STATEMENT OF A. M. FRENDBERG

Mr. FRENDBERG. I am Milt Frendberg, presently manager of Engineering Services for the Fossil Power Generation Division of the Babcock & Wilcox Company in Barberton, Ohio.

Our group specializes in working with existing units for fuel conversions, upgrading older equipment, that type of thing.

I learned first about this yesterday morning so maybe I ought to talk as a technically knowledgeable individual rather than representing Babcock & Wilcox. The brief I submitted really was pretty much a paraphrased thing. We could furnish you papers that are broader in scope if you so desire, if somebody would request that. We would be glad to do it.

Let me just then talk for a few minutes about boiler design and how these boiler designs differ radically for the various fuels fired.

I could talk for hours on this subject, but hopefully in a few minutes I can hit enough of the highlights to show you what the constraints might be. Mr. Norton has covered some of them already.

Let me just review quickly. A boiler is a heat exchanger in which fuel is burned to generate heat which will be absorbed in the boiler to generate steam, superheat that steam and in utility boilers, particularly, to reheat that steam.

These may range in size from one that heats this building, or even smaller, to the largest ones today, 1,300 megawatts, which physically are probably bigger than this building, capable of burnng up to 600 tons of coal of a reasonably good coal—if you start talking about western coals, greater quantities of that—every hour.

Every boiler has to be designed for the fuel for which it is to be fired. Fuels normally used in boilers are coal, oil, or gas, but particularly for boilers of industrial applications there are a lot of other fuels fired, such as bark, wood, sawdust, blast furnace gas, coke oven gas, various pulping liquors, coffee grounds, sunflower seed hulls, tar, municipal solid waste, bagasse, and so forth.

Some of these such as natural gas and No. 2 oil are clean, they have no ash in them, easy to burn. However, most of the solid and liquid fuels do contain ash and this ash is a real culprit in the boiler operation and maintenance; so serious consideration must be given to this ash during the design stage.

As I said, natural gas is a clean fuel, easy to burn. The furnace for burning natural gas need be only large enough to satisfactorily complete the combustion of the fuel. The heating surface can be a very compact arrangement with high velocity of the flue gas over the heating surface to provide maximum heat transfer. A boiler designed for firing only natural gas can be a very compact, relatively low-cost unit. Oil-fired units are probably only relatively less conservative than a gas-fired boiler.

On the other hand, coal contains considerable ash, ranging from somewhat less than 10 percent to more than 30 percent of the fuel fired. This ash causes serious problems in the operation and maintenance of the boiler. The ash in most coal would melt at the temperatures that exist in the furnace. This ash then sticks on the furnace walls. It also sticks to the heating surface just beyond the furnace; it can cause a reduction in the heat transfer to these surfaces and cause fouling of the gas lines between the tubes, even to the extent of forcing the unit out of service to clean out the slag. As the ash passes through the unit, it cools off and solidifies and then in the gas stream it acts like a sandblast and causes erosion of the boiler parts. This erosion, if not given proper consideration, can cause failure in short order.

Coal has constituents such as sulfur or sodium which can cause corrosion of the high temperature parts of the boiler, as well as the low temperature parts.

In designing a boiler, all of these characteristics must be taken into account. The furnace must not only be of sufficient size to provide time for complete combustion of the fuel, but it must be arranged with sufficient clearance from burners to walls and clearance between burners to minimize furnace slagging. It must have sufficient heating surface to cool the products of combustion to a temperature low enough so the particles will not stick to the surfaces and cause fouling of the convection pass.

In present-day coal-fired designs, we design to gas velocities of 65 feet per second or lower. By comparison, flue gas velocities in the gas-fired boiler are 100 feet per second or higher.

A boiler designed for coal firing, therefore, is physically much larger than one designed for natural gas firing because more heat must be absorbed in the furnace, the flue gas quantity is considerably greater, the convection pass tube spacing must be greater and the flue gas velocity must be lower than when firing natural gas.

With the written testimony submitted there is a figure that shows the physical size of a coal-fired boiler versus a gas-fired boiler for the same capacity. You can see the radical difference. This shows a side sectional view.

The coal-fired boiler is 30 percent wider than the gas-fired boiler, as well.

As I said, I have tried to touch some of the high points in the design of boilers for various fuels. Based on what I have said, we can almost categorically say that unless consideration was given to coal firing during the design stage, any existing boiler cannot be converted to coal without limiting the output to less than something under 50 percent of its design output.

Now, assuming that the preceding could be overcome, which I say it cannot, but just assume that it could, the environmental regulations say that new boilers must meet rigid environmental restritions. One of these is the limit on NOx emissions. That is nitrous oxides, with which I am sure you are all familiar.

If an existing boiler were to switch to firing coal, it must meet the new boiler limits. I could give you a long discourse on the design requirements of burners and furnaces to minimize the emissions of nitrous oxides, but let it suffice to say that there is no way that a boiler that was designed strictly for gas or oil firing could be fired with coal and meet those nitrous oxide limits.

Again, assuming conversion was possible, as Mr. Norton has pointed out, it has to meet the standards for particulates, sulfur oxides and equipment would have to be added to meet those requirements.

Again as Mr. Norton pointed out, a number of boilers which were originally fired with coal have in recent years been converted to oil firing. Obviously these are capable of firing coal again, but again there are some constraints.

I have alluded to the fact that there is more maintenance for a coal-fired boiler than for a gas- or oil-fired boiler. Some of the units presently burning oil would require major revamping to make them reliable coal-fired units. This is because of the deterioration of the equipment due to many of the things that have been are brought out that happen when firing coal.

The coal handling and preparation equipment would require complete overhaul before being put back into operation.

One of the reasons for switching to oil was to meet air quality standards. Switching back to coal would mean facing these same problems again.

With that I will wind up and see what happens.

[Mr. Frendberg's prepared statement follows:]

STATEMENT OF A. M. FRENDBERG

Mr. Chairman and members of Subcommittee:

I will talk to you a few minutes about boiler design and how boiler designs differ radically for the various fuels fired.

I could talk for hours on this subject, but hopefully I can hit enough of the highlights in a few minutes to show you some of the constraints in converting existing boilers to firing coal.

A boiler is a heat exchanger in which fuel is burned to release heat to be absorbed in the boiler to generate steam, superheat the steam and (sometimes) reheat the steam after it has passed part way through the turbine. Boilers range in size from one used to heat this office building (or even smaller) to one capable of driving a 1300 MW turbine - one that would burn about 600 tons of reasonably good coal per hour, or almost enough electricity for a city the size of Washington.

The boiler must be designed for the fuel to be fired - that is the size of the furnace, the arrangement of heating surface, the clear space between tubes, the velocity of the flue gas over the tubes, the level of gas temperature leaving the boiler, the means of disposing of the ash in the fuel, the arrangement of sootblowers- these and many other things must be given consideration in the design.

The fuels normally used in a boiler are coal, natural gas or oil, but there are many other fuels fired in boilers, particularly boilers for industrial applications. Some of these other fuels are bark, wood, sawdust, blast furnace gas, coke oven gas, various pulping liquors, coffee grounds, sunflower seed hulls, tar, municipal solid waste, etc.

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Some of these, such as natural gas and No. 2 oil are clean fuels, that is, they have no ash. However, most of the solid and liquid fuels do contain ash. This ash is a real culprit in boiler operation and maintenance; so serious consideration must be given to it in boiler design. I will tell you more of that later.

Natural gas is a clean fuel, which is easy to burn. The furnace for burning natural gas need be only large enough to satisfactorily complete combustion of the fuel. The heating surface can be a very compact arrangement with high velocity of the flue gas over the heating surface to provide maximum heat transfer. A boiler designed for firing only natural gas can be a very compact, relatively low first cost unit.

Oil contains ash, but in very small quantities. The boilers designed for firing oil are generally only slightly less conservative than boilers designed for firing gas.

Coal contains considerable ash, ranging from somewhat less than 10% to more than 30% of the fuel fired. This ash causes serious problems in the operation and maintenance of boilers. The ash in most coal will melt at the temperatures existing in the furnace, and it will stick to the furnace walls and to the heating surface just beyond the furnace causing a reduction in heat transfer and causing fouling of the gas flow lanes between tubes, even to the extent of forcing the unit out of service to clean out the slag. As the ash passes thru the unit, it cools and becomes solid and has the effect of sandblasting to erode the heating surfaces. Unless proper consideration is given in the design, the erosion can cause failures in short order.

Coal has constituents such as sulfur and sodium which can cause corrosion of the high temperature parts of the unit, as well as the low temperature portion of the air heater.

When designing a coal fired unit, these characteristics of the fuel must be taken into account. The furnace must not only be of sufficient size to provide time for complete combustion of the fuel, but it must be arranged with sufficient clearance from burners to walls, and clearance between burners to minimize furnace slagging; and must have sufficient heating surface to cool products of combustion to a temperature low enough so the ash particles will not cause fouling in the convection pass.

In present day coal fired designs the velocity of the flue gas over the heating surface is limited to 65'/second, or less with some coal, to minimize erosion of the boiler parts. By comparison, flue gas velocities of more than 100'/second are common on gas fired units. When you consider that erosion is a fourth power function of velocity, you can realize that the fly ash erosion would be intolerable, if a gas fired boiler were to be converted to coal firing.

A boiler designed for coal firing is physically much larger than one designed for natural gas firing because more heat must be absorbed in the furnace, the flue gas quantity is considerably greater, the convection pass tube spacing must be greater and the flue gas velocity must be much lower than with natural gas firing.

I have tried to touch on some of the high points in the design of boilers for various fuels. Based on this, we can categorically say that unless consideration was given to coal firing during the design stage any existing boiler cannot be converted to coal without limiting the output to less than 50% of the design output.

Assuming that the preceding could be overcome:

The law says that new boilers must meet rigid environmental restrictions. One of these is the limit on NO_x emissions. If an existing boiler switches fuels, it must meet the new boiler limits. I could give you a long discourse on the design requirements of burners and furnace to minimize the generation of NO_x, but let it suffice to say that there is no way that coal could be fired in a furnace designed for gas firing and meet the NO_x emission limits.

Again assuming a conversion was possible, equipment would have to be added to meet the emission standards for particulates and sulfur oxides.

A number of boilers which were originally fired with coal have, in recent years, been converted to oil firing. Obviously, these are capable of firing coal again, but there are some constraints:

1. I have alluded to the fact that there is more maintenance for a coal fired unit than for gas or oil. Some of the units presently burning oil would require major revamping to make them reliable coal fired units.

2. The coal handling and preparation equipment would require complete overhaul before being put back in operation.

3. One of the reasons for switching to oil was to meet air quality standards. Switching back to coal would mean facing the same problem that brought about the switch to oil.

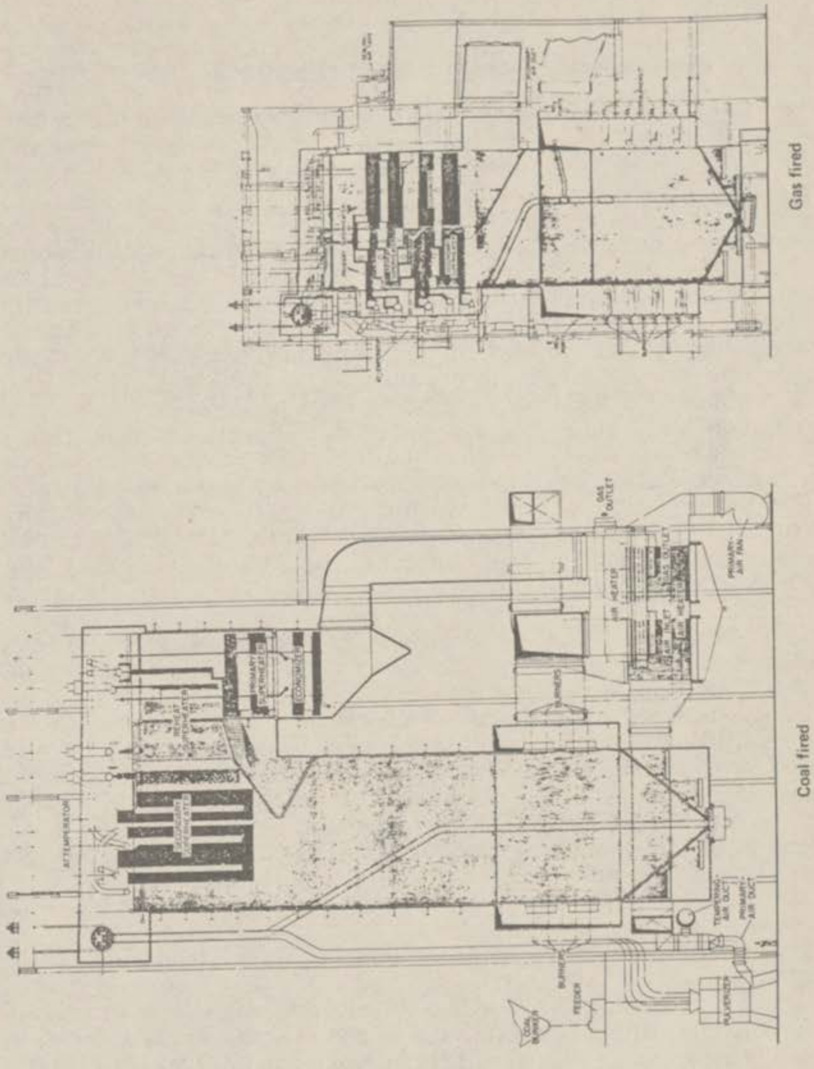
Gas fired
Coal fired
ATTEMPERATOR
PRIMARY SUPERHEATER
ECONOMIZER
BURNERS
GAS OUTLET
AIR HEATER
PRIMARY AIR FAN
TEMPERING AIR DUCT
PRIMARY AIR DUCT
FEEDER
PULVERIZER
COAL BUNKER

Figure 1

Mr. MOFFETT. Thank you very much.
Mr. Price.

STATEMENT OF JOEL PRICE

Mr. PRICE. My appearance here is equally as impromptu as the preceding speaker since my call came around 10 o'clock yesterday.

To say I have not prepared a written presentation is an understatement.

I would like the opportunity to place into very quick and simple perspective a number of items talked about in recent weeks which relate to the impact of the conversion message, Clean Air Act, best available control technology, effect on supply and demand, capital and equipment needs and, one last point, the danger and the threat of something called overzealous environmentalism, and try to wrap everything up into a simple package.

If you look at the Carter energy message, as it relates to the coal conversion bill, you might perhaps divide it into six categories.

Number one is the conversion of oil and gas plants to coal where there is preexisting coal-burning capability. As you know, this falls under the provisions of ESECA, which started out with 32 sites, and 74 units. This involved a grand total of 26 million tons of potential conversions, of which 14 million tons have taken place already—not one ton at the behest of the FEA. That leaves 12 million tons to be converted.

The second set of what we call NOIs, notices of intent, would have included 39 sites and 69 plants and involved 21 million tons, of which 2 million have been converted already.

In the last set of NOIs, the FEA decided to leave out certain utilities, like Commonwealth Edison of New York. So if I have to give you the maximum universe to be converted over the next 5 years, it is somehwere in the area of 25 million tons which, very simply expressed in New York language, is no big deal. The whole universe, if you want to go all the way out to 1985, is an absolute maximum of 50, and I will not live to see it happen.

Mr. BROWN. Fifty what?

Mr. PRICE. Fifty million tons.

The second category relates to industrial conversions where there is a great deal of data in the FEA, which it very zealously guards and will not let out, the Freedom of Information Act notwithstanding. That data should be available to me in some form, at least, in two weeks, which I will have programmed in our firm. Apparently companies have been surveyed in terms of connections on various pipelines to determine how much coal they plan to use—if in fact they are going to convert—whether they are going to switch to electricity, or instead to oil.

For the time being let me make the statement that your universe for industrial conversions is 15 million tons over the next 4 to 5 years, a far cry from some of the numbers floating around Washington and elsewhere, not to mention the difficulty of accomplishment. It is sad that when the FEA issued its notices of intent the other day, claiming that 9.3 million tons are going to be added, some 5.3 million of that was already scheduled, whether the FEA existed or not, and only 4 million related to pure conversions. You can do many things with numbers in Wall Street, in Washington, and everywhere else.

The third category worthy of comment is conversion of oil to coal where there is no preexisting capability to burn coal. As some of the prior witnesses have testified, if you want to convert in an existing boiler, you will reduce the capacity of that boiler—I think the preceding witness said up to 50 percent, let's say up to 60 percent, which came out of a Combustion Engineering document.

You would have to derate. Rather, to accomplish anything, you must rip out the boiler and install a new one—great for Babcock & Wilcox and Combustion Engineering, but for nobody else.

Very simply expressed, all this is not about to happen. So the whole Carter energy message on this score means nothing.

The next category is the straight conversion from natural gas to coal. By 1990—which I believe is the cut-off date—most of the pure gas-fired boilers in the United States will be 30 years old or more, which, from a commonsense point of view, suggests that some years prior to that, there should be phase-outs and replacement by coal-fired units.

Look at the State of Texas. It burned something like 9 million tons of coal in the year 1975, and is projected to burn about 50 million tons in 1980 and 100 million tons in 1985. Now for sure Texas is not growing that fast. This is the phase-out of natural gas, which is being replaced by coal-fired boilers. There are no conversions.

The fact remains, however, that the cost of switching from natural gas to oil is not very large; it can be accomplished within the same boiler. If you look carefully, as I am sure you have, at the President's energy message, it says that you can do this with permission. It is questionable how many units would even be converted under these circumstances, because so many can burn either natural gas or oil.

There is another category where there are some utilities that burn coal in the winter and gas in the summer, like Northern Indiana Public Service and Northern States Power. Obviously what will happen here is summer gas will be eliminated. No capital cost is involved and the incremental demand is minimal.

The last statement contained in the Wall Street Journal a week before the energy speech was that all new fossil fuel plants will burn coal and add 225 million tons to demand, which certainly wins the award for the charade of the year. The fact remains that no oil-fired plant has been commenced in the United States since prior to the Arab oil embargo, and while it is a fact that some are still coming on stream, they represent deferrals as a result of zero energy growth the year after the embargo. There are a few more coming on, with 1981 the last, I believe.

According to our utility specialist in Dean Witter there has not been a pure gas-fired boiler for utility purposes built since the late 1960's.

So all this is very nice, considering S. David Freeman, the advocate of zero energy growth, composed this energy message for

Mr. Schlesinger for forwarding to President Carter, which will materially affect the lives of all of us.

Another disturbing aspect which will impact on supply and demand, is the provision to force scrubbers on all new plants, which has been widely misinterpreted by people in terms of meaning.

The current understanding, subject to change 2 minutes ago, is that we are talking about unpermitted plants. Hence if you receive permission to build a utility plant today and it will take 6 years to bring it on stream, that is considered an old or an existing plant and does not need a scrubber. So what is being very directly suggested to you is that the impact of the scrubbers on all new plants would not be felt until 1983 at the earliest and progressively magnify in 1984 and 1985.

Frankly, it all makes little sense with something of the saccharine and the cyclamate overtones. Effectively, we are tightening our sulfur standards. Apparently the rationale emanates from the EPA, because when we passed the Clean Air Act of 1970, there were basically no scrubbers around except one that worked in Japan. We said, "Well, scrubbers have 70 percent efficiency, so let's put in the new source emission standards at 1.2 pounds of SO_2 per million Btu."

Now we have finally managed to achieve something like 90-percent efficiency. Of course, I do not know of any manufacturer that gives a scrubber guarantee of more than 90 days, which is just lovely for the amount of money you are expending.

Since they work so much better environmentalists say, "Let's put scrubbers on all new plants, which effectively reduces sulfur emissions." It has been tough enough meeting these standards. If anything, there is a very strong case to be made for abating some of the standards. But now we are going to tighten them even further.

What does all of this mean for supply and demand?

Frankly, whether President Carter stayed in Georgia or President Ford remained in office, we were targeted to produce over a billion tons in 1985—no matter what happened. Hence, not too much really has changed, and that is a fact.

Some things will change around within the context of that, sort of a micro as opposed to macro, but the billion tons was really in place. Even allowing for some conservation, for example, as a result of insulation, counterbalanced by some of the utility conversions, even the administration planners will admit it does not expect utility consumption of coal to be much different in 1985 than without the message at all.

The industrial sector will change; obviously the export and metallurgical sectors are not involved in any way, shape, or form. But what we really come down to is this: The average utility buyer located in the Midwest might be thinking of bringing on a boiler or a plant in 1983 or 1985, and is uncertain which way to go. He has the following alternatives:

Number one: Do I go West like Gillette, Wyoming, and the Powder River Basin with its very high moisture coal which requires a special boiler; low Btus, which means one and a half times as much as for eastern coal to get the Btu equivalent; and spiraling transportation costs, which are compounding around 15 percent a year?

Or: Do I use midwestern, high sulfur coal, with scrubbers that admittedly do not work now but with the full knowledge that the state of the art in scrubbers is unlikely to be much different in 1985 than it is now?

Maybe we will use lime and limestone a little better, and obviously we will be closer to fluidized-bed combustion but, basically, that will be it.

Or do you go to the East and try to find that proverbial needle in the haystack, compliance coal which is very difficult to obtain. Frankly, some of the steel companies, like U.S. Steel, Armco, and Republic, are considering developing some of their marginal reserves in order to supply that market.

If you are a utility, as a result of the Carter energy message what you now do is nothing. You were uncertain as to what to do before; and now you are more confused.

So with absolute uncertainty—and I am sure some of the companies represented here have noticed it—capital equipment ordering comes to a standstill until there is some resolution. What then happens when you get out to say 1983-84 and scrubbers become universal? I do not know whether we can kill that scrubber provision or not; I want it killed, but can one voice make that much difference? Western coal will go only West, none of the incremental amount will be shipped to the Midwest—94 percent is scheduled for the West anyway—Midwest coal stays in the Midwest, and that should pick up in demand. Eastern coal which has two geographic markets will be distributed only in the East.

In the interim, we can expect that compliance coal, that is, legally burnable without a scrubber, will sell at a premium over high sulfur coal at least equal to the cost of a scrubber, or phrased in simple terms, $12 a ton added to the price of coal.

A number of companies will try to develop the compliance coal market. Whereas the going rate be $27 in the East, we are on our way to $35 or higher.

When scrubbers must be installed on all new plants, there will be no reason for any utility to pay a premium for compliance coal. As a result, the spread may only be $2, representing the cost of removing the excess sludge from the scrubber; so for compliance coal, if you can sign a contract now, that is fine, but development is 7 or 8 years out, forget it. There is no future.

There are other things that concern me. Even if nothing will be done, let my lonely voice be heard for whatever it is worth. One relates to the nondegradation provisions of the Clean Air Act. There are class 1 regions—pristine areas—we shall not sully them in any way. Okay, 50 miles within a national park; I can live with that.

We have class 2, where you are allowed a limited amount of pollution; you can put in a powerplant, but not industry. That is great. A powerplant and no industry. That is some of the bizarre logic incorporated in our energy policy.

Then there is class 3 which says if you want to develop Los Alamos, New Mexico, go ahead except the Senate knocked it out, so there isn't a class 3.

Then comes the other side, that is, dirty areas where you have a really forward-thinking policy. You can't put any pollution into a dirty area more than is removed. You have Ford Motor wanting to open up an auto assembly plant in Oklahoma City, but not eight plants can be convinced to incorporated pollution control.

I honestly believe the average Member of Congress is unaware of the deleterious effects of the limits and constraints placed on expansion within this country, in clean as well as in dirty areas. A very good case in point is the strip-mining bill which both bodies will be voting on soon. There is no question of either passage or President Carter's signature. I am basically in approval, though a previous opponent, because Congress was unaware of all the ramifications. Most people were talking about the West; my concern was the East.

If that bill had passed a year ago, incredible restraints would have been placed on mountain-top mining in West Virginia and East Kentucky, the predominant method of mining in some parts of those States. Most committee members had never seen these mines. Thank the good Lord that Mo Udall decided to take a helicopter tour and upon his return, really admitted previous myopia with the result the bill was rewritten in a proper fashion.

A year ago the bill would have been passed the other way around. The only thing that changed it was someone went and ascertained the facts. The same logic applies with certain provisions of the Clean Air Act.

The final comments I would like to make before this body and expressed to Mr. Barrett over the phone yesterday relates to environmentalism. If I am a little long-winded, I apologize, but I am so concerned about the power of the environmental lobby in the United States, some forum is required to place matters into proper perspective. I am not against environmentalism per se. I am against overzealous and unbalanced environmentalism. By and large what we really have faced in the coal industry is a 2-headed sword, that is, the inability both to mine all the coal we can burn and to burn all the coal we can mine.

When one looks at the administration and the type of people lured to Washington, starting with the Energy Department, to the CEQ, to the FEA, to the Interior Department, Justice Department, to the Office of Management and Budget, appointments have been so stacked in favor of the environmentalists, one would think no other side exists. It is one thing to make peace with these people and another thing to dampen the voice of opposition. It is just like putting the Russians in the Pentagon and asking them not to steal our military secrets.

An interesting quote is that of Brock Evans, of the Sierra Club, who said, "Half the environmental movement is now downtown in the administration, and the other half is always going downtown to visit them."

I am bothered that there doesn't seem to be any other side. A logical opposition is the oil industry, which sadly, has a credibility factor of minus 50. If there is 1 person out of 10 in America who has believed anything the oil industry says after the Arab oil embargo, we are lucky.

While I make a career out of the coal industry, I am also a critic. Every time the coal industry testifies, its point of view is well known in advance; the same is true of utilities.

Maybe we should form a coalition. Get 100 large corporations each to contribut $50,000, and take full-page ads in the Wall Street Journal, and the New York Times. Then comes the problems: If we bring in the auto companies, environmentalists will jump all over them, because they have a vested interest with the gas guzzlers. In the final analysis we may only be left with the likes of an IBM. Environmentalists will then go after the mutual funds, threatening to sell their shares if the funds do not liquidate IBM; the banks, threatening deposit withdrawals. They will picket annual meetings, parade in the streets, and bring class actions. There seems to be no limit.

You had floods in West Virginia and Kentucky a month and a half ago and 8,000 people marched on Charleston and claimed the coal industry was the cause despite government averrals that floods would have occurred there was no coal mining industry.

In Alton, Illinois, the Army Corps of Engineers wants to widen the locks by 35 feet because the old ones are worn out and to allow more efficient use of our inland barging system. This brought about a protest in the Isaac Walton League, claiming that the wildlife might be endangered, which immediately was seconded by the Burlington Northern because, after all, barges represent competition for the railroads.

So you wonder if the world hasn't gone berserk. If there is one final message, I ask that each member of this committee and those who are not here whom you may influence, consider the other side. If you have not heard much noise because you are taking pro-environmental positions, one of the reasons is that the average American has been hoodwinked and doesn't know what to believe. The other side is alien to him. Our democratic process is such that you react to your constituency, but who is to say it can't work both ways wherein you present the other side to your constituents? I pray that in the months ahead, as we try and formulate an energy policy, we will consider coal and nuclear must be the cornerstones of our energy policy, that we must provide production incentives—despite S. David Freeman—which in turn will require the removal of environmental roadblocks which have hindered us all throughout this decade and threaten to worsen to everyone's detriment.

I thank you very much and apologize for the length of my comments.

Mr. MOFFETT. Thank you, Mr. Price.

Mr. Gray, do you think you could summarize your statement in about 4 or 5 minutes and then we would go and vote and come back?

Mr. GRAY. I can summarize it in about 5 minutes.

STATEMENT OF WILLIAM R. GRAY

Mr. GRAY. I am Bill Gray, of Inland Steel Company, and the incoming chairman of the Committee on Energy of the American Iron and Steel Institute. I did submit written testimony, and I would like to make this brief statement and have the written testimony entered in the record.

Our position on coal conversion is very simple. It is the policy of the American Steel industry to increase the use of coal, whenever feasible, in the industry's production facilities. The steel industry is unique among energy users in the United States because coal currently supplies 67 percent of its energy. Most of the coal used by the steel industry is consumed by integrated steel plants in the coke oven/blast furnace complex. The steel industry is in the coal gasification business, for coke ovens and blast furnaces produce large quantities of useful by-product fuels. In 1976, blast furnace and coke oven gas used by the industry was the equivalent of 850 billion cubic feet of natural gas.

While we believe that the maximum economic use of coal is desirable, we also believe that coal conversion must be accomplished in an orderly and practical fashion with due regard for several important considerations. Among these considerations are capital availability, equipment availability, additional coal supply and coal transportation availability and the avoidance of economic waste.

The steel industry believes that greater use of coal in boilers and other facilities should be encouraged, but opposes mandated conversion. Industry faces the problem of trying to conserve all scarce resources including capital as well as oil and natural gas. As written, the National Energy Act places an enormous responsibility on the Administrator to assess these tradeoffs, that is, weigh the benefits of coal conversion versus the cost of other resources. Our objective is to point out some of the difficulties we can foresee in administering this section of the act and recommend changes to minimize these difficulties.

In discussing our recommendations I will refer to the section numbers of the proposed amendments.

First, sections 106 and 107 would significantly reduce our ability to use by-product gases by prohibiting natural gas and petroleum as energy sources in new major fuel-burning installations. By-product gases are characterized by large variations in their output. In order to meet a constant demand for fuel, oil or natural gas must be used to level out periods of low by-product gas supply. Prohibiting such use would mean that industry would either forgo the full utilization of these by-product gases or fully utilize them and thereby risk the safety of the plant. The use of coke oven gas in steel reheating furnaces and blast furnace gas in boilers are examples of this problem. The term "energy source" as currently defined in section 102(11) permits the use of natural gas or petroleum required for start-up, testing, flame stabilization, and controlled uses. We recommend that this list be expanded to include oil and natural gas used as a supplemental source to insure the full utilization of by-product fuels and/or waste heat.

Second, the definition of natural gas in section 102(3) could result in wasting coke oven gas. This section defines synthetic gas derived from coal which contains 500 British thermal units per cubic foot or more as natural gas. This would prohibit the use of coke oven gas by major fuel-burning installations because coke oven gas is derived from coal and has a heating value of 500 Btu per cubic foot or more. This medium Btu gas would then be wasted, since it cannot be used directly by residential appliances designed for pipeline quality natural gas. We recommend that the definition of natural gas in section 102(3) be changed to read "excluding synthetic natural gas which is derived from coal and which has a Btu content below 600 Btu per cubic foot." We have assumed that the definition which currently reads 500 Btu " per cubic foot."

Third, we are concerned about the size of major fuel-burning installations to which the legislation should apply. We suggest that the statutory minimum be established at a design firing rate of at least 250 million Btu per hour for a single combustor. A boiler of only 100 million Btu per hour set forth in the bill would consume about 4 tons of coal per hour. We believe this figure is unnecessarily low and that 10 tons of coal per hour limit is more realistic. This is roughly equivalent to 250 million Btu per hour.

Fourth, because of the provisions of this bill, utilities and others may greatly increase their consumption of low sulfur coal. Unfortunately, low sulfur coal includes the limited reserves of premium grade recoverable low sulfur coking coals. It is as much a waste of resources to use low sulfur coking coals for boiler fuels as it is to use natural gas for this purpose. We recommend that sections 111 and 102(5) be expanded to recognize the unique attributes of coking coal.

Fifth, the standards of granting exemptions under sections 106 and 107 are vague and give the Administrator great latitude for interpretation. In our opinion, the standards as written do not adequately consider all of the economic factors in the use of coal.

Sixth, section 110, which deals with costs due to disruption of natural gas contracts, does not appear complete. For example, while it recognizes the cost impact on natural gas contracts of a required conversion, it does not consider the cost impacts on contracts resulting from the installation of a new facility. If industry were to choose new facilities instead of conversion of old facilities, the impact on natural gas contracts would be the same, but without relief under the law.

Last, although we realize that the tax provisions of the energy bill are not the direct responsibility of this committee, we would like to note that several provisions of title II, Tax Provisions, are in conflict with the coal conversion objectives of title I, section 601. For example, sections 1301 and 1502 limit the business energy tax credit and tax rebate to the retrofitting of existing property. In fact, the greatest potential increase in the use of coal, improvement in energy efficiency, and most effective use of investment capital in the steel industry, is frequently to build new facilities with the latest technology rather than to retrofit old facilities. We are also concerned that coke ovens are specifically excluded from tax rebate and tax credit, yet coke ovens are the most efficient coal gasifiers currently available and provide an important means of replacing petroleum with coal in the steel industry. We recommend that investment in new facilities and plants, particularly ones which substitute more energy-efficient new process technology, be eligible for the business tax credit or rebate.

The committee has asked that we include in our statement an indication of the steel industry's capacity to meet future steel demands. There is not a simple answer to this question. Briefly, let me conclude by saying as the coal conversion program goes forward, it is reasonable to anticipate that there will be increased demand for mining and power generating equipment, rail transportation facilities, pipelines, and a variety of steel mill products required for the production of these facilities.

With the present relatively low level of heavy construction activity in the United States, the current capacity to produce these products has been adequate. Demand is expected to increase, however, and the industry has capital programs underway aimed at meeting future demands. In order to assess the adequacy of projected capacity to meet the demands for these products in the future, it is necessary to have an understanding of the timing and material requirements of the coal conversion program. We in the steel industry would be pleased to cooperate with appropriate government officials in assessing the adequacy of capacity as progress is made in defining these material requirements.

Thank you.

[Mr. Gray's prepared statement follows:]

American Iron and Steel Institute

May 25, 1977

Testimony of American Iron and Steel Institute before the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce on H.R. 6831, The National Energy Act, Title I Part F, Amendments to the Energy Supply and Environmental Act.

Mr. Chairman and members of the Subcommittee, good afternoon -- I am William R. Gray, General Manager, Corporate Planning, of Inland Steel Company. I am the incoming chairman of the Committee on Energy of the American Iron and Steel Institute. The AISI represents 64 member companies which produce over 93% of the raw steel made in the United States and employ approximately 700,000 people in steelmaking and non-steel related activities.

Our position on the issue of coal conversion can be stated very simply. It is the policy of the American steel industry to increase the utilization of relatively abundant domestic coal as a fuel, wherever feasible, in the industry's numerous manufacturing and production processes. Coal currently supplies 67% of the energy used in steel manufacturing.

This policy is based upon our agreement that the maximum economic utilization of coal as a fuel is in the best interests of the nation and the steel industry. However, this is difficult to accomplish considering the simultaneous goals of environmental protection and energy conservation. Greater coal utilization often results in greater energy consumption per unit of production. We also believe that coal conversion must be accomplished in an orderly and practical fashion with due regard for several important considerations. Among these considerations are capital availability, equipment availability, additional coal supply and coal transportation availability and the avoidance of economic waste.

The steel industry believes that greater use of coal in boilers and other facilities should be encouraged but opposes mandated conversion. Industry faces the problem of trying to conserve all scarce resources including capital as well as oil and natural gas. Fuel price deregulation, more reasonable sulfur oxide limits and financial incentives would be more effective in promoting both conversion to coal and the efficient use of all resources.

It is the impact which House Bill 6831 would have on these considerations to which we direct our remarks today.

Background

Since its inception, the steel industry has been a major producer and consumer of coal. With this background of experience and with its interest in energy independence, the steel industry is certainly in agreement with the objective of more reliance on coal which is the purpose of the National Energy Act and particularly of Part F, of Title I, the Amendments to the Energy Supply and Environmental Coordination Act. However, we do have important concerns about certain portions of the Act as it is now written. The following sections spell out these concerns and the logic underlying them, and offer recommendations for realistic improvements in the Act.

At present, approximately two-thirds of the total energy consumed in the energy intensive steel industry is directly coal based. About 90 percent of the coal is metallurgical grade used in the coking process and the remaining 10 percent is used for steam generation. The other one-third of the industry's total energy supply is comprised of natural gas, petroleum products and purchased electricity. Much of these energy forms are used in areas which do not lend themselves to direct coal use because of vital technical and economic considerations.

However, it is necessary to recognize that the steel industry is not a homogeneous industry and that the processes and facilities of the various steelmaking plants are significantly different. Only integrated plants have by-product gases available from blast furnaces and/or coke plants. Non-integrated plants rely more heavily on scrap usage and non-coal based energy.

There are a number of provisions in Section 601 of the National Energy Act which we believe should be revised or clarified if the desired effect of greater coal use is to be achieved. The Sections referred to below are the amended Sections of The Energy Supply and Environmental Coordination Act of 1974 as proposed by Section 601 of the National Energy Act.

Use of Gas Derived from Coal

There are several items in the bill which may limit the use of gas derived from coal. First, the definition of natural gas in Section 102 (3) states:

> "(3) The term 'natural gas' means natural gas as defined in the Natural Gas Act, including synthetic natural gas derived from petroleum and liquid petroleum gas, but excluding natural gas produced from a well at the site of use by the user, in commercially unmarketable quantities, as determined by the Administrator, and excluding synthetic natural gas which is derived from coal and (A) which has a British thermal unit content below 500 British thermal units per thousand cubic feet, or (B) (i) which is owned by the user when it enters a pipeline for transportation to the user, and (ii) which has been approved by the Administrator for use by an electric power plant or major fuel-burning installation."

This definition could prevent the sale or transfer of coke oven gas for use by major fuel burning installations because coke oven gas usually has a heating value of 500 or more British thermal units per cubic foot. If the use of such gas in industrial applications were prohibited, the gas would be wasted because it cannot be used directly by residential appliances designed for natural gas.

We recommend that Section 102 (3) (A) be changed to read, "... and (A) which has a British thermal unit content below 600 British thermal units per cubic feet."

Another concern with the definition of natural gas is inclusion of high-Btu gas derived from coal except in very limited cases. It may become environmentally and economically sound in many cases to install very large coal gasification plants remote from the principal users. If industrial use of such gas were prohibited, such plants probably would not be built because the demand would not be great enough to provide economical operation. This situation could be avoided if all coal-derived gas were excluded from the definition of natural gas.

The National Energy Act as written will have other adverse effects on the use of coal-derived by-product gases within integrated steel plants. Section 106 under Part F appears to prohibit use of natural gas or petroleum in combination with coal based fuels and under Section 107 (a) (3), the use of such combinations of fuels with existing major fuel burning installations may be prohibited. By-product gases would be wasted and, in some cases, the safety of the plant would be threatened if there were an absolute prohibition of fuel combinations. Three examples illustrate why this is true. In many integrated plants, a "mixed gas" distribution system is used to supply coke oven gas (surplus from coking operations) to fuel burning facilities such as soaking pits, slab and billet reheat furnaces, certain annealing and heat treating furnaces, ladle drying and heating stations, coal car thaw burners, and blast furnace stoves. Both the production of coke oven gas and the demand for it vary significantly over time. Long term demand which exceeds the supply of coke oven gas can be met in many cases by the use of petroleum fuels at the individual units. However, it is not possible to alternate fuels quickly enough to deal with the instantaneous changes of production and use. This condition has led many steel plants to install mixing stations where a natural gas-air mixture is added to the "mixed" gas supply to meet peaking requirements. This supplement to coke oven gas allows for base loading a sufficient number of fuel consuming units with coke oven gas to prevent flaring (wasting) gas during low consumption periods resulting from mill delays, product mix, and other variable operating conditions.

The second example concerns the use of the blast furnace gas, the low Btu waste gas from the ironmaking operation. This top gas, a by-product of the combustion of coke in the furnace, is a prime source of energy in an integrated steel plant. The gas is used to supply heat to blast furnace hot blast stoves, underfire coke ovens, boilers, and some steel reheating facilities. The boilers supply steam for the compressors which in turn supply the "wind" (pressured air) to the blast furnaces, for electric power generation and for plant use.

The generation of blast furnace gas varies much more than does that of coke oven gas. For example, to remove the molten iron from the bottom of the blast furnace, cast holes are pierced. To prevent toxic gas and molten metal eruption from these holes, the normal operating pressure in the furnace is dropped. As a consequence, the lowering of pressure radically reduces the generation of blast furnace gas. If the boilers are to be protected from losing their ability to produce steam and to prevent loss of ignition, supplemental or replacement fuel must be instantaneously injected to keep the combustion level in the boiler stable. Natural gas is the safest, most reliable and most efficient fuel adaptable for this purpose. It is not feasible to substitute coal to fulfill this protection function because of the protracted time to furnish the required infusion of Btu's if it is not actually in use simultaneously at the time of an instant disruption. In any case, prohibition of combined fuel use can result in decreased blast furnace gas utilization.

The third example deals with the problem of decreasing blast furnace gas heating value. As blast furnaces have used more high-quality raw materials and become more energy efficient, the Btu value per cubic foot of blast furnace gas has declined. Therefore, it is necessary to mix higher Btu gases with the blast furnace gas for some high temperature applications, e.g. in hot blast stoves. In some cases, natural gas must be used because no other gas is available.

Minimum Capacity for Conversion

Let's turn now to the question of the size of major fuel burning installations to which the legislation should apply. We suggest a statutory minimum be established of a design firing rate of 250 million Btu per hour for a single combustor. A boiler of only 100 million Btu per hour would consume about four tons of coal per hour. We believe this figure is unnecessarily low and that a more realistic recommendation would be 250 million Btu per hour minimum. A coal consumption of approximately 10 tons per hour would reflect the more favorable economic conversion of existing facilities.

This recommendation is based on the economic sensitivity to scale of boiler conversion, including installation of coal firing capability and emissions control. We believe that a revision upward in the size of boilers requiring conversion would be more realistic. In addition, retrofitting present gas or oil-fired boilers to use coal is at best inefficient, due to the small combustion space, and lack of ash hoppers and soot blowers in these units. Furthermore, it is probably impossible to convert present gas and oil-fired boilers to coal without loss in capacity of about 50% so these conversions could also require new boiler installations just to maintain present capabilities.

Application of Exemption and Temporary Exception Rules

The standards for granting exemptions and the definitions of major fuel-burning installations in Sections 106 and 107 are vague and therefore their interpretation by the Administrator could cause undue hardship to many firms. First, Section 106 may not consider unfavorable economic impact including investment costs as a reason for permanent exemption, or for temporary exception in the case of new major fuel-burning installations unless the economic impact is related solely to the coal supply. It must be recognized that the cost of using coal as well as obtaining a reliable supply may be more expensive than imported petroleum even in a facility specifically designed for coal. For example, a process which requires a gaseous low-sulfur fuel might be able to use coal only if a coal gasifier and desulfurization unit were employed. This added cost, which probably would include new coal receiving, storage and processing equipment, could result in the deferral or abandonment of plans for new facilities.

The example just discussed deals indirectly with another concern with Sections 106 and 107. The Administrator alone has the right to define categories of major fuel-burning installations and to prohibit natural gas or petroleum use in any such category without a reasonable right of appeal available to the affected parties. Mandated conversion or prohibition of non-boiler installations is too broad to be practical. Prohibitions should be made only on an individual facility basis and a procedure should be established for appealing denials of applications for temporary exceptions or exemptions.

Costs Due to Disruption of Natural Gas Contracts

Section 110 provides for the recovery of costs incurred because of distruption of a natural gas contract because of prohibition of natural gas use by an existing power plant or major fuel-burning installation. There are two apparent defects in this section. First, disruption of gas contracts by installation of new boilers and MFBI is not considered. An operator may be unable to use all or part of his contracted gas when a new power plant or MFBI replaces existing facilities. Sections 104 and 106 should be added to the causes for disruption under Section 110 (a) and 110 (b).

The second omission in Section 110 is the lack of recovery of added fuel costs. It is possible that the user will have to pay more for alternate fuel than the maximum lawful price for natural gas as provided in Section 110 (a). The recovery of added fuel costs should be allowed.

Coal Allocation

Because of the provisions of this bill, utilities and others may greatly increase their consumption of low sulfur coal. Geological Survey Bulletin 1412 shows total estimated coal resources remaining in the ground January 1, 1974 at 3,986 billion tons. Unfortunately, only 50 billion tons of this amount is identified as premium grade recoverable low sulfur coking coal. It is as much a shame to use low sulfur coking coals, which are feed stocks for steel plants, as boiler fuel as it is to use natural gas for this purpose.

Steel plants require coke which has to be produced from the limited reserves of metallurgical coal. Steam generation facilities have greater flexibility to utilize coals of varying qualities than do coke production facilities. Utilities can utilize metallurgical coal for steam generation but the steel industry cannot use steam coal for coke production.

We recommend that Section 111 be expanded to note that metallurgical coals should be specifically identified so that they would not be considered reserves for fuel usage when the availability of coal is determined under this act in emergency allocations. Further, the definition of coal in Section 102 (5) should recognize the unique attributes of coking coal.

Tax Considerations of Coal Conversion

The coal conversion provisions of Part F of Title I of the National Energy Act are affected by several provisions of Title II -- Tax Provisions and in some cases, the coal conversion policy and tax provisions are in conflict.

Section 107 (d) (3) recognizes that prohibition of natural gas and/or petroleum fuel use may be technically infeasible in some major fuel-burning installations. However, Section 1501 - Oil and Gas Consumption Taxes, taxes all use of petroleum or natural gas use whether or not there is a technically feasible alternate energy source. We recommend that where the Administrator finds direct coal use infeasible, the fuel used by such major fuel-burning installations should be exempted from the oil and gas consumption taxes of Section 1501.

Part C of Title II, the Business Energy Tax Credit, Section 1301, and Part E, the Industrial Oil and Gas Conservation Rebate, Section 1502, also work against the purpose of the coal conversion provisions. First, the greater use of coke by the steel industry is discouraged by excluding facilities where coal is used as feedstock for coke and facilities for conversion of coal into synthetic gases with heat content greater than 500 Btu's per standard cubic foot from the special business energy property investment tax credit. Gas from coke oven conversion of coal may have a heat content as high as 600 Btu's per standard cubic foot.

The definitions of alternate energy property under Section 1301 and Section 1502 referred to above should be modified to consider coke manufacture as an allowable feedstock operation and to include synthetic gases up to 600 Btu's per standard cubic foot.

The major defect of Section 1301 and Section 1502 is the limitation of the business energy tax credit and tax rebate to property facilities and equipment added to existing property. Further, coal conversion credit is limited to the burners and coal handling equipment. In addition, facilities which significantly alter the manufacturing process are excluded from the business energy tax credit. The greatest use of coal and the most efficient use of energy will be possible with completely new facilities and particularly with "greenfield" plants using the newest technology and most effective product flows. Such new facilities are discouraged by the National Energy Act while the retrofitting of old fuel-consuming facilities with relatively inefficient heat recovery and with coal-conversion equipment which may reduce productive capacity and affect product quality is promoted. This is an uneconomic approach to the national energy problem which will have long-range adverse consequences.

We recommend that investment in new facilities and plants, particularly ones which substitute more energy-efficient new process technology, be eligible for the business energy tax credit.

CONCLUSION

We believe that the above recommendations to revise the proposed coal conversion provisions of the National Energy Act will further the objective of greater utilization of coal and at the same time recognize other objectives such as efficient use of capital, conservation of all forms of energy and minimizing the disruptive effects of the conversion process.

As the coal conversion program goes forward, it is reasonable to anticipate that there will be increased demand for mining and power generating equipment, rail transportation facilities and pipelines. Production of these facilities could require large quantities of a variety of steel mill products including plates, structural shapes, bars, rails, wheels, axles and pipe. The Committee has asked the steel industry to consider whether there will be sufficient future production capacity.

Recently, with the relatively low level of heavy construction activity in the United States, the capacity to produce these products has been more than adequate to meet demand. In order to assess the adequacy of capacity to meet demands for these products in the future, it is necessary to have an understanding of the timing and material requirements of the coal conversion program. We in the steel industry would be pleased to cooperate with appropriate government officials in assessing the adequacy of capacity as progress is made in defining these material requirements.

At this time, I can only state a general concern that returns on investment in steel-producing facilities are quite low. Furthermore, the steel industry is having to spend vast amounts of capital for replacement and expansion of productive facilities as well as for economically non-productive facilities for the improvement of the environment. Capital availability will be a serious problem unless investment returns improve. With respect to the proposed energy bill, AISI in its testimony before the House Ways and Means

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Committee on April 18, 1977, stated "that the rebate and tax credit provisions should be used to promote energy efficiency and not only to promote conservation of existing facilities or conversion to coal. Thus, the rebate should apply to energy saving facilities or devices added as an integral part of the manufacturing process but which result in conservation of oil or natural gas."

Mr. MOFFETT. Thank you, Mr. Gray.

The committee will stand in recess for about 10 minutes.

[Brief recess.]

Mr. MOFFETT. The subcommittee will come to order.

Mr. Norton, you gave us some categories of plants. Do we have a breakdown nationally on that? I don't know if that has already been submitted to the committee, but does anyone on this panel, or do you, have a breakdown of the percentages of plants that fit into those categories?

Mr. NORTON. I don't have it right at my fingertips. I think it is information that can be come by quite readily.

Mr. MOFFETT. I don't want to have it gathered if it has already been gathered. We can probably get it.

Mr. NORTON. I think the principal boiler manufacturers could tell you which of the boilers that they have sold for gas and oil had minimum provision for future conversion to coal. There are numbers of those. I don't think they are in great proportion, but I know of a number of cases, myself.

Mr. MOFFETT. I would yield at this time to Mr. Barrett, the counsel, for questions.

Mr. BARRETT. Mr. Price, one of the major areas that the administration expects will grow in the coal conversion program is the industrial area. Is it my understanding of your testimony that you don't believe that that is going to happen?

Mr. PRICE. No, that is not correct. I was really talking, Mr. Barrett, in terms of the next 5 years, in which instance I mentioned a universe of maybe 15 million tons. I said when more data became available out of the FEA, perhaps within the next month, better numbers would be produced.

There is no question that the industrial plants of tomorrow will burn coal. I don't include, for example, cement, where sulfur is burned in the cementmaking process, and ash, of course, is a raw material, and where this conversion process has been ongoing voluntarily for the last 5 years. There should be a very sharp growth in the industrial sector. I wish the numbers could be furnished you today, but they are not available anywhere. No one in the City of Washington really has them.

I would make this statement: If you look at some of the numbers provided by the Energy Department or via the President's message, the magnitude of plants that will be burning coal is without question wildly exaggerated. It will not be anywhere near that big, but at this point, lacking the actual numbers to analyse, I can't furnish you the data. I will provide it in a month or so if desired.

Mr. BARRETT. We were provided yesterday with some numbers that would indicate that without the Carter plan we would have 205 million tons by 1985 used by industrials and with the plan there would be 385 million tons per year.

Now that represents an increase in the industrial area of 180 million tons by virtue of the legislative package.

Do you think that is a realistic figure?

Mr. PRICE. I think neither figure is realistic.

Mr. BARRETT. Neither the 205 million——

Mr. PRICE. Correct.

Mr. BARRETT. Without the plan or——

Mr. PRICE. The industrial sector last year was somewhere in the area of 60-61 million tons. Now for anybody in this room to believe that it is going to 205 million, on one hand, or 385 million, on the other, is nothing short of wishful thinking, and irrespective of whoever put that data together, that data has to be very suspect. The 205 million ton estimate includes metallurgical coal used to make coke, which probably should be excluded.

Mr. MOFFETT. I would like to follow up on that, if we might. You think the data is suspect simply because you just can't imagine that kind of increase; is that right?

Mr. PRICE. Yes. But it is very difficult to make flat statements without the material. The raw data will be sold in book form by McGraw-Hill, and people can make their own interpretations. As soon as it is on tape, Dean Witter will program it on a computer. For one thing, I don't think the small industrial plants will convert to coal. It doesn't make any economic sense. Some will opt for oil, others will move to electricity.

I just have to say those numbers are unrealistic for the time being and should not be believed until hard data is given you.

Mr. BARRETT. Perhaps Mr. Frendberg and Mr. Norton could tell us, the definition that we are dealing with in the bill of a major fuel-burning installation describes one which is capable of consuming fuel at a heat input rate of 1 million Btu's per hour or greater. It is my understanding that is a relatively small unit. Is that correct?

Mr. FRENDBERG. One hundred million is equivalent to a little more than 4 tons of high grade coal. This would be less than 100,000 pounds of steam an hour.

Mr. BARRETT. In terms of size, though, are we reaching down too small in ordering these kinds of installations to convert?

Mr. FRENDBERG. My opinion is very definitely yes.

Mr. BARRETT. I see Mr. Gray nodding his head yes.

Mr. GRAY. I testified directly to that point, that we believe that it should certainly not be less than 10 tons per hour which would be the equivalent of 250 million Btu's per hour. That can be argued as still pretty small, and I certainly agree that the economics below that would be extremely difficult to make any sense out of.

Mr. FRENDBERG. My comments were primarily directed at the utility-type boiler. The industrial boiler of 100,000 pounds or less is a so-called package boiler, and its physical design is totally incapable of being fired by coal other than—I mean just to get the coal to it—other than pulverized form, and then the comments I made of its incapability to handle coal still apply. To try to put pulverized coal into a boiler of that size in an industrial unit; the expense would just be intolerable.

Mr. BARRETT. To someone faced with that situation of having to convert, what kind of remedy would he have to seek using electricity as an alternative fuel?

Mr. FRENDBERG. Even with the use of electricity he has to purchase new equipment. If there were no gas or oil, absolutely, he would have to replace the unit with a unit designed for coal.

Mr. NORTON. It is somewhat in the future, but, of course, there is the ERDA program and the interest of EPRI in fluidized bed combustion and a program of trying to develop industrial-size small boilers, and then there is also a great interest, particularly in the Northeast, in the possibilities of coal liquefaction and the possibilities of being able to substitute a coal-derived liquid fuel as a direct replacement for petroleum fuels, but there is a lot more than that that has to be determined and examined before that is known to be a real practical possibility, because there hasn't been that much testing of the material of the product that has been produced by the liquefaction processes.

Mr. MOFFETT. Mr. Gray.

Mr. GRAY. Mr. Barrett, I think in the written testimony that we submitted, we tried to deal with that a bit under the section on the exemption conditions. As we understand it, the exemption condition, either for retrofit or new facilities, is measured against the cost of imported fuels. And our concern there is that that would, in fact, bring great hardship to people who are in that position because it does not appear to reflect the fact that the economics of installing the coal-receiving facilities, installing all of the capital investment necessary to either replace the boiler, if that is the only way you have to do that, or convert to an alternate means, neither way is dealt with in the rules, as we read them, as they apply to the remedy under the exemption clauses.

They are very vague and they leave great matter of interpretation to the Administrator. And I think it would be a very, very difficult problem in that particular area.

Mr. BARRETT. Mr. Price, are there going to be capital constraints which will limit both production of coal and the demand for coal? What are the money markets going to do about the supposed increased demand and supply problems?

Mr. PRICE. There is no question in my mind that if both bodies of Congress don't lose their heads and force oil divestiture, there will be ample capital available. Nothing will be developing in the supply-demand picture to change anything already known.

When you revert to the Arab oil embargo and look at some of the studies put out about how many large mines must be opened, men trained and railroad cars ordered, some of those figures were truly fanciful and will not come to pass because we lack the capability to produce the kind of coal numbers that President Nixon said. But Wall Street is geared up to handle this financing. Our own firm has a financing subsidiary especially designed for this. Any real creditworthy customer can obtain financing today for large-sized expansion programs, the money markets are available, and, if anything, are hungry to handle such needs. I do not see capital constraints.

Mr. BARRETT. How about the transpcrtation? Have you analyzed transportation of coal?

Mr. PRICE. Well, as we develop between now and 1985, your big growth is in the West. You might have to tone down some of the projections several years back because of the effect of environmental impact studies, the continued moratorium on coal leasing and the real failure of the coal-leasing program. No, there will not be a serious railroad car shortage. There will be limited production increases in Appalachia and the Midwest. Your biggest single problem is going to be ConRail. If New England, for example, opts more heavily for coal, there are plans afoot for barges, say, from Hampton Roads and Newport News up to New England, which can be achieved fairly economically. One of the sad things, of course, about the railroad industry is it only seems to place its car orders when business is good. It is not accustomed to planning ahead and ordering when the railroad car shops are empty. As a result, the demand for railroad cars presently is about as low as you can possibly get.

It all relates to uncertainty in direction.

Mr. MOFFETT. How do you see the picture in the Northeast and New England aside from that?

Mr. PRICE. Are we talking about getting the coal to the user or using the coal?

Mr. MOFFETT. Using coal.

Mr. PRICE. As you know, Mr. Chairman, those New England utilities being given conversion orders seem to be fighting tooth and nail—Northeast Utilities, New England Electric. I don't really object to some of their fighting because people on the outside don't really understand their source of irritation.

One of the points that I did not make is that a major change is necessary wherein States should not be allowed to have standards more stringent than that of the Federal Government, which in many instances are too rigid already.

Now, the definition of compliance coal is, for example .75 percent sulfur at 12,000 Btu's. New England Electric tells me that it must burn .65 percent sulfur coal, and less than 8-percent ash, with a specified grindability. As such, the only usable coal is metallurgical grade quality, which is sort of silly.

If you talk to people up in Massachusetts, they tell you that State is unique. It imports pollution and exports clean air. If one examines the air regulations there is no allowance for breezes blowing out to sea.

It applies to New York, Connecticut, New Jersey, and Massachusetts. The first step really is not so much how will you get the coal but will there be realistic standards to allow the burning of coal. If you accomplish that, then the other things fall in place.

In the interim, the utilities are going to fight. In fact, it is no secret that New England Electric is looking to buy a semimetallurgical type mine in eastern Kentucky as the only way to handle its coal needs.

Mr. MOFFETT. So you don't buy the contentions of those in Connecticut and other places that we have a serious health problem and we can't afford to lower our standards?

Mr. PRICE. No, I don't.

Mr. MOFFETT. You have analyzed their data and you just don't buy it.

Mr. PRICE. I avoid shooting off my mouth on that which I am uninformed. To make the statement before this body that I have analysed data from Connecticut would be untrue. I have tried to examine the whole area of sulfur emissions, sulfates, and so on. I do not equate it to tobacco industry assertions that you cannot prove cancer is related to tobacco. The truth of the matter is that evidence was really quite persuasive all along. The evidence is far from persuasive in terms of the dangers of sulfur emissions.

Electric Power Research Institute has done much work in this area. This is a body not necessarily obliged to come up with a preconceived answer. It raises all kinds of questions about inflated sulfur emission and sulfate dangers.

A scandal of sorts broke last year when one person in a West Coast office of the EPA was reputed to have falsified data to produce the findings that EPA wanted.

No, the worries about sulfur are not well founded in terms of all sulfur. Yes, the unlimited use of high sulfur coal without some kinds of controls represent potential risks. But, to take compliance coal and say that represents a danger, too, is nothing short of overkill.

Mr. MOFFETT. Any further questions by counsel?

Mr. VLCEK. Thank you, Mr. Chairman.

Mr. Norton, in your statement you addressed the powerplant situation and presented the problems that exist with respect to those. In the area of industrial conversions, are there other problems that exist that you could articulate for us, in addition to the ones you described here for powerplants, further constraint that might exist in a situation where there is an industrial conversion?

Mr. NORTON. I expect there would be the same limitations perhaps on a smaller scale to the extent that the facilities are smaller. I think my associates here would support that it is as impossible to convert a gas-fired boiler to coal firing in the industrial size as it is in the utility size, if it was not designed for that in the first place.

Also, I don't think that there is a parallel in the industrial case where a boiler was designed initially for burning oil and gas in anticipation of ever converting it to coal unless it was of a scale of a utility size boiler. I just don't think there is a case like that.

Mr. VLCEK. Generally speaking, the problems you have articulated here are the same in the industrial sector as the utility sector.

Mr. NORTON. I think the principles are the same. I think the cases are not parallel. I don't think there are industrial boilers that, as I say, are designed for possible future coal. I think those that were designed for coal were the old chain grate stoker type, and I think they have generally been replaced, say, rather than converted.

Mr. VLCEK. I wonder if either you or Mr. Frendberg could give the committee some idea of the costs we are talking about here in the individual conversion case. You cite, Mr. Norton, on page 3 of your testimony an example of a type of boiler. You mention one that could be in the order of 200 tons per hour. If we had such a typical boiler, and it was in a situation as described in the previous paragraph, where you say the boiler is designed exclusively for burning gas, and it had to be converted to coal, could you give the committee some idea of what the general range would be of performing that operation?

Mr. NORTON. When it comes to the boiler itself, that is a little bit out of my area. However, I think the most restrictive thing there—if you could accomplish the changes needed to get the coal to the unit and into it for burning, and could adjust the heat transfer surface, etc., you are faced with the problem that the furnace box is just so small, when you recognize that it is going to take twice as much furnace volume to burn coal for the same rating as gas. On this basis, the gas boiler converted to coal will be half as big in outout as its original application.

So, if you were to go to the expense of converting a gas boiler and end up with half a boiler by way of capacity, you would have to supplement that with another boiler.

My opinion would be that the combination of converting the gas boiler plus adding the supplemental would be more than if you just took the original gas-fired boiler out and built a coal-fired boiler.

Mr. VLCEK. Does anybody on the panel have any impressions as to the costs of performing these sorts of conversions on an individual basis? If you do, I wish you would provide that for the record.

Mr. NORTON. I can add one thing. I recall the comment made after we had made a study for a utility, for making the conversion to simply upgrade the operation to the present requirements, increasing the sizes of the precipitator and adding the scrubber, and that the cost approached the original cost of the plant.

Mr. VLCEK. Okay.

Mr. Price, I want to clarify a couple of things that you stated. In response to a question you said that you felt there were no constraints on the capital markets for purposes of this program. Now, I want to understand—is that on the supply side—that is for purposes of opening new mines, expanding mine production, or are you also saying there are no constraints in the capital markets for purposes of performing the types of conversions that we have been talking about here, either in the industrial or utilities sector?

Mr. PRICE. I was talking in terms of the supply side for coal. If we were to take literally the conversions which in theory could embrace, say, 1,200 to 2,400 units, and cost perhaps $50 billion in terms of 1976 dollars——

Mr. VLCEK. Wait. Where are you getting the numbers?

Mr. PRICE. 1,200 to 2,400 plants could be the total universe of maximum conversions—all oil and gas to coal. As a matter of fact, I think the source is Senator Jackson. The cost of that would be $50 billion in 1976 dollars as cited by NERA and the National Coal Association. That money is not available. I am talking coal supply, financing of building of coal mines and so on, together with support facilities.

Mr. VLCEK. What sort of capital availability is there? How short of the mark are we? You say $50 billion according to the NERA study. Can you give us any impression of that? You say people are hungry to provide money for the expansion of supply. Is there hunger at all in the other area?

Mr. PRICE. First of all, we must define our objectives, and what its share of the $50 billion is. In the final analysis, it will come down to a fraction of that. This favors creditworthy companies for whom that money will be available. If we include every small industrial firm looking for money to convert, funds will be limited. It is comparable to the capital markets of today where there is easy access for major corporations but little corporations have to work with their local banks and have no access to selling common stock on the market.

Mr. VLCEK. The administration told us in briefings they are talking about major industrial entities in terms of the industrial conversion program. Therefore, what you are saying is there would not be a capital constraint if we are talking about the Fortune 500 companies.

Mr. PRICE. There won't be a capital constraint if spaced out over a period of time. I am making the assumption this $50 billion number is the top of the mark and we are alluding to something considerably less. If you took the whole ball of wax and said maximum conversions, it would be a nightmare.

Mr. VLCEK. What about on the utilities side? You mentioned creditworthy institutions. Is there some problem with creditworthiness in the utility sector?

Mr. PRICE. When you talk of the utilities you run into some very interesting circumstances. If you are the average utility, it has been much easier until now not to convert and to use expensive imported oil because, with the automatic fuel adjustment clauses, you just push a button and pass through the costs.

On the other hand, if you want to install a scrubber or build a new plant, whatever it may amount to, you have to get a rate adjustment, which means lengthy procedures before the State regulatory commissions. By the time a rate increase is approved you are ready to file for another one.

So, the line of least resistance has been the automatic pass through. It is no secret that a couple of years ago utilities were in very serious financial binds. Detroit Edison sold part of its coal stockpile to raise capital. If capital seeking is to be an orderly process, the funds will be there.

Much depends on the magnitude and the timespan with which it is all encompassed.

Mr. VLCEK. That is the key question. Is the timespan in the administration proposal too short, too long, and how should it be extended in your view if it should be? You can think about that and answer for the record.

Mr. PRICE. If we are merely talking about the types of conversions that I alluded to, which was those that have a prior coal burning capability, plus some of the smaller industrial plants deciding to go to electricity, you do not have a capital problem.

If you are to force all the utilities, by taxes and so on, to switch from oil and gas to coal, then the money will not be available, one of the reasons being that the public will eventually wake up to the effect on the cost of living, the cost of electric power, the cost of everything.

At this point in time, the average person has absolutely no comprehension of the costs that lie ahead. When you finally get down to the nitty-gritty of raising large sums of money, the day of reality will hit and the money won't be there. It will be where it makes economical sense.

Mr. VLCEK. Thank you, Mr. Chairman.

Mr. MOFFETT. Do you have a statement?

Mr. FRENDBERG. I think you have a panel on Friday, in which Bill Marks of ABMA is going to be part. I think he will have some of the answers on these industrial questions that you asked.

Mr. CORBIN. One quick point. The steel industry believes there is a capital problem and we would like to supply some information to Mr. Vlcek.

Mr. MOFFETT. Gentlemen, thank you for your testimony. We have found it very helpful.

The subcommittee will stand adjourned until 9:30 a.m. tomorrow.

[Whereupon, at 5:15 p.m., the subcommittee adjourned, to reconvene at 9:30 a.m., Thursday, May 26, 1977.]

NATIONAL ENERGY ACT

THURSDAY, MAY 26, 1977

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
Washington, D.C.

The subcommittee met at 9:30 a.m., pursuant to notice, in room 2123, Rayburn House Office Building, Hon. Anthony Toby Moffett presiding, Hon. John D. Dingell, chairman.

Mr. MOFFETT. The subcommittee will come to order.

The hearing this morning considers a number of questions related to coal conversion, specifically H.R. 6831, the National Energy Act, title I, part F. The first panel this morning will focus on health and safety issues.

We are very happy to have with us Dr. John F. Finklea, Director, National Institute for Occupational Safety and Health; Ralph E. Bailey, chairman and chief executive officer, Consolidation Coal Company; Dr. Bertram Carnow, Director of Occupational & Environmental Medicine, University of Illinois; and Robert E. Barrett, Administrator, Mining Enforcement & Safety Administration, U.S. Department of the Interior.

Mr. Barrett, would you begin, please, and, if you would, because we do not have as much time as we would like, we would appreciate your paraphrasing your statement. Without objection, your entire statement will be included in the record.

STATEMENTS OF ROBERT E. BARRETT, ADMINISTRATOR, MINING ENFORCEMENT & SAFETY ADMINISTRATION, U.S. DEPARTMENT OF THE INTERIOR; DR. JOHN F. FINKLEA, DIRECTOR, NATIONAL INSTITUTE FOR OCCUPATIONAL SAFETY AND HEALTH, DEPARTMENT OF HEALTH, EDUCATION AND WELFARE; RALPH E. BAILEY, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, CONSOLIDATION COAL COMPANY; AND DR. BERTRAM CARNOW, DIRECTOR OF OCCUPATIONAL & ENVIRONMENTAL MEDICINE, UNIVERSITY OF ILLINOIS, NORTHBROOK, ILLINOIS

Mr. BARRETT. Thank you, Mr. Chairman. We in MESA, of course, are charged with enforcing the Federal Coal Mine Health and Safety Act of 1969, and through that act we have the responsibility for protecting as best as possible the health and safety of the miners at the Federal level.

We feel that the increase in production is welcomed by the total industry as well as MESA. We are charged to see that this increase in production is not accompanied by an increase in numbers of accidents and numbers of fatalities as well as an increase in occupational disease. Primarily that is what we are charged to do. We welcome this increase in production if it occurs through conversion, and we will do our best to see the health and safety of the miners remains our primary concern.

Thank you.

[Mr. Barrett's prepared statement follows:]

TESTIMONY OF ROBERT E. BARRETT
ADMINISTRATOR, MINING ENFORCEMENT AND SAFETY ADMINISTRATION
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER
OF THE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
THURSDAY, MAY 26, 1977
9:30 A.M., ROOM 2123 RAYBURN HOUSE OFFICE BUILDING
REGARDING H.R. 6831

AT YOUR REQUEST, MR. CHAIRMAN, I AM HERE TODAY TO DISCUSS H.R. 6831 AND MORE SPECIFICALLY PART F OF TITLE I--CONVERSION TO COAL AND OTHER FUELS.

THIS BILL, CITED AS THE "NATIONAL ENERGY ACT," WOULD ESTABLISH A COMPREHENSIVE NATIONAL ENERGY POLICY. THE CHALLENGES FACING THE ADMINISTRATION AND THE CONGRESS IN ACCOMPLISHING THE GOALS OF THIS MOST COMPLEX LEGISLATION ARE FORMIDABLE.

AS TO THE INCREASED USE OF COAL THROUGH CONVERSION, AND ITS IMPACT ON THE HEALTH AND SAFETY OF COAL MINE WORKERS, LET ME STATE THAT THE MINING ENFORCEMENT AND SAFETY ADMINISTRATION HAS EVERY CONFIDENCE IN THE PRESIDENT'S COMMITMENT TO PROTECTING THE HEALTH AND SAFETY OF THE NATION'S MINERS.

MESA'S BASIC MISSION WILL NOT CHANGE WITH ENACTMENT OF H.R. 6831; AND I PLEDGE TO YOU ON BEHALF OF MESA, THAT THE WELFARE OF THE MINE WORKER WILL CONTINUE TO BE OUR NUMBER ONE PRIORITY. WE CONTINUE IN OUR FIRM BELIEF THAT A SAFE MINE IS A PRODUCTIVE MINE; AND WE CONTINUE IN OUR FIRM RESOLVE THAT INCREASED DEPENDENCE ON COAL SHALL NOT BE ALLOWED TO RESULT IN INCREASED DEATH AND SUFFERING FOR OUR MINE WORKERS.

CLEARLY, INCREASED PRODUCTION OF COAL RESULTING FROM THE COAL CONVERSION PROVISIONS OF H.R. 6831 WILL REQUIRE INCREASED INSPECTION ACTIVITIES BY MESA AND SOME INCREASE IN MESA'S BUDGET. FOR EXAMPLE, 1976 FEDERAL ENERGY ADMINISTRATION STATISTICS PROJECT AN INCREASE IN UNDERGROUND COAL MINING PRODUCTION FROM 304.1 MILLION TONS IN 1977 TO 383.9 MILLION TONS IN 1982. THE MAJORITY OF THIS INCREASE WILL RESULT FROM AN INCREASE IN THE NUMBER OF UNDERGROUND MINING SECTIONS RATHER THAN A SUBSTANTIAL INCREASE IN THE NUMBER OF UNDERGROUND MINES. HOWEVER, THIS STILL WILL REQUIRE A SIGNIFICANT INCREASE IN MESA INSPECTION MANHOURS. FOR INSTANCE, IN 1979 THE FEDERAL ENERGY ADMINISTRATION'S PROJECTIONS PREDICT AN INCREASE OF ABOUT 21 MILLION

TONS OF COAL FROM DEEP MINES. BASED ON AN AVERAGE OF 400 TONS PER WORKING SECTION PER DAY, THIS INCREASE EQUATES TO APPROXIMATELY 220 ADDITIONAL WORKING SECTIONS.

COAL MINING HAS UNDERGONE SOMETHING OF AN INDUSTRIAL REVOLUTION OF ITS OWN SINCE WORLD WAR II. A COAL SHOVEL IS A THING OF THE PAST AROUND A MINE NOW. MANUAL LABOR HAS BEEN REPLACED TO AN AMAZING DEGREE BY MACHINERY. THE GENERAL PUBLIC'S MENTAL PICTURE OF A MINER AS A BEGRIMED MOLE CLAWING THE COAL OUT OF THE GROUND WITH A PICK AND SHOVEL IS AS OBSOLETE AS A HORSE-DRAWN TROLLEY CAR. YOU ARE LIKELY TO FIND TODAY'S MINER PRESSING BUTTONS OR PUSHING LEVERS TO OPERATE EXPENSIVE EQUIPMENT WHICH REMOVES THE COAL FROM THE EARTH, CLEANS AND SIZES IT, AND SHIPS IT TO THE USER.

THE TECHNOLOGY EXISTS TO USE COAL AS THE KEYSTONE OF A NATIONAL "CRASH PROGRAM" TO MAKE UP OUR ENERGY SHORTFALL, NOT IN A DECADE OR TWO BUT WITHIN THE NEXT TWO OR THREE YEARS. THE MAIN INGREDIENTS NEEDED TO MAKE SUCH A DREAM BECOME A REALITY

WOULD BE AN INVESTMENT IN BILLIONS OF DOLLARS' WORTH OF SOPHISTICATED MINING EQUIPMENT AND A RECRUITMENT PROGRAM TO ADD UPWARDS OF 100,000 MINERS TO THE NATIONAL WORK FORCE.

THIS INCREASE WOULD LIFT THE OVERALL INDUSTRY-WIDE LEVEL OF MANPOWER TO 289,000, A 45 PERCENT JUMP FROM THE PRESENT LEVEL. COAL OPERATORS WILL NEED TO ADD 42,000 NEW HOURLY WORKERS AND 8,000 NEW SALARIED OR SUPERVISORY WORKERS BY 1980, NOT INCLUDING REPLACEMENTS FOR THOSE WHO WILL DIE, RETIRE, OR BE LOST TO ATTRITION DURING THAT TIME SPAN. ALL TOLD, REPLACEMENTS AND NET ADDITIONS COULD TOTAL 152,000 DURING THE NEXT 10 YEARS. THE MAJORITY OF THESE, IF NOT ALL, WILL BE INEXPERIENCED IN MINING, THEREFORE, INCREASED SELECTIVITY IN HIRING -- THAT IS, EMPLOYING MORE WORKERS WITH AT LEAST A HIGH SCHOOL EDUCATION -- WILL AID IN MINIMIZING SERIOUS REPERCUSSIONS OF TOTAL PRODUCTIVITY.

substantial
THEREFORE, A ~~HUGE~~ TRAINING PROGRAM WOULD BE REQUIRED TO GET THE JOB DONE. SOME OPERATORS PRESENTLY HAVE 25 PERCENT OF THEIR WORK FORCE IN TRAINING. NOT JUST ANYBODY CAN MINE COAL, ANY MORE THAN

JUST ANYBODY CAN EXTRACT PETROLEUM OR NATURAL GAS FROM COAL.

EDUCATING AND TRAINING MINERS IS A PRIMARY CONCERN OF THE INDUSTRY. CERTIFIED MINE FOREMEN ARE IN CRITICALLY SHORT SUPPLY AND THE OPERATORS HAVE SUGGESTED A SPECIFIC CHANGE WHICH WOULD HELP TO ALLEVIATE THE SHORTAGE; THAT IS, REDUCE THE NUMBER OF YEARS OF EXPERIENCE REQUIRED ON THE BASIS THAT MEN ARE NOW ENTERING THE INDUSTRY WITH A MUCH HIGHER LEVEL OF EDUCATION THAN THEY DID WHEN STATE LAWS WERE PASSED.

THE PRIMARY CONSTRAINT TO INCREASED COAL PRODUCTION TO MEET OUR ENERGY NEEDS IS SOCIETY'S REJECTION OF COAL AS A BASE FUEL. SOCIETY'S REJECTION OF COAL CONTINUES DESPITE THE FORECAST THAT OUR SHORT AND MID-RANGE ENERGY REQUIREMENTS MUST BE SATISFIED BY COAL. IF COAL EVER BECOMES ACCEPTED ON A WIDESPREAD BASIS, IT SHOULD NOT BE IMPLIED THAT THE PRODUCTION EFFORT SHOULD SUPERSEDE OUR CONTINUED EFFORTS TO COPE WITH AN ALREADY UNACCEPTABLE ACCIDENT RATE AND THE POTENTIAL FOR OCCUPATION DISEASE. TO

BE SURE, THE HEALTH AND SAFETY OF THE COAL MINER CANNOT BE COMPROMISED. A HISTORICAL REVIEW OF COAL MINE HEALTH AND SAFETY STATISTICS SUPPORTS MESA'S POLICY OF STRICT ENFORCEMENT OF MEANINGFUL REGULATIONS FOR THE PROTECTION OF THE MINER.

THANK YOU VERY MUCH FOR THE OPPORTUNITY TO TESTIFY HERE TODAY, AND IF YOU HAVE ANY QUESTIONS; I WILL BE MORE THAN PLEASED TO ATTEMPT TO ANSWER THEM.

Mr. MOFFETT. Mr. Finklea.

STATEMENT OF DR. JOHN F. FINKLEA

Dr. FINKLEA. Mr. Chairman, our Institute works with Mr. Barrett in MESA. We do health research that is used in the enforcement compliance program of MESA.

Our studies have shown that coal mining continues to be one of the most hazardous operations in the United States.

Under the Federal Coal Mine Health and Safety Act of 1969, NIOSH conducts research directed toward protection of life and health, detection of respiratory impairment, and prevention of occupational diseases of coal miners. We also establish coal mine health standards and assure the availability of medical examinations for underground coal miners, while the Mining Enforcement and Safety Administration (MESA) of the Department of the Interior establishes coal mine safety standards and enforces both health and safety standards. NIOSH works cooperatively with MESA to test and approve air sampling instruments and personal protective devices for coal mine use. Under this program, our Testing and Certification Branch evaluates and approves respirators, coal mine dust personal sampler units, and gas detector tubes.

Morbidity and mortality studies show that coal mining continues to be one of the most hazardous occupations in the United States. Studies have shown that coal miners have excessive rates of chronic bronchitis and airway obstruction. Coal workers' pneumoconiosis continues to be a common finding. Mortality studies have shown consistent excess deaths due to accidents and assorted respiratory diseases. In addition, a recent study of a large group of coal miners suggests significant excess in deaths from both lung cancer and stomach cancer.

If U.S. coal production is increased from the current 620 million tons per annum to 1 billion tons per annum and the mining techniques utilized remain unchanged, we estimate the mining population will need to increase from the current number of 191,000 to roughly 308,000. The immediate health impact of this increase would be most easily seen in the number of fatal and nonfatal injuries. Fatalities might increase by roughly 80 each year, while nonfatal injuries might increase roughly 8,000 each year.

The respiratory hazards of mining do not usually become manifest until 10 to 20 years after exposure has begun and depend upon duration and concentration of the dust exposure. To assess the health impact of increased coal mining on respiratory disease is more difficult as both dust concentrations and the average age of coal miners are decreasing. Despite these trends in underground coal mining and a probable shift to more surface miners which is less hazardous, several thousand additional cases of coal workers' pneumoconiosis and coal related obstructive airways disease are expected among the current workforce of miners as they accumulate coal mine dust exposure in the years to come. Because of the excess mortality already observed for cancer of the stomach and, to a lesser extent, cancer of the lung in miners, it is anticipated that there could be increases in these diseases. Available data do not allow reliable prediction of the size of these increases.

Changes in mining techniques could also be accompanied by other health risks. The introduction of diesel-powered equipment into underground coal mines is of particular concern to NIOSH because of the possible health effects of long-term exposure to a combination of coal dust, known to cause pneumoconiosis, and the gases and vapors of diesel exhaust, many of which are known or suspected pulmonary irritants. NIOSH is working cooperatively with MESA to study the health effects of exposure to dust and diesel exhausts found in other underground mines. We also plan to conduct a second phase of the study in coal mines where diesel engines are regularly employed underground.

CONVERSION TO COAL-FIRED POWER PLANTS

Numerous studies have documented the community health hazards of emissions from coal combustion including excess mortality during air pollution episodes. Since the National Institute of Environmental Health Sciences is sponsoring research in this area, I will focus on the occupational safety and health aspects of coal combustion, which have been given little attention.

A number of coal pretreatment steps are being proposed to decrease sulfur and trace metal emissions from coal-fired powerplants and these may pose significant hazards to workers. Pretreatment techniques include physical and chemical coal cleaning and involve, for example, pulverizing the coal and cleaning it with organic solvents. The dust generated is likely to be a lung toxicant. The solvents employed in pretreatment or in pollution control may be hazardous themselves or may concentrate even more harmful substances in the liquid streams. This can cause a health problem for workers who maintain these systems and handle and dispose of the wastes.

Exposure to sulfur dioxide also poses a potential problem to workers in coal-fired powerplants, as do noise and asbestos or other fibrous materials used for insulation. For example, a recent study of a 5,000-ton per day coal-burning powerplant revealed that over one-third of the working population were exposed to unacceptably high noise levels. Exposure to old insulation mateials may pose a significant problem during the process of converting oil- and gas-fired powerplants and industrial boilers to coal. Incomplete coal combustion in industrial boilers could be a significant source of polynuclear aromatic compounds, many of which are documented carcinogens.

The use of coal presents potentially more hazardous conditions in these converted plants in the materials handling and coal preparation processes. These hazards are principally related to increased risks of injury ro death due to coal transport, storage, conveying, and crushing and the attendant potential for fire and explosion. The reconstruction phase is an important area of concern also, as major changes to an already complex and relatively massive plant may be required. NIOSH and the TVA are cooperating in occupational safety and health studies of workers in coal-fired powerplants, and recently the Institute has undertaken a project to evaluate the potential for increased safety risks in the construction and operation phases of oil- and gas-fired powerplants which are converted to coal.

NIOSH strongly supports the principle that before a new technology is introduced or an existing technology is modified, its occupational health and safety impact should be evaluated. Historically, advances in technology have been accompanied by new hazards which are often not apparent for many years, after which workers become sick or die. One such example is in the styrene-butadiene rubber industry. In the 1940's with 90 percent of the natural rubber supply cut off, the government financed the building of 15 styrene-butadiene rubber plants. Today employees at such plants have a six-fold risk, as compared with other rubber workers, of dying of cancer of the lymphatic and hemopoietic system. If occupational health and safety are considered in developing coal conversion technologies and in the mass conversion of oil- and gas-fueled powerplants to coal, these plants should not contribute to serious health problems in the next 20 or 30 years.

We do not believe that the occupational health and safety problems involved in increased production and use of coal are insurmountable. In addition to our own research under the Federal Coal Mine Health and Safety Act of 1969, we are working cooperatively with the Environmental Protection Agency and the Energy Research and Development Administration to find practical solutions to the new problems.

Mr. Chairman, we will be pleased to answer any questions that you or members of your subcommittee may have.

[Dr. Finklea's prepared statement follows:]

Statement of

John F. Finklea, M.D., Director
National Institute for Occupational Safety and Health
Center for Disease Control
Department of Health, Education, and Welfare

Before the

Subcommittee on Energy and Power
House Committee on Interstate and Foreign Commerce

May 26, 1977

Mr. Chairman and Members of the Subcommittee:

I am Dr. John F. Finklea, Director of the National Institute for Occupational Safety and Health (NIOSH). Accompanying me today are the Director of our Applachian Laboratory for Occupational Safety and Health (ALOSH) in Morgantown, West Virginia, Dr. James A. Merchant, and the Director of our Office of Extramural Coordination and Special Projects, Dr. Kenneth Bridbord. We welcome the opportunity to testify before you today to discuss the occupational safety and health aspects of increased coal production, the conversion of oil and gas fired boilers to coal, and proposed coal conversion technologies.

Under the Federal Coal Mine Health and Safety Act of 1969, NIOSH conducts research directed toward protection of life and health, detection of respiratory impairment, and prevention of occupational diseases of coal miners. We also establish coal mine health standards and assure the availability of medical examinations for underground coal miners, while the Mining Enforcement and Safety Administration (MESA) of the Department of the Interior establishes coal mine safety standards and enforces both health and safety standards. NIOSH works cooperatively with MESA to test and approve air sampling instruments and personal protective devices for coal mine use. Under this program, our Testing and Certification Branch evaluates and approves respirators, including self-rescuers, coal mine dust personal sampler units, and gas detector tubes.

Morbidity and mortality studies show that coal mining continues to be one of the most hazardous occupations in the United States. Studies have shown that coal mines have excessive rates of chronic bronchitis and airway obstruction when compared with a control population. Coal workers' pneumoconiosis, both in its simple and complicated form, continues to be a common finding in morbidity studies. Mortality studies have shown consistent excesses in death rates due to accidents and assorted respiratory diseases. In addition, a recent study of a large group of coal miners suggests significant excess in deaths from both lung cancer and stomach cancer.

Based on 1976 estimates, 44 percent of U.S. coal production is derived from underground mining which employs 71 percent of the coal mining population. Underground mining currently accounts for 82 percent of mining fatalities and 85 percent of non-fatal injuries. Recent chest X-ray studies of the prevalence of coal workers' pneumoconiosis for underground miners suggest that approximately 13 percent have the disorder, while the prevalence is only around 2.5 percent for surface miners. These figures are a conservative indication of the overall effect since prevalence studies cannot take into account sick miners who have left mining. Moreover, chronic obstructive airways disease which is detected by lung function tests has been found in 30 percent of underground miners as opposed to 19 percent of surface miners.

If U.S. coal production is increased from the current 620 million tons per annum to 1 billion tons per annum and the mining techniques utilized remain unchanged, we estimate the mining population will need to increase from the current number of 191,000 to 308,200. The immediate health impact of this increase would be most easily seen in the number of fatal and non-fatal injuries. Fatalities might increase by a total of 82 each year, while non-fatal injuries might increase by 7,983 each year. This represents an increase of approximately 60 percent over 1976 rates.

The respiratory hazards of mining usually do not become manifest until 10 to 20 years after exposure has begun and depend upon duration and concentration of the dust exposure. To assess the health impact of increased coal mining on respiratory disease is more difficult as both dust concentrations and the average age of coal miners are decreasing. The effect of these decreases may not be fully apparent for another 5 to 10 years. Even by taking into account these trends in underground coal mining, several thousand additional cases of coal workers' pneumoconiosis and coal related obstructive airway diseases are expected among the current workforce of miners as they accumulate coal mine dust exposure in the years to come. Because of the excess mortality already observed for cancer of the stomach and, to a lesser extent, cancer of the lung in miners, it is anticipated that there could be increases in death from these diseases. Available data do not allow reliable prediction of the size of these increases.

It is unlikely that the increased amounts of coal currently being discussed would be obtained by the present split between surface and underground mining. If the increase in coal production is to be achieved by 1980, it is very likely that the majority of increased production would be derived from surface mines. A major factor in reaching this conclusion is that currently there is often a delay of several years in obtaining new mining equipment. This, of course, could change if emphasis on mining were increased. Increased surface mining, unless properly conducted, can of course, lead to degradation of environmental quality and to increased particulate exposures for nearby communities. We have considered a number of model systems based on achieving the target of 1 billion tons with 10 percent, 20 percent, and 30 percent of the additional tonnage required being derived from increased underground mining. In the situation where 10 percent of the increase is derived by increased underground mining, fatal and non-fatal injuries can be expected to increase by 39 and 3,483 respectively. This represents an increase of approximately 28 percent.

Considering the chronic health effects, it can be expected that there would be several hundred additional cases of coal workers' pneumoconiosis and several thousand additional miners with coal dust associated obstructive airway diseases. The estimates for 20 percent and 30 percent of the additional 380 million tons being derived from underground mining fall between two cases outlined. Our estimates are based on current methods of mining and do not take into account the possibility that there could be improvements in mining techniques which could minimize the occurrence of accidents and adverse effects on the health of miners.

Changes in mining techniques could also be accompanied by other health risks. The introduction of diesel-powered equipment into coal mines is of particular concern to NIOSH because of the possible health effects of long-term exposure to a combination of coal dust, known to cause pneumoconiosis, and the gases and vapors of diesel exhaust, many of which are known or suspected pulmonary irritants. NIOSH is working cooperatively with MESA to study the health effects of exposure to dust and diesel exhausts found in non-coal underground mines. We also plan to conduct a second phase of the study in coal mines where diesel engines are regularly employed underground.

Although standards currently exist for coal mine dust and for nitrogen dioxide and other components of diesel exhaust, these are based on controlling health effects of single exposures. We cannot be confident that adherence to these individual standards will protect the miner subject to mixed exposures. In fact, we have scientific evidence that the absorption of certain irritant gases to respirable-sized particles can potentiate their effect upon the lung tissues. The possibility is that such synergism exists between respirable coal dust particles and known or suspected respiratory irritants. We also know very little about the possible carcinogenic potential of chemicals which may be formed by the interaction of gases and vapors from diesel exhausts and organic substances which may be present in the coal mine atmosphere.

Unfortunately, none of the potential benefits of diesel use have been scientifically and objectively documented at this time. NIOSH and MESA are currently assessing the environmental and biological effects of diesel now operating in metal and non-metal mines and in a limited number of coal mines. In addition, NIOSH is sponsoring an international workshop designed to address key issues involved in the possible use of diesel engines in underground coal mines. Based on available evidence concerning underground exposure to diesel emissions, NIOSH has advised MESA to caution all concerned in the coal mining industry against further introduction of diesel equipment into underground mines until the health and safety production of implications have been scientifically assessed.

Conversion to Coal-Fired Power Plants

Numerous studies have documented the community public health hazards of emissions from coal combustion including excess mortality during air pollution episodes. Since the National Institute of Environmental Health Sciences is sponsoring research in this area, I will focus on the occupational safety and health aspects of coal combustion, which have been given little attention.

A number of coal pretreatment steps are being proposed to decrease sulfur and trace metal emissions from coal-fired power plants and these may pose significant hazards to workers. Pretreatment techniques include physical and chemical coal cleaning and involve, for example, pulverizing the coal and cleaning it with organic solvents. The dust generated is likely to be a lung toxicant. The solvents employed in pretreatment or in pollution control may be hazardous themselves or may concentrate even more harmful substances in the liquid streams. This can cause a health problem for workers who maintain these systems and handle and dispose of the wastes.

Coal with varying levels of toxic trace elements is likely to be increasingly utilized in these plants as new coal sources are exploited. Potential toxic metal emissions associated with coal combustion, which pose potential hazards to workers, as well as the general population, include mercury, selenium, arsenic, lead, cadmium, nickel, beryllium, and chromium. Incomplete coal combustion in industrial boilers could also be a significant source of polynuclear aromatic compounds, many of which are documented carcinogens.

Exposure to sulfur dioxide also poses a potential problem to workers in coal-fired power plants, as do noise and asbestos or other fibrous materials used for insulation. For example, a recent study of a 5,000 ton per day coal-burning power plant revealed that over one-third of the working population were exposed to inacceptably high noise levels. Exposure to old insulation materials may pose a significant problem during the process of converting oil- and gas- fired power plants and industrial locations to coal.

The use of coal presents new potentially more hazardous conditions in these converted plants in the materials handling and coal preparation processes. These hazards are principally related to increased risks of injury or death due to coal transport, storage, conveying, and crushing and the attendant potential for fire and explosion. The reconstruction phase is an important area of concern also, as major changes to an already complex and relatively massive plant may be required. NIOSH and the TVA are cooperating in occupational safety and health studies of workers in coal-fired power plants, and recently the Institute has undertaken a project to evaluate the potential for increased safety risks in the construction and operation phases of oil-and gas-fired power plants which are converted to coal.

With regard to current practices and experience in the coal, oil-and-gas-fired power plant sector, NIOSH is studying both the details of current safety practices in this industry and evaluating the incidence rates of recordable injuries and fatalities. This program will establish an information base so that we can better evaluate the impact of emergency energy technologies in future years.

Coal Conversion Technologies

The hazards to human health associated with large-scale coal conversion can be divided into three areas: (1) hazards to workers in the conversion plant itself; (2) hazards to people living in the vicinity of the plant due to the effluent dischanges or spills resulting in atmospheric exposure and contamination of drinking water and food; and (3) hazards to workers in downstream industries, to distributors, and to users of coal conversion products or by-products.

Perhaps the most serious environmental threat to workers and the general public is from chemical carcinogens. For example, during the operation of a coal hydrogenation plant, the strongly carcinogenic compound benzo(a)pyrene was detected at high concentrations near blowndown and steam cleaning operations. More recently, carcinogenic compounds such as benz(a)anthracene, benzo(c)phenanthrene, and unspecified mono and dibenzopyrenes have been reported in the hydrocarbon streams of two coal conversion processes currently under development.

Coal conversion also results in the formation of a number of inorganic gases which can be toxic at sufficiently high concentrations. These include hydrogen sulfide, carbon monoxide, ammonia, and metal sub-sulfides and metal carbonyls. The nature of the other gases will vary from process to process, but a substantial protion may eventually be vented along with some residual sulfur compounds. Trace amounts of many elements (chromium, manganese, lead, and antimony) in coal may also pose a potential problem to workers in coal gasification and liquefaction facilities.

In addition, coal dust itself and common industrial hygiene problems such as noise and heat stress from industrial processes involving crushing, high pressure, and high temperature operations pose potential problems to workers in those industries.

The problems associated with organic pollutants are basically different from those associated with other fuel production processes such as petroleum refining. The most prominent difference is the greater concentration of chemical carcinogens in the heavier and more aromatic fractions of coal-derived synthetic fuels. For example, polycyclic aromatic compounds are present in coal pitch in concentrations several orders of magnitude higher than that found in similar petroleum products such as asphalt.

Flowsheets for the various proposed processes do not generally indicate whether significant quantities of polycyclic compounds will be released via liquid and gaseous waste streams. Compounds such as phenols and cresols will be found in some aqueous process wastes as well as small amounts of less soluble organic compounds. It is extremely difficult to trap aerosols generated by the rapid cooling of high boiling vapors. Therefore, all effluent gas streams should be considered as potential sources of particulate polycyclic compounds. Particular attention should be given to the effluent from catalyst and catalyst regenerator systems because polycyclic compounds have been found to be emitted in significant concentrations during the regeneration of petroleum cracking catalysts and because some catalysts such as nickel are toxic.

NIOSH strongly supports the principle that before a new technology is introduced or an existing technology is modified, its occupational health and safety impact should be evaluated. Historically, advances in technology have been accompanied by new hazards which are often apparent only many years later, after workers become sick or die. one such example is in the styrene-butadiene rubber industry. In the 1940's with 90 percent of the natural rubber supply cut-off, the government financed the building of 15 styrene-butadiene rubber plants. Almost 35 years later, we find that styrene-butadiene rubber employees have a six-fold risk, as compared with other rubber workers, of dying of cancer of the lymphatic and hemopoietic system. If occupational and public health and safety are considered in developing coal conversion technologies and in the mass conversion of oil and gas fueled power plants to coal, these plants should not have contributed to serious health problems in 20 or 30 years.

We do not believe that the occupational health and safety problems involved in increased production and use of coal are insurmountable. In addition to our own research under the Federal Coal Mine Health and Safety Act of 1969, we are working cooperatively with the Environmental Protection

Agency and the Energy Research and Development Administration to find practical solutions to the new problems. In terms of worker protection, the proposed new coal conversion technologies hold special promise in that they offer the opportunity to design controls into the processes rather than attempting to correct problems after the fact.

Mr. Chairman, we will be pleased to answer any questions that you or members of your Subcommittee may have.

Mr. SHARP. Mr. Bailey.

STATEMENT OF RALPH E. BAILEY

Mr. BAILEY. Mr. Chairman, members of the subcommittee:

My name is Ralph E. Bailey. I am chairman and chief executive officer of Consolidation Coal Company, whose principal office is in Pittsburgh, Pennsylvania. Consol operates 57 mines located in 8 States, employs nearly 22,000 people, and produces approximately 9 percent of the coal mined in the United States. About 60 percent of our production is from underground mines and the balance is from surface mines.

Because of the severe time constraints imposed on me, I will limit my remarks this morning to responding to the vital question of the impact of doubling coal production on health and safety conditions in the mines.

I will preface my remarks by advising you that in my judgment, the coal industry can indeed be expanded to meet the President's production target without any sacrifice in the industry's health or safety goals.

For the most part, the mining of coal takes place in a relatively hostile environment that is constantly changing. Unlike most industrial workers, a miner has a new workplace every day as the mine entries or pits advance.

My company has divided its safety program into three principal areas:

—The physical condition of the mine and equipment;

—The mining methods and procedures;

—And worker skills and motivation.

We also have studied the data from our many mines and have carefully cataloged the causes of accidents. Only in so doing can meaningful preventive measures be designed.

Our studies have revealed that only approximately 15 percent of our mine accidents are related to the physical condition of the mines. You may be surprised to know that the provisions of the 1969 Federal Coal Mine Health and Safety Act under which we have operated for over 7 years relate only to this small percentage of accidents.

We have made great strides during the past 7 years under the act in improving physical conditions, such as improved ventilation, improved roof support, a drastically reduced level of respirable dust, improved electrical distribution systems, marked reduction in fires and ignitions, improved transportation of men and materials, and many other conditions that might relate to worker safety. But after having done so, the industry accident frequency has not improved. It is clear that Congress has approached the problem of improving mine safety in the wrong way.

Our analysis of mine accidents indicated that the remaining 85 percent of the causes could be assigned to a lack of training and education, poor work habits, and lack of motivation.

In the early part of 1973, we began the most extensive safety program in our company's history. Programs were instituted which went far beyond the requirement of the regulations at that time. Every member of labor and management was involved. Millions of dollars have been spent in the training and education of our foremen and miners in safe work practices. Incentive and communication programs were designed to motivate the work force to use the safety and job skills they have acquired. The results have been gratifying and most encouraging. Our accident frequency rate per million man-hours of exposure was reduced from 23.5 in 1972 to 11.0 in 1976. This compares favorably with the industry average of about 36.0.

We believe further improvement is possible and that coal mining can be made just as safe and just as healthful as the average industrial occupation.

We also believe that Congress has little chance of improving mine safety by additional legislation, regulation, or enforcement. Congress must focus its attention on training and motivation and not more regulation of physical conditions.

A special blue ribbon study commission appointed by the Governor of Kentucky reported that approximately two out of three mine fatalities in that State during 1975 resulted from "human negligence—taking shortcuts, unsafe practices and/or unsafe work habits, ignoring safety procedures and protocol, etc." The committee recommended that Kentucky "initiate a mine safety program that places trained safety analysts in underground coal mines to observe and evaluate the work habits of all persons involved in coal production and to contact, advise and assist these individuals in correcting unsafe, careless or potentially hazardous actions." The Kentucky safety analyst would play a complementary role, primarily leaving inspection and enforcement for the Federal inspectors. Ths recommendation was endorsed by the coal companies and the mine workers and has since become the law in Kentucky.

I believe this is a very progressive step, which both focuses attention in the area offering the greatest improvement potential and also eliminates the confusion of dual enforcement.

Regulation and enforcement of the 1969 Health and Safety Act has dramatically reduced coal industry productivity—it has been estimated by at least 35 percent to 40 percent. Much of this productivity loss has been caused by enforcement procedures that have little, if any bearing on health and safety.

In summary, I conclude that:

—Opportunity exists for Congress and the industry to make improvements in mine safety by focusing attention on training and motivation;

—Congress should fairly appraise the 1969 Health and Safety Act and make amendments that will remove production constraints that have no bearing on mine health and safety;

—Congress must not impose additional legislation that serves to constrain production without improving safety.

By following these recommendations, I sincerely believe that industry capacity can be increased to meet the production targets in the President's energy plan with an improved, not impaired, safety record.

Thank you for asking me here. I shall be happy to answer your questions.

Mr. MOFFETT. Dr. Carnow.

STATEMENT OF DR. BERTRAM CARNOW

Dr. CARNOW. I do not have a prepared statement. I was asked to appear only last week. I will have a prepared statement but I certainly have something to say, I think. I am not going to discuss the health and safety of coal mining itself. I am head of a division of occupational medicine at Cook County Hospital. We have seen a continuous stream of workers with destroyed lungs as a result of coal mining. I suggest anything we do should take into account the impact on the health of workers, since we are paying for this now at an incredible rate for our mistakes. I think we have learned a great deal and I think we should implement it.

In Illinois this is not an academic question for us. I am charged with looking at potential hazards for the people in the State. We have an abundance of soft coal. Its use would go far toward solving our energy problem and the energy problems of a lot of areas close to us. New processes are very important in that they may do that because a process like coal gasification will remove sulfur from the areas where the energy is being used and, because of that, is an extremely valuable resource.

We have become very much interested in gasification. As you may know, we will be building a plant in Illinois to produce coal. We were asked by the Governor of the State to try to make an estimate of the possible health effects of a new process in order to protect the people of our State. I would like to address myself to this question.

The impact of these hazards from coal gasification is most where the plants are built. There are some health and economic benefits which may result from coal gasification but the health impact may also be considerable.

Many of the emissions, effluents and byproducts of the coal gasification process are presently unknown. In addition, there are several different processes which may be used. The nature and quantities of the environmental contaminants from each are very much a function of the specific process. With these reservations, I have prepared a list of probable pollutants.

I would just give you the groupings of these because they are many. There are many gases which are produced including carbon monoxide, carbon dioxide, hydrogen, sulfur in abundance.

In regard to waste products, product gases, hydrogen sulfide and other sulfide compounds, ammonia, hydrogen, cyanide, particulate matter.

In regard to trace metals—mercury, cadmium, beryllium, lead, vanadium, arsenic, and nickel—which are used in many of these processes in the methanization of coal will be produced and will produce nickel carbonyl, which is a known potent carcinogen—chromium, manganese, molybdenum, titanium, and selenium, and a host of hydrocarbons, many of them capable of producing cancer, many polycyclics, oils and tars, in a mountain of material we call char, a solid material which contains carcinogens.

I think much of this can be dealt with. I think one of the problems we have had in the past is we have looked at producing a product at salable cost but we have not looked at what to do with what comes out. Until you solve this question, which is the key question, until you protect the workers and the community with what comes out of a process, you cannot produce such a process for the good of a society.

I think this can be done with this process as well. We have urged the Governor of our State, and I would urge you, that anywhere it is contemplated to build such a plant, the air, water, soil, workers and the community be monitored before, during, and after, so that we do not have as we had with coal mining, 300,000 miners or their families now receiving benefits for disabilities.

I think we can avoid that. I think we can develop such processes for us and we do need them.

I will prepare a statement for this panel and I will be happy to answer questions about health effects.

But the materials that I spoke about, which come from this process, are capable of causing a host of diseases if they get out into the community or into the bodies of workers in large quantities. What I am urging be done by engineers and by all of us responsible for enforcement is that in the development of such a process we structure into it the means of protecting people from what we know will be hazardous materials coming from it.

Mr. MOFFETT. Thank you, Dr. Carnow.

In that statement you submit would you be sure to include the list of pollutants you mentioned?

Dr. CARNOW. I certainly will.

Mr. MOFFETT. The Chair now recognizes the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. Thank you, Mr.Chairman.

Dr. Finklea, I was wondering if you could give us any indication of whether there has been improvement or to what degree in terms of respiratory problems, since efforts have begun with the Mine Safety Act, to reduce those problems in the mine?

Dr. FINKLEA. I think there are several aspects of this problem, Mr. Sharp. I think our miner population has been changing rapidly. As we have expanded the coal miner population, a number of new miners have come in and they have not been exposed to levels of dust in the mine that are equal to levels of dust that older miners have been exposed to in the past.

Also they have not been in mining long enough for us to be sure that the existing dust standard is completely protective.

I think we would say we are encouraged by reduction of dust levels in the mines and, based on the experience of our colleagues in Great Britain, would believe that the reductions of the dust levels in the mines that have occurred since the passage of the act will certainly help if not completely protect the health of miners.

As you know, that act primarily addresses the black lung problem and depends heavily on X-ray diagnosis. As we have conducted our rounds of examinations of coal miners, we have utilized certain other medical tests that detect disease of the small airways. This disease is a little more frequent than coal workers' pneumoconiosis. We found both black lung disease and the small airways disease to be much less prevalent in surface miners.

In summary, from a public health point of view we would feel that progress has been made. We will be entering another round of examination of coal miners that should provide additional information this year, but it is too soon to say exactly how much beneficial effect has occurred because of the act.

Mr. SHARP. Thank you.

Do you have any differing view, Dr. Carnow?

Dr. CARNOW. I do not think so. We unfortunately are dealing with the errors of the past in our clinical activities. Again, as Dr. Finklea points out, it becomes easier now for us to make determinations of early disease and I think that given a reasonable degree of concern and effort, we can at least prevent the kind of catastrophe that occurred. We can find problems early, if not prevent them, but certainly with new processes I think our efforts have to be directed toward prevention because some of the problems that we face with the new process include the production of cancer. I think this is a disease with a long incubation period which is either irreversible or destructive.

Mr. SHARP. Thank you. My time is very short and I would appreciate it if you could keep your answers short.

Mr. Bailey, you take exception to what value is coming out of the occupational safety and health rules. Does that relate to the black lung problem as well or is that a minor part of the expenses you people have to engage in under the safety and health rules?

Mr. BAILEY. I am not medically competent to speak about the results from the program but I can speak to how effectively the program has been carried out in removing the dust from the mine.

Dr. Finklea mentioned the history of the British coal industry, that has a long history in diagnosing the black lung problem, and what effects coal dust has on the health of miners. In this country the industry went far beyond the dust level standards that the British concluded would be a safe level and a level which would not impair the health of their miners.

As you know, when the study commission from our Congress went to Great Britain to investigate this important matter, they were advised that the U.K. industry thought a level of about 7.5 milligrams per cubic meter exposure in an 8-hour period would be a safe level. But our regulations, when issued, required that we first meet interim standards of 4 milligrams per cubic meter, then downward to 3, and ultimately to 2. I am sure Mr. Barrett would agree with me that the testing of the dust levels inside the mines of this country today shows that we are virtually in compliance with that level. So the level of dust in our mines today is far below what the British said was satisfactory.

Mr. SHARP. I am not familiar with the issue of this subcommittee but I am trying to get some more information. You indicate that your productivity has been reduced dramatically. Is this a major element in that or is it the other safety rules as far as the dust question?

Mr. BAILEY. There are several elements of the law and effects of the law affecting productivity but certainly meeting the dust levels is one of them.

Mr. SHARP. Could you give me some kind of estimate?

Mr. BAILEY. No.

Mr. SHARP. I realize this is not mathematically—

Mr. BAILEY. I cannot quantify it but I will point out that coal dust is generated by the cutting action of the bits of the machine at the mining face. The faster you cut the more dust you generate.

In order to make certain the dust levels are met, there have been instances where mining rates have been impaired. I cannot quantify it but it is substantial.

Mr. SHARP. We are hearing a lot of talk that we hope to solve some of the problems of coal pollution, not at the mine but when we burn it with the fluidized bed combustion system. I was wondering if any of you on the panel have any information relative to the experience that already exists on this in Great Britain and some other places as to whether or not there are other problems as Dr. Carnow was suggesting with these new technologies that we are not aware of.

Dr. FINKLEA. Mr. Sharp, I think there is a Committee on Energy Technology that includes the EPA, ERDA and HEW, and some of the actual or potential health problems in the fluidized bed system have been addressed by that group. We can provide some of that material for the record if you would like for us to do so.

[The following material was received for the record:]

FLUIDIZED BED COMBUSTION

Several concepts utilizing fluidized bed combustion are currently under development for early large scale implementation. However, smaller fluidized bed units are currently commercially available. This technology, which includes both atmospheric and pressurized fluidized bed techniques and coal/oil slurry combustion techniques, is being developed to enable coal to replace oil and gas in utility and major industrial heat and steam plants. This technique will enable the use of coal of all ranks, quality and sulfur content.

Although the technology and problems involved in fluidized bed combustion are similar to those of conventional coal-fired power plants, the nature and conditions of the combustion medium could significantly affect the quality and quantity of emissions into the environment as well as the nature of health hazards to workers in these plants. In particular, the emissions from fluidized bed reactors may vary significantly with minor changes in operating conditions. Potential pollutants of concern include polynuclear aromatics, toxic metals, nitrogen oxides, and secondary pollutants formed by high temperature chemical reactions or by erosion of reactor materials. Because experience with fluidized bed combustion is limited, the nature of potential health problems is largely unknown. They are expected to be similar to those associated with conventional coal-fired power plants. However, because of the wide variety of coals which can be used in existing plants of older design, and operated in a variety of locations such as factories, businesses, schools, etc., the nature and extent of the occupational and public health hazards associated with fluidized bed combustion are more uncertain than in conventional coal-fired power plants. For these reasons systematic health and safety studies are required.

Thus, there is an urgent need to screen for the presence of a variety of pollutants associated with fluidized bed combustion and to characterize their effects. In addition, inhalation toxicology studies need to be performed on fluidized bed emissions; tests to evaluate their synergistic effects and tests for potential mutagenic, carcinogenic, teratogenic, reproductive, and behavioral effects are required; appropriate pharmacokinetic and organ toxicity studies need to be conducted; studies of occupational and high risk population groups in close proximity to these technologies need to be initiated, including medical surveillance, epidemiologic and clinical studies; tests to extrapolate laboratory animal data to the human exposure situation need to be conducted; and, based on these results and epidemiological and clinical research, recommended standards to protect exposed populations need to be developed.

Dr. FINKLEA. We are working with ERDA in Morgantown looking forward to the construction of a small fluidized-bed plant there that will hopefully be used to produce power for the university and university hospital complex there. We are trying to evaluate potential problems at the pilot plant stage so we can have adequate occupational safety and health guidelines for standards and regulations to assure that this technology can be used without endangering workers. I am sure EPA is working on the community aspect.

Mr. SHARP. As I understand, there are some small systems in existence in the world. Does the experience from there tell us there are going to be some major problems to overcome or is it something that is manageable?

Dr. FINKLEA. We are developing occupational health standards for coal gasification and liquefaction. There will be problems. One has to deal with the waste treatment but I do not think we feel these problems are unsurmountable.

Mr. SHARP. You really do not think we are dreaming with the use of these technologies and will find ourselves 3 years from now, now that we have pushed coal, we are going to find the health hazards are so great we do not want to use it?

Dr. FINKLEA. Our best judgment is that these hazards can be overcome. It is probably much more efficient economically to engineer these hazards out before a system is utilized. Retrofitting is very expensive.

Mr. SHARP. I agree with that.

Does anybody disagree with the basic premise that we can overcome the health hazards with the kinds of technologies that are being discussed as a way of utilizing coal?

Dr. CARNOW. If they are considered in development of the process. They must be considered.

Mr. SHARP. Thank you, Mr. Chairman.

Mr. MOFFETT. The Chair recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

I simply would like to say that I do not think it is the intent of anybody on this subcommittee in meeting the administration's desire to use more coal, we have any intention of sacrificing or reducing the situation that concerns miners' health and safety issues. As a matter of fact, I do not see the Congress doing anything in that regard whatsoever.

With that, I yield back the balance of my time. I thank the gentlemen for testifying before us this morning.

Mr. MOFFETT. I would like to direct a question to Mr. Barrett. It is obvious that one of the reasons ths panel is here is given the President's statement that we could have a much more serious problem than we have now, and we want to take steps to make sure, as the gentleman from Louisiana just indicated, that this does not happen, I think back to a year or so ago when we had a disaster of sorts in the Scotia mine. Some assertions were made at that time about your agency by various Members of Congress and others.

There is a Congressional Record statement by the chairman of the Education and Labor Committee, Mr. Perkins of Kentucky, in which he said:

"These disasters were"—he is speaking of the disasters of March 9 and March 11 of the Scotia mine—"were not due to any inadequacy in the 1969 Act. They were the fault of a lack of law enforcement on the part of MESA"—your agency. He goes on to say—I will not read the whole thing—"The staff director for all three of the Scotia mines stated he knew of no safety drills in the 3-1/2 years he had been at the mines. Evidence shows tht MESA officials were aware of this even though regulations require safety drills every 3 months. Scotia miners never received training on their air breathers or escapeways, and MESA knew or should have known about this. It is covered in 30 U.S. Code 877(n) and in MESA's own regulations. At least six of the victims could have walked out if they had received better training."

He cites the list of areas in which MESA did not act. MESA did not use its authority under the present law to close this mine. Yet, since 1970, MESA had cited this mine for 855 violations of the law and closed it 110 times for imminent dangers. MESA officials testified this is the most dangerous and gassy mine in the district. MESA has never assessed a criminal fine against Scotia, in spite of the fact that local personnel have recommended this action for wanton negligence on Scotia's part.

I am sure you are familiar with what he was saying at that time and what others were saying. I wonder what has changed since then, if he is correct. You may want to quarrel with his assertions. How is the situation changed? How has it improved in terms of the agency's competency and sensitivity to these problems?

Secondly, what more would we have to do, given the coal conversion proposals of the administration? What is being assessed to determine what more we have to do in terms of funding to cope with the problems that might come up?

Mr. BARRETT. You asked a number of questions and made a lengthy statement, which I could probably rebut, and it would take me several hours to rebut. I have no intention of getting into a verbal battle with Congressman Perkins, although I do take exception to that report.

Mr. MOFFETT. Are the facts wrong?

Mr. BARRETT. The facts are right, for the most part, but the context in which they are put in that report is questionable. For example, the citations. True, that mine was cited a large number of times. We have questioned whether we can close a mine based on the number of violations of a particular nature. Our attorneys have told us the law does not allow us to issue a closure order based on a series of violations of a particular type.

Last year we challenged that. We did issue a closure order based on a series of violations of a particular type. That citation is going through the system. The operators have, under the law—although it is addressed primarily to the health and safety of the miner—equal rights under that same act to appeal the actions that are taken by MESA.

We are taking off in that direction to see if in fact we can establish some case law to issue closure orders based on citations.

Mr. MOFFETT. Let me ask this question which I think is pertinent. Has the new Secretary given any new instructions to your agency?

Mr. BARRETT. The new Secretary is much more supportive of our programs than has been in the past. We have had difficulty in funding and getting people into the program. We have been assured we will get support from the new Secretary. We have done a number of things at MESA. We have initited what we call a blitz inspection program whereby we inspect a total mine during one inspection so that there cannot be any changes or preparations made ahead of the inspector. We are putting together a management information system whereby we can retrieve data on individual mines at the touch of a key.

We have upgraded, updated, and computerized our assessment programs.

When I became the Administrator we had a backlog of literally hundreds of thousands of violations that were not assessed. As of July we will be current with our assessments, which to me is a tremendous stride. We issue about 15,000 citations per month. Our backlog will reflect that kind of issuance of penalties. We are trying to get the penalties closer to the citation. We have assessment penalties in the system anywhere from the Federal courts to ALJ's hearings, some of which date back 4 or 5 years. The assessment of a penalty for a violation that is 4 or 5 years' stale has lost its savor.

What we are shooting for is that from the time the assessment office receives the violation, we should have the citation out to the operator within 15 days. I think this will make our penalty system more effective. In other words, it will become an enforcement tool whereas up until recently it has not been an enforcement tool.

Mr. MOFFETT. All of these things are going on, and would have, whether or not the President on April 20 had issued his statement; is that not correct?

Mr. BARRETT. True.

Mr. MOFFETT. Whether or not he had placed a heavy emphasis on coal?

Mr. BARRETT. Yes.

Mr. MOFFETT. Is there anything as a result of the April 20 statement that is being done to attempt to analyze what your challenge might be?

Mr. BARRETT. Yes. We are projecting new mine openings and we have been projecting them for some time. Usually we hit the numbers by about 10 to 12. We projected a number of new sections underground, for example. We feel it will take by 1985 to have 220 new sections come on stream.

Mr. MOFFETT. Your agency is doing that?

Mr. BARRETT. Yes, because we need to project where we will be in 1985.

Mr. MOFFETT. Do your projections square with the administration's projections?

Mr. BARRETT. I think so.

Mr. MOFFETT. We had considerable testimony yesterday that the administration's projections were more than a little bit off.

Mr. BARRETT. I can give you the last 5 years' projections, and you will find we have hit them very closely.

Mr. MOFFETT. Did they rely on your agency in making their projections at all?

Mr. BARRETT. You mean FEA?

Mr. MOFFETT. To what extent—you have some experts there—did Schlesinger's people rely on your expertise in coming up with their assumptions and projections?

Mr. BARRETT. I do not know. They have not been over to talk to me personally. We have people in the mines every day. On any given day we probably have a thousand people in the mines. We have a pretty good handle of what is taking place underground as well as at surface operations.

Mr. MOFFETT. I find it remarkable that they have not talked to the Administrator of this agency, but maybe I am missing something. It is certainly not your burden.

Do you agree with Mr. Bailey that enforcement of the Health and Safety Act has reduced productivity by 35 or 40 percent?

Mr. BARRETT. No.

Mr. MOFFETT. Would you like to say anything besides "no"?

Mr. BARRETT. I do not like to get into a verbal battle.

Mr. MOFFETT. We do not mind that at all.

Mr. BARRETT. I will take him on. He is bigger than I.

Productivity has dropped 35 or 40 percent; I do not disagree with that. That is underground productivity. Let me state there is a difference between production and productivity. I say that the act did have an impact on productivity but not to the extent that is being published by the operating people. There are a whole host of constraints that have entered the picture in the last 5 or 6 years. A good example is that during the years in which coal had declined, whenever most of our energy was produced from oil in the 1950's, 1960's, the work force was so depleted at that time, that all the young people left the mines. I can give you a figure; for example, one of Mr. Bailey's mines in 1963, 1964, the mean age of the miners was in the low fifties and if he were to think today he would admit that the mean age is probably 30 to 35.

Mr. MOFFETT. Of people working in the mines?

Mr. BARRETT. Yes. So we lost a tremendous part of our work force. There was very little continuity in the work force. After the Arab embargo in 1973, coal caught on again. As a result, there has been a tremendous influx of new people in the industry. These new people are not the traditional miners that are the father, the son. These are people who are not acclimated to the mining scene.

So we have a different work force, a different group of people that have to be dealt with in a different way than traditionally they have been dealt with.

We also have a lot of constraints so far as water quality is concerned. The operators have to treat their water before they put it into the streams. State inspection agencies have accelerated their inspection activities as a result of our acceleration. The supervisory force is much different today than several years back. There are a whole host of things that enter into the picture.

I personally queried some people in the industry as to what the five major causes for productivity decline were, and one of the first ones is the unrest in the labor force. I think the Coal Act was about third or forth in that list.

Mr. MOFFETT. We do have a vote, so we are going to take a brief recess. At that point, let me ask you this: Do you agree with Mr. Bailey's statement that lack of training and education, poor work habits, and lack of motivation account for 85 percent of the accidents?

Mr. BARRETT. I would say that is a good figure. Eighty-five percent of accidents are from acts of people. I think, however, we must realize the fact that the burden cannot all be placed on the miners. That has to be shared equally with the operating people.

Mr. MOFFETT. You think it might be——

Mr. BARRETT. Our figures indicate about 85 percent of the accidents are because of actions of people versus machinery type accidents or accidents that would be caused by the environment.

Mr. MOFFETT. Okay. The subcommittee will stand in recess for 10 or 15 minutes, and we would appreciate it if you gentlemen could stay here. We will be right back.

[Brief recess.]

Mr. MOFFETT. The subcommittee will come to order. I apologize for the delay.

Mr. Bailey, how many new miners do you anticipate will be needed by 1985 to meet the increased production goals for 1985 that the President has set out?

Mr. BAILEY. We have nearly 200,000 miners in the industry today. In our judgment that number will have to nearly be doubled. So, that means recruiting and training nearly 200,000 new miners.

Mr. MOFFETT. What productivity does that assume?

Mr. BAILEY. The productivity that they assume there obviously is a new mix of the manner in which the industry will be mining coal by 1985. Right now it is about 50 percent underground mining, and about 50 percent surface. By 1985 there will be a shift so that a larger percentage of the total output will be surface.

I think the estimated percentage is about 65 percent would come from surface mines. This is very largely due to the fact that the western part of our industry, which is mostly surface mining, is going to be dramatically expanded. We have also assumed that productivity levels in our underground mines would be at the levels that we are experiencing today.

Mr. MOFFETT. Mr. Barrett, as I recall, said on page 2 of his testimony, "The 1976 FEA statistics project an increase in underground coal mining production from 304.1 million tons in 1977 to

383.9 million tons in 1985. The majority of this increase will result from an increase in the number of underground mining sections rather than a substantial increase in the number of underground mines."

Do you agree with that?

Mr. BAILEY. I don't have any data at hand to either agree or disagree. It is available and easily checked, our own estimate. I simply don't have——

Mr. MOFFETT. We would like to have that for the record.

Mr. BAILEY. We would be happy to give you our estimates.

Mr. MOFFETT. Without objection, it will be included in the record.

[See letter dated June 6, 1977, with attachments, p. 399.]

Mr. MOFFETT. You stated, Mr. Bailey, on page 3 of your testimony that, "In the early part of 1975 we began the most extensive safety program in our history." What happened in 1975 for your company to initiate that program? The act was passed in 1969, correct?

Mr. BAILEY. Yes. The act passed in 1969 and it was effective April 1970. My company has always had a very broad safety program, but we recognized that the manner in which we were going at the attempt to reduce mine accidents would have to be shifted more towards the training and motivation of our people, and after having studied the data and determining what we thought the underlying cause of most accidents was, we then instituted a whole new program that did in fact focus more attention on the training phase of our program.

I also did mention what those directions were. The program consisted of making certain that everyone, all the managers from the top to the bottom, including myself, was totally involved in this process. Then we had a very firm and definitive safety policy which was issued, and made certain everyone understood that policy, and maintained a very low tolerance level if that policy wasn't followed.

Mr. MOFFETT. What was the policy before 1973? How did it differ? You say you began the most extensive safety program.

Mr. BAILEY. I think our policy prior to that time was more like the attempts being made by Mr. Barrett's forces now, focused on controlling physical conditions in the mines. We recognized that just dealing with the physical conditions through inspections, our own inspections included, was not sufficient. We had to deal with the kind of a work force that we had in the mines, recognizing that you can only go so far dealing with the working environment, and then beyond that you have to get at the real causes of accidents.

When you examine what they are—stumbling, falling, tripping, lifting, failure to use eye protection, or failure to use hand tools properly, leaning out of protective cabs and canopies, the kind of accidents that happen despite the fact that the physical conditions might be as close to being perfect as you can arrange for. That is what our program really emphasizes.

I did make the point that we are encouraged by the results from it.

Mr. MOFFETT. What lessons were learned as a result of the November 20, 1968, accident in which I think 78 miners were killed? Farmington, West Virginia, was that yours?

Mr. BAILEY. Yes. Of course, the cause of that explosion has not yet been determined. We have been in the process of recovery operations in that mine for more than 7 years now. Those recovery operations are still going on today. It is done at our expense, but in cooperation with MESA, and with the United Mine Workers and the State Department of Mines and Minerals in the State of West Virginia.

We have now recovered a very large percentage of the bodies of the men who were lost in that disaster. We have been into many of the operating sections that were operating at the time the explosion occurred. We have not yet reached the far recesses of the mine, and whether we will be able to get there or not, I don't know.

I can say that up to this point in time we have not yet been able to determine the cause of that disaster. I cannot comment on whether we have or have not corrected the reasons that it happened.

Mr. MOFFETT. That is understandable.

The Chair recognizes counsel at this time.

Mr. FINNEGAN. Thank you, Mr. Chairman.

Mr. Barrett, as you know, MESA has a dollar limitation on the amount of R and D it can undertake and the Bureau of Mines undertake in connection with health and safety. Has the administration, in connection with this energy plan, recommended any increase in that dollar limitation and, if so, what is it?

Mr. BARRETT. Not that I am aware of. The act restricts the numbers of dollars to be allocated for health and safety research. The Bureau of Mines is currently operating at that ceiling.

Mr. FINNEGAN. You have been operating under that ceiling for some time.

Mr. BARRETT. That is true.

Mr. FINNEGAN. Have you made a recommendation that that ceiling be increased?

Mr. BARRETT. It is my understanding that if the two bills that are being considered in both the House and Senate, especially on the Senate side, are passed, there will be an increase in funding to accommodate the metal-nonmetal industry. There have been recommendations by the Bureau of Mines to increase that limitation.

Mr. FINNEGAN. Would that accommodation be adequate to meet the Federal Coal Mine Health and Safety Act?

Mr. BARRETT. It all depends on how it finally ends up dollarwise. We feel that dollars spent for health and safety research are well spent; that is, the programs that the Bureau of Mines has initiated, and the results of the programs, I should say, that have been turned over to us have been very beneficial to us, so far as our activities are concerned.

Mr. FINNEGAN. So you would suggest that there should be some increase, particularly since we are going for a larger program for coal conversion?

Mr. BARRETT. Yes.

Mr. FINNEGAN. Can you tell us what the present requirements are of MESA for training of new miners, new inexperienced miners?

Mr. BARRETT. There are certain parts of the act that address the training of miners. They are very vague and very limited. Primarily they address gas detection, certification of electricians. Miners are to be trained in the tasks which they perform. However, we do not set specific numbers of hours or specific courses that new miners should be trained in.

We do have presently mandatory training regulations which we are working on. We have just put together recently and published in the Register the comments that we received on those training regulations, and it shook down to about 50 issues.

We are presently addressing those issues, and at this very moment the joint industry training committee, or part of the committee, at least, and two of our people are looking at the European experience so far as training is concerned. When those people come back, they will be making recommendations to us to modify or upgrade our training requirements to be equal to the European training.

Mr. FINNEGAN. Can you tell us when you anticipate that those regulations, mandatory regulations, will be finalized?

Mr. BARRETT. Midsummer, my counsel tells me.

Mr. FINNEGAN. I see.

Mr. Bailey, how many hours of training are afforded to new miners at your company?

Mr. BAILEY. I don't have that information with me. It is substantial. I would be happy to send you the requirements of our programs. I simply don't have it with me. [See letter dated June 6, 1977, p. 399.]

Mr. FINNEGAN. Also, we understand that MESA has recently been providing a rating of mines on safety. Could you, Mr. Barrett, provide us with a copy of that rating, and any related documents that explain it, as well as the background material?

Mr. BARRETT. I would hurry to say that the mine profile rating system is a system that we have put together based on several criteria. That really doesn't mean much in certain contexts.

Now, for example, if a mine has an extremely low number, numerical rating, that doesn't necessarly mean it is worse than a mine with a higher rating. What it does in effect is assign a number of points to a mine based on its accident frequency rate, the violation density, as well as a safety management program at that particular operation.

So, the mere fact that that system does indicate numerically where a mine stands based on this system doesn't necessarily mean it is better or worse than another mine.

Mr. FINNEGAN. But you are going to take some sort of actions based on that.

Mr. BARRETT. Yes. We will use that for accelerating our inspection programs, for our action prevention programs, our hazard analysis programs. We will be devoting 50 people to that program full-time.

Mr. FINNEGAN. I see. You will provide that information for the record?

Mr. BARRETT. Yes.

[The information referred to may be found in the subcommittee files:]

Mr. FINNEGAN. One last question. Could you provide also for the record, or maybe you can tell us now, what is the number of fatalities in 1975-76, and up to the present time in mining?

Mr. BARRETT. I have them, 1975-76, if you want them. As of this morning there are 10 less than there were this time last year.

Mr. FINNEGAN. Was last year an improvement over the previous year?

Mr. BARRETT. Yes.

Mr. FINNEGAN. I see.

Thank you very much, Mr. Chairman.

Mr. MOFFETT. The Chairman recognizes minority counsel.

Mr. VLCEK. Mr. Barrett, following up on those last questions, I have a set of statistics here from the Bureau of Mines, and they are fatal-nonfatal injuries based on a rate per million manhours, and a rate per million tons. I want you to clarify something for me, if you will.

Apparently there was a change in the method of measuring nonfatal injuries that occurred between 1973 and 1974. Could you explain what that change was and how it affected the numbers?

Mr. BARRETT. We didn't have the regulations we have in effect today at that time. We went to what they call Z-16, using Department of Labor criteria, as our base. We presently count accidents—well, it is a rather complicated system. But, primarily the mine operator must report to us, on a form we provide them, every accident that occurs at his operation, where there is an injury involved. We had not done that before, so we are getting every accident. Previous to that, we were getting for the most part disabling accidents.

Mr. VLCEK. In other words, the 1974 figure would necessarily be higher because you are measuring a greater universe?

Mr. BARRETT. Yes, sir.

Mr. VLCEK. Dr. Finklea, I have some questions about figures you presented to us and projections you made with respect to the impact of increased coal production on fatal injuries and nonfatal injuries. On page 2 you speak of underground mining currently accounting for 82 percent of mining fatalities and 89 percent of nonfatal injuries. Could you tell me what that is in gross terms, national numbers?

Dr. FINKLEA. Excuse me?

Mr. VLCEK. Page 2, you are using percentages there. I wonder if you had available then the actual figures. Page 2, first full paragraph.

Dr. FINKLEA. I think that is in some material that Dr. Merchant from our laboratory in Morgantown would be glad to comment on for you, if you would like him to do so.

Mr. BARRETT. I have the numbers here, if you want them. I can enter them for the record.

Mr. VLCEK. Why don't you do it for the record, if you will.

Mr. BARRETT. I have the numbers of disabling injuries, fatal-nonfatal.

Mr. VLCEK. What are they for 1976?

Mr. BARRETT. Underground, surface or total?

Mr. VLCEK. This breaks it down and says underground mining currently accounts for 82 percent—let's just do underground.

Mr. BARRETT. Total disabling injuries underground were 11,092. Others—that is, surface mines or surface areas in underground mines—2,852.

Mr. VLCEK. Do you have fatalities, also?

Mr. BARRETT. Fatalities for 1976 were 141—109 underground and 32 on surface.

Mr. VLCEK. Thank you.

Dr. Finklea, you go on to say—and this is about four lines from the bottom of page 2—"fatalities might increase by a total of 82 each year, while nonfatal injuries increase by 7,983." That would raise the 141 to 220, and it would increase the 11,000 to about 18,000. How did you derive this figure?

Dr. FINKLEA. This is just a proportionate model increase assuming the same mining practices. The intent here is to show that as one expands the number of miners, one should be careful about the safety education programs, and about the measures to protect the health and safety of miners as the population expands.

Our experience in general in industry has been the workers at greatest risk are people who, when they first come on the job, especially those that have not had appropriate training, and people who are very mature, older people, who are there when the process changes.

The young, new employees are people that generally are most susceptible to accidents and risk. The second part of that would be the attitude of the supervisor towards safety, and our experience in general, that has been very important. This paragraph assumes, that one could not really change the situation from what it is today. There would be things that would tend to lower that, and some things that would tend to raise it.

Mr. VLCEK. Is that a historical projection?

Dr. FINKLEA. Yes.

Mr. VLCEK. Going back how far?

Dr. FINKLEA. Based on the 1976 figures alone, I believe.

Mr. VLCEK. Did you take into account the fact there has actually been a decline both in fatal and nonfatal accidents, both in terms rate per million manhours and rate per million tons?

Dr. FINKLEA. This model just assumes you would not necessarily be able to improve—

Mr. VLCEK. Even though they have improved over the last 5 years?

Dr. FINKLEA. There are a couple of reasons for this. One is with rapid expansion of the work force. As we discussed earlier, there is a group of much younger workers coming in. The training of these new workers and training of their supervisors is very important in controlling the human factors that Mr. Barrett and Mr. Bailey talked about that contribute to accidents.

Mr. VLCEK. Okay.

Dr. FINKLEA. Then there is a mix between underground and surface mines, too, to be considered. With more surface mines, there should be fewer accidents.

Mr. VLCEK. How long has the dilution of the work force been going on?

Dr. FINKLEA. I think as described earlier, it probably started after the embargo in 1973 when there was an influx of a large number of new people in the mines.

Mr. VLCEK. We have had this influx of younger workers, yet according to the figures I have had from the Bureau of Mines, we have had an improvement both in terms of fatal and nonfatal accidents. Perhaps the trend does not actually work the way it has been described.

Dr. FINKLEA. I am saying those are factors that would necessarily be involved. I am saying the model only projected on a single year. We would certainly hope, as we have said in the testimony, with improved training and close attention to the safety problems, that the problem would not nearly reach this magnitude. It is my understanding that the committee had wanted some estimates about the kinds of problems that we faced in reaching these production figures. This is sort of a ball park estimate.

Mr. VLCEK. But these are projections based on 1976?

Dr. FINKLEA. Yes, sir.

Mr. VLCEK. Okay. Thank you.

Mr. Bailey, I wonder if you could provide for the record, since my time has expired, the basis of your statement that productivity has declined by at least 35 to 40 percent because of regulations and enforcement of the 1969 act? I imagine you must have some studies.

Mr. BAILEY. Yes, indeed. Probably the two most exhaustive studies of that subject that have been made, to my knowledge, and are the source of my estimates, were made by John Stratton, who is a member of the firm of Gates Engineering, in Beckley, West Virginia, and he made two reports that I have used, and I would be happy to submit those for the record.

Mr. VLCEK. If you could submit them to the committee for the files, Mr. Chairman.

Mr. BAILEY. If I have other information, I will also submit that.

[The following letter, with attachment, was received for the record:]

CONSOLIDATION COAL COMPANY
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TELEPHONE 412/288-8700

RALPH E. BAILEY
CHAIRMAN AND
CHIEF EXECUTIVE OFFICER
412/288-8474

June 6, 1977

U. S. House of Representatives
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
Room 2125, Rayburn House Office Building
Washington, D.C. 20515

Attn: W. E. Williamsen
Clerk of the Committee

Gentlemen:

During my testimony on May 26, 1977 before the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce, several members of the Committee asked me to submit supplemental information for the record.

First, in response to a request by Mr. Moffett (pages 43 and 44 of the transcript, lines 826-843), I have enclosed a copy of a report prepared by the National Coal Association entitled: "A Study of New Mine Additions and Major Mine Expansion Plans of the Coal Industry." This study, dated August 1976, shows that between 1976 and 1986, 193 million tons of new and replacement underground mining capacity is scheduled to be built (page 4). Unfortunately, this report does not identify separately the planned expansion of existing coal mines nor the capacity of entirely new coal mines. A second report, released by FEA in May 1976, is also enclosed. It indicates that total planned additions to deep mine capacity during the 1975-1985 period amounts to 166 million tons, and a possible additional capacity of 45 million tons is indicated (page 2). The FEA report, also, does not break out capacity expansion of existing and new underground coal mines.

All similar studies with which I am familiar show data for aggregate capacity expansion in the coal industry by mining method and by region. They do not quantify separately capacity expansion for existing mines and new coal mines; therefore, I have no documentation that will permit me to either agree or disagree with Mr. Barrett's statement that most of the increase in underground production "will result from an increase in the number of underground mining sections rather than a substantial

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increase in the number of underground mines." These reports, however, generally show that surface coal mines account for about 60% of the planned capacity expansion in the United States. More than 50 percent of all new productive capacity in the coal industry will be west of the Mississippi River, although Appalachia will also show a sizeable increase, particularly in deep mining. The projected additions of new capacity allow for little or no delays and cancellations which might result from unfavorable legislation or regulations pertaining to underground and surface mining, sulfur emission standards, energy conversion, coal leasing, among others.

Second, in response to Mr. Finnegan's question concerning the number of hours of training afforded to new miners employed by the Consolidation Coal Company (page 51 of the transcript, lines 971-979), I believe the following statement covers the matter.

Each new employee who will work in mining or related activities receives on the average between 50 to 55 hours of company-paid training during the first few months of employment. The person receives 32 hours of orientation prior to his or her first working start. This program includes instruction in the mining process, safety rules and regulations, mine operations, et cetra. In addition, all new employees receive during the first few months of their employment an additional 20 hours of instruction in first aid, ventilation, mine rescue, Federal mining law, roof and rib control, weekly safety training, as well as individualized training that stresses safe work practices on jobs to which they are assigned. The latter item varies from two to four hours per new assignment.

Third, in response to Mr. Vlcek's request (pages 60 and 61 of the transcript, lines 1153-1159), I am submitting two articles written by John W. Stratton, Executive Vice President-Operations, Gates Engineering Company.

> "Effects of Safety Legislation on Productivity." Mining Congress Journal, August 1971, vol. 57, no. 8, pp.28-32; and,
>
> "1970-1975 ---- A Period of Adverse Changes in Productivity and Costs at Underground Bituminous Coal Mines." Mining Congress Journal, October 1975, vol. 61, no. 10, pp. 34-39.

In these articles, Mr. Stratton discusses the deterioration in labor productivity at underground coal mines in the United States subsequent to passage of the Federal Coal Mine Health and Safety Act of 1969. His analyses are based upon at least three surveys of the coal industry. I have enclosed a brief summary of Mr. Stratton's two articles. In his earlier article, he discusses

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many of the basic factors that caused the 1969 Act to have an adverse effect on performance in underground mines, such as mine workers' attitudes, supervisory frustrations, lower daily mine capacity, increased total employment, among others.

I believe the above three items were the only topics which the Committee asked me to submit for the record. If, however, my response is incomplete or there is other information that I might submit, I will be pleased to have additional material sent to the Committee.

Respectfully,

Ralph E. Bailey

/gc

Impact of the 1969 Federal Coal
Mine Health and Safety Law

From articles written by John W. Stratton
Executive Vice President - Operations
Gates Engineering Company

Analyses of the impact of the 1969 Federal Coal Mine Health and Safety Act on labor productivity and costs in the bituminous coal industry were published on at least three different occasions by John W. Stratton. Results of his surveys indicate that average labor productivity in underground operations between 1969 and 1974 declined by 40-45 percent for independent (commercial) coal mines, and 30-35 percent for captive coal mines. The latter are coal mines owned and operated by the steel, electric utility, and certain other industries. All the coal produced in these mines is consumed by the parent firms in their operations, such as in steelmaking, electric generation, chemical manufacture, et cetra. According to Stratton's most recent published results, between 1969 and 1974, some coal mines experienced as much as a 60-65 percent decline in tons of coal produced per man-day. (See page 39 of enclosed article that appeared in the October 1974 issue of Mining Congress Journal.)

Gassy and Non-Gassy Mines
(Mining Congress Journal, October 1975, pg. 35)

Prior to the 1969 Act, underground coal mines were classified as gassy or non-gassy depending on the quantity of methane liberated with a particular mine. The Act, however, decreed that all underground mines will be classed as gassy and regulated as such.

Coal mines originally classified as non-gassy were more adversely affected by the Act as shown in the following comparison:

	Average Loss in	
Mine Type	Tons/Unit-Shift	Tons/Man-Day
Gassy	-30%	-36%
Non-Gassy	-34	-47

Commercial and Captive Mines
(Mining Congress Journal, October 1975, pp 35-36)

The new law had a more adverse effect on the commercial or independent mines than on the captive mines.

Mine Type	Average Loss in Tons/Unit-Shift	Average Loss in Tons/Man-Day
Captive	-22%	-33%
Commercial	-27%	-45%

Stratton attributes some of the difference in relative decline between captive and commercial mines to differences in safety rules and enforcement between the two types of ownership. He also states that a major factor accounting for the steeper decline in productivity at independent mines is due to the fact that non-gassy mines account for a higher percentage of commercial coal mine production than in captive coal production. As noted above, non-gassy mines were more adversely affected by the law.

Causes and Outlook for Future Reductions in Productivity

In the first of the series of articles he wrote on this subject, John Stratton discusses many specific reasons for the reduction in labor productivity attributable to the 1969 Act. (Mining Congress Journal, August 1971, pp 28-32) In his most recent article, he concludes: "In 1975 there are few, if any, mine operators who believe that there will be any improvement ahead (in labor productivity) in the near future."

[The studies referred to may be found in the subcommittee files.]

Mr. BAILEY. I would like to go ahead and comment just a little, if I might, in response to Mr. Barrett's disagreement with my number.

We are talking here about underground mine productivity, and the fact is it has gone down even more since 1969 than the amount which I have assigned as an estimate of the effects of the Coal Mine Health and Safety Act. There are a number of factors involved. Certainly the attitude of the work force, the experience level of the mine workers, the experience level of the managers in the mines, and the changing of mining conditions are all factors.

Also keep in mind that there are some very important offsetting factors in that the industry has spent heavily for equipment that is much more productive than that which we had used in prior years—more efficient and highly productive mining machines.

So, it is difficult to quantify exactly what the assigned amount is. I am completely convinced from the mines that we operate, from the studies that we have made in our mines, and from estimates of the additional cost due to reduced productivity, that this is about the right estimate.

Mr. MOFFETT. Mr. Bailey, let me at this point ask if there are not some other factors, such as the type of mining that is going on in a period of real slack demand. Isn't it true there might be a different kind of mining? Maybe there was a different kind of mining going on in the sixties in terms of easy to get at coal, than in a time of higher demand. Doesn't that have an effect on your productivity figures.

Mr. BAILEY. I said the change in mining conditions was also a factor.

Mr. MOFFETT. Okay. Yesterday, you know, Governor Rockefeller of West Virginia gave us the statistics of 30 tons per man per day in nonunion; nine, I guess it was, in union; and three in Britain. It was rather startling. The reason I raise the point about the changing conditions—I am not sure those figures tell the whole story, do they?

Mr. BAILEY. I think to have a very accurate assessment it would be necessary to take a given mine that was large enough to be representative, and track it all the way through. Certainly there is no way to compare productivity in an underground mine in Great Britain, and productivity in mines here. We mine under different laws, different seam conditions, use different equipment. You cannot generalize in that way.

Mr. MOFFETT. You agree with that, I assume, Mr. Barrett?

Mr. BARRETT. On the English experience, yes, but the Governor's figures were pretty good figures, I would think.

Mr. MOFFETT. I have one more question of Dr. Finklea, and that is on page 6 of your testimony you talked about the use of coal in converted plants and the fact it may be more hazardous than plants originally designed for coal.

How great is that hazard, and should it lead us to move away from the direction that the President wants us to go and how significant a hazard is it?

Dr. FINKLEA. I think we are trying to work to quantify this hazard now. I think the preliminary information would lead us to believe we can accomplish many of the conversions that are being talked about, but we should be aware of the problems we have brought up here.

Of course, how much you can do with the fuel source will depend on the configuration of a particular industrial boiler, its age and capacity, or the particular power plant and its age and capacity. So it's very difficult to generalize. I am sure it would be more difficult in some places than others, but basically we have pointed out the kind of problems that will be encountered in doing this. We are alert to these problems and will be able to work with the people who will be involved in conversion and try to get on top of them rather than have them upon us piecemeal.

Mr. MOFFETT. Let me ask the question I asked Mr. Barrett earlier: To what extent were you involved, to what extent did the President's energy planners consult with you?

Dr. FINKLEA. We have been working with the interagency group dealing with the energy program now for three years, first with the committee that the former Commissioner of the then AEC headed.

Mr. MOFFETT. I know about that group, but we have had a new President that came in, as you know, in January, who said his first domestic priority would be making of an energy policy, and there was a great deal of work put into that. I just would like to know to what extent you and your agency were consulted, since you do have a great deal of experience and since this subject has a great deal of impact on the overall question of coal conversion.

Dr. FINKLEA. I think that our direct involvement has been minimal. However, NIOSH has participated on interagency groups that have contributed working papers on problems with the energy technologies and some of the problems with energy conservation.

Mr. MOFFETT. Do you know that they use the interagency group?

Dr. FINKLEA. I know that our colleagues in the Energy Research and Development Administration were working on this and had these materials available. How extensively they were used I cannot comment.

Mr. MOFFETT. Gentlemen, thank you very much.

You have made an excellent contribution to our hearings and we appreciate it very much.

Thank you.

Our next panel is a panel that will address itself to environmental issues.

The Chair would appreciate it at this time if the following witnesses would come to the table:

Mr. C. K. Mallory, vice president and general counsel, Middle South Services, Inc., New Orleans, Louisiana, presenting the Edison Electric Institute; Dr. Hans L. Falk, Associate Director, Office of Health Hazard Assessment, National Institute of Environmental Health Services; Richard E. Ayres, Staff Attorney, Natural Resources Defense Council, Inc.; Robert F. Ripley, Jr., Commonwealth's Attorney, Yorktown, Virginia; Edward F. Tuerk, Acting Assistant Administrator for Air and Waste Management, Environmental Protection Agency; and Dr. James N. Galloway, University of Virginia, Charlottesville, Virginia.

Will each witness from left to right please identify himself for the record?

STATEMENTS OF EDWARD F. TUERK, ACTING ASSISTANT ADMINISTRATOR FOR AIR AND WASTE MANAGEMENT, ENVIRONMENTAL PROTECTION AGENCY; DR. JAMES N. GALLOWAY, ASSISTANT PROFESSOR OF ENVIRONMENTAL SCIENCES, UNIVERSITY OF VIRGINIA; RICHARD E. AYRES, STAFF ATTORNEY, NATURAL RESOURCES DEFENSE COUNCIL, INC.; DR. HANS L. FALK, ASSOCIATE DIRECTOR, OFFICE OF HEALTH HAZARD ASSESSMENT, NATIONAL INSTITUTE FOR ENVIRONMENTAL HEALTH SCIENCES; ROBERT F. RIPLEY, JR., COMMONWEALTH'S ATTORNEY, YORKTOWN, VIRGINIA; AND C. K. MALLORY, VICE PRESIDENT AND GENERAL COUNSEL, MIDDLE SOUTH SERVICES, INC., NEW ORLEANS, LOUISIANA, ON BEHALF OF EDISON ELECTRIC INSTITUTE

Mr. MALLORY. I am C. K. Mallory, Vice President and General Counsel, Middle South Services, Inc., New Orleans, Louisiana, representing the Edison Electric Institute.

Dr. FALK. I am Dr. Hans Falk, Associate Director, Office of Health Hazard Assessment, National Institute of Environmental Health Sciences.

Mr. AYRES. I am Richard Ayres, Esquire, Natural Resources Defense Council, Inc.

Mr. RIPLEY. I am Robert F. Ripley, Jr., Esquire, Commonwealth's Attorney, Yorktown, Virginia.

Mr. TUERK. I am Edward F. Tuerk, Acting Assistant Administrator for Air and Waste Management, Environmental Protection Agency, Washington, D. C.

Dr. GALLOWAY. I am Dr. James N. Galloway, Environmental Sciences, University of Virginia, Charlottesville, Virginia.

Mr. MOFFETT. Thank you, gentlemen.

As with our previous panels, we would appreciate your paraphrasing your statements, and without objection your statements will be included as a part of the record.

STATEMENT OF EDWARD F. TUERK

Mr. TUERK. You have our statements for the record and included with that statement are a series of three bar charts which basically represent our EPA estimates of the changes in emissions of the three major pollutants, sulfur oxides, particulate matter, and hydrogen oxides, as a result of the coal conversion program.

I think, with your permission, what I would like to do is merely highlight those three charts, and press some of the specific numbers that the bar charts reflect but don't delineate.

The charts essentially show two types of comparisons. These show a comparison of the projected 1985 emissions from the coal conversion program, total, and coal conversion program in relationship to the 1975 or current emissions.

Secondly, they present a series of comparisons in 1985 of several different scenarios.

The three scenarios I am going to discuss basically are the 1985 emissions, assuming the amendments to the Clean Air Act imposing best available control techologically, but no energy program, the emissions assuming the Clean Air Act amendments with best available control technology, and the coal conversion program without other energy saving aspects of the President's recommendations.

Thirdly, the emissions which would assume the Clean Air Act amendments, the coal conversion program, and the energy savings associated with the President's program.

Those numbers go somewhat like this, and what I want to compare at this point would be solely the different emission levels projected in 1985.

Our estimates indicate for sulfur dioxides emission, given the Clean Air Act amendments and best available control technology would assume an emission level of about 30.8 million tons in 1985. With the coal conversion program, and no energy saving as reflected in the rest of the President's program, we would anticipate that level icreasing to 32.3 million tons or by 4.9/10 percent.

Most of that increase would occur in the industrial sector of the economy. If there is, if we assume, both the coal conversion program and the President's energy saving provision of the President's program, the emission would drop from the 30.8 down to 30.4 million tons, or about a 1.3 percent decrease.

The other pollutant I would like to address quickly of concern where there would be major changes under the coal conversion proposal, are the emissions of nitrogen oxides.

Our estimates essentially are in 1985, assuming Clean Air Act amendments and no coal conversion program, that the nitrogen oxide emissions from utilities and industry would be 15.6 million tons. With the coal conversion program——

Mr. MOFFETT. What is the assumption you were making as far as the Clean Air Act is concerned?

Mr. TUERK. We are assuming the Clean Air Act amendments, including the requirements of best available control technology, pass this session of Congress.

Mr. MOFFETT. The administration proposal?

Mr. TUERK. Yes.

Mr. MOFFETT. Okay.

Mr. TUERK. That level would be, in our estimate, 15.6 million tons, given the conversion program, as a change, and the level would go up to 16.3 million tons or a 4-1/2 percent increase. Assuming the coal conversion program and the other aspects, energy conservation aspects of the President's proposal, the increase of the 1985 level would be only 1.9 percent, or a total of 15.9 million tons.

So in summary, I think, in our judgment, the coal conversion program would create a situation in which we would have a total, would have an increase in the total loading of the atmosphere for both SO_2 and NOx. The application of the energy conservation provisions in conjunction with that program, however, would minimize those increases and give us levels approximately about the same as we would have observed without the coal conservation program.

I will stop there and leave it open for questions and discussion.

[Mr. Tuerk's prepared statement follows:]

STATEMENT OF
EDWARD F. TUERK
ACTING ASSISTANT ADMINISTRATOR
FOR AIR AND WASTE MANAGEMENT
ENVIRONMENTAL PROTECTION AGENCY
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES
WASHINGTON, D. C.
MAY 26, 1977

Mr. Chairman and members of the Subcommittee. Thank you for the opportunity to appear before this Subcommittee to present EPA's views on Part F of the National Energy Act, the coal conversion legislation proposed by the President. We are, of course, primarily concerned with the environmental impact that any conversion program might have. Consequently, my testimony will concentrate on how coal conversion may affect levels of air pollution.

The U.S. Environmental Protection Agency strongly supports the National Energy Plan, with its dual emphasis on conservation and increased coal production. One of its basic tenets is that increased utilization of domestic fuels must be accompanied by strong efforts to conserve energy and by stringent enforcement of environmental controls.

Because coal is the most abundant alternative to use of oil and natural gas, the National Energy Plan relies heavily on its increased use. If the National Energy Plan were adopted there would be a substantial increase in coal use — from approximately 600 million tons per year at present to about 1.2 billion tons per year in 1985, compared to expected coal use of about 1 billion tons without the National Energy Plan. With the increased coal use expected even without the Plan we would need to ensure that both new and old coal-burning facilities are sufficiently controlled to prevent an unacceptable increase of emissions. The further increase in coal use under the National Energy Plan will make vigorous and effective control even more urgent.

The Administration's coal conversion bill requires, with certain exemptions, that all new utility plants and large industrial facilities (greater than 10 megawatts) must burn coal rather than oil and gas. The bill also gives the Administration the authority to require the use of coal by other new industrial facilities. Roughly 10% of the facilities to be affected have previously burned coal; 90% will be new sources or facilities that have only burned other fuels. Sources unable to meet environmental standards can be exempted from the provision's requirements.

The Administration's bill would also impose conservation taxes on the use of oil and gas by utilities and large industrial companies. These taxes start in 1979 for industry and in 1983 for utilities. As an additional incentive, companies may receive rebates of tax payments for all investments in non-oil and gas facilities. These rebates would apply to pollution control equipment as well as to other capital expenditures.

In the copies of this testimony that I have distributed, you will find three tables showing the effects on national emissions loadings the National Energy Plan and the Administration's proposed Clean Air Act Amendments will have. These tables address the changes in emissions of the three pollutants which will be most substantially affected by coal conversions: particulates, sulfur dioxide, and nitrogen dioxide.

While coal conversions would tend to increase emissions, the Administration's Energy Plan would also encourage energy conservation. Together with the Administration's proposed changes in the Clean Air Act, these conservation measures would result in compensating decreases in emissions. The energy conservation measures include peak load pricing, mandatory insulation standards for new buildings, mandatory standards for new appliances, financial incentives for energy conservation in existing buildings, and oil and gas pricing policies. As shown in the tables, if the Plan's energy conservation measures and the Clean Air Act changes are enacted, nationwide emission levels will not be much different in 1985 than they would have been in 1985 without the adoption of the President's Energy Plan.

The President's Energy Plan would affect both utility and industrial fuel use. However, the effects in these two sectors would be very different. Even without the Energy Plan, we estimate that coal use will double in the utility sector. Utilities are already planning to burn coal rather than oil and gas in most new fossil fuel units. While the coal conversion program would tend to increase coal use (with related oil and gas savings), the Plan's conservation measures would reduce coal consumption. The net effect is that coal use by utilities in 1985 is projected to be approximately the same both with and without the National Energy Plan. However, oil and gas use by utilities would be reduced substantially. Therefore the emissions from utilities in 1985 under the President's Plan will actually be less than they would be without the Plan.

The effect of the Plan on the industrial sector would be much more pronounced. By 1985 industrial facilities would consume almost 200 million more tons of coal a year than they would without the Plan. Without the Plan industry would, by and large, continue to burn oil and gas, chiefly because fuel costs for industry are not as large a fraction of operating expenses as they are for utilities and because oil is less troublesome to handle at an industrial site than is coal. However, significant shifting from gas and oil to coal is expected under the Plan.

The result of this increase in coal use will be increased emissions in the industrial sector. However, these emissions can be substantially but not entirely offset by installing best available control technology on all new industrial sources burning coal. Pollution control hardware now available can limit emissions of SO2 and TSP from a new coal-fired facility to that which would be emitted from an existing oil burning source. The emissions loadings in the tables are based on the assumption that this control hardware is installed on all new industrial sources starting operation after 1980.

A net increase of emissions is projected for SO2, TSP, and NOx from industrial sources over the levels that would have occurred without the President's Plan. However these increases are projected to be compensated for by decreases in emissions from the utility sector. The net result is that the total of industrial and utility emissions are expected to be about the same under the President's Plan in 1985 as they would be without the Plan. While emissions of NOx are approximately the same in 1985 with and without the National Energy Plan, NOx emissions are projected to be 25% above 1975 levels.

These conclusions are based on several critical assumptions regarding pollution controls. First, as stated, best available control technology must be required on all new facilities. Second, existing facilities must install equipment needed to meet current emissions limitations. Third, the pollution control equipment must be operated and maintained properly. Basically, in order to avoid aggravating existing pollution problems through increased coal use, it is necessary to take measures to assure that stringent controls are installed and operated properly wherever possible.

Thus, the Administration supports amendments to the Clean Air Act requiring the use of best available control technology (BACT) on new sources, requiring prevention of significant deterioration, disallowing credit for tall stacks as a means of meeting air quality standards, and establishing noncompliance penalties to eliminate any incentive to delay compliance or to operate or maintain pollution control equipment inadequately.

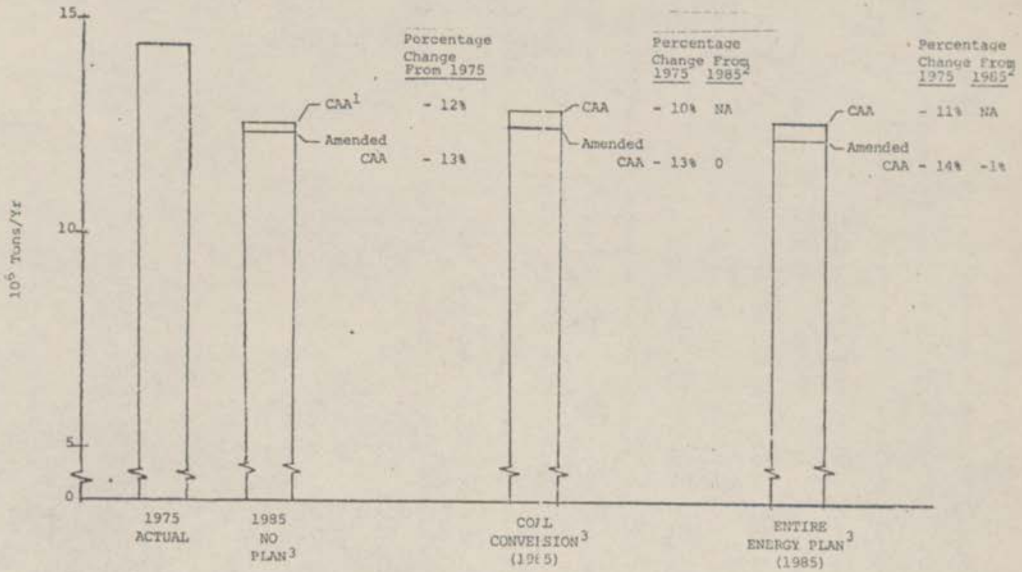
The costs of these environmental controls are reasonable in view of the environmental protection these additional controls provide. EPA estimates that they will add a total of about $5 billion to the cost of new coal-fired power plants by 1985 and about $12 billion by 1990. This cost will increase utility capital costs between 1975 and 1985 by about 2% and will result in average rate increases of about 1% nationally by 1985, with higher increases in some regions. The incremental capital costs of the BACT requirement for other industrial facilities will be about $4 billion in 1985.

The national emission loadings shown in the charts do not tell us very much about how coal conversion would affect the attainment of air quality standards in specific areas of the country. There are some areas of the country where additional use of coal could impair attainment of the health standards. The National Energy Plan was developed assuming that significant coal conversions would not occur (and should not be allowed) in some areas due to environmental constraints.

In conclusion, stringent environmental controls must be installed and measures must be taken to insure that they are operated and maintained properly if we are to minimize the effect of increased coal use that would occur even without the National Energy Plan. The coal conversion program accentuates the need for adoption of these provisions and of the Plan's energy conservation provisions so that further environmental degradation does not occur. With these provisions the potential for conflict between increased coal use and environmental protection can be minimized, and both programs can move forward successfully.

This concludes my prepared testimony. I will be happy to answer any questions you may have.

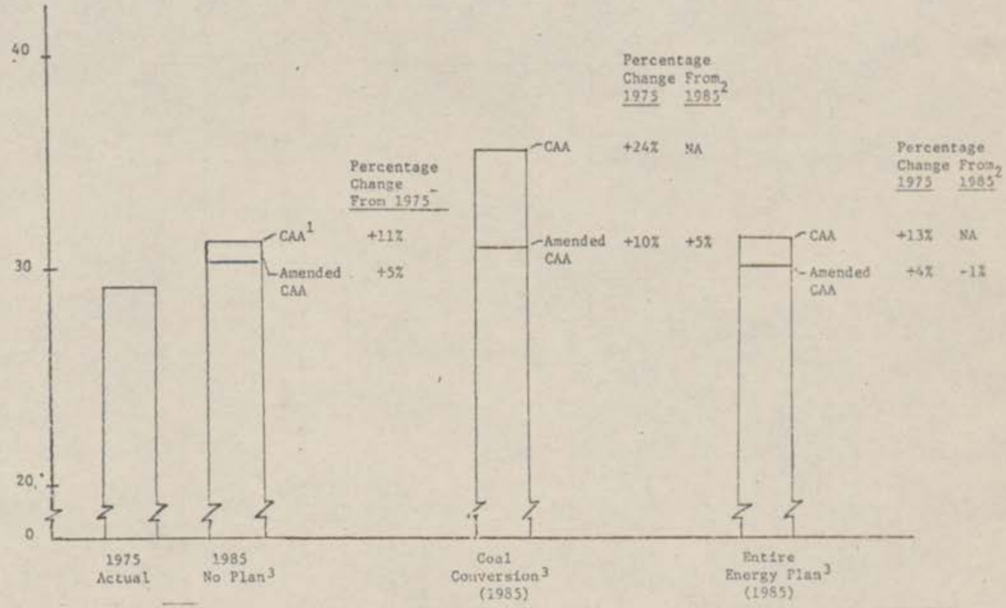
TABLE 1 -- PARTICULATE EMISSIONS FROM INDUSTRY AND UTILITIES
(National Loadings)



1/ CAA = Current Clean Air Act
2/ 1985 Assuming Amended CAA
3/ Assumes full compliance with applicable emission limitations; comparisons with 1975 actual emissions may be misleading since the 1975 figure includes delayed compliance and the 1985 figures do not.

PRELIMINARY EPA ESTIMATES
5/24/77

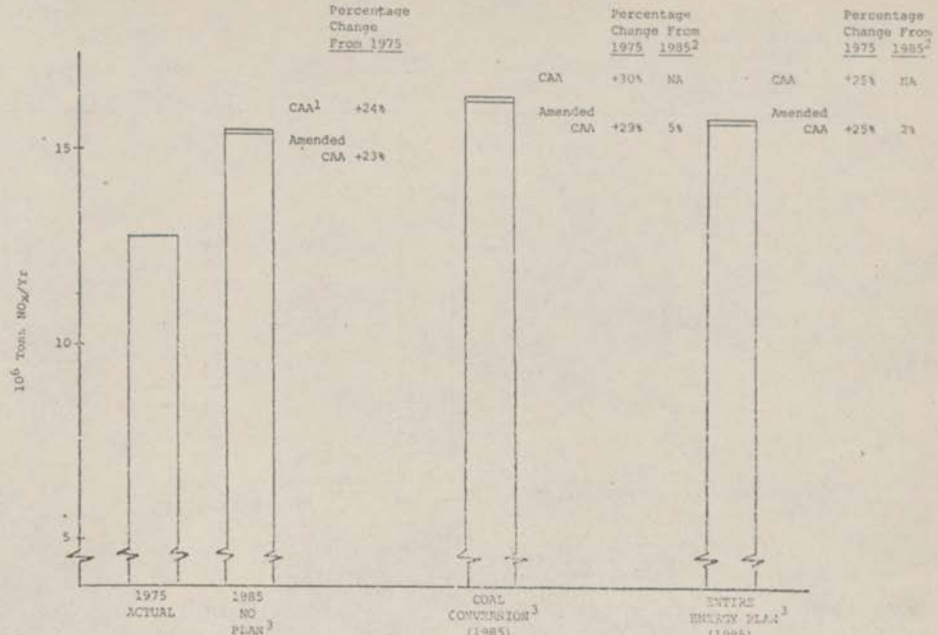
TABLE 2 -- SO_2 EMISSIONS FROM INDUSTRY & UTILITIES (National Loadings)



PRELIMINARY EPA ESTIMATES
5/24/77

1/ CAA = Current Clean Air Act
2/ 1985 Assuming Amended CAA
3/ Assumes full compliance with applicable emissions limitations; comparisons with 1975 actual emissions may be misleading since the 1975 figure includes delayed compliance and the 1985 figures do not.

TABLE 3 -- NO_x EMISSIONS FROM INDUSTRY AND UTILITIES (National Loadings)



1/ CAA = Current Clean Air Act
2/ 1985 Assuming Amended CAA
3/ Assumes full compliance with applicable emissions limitations; comparisons with 1975 actual emissions may be misleading since the 1975 figure includes delayed compliance and the 1985 figures do not.

PRELIMINARY EPA ESTIMATES
5/24/77

Mr. MOFFETT. Thank you, Mr. Tuerk.
Dr. Galloway, please?

STATEMENT OF DR. JAMES N. GALLOWAY

Dr. GALLOWAY. I am Dr. James Galloway of the Environmental Sciences Department, University of Virginia.

I plan to speak about the acidification of rain and snow by the combustion of fossil fuels including coal.

First, a definition of acidity of precipitation—rain and snow. Acidity is a measure of hydrogen ion concentration. In natural waters, including precipitation, the hydrogen ion concentration can vary several orders of magnitude. To simplify that, we use the function pH, as a measure of acidity; pH is a logarithmic function. A pH of 7 is neutral in precipitation; a solution of pH 6 is slightly acidic, with 10 times the concentration of hydrogen ions as a pH 7 solution. A pH 5 solution is more acidic with 10 times the concentration of hydrogen ions that exist at pH 6. So as an acidity concentration increases, the pH decreases, an important point.

The range of precipitation pH in a natural environment in the absence of anthropogenic contamination—SO_2 and NOx—is 5.6 to about 8. Currently the pH of precipitation in the Eastern United States is at least 4.6. This represents an increase in acidity of a factor of 10 over natural conditions.

My comments are directed to lower end of the pH scale and the acidification of precipitation by the combustion of coal.

I am here today not as an advocate but as a scientist, and to present to you the facts we know about the acidification of precipitation, the types of things we suspect, and things we definitely don't know.

As I mentioned, we know the lower limit of the pH in precipitation is 5.6 in a natural system.

We know that in the last 20 years the annual average pH of precipitation in the Eastern United States and Scandinavia has steadly decreased down to levels of pH 4.0 in some areas. This represents an increase in the hydrogen ion concentration of a factor of 40 over natural levels.

Figure 1 of the testimony that you have in front of you shows two maps. The map on the left is the pH of precipitation on an annual basis in the years 1955-56. The map on the right is the pH of precipitation on an annual basis in 1972-73 for the Eastern United States.

There are three important things to note from this map. In 1955-56, the shaded area represented pH's of precipitation below 4.52, that is a factor of 10 below the natural limit, and encompasses most of the Northeastern United States.

In 1972-73, this same area where the pH of precipitation is a factor of 10 lower than the natural situation—acidity of a factor of 10 higher—now encompasses most of the Eastern United States.

In 1976 data exists to show that the shaded area essentially covers the Eastern United States.

Those are facts.

We know also that this increased acidity of precipitation, decreased pH, is due to the combustion of fossil fuels.

Combustion of fossil fuels releases SO_2 and NOx into the atmosphere; these gases are transported for long distances; this is partially caused by the heat in the gases that are emitted and also the height of the stack.

This causes a regional loading of SO_2 and NOx in the atmosphere. Atmospheric water vapor, and oxygen oxidize these gases to sulfuric and nitric acids; the acids form small particles called aerosols, and these aersols are scavenged out by precipitation which results in the acid rain phenomena.

We might also state that in Scandinavia they observed the same phenomenon. They are downwind of the industrial complexes of England and Germany, and the Eastern European countries.

What do we know about the effects? Compared to what we know about the phenomenon and the causes, we know very little about the effects.

You can divide the effects up to aquatic and terrestrial ecosystems. In aquatic we know that acid precipitation can acidify poorly buffered lakes on a regional basis. We know that fish in these lakes below pH 5 do not reproduce; so the lakes eventually become sterile with respect to fish.

In Scandinavia there are over 2,000 lakes in the past 20 years that have become sterile with respect to fish reproduction due to the acidification of the lakes by acid precipitation.

In the United States there are several areas containing lakes that are potentially sensitive to acidification by acid precipitation. Figure 2 of my testimony shows a map of sensitive aquatic ecosystems in the United States. Note that the Northwestern United States, Northeastern and portions of the Southeastern United States have areas that contain lakes that are potentially sensitive to acidification.

In New York State in the Adirondack State Park, there are 100 to 200 lakes that have been acidified in the last 30 years. The causes are most certainly due to acidification by acid precipitation, and in these same lakes the fish no longer reproduce.

The effects of acid precipitation on terrestrial ecosystems—forests, vegetation, and agriculture—are less well known. We do know, however, that acid precipitation causes decreases in the soil respiration, it affects nitrogen mineralization; It weathers minerals from the soils faster, therefore causing nutrient depletion and a whole host of other effects that are included as an appendix to my statement. This appendix to my statement is a summary report from the International Conference on the Effects of Acid Precipitation, held in Telemark, Norway, June 1976. It represents the state of the art knowledge about the phenomenon of acid precipitation and its effects.

In summary, I would like to state that we require a network for monitoring long term changes in the chemistry of precipitation in the United States. To date we do not have an adequate network and we need to have this data so we can make decisions as scientists, and you can make decisions as policymakers on the effects of man of the combustion of fossil fuels on precipitation on a long-term basis.

Second, emission of sulfur oxides from the increased combustion of coal should be minimized, and third, areas sensitive to acid precipitation should be defined and research on the effects of acid precipitation should be expanded.

[Dr. Galloway's prepared statement follows:]

Statement by Dr. James N. Galloway, Assistant Professor of Environmental Sciences at the University of Virginia, Charlottesville, Virginia to the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce, United States House of Representatives at hearings on H.R. 6831. May 26, 1977.

My name is James N. Galloway and I am an assistant professor at the University of Virginia. I am here today to present information on the acidification of precipitation (rain and snow) by the combustion of coal. I am not here as an advocate, but as a scientist. I will present testimony on what we know, what we suspect and what we don't know about acid precipitation.

I have a Ph.D. in Chemistry. My area of professional expertise is environmental chemistry. I study how man changes his chemical environment. For the last three years I have investigated the phenomena of acid precipitation. During this period, I have written ten professional papers on this subject and have been invited to give expert testimony at the local, state and federal level.

There have been two international symposia in the last two years relative to acidification of precipitation by the combustion of fossil fuels and its effects on aquatic and terrestrial ecosystems. Copies of both the proceedings will be provided as supplementary material for the committee. The results of research conducted in Europe and in North America was reported at the two symposia. These reports and other published papers (bibliography provided) support the following statements.

The acidity of precipitation is determined by the concentration of hydrogen ion in solution. Because the concentrations of hydrogen ion in natural waters can vary by a factor of one hundred thousand (from .001 grams/liter to .00000001 grams/liter) it is convenient to express the concentration of hydrogen ion as a logarithm term, pH. For example, in precipitation the range of hydrogen ion concentration is pH 3 to pH 8. A pH 3 solution has ten times the hydrogen ion as a pH 4. A pH 4 solution has ten times the hydrogen ion concentration as a pH 5 solution (Table 1). Because the lower limit of the natural pH of precipitation is pH 5.6, acid precipitation is defined as precipitation with pH < 5.6.

During the past two decades, rain and snow in northern Europe and in the eastern United States have become progressively more acidic (Oden, 1968; Likens and Borman, 1974; Cogbill and Likens, 1974). Precipitation formed in an atmosphere relatively free of natural or anthropogenic contamination with oxides of sulfur or nitrogen would be expected to have a pH range from 5.6 to about 8. But individual storms in Sweden, Norway, New Hampshire and North Carolina have produced rain of pH 3.0 - 3.6. The average acidity of precipitation in much of the eastern United States was estimated to be below pH 4.5 in 1972-73 (Cogbill and Likens, 1974). This decrease in precipitation pH from pH 6.0 to pH 4.5 represents about a 32-fold increase in the hydrogen ion concentration.

Figure 1 has maps of precipitation pH in the eastern United States for the years 1955-56 and 1972-73. Note the increased area receiving acid precipitation and the increased acidity of acid precipitation in the northeastern United States (Likens, 1976). These changes are due to increased emission of oxides of sulfur and nitrogen (NO, NO_2) produced during combustion of fossil fuels. These oxides are oxidized to sulfuric and nitric acids which are scavenged by precipitation. Sulfuric acid has been recognized as a major component of the acidic substances in precipitation both in Europe and in North America (Oden, 1968; Cogbill and Likens, 1974; Likens and Bormann, 1974). It is now known from the amounts and stoichiometric balance among ions in natural rain that sulfuric acid probably accounts for about two-thirds of the total acidity now observed in precipitation in eastern North America (Cogbill and Likens, 1974; Galloway et al., 1976). The remaining one-third of the acidity is due to nitric acid.

Relatively little is known about the effect of acid precipitation on aquatic ecosystem. It is known that poorly buffered lakes become acidified by acid precipitation. We know that fish can no longer reproduce in lakes with a $pH < 5$. In Scandinavia there are 2000 such lakes that are sterile with respect to fish. There are large areas of North America that contain lakes that are potentially sensitive to acid precipitation (Figure 2). In the Adirondack Mountains, New

York State, there are 100 - 200 lakes that have been acidified. If the intensity of acid precipitation continues to increase and the geographical areas receiving acid precipitation continues to increase, then we can expect acidification of more lakes.

Little is known at present about the direct or indirect effects of acidic precipitation on terrestrial vegetation. It is known that the average raindrop falling from the atmosphere does not fall directly to the soil where acidic substances potentially could be neutralized in well buffered soils; most rain is intercepted by the foliage to terrestrial plants where it can induce various physiological changes before reaching the soil. In a forest, rain will fall upon an average of three layers of foliage before reaching the soil. Because of variation in soil buffering capacity, plants growing on recently formed sandy soils and glacial outwash areas would be expected to be more vulnerable to acid rain effects mediated through the soil than older soils of high clay content and consequently large base exchange capacity.

The most striking vegetational effect reported to date is the development of peat moss as a submarine rather than a terrestrial plant in lakes and streams in Sweden receiving large amounts of acidic precipitation (Grahn, Hultberg and Landner, 1974). Dense mats of Sphagnum and an apparently parasitic aquatic fungus have developed at the bottom of acidified lakes at water depth up to 54 feet. General investigators have reported direct injury of terrestrial plants by artificial mists or simulated rain containing dilute sulfuric acid. Increased leaching of nutrients from pinto bean and sugar maple seedlings by acidic mists has been reported by Wood and Bormann (1974).

A summary of the known effects of acid precipitation is included as an appendix to this statement (Appendix I). This summary is from the 1976 International Symposium on the Impact of Acid Precipitation on Forests and Freshwater Ecosystems held in Telemark, Norway.

On the basis of the experience and knowledge outlined above, I offer the following comments and recommendations:

1) A network for monitoring long-term changes in the chemistry of precipitation should be established throughout the United States. This is necessary to detect changes in precipitation composition due to anthropogenic activities. The sampling stations should include the calibrated watersheds maintained by the U.S. Forest Service so that analytical data extending back over time at these watersheds can be integrated with analytical data collected forward in time.

2) Emission of sulfur oxides from the increased combustion of coal should be minimized.

3) Areas sensitive to acid precipitation should be defined and research on the effects of acid precipitation should be expanded.

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TABLE 1

Comparison of pH and Hydrogen Ion Concentration

increasing hydrogen ion concentration (acidity)

pH pH	Hydrogen concentration micrograms/liter
3	1000
4	100
5	10
5.6	2.5
6	1.0
7	0.1
8	0.01

* The pH range of precipitation in natural systems is pH 5.6 to pH 8. Therefore pH 5.6 represents the lower limit of pH in precipitation uninfluenced by fossil fuel combustion products.

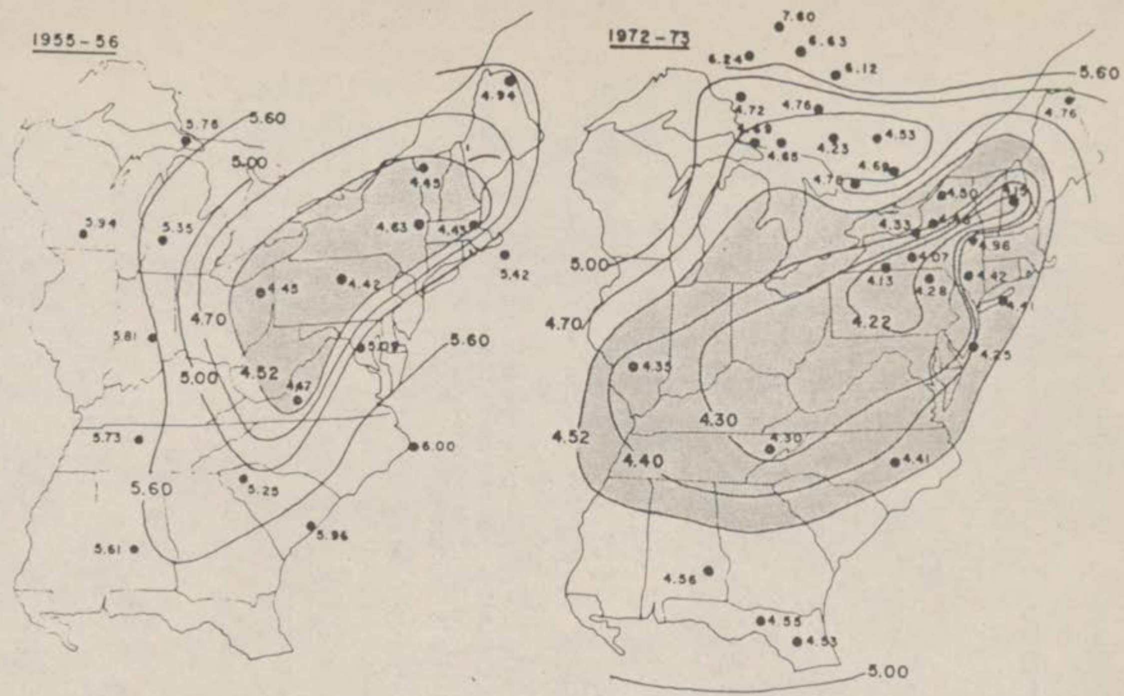

FIGURE I. THE WEIGHTED ANNUAL AVERAGE OF pH OF PRECIPITATION IN THE EASTERN UNITED STATES IN 1955-56 AND 1972-73.

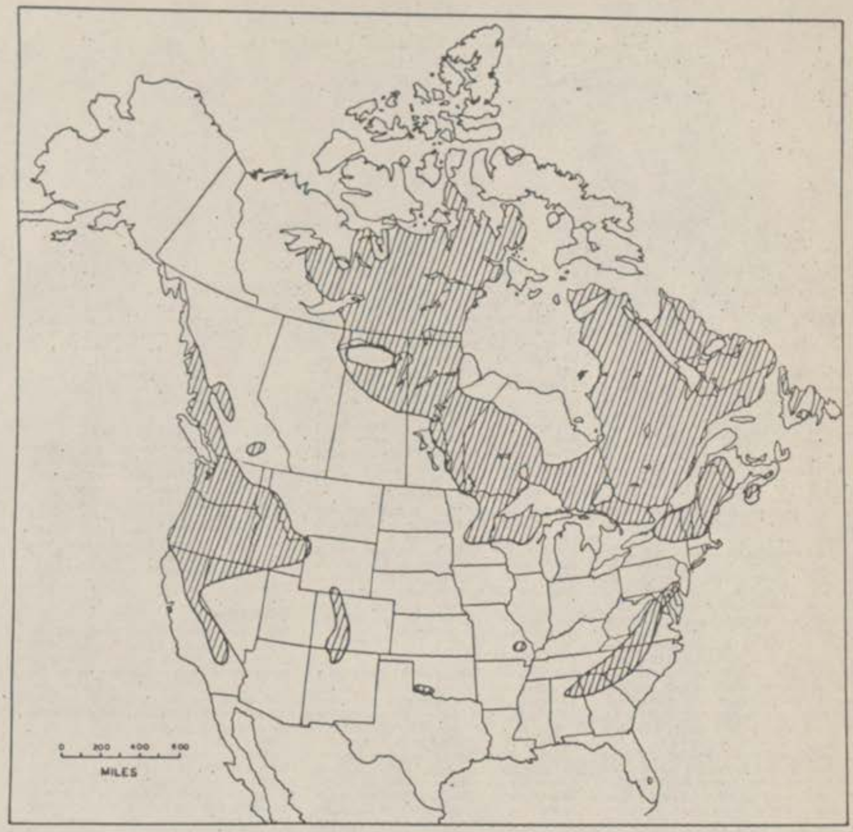

FIGURE 2. REGIONS IN NORTH AMERICA CONTAINING LAKES THAT ARE SENSITIVE TO ACIDIFICATION BY ACID PRECIPITATION.

Appendix I

Report from the International Conference on the Effects of Acid Precipitation, held in Telemark, Norway, June 14-19, 1976

This report summarizes the conclusions from the Conference, with emphasis on the effects of acidity upon forest and freshwater ecosystems. It represents a consensus of the scientific opinions of the participants.

BACKGROUND

In addition to naturally occurring sulfur oxides and hydrogen sulfide, atmospheric loads of sulfur in various regions are augmented by sulfur dioxide and particulate sulfate from the combustion of fossil fuels and from industrial processes.

Whereas the emissions of sulfur dioxide in Europe in the period 1910–50 seem to have been fairly constant, with around 25 million metric tonnes emitted annually, there has been a large increase in the last decades. The emissions in Europe in 1973 have been estimated at 60 million tonnes of sulfur dioxide.

Sulfur compounds are removed from the atmosphere by two processes, *viz* a) dry deposition including the absorption of SO_2 on exposed surfaces and the sedimentation and impaction of particulates and b) wet deposition in which sulfur compounds are frequently deposited as acid precipitation.

Dry deposition is a continuous process depending mainly on the concentration of sulfur dioxide near the ground, the yearly amounts deposited generally decreasing with increasing distance from the source. Wet deposition is much more variable being dependent both on the rainfall pattern and on the burden of sulfur compounds within the mixing layer. It can be substantial in areas exposed to orographic precipitation from air which has passed large emission sources. Yearly averages of acidity in precipitation in some areas of Europe and eastern North America correspond to pH 4.3 and 4.0 respectively.

It has been shown that amounts deposited in some areas are appreciably in excess of amounts emitted in the sames areas. By tracing the trajectories of polluted air masses, it has been possible to broadly characterize the movement of air pollutants over long distances from emission sources.

In cold climates air pollutants deposited during the winter usually accumulate in the snow pack. When this melts, much of the pollutant load is released in concentrated form with the first meltwater. This may lead to sudden increases of acidity in the watercourses and in the soil.

Wet precipitation and dry deposition not only remove sulfur compounds from the atmosphere but also a variety of other manmade and natural substances, including nitrates and ammonia, as well as metallic compounds and a wide range of organic compounds.

CONFERENCE DISCUSSIONS

The Conference was primarily concerned with the effects of acid precipitation on aquatic and terrestrial ecosystems. However, the participants were aware that there are many other areas of concern, related to the emissions of sulfur compounds. Noted particularly was the relation to impacts on human health and the corrosion of materials (more generally considered in urban and industrial situations) as well as possible effects on local and global climate.

HEALTH HAZARD

Epidemiological investigations have established an association between deterioration in human health and atmospheres containing high concentrations of sulfur dioxide among other pollutants, but they do not identify the specific role of sulfur dioxide or oxidation products of sulfur.

On the basis of biological experimentation it now appears that aerosols of sulfuric acid and some sulfates are more reactive than sulfur dioxide, which has often been used as an indicator of air pollution. Sulfate ions *per se* are not necessarily toxic; instead their toxicity seems to depend upon the species of associated cations. Because other sulfur compounds seem more important than sulfur dioxide, increasing attention should be paid to them and to factors that encourage oxidation, *eg* photochemical activity and catalysts.

CORROSION DAMAGE

Comparative studies made in polluted and nonpolluted areas have highlighted the corrosion effects of sulfur dioxide on materials. The role of acid precipitation has not yet been clarified. In 1970 the annual costs per person of damage ascribable to the main atmospheric sulfur pollutants were estimated to be about $7 and $4 in the USA and Sweden respectively.

EFFECTS ON GLOBAL CLIMATE

The continued use of fossil fuels may increase ambient carbon dioxide concentrations as well as amounts of suspended particulates. Carbon dioxide concentrations are expected to increase to levels which may possibly affect global temperatures. The effects on climate of particulates, including acidic sulfate and nitrate compounds, are more difficult to predict. However, their role in absorbing and scattering radiation, and as cloud condensation nuclei, should not be disregarded.

ECOSYSTEMS

Ecosystems are complex organizations with the differing biological elements, microbes, plants and animals, responding, each in its own way, to environmental changes. For convenience the Conference participants discussed forest and freshwater ecosystems separately, but in reality they are interdependent with a continuing interchange of energy and matter.

Freshwater ecosystems Water quality has changed during the last decades in numerous lakes and rivers in southern Scandinavia and eastern North America, pH often falling below 5, with sulfate becoming the most important anion. There is strong evidence that this change is due to acid precipitation. It is associated with the loss of buffering capacity, and the occurrence of additional short-term decreases in pH, related to meltwater from snow or episodic inputs of acid precipitation from polluted air masses.

The acidification of freshwater ecosystems leads to many changes, most of which involve decreases in biological activity and important changes in nutrient cycling. For example, decomposer organisms are less active in acid waters, resulting in increased accumulations of organic matter. When the pH drops below 6, numbers of species in several groups of organisms (phytoplankton and zooplankton, bottom fauna and several other groups of invertebrates), decrease considerably, thus affecting the variety of food for fish and other animals depending on freshwater ecosystems. Shifts have been observed from higher aquatic plants toward mosses, and this will influence not only the bottom fauna but also nutrient exchange with the sediments.

High acidity (pH <5.5) seriously affects fish populations, particularly when occurring in waters of low ionic strength. Rapid extinction rates of fish populations inhabiting acidified waters have been observed during the past few decades in southern Scandinavia as well as in parts of eastern North America.

Case studies of several fish populations and experiments clearly indicate that the elimination of fish is often a result of chronic reproductive failure in acid conditions and of damage done to sensitive stages, especially the newly hatched larvae. Such a process is insidious and not readily evident in terms of fishery yield until extinction is imminent.

In lakes and streams with soft waters acid stress has also been shown both experimentally and in field studies to cause mortality among adult fish as a result of interference with physiological mechanisms regulating active ion exchange across gill membranes. In this case factors such as size, age, acclimation history, genetic background and ionic strength of the water interact in complex ways to determine the relative acid tolerance of the fish.

There is strong evidence that the increased acidity of precipitation is now the main cause of these extensive losses of salmonid fish stocks as well as other populations of economic importance both in southern Scandinavia and the northeastern part of the United States and parts of southeastern Canada.

Sensitivity is related to the tolerance of the differing species (reflecting their genetic diversity), to the timing of episodic acid precipitation in relation to the stage in the life cycle, and to the influence of the geological evironment, ex lakes and rivers on bedrock, overburden and soils highly resistant to chemical weathering. This may also be the case in geological areas of this type elsewhere in the world. Special consideration should be given to the preservation of unique gene pools and habitats.

*There may be complex interactions with other environmental factors, including some organic compounds. In waters of low pH the adverse effects of heavy metals on fish and other organisms can be enhanced, whereas at pH values nearer neutrality these substances would have been tolerated.

Forest ecosystems For a long time the effects of sulfur compounds have been observed near sources of emission. Recently, however, interest has also been devoted to regional effects at sites remote from these sources where vegetation is influenced by both "wet" and "dry" deposits of sulfur compounds. However, instead of being exposed to mean annual sulfur dioxide concentrations of up to 200 $\mu g/m^3$, which are associated with the development of obvious foliage blemishes ex chlorotic spots, they are subject to annual average concentrations of possibly 25-30 $\mu g/m^3$ which normally would not be expected to cause blemishes, although other physiological disturbances may occur.

Because tree growth has been shown to be directly related to base saturation-a widely accepted indicator of soil fertility-adverse effects of acid could be expected, base saturation being inversely related to acidity.

In field and/or laboratory experiments, it has been found that acid precipitation

a) decreased soil respiration, an indicator of microbial activity;

b) affected nitrogen mineralization;

c) increased amounts of minerals leaching from soil;

d) affected the germination and establishment of conifer seeds and seedlings which were maximal at about pH 5.0;

e) accelerated cuticular erosion of leaves;

f) enhanced the leaching of nutrients and organic compounds from leaves;

g) decreased the activities of associated pathogens, of some beneficial symbionts, also of saprophytes;

h) produced leaf damage at pH 2.5-3.5.

Although many of these factors might be expected to adversely affect tree growth, it has not yet been possible to demonstrate unambiguously decreased tree growth in the field. However, it is possible that acid damage might have been offset by the nutritional benefits gained from nitrogen compounds commonly occurring in acid precipitation. Changes already detected in soil processes may as yet be too small to affect plant growth.

Forests are complex. It has been shown that the nature of throughfall (rainfall reaching the forest floor without being intercepted by the crown canopy) and stemflow (rainfall reaching the forest floor by draining down the trunks of trees) is affected differently by different tree species. Thus the composition of "precipitation" reaching soil possibly affecting soil processes and transfers to freshwater systems, could be influenced by the nature of the tree cover.

CONCLUSIONS AND RECOMMENDATIONS

During the meeting the participants considered the effects of acid precipitation on forest growth and fish production. Whereas no unambiguous effect on tree growth has been demonstrated at present, the disappearance of fish from freshwater lakes, streams and rivers in certain regions was recognized as being strongly linked with increased acidity due to acid precipitation.

Considering the role of sulfur compounds in affecting freshwaters and as a threat to forest ecosystems and to human health, it is recommended that all governments reconsider their approaches to the control of the emission of relevant pollutants, bearing in mind the available range of technical solutions. A reduction of emissions would also have beneficial effects in areas close to the emission sources.

At the same time the Conference participants considered that further research should be undertaken to elucidate and monitor the effects of acid precipitation on ecosystems, taking into account work in progress in relevant international organizations.

A list of specific research subjects which would be of value in this context was prepared at the Conference for further consideration by countries.

Mr. SHARP [presiding]. Thank you very much.
Mr. Ayres?

STATEMENT OF RICHARD E. AYRES

Mr. AYRES. Thank you, Mr. Chairman.

My name is Richard Ayres. I am a staff attorney for the Natural Resources Defense Council and I appreciate your invitation to be here today to discuss this issue.

I think the critical question before us is to take a serious look at whether the coal conversion program as it has been proposed will, on the one hand, minimize to the extent possible dependence on foreign oil, the benefit that is proposed, and, on the other hand, minimize the health effects costs of the reducing dependence on foreign oil. We have some serious doubts about whether the program, at least as proposed, will do either of those things.

To take up public health first, we are concerned that the air quality safeguards in the President's program are not sufficient adequately to prevent disease.

I think it's important also to understand the potential for increased pollution that exists in a coal conversion program, and on page 5 of my testimony you will see some numbers showing the very small emissions that now come from boilers that burn gas—and a number of the boilers we are talking about converting are gas-burning boilers. If you substitute 1 percent sulfur coal for the fuel now being used in those boilers—which is rather low sulfur coal—we are talking about increases on the order of 3,000 times in the emission of sulfur oxides from that boiler.

Even if this coal were scrubbed by 90 percent, you are still talking about a 300-percent increase in sulfur oxide emission.

You are also talking about substantial increases in nitrogen oxide emission and very large increases in particulate emission.

We think it's also important to look at what rules would apply to a converted plant under the President's program. Once a plant converts, by 1980, it must meet the applicable emission standards for that State. The suggestion in that is that this will be adequate to safeguard public health, but when you look at some actual State emission limitations for coal, you can see they allow very large increases.

To take that same large gas fired plant, on page 6 you can see an example of what would happen if it were converted in the State of Kentucky. There are emission limitations applicable for SO_2 and particulates, but there are none for nitrogen oxide. Compared to gas fired emissions, these limits are 4,000 to 12,000 times greater for SO_2 and 22 to 33 times greater for particulate matter. You could expect with uncontrolled emissions of NOx you could have an increase of about 4 times. I think the nitrogen oxide increase is particularly significant in view of the likelihood the Congress will today weaken the Clean Air Act standards, which are the only other major control on nitrogen oxide, for nitrogen oxide emissions from new automobiles. So that makes this an even more serious problem.

I have also included on page 7 some examples of the increases in these pollutants that we can expect from conversion of powerplants which have already been proposed for conversion. This is only a small sample of the conversion that would be required under the President's program, but these are the only ones we have data for. We can see from the environmental impact statements filed by the Federal Energy Administration on those programs that for sulfur oxides you would have a 108-percent increase in the Hartford-Springfield-New Haven area, 387-percent increase in Boston; 271 percent in the New York, New Jersey, Connecticut metropolitan area; and for particulates, as you can see, much larger increases yet.

In addition to those increases, the conversions that would be added under the existing program would create a pollution problem in places where powerplants now don't really cause them—places like Sioux City, Iowa, Kansas City, Denver, and parts of rural Wisconsin, Iowa, Alabama, Missouri, and Oklahoma.

Again, the President's program would expand considerably the list of the areas to be expected, and the degree of effect on the areas I have mentioned here.

We have outlined, on page 9, some changes we believe are necessary to try to limit the adverse effects of the coal conversion program, if it is enacted:

First, the best available control technology should be required on all significant coal fired sources, not just on the new ones as the program now requires.

Second, there should be an offset policy, so that other emission reductions in the same areas offset the inevitable increases from coal conversion, so that the total emissions will not increase.

Third, there should be a strong significant risk provision in the Clean Air Act to protect against the sulfate and fine particulate problems, and the acid rain problem we have just heard talked about.

Fourth, the research and development on alternative coal use cycles, such as fluidized bed combustion and other cycles that provide for cleaner combustion, should be accelerated much more rapidly and we think that conversions—particularly of industrial boilers—should be scheduled so that those techniques are used when the boilers are converted.

Otherwise, we may be in a position where many boilers have been converted before these techniques are available, and 3 or 4 years from now people who have done those conversions will be in a position to say "You can't make us change again, we just finished with a major capital expenditure in order to convert." We think if you schedule the program properly, then there is a chance you will be able to have far cleaner conversions on those kinds of sources, and still use very little additional oil in the interim.

Finally, I wanted to raise a couple of questions about the supposed benefits of the program. Since we don't have an NEPA statement or anything akin to an NEPA statement on this program, we really don't know the answers to some of these questions. But there are certain points which have not been discussed that seem to me important to consider.

One is that there is an irreducible minimum of residual oil produced by American oil refineries, and it would be foolish to completely phase out oil as a boiler fuel, if it meant that that residual oil was to be wasted or to be exported or used in some other way. Using that 20 percent or so of the oil as a boiler fuel does nothing to increase our dependence on foreign fuels. We should keep that in mind, it seems to me, as we talk about a coal conversion program, and use that residual oil where it will do the most good.

A second point is that we need to do some economic analysis of the value of converting some of the older boilers, as compared with other programs that might cost no more, but produce greater reductions in the use of oil. On many old plants the cost of conversion alone will come close to the cost of building a new plant; and conversion plus the needed pollution control equipment will even make that more expensive. On those plants, it seems to us, you ought to consider very seriously whether it's really worth conversion to coal or whether the same money could be better spent in some other way.

Thank you very much.

[Mr. Ayres' prepared statement follows:]

STATEMENT OF RICHARD E. AYRES ON BEHALF OF

NATIONAL RESOURCES DEFENSE COUNCIL, INC.

My name is Richard Ayres. I am a Staff Attorney for the Natural Resources Defense Council, a private charitable organization concerned with the protection of public health and the environment. I appreciate the Chairman's invitation to offer our views on the President's proposed energy legislation.

A program to convert power plants and industrial facilities from oil and gas to coal inevitably will result in increased death and disease from additional pollution. If the government is to undertake this program responsibly, it must be sure that it will really help reduce dependence on foreign oil, and will minimize the ill-effects on people's health.

At this point we have no analysis that provides the information needed to decide whether the Administration's proposal meets these criteria. As you know, this is precisely the kind of analysis that must be provided in an environmental impact statement under the National Environmental Policy Act. NEPA statements are required by law on legislative proposals such as this one. Environmental organizations have not insisted on adherence to the letter of this requirement, because we thought that the Administration was undertaking an analysis that would provide the same information. But none has yet been provided.

We do not see how you can be expected to legislate responsibly without this analysis.

I. Public Health

What we do know suggests that unless additional safeguards are added, the proposed program will severely worsen air quality and public health. Virtually all significant new and existing oil or gas-fired stationary sources -- both power plants and industrial boilers -- can be compelled to burn coal under the President's program. Those few plants not ordered to convert will be induced to do so "voluntarily" by a tax imposed on continued oil and gas use. These measures are projected to cause coal use in 1985 to be 565 million tons per year greater than 1976 levels, almost double present levels.

The air quality safeguards in the President's program and those in the current Clean Air Act and state programs simply are not adequate to prevent a massive pollution problem from developing as a result of such increased coal burning. The President's program includes two safeguards: primary standards must not be violated and the source must comply with state emission limitations by 1980. However, we believe the likelihood that ambient standards will be violated in practice is great despite the prohibition. Moreover, there are no safeguards to prevent severe health and welfare threats from the large increases in sulfate concentrations, fine particulates and acid rain which are likely to result from the coal program.

Primary Standards. The technique that will be used to determine whether using coal will violate the primary air quality standards will be dispersion modelling. It produces uncertain results, often differing by a factor of two from actual measured air quality. The only well-developed models are limited to sulfur oxide prediction. Those models have never been validated for use under the conditions presented by the coal program: large increases in emissions rates from a great many sources of all sizes in a small area. To our knowledge there are no models now in routine use to predict the impact of particulate and nitrogen oxides on air quality. Thus, the modelling effort is bound to produce mistaken estimates of air quality impact. Given the enormous economic interests of the fuel burning sources, the mistakes are certain to be underestimates.

Compliance with State Emission Limitations by 1980. Requiring compliance with current state emission limitations by 1980 is really no safeguard at all. Current emission limitations for sulfur oxides and particulates are mostly set so that they are just barely adequate to protect air quality standards assuming most facilities burn oil or gas and not coal. Most states have less stringent regulations for coal-fired sources because existing coal-fired sources are few enough and isolated enough so that a lenient limitation is adequate to protect ambient standards. A coal conversion program will change the situation dramatically. There will be many coal burners, closer together. The current limitations will no longer suffice to protect ambient standards.

Thus if they are to protect health standards states will have to revise their emission limitations that apply to coal burning plants to make them tougher. This is easy in theory but politically difficult in practice. If the state proposes to tighten its emission limitations on plants that have been selected for conversion, the plants will charge that the federal and state governments are working at cross-purposes: the "feds" are demanding that coal be burned and the states are making the task more difficult or expensive by tightening air quality rules. Coal interests will cry that the states are thwarting a presidential and national objective. The strain that this confrontation will put on the Clean Air Act will be enormous.

If a state finds itself politically unable to revise its plan, the Clean Air Act requires EPA to promulgate a substitute. Relying on EPA to come to the rescue in this situation is a risky proposition and probably increases political stress. EPA promulgation is a slow process: EPA has been working on sulfur oxide regulations for Ohio for years and they are still in court. Second, under the pending amendments to the Clean Air Act (S. 252) industries and states may argue that the new subsection (g) of section 113 (dealing with plan submission in non-attainment areas) strips EPA of any authority to promulgate plans before July 1979. Third, if the Administration is still firmly committed to rapid coal conversion, a widespread EPA promulgation effort (which would increase utility resistence to those conversions) would likely be stifled by interagency objections.

Greatly Increased Emissions -- Sulfates and Other Fine Particulates, Acid Rain. Conversion of oil or gas-fired plants will produce enormous increases in emissions of sulfur oxides, particulate matter and nitrogen oxides. For example a small (50 million BTU/hour) industrial boiler fired by natural gas has the following emission factors in pounds per million BTU:

SO_2	Particulates	NO_x
0.0006	0.0174	0.169

If this boiler were converted to coal its emission rates would be much higher. If 1.0% sulfur coal were burned the emission rate for SO_2 would be 1.8 pounds per million BTU. This is over 3000 times greater than the gas-fired emission rate. Even if the 1% coal were scrubbed by 90%, the coal emission rate would be 300 times greater than the gas emission rate.

However, low sulfur coal will not be scrubbed on existing plants that convert to coal. Contrary to widespread misunderstanding, the President's plan does not require existing plants that convert to coal to use best available control technology (BACT). Only new plants must use BACT.

An example from one state demonstrates that existing plants which convert to coal and simply comply with typical existing SIP regulations will pollute a great deal more than when burning gas. In Kentucky the emission limits for the small coal-fired industrial boiler discussed above are as follows in pounds per million BTU:

SO_2	Particulates	NO_x
2.4 - 7.3	0.38 - 0.57	No Limit

Compared to gas-fired emissions these limits are 4000-12,000 times greater for SO_2 and 22 - 33 times greater for particulate matter. Uncontrolled NO_x emissions for coal-fired units are at least 4 times greater than gas-fired emissions.

To illustrate further what these conversions will mean, I have attached a chart showing the increased emissions projected for the metropolitan areas where FEA has proposed to force coal conversion already. Because we have no data for the President's program, this table can show increases from conversion of the 60-odd power plants already on the way to conversion under present law. It thus severely underestimates the impact of the additional power plants and of the industrial boilers the President would add.

Nonetheless, it shows that emissions in already polluted cities will jump precipitously, even if primary standards are met; for sulfur oxides, by 108% in Hartford-Springfield-New Haven, 387% in Boston, 271% in the New York-New Jersey-Connecticut metropolitan area; for particulates, 499% in Hartford-Springfield-New Haven, 7,513% in Boston, 870% in metropolitan New York-New Jersey-Connecticut. In other areas that presently have virtually no pollution problem from power plants, conversion will create one -- places such as Sioux City, Iowa, Kansas City, Denver, and parts of rural Wisconsin, Alabama, Iowa, Missouri, and Oklahoma.

There may be more than 2000 small industrial units converted to coal under the President's program. The impact of the emissions increases from these and additional power plant conversions on sulfates, acid rain and fine particulates problems will be large.

Those of you who serve on the Subcommittee on Health and Environment are aware because of the debate over the Clean Air Act that much of the northeast quadrant of the country already experiences concentrations of sulfates and other fine particles beyond those considered dangerous to health. You also know that rainfall throughout the same area is as much as 30 or more times as acid as normal as a result of excessive sulfur and nitrogen compounds in the air -- so acid that it has killed the native fish populations in most of the lakes in the remote Adirondack Park in New York. Three years ago, EPA scientists were warning of the danger that continuing to load the atmosphere with acids might soon exhaust the soil's buffering capacity in many areas, with disastrous results on agricultural and silvicultural productivity. Unless substantial additional safeguards are added, the President's coal conversion program will drastically worsen these trends.

The current Clean Air Act contains a "significant risk" provision which in theory would allow EPA to mitigate these impacts if a significant health risk could be shown. Even if the provisions stays in the law (an amendment pending in the Senate would strike it), it will be politically difficult for it to be used effectively unless there are clear statements now by leaders in the Congress and the Administration that these air quality problems should and must be avoided even if it means modifying the pace and extent of the coal conversion program.

Needed Changes in President's Program. In essence, we see a fast developing confrontation between the coal conversion program and public health air quality objectives. The Clean Air Act might eventually remedy air quality problems created by the coal program but we do not think the Act can prevent the problems from occurring in the first place unless changes are made now. Both the SIP revision mechanism and the ambient standard revision mechanism are so slow that the coal program will be a fait accompli before new air quality safeguards can be implemented.

Clean-up after the fact will be slow as history demonstrates. In theory, the 1970 amendments had adequate authority to clean-up Los Angeles and Pittsburgh by 1977. However, this did not happen because the dependence of the communities on the sources creating the problems was too great an obstacle for the legal directives of the Act to overcome. We fear that the same dependence on converted and new coal-fired sources will prevent their clean-up after the inevitable air quality effects have been documented.

A variety of steps can be taken now to prevent this calamity.

- First, BACT should be required on all significant coal-fired sources, not just on new ones.
- Second, an "offsets" policy should apply to converters in critical areas so that total emissions will not increase.
- Third, a strong "significant risk" provision should be included in the Clean Air Act to protect against the sulfate, acid rain, and fine particulate problems.
- Fourth, federal research and development on alternative coal use cycles (fluidized bed combustion, solvent refined coal, gasification and liquifaction) should be accelerated more rapidly than planned and the coal conversions should be scheduled -- particularly for industrial boilers -- so that the bulk of new and converting sources are able (and required) to use these cleaner technologies.

It would be a tragedy if we were forced to wait a generation or more for the installation of fluidized bed or other cleaner combustion techniques because we forced premature investments in "dirty" conversion of industrial boilers.

II. Questions About the Purported Benefits of the President's Program

Aside from its environmental costs, we think you should also ask whether the goal of eliminating the use of oil as a boiler fuel will have a sizable effect on imports, at a price that make economic sense. The United States still provides about one-half the crude oil it uses, and an irreducible portion -- about 20% -- of that crude remains as "residual oil" after refining, suitable only for fueling large boilers. Eliminating the use of this and other heavy oils, which are still usually cleaner than coal, will not reduce oil imports by a barrel, but it will dirty the air.

Likewise, this Committee should consider the economics of saving imports by converting boilers built to burn oil, compared to adopting measures to discourage the use of automobiles or other conservation measures not included in the President's proposal. The costs of converting will often approach the costs of new boiler construction. We agree with the late John Blair, the Senate's recognized expert on the oil industry, who said "any real easing of the energy crisis depends primarily on improving the supply-demand relationship for motor fuel."* We suggest that Subcommittee might find less expensive, more environmentally sound ways of saving energy in measures to reduce automotive traffic, rather than eliminating the use of oil as a boiler fuel.

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*/ John M. Blair, The Control of Oil (Pantheon, 1976) at 326.

EMISSIONS INCREASES --

A. Conversions meet primary standard

Census Region and AQCR #	Name of Region	Name of Plant	SO_2 (tons/yr.) Present	SO_2 (tons/yr.) Converted	Particulate (tons/yr.) Present	Particulate (tons/yr.) Converted	SO_2 Percent Change from Present to Converted Base Case	SO_2 Percent Change from Present to Converted Primary Standard	Particulate Percent Change from Present to Converted Base Case	Particulate Percent Change from Present to Converted Primary Standard
I.		*not in EIS								
041	Eastern Ct.	Montville	1,130.10	1,130.10	70.22	70.22	271.86	0	2,003.25	0
042	Hartford New Haven-Springfield	Devon Middleton Mt. Tom West Springfield	13,461.60	28,037.60	780.50	4,677.30	259.89	108.28	2,002.53	499.3[illegible]
107	Androscoggin Valley	Mason	3,086.35	3,086.35	71.80	71.80	0	0	0	0
119	Metropolitan Boston	Salem Harbor Salem Harbor #5 *Kendall Square	4,091.30	19,912.00	254.20	19,351.60	271.83	386.69	1,878.91	7,512.75
120	Metropolitan Providence	Somerset Drayton Point South Street	20,899.10	20,899.10	1,159.10	1,159.10	231.85	0	1,507.58	0
121	Merrimack Valley (Southern New Hampshire	Schiller	3,875.70	3,875.70	87.00	87.00	0	0	0	0
II.										
043	New Jersey-New York-Connecticut	Norwalk Harbor Sayreville Werner Bergen Hudson Kearny Sewaren Arthur Kill Astoria Ravenswood Barrett Far Rockaway Port Jefferson Lovett	33,305.00	123,433.40	2,991.60	29,011.10	468.68	270.62	1,634.77	[illegible]

D. Conversions meet primary standards

045	Metropolitan Philadelphia	Edge Moor Deepwater Burlington Cromby Delaware	19,265.20	25,375.20	1,125.80	2,611.40	264.89	31.72	1,377.23	131.96
150	New Jersey	England Down	5,684.20	7,585.30	293.90	345.50	210.54	33.92	1,540.59	17.56
161	Hudson Valley	Albany Danskammer	22,327.60	22,327.60	461.30	461.30	0	0	0	0
III.										
047	National Capitol	Possum Point	17,939.60	17,939.60	408.10	408.10	36.12	0	2,003.32	0
049	Jacksonville--Brunswick	McManus	4,433.80	16,017.00	102.20	2,060.50	38.00	261.25	2,003.32	1,916.14
052	W. Central Florida	Crystal River Lakeland	29,575.45	29,575.45	670.50	670.50	0	0	0	0
114	Eastern Shore (Maryland)	Vienna	781.65	781.65	36.55	36.55	0	0	0	0
115	Metropolitan Baltimore	Gould Street Riverside Wagner Crane Brandon Shores	13,922.60	13,922.60	720.40	720.40	209.55	0	1,097.38	0
116	Southern Maryland	Morgantown	19,956.50	85,842.00	608.90	12,273.90	82.57	330.15	2,002.32	1,915.75
170	Southern Coastal Plain	Sutton	13,539.30	41,169.20	328.50	6,622.30	45.19	204.07	2,002.50	1,915.92
223	Hampton Roads	Portsmouth Yorktown	24,997.10	37,539.90	554.20	1,826.40	33.81	50.18	2,020.46	229.56
225	State Capital	Chesterfield	41,777.10	41,777.10	929.60	929.60	33.14	0	2,002.18	0

IV.			C.	EMISSIONS INCREASES -- Conversions meet primary standards						
067	Metropolitan Chicago	Ridgeland	7,189.15	7,189.15	423.45	423.40	0	0	0	0
123	Metro Detroit-Port Huron	St. Clair	3,441.10	3,441.10	116.90	116.90	0	0	0	0
128	S.E. Minnesota -La Cross	Fox Lake	1,514.70	1,514.70	33.50	33.50	84.72	0	2,834.33	0
238	N. Central Wisconsin	Weston	.30	.30	8.10	8.10	603,533.30	0	7,754.32	0
V.										
006	S.E. Alabama	McWilliams	.11	929.10	2.64	132.60	537,627.27	844,536.36	7,543.94	4,922.73
VI.										
085	Metro Omaha - Council Bluffs	Jones Street	.10	.10	3.40	3.40	7,692.00	0	7,850.00	0
086	Metro Sioux City	George Neal	.60	7,493.60	15.90	800.10	596,266.67	1,248,833.33	44,704.40	4,932.00
088	N.E. Iowa	Maynard Street	.30	.30	7.90	7.90	593,833.33	0	7,824.05	0
092	S. Central Iowa	Sutherland Des Moines Ames	3.50	3.50	52.00	52.00	332,731.43	0	3,990.96	0
094	Metro Kansas City	Quindaro 2 Quindaro 3 Kaw River Blue Valley Hawthorne Lake Road	5.60	10,624.00	140.20	2,064.80	562,266.07	189,614.29	5,293.30	1,372.73
095	N.E. Kansas	Lawrence Tecumseh	735.80	735.80	130.00	130.00	3,451.56	0	6,962.54	0
139	S.W. Missouri	James River	.60	.60	16.10	16.10	601,716.67	0	7,779.30	0
146	Nebraska	L.D. Wright	.10	.10	3.50	3.50	7,874.00	0	7,342.80	0

D.				VII						
.40	3,596.70	10.20	511.40	184	Central Oklahoma	Mustang	.40	2,289.90	10.20	757.20
				VIII.						
.96	1.00	24.00	24.00	036	Metro Denver	Zuni	.96	5,392.70	24.00	1,894.60

Sources:

1.) Federal Energy Administration, prepared by the Office of Coal Utilization, Coal Conversion Program --Draft Revised Environmental Impact Statement. (ESECA, Sec. 2). DES-77-3, FEA/G-77/061, February 1977.

2.) Federal Energy Administration, prepared by the Office of Fuel Utilization, Coal Conversion Program--Draft Environmental Statement. (ESECA, Sec. 2.) DES-75-1, January 1975.

Mr. MOFFETT [presiding]. Thank you.
Dr. Falk?

STATEMENT OF DR. HANS L. FALK

Dr. FALK. Mr. Chairman and members of the subcommittee, it is a pleasure to appear before you today to discuss the potential carcinogenic hazard of polycyclic and heterocyclic compounds resulting from coal liquefaction.

Coals vary in composition but all contain polycyclic and heterocyclic compounds of which the best known probably is benzo(a)pyrene. This compound is a well known carcinogen for experimental animals and is suspect of being a human carcinogen. However, carcinogenicity of polycyclic aromatic hydrocarbons, detected in coal, is not limited to this structure but is also observed with alkylated 3-ring compounds, derivatives of anthracene, 4-ring compounds like chrysene, or benz(a)anthracene as well as alkylated 5-ring compounds such as benzo(a)pyrene derivatives.

Among the heterocyclic carcinogens, many are derived from dibenzacridines and dibenzcarbazoles but it is very likely that the analogues of all above mentioned polycyclic hydrocarbons also occur in coal having one carbon atom or two in the rings replaced by nitrogen. Similarly sulfur can replace 2 carbons in these polycyclic structures to produce heterocyclic compounds which may also be carcinogenic.

These varieties of compounds are present in coal itself, their identification has not been completed and their biological activity not always determined. The starting material for the liquefaction process therefore is very complex even when considering only one type of chemicals. When coal liquefaction is carried out hydrogen has to be supplied which can be done by a variety of ways and in the presence or absence of catalysts. In any case, however, this process tends to increase the quantity and variety of polycyclic compounds which may depend on the temperature of the process—the higher the temperature the greater the production of carcinogenic polycyclic hydrocarbons,

The products of the reaction usually are separated on the basis of their boiling points for future uses. Some will be low or devoid of carcinogenic compounds of this type, others will contain large quantities. However, the carcinogenic potency of these fractions may not correlate with their content of these compounds. Much of the available information on the carcinogenicity of coal tar—which started in 1915—has been obtained from other than coal tars, namely tars obtained from oil where similar types of products undergo similar processes to give the various products like kerosene, naphtha, asphalt, et cetera.

Epidemiological studies suggested that the presence of these carcinogenic chemicals could not completely account for the observed carcinogenic effects but laboratory studies could give an explanation.

The interaction is referred to as "cocarcinogenesis" and describes the process when an unexpectedly high tumor incidence results from exposure to a low dose of carcinogen in the presence of certain other chemicals.

The higher-than-expected activity was shown to be contributed by several fractions of mineral oils or catalytically cracked oils and opened up a complicated situation for which an explanation is still missing. Straight chain aliphatic and olefinic hydrocarbons as well as long chain alkyl aromatic compounds were seen to enhance the carcinogenic potency of polycyclic hydrocarbons like benzo(a)pyrene or benz(a)anthracene as much as 1,000 fold. However, the aliphatic hydrocarbons had to be present at high concentrations to exert the cocarcinogenic effect.

These observations were made in the laboratory on mice by application of the oils to the skin. In the occupational exposure to oils cancers produced in man were often also skin cancers. The structure/activity correlation for the cocarcinogenicity was determined. The activity was found absent in short chain hydrocarbons up to a length of 8 carbon atoms, it reached a maximum at 12 to 14 carbons in the chain and decreased slowly with higher chain length.

These cocarcinogenic compounds are also of great importance because of their ability to change apparently inactive chemicals or very weakly carcinogenic polycyclic hydrocarbons to higher potency. Thus the weak carcinogen chrysene can become highly active, the noncarcinogens pyrene and triphenylene become active, while others like fluoranthene and perylene do not respond. These are only a few of the "inactive" compounds normally present in these tars.

Another important variable is found in the presence of sulfur-containing simple organic compounds, even sulfur itself. These compounds in the presence of carcinogens and cocarcinogenic fractions enhanced the potency quite considerably.

The opposite effect is also of considerable importance. Several polycyclic hydrocarbons present at the same time may interfere in their activity and produce less than the expected carcinogenic response leading to "anti-carcinogenesis." This has been observed in studies on mice using benzo(a)pyrene in combination with other commonly occurring weak or inactive polycyclic hydrocarbons. It was observed on skin painting with dibenz(a,c)anthracene or perylene as antagonists. Similar results were obtained by subcutaneous injection of benzo(a)pyrene with and without perylene or related compounds. This is not a very well studied subject.

It appears important to keep all these observations in mind when considering the potential carcinogenic hazards of coal liquefaction. It is possible that with proper hydrogenation the sulfur-containing heterocyclic compounds may be inactivated, but very little effort has been made to identify all the heterocyclic polycyclics in these coal tars or to test their carcinogenic activity in the presence or absence of cocarcinogenic solvents.

I have tried to mention a few principles which have been discovered in dealing with coal tars and oils and which have not been resolved to the extent that all carcinogens and cocarcinogens have been identified or quantitated.

Also it seems quite difficult at times to destroy all carcinogenic activity in the residual material, specifically the asphalt portion and as large amounts of coal will be used for liquefaction the destruction of the carcinogens whether present originally in coal or formed during the process of liquefaction must be given high priority. Many of the polycyclic hydrocarbons are not readily decomposed in soil and may persist.

The problems are not new, but they demand recognition and study in order to avoid health hazards that take time to reveal themselves.

Thank you, Mr. Chairman.

Mr. MOFFETT. Thank you, Doctor.

Mr. Ripley?

STATEMENT OF ROBERT F. RIPLEY, JR.

Mr. RIPLEY. Thank you, Mr. Chairman.

May I approach you and give you some exhibits? As I said to begin with, I am a Commonwealth Attorney in Virginia, and in Virginia that is a prosecuting attorney, one that prosecutes criminal laws.

In 1971 I was elected Commonwealth Attorney, and I was 26 years old, and we had a significant problem in York County and that was the pollution that was being created by the Virginia Electric and Power Company, in the operation of its Yorktown power plant. It had at that time two units, a unit identified as unit 1, and a unit identified as unit 2.

Subsequently, they have built a unit which is now identified as unit 3. Unit 1 and 2 were coal fired units, and they were spewing in a radius of 2 or 3 miles from the single stack a plume which had soluble particulate matter. In that big jar I handed you, that is the soluble particulate matter when you have a problem with either the electrostatic precipitator or if you have a problem with the mechanical separator.

As I said, we prosecuted this as a criminal public nuisance, and that is different from the civil suit. A civil suit you only have to prove things by a preponderance of the evidence, and in a criminal suit we had to prove that Vepco was, in fact, creating a public nuisance beyond a reasonable doubt.

We took the soluble particulate matter that was collected from the plume to NASA and put it on an electronic microscope, and you have a copy of it there, and I know we have a scientists here at the table who I would like to have take a look at that thing and we could prove beyond a reasonable doubt that what was being emitted, falling out of the plume was, in fact, burnt coal and coke.

The Yorktown plant is unique in that it is built right at the York River, and contiguous to the Amoco oil refinery. We were having a problem who was the polluter, was it Amoco or Vepco and in the criminal case we have to prove which one.

At any rate, we felt we were prepared after about 4 months of work gathering evidence, standing out in the plume, doing all sorts of ridiculous things, we were prepared to take Vepco to court, who was denying everything. We took them to court.

The Environmental Protection Agency sent some of their legal counsel down and sent some of their engineers who came in from California, and they, along with Vepco's engineers, the State Air Pollution Control Board's engineers, went into the plant, discovered what was wrong in the operation of the plant and we came up with a consent decree. The consent decree required them to operate the plant efficiently, while they were still using coal, and until they could be converted to oil.

The consent decree requires that they convert to oil in units 1 and 2 and it will hold them in contempt of court if they convert back to coal.

So, we have a unique problem at Yorktown.

I really think the thrust of what I have to say to you is that there has got to be exceptions to everything, and one of the gentlemen here, Mr. Ayres, mentioned that if you are going to require these older units to convert back to coal you ought to be able to install the best available control technology.

Look what is going to have to happen to Yorktown if these units which produce about 28 percent of the total power of the plant are required to convert back to coal. First you have to take the mechanical separators and get them in proper shape. You have to install a new electrostatic precipitator on unit 2 because that one does not have one. The electrostatic precipitator on unit 1 will have to be brought up to best available control technology.

I think what these men are saying, in order to avoid the acid rain, the sulfur acid rain, you are going to have to put scrubbers on these units. I think that is what is contemplated. We don't have room, I don't believe, according to Vepco, and I believe EPA, to put scrubbers on units 1 and 2 at Yorktown.

Therefore, if you require the conversion for units 1 and 2 at Yorktown, you are going to get rid of the soluble particulate matter, but you are still going to have the acid rain problem.

We didn't know what that was that was causing all of the white cars that turned various shades of colors and all of the problems we were having at Yorktown, but today from this gentleman on the far end of the table I understand it might be acid rain.

Another problem that you have in making the conversion back to coal is that you are requiring conversions of units 1 and 2 at this time. Unit 3 was engineered only to burn oil, and you are only going to be effecting 28 percent of the total oil that is consumed by that plant.

There is a tremendous cost that is going to be borne by the Virginia taxpayers in making the conversion. Vepco has been whipsawed back and forth. They were made to go one way by the criminal suit that we brought in Yorktown, and now they are being made to go the other way, all within a few years.

The taxpayers paid for it the first time, and now we are going to, I guess, pay for it the second time.

The coal pile, the existing coal pile, is dormant today. It is sprayed with a film. We don't get the coal dust storms like we used to get, but the moment you start activating bulldozers and things like that in that coal pile, we will again have the coal dust storms that we had in the past, unless there is some new technology that allows you to go out and spray it constantly. That is a problem.

Then you have occasions where the Virginia Electric Power Company says we must buy coal in large quantities because we are afraid of a strike in the coal business. So they will just dump massive quantities of coal onto the coal piles and with the result of the coal dust storms in the community.

Our community, by the way, Mr. Chairman, has increased in population since we brought that suit, and this means more and more houses will be contaminated.

I want to talk about some other problems, if I may.

In making the conversion and assuming you could use the best available control technology, we asked the question: Where are you going to put all of that fly ash or where are you going to put all of the lime sulfur, because York County right now is passing a master plan, and we haven't taken into consideration the disposal of any ash.

The Virginia Electric and Power Company has informed me they will have to acquire at least one 100 acre tract of land that will have to be, I guess, dug out and prepared to accept the fly ash.

The people in York County are worried what will happen, can you do this so it will not affect the environment, because we use wells in York County. It's a suburban area, but we do't have city water in many places, and we are worried about our public water supply. Will it be contaminated by the seepage of soluble particulate matter into the water system?

We have had that problem before, because it did seep in the past into the various streams and creeks that were contiguous, anywhere near by the areas where they deposited the spoil. That is a big problem.

Amoco recently tried to bury its coke, which was formerly being consumed by the Virginia Electric and Power Company in burning it, in burning units 1 and 2. They tried to bury it in York County. The board of supervisors and the planning commission were so inundated by complaints by citizens concerned about what this would to the environment, to the water, that the county did not allow the Amoco Oil Company, and, of course, it was such an adverse thing publicly for Amoco to bury it.

So we asked where are you going to take it, and the next question is how are you going to get it there?

Yorktown has small roads, and these large dump trucks that carry the waste, the fly ash, tear the roads up during the changing weather, they drop fly ash on the road, you can follow the path of the trucks by looking at the holes that are contiguous to the road. They are polluted. They are gray. Where it should be a white house, it's a gray house because the fly ash falls from the truck and falls and blows off the truck.

We are also having a problem with that. The power company enters into an agreement that the moment they drop the fly ash into the truck, legally, it becomes the property of the operators of the truck, and we are constantly hauling the operators of the trucks into court prosecuting them for dropping fly ash on the roads.

Most importantly, I think, is that you must remember we do have that court order. The President's action may take precedent to it, but I think there should be an exception in this particular case at Yorktown, and I want to read you, if I can, the latter part of my statement that was submitted to you.

No Commonwealth's Attorney in the United States of America could possibly have been more appreciative of the energy, time and money that the Environmental Protection Agency gave to the Commonwealth of Virginia in our successfully obtaining the consent decree in the criminal action against the Virginia Electric and Power Company back in June of 1977.

It is now a strange twist of fate that the Federal Government seeks to undo its steps to clean up the environment. It is my understanding that in a letter from the Acting Regional Administrator of the United States Environmental Protection Agency to the Federal Energy Administrator dated May 17, 1977, that EPA has determined that units 1 and 2 can never again burn coal and comply with all applicable air pollution requirements as long as the court order stands.

Furthermore, it is my understanding that only if the legal impediments, that is the York County Circuit Court Order, is removed can the Yorktown Units 1 and 2 be allowed to burn coal.

For the above reasons, I can tell you we will resist in any way we possibly can to prohibit going back into the position we were in before. It was an intolerable position. If you lived there you wouldn't have liked it, and I ask the committee to give consideration to providing exceptions for situations like this where citizens have gone to court, won, gotten the power company to stop being a polluter, and now the Federal Government seems to come along and want to change the situation.

Thank you very much, Mr. Chairman.

[Mr. Ripley's prepared statement follows:]

County of York, Virginia

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Congress of the United States
House of Representatives
Subcommittee on Energy and Power
of the Committee on Interstate and
Foreign Commerce
Washington, D.C. 20515

May 26, 1977

In the fall and winter of 1971 and the spring of 1972, pollution in the form of the emission of soluble particulate matter from the stack of the Virginia Electric and Power Company Yorktown station became unbearable for the residents of the County who were within a two or three mile distance from the plant. Heavy pieces of gray particulate matter fell from the air from the plume of the stack landing on homes, cars, swimming pools, boats and anything that was exposed to the weather.

In the spring of 1972 the citizens, after about 4 months of gathering of evidence to make a law suit, went to the York County Grand Jury and sought and obtained a criminal indictment against the Virginia Electric and Power Company for operating a public nuisance. The Environmental Protection Agency, while not being familiar with any successful criminally prosecuted public nuisance case of this nature, sent an attorney to pre-trial conferences and an expert to the Power Plant to ascertain the problem. As a result of the findings of the Environmental Protection Agency expert, VEPCO began to operate and maintain the Yorktown Power Plant in a manner that was tolerable until the conversion to oil, pursuant to the Court decree, could occur.

The Yorktown VEPCO Power Plant is located "on" the York River contiguous to Amoco's Yorktown Refinery. Prior to the conversion of oil pursuant to the consent decree, Units 1 and 2 were fired with coal and coke. Unit 3 was built and engineered solely for the burning of oil.

It is now my understanding that the Federal Energy Administration is ordering VEPCO to convert Units 1 and 2 back to being coal fired. This is a strange paradox in the history of attempting to clean up the ENVIRONMENT at Yorktown. Through the combined efforts of the indignant citizens, the Commonwealth Attorney's Office, the ENVIRONmental Protection Agency's legal staff and their expert engineers and the State Air Pollution Control Board, VEPCO consented to make the change to oil. Now, five years and 4 or 5 million dollars later (which was paid for by the Virginia taxpayer), the Federal Government is attempting to return the citizens of York County back into perhaps a more intolerable condition than we were in before we took VEPCO to court.

It should be pointed out that Units 1 and 2 only burn approximately 28% of the oil used at the Yorktown Power Plant. In order to make a conversion so that this 28% figure could be coal-fired, a number of things will have to occur at Yorktown, not all of which would have positive consequences on our ENVIRONMENT.

First, there will obviously have to be required A REBUILDING OF the existing mechanical separators on both Units 1 and 2. The electrostatic precipitator on Unit 1 will have to be refurbished and put into operating capacity. There will have to be installed an electrostatic precipitator on Unit 2. There should be installed scrubbers for the purpose of absorbing the sulphur by-product from the burning of both coke and coal. Because of limited space problems (the power plant was built with its back right up against the York River), there is the very real QUESTION being raised as to whether scrubbers can be installed on the site. The Virginia TAXPAYER can justifiably ask the question as to who will pay again this time for the conversion?

If scrubbers can be installed, and if the best available control technology could be worked into the system, we who have been through it before and had to go to to court to correct the situtation, have some obvious questions. We will have the coal pile problem back with us. Now, while the units are burning oil, what remains of the coal pile is CONTROLLED BY the sprayed plastic film WHICH works fairly well AS LONG AS THE COAL PILE REMAINS DORMANT. If there is a conversion to oil, the residents will again be faced with "coal dust storms" throughout the community by the power company's activities in controlling and managing the mountainous coal pile. Most importantly, however, how are we going to be able to dispose of the soluble particulate matter, commonly known as fly ash, which will be generated by the successful operation of anti-pollution devices, and how are we going to be able to dispose of the lime slurry which will be the probable residue from the scrubbers?

It is estimated that [redacted] it will be necessary to [redacted] at least 100 acres ecologically prepar[redacted] to accept the fly ash residue and within a few years VEPCO will outgrow this area and have to purchase more land FOR THIS PURPOSE.

York County is a RAPIDLY GROWING SUBURBAN [redacted] community on the peninsula and the roads that lead from the Yorktown Power Plant [redacted] for THE disposal of the fly ash are [redacted] narrow and curved. [redacted]. With an additional electrostatic precipitator on Unit 2, the quantity of the fly ash being transported [redacted] will substantially increase. The roads in the county from the Power Plant to the disposal area will be constantly damaged by these trucks. In addition, there is the inevitable problem of fly ash falling from the trucks and flying off the trucks polluting the entire path along the way and creating a nuisance for those who live along the route.

The Power Company may have a substantial problem in finding an acceptable area to place the fly ash and/or the slurry for a number of reasons: (1) York County is in the process of passing a master plan which does not contemplate an area for the disposal of fly ash and slurry; and, (2) the disposal area will have to meet ecological requirements imposed by all state and federal agencies; and (3) the citizens' outcry from the use of land in this MANNER [redacted] has already been seen when Amoco UNSUCCESSFULLY tried to bury coke and the Board of Supervisors and the Planning Commission of the County were inundated by citizens' complaints from fear of the contamination of the local water supply.

It should be pointed out that RESIDENTIAL York County [redacted] primarily uses individual wells for the home owners water supply. That prior to 1972, when VEPCO was hauling fly ash to THEN EXISTING disposal areas, erosion from these sites caused residue of soluble particulate matter to be found in great QUANTITIES [redacted] throughout the local rivers and creeks of the County.

Also, if the Federal Energy Administration is successful in requiring the conversion of these two units, it will be imperative that someone require source monitoring at the TOP of the stack. Only in this way would the citizens be able to find out precisely what is coming out of the stack as we have the unique and unusual problem in York County IN THAT our Power Plant is located contiguous to an Oil Refinery and the citizens are faced with the constant problem of who is actually the pollutor, the Power Plant or the Oil Company.

No Commonwealth's Attorney in the United States of America could possibly have been more appreciative of the energy, time and money that the ENVIRONMENTAL Protection Agency gave to the Commonwealth of Virginia in our successfully obtaining the consent decree IN THE CRIMINIAL ACTION against the Virginia Electric and Power Company back in June of 1972. It is now a strange twist of fate that the Federal Government SEEKS to undo ITS STEPS TO CLEAN UP THE ENVIRONMENT. It is my understanding that in a letter from the acting Regional Administrator of the United States ENVIRONMENTAL Protection Agency to the Federal Energy Administrat dated May 17, 1977, that EPA has determined that units 1 and 2 can never again burn coal and comply with all applicable air pollution requirements as long as the Court order stands. Furthermore, it is my understanding that only if the legal impediments, that is the York County Circuit Court Order, is removed can the Yorktown Units 1 and 2 be allowed to burn coal. For this reason and all the above mentioned reasons, THERE is no conceivable way that the people of the County of York could willingly be made a party to attempting to remove or RESCIND that Court order.

For a 28% reduction in the consumption of oil for one power plant, the people of the United States of America would gain very little, and the people of York County would have lost so very much.

Respectfully submitted,

Robert F. Ripley, Jr.

Robert F. Ripley, Jr.

Commonwealth's Attorney

Mr. MOFFETT. Thank you.
Mr. Mallory?

STATEMENT OF C. K. MALLORY

Mr. MALLORY. I am here to represent the people Mr. Ripley said were getting whip-sawed; the Edison Electric Institute represents about 80 percent of the electric-generating capacity in the country.

The message you have been hearing from these gentlemen here today, Mr. Ripley, Mr. Ayres, and the rest, is the same one we are trying to get to you in our statement which is submitted for the record and which I will lay aside. That is, the administration in drawing this program has badly failed to reconcile the applicable environment provisions that we, in the industry, must face, with the policy of moving from oil and gas as boiler fuels and getting off imported fuels.

One of the points I would particularly like to emphasize is the fact you have plants being ordered under this program to convert from oil and gas on a very untimely basis which has environmental implications as well as economic implications which are quite considerable.

Mr. Ayres made the point you should not require the conversions before the technology is available. I would add as an aside that we have the same position with respect to the requirements in the bills pending before Congress for BACT and scrubbers on all coal including compliance coals. We may be faced with the possibility that there will be a new scrubber developed that will have to be retrofitted, or we may be told to remove new emissions, such as NOx.

When we testified before the Ways and Means Committee on the tax aspects of this bill, Congressman Stark from California commented that one thing that could be done to avoid any conversions was for the state to impose such stringent State implementation plans that it would be impossible to convert to coal.

I raise the question because I think it is something you have to consider. This program could become totally meaningless, if it should be enacted at all, by virtue of State action imposing stringent implementation plans prohibiting the burning of coal.

We feel the program, together with the pending Clean Air Act amendments, is moving us in one direction. We are going to have to provide power. We are under a legal obligation to do so. This program, together with the amendments pending right now on the floor of this House, are making us move into nuclear generation and not a balance of coal and other forms of generation.

One brief point. This program's definitions make the provisions of the conversion program applicable to facilities owned by everybody, States, municipals, co-ops, but not the Federal Government. We think this is an oversight which should be corrected no matter what happens. What is sauce for the goose is sauce for the gander.

We think federally owned plants should have the same rules applicable to them.

In summary, the message you have gotten here today is that it is going to be very difficult to have this program and the Clean Air

Act amendments—the administration has not reconciled these two policy conflicts in its program and it is going to be up to the Congress to do so and give us a national energy plan if we are to have one.

Mr. MOFFETT. Thank you.

[Mr. Mallory's prepared statement follows:]

Statement Of
C. King Mallory, Vice President And
General Counsel Of Middle South Services, Inc.
Before The Subcommittee On Energy And Power Of
The United States House Of Representatives
Committee On Interstate And Foreign Commerce
On H.R. 6831

I am C. King Mallory, Vice President and General Counsel of Middle South Services, Inc. I am appearing as a spokesman for the Edison Electric Institute (EEI), the principal national association of America's investor-owned electric utility companies, whose members provide approximately 79% of the total electric generating capacity in the United States. My statement will provide an overview of the relationship of coal conversion, as envisioned in the President's proposed national energy policy, and the constraints on coal utilization under the currently proposed Clean Air Act amendments from an electric utility industry perspective. I am also accompanied by John J. Adams of the law firm of Hunton & Williams, special counsel to the Electric Utility Industry Clean Air Coordinating Committee (Coordinating Committee), an ad hoc group of electric utility systems and their associations, including EEI, encompassing the investor, cooperatively, and publicly-owned segments of the electric utility industry.

INTRODUCTION

We believe that every practical effort should be made to reduce oil imports. We also agree that greater use of our domestic coal and nuclear resources is one way to effect this goal. As far as the electric utility industry is concerned, the focal point of efforts to reduce oil and gas consumption for the generation of electricity has been, and should continue to be, the construction of new base-load electric generating plants, utilizing coal or nuclear fuel for the immediate future. Happily, most of the new base-load electric generating plants being built in the United States today are coal-fired and nuclear because of three factors: (1) the lower costs of nuclear or coal-fired generation as compared with oil-fired generation (the economic advantages of coal versus nuclear have varied from region to region); (2) growing natural gas shortages and governmental restrictions on its use; and (3) the vulnerability of oil imports. Reliability considerations have tipped the balance in favor of coal and nuclear in the few situations where oil was economically competitive with them.

But, as much as the electric utility industry may want to avoid new natural gas and oil-fired generating units and as much as Congress may wish to encourage or compel it to convert existing units to coal, you must recognize that there are many other federal policies that directly affect how much and what kind of new generating capacity can be built by this industry. At present, these federal policies are often confused and conflicting but their composite effect will inevitably determine whether, where, what kind of, what size, and at what cost to the American consumer new plants can be built. In the past, the net effects of these multiple federal policies have generally been unforeseen by single-mission-oriented policy makers in Congress or the various federal departments or agencies. This is not because these policy makers do not want to see the big picture and make these trade-offs consciously, but rather because they have been institutionally handicapped by the single subject orientation of congressional committees and federal agencies. So, the final outcome is the unplanned consequence of haphazardly conflicting policies.

While some efforts have been made in recent years through the formal National Environmental Policy Act (NEPA) statement process and the more informal "quality of life" interagency review process under the auspices of the Office of Management and Budget to identify and resolve consciously these federal policy conflicts, those processes have been confined essentially to implementing legislation already on the books. Certainly, there is no equivalent of those processes in Congress for identifying and resolving major federal policy conflicts <u>before</u> legislation is enacted. Because of the way Congress acts through subject-oriented committees, it has generally been unable to identify systematically potential conflicts among multiple federal policies and to resolve them <u>before</u> new laws are passed or new programs launched. Even the House's new ad hoc Committee on Energy, created to deal with President Carter's energy proposals, does not have the plenary jurisdiction that is needed. That is dramatically illustrated by the fact that while these hearings are in progress, the House is in the midst of floor debates on Clean Air Act amendments that will impose substantial new restrictions on the use of coal for new base-load electric generating plants. Their enactment in the form reported out of Committee will directly inhibit the result that H.R. 6831 seeks to achieve. Thus, unless amendments to this clean air legislation are adopted on the floor, much of what you will be doing during your considerations of the greater coal utilization provisions of the omnibus energy bill will be largely academic.

In our system of government, the Presidency is the institution that is supposed to provide the necessary overview for reconciling major federal policy conflicts. The President is in a unique position to marshall the facts within each of the relevant departments and agencies and to present the policy options to Congress and the American people. Unfortunately, while we have had a Presidential assessment of the mix of conflicting programs now constituting our piecemeal national energy policy, the attempts to reconcile a national energy policy with a national environmental policy in a way that will accomplish together what is in the best interests of the American people as a whole have been largely retorical. In the Presidential reassessments, where conflicts emerged between domestic energy resources and a particular environment amenity, the environmental value always won. So, once again, we have permitted fixation with one particular aspect of the public interest -- such as industrial development in the first part of the century and clean air and water in the last decade -- to be given unwarranted priority over all other equal, or more important, social needs.

Turning specifically to oil imports, coal utilization, and the nation's electric utility industry, there are a number of existing policies which limit the options otherwise available to us. These include tariffs, taxes, import fees, and regulation of the various facets of the energy industry as a whole. Among the latter are the restrictions on surface mining and of the Federal Water pollution Control Act, the Resource conservation and Recovery Act, the Coastal Zone Management Act, and the Clean Air act. We will address some of the restrictions under the proposed Clean Air Act amendments now being debated on the floor that are directly relevant to the energy legislation before this Committee today. We will show you how those amendments signal (directly through prohibition on new plant siting and indirectly through economics) the direct opposite the President's announced policy of making coal the primary means of new electric generation with nuclear as the back-up. Before doing that, however, I will summarize our general comments in the greater coal utilization provisions of H.R. 6831.

H.R. 6831

H.R. 6831 focuses on new and existing plants, while relying on the Energy Supply and Environmental Coordination Act of 1974 (ESECA) for the conversion of another, special class of existing plants subject to its restricted limitations. But, in their present form, neither H.R. 6831 nor ESECA, alone or in combination, will substantially increase utilization of our national coal resources for the generation of electricity. First, the electric industry does not plan any substantial addition of base-load oil or natural gas-fired generation. So, the new plant provisions of the bill do not really change anything. They simply codify the status quo. Second, many of the existing plants which are conversion candidates are either in particulate or oxidant non-attainment areas or are barred from conversion because of the ESECA-Clean Air Act limitations.

H.R. 6831 in its present form ignores those Clean Air Act restrictions that would make this bill largely a futile gesture.

What is needed is to face up to other Clean Air Act conflicts and to recast H.R. 6831 and ESECA to specify a single set of rules for all existing oil-fired plants, another to existing natural gas-fired plants, and a single, but different, set of rules to all new plants. The following principles should be written into the resulting bill and other related federal policies:

1. These rules should apply to all base-load electric generating plants regardless of who owns them. The Administration bill's exemption for federally owned facilities, contrary to S. 273 and S. 977, is completely incomprehensible.

2. The legislation should encourage voluntary conversion of existing base-load generating plants to coal where feasible and the voluntary construction of new coal-fired base-load generating plants. In this regard, extending the exemption for existing natural gas or oil-fired plants that receive coal conversion orders from new source standards of the Clean Air Act to all existing plants that convert <u>voluntarily</u> would be a major step in that direction. Can you imagine a less rational policy of encouraging coal utilization than the proposed amendments: those who would comply <u>voluntarily</u> with the national objective of greater coal utilization are <u>penalized</u> while those who are ordered to convert to coal are given favorable treatment? To the extent Congress wants to enact provisions forcing involuntary conversions incentive programs for greater coal utilization would be important additions to administrative orders. Such programs and the other non-governmental incentives would lead to decision making more nearly based on market conditions, and they would also limit the distortion in the supply and demand relationships for coal, concersion equipment, and pollution control equipment which governmental decrees create.

3. If conversions of natural gas or oil-fired electric generating plants are to be ordered, the statutory criteria for conversion should be as specific as possible and not be left to subjective interpretations of vague statutory language. Examples of clear and specific ground rules include:

(a) The remaining useful life of the conversion candidate should be sufficient (at least 15 years) to anortize the costs of conversion.

(b) The conversion candidate should have a projected usage of 3,000 hours or more a year in the 1980's. Old plants used to meet peak load cannot absorb the cost of conversion.

(c) New peaking units, such as gas turbines and combined cycle units must use oil or natural gas and should not receive conversion orders.

(d) Provisions for the use of oil for boiler startup, testing, flame stabilization, control, and topping should be included. "Topping" (using small amounts of oil to increase power generation at some coal-fired units) is important because some units would not be able to achieve their rated capacity without it and because of the limited amounts of oil involved and of the very low costs for the added output.

(e) The conversion candidate must have a site that will accommodate a coal pile; rail, barge, or conveyor fuel deliveries; and waste disposal facilities.

(f) Shutdown for conversion must be able to be scheduled so that it will not create a capacity shortage.

(g) Since a conversion candidate may not have the physical or economic capability to meet all clean air requirements, it should be required only to meet emission limitations that represent a reasonable contribution toward attainment of primary ambient air quality standards. The converted plant should also be "grandfathered" against future state implementation plan (SIP) revisions. This plant-by-plant specification of an emission limitation is the logical extension of EPA's present policy of permitting states to subdivide air quality control regions (AQCR's) for their SIP's. This would enable many plants to avoid installation of very costly flue-gas desulfurization equipment by using naturally low sulfur coals or coals that have been cleaned through washing or the solvent refining process. "Grandfathering" would permit the utility to make the long-term contracts that may be necessary for obtaining such coals. This "grandfathering" should apply to plants that have converted, are now in the process of converting, or will convert to coal. In addition, restrictions on tall stacks should not be imposed directly or through denial of "credit" for them in determining compliance with Clean Air Act requirements.

(h) The costs for electric utilities to convert to coal will vary from <u>system</u> to <u>system</u> and from <u>region</u> to <u>region</u>, while the benefits of conversion are essentially <u>national</u>. The East and West Coasts, where utilities currently have a substantial portion of their systems burning oil, and the South-Central region, which is still heavily dependent on natural gas, would be the principal targets for coal conversion. The economics of conversion will turn on numerous factors such as the remaining age of the unit, the capital costs of conversion (generally no conversion should be ordered if its capital costs exceed 50% of the depreciated value of the plant), and projected differences in the delivered costs of oil and coal. Conversions of units which cannot be justified on the basis of net economic impact on the utility's customers should not be ordered unless some provision is made to spread these extra costs of conversion to taxpayers generally. Congress could provide for loans or for loan guarantees which might help some systems, but they will not solve the problem since, among other things, they will not reduce the rate base nor the impact on the rate payer. Federal tax relief may also help to spread the load more equitably but it is not the complete answer. Direct federal equalization payments should be given serious consideration.

(i) As a general rule, conversion of plants originally designed to burn only natural gas or oil to coal is usually not technically feasible because of furnace volume, combustion characteristics, spacing, and many other factors. These plants should therefore, not receive conversion orders because of the economic and technological impracticability of converting such units.

4. Certain general provisions should be applicable to both existing and new plants. For example:

(a) A coal supply for the particular plant should be available. This includes a dependable supply of coal for the life of the plant, adequate transportation from the mine to the plant, adequate off-loading facilities, space for handling waste products, and an ability to accommodate such plant equipment as modified burners or scrubbers, if required.

(b) Emergency provisions should permit suspension of clean air requirements that are more stringent than those necessary to meet federal ambient standards during a power shortage and suspension or cancellation of conversion orders if shortages for coal or pollution control equipment develop.

(c) In order to help solve our natural gas problems, we must recognize that some increase in the use of oil in regions now heavily dependent on natural gas will be necessary. Accordingly, there should be an exemption mechanism for these special geographic situations.

We will subsequently offer detailed suggested amendments to you and your staff to effectuate these recommendations.

CLEAN AIR RESTRAINTS

H.R. 6831 is only half of the picture. There is absolutely no trade-off in this bill between energy requirements and environmental constraints, the other half of the picture. The Administration bill repeatedly refers to compliance with "applicable environmental requirements," while the House is simultaneously consideraing amendments to the Clean Air Act which, if passed in the form reported out of Committee, will make the "applicable environmental requirements" far more stringent on coal-fired generation. These two bills, the Administration's Bill dealing with coal conversion and the Clean Air Act amendments, look in different directions. Taken together, they will actually diminish, rather than increase, the utilization of our national coal resources. Let us now turn to the hard realities of the Clean Air Act that Congress, the Administration, and the states must address if we want to make greater coal utilization, as envisioned in H.R. 6831, practical.

No Significant Deterioration

The "no significant deterioration" (NSD) provisions of the Clean Air Act amendments (S. 252 and H.R. 6161) presently pending before Congress will have major impacts on the type (oil, coal, or nuclear), size, location, and cost of new base-load electric generating plants. The restrictions on a power plant's emissions of sulfur dioxide alone resulting from these bills' NSD provisions would severely complicate the siting of fossil-fired power plants. Detailed analyses show that enactment of these proposed NSD provisions in their present form would discourage, and in some instances prohibit, construction of new, economically sized, base-load coal-fired plants, even with flue-gas desulfurization equipment, in areas of hilly terrain. These restrictions on 3 and 24-hour emissions could largely preclude new base-load mine-mouth plants in Appalachian and mountainous Western states. These 3 and 24-hour NSD restrictions would tend to confine the location of future base-load coal-fired plants to the flat terrain areas of the eastern coastal plains and the Mississippi River valley. Generally, this would require substantially longer transportation hauls from mine to plant, thus increasing oil consumption by the rail or barge carriers.

Even where new plants could be built, they would be smaller. Construction of smaller power plants would require development of more power plants and sites, with greater duplication of coal-handling facilities and equipment. This would severely limit attainment of economies of scale and energy efficiencies.

The S. 252 best available control technology (BACT) requirements and H.R. 6161's required revision of new source performance standards (NSPS) could require flue-gas desulfurization equipment (scrubbers) on nearly all new base-load fossil-fueled plants. In addition, nationwide scrubber shortages could develop for five years or so. This could imperil utility industry compliance with present clean Air Act requirements by both existing and new plants. In addition, coal conversion requirements and the increased energy demands of pollution abatement equipment could lead to coal supply shortfalls.

The relationships of alternative Clean Air Act and coal conversion policies to scrubber and coal supply were explained in detail in hearings in the last Congress on S. 1777.[1] We

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1/ Joint Hearings on S. 1777 Before the Senate Committees on Interior and Insular Affairs and Public Works, 94th Congress, 1st Session, Serial No. 94-18 (92-108) Parts 1-3 (1975).

believe that the estimates of coal and scrubber supply shortfalls appear approximately the same today as in the S. 1777 hearing record. In 1975, the limited production capacity of the scrubber manufacturers to meet electric utility demands was obvious. You should ask the scrubber manufacturers to provide current information on their capabilities prior to Congressional action, lest you order our industry to do what may be impossible in the time frames you contemplate. You should also focus on scrubber costs and reliability before mandating their use across the board. Any Federal Energy Administration (FEA), Bureau of Mines, Federal Power Commission, or coal industry estimates of coal production for the next decade should also be made available to you. We would welcome the opportunity to review them and to comment to you on them. Our past experience has shown such estimates to be overly optimistic since they usually did not consider the constraints imposed on the location of mines, the available transportation, and the location of new power plants. In short, you and we need to know how many scrubbers and how much coal will actually be available for electric utility use and the ability of those two industries to respond to sharply increased demand, before we can assess and advise you of our ability to comply with both clean air and coal conversion policies.

It should be noted that, if Congress requires scrubbers at all new coal-fired plants, utility system fuel consumption would increase since scrubbers impose an "energy penalty" of up to seven percent. When coupled with installation of cooling towers (with an average three percent energy penalty), the gross penalty per new coal-fired plant would range up to ten percent. This would increase gross utility consumption of both coal, oil, natural gas, and uranium and require construction of additional capacity to meet peak load.

Finally, these "BACT" and "revised NSPS" provisions together with these NSD provisions could leave no area of the country where nuclear power does not enjoy an economic advantage over coal for new base-load electric generating units. (See Exhibit 1 to this testimony.) If the nuclear option remains available -- and that is imperative -- this would tend to reduce substantially the number of new coal-fired plants built by the electric utility industry. The higher costs of all new base-load electric generating plants (costs imposed directly on fossil-fired units for compliance with these NSD constraints and indirectly through the greater demand for nuclear) would encourage extension of the service life of older, less efficient fossil-fired electric generating plants. This would tend to increase coal, oil, and natural gas consumption and to increase net pollution, shifting much of it from remote rural areas where the new plants would have been built to heavily populated, "non-attainment" regions (areas where federal ambient air quality standards are being exceeded) where most of the older plants are located.

Non-Attainment

The pending House amendments to the Clean Air Act do not resolve the current major oxidants non-attainment barrier to new coal-fired or oil-fired power plant construction. Unless that problem is resolved, the main purpose of H.R. 6831, to encourage utilities to build new coal-fired base-load generating plants, could be thwarted. EPA's recent selection of AQCR's which must revise their oxident-related SIP provisions by July 1, 1978, tends to discourage or prohibit construction of new coal-fired electric generating plants in the entire region north of North Carolina and east of the Mississippi River. The present sporadic pattern of monitoring for oxidants also tends to favor construction of new oil-fired generating plants on the southeast coasts, in the short run. Even if lack of monitoring data or lenient enforcement offers some temporary relief, virtually all new fossil-fired plants could be tied up in litigation. The details of this problem are spelled out in Exhibit 2 to this testimony. In particular, we invite your attention to its maps which dramatically portray the nationwide dimensions of this serious problem.

The Senate Clean Air Act amendments, in contrast, to the House amendments provide a short respite from the oxidants non-attainment constraint. The unspoken premise in the Senate bill is that EPA will have time to review and revise the primary standard for oxidants. Clearly, some broader based long-term solution to this problem is imperative.

Another, although perhaps less pressing, non-attainment problem relates to particulates. This can be handled administratively by specifying size-discriminating monitoring methodology so that natural background can be "discounted" for determining attainment of standards. While this procedure is given the "blessing" of the Environment and Public Works Committee in its report (at page 98) accompanying S. 252, neither S. 252 nor H.R. 6161 require EPA and the states to adopt and to implement such procedures. If background particulate concentrations are not discounted, a major impediment to coal conversion exists, because particulate standards will be exceeded in virtually all regions of the nation.

Other Fuel Effects of the Clean Air Act Amendments

Backfit of existing fossil-fired electric generation plants to meet the proposed new compliance deadlines for recently set or pending SIP revisions (e.g., Ohio, Indiana, and Illinois) and to avoid the proposed new compliance penalty or fine provisions proposed in S. 252 and H.R. 6161 could present reliability problems for some utility systems, particularly in the Midwest. To the extent these reliability problems could be eased by reliance on interconnections to east coast utilities, oil consumption by the latter would increase substantially.

S. 252 can be read to preclude giving effect to some SIP revisions liberalizing requirements for complying fuels. This would undercut for plants that will have outstanding compliance deadline orders the benefit of future ESECA-inspired SIP revisions or temporary emergency revisions similar to those adopted in some states this past January. This would tend to decrease consumption of available middle or high sulfur coals and increase low sulfur oil consumption.

Increased electric rates resulting from enactment of any of these bills in their present forms, coupled with continuing national natural gas shortages, will tend to favor greater oil consumption for space heating and industrial production.

CONCLUSION

This brief analysis has shown that the presently pending Clean Air Act amendments, if enacted in the form they emerged from their respective Committees in the House and Senate, would severely curtail options available to encourage or compel a reduction in oil imports by greater coal utilization. Yet, to date, no spokesman for the Administration has offered any advice as to the necessary energy and environmental trade-offs. FEA Administrator O'Leary touched on this briefly when he testified before the Senate Energy and Natural Resources Committee on March 21, 1977, on S. 273 and S. 977, but he offered no thoughts of his own or of the Administration on how to reconcile these pending Clean Air Act amendments with coal conversion. Sad to say, the Administration's position appears to boil down to a pollyanna hope that we can somehow have its omnibus energy bill and the House Clean Air Act amendments and still get greater net coal utilization than would have occurred without either. Our analysis shows that will not be the case. The Clean Air Act amendments in their present form will more than cancel out the omnibus energy bill in this regard. We have appealed in vain to date to the Administration and to the House and Senate Committees responsible for the Clean Air Act amendments for a careful joint analysis of the impacts of those amendments and coal conversion legislation before either is adopted. At this eleventh hour with final debate on the Clean Air Act amendments in progress, we appeal to you to stop this mad rush to legislate in the dark.

It will be tragic if this Committee sits by and permits vital energy options to be silently foreclosed by enactment of the presently proposed Clean Air Act amendments. Only if you and the Committees with jurisdiction over the Clean Air Act amendments work together with the President to reconcile the still outstanding conflicts between environmental and energy policies, can we obtain the kind of balanced overview of how to interface Clean Air Act amendments and oil and natural gas curtailment legislation (like H.R. 6831) in order to create a meaningful national energy policy that is consistent with national environmental policy objectives.

The electric utility industry is willing to do its fair share to reduce oil imports and natural gas consumption and to maintain a clean environment. But we need realistic governmental policy directives to follow -- not those that duck the hard trade-offs that are inevitable. To be credible, our new energy policy and our existing environmental policy must face up to these realities. We have been told that we are faced with war-time conditions and yet we can and should have greater coal utilization and more stringent applicable Clean Air Act restrictions at the same time. We do not think that is realistic. Even Bismarck's remark that you cannot have guns and butter referred to peace time.

We know that we and American consumers will be asked to make sacrifices -- that our new policy must be "tough." But it is not enough that it be tough; it must also be fair and it must also be realistic. Unfortunately,to date, as far as greater coal utilization is concerned, we seem to be headed toward a national flight into fantasy.

EXHIBIT 1

n/e/r/a
NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
NEW YORK / WASHINGTON / PHILADELPHIA / LOS ANGELES

TO: Clean Air Coordinating Committee

FROM: Lewis J. Perl

RE: Impact of Non-Significant Deterioration Legislation on the Coal/Nuclear Cost Balance and Estimates of the Cost Effectiveness of Alternative Clean Air Legislation

DATE: May 4, 1976

In NERA's initial study plan for the Committee, we agreed to undertake studies of the impact of Clean Air Legislation on the coal/nuclear cost balance and to examine the cost effectiveness of alternative Clean Air Legislation in reducing SO_2 emissions. While these efforts were not completed in time for inclusion in our April 16, 1976 review, we have now completed work on these topics and the results are summarized below.

A. Cost Effectiveness

The primary objective of the Clean Air Act and the currently-proposed NSD amendments is the reduction in emissions of SO_2 and total suspended particulates. One way to evaluate the legislation is to consider its cost effectiveness in achieving this objective. Table 1 and Figure 1 describe the results of one such cost-effectiveness analysis. In Table 1, we indicate the emissions of SO_2 from coal-fired power plants coming on-line between 1975 and 1990 under alternative legislative prescriptions and the cost of achieving specified emissions reduction. Without any controls, emissions from these plants in 1990 would be 54 billion pounds. By imposing New Source Performance Standards (NSPS), 37 billion pounds or 69 percent of these emissions are eliminated, leaving only 16.7 billion pounds. The cost of this reduction is $8.17 billion, or approximately 22 cents per pound.

Moving from NSPS to the most probable case of nonsignificant deterioration (50 percent of NSD increment for utilities and no BACT) achieves a further reduction of 6.04 billion pounds at a cost of $3.4 billion or 56 cents per pound. If, on top of this, a BACT provision is added to the legislation, emissions are further reduced by 1.9 billion pounds but the incremental cost is 68 cents per pound. These results are described graphically is Figure 1.

Thus, compliance with NSPS eliminates 69 percent of all SO_2 emissions produced by new coal-fired capacity at a cost of 22 cents per pound. With BACT, NSD legislation removes only an additional 15 percent of base SO_2 emissions but increases total Clean Air Act costs by 57 percent. The public has the right to ask whether it is getting its money's worth for these additional dollars.

B. Coal/Nuclear Cost Balance

In previous analyses of the costs of Clean Air Legislation, it has been assumed that the distribution of capacity in the industry between nuclear- and coal-fired capacity is unaffected. Given the constraints on further expansions in nuclear capacity, this may be a reasonable assumption. However, it should also be recognized that the Clean Air Act does dramatically affect the cost balance between coal-fired and nuclear-fired generation. Table 2 presents estimates of the cost of electric energy generated from coal and nuclear sources for each of six regions in the United States. These estimates are presented for costs in 1980. A single estimate is presented for the costs of nuclear generation, but for coal, estimates are presented under four separate sets of circumstances.

In the first case, no constraints on sulfur content are assumed and therefore, in each region, the coal used is that which can be obtained at the lowest cost. In the second case, it is assumed that NSPS must be met, but that these can be met either with low sulfur coal or with high sulfur coal and scrubbers. In the third case, it is assumed that scrubbers must be put on everywhere, but there are no constraints on the sulfur content of the coal which can be used with these scrubbers. Consequently, in the West, low sulfur coal and scrubbers are used together whereas, in the East, high sulfur coal is used with scrubbers. In the final case, it is assumed that both low sulfur coal and scrubbers must be used everywhere. Thus, the first of these cases corresponds with no Clean Air Act Legislation, the second with the Clean Air Act as written in 1970, whereas the third and fourth cases represent approximations of two variants of current non-significant deterioration legislation being considered in Congress.

It is interesting to note that, in the absence of any constraints on sulfur usage, coal and nuclear generating costs are really quite similar in each region. Coal costs range from 22 to 26 mills, while nuclear costs range from 20 to 23 mills and the pattern of inter-regional variation is similar. However, compliance with NSPS drives up coal costs substantially in the North Atlantic, South Atlantic, and in the North Central regions--to a range of 27 to 28 mills per kilowatt-hour--making nuclear capacity, on average, more economically attractive. However, since there are relatively low-cost supplies of low sulfur coal available in the West, compliance with NSPS in that region has no impact on coal costs and, therefore, the costs of coal and nuclear remain equivalent.

If scrubbers are imposed everywhere, this has no effect on coal costs in the East because the primary method for complying with NSPS in the East would be some form of scrubber technology. On the other hand, it has very dramatic effects in the West where coal costs rise to between 28 and 32 mills per kilowatt-hour--28 to 37 percent over the average costs of nuclear generation. If the more extreme form of non-significant deterioration regulation is imposed, we would have the equivalent of scrubbers and low sulfur coal everywhere. In the West, this would have no effect over and above the "scrubbers everywhere" case, but in the East, it would increase the price of coal generation still further to the 31 to 34 mills per kilowatt-hour range, about 50 percent in excess of nuclear costs.

What this table illustrates is that the Clean Air Act plays a major role in determining the relative cost effectiveness of nuclear and coal generation. If there were no Clean Air Act constraints, we might expect to see nuclear- and coal-fired generating sources use roughly equal proportions all around the country. The imposition of NSPS, more or less, makes coal-fired generation uneconomic in the East and particularly in the Northeast. The effect of the latest proposed amendments would be to make coal-fired generation equally uneconomic in the balance of the country and if the most extreme forms of this legislation were pressed, it would make coal-fired generation still more uneconomic in the East.

LP:kk

Figure 1

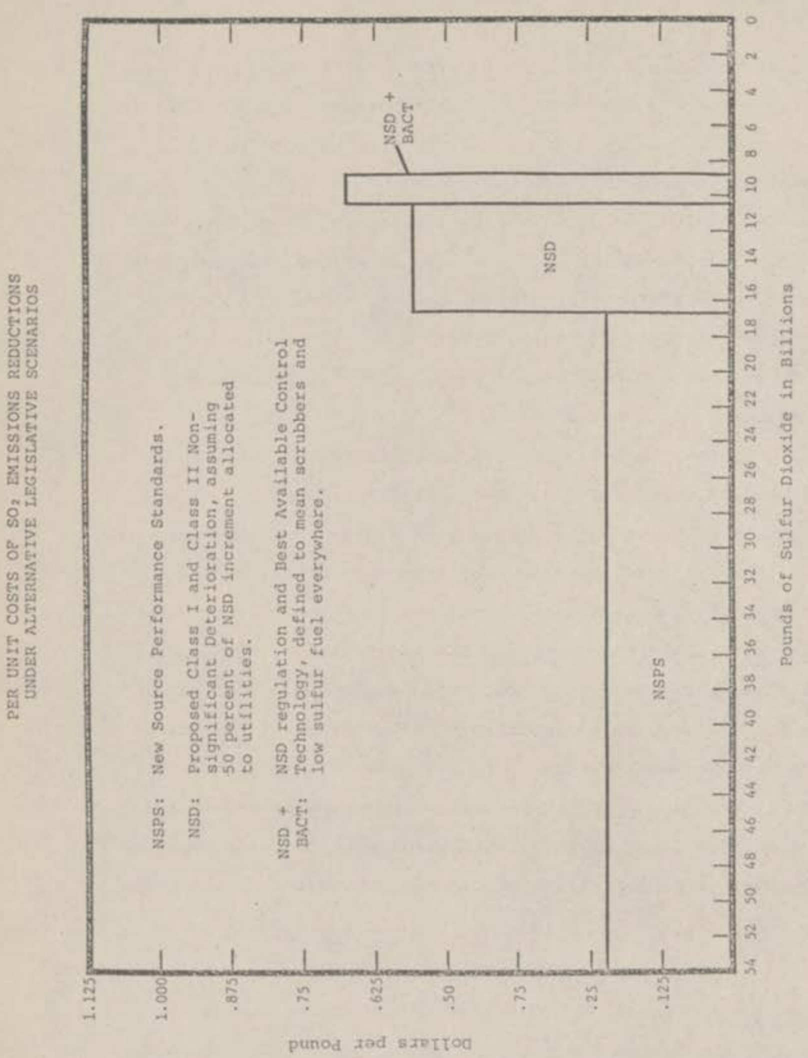

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TABLE 1

REDUCTION IN 1990 SO_2 EMISSIONS
FOR ALTERNATIVE LEGISLATIVE PROPOSALS FROM
COAL-FIRED POWER PLANTS[1]

Cases	Emissions of SO_2	Incremental Decrease in SO_2	Incremental Cost	Cost per Pound of SO_2 Reduction	Percent of Base Emissions Removed
	--(Billions of Pounds)-		(Billions of 1975 Dollars)	(Dollars)	(Percent)
	(1)	(2)	(3)	(4)	(5)
Base[2]	54.12	0	0		
NSPS[3]	16.74	37.38	8.17	0.22	69.1
Senate NSD[4]	10.70	6.04	3.39	0.56	11.2
Senate NSD plus BACT[5]	8.82	1.88	1.27	0.68	3.5

[1] Capacity added between 1975 and 1990.

[2] With no restriction on SO_2 emissions.

[3] New Source Performance Standards.

[4] Proposed Class I and Class II Non-Significant Deterioration, assuming 50 percent of NSD increment allocated to utilities.

[5] NSD regulation and Best Available Control Technology, defined to mean scrubbers and low sulfur fuel everywhere.

Source: NERA estimates.

TABLE 2

ESTIMATED COSTS IN 1980 OF ENERGY
FROM NUCLEAR PLANTS AND
COAL PLANTS UNDER FOUR ALTERNATIVE
SO_2 CONTROL SCENARIOS

Region	Coal				
	No Sulfur Constraint	NSPS	Scrubbers Everywhere	Scrubber and Low Sulfur	Nuclear
	(Mills/Kilowatt-hour)				
	(1)	(2)	(3)	(4)	(5)
I North Atlantic	22.5	28.2	28.2	34.4	23.0
II South Atlantic	21.6	27.3	27.3	30.9	20.4
III North Central	22.0	27.6	27.6	32.1	22.3
IV South Central	22.1	22.1	27.8	27.8	20.5
V Plateau Division	21.8	21.8	27.5	27.5	21.5
VI Pacific Coast	25.7	25.7	31.6	31.6	23.1

Source: NERA estimates.

March 7, 1977
Revised Briefing Paper
For The Senate Public
Works Committee
And Its Staff

The Oxidant Non-Attainment Problem

I. The current oxidants "non-attainment" problem is a major national problem because:
   A. Federal ambient air quality standards for oxidants are being violated in almost every place we monitor (see Map 1).
   B. Where there is monitoring and no violation, it may be because of the fortuitous location of the monitor.
   C. If there were adequate monitoring (numbers and locations), there would probably be violations everywhere.
   D. Indeed, EPA appears to recognize this (except for some unexplained exceptions), as shown by its recent designation of Air Quality Control Regions (AQCR's) in which oxidant related provisions of state implementation plans (SIP's) were to be revised by July, 1977 (see Map 2). This date was recently postponed one year by Roger Strelow's letter of January 13, 1977, to EPA Regional Administrators (Attachment 3).

II. Ambient standards for oxidants are being violated because:
   A. The standards were set hastily and probably improperly (low numbers, short time frame, only one "exposure").
   B. The origin of oxidants -- Oxidants at ground level come from two sources (a) they are formed by interaction of NO_x and hydrocarbons in the presence of sunlight or (b) they are formed in the upper atmosphere or during thunderstorms.
      1. Natural
         a. conifers (hydrocarbons)
         b. upper atmospheric ozone
         c. thunderstorms
      2. Man-made sources of hydrocarbons and/or NO_x: auto (usually major); other uses (usually less than autos). The latter includes, among other things, (1) fossil fueled electric generating plants, (2) any other large fuel burning plants, (3) incinerators, (4) fibre manufacturing plants, (5) coke ovens, (6) charcoal manufacturing, (7) asphalt roofing manufacturing, (8) plywood veneer

production, (9) anhydrous ammonia manufacturing, (10) petroleum refining, (11) large scale gasoline storage facilities, (12) large solvent-using operations, (13) paint plants, and (14) residences heated with oil or coal.

C. Ozone is a rural as well as an urban problem. Oxidants concentrations near or in violation of ambient standards are often present in rural areas because of the (1) natural background sources such as coniferious forests, (2) long distance transport, (3) ozone advection from the stratosphere, and (4) general omnipresence of roads and cars.

III. The practical consequence of the existing law and the present ambient standards for oxidants is that virtually no new major facility emitting hydrocarbons (presently 100 tons per year or more) (see II.B.2 above) can be built anywhere in the United States, except in regions which may escape temporarily because of inadequate monitoring data (see IV.A below) or possible under EPA's new "emission offset" policy. In the past, we have not generally recognized the extent of this oxidants-imposed new construction moratorium because of the (1) limited enforcement of the Act as to this pollutant and (2) postponed new plant construction because of the short-term surplus capacity in most industries in our sluggish economy.

IV. Present EPA policies and the alternatives currently proposed in S. 252 (the Senate Bill) and S. 253 (the Conference Bill) are inadequate to cope with the problem.

A. While some areas may have relief from the present construction moratorium because of inadequate monitoring (either none or none up to EPA standards), that relief is probably only temporary. The injustice of a long-term national policy which permits new plants to be located only in areas where monitoring is non-existent or below national standards is obvious.

B. Some relief may be afforded in a non-attainment AQCR by administrative subclassification. Both EPA's "offset" policy, S. 252, and S. 253 would permit this. But this administrative relief can be obtained only if (1) the subdivision is into no smaller than counties and (2) adequate monitoring data exists to justify the subdivision (see Senate Report on last session's S. 3219 at page 14). In addition, location in "clean air" counties within certain distances of "urban centers" would still be forestalled by EPA's present policy statement.

C. EPA's new "emission offset" policy does not resolve the oxidants problem for non-attainment regions. For many new industrial facilities which emit hydrocarbons there is usually no technology available for holding the emissions below 100 tons per year. Where this is the case, there is no way that an owner can build his first plant. Even if an owner already has existing plants, backfit of them to obtain the necessary "emission offset" increment will almost always be impractical. It will usually be impractical for an owner to buy the emission offset increment from another major polluter, since the principal sources of oxidant precursors are usually either mobile sources such as automobile traffic or area sources such as home hearing units, etc. (See Attachment 4.)

D. The so-called "Steel Amendment" in S. 252 and S. 253 has the same weaknesses as EPA's present policy with regard to <u>oxidants</u>. Further, enactment of either bill in their present forms would limit one of the options currently available for ameliorating it since writing the 100 ton per year cut off point for <u>de minimis</u> exception into the Act would preclude its being changed administratively.

V. Several other possible alternatives for dealing with this problem have been mentioned, but at first glance each has serious drawbacks as an "instant" solution:

A. Extension to oxidants of the "administrative practice," blessed in language in the Senate Report on S. 3219, of discounting naturally occurring background particulates for purposes of classifying an area as "no significant deterioration" or "non-attainment" -- But this may not be justifiable on health grounds for oxidants. With particulates, natural background dust and salt spray are not thought to present serious health problems. But we are told that scientists and doctors may view all oxidants as equally dangerous whether they originate from hydrocarbons and NO_x in automobile exhaust or from hydrocarbons from the conifers of the Smokies, Adirondacks, or Rockies (though this is hard for a layman to believe). There has been considerable resistance at EPA to permitting states to discount naturally occurring background oxidants. At any rate, it would be extremely difficult, if oxidants in fact are transported over long distances.

B. EPA's revision of the present ambient standards for oxidants -- It has been suggested that the health studies underlying the present one hour standard would justify substitution of exposure time limits. Alternatively, the number of permitted exceedances might be increased from one per year to four or five per year. One or both of these changes might limit violations generally to urban areas with substantial traffic or regions surrounding large industrial complexes. The American Petroleum Institute (API) has petitioned EPA for revision of the oxidants standard. EPA's response to date is that it is studying the problems (see 42 Fed. Reg. 9202), but the study may not be completed until early next year (see Attachment 3). The EPA studies may offer a long-term administrative solution to the problem but there are still short-term problems to resolve. The sensible legislative approach would be to deal with this matter after results are available from the EPA studies. In this regard, it is significant that EPA has postponed the deadline for oxidant SIP revisions from July, 1977 to July, 1978 (see Attachment 3).

VI. In the face of these realities, the Committee should consider: (a) asking EPA, ERDA, and the National Academy of Science to respond to you on the points in this memorandum and invite other federal agencies, the states, and any affected industries to review and to comment on these responses and (b) then scheduling further hearings on this problem, where the states, as well as affected industries, can fully advise you of their views.

A. We believe that review process will develop information showing that (1) the present oxidants standard was not properly set, (2) as a result, we are facing a potential nationwide moratorium on new construction across a vast segment of American industry that presents a serious, immediate obstacle to long-term revival of the nation's economy, and (3) a number of options which should be considered in the current formulation of a national energy policy may be foreclosed.

B. If EPA cannot act expeditiously, then temporary legislative relief may be needed in order to forestall serious national economic difficulties. The alternatives for temporary legislative relief which might be considered, if justified by the hearing record, might include, among others:

1. Extension of the statutory deadlines for compliance with the federal ambient air quality standards for oxidants until a date adequate to afford a reasonable time for new SIP's to be set after EPA's estimated completion date for action on new oxidants standards, and
2. Authorization for a state to grant exceptions from current oxidant requirements for new sources where it determines either that (a) the new source's emissions of hydrocarbons will be _de minimis_ or (b) the source will utilize best available control technology for hydrocarbons, as determined on a case by case basis.

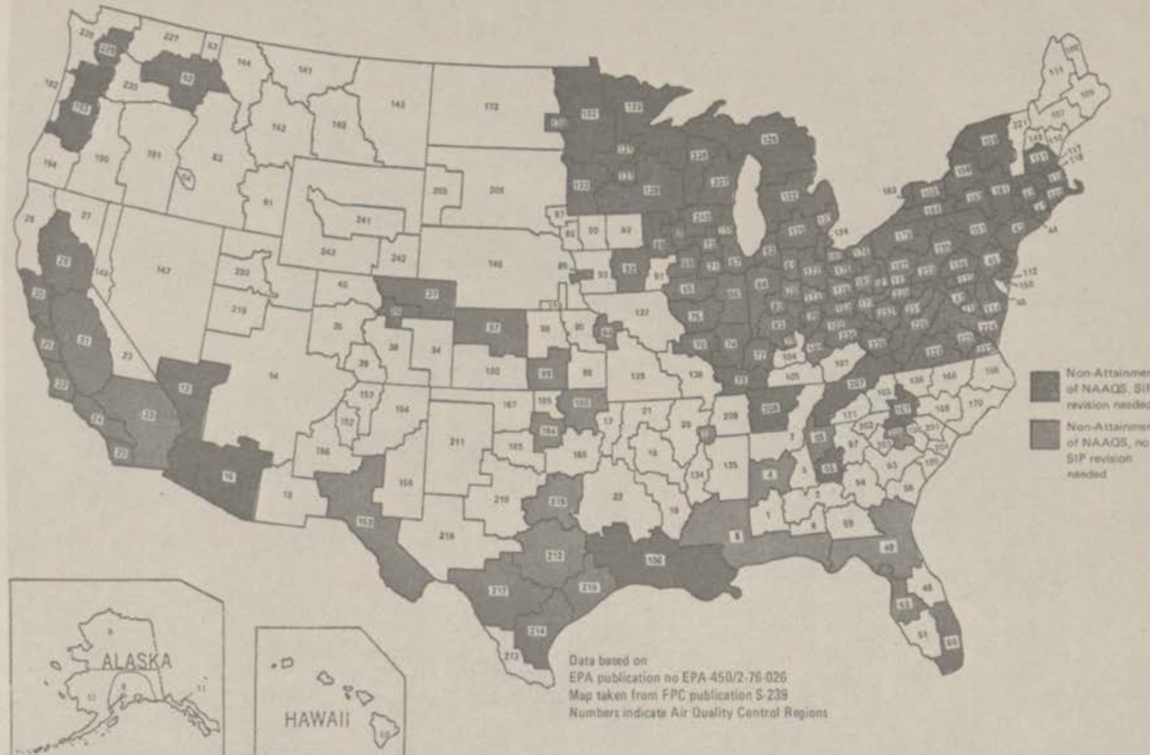
George C. Freeman, Jr.
March 7, 1977

Attachments:

Map 1
Map 2
Attachment 3 (Strelow letter)
Attachment 4 (Nationwide Emission Table)
Attachment 5 (The Oxidant Non-Attainment Problem as it Affects the Electric Utility Industry)

AIR QUALITY CONTROL REGIONS

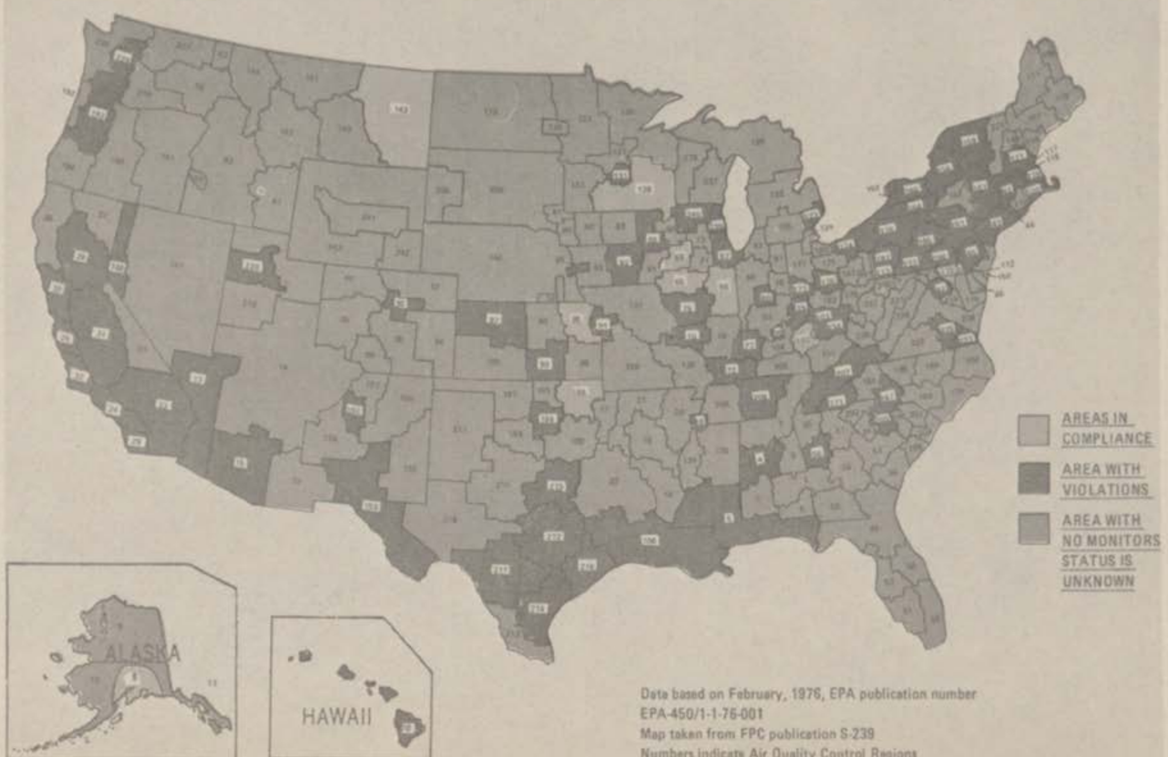
STATUS OF COMPLIANCE WITH NATIONAL AMBIENT AIR QUALITY STANDARDS FOR OXIDANTS



Data based on
EPA publication no EPA-450/2-76-026
Map taken from FPC publication S-239
Numbers indicate Air Quality Control Regions

Note: The status of uncolored regions is unknown; many such regions do not monitor for oxidants. In 1974, 5.5% of these regions had monitoring data available.

AIR QUALITY CONTROL REGIONS
STATUS OF COMPLIANCE WITH PRIMARY AMBIENT AIR QUALITY STANDARD FOR OXIDANTS
90% OF REPORTING REGIONS ARE AREAS WITH VIOLATIONS



Attachment 3

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JAN 13 1977

OFFICE OF
AIR AND WASTE MANAGEMENT

SUBJECT: Activities Related to SIPs for Oxidant

FROM: Roger Strelow, Assistant Administrator
for Air and Waste Management

R. Strelow

TO: Regional Administrators
Assistant Administrators

Of all the criteria pollutants, photochemical oxidants (O_x) create the most widespread violations of the health-related, primary ambient air quality standards. This was reflected in the large number of calls (122 air quality control regions) for revisions to the State Implementation Plans for O_x made by EPA in July, 1976. There are numerous programs underway that will provide additional support for these revisions and will influence the schedules for their submission. This memo provides summary information on the status of these programs and provides guidance for the next 18 months of O_x regulatory efforts.

Control strategies for O_x are complex and provide some of the most difficult technical challenges to the air quality management concept. In 1971, EPA published as formal rulemaking a series of procedures on the preparation of SIPs to attain the O_x standards (36 FR 22398, November 25, 1971). Since that time, new data from laboratory and field studies indicate that attainment of the O_x standard will be more difficult and will require more control of organics than initially anticipated.

EPA has been working for more than a year on a number of new guidelines to support preparation of SIPs for O_x. Many of these guidelines are nearing completion, and the remainder will be available in time to prepare the required SIP revisions for O_x by mid-1978. The major programs being undertaken by OAWM and the current schedule for review and publication are attached.

The basis for approvable SIP control strategies for O_x remains the demonstration of attainment and maintenance of the air quality standard. It is clear, however, that attainment in many areas will require regulatory strategies and control measures beyond those that can be promulgated or implemented in the immediate future. Therefore, for these areas, forthcoming SIP submissions will focus on application of reasonably available control measures to all important sources of organic emissions in broad metropolitan areas and adjacent areas of high population density.

These SIPs will result in significant air pollution control programs and EPA cannot expect the development of them to proceed fully until definitive information can be provided on the need, the effectiveness, and the acceptability of the measures being considered. Therefore, some adjustments have been made to the timetable for submission of O_x SIPs. The original timetable for SIP revisions required states to promulgate regulations for the various emission sources as expeditiously as they could be developed, reviewed, and accepted. Initially, this was interpreted as emission limitations for all major sources by mid-1977, and any necessary land use and transportation control measures by mid-1978. Publication of the various SIP guidelines for O_x has been delayed and it is clear that comprehensive sets of emission limits generally cannot be promulgated by mid-1977. However, the final submission date of mid-1978 remains realistic and continues to be the target for completed SIP revisions.

Specifically, the Regions should require that states submit tangible items demonstrating progress by mid-1977. At a minimum, this submission should include: (1) an emission inventory, (2) an outline of a proposed control strategy, (3) a detailed schedule for RACT determinations, and (4) regulations for sources for which additional RACT guidance is unnecessary. The first three items will help the Regions to determine whether the state will be able to develop the full plan or whether an EPA promulgation may be necessary. The fourth item is included to ensure that currently available organic emission controls are initiated as expeditiously as practicable.

The mid-1978 submission should constitute the full plan revision. This submission should include: (1) a control strategy, (2) emission control regulations for all industries for which reasonable control technology is known, and (3) transportation controls and land use measures. This submission should provide for all of the organic emission control that is practicable at that time. As noted above, in many areas the application of all practical measures will not result in attainment and maintenance of the oxidant standard. In these areas, the SIP will need to be further revised periodically to include additional controls as technology improves and as new transportation and land use measures become available.

In headquarters, work on organics will continue to be emphasized both in SIP related programs and in other regulatory programs. The latter include new source performance standards, and additional motor vehicle programs including evaporation controls, medium and heavy duty vehicle controls, assembly line testing, demonstration of inspection/maintenance effectiveness, and other actions to ensure the continued effectiveness of vehicle control systems.

We will keep you informed on progress on the O_x related activities and will request full review by the Regions prior to significant external discussions with regulatory-oriented groups.

I expect that you will provide the information in this memo to your states and cities as appropriate. In conclusion, I would like to state that the control of organics continues to be one of the Agency's highest priority programs. The adjustment to the schedule for submission of SIP revisions is being done solely to insure that the revisions are of the highest possible quality and should not be misinterpreted as a relaxation of effort. Every effort needs to be made to ensure that needed oxidant controls are developed as soon as possible. Although the upcoming revision of the oxidants criteria document may lead to some modification of the standard there is no likelihood in my judgment that any such changes would in any way obviate the need for <u>at least</u> RACT-oriented controls.

Enclosure

cc: Director, Air and Hazardous Materials Division Regions I, III-X
Director, Environmental Programs Division, Region II
W. Barber
E. Stork
F. Brands
R. Wilson
H. Shutler
R. Hamner
J. Bonine
P. Cashman
E. Tuerk

SCHEDULE FOR REVIEW AND PUBLICATION
OF OAQPS GUIDELINES RELATED TO SIP FOR O_x

a. Control Strategy Manual for Photochemical Oxidants (O_x Cookbook) draft was reviewed in October 1976; initial publication available in mid-January 1977; the initial version will be revised as additional EPA guidelines and policy decisions become available.

b. Revised Appendix J: a quantitative procedure for relating various degrees of control of organics to O_x reduction; EPA guideline completed by April 1977; promulgation in FR Part 51 in 1978.

c. Guidelines for determining geographical areas for the most effective control of organics based on hydrocarbon to NO_x ratios and population of metropolitan areas; discussed in advanced notice of proposed rulemaking (ANPR) on December 21, 1976 (as part of ANPR on new source review); EPA guideline completed by March 1977; promulgation in FR Part 51 in 1978.

d. Guideline on reasonably available control technology (RACT for sources of organics emissions. General definitions and philosophy provided in a memo from Roger Strelow to the Regional Administrators dated December 9, 1976. Conceptual model regulation for major solvent users available by March 1977. EPA revised policy on reactivity of organics and on role of solvent substitution in RACT by March, 1977. Control documents on selected major sources: first five to be distributed by mid-January 1977; draft documents for ten additional sources available by mid-July 1977. The schedule for publication of the control guideline documents is as follows:

Surface Coatings	
Coal, Fabric, Paper, Can Coating, and Auto and Light Truck Manufacture	Mid-January 1977
Metal Furniture	July 30, 1977
Fabricated Metal Products (Doors)	August 30, 1977
Major Appliances	August 30, 1977
Small Appliances	August 30, 1977
Wood Paneling (Plywood)	August 30, 1977
Insulation Varnish (Wire)	September 30, 1977
Dry Cleaning	February 1, 1977
Stage I Service Station Controls	April 15, 1977
Degreasing	April 30, 1977

Rubber Products	April 1977
Miscellaneous Refinery Sources	May 1, 1977
Gasoline Bulk Terminals	May 15, 1977
Gasoline Bulk Plants	May 15, 1977
Pharmaceuticals	June 1977
Fluid Catalytic Cracking Unit Regenerators	July 15, 1977
Adhesives	July 1977
Additional Solvent Related Sources	
Graphic Arts	Early 1978
Paint Manufacture	Mid-1978
Plastic Products	Mid-1978
Additional Petroleum Related Sources	
Ship and Barge Transfer Operations	
Phase I (Qualitative)	January 1977
Phase II (Quantitative)	January 1978
Gasoline and Crude Oil Storage Tanks	October 15, 1977
Offshore Drilling and Production	Mid-1978
Onshore Drilling and Production	Mid-1978
Refinery Liquid and Solid Fuel Burning	1978
Secondary and Tertiary Oil Recovery	1978
Storage of Other Petroleum Products	1978
Organic Chemical Manufacturing	March 1978
(The contract is tentatively scheduled to be let in February-March 1977; this date is based upon the letting of the contract.)	

e. Revised emission factors for motor vehicles and techniques for estimating future impact of federal standards and the effectiveness of transportation control measures such as inspection and maintenance: initial information has been distributed; Appendix N, "Emissions Reduction Achievable Through Inspection, Maintenance, and Retrofit of Light Duty Vehicle," proposed by March 1977; revised Supplement 5 to AP-42, "Compilation of Air Pollution Emission Factors," available by April 1977.

f. Revised criteria document for air quality standard for O_x: draft available for external review by March 1977; information on initial re-evaluation of standard available by August 1977.

A-3

EPA realizes that programs for O_x reduction depend to a large extent on state and local initiative and implementation. Also, there seldom is a single correct technical solution to many of these problems. Therefore, for most of the activities outlined we are attempting to identify alternatives which have widespread support with the technical community and affected parties. There is underway, or scheduled, contact with a variety of appropriate groups outside of EPA to assist in problem definition, evaluation of alternatives and selection of policy. Generally these are proceeding in two stages: scientific, to define alternatives that have technical credibility; and regulatory, to develop the optimum course of action jointly with those affected such as state and local agencies, industry and the general public. For example, issue papers for several of the issues (revised Appendix J, area for control of organics, conceptual regulation for solvent users and solvent substitution policy) will be available for a general review in January. This will be followed by a two day meeting in February, probably in Denver, and publication as EPA decision document during March and April. These documents will be the basis for decision-making related to SIPs for O_x during the forthcoming program of SIP revisions. Formal rulemaking will follow for many of the issues to further strengthen the credibility of the program and to minimize litigation.

Attachment 4

Table 4-7. NATIONWIDE EMISSION ESTIMATES, 1975 (PRELIMINARY)

(10^6 tons/yr)

Source category	HC
Transportation	11.7
Highway	10.0
Non-highway	1.7
Stationary fuel combustion	1.4
Electric utilities	0.1
Other	1.3
Industrial processes	3.5
Chemicals	1.6
Petroleum refining	0.9
Metals	0.2
Mineral products	0
Other	0.8
Solid waste	0.9
Miscellaneous	13.4
Forest wildfires	0.6
Forest managed burning	0.2
Agricultural burning	0.1
Coal refuse burning	0.1
Structural fires	<0.1
Organic solvents	8.3
Oil and gas production and marketing	4.2
Total	30.9

Attachment 5

March 7, 1977
The Oxidant Non-Attainment
Problem As It Affects The
Electric Utility Industry

1. The Revised Briefing Paper For The Senate Public Works Committee And Its Staff, and its attachments, is a good starting point for ascertaining the general problems under the present Clean Air Act and EPA's new "emission offset" policy (as well as S.252 and S.253) confronting the owner of any proposed new facility that would emit hydrocarbons. The instant briefing paper illustrates specifically how those general problems affect an electric utility seeking to build a new coal or oil fired ("fossil fueled") base load generating unit.

2. The problem exists whether the new unit is proposed to be added at an existing plant site where other units are already located or at a new site, usually with the thought that several additional units will subsequently be added there. Coal-fired base load electric generating power plants usually consist of several generating units with their associated coal storage, handling, and transportation facilities, waste disposal and other pollution control facilities, and transmission lines. This aggregation achieves economies of scale with reduced environmental impact with its avoidance of wasteful duplication of these associated facilities.

3. New "base load" fossil fueled generating units now being built or planned generally range from 400 to 800 megawatts (and could be as large as 1300 megawatts). These units emit hydrocarbons. As examples: most intermediate and larger sized individual fossil fired units are thought to emit HC in sufficient quantities as to make them "major emitting facilities" under EPA's present "emission offset" policy (currently 100 tons/year, reduction to 50 tons/year being considered) or under S.252 and S.253 definitions (100 tons/year for oxidants). Based on EPA's Emissions Factor Book (AP-42, Supp. 6), hydrocarbons are emitted from bituminous coal-burning power plants at the rate of 0.3 pounds per ton of coal burned, and from residual oil-burning plants at one pound per 1,000 gallons of oil consumed. As an example, a 550-megawatt coal-fired unit at 5 x 10^9 Btu/hour and a 100% load factor would emit 285.6 tons/year of HC while an equivalent oil-fired unit would emit 151 tons/year of HC (assuming 11,500 Btu/lb of coal and 145,000 Btu/gallon of oil).

For perspective, a coal-burning power plant of only about 300 megawatt capacity (assuming 60% load factor) would emit 100 tons of hydrocarbons per year and would be classified a "major emitting facility" subject to all requirements applicable to sources proposed to be constructed or modified in areas where the ambient oxidant air quality standards have not been achieved; similarly, an oil-burning plant of only 570 megawatt capacity would be subject to such requirements. Such units are generally smaller than economically sized ones being installed in modern plants. Technology is generally not available to retrofit existing plants to reduce hydrocarbon emissions substantially to accommodate growth in accordance with EPA's "emission offset" policy, S.252, or S.253.

4. If a new unit is proposed to be located in an air quality control region where the federal ambient air quality standard for oxidants is being violated then it may not be possible to construct the unit under present law for the following reasons:

   A. See Map 1 attached to the Briefing Paper (it is based on EPA publication EPA-450/1-1-76-001) for 1974 monitoring data as to air quality control regions (AQCR's) in violation of either ambient oxidants standard (shown in red). Note also the few regions where available data showed compliance with both standards (shown in blue) and the many regions where inadequate monitoring data were available (shown in yellow).

   B. In regions where published monitoring data is not presently available, it is generally believed that the standard will be violated at some point. (See Map 2 for AQCR's where revisions of SIP oxidant provisions have been ordered by EPA.) Thus, any relief from the oxidants non-attainment barrier afforded by the current administrative convention (also reflected in S.252 and S.253) of assuming areas with inadequate data as to criteria pollutants to be "no significant deterioration" ("clean air") areas, as distinguished from a "non-attainment" ("dirty air") area, may be short lived.

   C. Some relief might be afforded in a non-attainment AQCR by administrative subclassification. Both EPA's proposed "emission offset" policy, S.252, and S.253 would permit this. But S.252 and S.253 would permit the administrative relief only if (1) the subdivision is into no smaller than counties and (2) adequate monitoring data exists to justify the subdivision. (See Senate Report on the 94th Congress' S.3219 at 14 and Conference Report from that Congress, page 86.) In addition, location in "clean air" counties within certain distances (it is presently uncertain as to what this distance will be) of urban centers (200,000 or more people) would still be forestalled by EPA's presently proposed policy statement.

D. The idea that utilities could still solve all their problems under EPA's new "emission offset" policy by buying up "pollution rights" from others is naive. While many utilities generally have the power of eminent domain, it would not extend to acquisition of such "rights." General conclusions that utilities could purchase these "rights" from others voluntarily are completely unsubstantiated. Some idea of the complexity of the matter is obtained by looking at the sources of gross national hydrocarbon emissions in 1975. (See Attachment 4 to the Briefing Paper.)

E. It _might_ be possible to resolve the oxidants "non-attainment" dilemma set forth above for the utility industry administratively under the present law by, among other things, (1) changing the oxidants ambient standard, (2) changing the EPA emission factors (see paragraph 3 above), (3) deriving new formula for the interaction of NO_x and hydrocarbons in the presence of sunlight, and (4) increasing the _de minimis_ emissions limit from 100 tons per year. But none of these "solutions" have been adopted to date. Nor would any of them or any other workable solution be afforded by S.252 and S.253 as presently drafted. Sufficient information for an intelligent resolution of the oxidants non-attainment problem will probably not be on hand until EPA's review of the oxidants standard, not scheduled to be completed until late 1977 or early 1978. (See Attachment 3 to the Briefing Paper.)

George C. Freeman, Jr.
March 7, 1977

Mr. MOFFETT. I would like to begin by asking Mr. Tuerk a couple of questions.

You mention the offsetting effect of pollution which will come from what we attain through conservation. But since much of the President's plan is voluntary, as you know, with regard to conservation, such as insulation of buildings, gasoline consumption, etc., how can you assess the benefits of conservation?

Mr. TUERK. When it is tied into economic incentives and other measures not necessarily regulatory in nature, it makes it difficult.

The assumptions made as to conservation are the assumptions drawn by the EPA whose conclusion is that the total reduction of energy use would reduce the powerplant coal energy consumption by about 12 percent and the energy consumption in the industrial sector about 8 percent. Beyond that, I can't address what the assumption and their analysis were.

Mr. MOFFETT. It seems over the last two days some very serious questions have been raised as to those assumptions, I might say.

EPA didn't have anything to do with those assumptions; is that right?

Mr. TUERK. We accepted their computations.

Mr. MOFFETT. You accepted them as accurate?

Mr. TUERK. Yes.

Mr. MOFFETT. What about regional analysis? On page 6 of your testimony you indicated significant coal conservation would not occur in certain areas. Why should the industries and utilities in those areas have to prove inability to meet categorical orders in addition to paying the user tax on oil and gas?

It does seem on its face unfair to impose the user tax if the utilities, for example, are going to prove they can't convert.

Mr. TUERK. Let me set the user tax issue aside for a moment and address what we think the regional limitations on conversion may well be.

As you are aware, the President's proposal makes clear that coal conversion would not take place in any area where, for environmental reasons, it could not be accommodated.

As you know, under the Clean Air Act, we have many portions of the country which are not in a status of attaining the required standards. The EPA would make an assessment as to whether any new plant could burn coal rather than oil or gas.

Mr. MOFFETT. I think I understand the process. But EPA does the analysis after the NOI and after the NOE under the current plan. Under the President's plan the possible environmental obstacles would be considered after the conversion orders are issued.

Mr. TUERK. That is my understanding.

Mr. MOFFETT. Again, I go back to the question of whether or not the environmental obstacles should be considered before the conversion orders because—I am looking at it now, from the point of view again of fairness and cost to consumers; cost to consumers coming, as you know, when it is passed on to utilities who after doing all the analysis have attempted to show they can't convert to coal.

Mr. TUERK. The actual operating relationship between FEA and EPA has been to be involved in a consultation process. There have been plants not issued in order of attempt based on EPA's assessment of the environmental problems. I am not sure of the best way to handle it, legislatively. All I am saying is that the interactive process makes it fairly clear before a prohibition order is made, whether or not there would be a situation which would prevent the conversion.

Mr. MOFFETT. Were you in consultation with FEA before the orders were issued?

Mr. TUERK. Yes.

Mr. MOFFETT. Your figures agreed?

Mr. TUERK. Our analysis of the plant in which they issued notice of intent basically were in agreement with their conclusion.

Mr. MOFFETT. Are you in agreement with the figures Mr. Ayres put forth on page 7 of his testimony?

Mr. Ayres, would you like to comment on the set of questions I have just asked, in any way?

Mr. AYRES. My understanding of what the real process of conversion so far has been like is in agreement with what he said. It has been essentially a consultative process in deciding which plants can be converted.

Our concern is that within the constraints the President is proposing, tremendous jumps in emissions would be allowed in areas already highly polluted.

A table demonstrating this point is at the back of my testimony. It is drawn from the environmental impact statements put together by FEA on these plants. You can see, when you look at the specific air quality control regions, that Hartford, Springfield, New Haven, New York and Boston, would suffer very great increases. And yet still not have the air quality exceeding the primary air quality standards.

Our concerns are, first, that those prediction methods may be off by considerable factors. That is a well-established fact. And second, the problem of total atmospheric loading, which brings with it greater acidity and rainfall, higher levels of sulfates, and so on, will be exacerbated because of the very substantial increases in total emissions in those areas. We feel the fact these things can be slipped under the existing air quality standards will have a serious effect on the public health and the environment.

Mr. MOFFETT. Do you think the figures on rainfall will affect plants in Connecticut and Massachusetts?

Mr. AYRES. Yes, those were ones which should not have been allowed to increase emissions by that much, not in those areas.

Mr. TUERK. The issue comes down to the requirements before a conversion can take place.

EPA is required in making its determination to set forth the emission limitation for a converting plant that would either keep that plant in compliance with the State limitation limits or otherwise make sure the plants don't violate the air quality standards. This doesn't say there would not potentially be some increase in emissions coming from those conversions. In other words, it could be in compliance with State regulations and yet put out greater emissions than it did when it was operating under oil. Total loading may well increase as a result of conversion orders.

Mr. MOFFETT. The chair now recognizes the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Mr. Tuerk, taking it graph by graph, I am impressed by your testimony. But when you put them together, I get a little wary. You mention on page 4:

The result of this increase in coal use will be increased emissions in the industrial sector. However, these emissions can be substantially but not entirely offset by installing best available control technology on all new industrial sources burning coal.

A net increase of emissions is projected for SO_2, TSP, and NOx from industrial sources over the levels that would have occurred without the President's plan. However, these increases are projected to be compensated for by decreases in emissions from the utility sector. The net result is that the total of industrial and utility emissions are expected to be about the same under the President's plan in 1985 as they would be without the plan.

If they are going to be the same as they would be without the plan, I am a little baffled. If you don't encourage the utilities to convert to coal, how do they balance out?

It seems to me the Clean Air Act—and maybe Mr. Ayres can help me here—as it is proposed, as you know, was written with a lot of environmental concerns, that it provides for air quality regions and if your utility is, in fact, a reduced polluter in one region and the industry increases in another region, that doesn't count.

You have to have your two emitter sources in the same region to balance each other out and if they happen to be in different regions, then, as I say, it doesn't count.

Am I right on that?

Mr. AYRES. I think Mr. Tuerk's statement was an aggregate statement that is for the Nation as a whole.

Mr. BROWN. All right, but am I right as to my concern about the fact if you are bouncing up against the limits in an air quality region, that you cannot increase unless somebody else in this region decreases? Isn't that correct?

Mr. AYRES. Yes, you are talking about the "emission offset" program. It depends on whether or not these converting plants are exempted from that program. That is something of an open question.

Mr. BROWN. Do you think it should be?

Mr. AYRES. No.

Mr. BROWN. Mr. Tuerk, do you think it should be?

Mr. TUERK. Let me respond to the issue of the total emissions first. You are quite right, our analyses to date are solely on the total national emissions——

Mr. BROWN. How do you get there if the law says you have to take it region by region?

Mr. TUERK. That is the analogy that is currently going on. We are doing a regional analysis to be completed in about two weeks.

Mr. BROWN. If I can just observe that the whole may add up to a lot more than the sum of the parts if you apply the law to the parts and the law does apply to the parts.

Mr. TUERK. I agree and I think we will have, in many areas of the country, situations in which the conversion program can't take place in the industrial sector.

Mr. BROWN. Then we are kidding ourselves with these total aggregate national figures.

Mr. AYRES. May I expand on my answer?

Mr. BROWN. First, I would like to go to the dollar figure. I don't mean to cut you off except that my time is very limited.

Mr. TUERK. On the offset issue, the current statement of the EPA emission offset policy, does exempt the conversion of plants from oil to coal where the coal-burning capability is already in existence, that is exempted from the offset. Nonetheless, it must meet the implementation plan requirements.

In any case, under the new proposal where conversions would be required an additional capability would have to be installed to burn oil, subject to the best control technology requirement.

Mr. MOFFETT. The gentleman has raised an important point. It is not really fair, is it, Mr. Tuerk, for the EPA to say the air quality control effects will balance out? Don't you think it is really too early without the regional analysis to make that kind of statement?

Mr. TUERK. I would not disagree with that.

Mr. MOFFETT. My good friend, and he is a good friend, Mr. Costle, testified before the Senate, unless the Washington Post is incorrect. He said there would not be a significant impact on air quality. We have a draft memo from Mr. Drayton, the Special Assistant Administrator to Mr. Costle, which says:

> Very preliminary results from an AQCR based analysis are expected within a month. We are currently planning to initiate a more detailed analysis of the nonattainment problem and coal conversion in several specific areas. These two study efforts should provide EPA with a detailed assessment of the air quality consequences of the energy initiatives before final energy legislation is passed.

The very clear implication is that we do not know yet, however.

Mr. TUERK. I have a slight correction to the Washington Post. Mr. Costle also indicated in his testimony before the Senate that he was certain there were highly industrialized areas in which this conversion could not take place for air quality reasons.

Mr. MOFFETT. So the FEA's orders may well be wrong on conversion as it affects Connecticut and Massachusetts, for example?

Mr. TUERK. He was talking as to the necessity of industrial plants burning gas and oil over coal in the future.

Mr. MOFFETT. Were you agreeing with my assertion that we really don't know yet, Mr. Ayres?

Mr. AYRES. Yes. Could I expand a little on our earlier discussion?

Mr. BROWN. I would love to, but let me get back to you at the end of my remarks, then it doesn't count because it is on company time. But I would like to pursue a couple of questions with Mr. Tuerk.

I assume what you are suggesting is that with the best available control technology, that this map which is on the back of the testimony of Mr. Mallory of EEI, which I guess is OK because it is taken from data based on an FPC publication, No. S-239. That and the Washington Post are bibles, I imagine. The red indicates noncompliance; blue places, OK; and yellow places, not sufficiently monitored to know whether things are OK or not.

I would assume you are telling me that with the best available control technology you can reduce the industrial and utility emissions if you switch to coal and maybe get your plant in compliance in some of these red areas.

Mr. TUERK. What this particular map reflects, essentially, is the attainment status of an area with respect to ambient air quality standards. It also displays the oxidant pollution problem; sulfur oxide and nitrogen oxide are the ones we are addressing today. So the map would look different as to those problems.

Mr. MALLORY. We have maps for the others. We were not addressing that in our statement.

Mr. BROWN. Well, so much for the maps. We will try to look at the maps and see for the different items how we are in control.

On page 5 of your testimony, you stated:

The costs of these environmental controls are reasonable in view of the environmental protection these additional controls provide. EPA estimates that they will add a total of about $5 billion to the cost of new coal-fired power plants by 1985 and about $12 billion by 1990. This cost will increase utility capital costs between 1975 and 1985 by about 2 percent and will result in average rate increases of about 1 percent nationally by 1985, with higher increases in some regions. The incremental capital costs of the BACT requirement for other industrial facilities will be about $4 billion in 1985.

I believe that is limited to utilities. The National Economic Research Associates, assuming high growth, the kind of growth we will need to provide 12 million jobs to get us down to 4 percent unemployment by 1980, which we are all looking at, estimate the cost would be $50 billion.

Could you tell us how you got the $12 billion?

Mr. TUERK. Yes, I can tell you how we got to $12 billion. The estimates you quoted basically address different costs. The estimate here of $5 million by 1985 is essentially an estimate of the additional cost associated with the Clean Air amendment and all new power plants and the numbers you cited reflecting EPA's last year's estimate as to the cost of the utility industry of compliance, there is already a built-in cost——

Mr. BROWN. Last year's estimate, what?

Mr. TUERK. Your statement as to EPA's cost of compliance. There is already a built-in cost in bringing plants in compliance——

Mr. BROWN. So your $12 billion is an incremental $12 billion?

Mr. TUERK. That is right.

Mr. BROWN. So that should be added to the $28 billion?

Mr. TUERK. It should be added to $14 billion, giving total cost of 25.6.

Mr. BROWN. Does that relate to the $28 billion? We are only just a couple of billion dollars off.

Mr. TUERK. Yes.

Mr. BROWN. We are within 10 percent.

Mr. TUERK. Surely.

Mr. BROWN. But we have the $50 billion estimate from NERA from what they call high growth. What growth estimates were included in the EPA studies?

Mr. TUERK. We can furnish that for the record.

[The following material was received for the record:]

EPA has estimated that the Clean Air Act Amendments including BACT would increase the electric utility capital expenditures by less than $5 billion through 1985 and $11.6 billion between now and 1990. This compares to the electric utility industry estimates of $22 billion in capital costs through 1990.

While both the EPA and industry estimates are based upon a fairly detailed analysis of 74 plant sites, other assumptions differed considerably. EPA believes that, had the utility industry used more realistic assumptions, their assessment of economic impacts would be comparable to the EPA estimates.

The differences between the EPA and industry estimates are primarily a consequence of two factors. First, the industry assumed that scrubbers which malfunctioned could not be by-passed resulting in plant shutdowns. The effect of this assumption is the construction of extra plant capacity which inflates the estimate of capital requirements by about $7 billion. EPA policy presently permits plant operation to continue when control equipment fails due to circumstances beyond the control of the operator and when the operator is making a good faith effort to repair the equipment.

Second, industry cost estimates assume that power plants will be unable to achieve economies of scale due to PSD regulations. THey assume that the industry will want to build 3,000 MW plants at most sites and that PSD will constrain plant size to smaller plants which have higher costs per megawatt. While 3,000 MW may be planned for a few sites, a review of the industry's construction plans indicates that the typical new plant size during the 1980 to 1990 period will be 1,000 MW not 3,000 MW. The 3,000 MW assumption artificially imposes cost penalties when the smaller plants which are actually planned can in fact be built under PSD.

When adjusted for these factors, the utility industry capital cost estimate is less than $15 billion for the period 1976 to 1990. This cost is comparable to the EPA estimate of $11.6 billion and is less than 4 percent of the projected capital expenditures by the utility industry in the absence of the Clean Air Act Amendments.

Mr. BROWN. I want to know if that is what it takes to clean up what we have now with no growth in industry or utility expansion.

It is all yours, Mr. Ayres.

Mr. AYRES. If I may respond to the last question.

Mr. BROWN. Respond to any question you want to, that is the way the game is played.

Mr. AYRES. In connection with the study the National Academy did last year, the difference between the $28 billion and $50 billion figure, most of it is a difference in assumptions about the costs of control. My conclusion after comparing very closely those studies, was that most of the NERA assumptions that produce the difference are quite exaggerated. The NERA study assumes, for example, that when a scrubber is down, an entire powerplant will be closed down. As a result of that, the utility will have to build additional powerplant capability. It is assumptions like that which account for the difference. I think the NERA figures are largely inflated.

Mr. BROWN. That is an interesting concept.

Mr. Mallory, do you want to comment on that?

Mr. MALLORY. I think we would have a considerable problem justifying the rates charged our customers if we built redundant scrubber capacity. I am not that familiar with that particular study myself but again I can attempt to procure it for the record and supply a copy. But it is my understanding they went on the basis that you build for the load you need, and we are not going to be building a plant with two scrubbers. We are very hopeful we won't have to put scrubbers on any plants that use compliance coal.

Mr. BROWN. May I get a figure from you as to the efficiency of scrubbers? It is about 10 percent down time; is that right?

Mr. AYRES. That is about right.

Mr. BROWN. So 1 day in 10 they are not working?

Mr. AYRES. That is more reliable than most utility boilers. The normal response to that 10 percent downtime has been to build redundant capacity. By that I don't mean double capacity. Scrubbers are built in modules and if you have seven modules to deal with the gas stream you might build eight modules so one could be down for scheduled outage while you were clean——

Mr. BROWN. Do you have any indication as to what the cost would be to the consumer in that?

Mr. AYRES. Well, your scrubber costs are about 10 percent of plant costs. So redundancy of one-eighth, say——

Mr. BROWN. A fifth would be another 2 percent of plant cost.

Mr. AYRES. Something of that order.

But that has been the normal practice as to the scrubbers built in the past few years.

Mr. MALLORY. I think you are talking about down time, reliability is another question. When the life of a plant is usually 35 years, ther are a lot of problems with scrubbers.

Mr. BROWN. Does anybody know the life of a scrubber?

Mr. AYRES. There is one which has operated for a long period of time. It is in a plant in England, put on in the 1930's. But in the United States there is no scrubber with that kind of operating time on it. There is a scrubber which this year will have its fourth or fifth year of operation with 90 percent operating efficiency.

Mr. BROWN. If we could provide gas at a price equivalent to oil and the cost of coal scrubbed, after it is burned, or something slightly less than that, would you advise us to mandate the conversion of utilities to coal-burning, at this point? Let us say we could do that within, say, 8 to 10 years, by the 1985 time frame?

Mr. MALLORY. If you could provide it at that cost there would be no need to mandate anything. We would be jumping to get at it. We have to provide reliable service at the lowest cost to our customers, we have to plan 10 to 15 years out in the future. We need assurances that the fuel will be there before making investment decisions on building the plant.

The industry is voluntarily going into the direction of the safest, cheapest fuel it can get.

Mr. BROWN. There has been a lot of conversion from coal to oil because of the Clean Air Act. If you could get a reliable source of gas, say, from natural gas at a price, gasified coal—would that be a preferable item as long as the price is not outrageously higher than coal with the scrubbers, and so forth and so on.

Mr. AYRES. We feel there needs to be some discrimination exercised in the use of fuel. Up to now the market has been affected by the Clean Air Act but the market itself has determined which fuel is to be used. Oil has been cheaper than coal, a lot cheaper, since the 1960's. But if you apply the President's program of using more coal, we think there are areas where you ought to use oil even if it is more expensive. If, on the other hand, oil is more expensive, there are areas where you should be able to convert to coal with limited effect on public health, if you require sufficient pollution control equipment.

Mr. TUERK. I think what the issue comes down to is the availability of gas. Natural gas is generally conceded to be more totally used for industrial or utility boilers.

Our thinking on this is that the provisions as in the President's proposal to put pressure on industries to use coal would perhaps encourage faster development of coal gasifiers for industrial use. It is a question of what things will force technology to lead to other things.

Mr. BROWN. Coal gasifiers, even in my area of the country, where we have coal in abundance but not gas and oil, except when it comes from elsewhere, are coming in at $3.25. There is some indication we might be able to get natural gas at less than that if the government would get out of the business of telling us what the price is.

This bill provides for telling us what the price is and then says, therefore, go to coal with the scrubbers. At some point here, there is a cross-over price, it seems to me, and my guess is that it might come below the cost of imported oil or artificial gas, or coal gasified or liquefied or fluidized or simply burned as it is and then scrubbed.

Mr. Mallory, do you have statistics on that?

Let me say one other thing. It is different from area to area. It may very well be to try to get coal into west Texas someplace, where you have to carry it in on the back of a pony or whatever, may be more expensive by the time you get the coal in and get it scrubbed, than to just let them go ahead and use gas for awhile.

Can you enlighten us or submit for the record any comparative costs by regions or neighborhoods or anything else?

Mr. MALLORY. We will attempt to do so. Congressman Moore is from my part of the country and we are facing this problem right now. This is a problem we have in gas-fired electric generation. We paid a horrible penalty when the FPC came in and made us switch to oil. The price of the fuel increased sometimes 5 to 10 times above that of the gas which had been flared by producers before we bought it under long-term contracts.

Now, the same people are having to pay the tab again to go to coal with facilities which can't burn it. So you have to tear them down, put a new coal plant in and lose all the economic life of the gas boiler. A 1990 deadline, we think, is unrealistic economically, but we very much agree there should be a way to evaluate this and we would try to get some figures.

Mr. BROWN. If you will put that in the record, we will appreciate that.

[The following material was received for the record:]

During my appearance before the Energy and Power Subcommittee on [illegible] you requested certain data relative to the total estimated cost of converting existing gas/oil electric generating units to coal-burning. We have prepared estimates of these costs for your use.

In order to aid you in assessing the overall impact of a forced coal-conversion program, I thought it would be appropriate to provide you with background information on the Middle South Utilities System.

Historical Background of the Middle South Utilities System

Middle South Utilities, Inc. is a holding company registered under the Public Utility Holding Company Act of 1935 and is comprised of five operating subsidiary companies; i.e., Arkansas Power & Light Company, Arkansas-Missouri Power Company, Louisiana Power & Light Company, Mississippi Power & Light Company, and New Orleans Public Service Inc. These Middle South Utilities operating companies are operated as a single integrated electric system.

All major generating units in the Middle South Utilities System were designed for burning natural gas as the primary fuel until about 1969 when evidence of the impending shortage of natural gas became apparent. Since 1970, its expansion plans have been based on having all future base load units in the form of nuclear and coal-fired. While the System's generating units were historically designed to burn only natural gas on a continuous basis, the boilers were designed to be able to burn fuel oil intermittently for very limited periods in order to handle emergency situations involving loss of gas fuel for short periods of time.

Under orders of the Federal Power Commission, delivery of natural gas to Middle South power plants by interstate pipelines already has been greatly curtailed. The System's natural gas usage as a boiler fuel has dropped by 31% in the period from 1970 to 1976, representing a total reduction estimated at 667,000,000 MCF of boiler fuel gas for the six-year period. Our present projections indicate an additional 61% reduction in use of natural gas as a boiler fuel by the System between now and 1986. Concurrently, the System's oil usage increased from 975,120 barrels in 1970 to 25,130,000 barrels in 1976.

Substitution of fuel oil and purchased energy for this gas (which was contracted for on a contract-price, firm-delivery basis but not delivered) has increased the fuel costs to our customers by an estimated $ 610,000,000 over this six-year period. These costs, together with associated boiler conversion costs, represent a burden already thrust upon the consumers in our service area by virtue of federal governmental action. At the same time, curtailments by United Gas Pipe Line Company, the interstate pipeline supplying the greater portion of the System's boiler fuel, have been about double those of the next largest pipeline's curtailments (Schedule I, FPC Curtailment Report, November 1976).

Additionally, the Middle South Utilities System operating companies have expended approximately $ 180,000,000 to convert their major boilers in order to permit burning oil for extended periods. None of these modifications were done with the contemplation of eventually converting to coal-firing; therefore, all of the modified facilities would have to be prematurely retired and replaced with new coal burning facilities. Furthermore, the System companies have experienced greatly increased operating and maintenance problems and expense as a consequence of the increased use of fuel oil in boilers not originally designed to burn oil on an extended basis.

It is anticipated that the Middle South Utilities System will consume about 40,000,000 barrels of oil in 1977 (60% more than in 1976) to supplant the natural gas shortfall and meet our customers' energy requirements. We feel that it is obvious from the foregoing facts that the Middle South Utilities System and its customers are already bearing a heavy financial burden as a result of shifting from natural gas to oil as a boiler fuel.

<u>Estimated Cost of Coal Conversion Program</u>

As I indicated on [illegible], the estimated capital cost for converting our existing gas and oil-fired units to permit coal-burning would be $ 4,913,825,000 (in 1976 dollars), exclusive of scrubbers. In response to your request, we have estimated the total cost of converting these units to coal-burning. Our analysis is summarized below:

	Estimated Cost in 1976 Dollars	
	$/Million BTU	Mills/KWH*
Annual Fixed Charges on Capital Expenditures for New Boilers Including Scrubbers	1.91	19.40
Operating and Maintenance Cost	.42	4.28
Capacity Loss Due to Scrubbers	.10	1.00
Minemouth Coal Cost (Powder River Basin Low Sulfur Coal)	.39	3.95
Transportation Cost	.80	8.11
	3.62	36.74

* Assuming average heat rate of 10,160 BTU/KWH

As you can see, the total cost of $ 3.62 per million BTU is considerably higher than the $ 1.79 cost for new gas suggested by the Administration. I would like to emphasize that the above-estimated costs do not include any provision for replacement capacity during the conversion period. These costs would be substantial; however, we have not attempted to quantify them because of the many uncertainties involved.

For comparison purposes, the following information should be of interest to you. Our actual 1976 cost for fossil fuel and operation and maintenance was $ 1.15 per million BTU (11.95 mills/kwh). Therefore, the net increase in cost compared to the coal conversion program would be $ 2.47 per million BTU, or 24.79 mills/kwh. The financial impact on our customers would be very significant. In 1976, our average revenue per residential customer was $ 308.56, or 30.5 mills/kwh. Adding the increase of 24.79 mills/kwh would raise the average residential customer's annual bill to about $ 560, an increase of over 80%. All these costs are in terms of 1976 usage and dollars and, of course, with inflation, the added cost at the time of completion of the conversion program would be even greater.

Practicability of Coal Conversion Program

Many technical and/or legal constraints make it impracticable to convert a number of our existing units to coal-firing. Included among these constraints are such factors as:

a. Lack of physical space for new boilers, coal storage, handling facilities, ash and sludge disposal areas. Some of our major generating stations are located in heavily populated metropolitan areas, and it would be literally impossible to acquire the necessary land, which we understand would require about 2,000 acres for a 1,000 MW plant.

b. Height limitations imposed by local, regional, state and/or federal regulations such as, proximity to commercial or private airports. Such limitations would preclude the possibility of constructing tall stacks (400 - 800 feet).

c. The lack of adequate manufacturing capability for boilers and associated equipment, which would be required if the proposed legislation were enacted.

d. The lack of adequate manufacturing capability for combustion turbines or other capacity, which would have to be constructed to provide replacement power for the existing facilities during the conversion period.

e. The problems associated with mining and transportation of the additional coal which would be required in the event of passage of such legislation. There is a serious question whether or not there are adequate mining and transportation facilities to accomodate coal units currently in the planning and/or construction period. Legislation authorizing the construction of coal slurry pipelines appears essential in order to supplement the capability of railroads for transporting coal.

The System's present plans call for substantial expenditures for electric production facilities during the period 1978 - 1985. The proposed legislation, if enacted, would approximately double these expenditures, making it impossible for our System to finance such a program when we are still burdened with financial difficulties brought about by factors beyond our control, such as inflation of recent years, the effects of inadequate rate relief, and higher fuel costs resulting from curtailments of firm contracts.

Summary

In summary, we are of the considered opinion that it is not feasible, technically or economically, to convert any of our existing gas or oil-fired boilers to permit burning coal. Conversion to coal-burning would involve (1) completely replacing the existing boilers with new boilers; (2) constructing new boilers remote from the existing boilers and reconnecting the steam lines to the new boilers; or (3) installing a coal gasification plant on the plant site and modifying the existing boilers to permit burning low BTU gas. None of these alternatives would be accomplished for a number of years because of the lead times involved in the design and construction of such facilities. The third option has not yet been proven as being viable for large scale, commercial application, with the degree of reliability required by the electric power industry. If we were forced to convert to coal-firing, the inevitable result, in our opinion, would be that electric service to our customers would be seriously jeopardized during the conversion period.

Alternative Approach

The estimated increased cost of \$ 2.47 per million BTU is equivalent to about \$ 15.40 per barrel of oil. Our average oil cost in 1976 was about \$ 11.40 per barrel; therefore, the incremental cost represents an increase of 135%. It appears to us that, in view of the above-described constraints and other major problems concerning the national energy situation, it would be much more appropriate and logical to use the \$ 15.40 per barrel equivalent for securing fuels through the use of more advanced technologies. It is possible that such a program could advance commercial development of such fuels which would be more compatible with our existing boilers.

Mr. MOFFETT. Mr. Moore, the gentleman from Louisiana.

Mr. MOORE. It is good to have somebody from my part of the country to explain our problems.

I would like to ask you, Mr. Mallory, since this is supposed to be a panel dealing with environmental issues. From my listening and reading of your statements, I don't think anybody debates that burning of gas is cleaner, environmentally, than coal.

I understand we can burn coal and we can use scrubbers and all that, but does anybody debate the fact I have just stated?

Mr. MALLORY. I don't see any dissenting view and I certainly don't.

Mr. MOORE. My question is, in my part of the country, we have all the practical problems of geting the coal and conversion of gas-fired burners. But we have another problem. I am looking at the charts prepared by EPA dealing with ambient air quality. It shows my part of the country, Louisiana, is in violation. Even with the emission trade-off program, which has just been put into effect in Louisiana this calendar year, we are arriving at great problems with it. Is it not true we will have an increase even with the scrubbers?

I think, Mr. Ayres, you mentioned a moment ago that the best we might hope for is 95 percent removal of our problems with scrubbers. We are, in fact, going to have an addition by virtue of converting to coal, to an existing problem we all have.

Mr. Tuerk.

Mr. TUERK. I would think there would be an increase in emissions, yes, sir.

Mr. MALLORY. That map is a nonattainment provision relating to oxidants, but I can tell you from having looked at others, the same thing applies to the Gulf Coast region.

Mr. TUERK. There is a difference between oxidants and SO_2 in which the violations seem to be localized. These are ACR maps and the whole areas. I think we just have a different situation when we come to particulate and SO_2, that it is quite possible to convert plants in a region that might have a violation.

Mr. AYRES. The burden of what we are saying, Congressman, is that conversions will cause problems in that area, but not all that area is as much in violation for the pollutants that will be emitted by coal burning as that map indicates because that is for oxidants rather than sulfur or nitrogen oxides, or particulate pollutants.

Mr. MOORE. What is the addition of oxidants?

Mr. TUERK. Hydrocarbons are emitted as part of the coal-burning process but it is a minor portion of the total emissions.

Mr. MALLORY. But if you are not in compliance it doesn't matter how small the addition is.

Mr. MOORE. The problem we are facing now, according to the State air quality commission, which is the State equivalent of EPA, is bringing in more industry. We are in a position now that we get into this exchange emission problem. We have to meet it, and we are being told we can't burn gas, which is clean burning and abundant. We have to bring coal in, it is swapping resources for one we don't have for one we have. It is a hard thing for us to be able to swallow. I would like for anybody to address themselves to the situation of the scrubbers. I had some dealing with this when I used to practice law, in the busines of saw mills. What is the problem today with the scrubbers in terms, at best, of what are we still letting go in the atmosphere and what do we keep out? I have heard of this thing called sludge when the scrubber is finished. Will somebody address themselves to what these problems are?

Mr. TUERK. We accept you as the neutral on this.

Mr. AYRES. That is a first.

The best estimate of the scrubber in use is something on the order of 95 percent. In practice, some of them are getting 95. The sludge problem is one which I think has been overrated. Not all types produce sludge, although most presently on-line do produce sludge. You are already dealing with another waste problem when you burn coal—fly ash—which is more troublesome. Indeed if the choice is between burning low sulfur western coal, or burning high sulfur eastern coal with a scrubber, you are probably talking about total waste if you use eastern coal with a scrubber. Western coal has a lot more ash in it than the eastern coal, as a general rule, although that is not true in every case.

Mr. MOORE. Let's start at this point. This comes from just burning the coal in the furnace?

Mr. AYRES. That is right. Ash disposal is a problem we have had for many years now. As long as we have been burning coal we have had that problem. I think the point to remember is that in terms of bulk the ash problem is as large or larger in most cases than the sludge problem, and in fact ash is a more troublesome chemical problem because it has a lot of the trace metals in it usually, whereas the scrubber sludge is relatively inert. The sulfur is captured chemically, so it does not leach out.

Mr. MOORE. I will be glad to yield to my colleagues on the other side of the aisle briefly.

Mr. BROWN. You get sulfur oxide from coal and a lot of particulate matter in the sludge or put the two together. We used to call them clinkers. You get nitrogen oxide from petroleum gasoline. What do you get from gas?

Mr. AYRES. The figures in my testimony show——

Mr. BROWN. Would you quantify it relatively? If you put coal at 100 percent, most polluting—and I know they different things——

Mr. AYRES. Take a look at page 5 of the testimony. You can see the emission factors in pounds per million Btu use from gas. If you compare that with coal, let's say, the present new source performance standard which is intended to be a fairly tight standard for coal, is 1.2 pounds per million Btu of SO_2. As you see, the gas emission factor is .0006 pounds. So that is a factor of about 2,000 times greater.

For particulates, I am not familiar with the number for the new performance standards.

Mr. TUERK. .1.

Mr. AYRES. .1. So there is a factor you can read, .01.

For nitrogen oxides we are suggesting that coal is about a 4 times increase over gas. If you scrub the sulfur oxides or use a better precipitator on the particulates, you can usually take some more of that out, but that gives you a rough idea.

Mr. MOORE. I would like to get back to the problem of the scrubbers. You were telling me there is a scrubber on the market that will not produce sludge or produce less sludge?

Mr. AYRES. There are a number of different chemical cycles which can be used to scrub. Several kinds which do not produce a sludge, because they recycle the reagent that is used to capture the sulfur, are at one stage or another of commercialization of development. I do not think it is fair to say any are commercial yet, although there is one process installed in a couple of powerplants.

The process that I think can be called commercial is the so-called throwaway limestone or lime process. I think it is fair to say, particularly if scrubbers are required by national policy, that we are going to see the development of perhaps several different kinds of regenerable scrubbers rather rapidly.

Mr. MOORE. How does that compare in cost with the existing scrubbers on the market?

Mr. AYRES. It is a little hard to tell because of the difference in the stage of development, but at this point the regenerable type is more expensive. When they reach similar states of development I do not think there would be any difference.

Mr. MOORE. The regenerable scrubber has a complete cleaning up; there is nothing left when you finish with its operations?

Mr. AYRES. It varies from process to process, but the ones that are being worked on are pretty much without any byproduct. You use the same reagent over and over a number of times. You may have to discard some of it, some of it is lost, but it is tiny by comparison.

Mr. MOORE. What is the available date of these scrubbers? Do you have any timeframe of when they will be available?

Mr. AYRES. I think the crucial determinant of that is national policy toward requiring scrubbers. I think if national policy is made clear that we are (a) going to go to coal and (b) we are going to have scrubbers, you are going to see fairly rapid development. The limestone scrubber has developed quite rapidly. It has reached the present stage in about 5 or 6 years and I think the last 2 or 3 years for limestone scrubbers have to be considered good first generation equipment. They will be improved in the next generation like anything else, but that has been a pretty rapid movement and I think we will see that with the others too if the law pushes that development.

Mr. MOORE. Mr. Mallory, do you have any comments?

Mr. MALLORY. I think one of our problems is that we are in total disagreement with Mr. Ayes and EPA on the reliability of scrubbers. Our own problem is that we do not feel it is appropriate, necessary, cost effective or anything to require scrubbers on low sulfur compliance Western coal, which is what the folks down our part of the country are trying to import, to take the place of the oil and gas that we have been using for boiler fuel, and is being taken away and shipped off to other places.

Our figures are that it adds probably $100 a kilowatt to the generating capacity cost of the plant. It is expensive. We are talking about pretty expensive plants, but those are expenses the ratepayers are going to have to pay for on top of the fuel costs that have gone up; and under this bill, on top of the cost of totally scrapping a plant with an existing economic life of 30 years. That does not make sense to us.

Mr. MOORE. What are your reliability quotations on the scrubbers?

Mr. MALLORY. I will have to attempt to get those for the record for you, Congressman.

Mr. MOORE. I would like to ask the record be held open to receive any quotations including source as to reliability of scrubbers.

Mr. MOFFETT. Yes, without objection.

[The following material was received for the record:]

WHY SCRUBBERS "WORK"--WHERE AND WHEN THEY DO

PEDCo - Environmental, Inc., under contract to the Environmental Protection Agency, prepares bi-monthly reports on the status of flue-gas desulfurization systems ("scrubbers") in the United States. The latest available report, entitled "Summary Report - Flue Gas Desulfurization Systems - November-December 1976," was issued by PEDCo on January 31, 1977. It lists 30 scrubbers as "Operational." Information on each of these 30, condensed from the report, is included in Table I.

By no stretch of the imagination can one conclude from Table I that scrubbers are an unqualified or universal success. On the contrary, it more reasonably could be concluded that flue-gas desulfurization is a failure or, at best, a technology in need of much further development.

While temporary operational problems must be expected during the startup of any new, large, complex facility, most scrubber installations have experienced continuing difficulties for several years. Many of the problems have not been solved despite expensive and persistent efforts, and only by devoting inordinate amounts of manpower to maintenance has it been possible to operate some units with a reasonable degree of reliability.

Quite simplistically, scrubber advocates discount all the practical problems and state cavalierly that scrubber technology has been adequately demonstrated (because EPA made that determination in August 1971, the courts have affirmed it, and Congress is reaffirming it). Thus, it appears that, first by administrative fiat, then by judicial fiat, and finally by legislative fiat research and development results have been predestined despite the physical facts--based on the philosophy that "technology forcing" is sound and necessary national policy.

Scrubber proponents do not attempt to justify--possibly because they cannot--universal application of scrubbers on the basis of air quality need; lacking any scientific foundation, they hide behind the theory that there <u>may</u> not be a health effects threshold and, therefore, it is necessary to reduce emissions of all pollutants to the minimum. Also, they religiously avoid any consideration of cost-benefit, although serious adverse economic costs, energy penalties, and environmental effects have been documented while benefits are illusory and conjectural.

Instead, with little supporting evidence, advocates glibly state that scrubbers work because "many" units are operational, under construction, or planned--the implication being that there is wide acceptance of desulfurization scrubbers by utility companies.

The fact is that, in almost every case, the utility's decision to apply a scrubber was under "gun-at-the head" pressure with no available alternative.

Typical of uniformed statements is the testimony by EPA Administrator Costle before the House Subcommittee on Health and the Environment on April 18; when asked his opinion on scrubber reliability, Mr. Costle replied that he had visited a scrubber installation in Wyoming and spoken to the operator, who expressed optimism about making the unit operable. According to the latest PEDCo report, there are no operational flue-gas desulfurization scrubbers or any power plants in Wyoming, nor even any under construction. Contracts have been awarded for three (Jim Bridger No. 4, to start up in Spetember 1979; Missouri Basin No. 1, April 1980; and Missouri Basin No. 2, October 1980) and at Missouri Basin No. 3, a scrubber is being "considered" for June 1983 startup. Mr. Costle probably had witnessed a scrubber that is used for control of particulates, which is a <u>physical</u> process quite dissimilar to, and considerably simpler than, the <u>chemical</u> process of flue-gas desulfurization, or he may have seen a small desulfurization unit that was installed on FMC Chemical Group's plant at Green River, Wyoming, and began operation in 1976. FMC, a vendor of desulfurization systems, hardly could be expected to speak adversely about its equipment.

Of the 30 units PEDCo lists as "operational," examination of the data in Table 2 shows that only a few qualify for that distinction. Where an installation truly is operational, one usually can attribute the "success" to one or more unique or unusual circumstances, and to ignoring of associated unsolved problems of sludge disposal, water pollution ("open loop"), inordinate cost and manpower requirements. Table II includes only those units in the PEDCo report which, in November and/or December 1976, had 90% or greater "reliability," "availability," or "operability" (see footnotes to Table I for definitions).

In summary, the history of scrubber operations has been erratic and very few successes have been experienced . It is patently wrong, although progress has been made, to conclude that flue-gas desulfurization has been adequately demonstrated. Many problems--related to economics, energy, and environment--remain to be solved. It is premature and risky to base decisions regarding national air pollution control policy on such unproven technology. At the very least, available data indicate that 90% SO_2 removal has not been accomplished when burning low-sulfur coal; this should be sufficient ground, in itself, for EPA to deny the petition by Sierra Club and two Indian tribes that new source performance standards be revised to require 90% removal of SO_2 from combustion gases.

TABLE I - "OPERATIONAL SCRUBBERS IN THE UNITED STATES"

OWNER	UNIT	RATING	COAL % SULFUR	PROCESS	STARTUP	EXPERIENCE 11/76	12/76
Arizona Public Service Co.	Cholla No. 1	115 mw	0.44-1.0	Limestone	10/73	99.7*	99.7*
Arizona Public Service Co.	Four Corners	160 mw	0.7	Lime	2/76	Test module, dis-assembled; no data given	
Central Illinois Light Co.	Duck Creek #1	100 mw	2.5-3.0	Limestone	9/76	Operated inter-mittently be-cause of mech-anical and chemical problems	
Commonwealth Edison Co.	Will Co. #1	167 mw	4.0	Limestone	2/72	Continuously plagued with problems, very low reliability at best	
Detroit Edison Co.	St. Clair #6	163 mw	3.7	Limestone	5/76	80**	51**
Duquesne Light Co.	Elrama	510 mw (Only 200 mw coupled to scrubber system)	1.0-2.8	Lime	10/75	Continuous prob-lems since start-up	
Duquesne Light Co.	Phillips	410 mw	1.0-2.8	Lime	7/73	Many problems, no reliability data given	
General Motors Corp.	Chevrolet Parma 1,2,3&4	32 mw	2.5	Double alkali	3/74	60***	22***
Gulf Power Co.	Scholz Nos. 1B & 2B	23 mw	5.0	Chiyoda Interna-tional	3/75	99* Prototype demon-stration unit	99*

- 2 -

OWNER	UNIT	RATING	COAL % SULFUR	PROCESS	STARTUP	EXPERIENCE 11/76	12/76
Kansas City Power & Light Co.	Hawthorne #3	140 mw	0.6-3.0	Limestone injection & wet scrubbing	11/72	Plagued with problems since startup. During most of period, operability factor has been zero, and the highest ever for Module A was 69 (Sept. '75) and 81% for Module B (Oct. '75). Virtually out of service since July '76; undergoing extensive conversion to lime scrubbing.	
Kansas City Power & Light Co.	Hawthorne #4	100 mw	0.6-3.0	Limestone injection & wet scrubbing	8/72	46* (Note for Hawthorne #3 applies to #4 also)	--
Kansas City Power & Light Co.	LaCygne #1	820 mw (Output reduced to 700 mw because of scrubber)	5.0	Limestone	2/73	94* Consists of 7 modules, one of which must be cleaned each night on a rotational basis, requiring 30-36 man hours. Plagued with problems since startup; additional modifications planned	90*

OWNER	UNIT	RATING	COAL % SULFUR	PROCESS	STARTUP	RELIABILITY* 11/76	12/76
Kansas Power & Light Co.	Lawrence #4	125 mw	0.5	Limestone injection & wet scrubbing	12/68	Numerous and continuous problems switched to low-sulfur Wyoming coal.	
Kansas Power & Light Co.	Lawrence #5	400 mw	0.5	Ditto	11/71	Ditto	
Kentucky Utilities	Green River 1 & 2	64 mw	3.8	Lime	9/75	98*	87*
Key West Utilities Board	Stock Island	37 mw	2.4(Oil)	Limestone	10/72	Shut down in Jan. '75, still out of service; many troubles	
Louisville Gas & Electric Co.	Cane Run #4	178 mw	3.5-4.0	Lime	8/76	95*** Mechanical problems hinder operation at full capacity; final testing incomplete.	90***
Louisville Gas & Electric Co.	Paddys Run #6	65 mw	3.5-4.0	Lime	4/73	99***	99***
Montana Power Co.	Colstrip #1	360 mw	0.8	Lime/Alkaline fly-ash scrubbing	10/75	No data given	
Montana Power Co.	Colstrip #2	360 mw	0.8	Ditto	7/76	No data given	
Nevada Power Co.	Reid Gardner #1	125 mw	0.5-1.0	Sodium carbonate	4/74	84*	92*
Nevada Power Co.	Reid Gardner #2	125 mw	0.5-1.0	Sodium carbonate	4/74	51*	Out of service for re-

OWNER	UNIT	RATING	COAL % SULFUR	PROCESS	STARTUP	RELIABILITY* 11/76	12/76
Nevada Power Co.	Reid Gardner #3	125 mw	0.5-1.0	Sodium carbonate	7/76	29*	99*
Northern States Power Co.	Sherburne Co. Sta. #1	710 mw	0.8	Limestone	3/76	93** Crew of 70 people required to maintain scrubber operations.	95**
Pennsylvania Power Co.	Bruce Mansfield #1	835 mw	4.7	Lime	4/76	"The availability index value for the entire scrubbing system has been in the mid 90 percent range since commercial startup." (No information for the Nov.-Dec. 1976 period)	
Philadelphia Electric Co.	Eddystone #1A	120 mw	2.5	Magnesium oxide	9/75	Numerous problems not operated since Feb. 1976	
Public Service Co. of Colorado	Valmont #5	50 mw	0.72	Limestone	10/74	Operated for particulate removal only since 9/75.	
U.S. Air Force	Rickenbacker Air Force Base	20 mw	3.6	Lime	3/76	No data given.	
Tennessee Valley Authority	Shawnee #10A	10 mw	2.9	Lime/limestone	4/72	Prototype experimental unit; no data given	
Tennessee Valley Authority	Shawnee #10B	10 mw	2.9	Ditto	4/72	Ditto	

*Reliability, expressed as a percentage, is the hours the scrubber operated divided by the hours the scrubber was called on to operate.

**Availability, expressed as a percentage, is the hours the scrubber was available for operation (whether operated or not) divided by the hours in the period.

***Operability, expressed as a percentage, is the hours the scrubber operated divided by the hours the boiler operated.

TABLE II - SCRUBBER UNITS WITH REPORTED
90% "RELIABILITY," "AVAILABILITY," OR "OPERABILITY"

Cholla No. 1 is a relatively small (115 mw) unit on a power plant burning low-sulfur (0.4-1.0%) coal; the SO_2 removal efficiency is only 58.5%; "very high quality grade" limestone is available; unstabilized sludge is disposed in an unlined pond; "open loop" operation (since evaporation exceeds rainfall, surface water runoff is not a problem, but there is possible groundwater contamination from leachate); operating cost is 2.2 mills/kwh.

Scholz Nos. 1B & 2B A very small (23 mw) pilot plant "for testing and process demonstration on a coal-fired application (of a system)...used in Japan exclusively on oil-fired and gas-fired boilers, and tail gas from Claus units"; unstabilized sludge is disposed in a dry gypsum pond; capital cost $130/kw; "open loop" water operation, waste water discharge is a problem; the system has had its share of breakdowns, and the last two report months of 99% reliability were preceded by erratic and often low operability.

LaCygne No. 1 "has been plagued with numerous problems since the first trial operation on December 26, 1972"; unstabilized sludge is disposed in an unlined pond; "open loop" water operation; one of the seven modules must be cleaned each night, requiring 30 to 36 man-hours; system has been derated from 820 to 700 mw (15% energy penalty) because of scrubber limitations; an eighth module is being installed "to improve system mechanical efficiency and decrease operating expenses"; SO_2 removal efficiency is 76%.

Green River Units 1 and 2. A small (64 mw) unit; stabilized sludge is disposed in an unlined pond; "open loop" water operation; guaranteed 80% SO_2 removal efficiency, but actual efficiency not reported; operating cost 2.0 mills/kwh.

Cane Run No. 4 uses carbide lime, a waste by-product from a nearly acetylene manufacturing plant, which is not generally available for scrubber operations; stabilized sludge is disposed in an unlined pond; SO_2 removal efficiency of 90% guaranteed, but final acceptance tests not completed.

Paddys Run No. 6 is a small (65 mw) unit, which also uses locally available carbide lime waste by-product; unstabilized sludge is disposed in an unlined pond; PEDCo reports that water make-up is both "open loop" and "the unit operates on a closed-loop mode"; this is a peak-load plant, which is operated only infrequently, so scrubber utilization is very low.

Reid Gardner Nos. 1,2 and 3 are relatively small (125 mw) units on plants buurning low-sulfur (0.5-1.0%) coal; unstablized sludge is disposed in unlined ponds, and overflow is pumped to a larger pond for evaporation; SO_2 removal efficiency is 85%.

Sherburne County Station No.1 is a plant burning low-sulfur (0.8%) Montana coal, and the scrubber was guaranteed at only 50% SO_2 removal efficiency; unstabilized sludge is disposed in a lined pond; "open loop" water operation; a crew of 70 is required to maintain scrubber operations; three or four of the 12 modules are taken out of service and cleaned each night.

Bruce Mansfield No. 1 appears, from the PEDCo report, to be the only large scrubber on a high-sulfur (4.7%) coal-burning unit that is operating reliably; sludge is stabilized and disposed in a dammed ravine seven miles from the plant; "closed loop" water operation; capital cost $133/kw, operating cost 2.7 mills/kwh.

The other 19 "operational" scrubbers listed by PEDCo are either prototype experimental units, have experienced so many operational problems that their low reliability renders questionable the "operational" classification, insufficient data are given to evaluate their performance, the units have been abandoned, or operation has been switched to particulate removal only.

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April 20, 1977

Enclosed is a copy of the January-February-March report on the Status of Flue Gas Desulfurization Systems in the United States. This report is prepared every other month by PEDCo Environmental, Inc., under a contract to the Industrial Environmental Research Laboratory/RTP and the Division of Stationary Source Enforcement of the U.S. Environmental Protection Agency. Table I, listed below, summarizes the current status of these systems.

Table I

NUMBER AND TOTAL MW OF FGD SYSTEMS

Status	No. of units	MW
Operational	24	5,997
Under construction	33	13,918
Planning		
Contract awarded	18	9,072
Letter of intent	3	865
Requesting/evaluating bids	9	5,492
Considering only FGD systems	32	14,346
TOTAL	119	49,690

Table II gives the categorized breakdown for FGD units, comparing the March report totals with those of the December report.

Table III summarizes the individual units that changed status during the report period.

BRANCH OFFICES

CHESTER TOWERS

Crown Center
Kansas City, Mo.

Professional Village
Chapel Hill, N.C.

96-231 O - 77 - 34

Table II

NUMBER AND TOTAL MW OF FGD SYSTEMS

MARCH REPORT PERIOD VERSUS DECEMBER REPORT PERIOD

Status	January-February-March 1977		November-December 1976	
	No. of units	MW	No. of units	MW
Operational	24	5,997	30	6,476
Under construction	33	13,918	31	13,309
Planning	62	29,775	63	29,399
Total	119	49,690	124	49,184

As shown in Table II, the number of operating units has decreased by six units. This resulted from the following: (1) two units are not properly classified as utility applications and are being transferred to a new summary report covering all non-utility FGD applications. These units are the Chevrolet Parma Steam Plant of the General Motors Company and Rickenbacker Air Force Base; (2) five units have been terminated or shutdown indefintely. These units are: Four Corners No. 5A of the Arizona Public Servie Co., St. Clair No. 6 of the Detroit Edison Co., Lawrence No. 5 of the Kansas Power and Light Co., Stock Island of Key West Utility Board, and Valmont No. 5 of the Public Service Company of Colorado; (3) one unit has been added to the operational category. This unit is Conesville No. 5 of the Columbus and Southern Ohio Electric Co. Several new units are scheduled to be placed in service during the upcoming report period, raising the current operational totals.

The performance of the operating systems is summarized in Table IV. Other activity highlights during the months of January, February, and March are outlined below:

Arizona Public Service reported the following items in connection with the utility's FGD installations:

° Cholla No. 1 remained in service throughout the report period. The average system reliability index values for the months of January and February were 83 percent and 99 percent, respectively. Average sulfur dioxide inlet and outlet concentrations to the scrubber plant were 350 and 175 ppm, respectively.

- Construction of Cholla No. 2 is still in progress and on schedule. Start-up is scheduled for June 1978.

- The experimental horizontal module test program at the Four Corners Plant has been permanently terminated and the module dismantled.

Basin Electric Power Cooperative provided some additional information regarding the nature of the emission control strategies for their Missouri Basin Station located in Wheatland, Wyoming. As was announced during the previous report period, the contract for the SO_2 scrubber plants planned for Units 1 and 2 has been awarded to Research-Cottrell. The contract, which will exceed $35 million, includes the design and erection of two double-loop (separate recirculation loops) wet limestone scrubbing systems. Units 1 and 2 will fire lignite having an average heating value of 8000 Btu/lb and ash and sulfur contents of 7 and 0.8 percent, respectively. Primary particulate control will be provided by ESP's installed upstream of the scrubber plants. Commercial operation dates for these two 550-MW power units are April and October of 1980, respectively. The utility has also reported that wet scrubbing strategies for SO_2 removal will be employed for two 450-MW lignite-fired boilers scheduled for operation at their Antelope Valley Station in 1981 and 1983, respectively.

Brazos Electric Power Cooperative reported that the design of the emission control system for the Atacosa McMullen No. 1 unit is proceeding. Babcock and Wilcox has the contract for the design and installation of this entire new unit, including the radiant lignite-fired boiler, electrostatic precipitators, sulfur dioxide absorption modules, and thickening equipment. The current schedule of events calls for scrubber plant construction to commence in early 1978. The boiler and scrubber plant start-up dates are tentatively scheduled for January and December of 1979, respectively.

Central Illinois Light Company reported that resumption of operations of the Duck Creek No. 1 scrubber module occurred in mid-March following a 2-month shutdown for boiler and scrubber overhaul and modifications. The 100-MW venturi-sorber scrubber module, supplied by Riley Stoker/Environeering, was put back in service during the middle part of March on an experimental basis to test the modifications made during the January-February shutdown. The module remained in service on a nearly continuous basis throughout the remainder of the month, with the exception of a few minor boiler-related outages. This module is the first of four scrubber modules, the remaining three of which will be brought on line in August 1978. The scrubber plant is designed to treat the flue gas resulting from the combustion of high-sulfur Illinois coal in the 400-MW boiler.

Colorado-UTE Electric Assn. reported that they are now requesting and evaluating bid specifications for calcium-based scrubbing systems for five 450-MW coal-fired units now under construction at their Craig Station. Bid evaluation is being conducted by the scrubbing project A-E firm, Stearns-Roger.

Columbus and Southern Ohio Electric reported that the B-side TCA module on Conesville No. 5 became available for commercial service on January 27, 1977. Actual start-up occurred on February 13 and the module remained in service a total of 286 hours throughout the duration of the month. Problems encountered during the period included mechanical failures due to the severe cold weather conditions and design-related problems. The longest period of continuous operation during February was 132 hours. The unit's boiler and electrostatic precipitator remained in service without incident. The A-side scrubbing train has been replaced by a new TCA tower. This module is expected to be in service by May 1, 1977.

Commonwealth Edison reported the following items in connection with the utility's FGD installations:

° The utility received a construction permit on February 18, 1977, and installation of the scrubber plant on Powerton No. 51 has commenced. Currently, work is proceeding with excavation and backfill, and some structural steel erection.

° Experimental scrubber operations at the Will County Station continued during the month of January. The current mode of operation has the scrubbing trains seeing service on a rotational basis, i.e. - one module in the flue gas stream while the other is out. Low-sulfur western coal was burned in the boiler during the month and sludge stabilization practices are continuing at the station.

° The utility also announced that SO_2 operations at the Will County demonstration facility will terminate on July 1, 1977. The scrubbing plant will remain in service, operating primarily in the particulate-removal mode, treating flue gases resulting from the combustion of low-sulfur western coal.

The Detroit Edison Company (DECo) reported that the St. Clair No. 6 internal SO_2 scrubber demonstration program was completed on December 31, 1976. At this point the scrubber plant was then shut down and sulfur dioxide-removal operations were terminated. Currently, the utility plans to keep the scrubber plant out of service for modifications until mid-June 1977. Resumption of scrubbing operations will occur at this point in the primary particulate-removal mode, treating one-half of the boiler flue gas resulting from the combustion of low-sulfur western coal. DECo plans to continue this mode of scrubber plant operations for a one-to-three year period.

Duquesne Light reported the following items in connection with the utility's FGD installations:

° The Elrama Station continued operations with flue gas from two boilers being discharged into the five module-single-stage scrubber plant. During the period, the IUCS sludge stabilization unit continued to operate, with the fixated material being hauled away to an off-site landfill. IUCS has been awarded a 10-year contract for the installation and operation of a permanent fixation facility. In addition, a thiosorbic lime scrubbing test was conducted during the month of March. The installation of additional thickeners and lime feeders is still in progress. This equipment is necessary for the initiation of full-compliance plant operations by the early part of 1978.

° All six boilers at the Phillips Station have been coupled into the scrubber plant. Operations during the period continued with a number of the boilers down for overhaul and repair. The interim IUCS stabilization unit remained in service, separating out water only (no addition of fixation additive as of yet). IUCS has been awarded a 10-year contract for the installation and operation of permanent fixation facility. Currently, installation of the additional thickeners and lime feeders is still in progress. Full compliance plant operation is scheduled for December 1977.

The Gulf Power Company, Southern Company Services, Incorporated, and Chiyoda International Corporation have jointly announced the successful conclusion of the CT-101 FGD demonstration program at the Scholz Steam Plant. Prototype scrubber plant operations were concluded after more than two years of operation, intensive testing and system evaluation.

During the reporting months, the total scrubber outage time was 0.33 hours, giving essentially 99+ percent values for all performance indices. The CT-101 prototype was shut down at 10 a.m., March 22, 1977, to allow Chiyoda to pursue the development of a new concept in FGD technology. A committment for the demonstration of this new process has not yet been made.

The Kansas City Power and Light Co. reported the following items concerning the utility's FGD installations:

° The conversion from limestone injection and tail-end scrubbing to a wet lime tail-end scrubbing process was completed at the Hawthorn Station during the period. The system installed on Unit No. 3 became available for service on February 7. The system operability index values for the months of February and March were high. Testing for compliance with particulate emissions regulations indicated the system was reducing the particulate loading well below the 0.17 lb/MM Btu heat input. The scrubber plant installed on the No. 4 Unit became available for service on January 1 and remained in service during the months of January, February, and March. Testing for compliance with particulate emissions regulations indicated the system was meeting the 0.17 lb/MM Btu code.

° LaCygne reported scrubber plant availability index values of 93, 93 and 92 percent for the months of January, February, and March, respectively. The utility is continuing experimentation and modifications in the areas of reheat and mist elimination. The installation of the 8th module has been completed and will be placed in service in April. The installation of an additional settling pond is now in progress.

Kansas Power and Light Co. reported the following items concerning FGD at the utility's Jeffrey and Lawrence Power Stations:

° Construction is progressing on schedule at the Jeffrey Power Generating Station, Units No. 1 and 2. These two units will function as base-load units, each having a generating capacity of 680 MW. Each unit will fire 250 T/hr of low-sulfur coal, with a sulfur content of 0.3 percent and a heating value of 8000 Btu/lb. Jeffrey Units No. 1 and 2 are scheduled for start-up in June 1978, and June 1979, respectively.

- The new rod section and spray tower absorber scrubber plant installed on Lawrence No. 4 commenced commercial operations during the first part of January. This new system, which is based exclusively on tail-end wet limestone scrubbing, replaced the original limestone injection and tail-end scrubber plant. During the period KP & L reported that the system remained in service without any scrubber system downtime.

- Combustion Engineering is also installing a new fully-automated scrubber plant on the 400-MW No. 5 Unit at the Lawrence Energy Center. This wet limestone scrubbing system, which replaces the original limestone injection and tail-end scrubbing plant, consists of two large spray towers, each capable of treating 50 percent of the boiler flue gas. Currently, construction on the foundation and structural steel erection are in progress.

Kentucky Utilities reported that the Green River FGD system was taken out of the gas path during the middle part of February to repair the lining in the scrubber stack. The scrubber plant will remain out of service until May 1 for completion of repairs. The system's availability, operability, reliability, and utilization index values for the month of January were 94, 94, 94, and 94 percent, respectively.

The scrubber plant installed at the Stock Island Plant of the Key West Utility Board has been removed from the operational category of the summary report. This was done because of the system's previous sporadic operating history and questionable future viability.

Louisville Gas and Electric reported the following items in regards to the utility's FGD installations:

- The Cane Run No. 4 scrubber plant did not operate for approximately a two month period, from mid-January to mid-March, because the frozen river conditions caused a cessation of lime supply shipments. The system was placed back in service on March 14 and demonstrated an operability index value of 83 percent during the remainder of the month.

- Construction of the scrubber plants for Mill Creek Nos. 3 and 4 is still in progress. Approximately 50 percent of the construction for the No. 3 system has been completed. Foundation work on the No. 4 system is now underway.

° The EPA-subsidized scrubber/sludge characterization study was restarted in mid-March, utilizing a high-calcium, virgin lime absorbent. Operations proceeded during the last hlaf of the month on a continuous basis with the exception of a one hour of down time.

Nevada Power reported the following items regarding the utility's FGD installations:

° The Reid Gardner No. 1 scrubber plant remained out of service from January 22 onward because of a rubber lining replacement in the separator of the scrubber module.

° Following a maintenance outage to the No. 2 unit, the scrubber plant was placed back in service and operated during the months of February and March. The system's availability index values for these two months were 93 and 92 percent, respectively.

° The Reid Gardner No. 3 scrubber plant remained in service throughout the report period, logging system availability index values of 98, 81, and 44 percent, respectively. Outage time during the month of March was caused primarily by a series of minor mechanical-related problems.

Atomics International has been awarded a contract for the design and supply of an aqueous carbonate scrubbing system which generates an elemental sulfur by-product. The installation site is Niagara Mohawk's C.R. Huntley Station, Unit No. 66, a 100-MW coal-fired application. This regenerable demonstration program is being funded by the Empire State Electric Energy Research Corporation and the U.S. Environmental Protection Agency. Start-up of this demonstration unit is scheduled for June 1978.

Northern States Power reported the following items concerning the utility's FGD activity:

° Sherburne No. 1 remained in service throughout the period achieving total system availability index values of 90, 91, and 95 percent for the months of Janaury, February, and March, respectively. Modification of the duplex strainer system to an in-tank strainer design was completed during the period. The utility is currently planning to conduct a full-load evaluation study, analyzing system operation on 10 scrubber modules in contrast to the designed 11 modules.

- Construction on Sherburne No. 2 has been completed and start-up operations commenced on April 1. Initial operations have been satisfactory. No major problems have been encountered.
- The utility is now requesting and evaluating bid specifications for FGD systems for both the No. 3 and No. 4 units at the Sherburne County Generating Station. Each of these Babcock and Wilcox boilers will have a nominal 860-MW rating, and will fire a subbituminous coal with a heating value of 8300 Btu/lb and sulfur and ash contents of 0.8 and 9.0, respectively. Particulate and SO_2 emissions for each unit will be controlled by a two-stage scrubbing design, and the design specifications will call for NSPS performance (though particulate control will be more complete, in order to comply with opacity requirements). Units No. 3 and No. 4 are schedule for start-up in May 1981, and May 1983, respectively.

Northern Indiana Public Service reported that modification and overhaul work to correct the No. 11 boiler unavailability at the Mitchell Station is nearing completion. Boiler restart has been tentatively scheduled for May 1, 1977. During the boiler outage period portions of the demonstration Wellman-Lord scrubber plant were removed to prevent damage resulting from the severe winter weather conditions. Recoupling and recalibration of the removal equipment is expected to be completed by May 1977. Start-up of the regenerable FGD system is scheduled for early May 1977.

Philadelphia Electric Company reported that the May 1977 start-up date for resumption of sulfur dioxide removal operations is still in effect. Relocation of the magnesium oxide regeneration facilities should be completed by May. The three parallel particulate scrubber modules were returned to service during the latter part of March.

The experimental sulfur dioxide scrubbing operations conducted at the Valmont Station of the Public Service Company of Colorado have not been resumed. Any further efforts in this regard will be dependent upon the outcome of regulatory agency hearings. This system has been removed from the operational category of the report because of it's current inoperative sulfur dioxide-removal status. The scrubber plant is continuing to operate in the particulate-removal mode.

The Public Service Company of New Mexico reported that the construction of the regenerable Wellman-Lord scrubber plants for San Juan Unit Nos. 1 and 2 is approximately one-third complete. Both FGD systems are scheduled to be placed in service in November 1977. The utility also reported that a letter-of-intent has been signed with Davy Powergas for the design and installation of one Wellman-Lord module for San Juan No. 3. This single absorber will enable the No. 3 unit to meet NSPS strategy for the balance of flue gas from the No. 3 unit has not yet been selected.

Springfield City Utilities reported that the scrubber plant for the 200-MW Southwest No. 1 Unit in Springfield, Missouri, did not start-up as scheduled in 1976. The delay has been caused primarily by computer programming problems (for scrubber plant control) and electrical wiring problems. Scheduled start-up date is now projected for early April 1977.

The Bechtel Corporation reported that experimental work is continuing at the Shawnee TVA/EPA Alkali Scrubbing Test Facility. Testing during the period included forced-oxidation studies, fly ash-free limestone scrubbing, and intensive flue gas characterization testing with limestone slurry scrubbing.

Southern Illinois Power Co-op reported that the construction of the power system is in progress for the coal-fired 184-MW rated No. 4 Unit at the Marion Station. Currently, foundation work has been completed and installation of the electrostatic precipitator is underway. The scrubber plant will consist of two Babcock and Wilcox spray tower absorbers, mist eliminators, thickener, control system, and sludge dewatering and disposal facilities. The scrubbing wastes will be stabilized with fly ash and disposed in an off-site landfill.

Texas Power and Light reported that bid specification request and evaluation is now in progress for a scrubbing system scheduled for Sandow No. 4, a lignite-fired 545-MW unit scheduled for start-up in July 1980. In addition, the utility reported that a firm decision concerning the sulfur dioxide-removal strategies for two new units at the Twin Oaks Stations has not yet been finalized.

Texas Utilities reported that the following start-up dates are now in effect for their units at Martin Lake and Monticello.

- Martin Lake No. 1: October 1977
- Martin Lake No. 2: First quarter 1978
- Martin Lake No. 3: December 1978
- Martin Lake No. 4: Fourth quarter 1982
- Monticello No. 3: First quarter 1978.

In addition, the utility reported that a new 750-MW lignite-fired power-generating unit is in the early planning stages for the Forest Grove Station in Athens, Texas. The tentative scheduled start-up date is late in 1981.

TABLE III

SUMMARY OF CHANGES

FGD STATUS REPORT, JANUARY-FEBRUARY-MARCH 1977

FGD status report	Operational		Under construction		Contract awarded		Letter of intent		Requesting/evaluating bids		Considering FGD		Total	
	No.	MW	No.	MW	No.	MW	No.	MW	No.	MW	No.	MW	No.	MW
12/31/76	30	6,476	31	13,309	20	9,981	2	365	4	2,327	37	16,726	124	49,184
Arizona Public Service														
Four Corners No. 5A	-1	160												
Colorado UTE Elec. Ass'n.														
Craig No. 1									+1	450	-1	450		
Craig No. 2									+1	450	-1	450		
Columbus & So. Ohio Electric														
Conesville No. 5	+1	400	-1	400										
Conesville No. 6			+1	400	-1	400								
Commonwealth Edison														
Powerton No. 51			+1	425	-1	425								
Detroit Edison														
St. Clair No. 6	-1	180												
General Motors														
Chevrolet-Parma	-1	32												
Kansas Power & Light														
Lawrence No. 5	-1	400												
Key West Utilities Board														
Stock Island	-1	37												
Niagara Mohawk Power Co-op														
Charles Huntley No. 6					+1	100					-1	100		
Northern States Power Co.														
Sherburne No. 3									+1	860	-1	860		
Sherburne No. 4									+1	860	-1	860		
Public Service Co. of Colorado														
Valmont No. 5	-1	50												
Public Service Co. of New Mexico														
San Juan No. 3							+1	500			-1	500		
Rickenbacker AFB														
Rickenbacker	-1	20												
Southern California Edison														
Mohave No. 1B											-1	620		
Mohave No. 2											-1	790		
Southern Illinois Power Coop.														
Marion No. 4			+1	184	-1	184								
Texas Power & Light														
Sandow No. 4									+1	545				
Twin Oaks No. 1											+1	750		
Twin Oaks No. 2											+1	750		
Texas Utilities														
Forest Grove No. 1											+1	750		
3/31/77	24	5,997	33	13,916	18	9,072	3	865	8	5,492	32	14,366	119	49,690

TABLE IV. PERFORMANCE OF OPERATIONAL UNITS DURING THE REPORT PERIOD

Plant	FGD system design capacity	FGD unit on-line during period*	No information for this period	Shut down throughout period	FGD system avail-ability (%)**			FGD system opera-bility (%)**			FGD system reliability (%)**			FGD system utilization (%)**		
					Jan.	Feb.	Mar.	Jan.	Feb.	Mar.	Jan.	Feb.	Mar.	Jan.	Feb.	Mar.
Cholla 1	115	115									82.5	99				
Duck Creek 1A	100	100														
Conesville 5	400	200		200												
Will County 1	167	167			56			50			50			49		
Elrama	510	200		310												
Phillips	410	410														
Scholz - Chiyoda	23	23			100	100	100	100	100		100	100	100	100	100	
Hawthorn 3	140	140						0	79	92						
Hawthorn 4	100	100						80	65	90						
La Cygne	820	820			93	93	92									
Lawrence 4	125	125														
Green River 1 & 2	64	64			94	36	0	94	91		94	91		94	36	0
Cane Run	178	178			0	0	48			83			83	0	0	48
Paddys Run	65	65			0	0				99			99	0	0	
Colstrip 1	360		360													
Colstrip 2	360		360													
Reid Gardner 1	125	125			72	0	0	68	0	0	87	0	0	59	0	0
Reid Gardner 2	125	125			0	93	92	0	75	86	0	88	97	0	56	76
Reid Gardner 3	125	125			98	81	44	98	74	51	98	72	52	91	63	44
Sherburne 1	710	710			90	91	95									
Bruce Mansfield 1	835	835														
Eddystone 1A	120			120												
Shawnee 10A	10	10														
Shawnee 10B	10	10														
Total (24)	5,997	4,647	720	630												

* This category includes the flue gas capacity being handled by the FGD system at least part of the time during the report period.

** The percent figures listed are average values for all the system scrubbing trains during the period in question.

Mr. MOFFETT. The Chair recognizes the gentleman from Indiana.

Mr. SHARP. I am sorry I had to be out of the room for a few minutes. I hope my questions won't be duplicative.

I wanted to ask Mr. Tuerk if EPA is taking any action that he is aware of regarding Dr. Galloway's recommendation of having a network monitoring chemistry precipitation.

Mr. TUERK. EPA generally agrees very much with Dr. Galloway's recommendation. We think such a network is desirable. There have been consultations, NOAA and other agencies, on this. I cannot give you a status report on where it is right now.

Mr. SHARP. Would it be possible to give us that in a letter to this committee?

Mr. TUERK. It certainly would.

Mr. SHARP. We are closing out the record in 7 days because of the speed with which we are trying to consider all of this. I think that may be a very significant question and we would like to have that information. It might be useful to others as well.

Mr. SHARP. I wanted to ask Mr. Ayres if I understood properly his testimony. I think you are recommending that we set up a timetable, if we set up any table at all, that does not press for conversion of existing plants until things like fluidized bed are readily available; is that what you are suggesting?

Mr. AYRES. I think it is a little more complex than that. We feel that powerplants, that the technology for controlling them substantially, is available—that is, the scrubbing technology. So we do not feel that the timetable needs to be as long for those conversions in the areas where it makes environmental and economic sense to make them.

My recommendation as to delaying really goes to industrial boilers where the scrubbing technology appears at this point not to be a proven means of control, and therefore we need time to develop fluidized bed, or whatever techniques to make that kind of conversion environmentally less destructive. Most of those kinds of boilers are located in the midst of population centers, emitting through short stacks,and their effects will be felt in the immediate vicinity of the conversion. So it is crucial, we think, to control them as much as possible.

Mr. SHARP. Have questions been asked about the fluidized-bed system and emission control?

Mr. MOFFETT. Yes.

Mr. SHARP. I wondered if there was any comment here. Let me ask the OSHA people. The suggestion is they are not sure whether this new system of fluidized bed would itself have major pollution problems. I wonder if any of you gentlemen have knowledge or experience in how quickly we think that technology will be available; and secondly, whether it is going to represent major problems that we ought to be aware of before we commit ourselves on the notion somehow that is going to be available.

Mr. AYRES. I do not, frankly. I need to know more about those technologies, and I have heard questions and I think those need to be answered before we rely on them. Maybe some of the EPA people know more about it.

Mr. TUERK. Most of what we are aware of on fluidized bed has been on a very small-scale demonstration. Some work is ongoing to bring them up to larger size. I think the kinds of estimates that we have been generally seeing on the availability of fluidized bed and industrial application is somewhere about 5 years off.

Mr. SHARP. That is 5 years before you think they can be in a sense mass produced?

Mr. TUERK. Before it has been demonstrated under operating conditions of sufficient size that there is engineering acceptance of its availability. With respect to powerplants, we do not think fluidized bed is the solution there any time before the 1990s.

Mr. SHARP. There you think we can rely on the scrubber technology, or are there other technologies?

Mr. TUERK. The scrubber technology is what we think is currently available. We think it has a reliability and efficiency in the 90-percent range. We see improvements in scrubber technology to put more emphasis on regenerable-type systems which give you a salable byproduct and reduce waste.

We think there are other developments which at the present economically price energy much too high, but in the areas of coal gasification there are other things which technology holds over the next decade.

Mr. SHARP. Thank you, Mr. Chairman.

Mr. MOFFETT. The Chair recognizes counsel.

Mr. FINNEGAN. We understand the chairman has written about the use of oil and gas in the incinerating of sludge. Could you provide for the hearings tomorrow the amount of oil and gas used for that purpose?

Mr. TUERK. I think we can do that.

[The following material was received for the record:]

The present annual fuel consumption of the incinerators is 4696 million cubic feet of gas, 15,358 thousand gallons of oil and 2458 thousand KWH of electricity. The known additional future fuel consumption for incinerators is projected to be 1368 million cubic feet of gas, 24,684 thousand gallons of oil and 2,612 thousand KWH of electricity on an annual basis.

Mr. FINNEGAN. Lastly, Mr. Ayres raised a question about NEPA's statement in connection with the legislation. Could you have the witnesses tell us the status of that NEPA statement? Is one prepared in connection with the legislation?

Mr. VLCEK. You stated here NEPA statements are required by law and then you said, talking about 102(2) and the case law thereunder, which indicates when you submit a legislative proposal you are required to accompany a NEPA statement; is that correct?

Mr. AYRES. Yes.

Mr. VLCEK. You said you thought the administration was undertaking analysis that would provide the same information. Where was this supposed analysis taking place and what happened to it, do you know?

Mr. AYRES. We had expected to see from EPA an analysis of the emission increases that could be expected from the program. I did not know of anyone who was, I thought, undertaking analysis of the relative economics of converting powerplants or fuel-burning installations of certain ages as compared with the cost of other ways of reducing imports of oil. That, I think, is an important question too, which should be addressed in an impact statement. We had some indication from the EPA people further down in the bureaucracy a month or so ago that analyses were underway. I judge from yesterday's testimony—I haven't read Administrator Costle's testimony, but I judge from that some more analysis than we had seen ——

Mr. VLCEK. Whose testimony?

Mr. AYRES. Mr. Costle testified yesterday before the Senate on this program. I have not seen that testimony. I was not there but I gather some figures were given as to emission increases. I think the development of those figures has gone much more slowly than we were given to believe it was going to go.

Mr. VLCEK. Have you received any indications from the administration as to the progress of this analysis since your initial contacts with them?

Mr. AYRES. We were told a couple times it was underway and would be available in a week or two weeks and did not see it.

Mr. VLCEK. Thank you very much, Mr. Chairman.

Mr. MOFFETT. The Chair would like to express the appreciation of the subcommittee for your testimony. We thank you. You made a very important contribution.

The subcommittee will stand in recess until 2 p.m.

[Whereupon, at 1 p.m., the subcommittee recessed, to reconvene at 2 p.m. the same day.]

AFTER RECESS

[The subcommittee reconvened at 2 p.m., Hon. Anthony Toby Moffett presiding.]

Mr. MOFFETT. The subcommittee will come to order, please.

This afternoon we continue our hearings on H.R. 6831, the National Energy Act, specifically on coal conversion. Our first panel this afternon will focus on transportation issues. The Chair would request the panel to come forward and be seated at the witness table.

Mr. William Dempsey, Dr. Zandi, Mr. Pat Jennings, and Mr. Joseph Bobzien.

Dr. Zandie, would you like to begin. We would request that, if possible, each of the witnesses paraphrase his testimony since we are limited with regard to time. Without objection, your full statements will be inserted in the record.

STATEMENTS OF DR. IRAJ ZANDI, PROFESSOR OF RESOURCES & ENVIRONMENTAL ENGINEERING, UNIVERSITY OF PENNSYLVANIA; W. PAT JENNINGS, PRESIDENT, SLURRY TRANSPORT ASSOCIATION; WILLIAM H. DEMPSEY, PRESIDENT, ASSOCIATION OF AMERICAN RAILROADS; AND H. JOSEPH BOBZIEN, JR., PRESIDENT, AMERICAN COMMERCIAL BARGE LINE COMPANY, JEFFERSONVILLE, INDIANA

Dr. ZANDI. Ladies and gentlemen:

Thank you very much for giving me the opportunity to express my views on some aspects of the problems involved in transporting coal.

Even if everyone, including myself, is not sold on all the elements of President Carter's energy program, there are few who would disagree with him that the expansion of U.S. coal production and utilization is essential to the Nation's economic growth and well being. The goal of raising coal production to 1.1 billion tons in 1985 is a move in the right direction, and if it is at all possible—and I believe it is—the goal should be set even higher. The fact that 75 percent of the Nation's energy needs are satisfied by oil and gas, which comprise only 7 percent of domestic energy reserves, is the best justification for a shift toward utilization of the Nation's plentiful coal resources. This goal, however, requires massive investment in coal production, delivery and conversion systems. Without adequate and reasonably priced delivery systems, the realization of the goal will be jeopardized. This is why the present controversy over granting the power of eminent domain to the coal pipeline assumes significance.

In the past few years, much has been said in support of or in opposition to the claim that coal pipeline is essential in order to achieve the national energy goal. It is not surprising that those who are in the pipeline business are for, and those who are in the railroad business are against providing the opportunity for coal pipeline to become widespread. Between these two opposite poles, you can find all shades of arguments—enough arguments to satisfy anyone's heart's desire. Any predisposed position can be defended by emphasizing those elements of reality that support the position, and by conveniently brushing aside those that do not—because, in fact, almost all of the arguments are correct under some specific conditions. Please note the following point-counterpoint arguments which I will present to you in very rough manner. I will just touch the highlights.

Item—It is true, as railroad interests have argued,that should pipeline be given an opportunity to penetrate significantly the coal delivery market, and if it is successful, railroads would suffer financially. This cannot be denied. However, the point can be made—and the railroad interests agree—that penetration will more likely be in the expansion market. Railroads are not in danger of losing the loads they are handling now—only their rate of growth will be affected.

Item—It is true, as utilities and pipeline interests have argued, that there have been, from time to time in the past, and probably will be in the future, shortages of railroad facilities to handle coal. However, it is also true that railroads are capable of developing the capacity to carry all the coal needed by the Nation within the required time. The question, again, is one of growth. Construction of a few pipelines, which would capture a portion of the railroad industry's potential growth, should not reduce substantially its expansion capabilities, even if the rate of growth slows down.

Item—It is true, as railroad interests have pointed out, that unit trains are extremely well suited to transport the large volume of coal requred by national energy policy. And quite often, they perform the job for the lowest cost. However, this is not universally true. There are conditions, as agreed at least by some railroad companies (such as the Southern Pacific Railroad, which owns the

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Black Mesa Coal Slurry Pipeline), under which other modes of transport, such as barge and coal pipeline, might prove to be more desirable.

Item—It is true, as it is pointed out by pipeline interests and supported by residents of a number of small towns in the West, that the additional railroad traffic needed to handle a large required volume of coal can extensively damage the environment of towns located around a railroad right of way. The excessive noise and traffic may be very harmful. However, it is also true that an appropriately located bypass loop could go a long way to alleviate the problem. The problem is one of economy.

Item—It is true, as it is pointed out by railroad interests and supported by environmentalists, that it is necessary to treat the water after coal slurry is dewatered at the end-point. However, it should be noted that the problem is strictly one of economy. In most cases, the water can be utilized as a coolant for production of electricity to economic advantage.

Item—It is true, as it is pointed out by railroad interests, that a pipeline system can best serve large producers and receivers of coal. Of course, the larger the annual shipment tonnage, the lower the unit cost per ton mile of coal transported. However, once a long distance trunk pipeline is in place, any size shipment can be economically added to it at any point on its course. There is no technological problem in having feeder pipelines—it is only a matter of economy. There is no reason why a pipeline cannot operate as a common carrier of coal.

Item—It is true, as railroad interests and some environmentalists have noted, that a coal pipeline of the slurry type introduces the significant problem of acquiring enough water. No one can deny that removing this precious resource from water-short areas may be undesirable. However, it is hard to deny that because of a variety of geological, meteorological, climatological, and human conditions, the water problem is strictly a regional problem—a problem which varies with the characteristics of the watershed. A given project must be examined in the light of information concerning the locality of its implementation. No doubt there are areas where water will not be available or will be otherwise better utilized, but there are also areas where the reverse is true. A generalization on this subject, as in all generalization, happens to be wrong.

In addition, a coal pipeline need not be a "water" slurry pipeline. There are other types of pipelines, known as freight pipelines, available that require little or no water at all. I am attaching as an appendix to this testimony, two papers which describe some of the other types of pipeline which can be used to carry coal. The Russians, for example, are presently operating several pneumo-capsule pipelines to convey sand and gravel. "Lilo 2"—the name of the system—is a 32-mile-long, 40-inch pneumo-capsule pipeline which has been transporting 2 million tons of sand and gravel per year in Georgia, U.S.S.R., since 1972. Adaptation of these systems to the transport of coal requires no new technology. These are described in detail in the document attached to the testimony. I shall be glad to answer any questions in this respect.

A U.S. commercial company has already constructed and successfully tested a demonstration project of this type in Georgia, U.S.A.

The attached papers also describe other pipeline possibilities which exist and require a minimum amount of water.

The points to be made are that (1) adequate water is only a problem in certain regions of this country and the use of it must remain a regional problem, and (2) if water is scarce or not available, other pipeline technologies which do not require water can be utilized.

My purpose in exhibiting these point-counterpoint arguments is a very simple one. I could have described other point-counterpoints.

I submit to you that there is no way that one can generalize the advantages and disadvantages of coal pipeline versus other modes of transportation. Any universal statement will no doubt prove incorrect under some specific local conditions. The best legislative choice is to allow for diversity of opportunity.

The Office of Technology Assessment of the U.S. Congress is presently studying the most important impacts of slurry pipeline. Since I am a member of its advisory panel, I do not wish to prejudge the results of the study. However, my own experience of life has taught me that one should be very careful in generalizing any topic. Because of this, I believe that when the OTA report is out, its caveats and assumptions will be as important as its conclusions. No matter what these conclusions and caveats, common sense tells us that in human affairs, it is prudent to keep all our options open.

Coal pipeline is a technological option. Under some conditions, it may be superior to other modes of transport. Under other conditions, it may not be so. To deny its utilization for all seasons and all conditions would irreparably damage the national energy policy.

[The attachments to Dr. Zandi's statement follow:]

FREIGHT PIPELINE INFORMATION SHEETS

Prepared in connection with

THE INTERNATIONAL SYMPOSIUM ON FREIGHT PIPELINE

December 5-8, 1976
Washington Hilton
Washington, D.C.
By Iraj Zandi, Chairman of the Symposium

Freight pipeline is a technology suited for the transport of solid cargos. It may help to alleviate the transportation problems of tomorrow. Under favourable conditions, it offers many advantages which include:

a) reduction of traffic congestion;
b) reduction of air pollution;
c) reduction of street noise;
d) fewer environmental disturbances;
e) fewer traffic accidents;
f) the possibility of complete automation;
g) low man-power requirements for construction, operation and maintenance;
h) all weather operation;
i) high degree of reliability and load factor;
j) simplicity of installation;
k) lower energy intensity requirements;
l) less sensitivity to inflation;
m) better protection against theft.

Freight pipeline technology employs a variety of fluids to entrap, fluidize and convey solid cargo through pipelines. Several types of freight pipeline exist. When a freight pipeline carries bulky solids such as coal or iron ore, and the conveying fluid is a liquid (normally water) it is referred to as a SLURRY PIPELINE. If the conveying fluid is a gas (normally air), it is known as a PNEUMATIC PIPELINE. A CAPSULE PIPELINE, on the other hand, is a pipeline which carries encapsulated solids (with or without wheels) with either a gas or a liquid as the conveying fluid. An air propellent capsule pipeline is known as a PNEUMO-CAPSULE

* Presented by the Department of Civil and Urban Engineering, University of Pennsylvania, under sponsorship of the Office of University Research, Office of the Secretary, U.S. Department of Transportation.

PIPELINE, while a water propellent capsule pipeline may be called a HYDRO-CAPSULE PIPELINE. Capsule pipelining extends the applicability of pipeline technology to the transport of materials which could not be conveyed via slurry or pneumatic pipelines. Encapsulation will protect the solid being transported against damage. Almost anything, even manufactured products, can be transported in this manner.

Knowledge about, experience with, and degree of confidence in these types of freight pipeline vary widely. Hydro-capsule pipeline is currently being studied in pilot plants, while other types have gained commercial application.

- Coal, gravel, iron ore, gilsonite, gold tailings, sulfur, lime, copper concentrate, and many other bulky materials have for years been conveyed through slurry pipeline over long and short distances. The Meza Coal Pipeline was commissioned in mid-1970 and traverses 273 miles through the state of Arizona to deliver 4.9 million tons of coal per year from a mine site in the Navajo-Hopi Indian Reservation to the Mohave power plant in the Nevada site. Its successful operation is undisputable proof that slurry pipeline is a viable mode of transport.
- Commercial experience with the pneumatic pipeline is plentiful for short haul distances. The list of materials transported via this system is impressive and includes agricultural products (such as alfalfa, cotton seeds, fish meal, oats, wheat, and live chickens), industrial raw materials (such as alum, borax, coke, phosphate rock and salt) and wastes. Numerous commercial installations around the world testify to the versatility and reliability of the pneumatic pipeline.
- Pneumo-capsule pipeline is an old art and its use dates back to the early nineteenth century. Nowadays, many large European cities such as London, Paris, and Berlin utilize this system for mail and parcel post delivery. In recent years, its application has been extended to serve industrial complexes for the transport of parts, samples and assorted products. A proposed plan for the new city of Etarea, Czechoslovakia includes a goods-distribution system which would deliver shopping items to individual homes.

FUTURE OF FREIGHT PIPELINE: BEYOND PHASE I

The pipelines discussed above are considered to be first generation freight pipelines(Phase I). The commercial development of a versatile capsule pipeline (other than for mail which now exists), will culminate successfully the first phase of freight pipeline development. Eventually, this now unconventional freight mover will be an ordinary occurrance. We can expect many bulky agricultural, mining, and manufactured products to be transported in the future via pipeline.

Looking beyond Phase I, we can envision many innovative schemes. Some of these schemes sound like science fiction, but they are technologically within grasp. Some of the more exciting futuristic possibilities are examined below.

a) DELIVERY AND PICK-UP SYSTEM

Two major requirements of a community are the delivery of goods to consumption points and solid waste removal from the generation points. At the present time these two functions are accomplished separately. A capsule pipeline system (either hydro or pneumo) could serve both functions, as well as other functions, such as mail and shopping. A more comprehensive system could operate in connection with a catalog order by which the shopper might order his or her requirements. The store would then dispatch a coded capsule containing the order through the pipeline to the consumer. The code could be made specific for a given terminal and be such that as the capsule approaches its destination, it would activate a bypass system allowing the delivery. the same system would be used by the residents to remove their solid waste. A household compactor might pack the waste to fit the recoded capsule which would then be forwarded to the recycling and disposal plant. The system would allow direct delivery and pick-up among residences, businesses, or various activity points within the same business.

b) FREIGHT PIPELINE REACTOR

Normally in a slurry pipeline, the freight would remain in the pipe about 20 minutes per mile travelled. For a distance of a hundred miles, this is a detention time of more than 30 hours. Since most of the materials undergo some type of treatment either before or after transportation, this detention time may be used to affect a desirable change. In other words, freight pipeline, whenever possible, could be used as a joint tubular reactor and transportation system. Reactions could be physical, chemical or biochemical.

The utilization of pipeline (pressure sewer) as a bio-chemical treatment facility to stabilize municipal waste water is a possibility. It has been shown that 30 per cent waste treatment can be attained in about 25 miles of a sewer line, reducing the load on treatment facilities. A number of other applications may be visualized. Mixing and blending solids, for instance, is a natural and simple extension of pipe transport. Particle size reduction is another possibility. Under favourable conditions, chemical reactions and pyrolysis may be feasible. Separation of a mixture into its components is also conceivable, i.e., a coal containing pyrolitic sulfur may be desulfurized.

c) JOINT VENTURES

The conveying fluid which provides the necessary force for moving the conveyed solid need not always be wasted. If a given liquid must be transported over the same route as a solid, the combined transport of these two is possible. There is a Canadian plan for transporting capsules containing wheat via oil in a pipeline from the midwest to the Canadian east coast.

d) DIRECT DELIVERY SYSTEM

The opportunity for almost one hundred per cent automation may be used advantageously to ship the goods directly from manufacturer to large department stores. Manufacturer A at location I may code capsules containing a given product to be delivered automatically to department store B at location II.

The purpose of the International Symposium on Freight Pipeline is to consider only Phase I of freight pipeline which is now within the realm of feasibility. The more speculative uses of freight pipeline must be left to the future.

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Freight Pipeline

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Since the congestion of highways and streets is due to both passenger vehicles and freight traffic, reduction in either will serve to improve the effectiveness of the transportation system. The purpose of this paper is to present the arguments in favor of utilizing pipeline as a mode of transporting goods and materials between and within the cities. It attempts to synthesize the available information in a manner that will permit the evaluation of the role of the pipeline as a component of transportation systems.

Contributed by the Intersociety Committee on Transportation for presentation at the Intersociety Conference on Transportation, Atlanta, Georgia, July 14-18, 1975.

Copies will be available until September 1, 1976.

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Freight Pipeline

IRAJ ZANDI

ABSTRACT

Since the congestion of highways and streets is due to both passenger vehicles and freight traffic, reduction in either will serve to improve the effectiveness of the transportation system.

The purpose of this paper is to present the arguments in favor of utilizing pipeline as a mode of transporting goods and materials between and within the cities. It attempts to synthesize the available information in a manner that will permit the evaluation of the role of the pipeline as a component of transportation systems.

INTRODUCTION

The purpose of this paper is to present information regarding the technological feasibility, environmental benefits and economical attractiveness of "freight pipeline". Freight pipelines (known also as solid pipelines) carry solid materials just as a "water pipeline" carries water and an "oil pipeline" carries oil. This paper advances the proposition that several varieties of freight pipeline have matured into commercial application. It argues that comprehensive planning cannot and must not ignore the utilization of this mode of freight conveyance as a viable component of a wisely planned transportation system.

Under favourable conditions, freight pipeline offers many advantages when compared with alternative transportation modes. These include three broad categories of benefits: 1) those benefits which exist under any conditions and cannot be readily expressed in terms of dollars, 2) those existing under any conditions and can easily be expressed in terms of dollars, and 3) those depending on the locations, timing and nature of the project and may or may not be expressable in terms of dollars. Type 1 includes: a) reduction of traffic associated with trucking, b) reduction of many of the air pollutants emitted by truck and train, c) reduction of noise in the streets, d) fewer environmental disturbances, and e) fewer traffic accidents. Type 2 advantages include: a) the possibility of complete automation, b) low man power requirement for construction, operation and maintenance, c) all weather operation, and d) a high degree of reliability and load factor (this can only be asserted with assurance for those variations of pipeline for which field experience exists). Type 3 advantages include: a) simplicity of installation as compared with a new highway or railroad, particularly in mountainous areas, b) lower energy intensity requirements of several variations of freight pipelines compared with other modes, c) less sensitivity to inflation, and d) better protection against thefts.

At the outset, to prevent misinterpretation, a caveat needs to be added. This paper does not claim a universal solution for problems in transportation through the use of freight pipeline. Such a panacea does not exist. Freight pipeline has its own shortcomings--and these will be discussed later in detail. The paper, however, advocates that, as a result of decades of research, pilot plant studies and commercial experiences, some varieties of freight pipelines have reached a very high level of technical sophistication and must not be ignored as a viable component in transportation planning. Freight pipeline is a newly developed technology and, under favorable conditions, can serve the interests of transportation planning. Its adoption in a specific case, of course, has to be justified based on its "benefits-costs" ratio as compared with other modes of transport (both costs and benefits have to include non-tangibles as well as direct dollar outlays).

THE STATE OF THE ART OF FREIGHT PIPELINE TECHNOLOGY

Freight pipeline technology employs a variety of fluids to entrap, fluidize and convey the solid cargos which are intended for transport through the pipeline. The conveying fluid can be either a liquid or a gas which for its own sake may have to be transported anyway (such as oil or natural gas), or it may be employed primarily for transporting solids (such as water or air). Even when the primary function of the conveying fluid is transporting solids, it may be utilized for secondary purposes. For example, water can be used to convey coal but also employed at the end of the line to serve as a power plant coolant.

A number of variations of freight pipeline exist. When a freight pipeline carries bulky solids such as coal, gilsonite, iron ore, or the like, and the conveying fluid is a liquid (normally water) it is referred to as a "slurry pipeline". If the conveying fluid is a gas (namely air), it is known as a "pneumatic pipeline". A "capsule pipeline", on the other hand, is a pipeline which carries encapsulated solids (with the cross section of the capsule almost as large as the inside of the pipe itself, with or without wheels) with either a gas or a liquid as the conveying fluid. An air propellent capsule pipeline is known as "Pnenmo-capsule pipeline" while a water propellent capsule pipeline may be called a "Hydro-capsule pipeline" pipeline. Capsule pipelining extends the domain of applicability of pipeline technology to the transport of materials which could not be conveyed via slurry or pneumatic pipelines. This includes either materials and products which would be ruined as a result of interaction with the conveying fluid or destroyed due to mechanical impact. Capsule can protect the solid being transported against both of these dangers.

A "pneumo-train" pipeline is a string of capsules which are guided within the pipeline on wheels and carried via air. When water or other liquids are used as the conveying fluid to carry wheeled capsules, no specific terminology exists (we will refer to it as a "liquo-train"). When the capsules within a pipe are powered internally by electric motors for the purpose of locomotion, the pipeline serves only as a guide, substituting tracks in normal railroad. In this system, no conveying fluid exists. The mode of operation in this "electric capsule pipeline" is thus quite different from that which would normally be considered freight pipeline.

The extent of knowledge about, the range of experience with, and the degree of confidence in these variations of freight pipeline vary widely. Some are in the stage of laboratory studies, while others have gained commercial applications.

- Commercial experience, all over the world, has provided confidence in the feasibility and reliability of slurry pipeline. Coal, gravel, iron ore, gilsonite, gold tailings, sulfur, lime, copper concentrate, solid waste and many other bulky materials have, for many years, been conveyed over long or short distances. Appendix A provides information about two of these pipelines (one 273 miles long transporting coal and the other 53 miles long transporting iron ore) and should serve as an example of the transportation capabilities provided by slurry pipelines. The successful operation of slurry pipeline is a matter of record and cannot be disputed. Slurry pipeline is a viable and proven mode of transport.

Presently, two major slurry projects are in the planning stage. One is an 1100 mile pipeline to convey coal from Colorado to Texas to supply the new Texas power facilities of Houston Power and Light. The other is a 1030 mile, 38-inch pipeline to deliver Wyoming coal to Arkansas power plants, a joint venture of the Bechtel Corporation and Lehman Brothers. This latter project is in the advanced planning stage and is designed to deliver 25 million tons of coal per year.

● Commercial experience with the pneumatic pipeline is also plentiful, although for much shorter haul distances. The list of materials transported via this system is very long and includes agricultural products (such as alfalfa, cotton seeds, fish meal, oats, wheat and live chickens), industrial raw materials (such as alum, borax, coke, phosphate rock and salt) and wastes. Appendix B provides an example which indicates the versatility and reliability of the pneumatic pipeline.

● is an old art and its use dates back to the early nineteenth century. Many large European cities such as London, Paris and Berlin utilize this system for mail and parcel post delivery. In recent years, its application has been extended to serve industrial complexes for the transport of parts, samples and an assortment of products. A proposed plan for the new city of Etarea, Czechoslovakia includes a "pneumatic dispatch" goods-distribution system for the delivery of shopping items to individual houses. Appendix C provides information regarding recent progress in this area and should convince the reader that pneumatic dispatch pipeline is a feasible and reliable technology.

● pipeline has been extensively studied by Canadians in the Research Council of Alberta. Until recently, most of their efforts have been directed towards a better understanding of the hydrodynamic aspects of the system. Through the years, much bench scale experimental data has been collected which, combined with theoretical analysis, provides a fairly reasonable method of design. Much work regarding the development of hardware components, capsule manufacturing, and the reliability of the system is required prior to its commercial adaptation.

None of the technical problems which can be envisioned, however, seem to be insurmountable. All are developmental in nature and none are basic. Sufficient information exists to make an engineering judgement as to the technical reliability of such a system. Appendix D provides further information regarding the hydraulic-capsule pipeline.

● Electric capsule pipeline, until recently, has found its application in the transport of mail. In Brussels, Belgium, for instance, the post office utilizes the electric capsule pipeline to haul mail for a short distance. Recently, however, proposals have been offered to utilize this system for urban freight transport.

This brief discourse on freight pipeline (plus the appendixes) should entice the reader to yield to the proposition that freight pipeline is a technological reality and several of its varieties have commercial application. If more information is required the references in the bibliography should be consulted.

WHY FREIGHT PIPELINE?

Freight pipeline technology offers an environmentally preferred mode of transport. In this respect it is superior to other modes. For this reason alone, it should receive serious consideration wherever it can be economically employed. However, it offers even more. A brief discussion of the benefits associated with freight pipeline follows.

Traffic Congestion

This impact cannot easily be quantified, although it is difficult to dispute the fact that whenever a truck or a railroad car is replaced by a pipeline, the overland traffic will be reduced. This reduction can be significant for both inter-city and urban traffic.

The previously mentioned planned 1030 mile Wyoming-Arkansas coal slurry pipeline will deliver 25 million tons of coal per year when fully operative. If the railroad is to accomplish the same task, it must operate 2500 unit trains of 100 cars each per year, in each direction, implying a steady flow of unit trains every hour and forty-five minutes running down the track at any given point, day and night, 365 days a year (1).

In urban areas where the traffic is heavy all of the time and bumper-to-bumper during the rush hour, the impact on traffic can be as important. According to the Motor Vehicle Manufacturers Association, in high density areas 65 to 90 truck trips are generated daily per 1000 population (2). In a center city, this amounts to a large number of trips. Any reduction would be significant. It is reported that the average truck in Manhattan, N.Y. currently loses 4 hours per day as a result of congestion and that 83 per cent of trucking costs in urban areas are attributable to time as opposed to miles of operation (3). No documentation seems to be necessary to argue that 1) considerable saving in the cost of freight transport can be achieved if this four hours is eliminated or reduced and 2) the elimination of any portion of trucks involved will bring about a commensurating relief in congestion for other vehicles.

Air Pollution

The motor carrier industries are reportedly responsible for 65 per cent of the air pollution in the business district of New York (3). How much of this is directly (due to the trucks themselves) and indirectly (due to the effect of trucks on the performance of other vehicles) related to the operation of trucks is a matter of conjecture. If the contribution of trucks would have been proportional to their relative numbers (on a nationwide basis), this would have been estimated at about 10 per cent. Because 1) the level of emission from motor vehicles is heavily influenced by the mode of operation of that vehicle, 2) in center cities, the relative number of trucks to other vehicles is more than a nationwide average, and 3) trucks, on the average, emit more pollutants than passenger cars (each truck emits more grams per mile of hydrocarbons, carbon monoxide, and nitrogen oxide, normally, up to two times greater than passenger cars (4)) it may be safely assumed that the contribution of trucks to air pollution in Manhattan is well over the 10 per cent figure. Substituting any portion of the truck fleet in Manhattan with freight pipeline will bring about a proportional amount of improvement in the quality of the air.

The trucking industry claims that the contribution of trucks to the cities' air pollution is rather small. This claim is apparently based on the fact that only 0.9 per cent of the total air pollutants emitted from all sources on a ton per year basis is due to diesel vehicles (5). Three points need to be mentioned: 1) diesel vehicles comprise only a portion of the total number of trucks, 2) there are proportionally more trucks in the center cities, and 3) diesel trucks emit a much higher percentage of the total oxide of nitrogen (about 3%) (5).

Noise

Motor vehicles produce noise. Noise affects human health, ranging from nuisance to injury and invading the accoustical privacy of citizens. Ward reports the result of a survey where only 3 to 7 per cent of residents were annoyed by trains, compared to 33 to 62 per cent by aircraft and 18 to 32 per cent by auto and trucks (6). The recognition of the inter-relationship between noise and health is creating an impetus for noise control within urban communities. Highway noise litigation is also gaining prominence. According to Bragdon, during 1971 the New Jersey Superior Court awarded $160,000 to the Elizabeth, N.J. Board of Education because highway noise interfered with the teaching process (7).

There are three components of the noise problem: the source, the path and the ultimate receiver. On the average, trucks are the sources of a sound level of 10 dB higher than automobiles (8). Consequently, any reduction in the truck population will have a more pronounced affect on the traffic noise than its numerical reduction would alone indicate. In most traffic-noise situations, the sound of any one individual vehicle (a source) is often indistinguishable from the merged sound of all the traffic unless the noise of that particular vehicle is significantly higher than average (which is the case for diesels). When, on the other hand, the proportion of diesel trucks to passenger vehicles is higher than a few per cent, the traffic sound shows a bimodal distribution where the noise of trucks occupies the higher dB band.

Accidents

The fatality rate is significantly less for trucks than for passenger cars. In the 1969-71 period, there have been 1.82 deaths per 100 million vehicle miles versus 2.06 for tractor trailors and 2.41 for passenger cars. However, during daylight hours in the metropolis, more trucks are involved in accidents. According to Wilbur Smith and Associates, the number of accident involvements per 100 million vehicle miles in 1969 was 207 for automobiles, 281 for light trucks and 220 for medium and heavy trucks (9). In Philadelphia alone, trucks have been involved in 8,160 accidents in 1973 which resulted in 1,441 injuries and 20 deaths (10). Pipeline will have no accidents of this sort. Much of this can be eliminated if freight pipeline can replace trucks.

Loss Damage

A Department of Transportation Report puts the total annual direct and indirect cost (administration, cost of processing claims and cost of lost business, etc) from loss and damage in the transportation industry at the \$8-10 billion level (11). Of this, approximately 66% (of the direct cost) is attributed to the trucking industry and 25% to railroad. Other reports estimate costs as high as \$13 billion. Only 10 per cent of this loss occurs as a result of hijackings, another 5 per cent involves breaking and entering kinds of burglaries of terminals and the remaining 85% goes out the front gate and is recorded as shortages, shrinkage, etc (12). How much of the total annual loss is susceptable to modal technology cannot be specified. What is certain, however, is that a fully automated transportation system, such as freight pipeline, can be designed to minimize the accessibility to cargo which in turn will reduce the opportunity for theft.

Energy Consumption

Of the 67,827 trillion Btu's (equivalent to 11.7 billion bbls of crude oil) or about 7 per cent of the total United States energy consumption was utilized to transport freight. Every single per cent reduction in the fuel requirement of freight transportation is equivalent to a saving of 8 million bbls of crude oil

A number of investigators have compared the energy consumption of various modes of freight transport by calculating a term known as "Energy Intensiveness", EI. EI is defined as Btu energy required to move a ton of materials a mile. Table 1 compiled by Zandi and Kim shows the EI's calculated on the basis of national figures for all materials moved intercity via various modes of transport (13).

While EI calculated in this manner imparts some useful information, it suffers from two basic deficiencies: 1) it represents an almost useless average value, and 2) it signifies energy consumption in only a portion of the system.

The first deficiency occurs because energy consumption is not only a function of the transportation mode, but also depends on the characteristics of the roadway, the nature of the environment that it serves, weather conditions, packaging, and the method of operation. The second deficiency occurs because EI calculated from national fuel consumption figures usually stop short of considering all the steps involved in various processes required to make either coal or oil available to vehicles.

Scrutiny of these deficiencies reveals that no significant conclusion can be drawn on the basis of these national averages. EI is a function of too many variables to be useful when it is stated in terms of statistical averages, even for a single mode of transport. For instance, using actual fuel consumption data for the Reading Railroad Company System, one finds that the EI varies between 140 and 1,920 (13). It should be obvious that the average values given in Table 1 do not convey much information for comparison of the various modes.

The value of EI for freight pipelines covers an even wider range as it is a function of diameter of the pipe, velocity of the flow, characteristics

TABLE 1 - Energy Intensiveness, EI (BTU/TM)

Investigators	Mode				
	Pipeline (oil)	Railroad	Waterway	Truck	Airplane
Hirst (1973)	450	670	680	2,800	42,000
Railway Age (1973): Battele's Columbus Labs	--	536-791	--	2,518-2,800	--
Railway Age (1973): Missouri Pacific's Traffic Research Division	--	500	--	1,800	--
Mooz (1971)	1,050	750	500	200	63,000

of solids to be transported (size, shape, density), characteristics of flow (concentration of solids and apparent viscosity of the suspension), and the nature of the conveying fluid.

A meaningful comparison can be achieved only when the EI is obtained for a given situation and specific transportation requirements. Zandi and Kim made such a study for two specific situations: 1) for inter-city transport, the actual EI of an existing coal slurry was compared with the EI of a railroad designed to perform the same task, and 2) for an urban setting, a hydraulic-capsule pipeline was compared to truck transport (13). Table 2 shows the result of these comparisons.

TABLE 2 - EI for Total System, BTU/TM

	EI at Work	EI for Total System
Intercity Transport		
Railroad	492	544
Slurry Pipeline	171	465
Urban Transport		
Spherical capsule	161	436
Cylindrical capsule	2,000	5,439
Truck, urban traffic (average value)	5,040	5,583

The table is self-explanatory and shows various degrees of energy saving that may be expected. However, it should be noted that a great improvement in the energy requirements of pipeline may be achieved by more sophisticated designs. Table 3 shows some of the recent test data which clearly improves the EI for pipeline.

TABLE 3* - Recent Data for the Freight Pipeline's EI

	Energy at Work	Energy at the System Level
Hydraulic Capsule Pipeline		
Field test in USSR	60**	163
Pneumatic Wheeled Capsule Pipeline***		
Field test in Japan (36")	446	1212
Field test in USSR	178	482
Field test in Atlanta	216	586
Field test in Germany (45 cm)	291	791

* The calculations are made by Mr. K.S. Kim
** This is an estimated value based on the report by a USSR engineer that capsule pipeline consumed 35% of the energy required by slurry pipeline. The value of EI for slurry pipeline was from Table 2.
*** These are experimental data and are useful for the specific experimental set ups used to obtain them.

A further observation may be made that there is a qualitative difference between energy consumed in trucks and energy consumed in freight pipeline. Trucks use oil which is domestically in short supply, but freight pipeline uses electricity which can be produced from coal for which a plentiful domestic supply exists.

Economy

How does the cost of transporting freight via pipeline compare with the cost of other modes of transportation? The answer must be that it all depends! There are so many variables affecting the cost of conveyance that any general statement must have exceptions. The ton per mile cost of slurry pipeline, for instance, reduces sharply as the volume to be transported or the hauling distance increases. Table 4 is prepared based on the Aude et al report and compares, in a rough manner, the cost associated with various modes (14).

TABLE 4 - Approximate Transportation Cost (¢/ton-mile), 1973

	Annual Throughput (million tons)				
Solid to be Transported (figures in parentheses shows haulage distance)	--	1	5	10	20
Coal					
Train (500 miles)	0.7	--	--	--	--
Barge (500 miles)	0.35	--	--	--	--
Slurry Pipeline					
(200 miles)	--	--	1.60	1.20	0.95
(500 miles)	--	--	1.00	0.58	0.55
(1000 miles)	--	--	0.80	0.40	0.40
Iron Ore or Copper Concentrate					
Train (New rail system--level train)	--	5.0	1.60	1.05	--
Trucks	4 to 5	--	--	--	--
Pipeline	--	2.5	0.7 to 9.0	.45 to .60	

It should be obvious that these costs are estimates and need to be ascertained for each specific case prior to any decision as to the selection of the transport mode.

A pneumatic dispatch pipeline is under consideration for the city of Atlanta, Georgia by the U.S. Postal Service and is estimated to cost about 10 per cent less than truck. Other studies show likewise the saving that may be achieved.

What the examination of various studies on the economics of freight transportation shows is that, under certain conditions and for certain commodities, the cost of haulage may be cheaper for pipeline than for other modes of transport. Each case should be decided based on its own merit.

One economical advantage of pipeline seems to be certain. Pipeline tariffs escalate at modest rates, usually less than for trucks or rail. This is because the major portion of cost is the capital cost and is spent at the beginning of the project. Huneke and Wasp give the breakdown shown in Table 5 for the 273 mile coal slurry pipeline presently operating in Arizona which is known as the Black Mesa Pipeline (1).

TABLE 5 - Cost Distribution for Black Mesa Pipeline (in per cent)

Fixed Cost		84
Variable Cost		
Power	6	
Labor	5	
Supplies	5	
Subtotal	16	16
Total		100

Once the investment is made, the portion of tariff associated with the capital cost remains fixed. Because of this, while the rate of escalation for average rail transport has been increasing about 6.5 per cent over the past 10 years, the rate of escalation in the Mesa pipeline has been somewhere around 3 per cent.

An additional point regarding the economy of the system needs to be made. Most economic comparisons assume that railroad track or highways exist. If this assumption is not correct, then the economy is more clearly on the side of pipeline. In developing regions, this is a very significant consideration.

Load Factor

Those variations of freight pipelines which have reached the commercial stage have proved to be quite reliable. The first long distance (108 miles) coal slurry pipeline which was built between Cadiz and Cleveland, Ohio was 98 per cent available during its operating lifetime. The Black Mesa pipeline has been available 99 per cent of the time (1).

Quantitative data does not exist for pneumatic pipeline collecting solid waste in Stockholm (see appendix A) but reports indicate very little trouble, if any at all. The situation is very much the same for pneumatic dispatches utilized for mail delivery in European cities.

Other Considerations

Freight pipeline offers other amenities which are not readily obvious. Among these are independence from weather, less susceptibility to labor strife, less impact on the environment, and the relatively short lead time required for its construction.

An example of this category of impacts is the quality and quantity of land disturbance which will be inflicted by pipeline versus other modes. Wasp's estimate for land utilization required for a typical 1000 mile, 38-inch pipeline is shown in Table 6 (1).

TABLE 6 - Typical Land Utilization for 1000 mile, 38" pipeline (in acres)

Slurry pipeline right of way	12,550
Water supply gathering pipeline right of way	610
Subtotal	13,160
Coal preparation plant	100
Dewatering plant	200
Pump stations (10)	420
Water supply pump station	60
Water supply well facility	10
Subtotal	840
TOTAL	14,000

It should be noted that, except for 840 acres of permanent land disturbance, the remaining acreage can be utilized for a variety of purposes without hindrance from the buried pipeline.

DISADVANTAGES

The reader will be justified at this point in assuming that the author biased. It should be admitted that, while the facts are presented honestly, they are organized in a fovourable and optimistic fashion. This bias exists inspite of full knowledge of the disadvantages of freight pipeline. The justification for optimism is, however, based on a judgement that all the difficulties involved are either developmental in nature and therefore amenable to solution, or are disadvantages only under some conditions while insignificant under others.

The following is an outline of some of the disadvantages of freight pipeline.

- The cost per ton mile of goods via freight pipeline is an inverse function of the total quantity of goods and the length of the haul (see Table 4). While this characteristic can be considered a strong point in favour of pipeline when the right conditions exist, it works against pipeline otherwise. Although it may be possible to combine various freights to increase the domain of economical application of pipeline it nevertheless makes the system inflexible.
- Existing freight pipelines are designed to connect one source to one destination. As such, they only serve a fixed route. This inflexibility, however, does not have any technical basis. There is no reason why a multi-source, multi-destination system cannot be designed, although a few technical innovations may be necessary.
- Highways and railroads carry more than freight. Pipeline, on the other hand, will be limited to freight transport--at least for the foreseeable future.
- The major portion of the cost of freight pipeline is the fixed cost (see Table 5). As it was discussed earlier, this has a favourable impact on cost escalation. On the other hand, the larger initial capital investment required may be unattractive to investors.
- In urban communities, the underground is criss-crossed with numerous pipelines, wires, tunnels, etc. Adding to this underground traffic jam may be undesirable.
- In both the hydraulic-capsule pipeline and the slurry pipeline, a conveying liquid is required. Water is normally used for this purpose. When water is scarce at the point of origin of the freight, pipeline can exaggerate the water situation. In this connection, two points need to be made: 1) if water is used, it can be employed beneficially at the destination, and 2) sometimes other liquids may be utilized. A very interesting possibility exists, for instance, when coal is the freight. A portion of the coal may be liquified and be used to convey the other portion of coal in slurry form.
- Freight pipeline competes with both trucks and railroads. Railroads are particularly dependent on bulky materials such as coal for their revenue. In a recent testimony before the House Interior and Insular Affairs Committee, witnesses for the railroad industry pointed out that, in 1972, the class I railroads

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in the U.S. handled 371,135,163 tons of bituminous coal. This amounted to 25.6 per cent of all traffic conveyed by the class I railroads and generated $1,361,205,950 gross revenue (10.5% of the railroad's gross receipt). Freight pipeline will endanger this revenue and will exacerbate the financial plight of the railroads.

- Not everything can be carried through pipeline. There is a size limitation that has to be met.

ADDITIONAL REMARKS

Freight pipeline is still in its infancy. Much of its potential has not yet even received serious discussion. Pipelines, however, can be used beyond the simple transport of solids. They can also be used as reactors (chemical, biological or mechanical) to change the quality of solids to be transported, while in conveyance. This and other uses of pipeline are discussed elsewhere (15).

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APPENDIX A

Slurry Pipeline

Bulk solid conveyance through pipes in slurry form is now an industrial reality. There are many commercial installations around the globe which testify to the viability of this mode of transport (14, 16 to 20). Although the early, industrial solid pipeline dates back to 1884, when in Pennsylvania the anthracite culm was pumped through pipes into the workout portion of a mine for the purpose of extinguishing a mine fire (21), the long distance line conveying high concentration slurries is a rather recent innovation. To exhibit the capability and versatility of this mode, two specific installations will briefly be described.

Black Mesa Pipeline. The Mesa Coal Pipeline which was commissioned in the mid-1970's traverses the state of Arizona to deliver 4.9 million tons of coal per year from a mine site in the Navajo-Hopi Indian Reservation to the Mohave power plant on the Nevada side, 273 miles away. The power for the system is provided by nine operational pumps in four pump stations with a total power of 9,585 kw, supported by a stand-by capacity of an additional 5,420 kw. The coal deliverd by this pipeline is used to generate 1,500 MW electricity (22).

Coal, as delivered from the mines, enters a series of impactors and parallel rod-mill lines to be reduced in size from a maximum of 51 millimeters to under 14 mesh. This fine coal then is mixed with water to form slurry and pumped through an 18 inch pipeline to the site of the power plant. At the plant, coal is stored in a holding tank for 24 hours and subsequently dewatered to 25 per cent moinsture content by centrifuges. The dried coal is then blown into the boiler with heated air (22).

Savage River Iron Ore Pipeline. This is a 9 inch, 53 mile long pipeline delivering 2.5 million tons per year of magnetic concentrate from a mine in Tasmania to Port Latta. The energy for the system is supplied by four parallel triplex plunger pumps, each producing a maximum of 140.6 Kg/cm^2 pressure.

This pipeline has been operative since 1967 with no significant problems (14).

APPENDIX B

Pneumatic Pipeline

Pneumatic pipeline is now more than a century old. In 1866, B.F. Sturtevant developed a system to remove dust in grinding and buffing operations (23). Since then, the technology has been applied in numerous industrial applications. The list of products handled in this manner is very long (24, 25, 26). The following example should be sufficient to present the capability of pneumatic pipeline.

In Sudeberg, a suburb of Stockholm, Sweden, a vacuum-sealed pipeline system presently collects the solid waste of about 5,000 apartments. The solid waste is swept along in an air stream of about 90 feet per second mean velocity. The destination of this waste is an incinerator of a space heating plant, 1.7 miles away, from which heat is distributed to the residential area. Underground pipes in this system range in diameter from 20 to 24 inches. Sufficient vacuum is produced by five turbo-extractors, each driven by a 100 kw electric motor. No presizing of waste is practiced. The system has been operative since 1966 with little difficulty.

The Swedish system described above

has been the fore-runner of many installations around the world including many in the U.S.

APPENDIX C

Pnenmo-capsule pipeline

Pnenum-capsule pipeline is an established technology. It dates back to when Dennis Papin presented his idea on vacuum capsule transport to the Royal Society of London in 1667. Since then, many commercial installations of this type have been constructed. Kim (27) has traced the history of the development of pneumatic dispatch and has presented many successful examples of such systems.

The recent development in this field is pioneered by M.R. Carsten who, in cooperation with Tubexpress Systems, Inc. of Houston, Texas, has developed a versatile and operational pneumatic dispatch system called Tubexpress. Large operating prototypes are tested in the U.S. and Japan. The Japanese test facility is a 1,500 meter long, 914.4 millimeters inside diameter pipeline, transporting capsules of 250 kilograms weight. The system has a capacity of 30 tons per hour and runs at speeds of 22 kilometers per hour. The energy for the system is supplied by a 54 kw motor. An interesting feature of Tubexpress is that turns in the pipeline can be achieved with radii as small as 38 feet, allowing for much space saving (28).

APPENDIX D

Hydro-capsule pipeline

The idea of Hydro-capsule pipeline originated because of interest in two-phase (liquid-liquid) flow in pipeline. Observation of the flow of a mixture of oil and water through a 3-inch diameter, 800 foot pipeline showed significant reduction in pump energy requirement when it was compared with the flow of oil alone (29). Subsequent observations indicated that rigid bodies behave in more or less the same way as the oil globules. The next stage of development was materialized when pastes were made of powdered coal and water and extruded into a mineral oil carrier liquid (30). Hodgson and Bolt, in 1962, introduced the idea of capsule flow and its potential industrial application (31). Almost at the same time, Hodgson and Charles (32) discussed the concept of capsule pipelining, while Charles (33) attempted a theoretical analysis of such systems. Ellis, et al, in 1963, presented limited data on the pressure gradient of capsule flow (34). Later on, in a series of papers, Ellis discussed in detail the results of the experimental studies made by the Research Council of Alberta on transport by water of single cylindrical and spherical capsules with density equal to or greater than water (35-37). Newton et al used numerical analysis to study the effect of a number of variables determining the free flow of capsules (38).

Charles derived theoretical relationships for the calculation of capsule velocity and pressure gradient for an idealized system in which a long cylindrical capsule moves concentrically with respect to the pipe.

Since these initial efforts, much research has been carried out, almost exclusively by the Research Council of Alberta (with a few notable exceptions; 39, 40 and 41). In March, 1965, the first trunk line test of capsule pipeline flow was carried out in a 109 mile, 20 inch diameter pipeline. A capsule, 60 inches in diameter and 50 inches long, weighing slightly in excess of 514 lbs was sent through the pipe (42). The most extensive research, however, was carried out by the Research Council of Alberta since 1971 under the sponsership of the Canadian Federal Ministry of Transportation. These studies have generated a wealth of both theoretical and experimental information invaluable in the design of such systems.

The Research Council of Alberta's experimentors measured many variables including the bulk velocity of the conveying fluid, capsule velocity, liquid pressure gradient, capsule pressure gradient, and pipeline pressure gradient. These variables were measured for various combinations of pipe diameter (1/2, 4 and 10 inches) pipeline materials (stainless steel, mild steel, and cellulose acetate butyrate), capsule diameter, length of the individual capsules, capsule materials (stainless steel, butyrate, P.V.C., aluminum, iron and mild steel), number of capsules in a train, capsule specific gravity, capsule shape (cylinders and spheres), liquid flow rates, liquid properties (water and water glycol mixture). Thanks to these pioneering works, much insight into capsule pipe flow (when water is the conveying fluid) is gained. In addition, detailed knowledge of experimental set up (a very sophisticated, computerized system), and experimental procedures are published (43, 44, 45, 46, 47, and 48).

RCA has extended the study beyond the hydrodynamic aspects of capsule pipeline and has explored the technology, instrumentation, system analysis and has constructed the techo-economic simulation model.

Mr. MOFFETT. Mr. Jennings.

STATEMENT OF W. PAT JENNINGS

Mr. JENNINGS. Mr. Chairman, I am president of the Slurry Transport Association, an organization of companies that will produce, transport or use materials that can be delivered by pipeline in a liquid slurry. The members of the STA are interested primarily at this time in the transportation of coal, which is unique among those solids that can be transported by slurry pipeline because of its importance to our national energy needs.

While coal slurry pipelines are not mentioned in the bill before you, H.R. 6831, it is apparent that if coal production is to be increased by two thirds, then the coal transportation system will have to be expanded to the same degree.

In transportation there are two basic questions: capacity and competition.

—Will there be adequate capacity to move the amount of coal needed to shift this country's energy base from oil and natural gas?

—And, will there be the discipline of competition to control the significant cost of hauling coal over long distance from the mines to industries and utilities that need it?

The impact of the severe cold which characterized the past winter was a powerful reminder of what is in store for any State that does not provide for the future use of alternate fuels. Each succeeding crisis raises awareness another notch. Now there seems to be general agreement that coal has an important role, particularly as a fuel for producing electricity, in the coming decades.

Greater reliance on coal as a national energy source will require a stronger, more diverse coal transportation system. This will mean the upgrading of the rail system, expansion of large lines, and the development of coal slurry pipelines.

The magnitude of the coal transportation problem is increased by the fact that the need for expanded capacity will not occur evenly. Since neither the supply of coal nor its demand are uniform, some areas will need only improvements to existing systems while others will require the creation of a practically new system.

The challenge is not beyond us, but it will require the best efforts of every energy transportation system available. I have serious doubts that an aging rail system, built to serve an earlier era, can handle the job alone.

The Association of American Railroads claims the railroads can handle all the coal that is produced, but there is no evidence that this is so. They say that coal accounts for a little less than 20 percent of total rail traffic and it can be doubled in 10 years at 2 percent a year, assuming that all other traffic remains the same. That line of reasoning obscures the dramatic increases that will be required in the West where five-fold increases could be needed to avoid shortfalls in deliveries.

The railroads have always carried most of this country's coal. The percentage of total production delivered by rail declined in recent years, but the railroads still handle about 65 percent of all U.S. coal shipments. Most of that traffic—better than 80 percent of it—is in the East and the South. The western railroads account for less than 20 percent of all rail shipments of coal.

The difference between the railroads east of the Mississippi River and those to the west of it is significant today because most of the new coal production is expected in the West. The Federal Energy Administration has estimated that by 1985, Eastern coal production will increase 30 percent to some 670 million tons. But in the West, production of 379 million tons is projected—an increase of more than 300 percent.

There is nothing to convince a prudent man that increases of this magnitude can be handled alone by the Nation's railroads.

Fortunately, there are alternatives. In the East, where the distance from the mine to the consumer is relatively short, the coal transportation burden is shared with the trains by barges, trucks and high-voltage transmission lines that carry the coal energy in the form of electricity from generating stations at the mine site.

But in the West the distances from the mines to the consumer are much greater than those in the East. Those distances eliminate most of the alternatives I have mentioned. In the West, the only alternative is the coal slurry pipeline.

There is nothing new or experimental about coal slurry pipelines. The first patent for a coal slurry pipeline was issued in 1891. The first commercial coal slurry pipeline in this country was built in Ohio in 1957. That pipeline operated successfully for 6 years. Not only did it produce significant savings in coal transportation, but it stimulated the development of the unit train with its resulting efficencies.

At the present time, a coal slurry pipeline carries coal 273 miles from the Black Mesa mine in Arizona to the Mohave generating station in southern Nevada. That pipeline has been in operation since 1970. During that time, it has demonstrated the kind of reliability and economy the electric companies will need when they convert to coal. It has been available more than 99 percent of the time and delivers coal at nearly half the cost of alternate modes of transportation.

The Black Mesa pipeline is operated by a subsidiary of the Southern Pacific Railroad, which boasted in the Wall Street Journal earlier this month about its automated coal slurry pipeline that delivers coal without disturbing the environment. The major constraint to the construction of other pipelines is the hostility of the railroad industry in general. Five major pipelines are proposed to carry western coal to the energy-hungry population centers of the South, the Southwest and the Pacific Coast. But they are blocked simply because they cannot get permission to pass beneath the railroad tracks.

It is illogical, but true, that coal can move freely in this country in any form except in its natural state in a pipeline. Converted into gas or some other synthetic fuel, it can flow through pipelines. It can be used to generate electricity that travels over high-voltage transmission lines. And, coal can be moved, unimpeded, in its natural state by train, truck, or barge. But the unprocessed coal cannot be transported by pipeline simply because the railroads say it cannot.

The story of transportation development is in part a story of railroad obstruction; the rail carriers have fought virtually every competitive new technology for moving goods—pipelines, trucks, buses, airplanes, barge lines.

Coal pipelines will provide needed competition for the railroads and there is more than enough coal to be delivered by both. The public interest will be served by the competition and its interests will be protected by the coal pipeline legislation pending in the Interior Committee. The President's energy message stressed the need for competition, and we wholeheartedly endorse that view.

Since transportation accounts for up to 80 percent of the delivered price of coal, the consumer desperately needs some alternative means of transportation if he is to have any protection at all. A good example of what can happen without competition occurred recently in San Antonio.

The situation there, briefly, was that the City of San Antonio began switching from natural gas to coal for its steam generating plants. Without competition from coal slurry pipelines, the Burlington Northern's rates for transporting the city's coal from Wyoming have increased from the opening quotation of $7.90 a ton in 1973 to a proposed rate as high as $17.34 a ton.

The city complained that these increases were unreasonable and unjust. They argued to the Interstate Commerce Commission that other unit train rates were lower than they were being charged, but the railroad replied—note this carefully—the railroad replied that the rates quoted by the city "are rates depressed by competition and are not suitable for comparison purposes."

On the question of escalating rates, the railroad argued that the city should not be concerned by the increases because the rail rates were still cheaper than either oil or gas and besides the city is—and I quote—"at liberty to pass on to their customers any increase in costs without the necessity of obtaining specific approval from any regulatory agency."

The ICC responded to that argument by observing that it had "more regard for the public interest than such a proposition would allow." And, in an extremely rare action, the ICC concluded that the rate imposed on San Antonio was, in fact, unreasonable and adjusted it downward, but it is still over $11 a ton at the present time. And that does not count the estimated $1 a ton cost associated with the city's having to purchase and maintain a fleet of 810 coal cars.

We are asking Congress to establish a procedure to make construction of coal pipelines possible. The bill we support, H.R. 1609, provides no Federal funding, approves no single pipeline and appropriates no water for use in the pipelines. But it would permit a properly certified pipeline builder to exercise the carfully protected right of eminent domain for the acquisition of rights-of-way. Hearings on H.R. 1609 were conducted by a joint subcommittee of the House Interior Committee last month, and we are hoping the joint subcommittee will act favorably on that bill next month.

The process described in H.R. 1609 for obtaining a certificate of convenience and necessity includes a rigorous review of each pipeline proposal before any builder obtains a certificate of convenience and necessity permitting him to exercise the right of eminent domain. Following construction of the pipeline, the bill further provides that the coal pipeline is to be regulated by the Interstate Commerce Commission as other pipeline common carriers. The bill also prohibits the use of eminent domain to obtain water and declares that the act is not to be construed as affecting any State laws relating to water rights.

Some States have acted to resolve the pipeline right-of-way issue for themselves. As you may know, both Texas and Oklahoma enacted bills this year to provide eminent domain for coal slurry pipelines. They join 5 other States—North Carolina, West Virginia, Ohio, North Dakota and Utah—that provide eminent domain for coal slurry pipelines by specific legislation and a number of others that grant it in general legislation.

The actions of these States do not diminish the urgent need for Federal eminent domain legislation. They do illustrate, however, the serious concern of those States over the need for new sources of fuel; for reliable, competitive transportation alternatives to assist with the anticipated conversion to coal. More to the point of this hearing, State action demonstrates the growing recognition of coal slurry pipelines as an important aid to the conversion to coal for a greater portion of our energy supply.

Coal slurry technology is well established. The slurry is formed by mixing a fluid, usually water, with coal that is pulverized to about the size of sugar. The water and the pulverized coal are mixed at a preparation plant in approximately equal parts and the resulting slurry is then introduced into a pipeline where large piston pumps push it on its way. Pumping stations every 80 to 100 miles keep the slurry moving through underground pipes to dewatering facilities at the pipeline's terminus. There the slurry is separated by centrifuges that spin the water from the mixture. The coal then can be burned and the water used for cooling processes associated with the coal's combustion.

[Mr. Jennings' prepared statement follows:]

STATEMENT OF W. PAT JENNINGS, PRESIDENT, SLURRY TRANSPORT ASSOCIATION, TO THE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE SUBCOMMITTEE ON ENERGY, U.S. HOUSE OF REPRESENTATIVES, IN SUPPORT OF H.R. 6831, MAY 26, 1977

Mr. Chairman, I am president of the Slurry Transport Association, an organization of companies that will produce, transport or use materials that can be delivered by pipeline in a liquid slurry. The members of the STA are interested primarily at this time in the transportation of coal, which is unique among those solids that can be transported by slurry pipeline because of its importance to our national energy needs.

While coal slurry pipelines are not mentioned in the bill before you (H.R. 6831), it is apparent that if coal production is to be increased by two thirds, then the coal transportation system will have to be expanded to the same degree.

President Carter's call for greater coal utilization raises a variety of questions about the ability to produce, transport and use more than a billion tons a year.

In transportation there are two basic questions: capacity and competition.

--Will there be adequate capacity to move the amount of coal needed to shift this country's energy base from oil and natural gas?

--And, will there be the discipline of competition to control the significant cost of hauling coal over long distances from the mines to industries and utilities that need it?

The impact of the severe cold which characterized the past winter need not be elaborated here. Although it caused much personal hardship and economic damage, it also had some positive value in restoring the urgency evident during the energy crisis three years earlier. The nation was reminded that natural gas is a declining source of energy and that imported oil, while currently available, is very expensive. Once again, there was serious talk about the vast resources of coal in the United States and about what must be done to shift the energy load to this abundant domestic resource, which could supply this country with energy for several centuries.

We also were reminded of some basic facts about energy transportation. We saw pictures of trains halted by heavy snow and tracks damaged by severe weather. Dynamite was necessary to blast frozen coal loose from rail cars. Barges were blocked by river ice. These are among the traditional hazards encountered by surface transportation, and by no means do they argue that railroads and barge lines should be abandoned. They do argue, we believe, for the development of available alternatives which are not affected by severe weather and thus can continue deliveries when surface systems are disrupted. Coal slurry pipelines, operating underground, offer such an alternative.

The problems of the frigid winter did not directly affect the southwestern states which produce much of the nation's natural gas and whose economies are heavily dependent on gas as a fuel. But the curtailments in the East, and the distress they caused, were a powerful reminder of what is in store for any state that does not provide for the future use of alternate fuels. Each succeeding crisis raises awareness another notch. Now there seems to be general agreement that coal has an important role, particularly as a fuel for producing electricity, in the coming decades.

The President has asked that coal production be increased by two-thirds, from the present 670 million tons a year to more than a billion tons annually, within the next decade.

Greater reliance on coal as a national energy source will require a stronger, more diverse coal transportation system. This will mean the upgrading of the rail system, expansion of barge lines, and the development of coal slurry pipelines. The National Academy of Engineering has foreseen the need for at least four 25-million ton per year coal slurry pipelines to supplement expanded rail and barge systems by 1985. That forecast is predicated on the assumption that there will also be 60 new eastern rail-barge systems, 70 new western rail-barge systems, two new gas pipelines, 8,000 new railroad locomotives and 150,000 new 100-ton hopper cars.

The magnitude of the coal transportation problem is increased by the fact that the need for expanded capacity will not occur evenly. Since neither the supply of coal nor its demand are uniform, some areas will need only improvements to existing systems to cope while others will require the creation of a practically new system.

The challenge is not beyond us, but it will require the best efforts of every energy transportation system available. I have serious doubts that an aging rail system, built to serve an earlier era, can handle the job alone.

The Association of American Railroads claims the railroads can handle all the coal that is produced, but there is no evidence that this is so. They say that coal accounts for a little less than 20 percent of total rail traffic and it can be doubled in 10 years at 2 percent a year, assuming that all other traffic remains the same. That line of reasoning obscures the dramatic increases that will be required in the West where five-fold increases could be needed to avoid shortfalls in deliveries.

The railroads have always carried most of this country's coal. The percentage of total production delivered by rail declined in recent years, but the railroads still handle about 65 percent of all U.S. coal shipments. Most of that traffic--better than 80 percent of it--is in the East and the South. The western railroads account for less than 20 percent of all rail shipments of coal.

The difference between the railroads east of the Mississippi River and those to the west of it is significant today because most of the new coal production is expected in the West. The Federal Energy Administration has estimated that by 1985, Eastern coal production will increase 30 percent to some 670 million tons. But in the West, production of 379 million tons is projected--an increase of more than 300 percent.

The Department of Transportation has noted that the railroads are essentially a 19th century phenomenon, built to satisfy America's agricultural and mining needs when the country was predominately rural. The basic configuration of today's rail system was in place by 1920 and it has not changed significantly since then, despite the dramatic shifts in population and industrial growth since World War II.

The railroads were dominant when the United States changed its energy base from wood to coal, but they did not follow growth that accompanied the transition to oil and natural gas. Today, there are vast new industrial complexes and population centers built around the once plentiful supplies of cheap oil and gas in the South and Southwest. They must convert now to coal energy--Texas, for example, already requires the phasing out of natural gas as a boiler fuel.

Those states have most of the nation's refining capacity, its primary petrochemical industry and its anhydrous ammonia plants on which the farm economy depends for fertilizer. Those petrochemical and fertilizer plants cannot run without large amounts of fuel and electrical energy. This means vast quantities of new coal will be required where little or none was needed before. In Texas alone, where 95 percent of the electrical energy is generated by natural gas, an estimated 127 million tons of coal will be needed by 1985.

There is nothing to convince a prudent man that increases of this magnitude can be handled alone by the nation's railroads, especially those in the West, where the great increases in production and utilization will come.

Fortunately, there are alternatives. In the East, where the distance from the mine to the consumer is relatively short, the coal transportation burden is shared with the trains by barges, trucks and high voltage transmission lines that carry the coal energy in the form of electricity from generating stations at the mine site.

But in the West, and again this is a significant difference, the distances from the mines to the consumer are much greater than those in the East. Those distances eliminate most of the alternatives I have mentioned. In the West, the only alternative is the coal slurry pipeline.

There is nothing new or experimental about coal slurry pipelines. The first patent for a coal slurry pipeline was issued in 1891. The first commercial coal slurry pipeline in this country was built in Ohio in 1957. That pipeline operated successfully for six years. Not only did it produce significant savings in coal transportation, but it stimulated the development of the unit train with its resulting efficiencies.

At the present time, a coal slurry pipeline carries coal 273 miles from the Black Mesa mine in Arizona to the Mohave generating station in southern Nevada. That pipeline has been in operation since 1970. During that time, it has demonstrated the kind of reliability and economy the electric companies will need when they convert to coal. It has been available more than 99 percent of the time and delivers coal at nearly half the cost of alternate modes of transportation.

The Black Mesa Pipeline is operated by a subsidiary of the Southern Pacific Railroad, which boasted in the Wall Street Journal earlier this month about its automated coal slurry pipeline that delivers coal without disturbing the environment. But the major constraint to the construction of other pipelines is the hostility of the railroad industry in general. Five major pipelines are proposed to carry western coal to the energy-hungry population centers of the South, the Southwest and the Pacific Coast. But they are blocked simply because they cannot get permission to pass beneath the railroad tracks.

It is illogical, but true, that coal can move freely in this country in any form except in its natural state in a pipeline. Converted into gas or some other synthetic fuel, it can flow through pipelines. It can be used to generate electricity that travels over high voltage transmission lines. And, coal can be moved, unimpeded, in its natural state by train, or truck or barge. But the unprocessed coal cannot be transported by pipeline simply because the railroads say it can't.

The story of transportation development is in part a story of railroad obstruction; the rail carriers have fought virtually every competitive new technology for moving goods--pipelines, trucks, buses, airplanes, barge lines. It is interesting to note, however, that railroads once had to fight against entrenched interests that were as determined then to preserve the status quo as they are now.

Like the railroads today, the early canal companies blocked potential competitors by refusing to permit the crossing of canals. Later, steamboat companies attempted unsuccessfully to prevent river bridges required by the westward movement of the railroads. A Virginia judge, ruling in favor of railroad passage over a canal, summed up the situation when he said, "Charter companies are ever sensitive at the approach of a rival," and, he added, "if these pretentions are listened to, there will soon be an end of the necessary improvement of the country..."

While coal pipelines will provide competition for the railroads, there is more than enough coal to be delivered. The public interest will be served by the competition and its interests will be protected by the pending legislation. The President's energy message stressed the need for competition, and we wholeheartedly endorse that view.

The railroads complain that competition from coal slurry pipelines will "skim the cream" from the coal transportation business by taking the profitable long distance hauls.

I'm a farmer, among other things, and I know that whenever you have cream there's been some milking going on. It's obvious to me, in this case, that it's the consumer who is getting milked.

Two recent studies, one done at MIT for the Department of Transportation and the other at Penn State support my view. Both studies say the "cream skimming" argument implies that the railroads are not pricing their services properly.

Alec Sargent at MIT says the idea that there is cream to be skimmed suggests that one class of customers -- consumers of electricity, for example -- is required to pay more than they should for the service they get. Both Sargent and Richard L. Gordon at Penn State say the simple answer to "cream skimming" is to make appropriate rate adjustments.

Without competition, however, the public has no alternative but to pay the extra rail transportation charges. Unfortunately, the public generally does not realize how much transportation contributes to the cost of the energy they consume.

The meaning of this is obvious. The long distance

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transportation of large quantities of coal by truck is not practical. There are no waterways in most of the West for barge traffic. So the coal in the western mine fields must either be converted into energy at the mine site, with the heavy water requirement that entails, or it must be moved by rail. Without coal slurry pipelines, there will be no competitive force whatsoever to help stabilize the cost of coal to the consumer.

Since transportation accounts for up to 80 percent of the delivered price of coal, the consumer desperately needs some alternative means of transportation if he is to have any protection at all. A good example of what can happen without competition occurred recently in San Antonio.

The situation there, briefly, was that the City of San Antonio began switching from natural gas to coal for its steam generating plants. Without competition from coal slurry pipelines, the Burlington Northern's rates for transporting the city's coal from Wyoming have increased from the opening quotation of $7.90 a ton in 1973 to a proposed rate as high as $17.34 a ton.

The city complained that these increases were unreasonable and unjust. They argued to the Interstate Commerce Commission that other unit train rates were lower than they were being charged, but the railroad replied--note this carefully--the railroad replied that the rates quoted by the city "are rates <u>depressed by competition</u> and are not suitable for comparison purposes."

On the question of the escalating rates, the railroad argued that the city should not be concerned by the increases because the rail rates were still cheaper than either oil or gas and besides the city is--and I quote--"at liberty to pass on to their customers any increase in costs without the necessity of obtaining specific approval from any regulatory agency."

The ICC responded to that argument by observing that it had "more regard for the public interest than such a proposition would allow." And, in an extremely rare action, the ICC concluded that the rate imposed on San Antonio was, in fact, unreasonable and adjusted it downward, but it is still over $11 a ton at the present time. And that does not count the estimated one dollar a ton cost associated with the city's having to purchase and maintain a fleet of 810 coal cars.

Unit train rates are set by negotiation. They cannot be higher than the rate for delivery of a single car or lower than the railroad's actual cost. But within that range there is a great deal of latitude, and in the absence of competition, the San Antonio case demonstrates what can happen.

Then there is the matter of the escalation clause, which calls for rate changes on July 1 of each year. Railroads are labor intensive. Seventy percent of their costs are subject to inflation. Since the rates for San Antonio escalated so quickly, imagine what the future holds now that the United Transporation Union, which represents most railroad workers, has announced its plan to ask for pay increases of 15 percent in each of the next three years.

Is it any wonder that far-sighted utility executives want the benefits that coal slurry pipelines can provide for their customers? The pipelines are capital intensive and highly automated. Once installed, about 70 percent of their costs relating to capital investment are fixed. Only the remaining 30 percent relating to labor, electric power and supplies are variable and subject to inflation. For this reason, pipeline operating costs, unlike those of the railroads, are relatively stable over long periods of time.

We are asking Congress to establish a procedure to make construction of coal pipelines possible. The bill we support (H.R. 1609) provides no Federal funding, approves no single pipeline and appropriates no water for use in the pipelines. But it would permit a properly certified pipeline builder to exercise the carefully protected right of eminent domain for the acquisition of rights-of-way. Hearings on H.R. 1609 were conducted by a joint subcommittee of the House Interior Committee last month, and we are hoping the joint subcommittee will act favorably on that bill next month.

The process described in H.R. 1609 for obtaining a certificate of convenience and necessity includes a rigorous review of each pipeline proposal before any builder obtains a certificate of convenience and necessity permitting him to exercise the right of eminent domain. Following construction of the pipeline, the bill further provides that it is to be regulated by the Interstate Commerce Commission as other pipeline common carriers. The bill also prohibits the use of eminent domain to obtain water and declares that the act is not to be construed as affecting any state laws relating to water rights.

Eminent domain is the only way to penetrate the network of rail barriers. Unfortunately, most of the rail industry clings to its tradition of fighting competition from any quarter. When it comes to pipelines, that tradition was established a century ago. It became apparent that pipelines were the most efficient way to transport crude oil, but the railroads were determined to hold the business by barring pipeline companies from crossing their tracks. The impasse was resolved finally by State grants of eminent domain authority for oil pipelines.

That did not end the matter, however. The railroads managed to fight off the longer interstate lines right up to World War II. Finally, Congress had to step in with Federal eminent domain to clear the way for construction of the pipelines which fulfilled wartime needs in the northeastern United States.

Provision of eminent domain by the Federal government is not unusual. In 1875, the Department of Interior not only granted the power of eminent domain to railroad companies, but the railroads were entitled under that particular authority to acquire the resources from adjacent lands which they were not given: timber, fill, rock, and so forth.

In 1902, the Secretary of the Interior was authorized to acquire property under eminent domain for irrigation projects specifically to be used by private individuals.

In 1920, the Federal Power Commission was empowered to grant the right of eminent domain for land to construct the necessary reservoirs and lines that a licensee could not acquire by contract.

In 1935, the Secretary of Interior was authorized to approve eminent domain for acquisitions by private companies for the purpose of conserving, producing, buying and selling helium. In 1938, the same right was granted to natural gas companies, and in 1953, eminent domain was authorized to facilitate the construction of pipelines for the transportation of oil, natural gas, sulfur of minerals.

Some states have acted to resolve the pipeline right-of-way issue for themselves since the 1975 hearings. As you may know, the legislatures in both Texas and Oklahoma have passed bills to provide eminent domain for coal slurry pipelines. They join five other states--North Carolina, West Virginia, Ohio, North Dakota and Utah--that provide eminent domain for coal slurry pipelines by specific legislation and a number of others that grant it in general legislation.

The actions of these states do not diminish the urgent need for federal eminent domain legislation. They do illustrate, however, the serious concern of those states over the need for new sources of fuel, and especially for conversion to coal. More to the point of this hearing, state action demonstrates the growing recognition of coal slurry pipelines as an important aid to coal conversion.

Coal slurry technology is well established. Congressional committees over the years have received an abundance of testimony attesting to the fact that coal can be transported in a liquid mixture called slurry. The slurry is formed by mixing a fluid, usually water, with coal that is pulverized to about the size of sugar. The water and the pulverized coal are mixed at a preparation plant in approximately equal parts and the resulting slurry is then introduced into a pipeline where large piston pumps push it on its way. Pumping stations every 80 to 100 miles, keep the slurry moving through underground pipes to dewatering facilities at the pipeline's terminus. There the slurry is separated by centrifuges that spin the water from the mixture. The coal then can be burned and the water used for cooling processes associated with the coal's combustion.

The success of pipeline transportation is well known. In the past century, hundreds of thousands of miles of pipelines for crude oil, petroleum products and natural gas have been laid all across the country. The totality of that experience has been extended to coal pipelines. The only significant difference is in the nature of the pumps required. Slurry pipelines are presently transporting over two billion ton-miles a year of coal, iron, limestone, copper, phosphate and other like materials in various parts of the world.

Five major slurry pipelines have been proposed as shown on the attached map. They include Energy Transportation Systems Inc.'s line connecting Wyoming with Arkansas; Houston Natural Gas Corporation's line from Colorado to Texas; the Wytex system from points in Montana and Wyoming to Texas, Northwest Energy Corporation's and Gulf Interstate Company's line from Wyoming to Oregon and possibly Washington, and the Alton line, planned by Nevada Power Corporation, from southern Utah to the Las Vegas area.

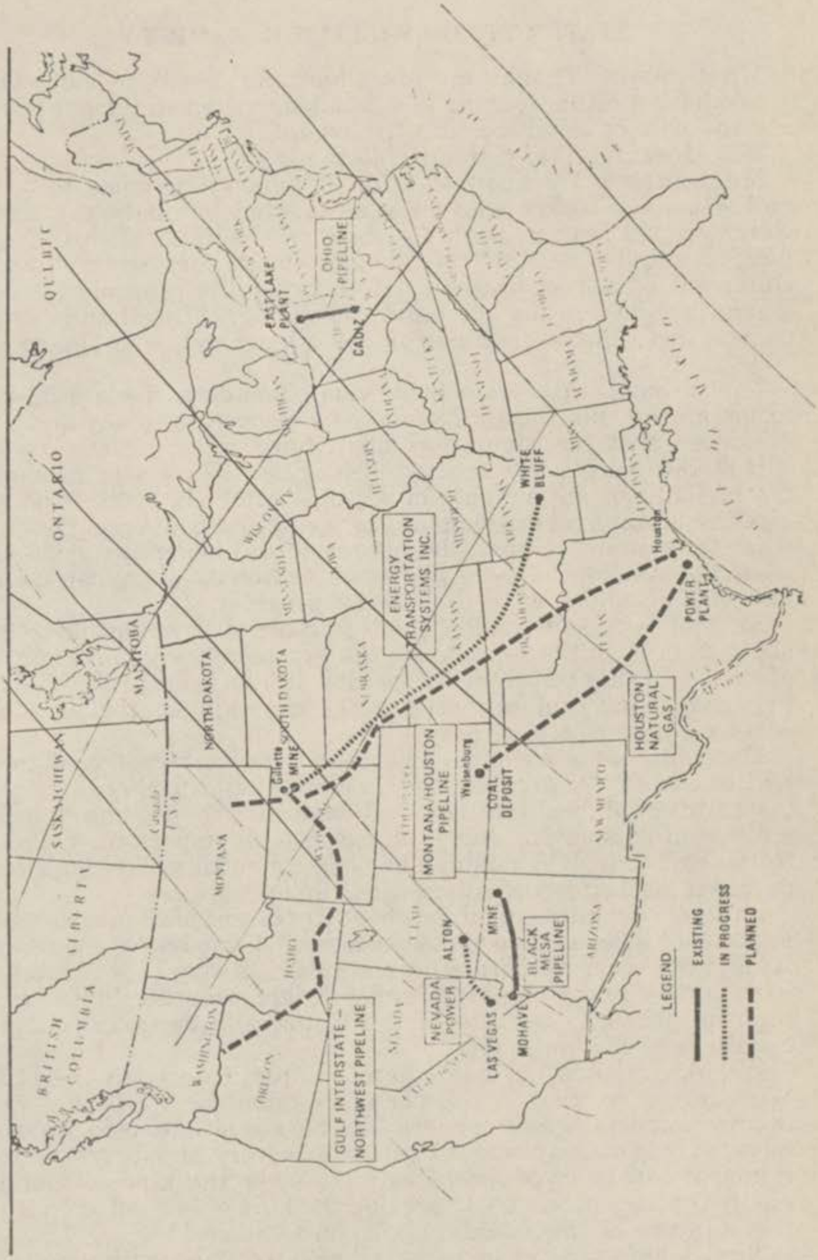
Railroads are in a position to block all but the last proposed line. Although the 183-mile route from Utah to Nevada requires two rail crossings, locations have been found on public resource land under the United States Bureau of Land Management, where the Secretary of Interior already possesses the authority to approve easements for coal slurry pipelines.

The Congress must decide whether all truly helpful technology will be available to move the coal required to carry out portions of H.R. 6831.

We are asking the Congress to provide eminent domain authority because it is the only way to cut through railroad obstruction on a timely basis. Coal slurry pipelines have proven their feasibility. Private capital is available to build them. We believe this technology should be available where it can serve the public interest, and we hope the Congress will agree that the availability of a supplementary coal transportation system to assure reliability and competition is in the public interest.

Thank you.

COAL SLURRY PIPELINES



Mr. MOFFETT. Mr. Dempsey?

STATEMENT OF WILLIAM H. DEMPSEY

Mr. DEMPSEY. Thank you, Mr. Chairman. I will be quite brief. I do have a rather lengthy and detailed written statement which I assume will be admitted into the record.

Mr. MOFFETT. Yes, without objection.

Mr. DEMPSEY. We knew that Mr. Jennings was going to testify, and we sort of took a wild guess as to what he might say, and as chance would have it, we hit it right on the head. With that good luck, I will be able to rely for the most part on my written statement in respect to the debate between the proponents of coal slurry pipelines on the one hand and the agricultural and environmental and railroad interests on the other hand, who oppose H.R. 1609.

That debate, of course, is being carried on extensively in another forum on the Hill, though I want to be responsive to any questions, of course, that the committee might have.

H.R. 1609 may not be enacted. If it is, coal slurry pipelines might not be built for any number of reasons. After all, there is no such pipeline of any real consequence in operation. So, it occurred to us what the committee might be interested in having our views on is what the system that is in place, the railroad system, can manage in terms of adjusting to the energy program.

So, that is what I would like to talk about. I would like to talk about the role of the railroads in the proposed energy program and, of course, in that respect what we look at is the role of the railroads in transporting coal primarily, since the shift to coal is such a centerpiece of this program.

The railroads are the number one transporter of coal in the United States. As Mr. Jennings, I believe, indicated we carry about two-thirds of all coal that is mined domestically. Looking at it from a different perspective, coal is an exceedingly important commodity to the railroads. It is our number one commodity. We don't really do anything better than carry coal in unit trains.

Last year coal accounted for about 29 percent of tonnage originating on rail lines, and about 14 percent of our gross freight revenue. Really, the energy program presents the industry as we perceive it with both a major challenge and a bright promise. It is a bright promise primarily because of the historically depressed financial condition of the railroads.

We have a situation now, therefore, particularly in the Middle West, where we have a number of marginal railroads that would become important coal carriers. We have a situation in which we have an opportunity now to better in a very significant way the financial capability of the industry to make the kinds of improvements that are necessary to provide the kind of level of service that the shippers of this country really are entitled to.

Now, what steps have to be taken? We have outlined them I think in considerable detail in my statement. Let me just summarize some of the highlights.

We, of course, will need substantial additional equipment—hopper cars and locomotives. The figures that we are looking at there, however, are not really startling. We calculate, for example, with respect to freight cars that we would need something between 9,700 and 13,400 additional coal cars a year if the program is carried out as the President projects it. That is to be compared with some 16,000 coal cars on the average that the industry has ordered for the last 3 years.

Really, what we have been doing is gearing up to a doubling of coal production by 1985 as President Ford announced originally. So, our pace of acquisitions for the last 3 years in short is ahead of what will be necessary to put the industry in a position to deal with the new target, 1985 target, under President Carter's proposals.

The same situation in general obtains with respect to locomotives. The detail again is contained in my statement.

We should have no difficulty with respect to lead times. We can secure freight cars and locomotives on the average in 3 to 5 months; rail in 90 days. It takes, in contrast, some 4 to 5 years to put a mine into production, some 8 to 10 years for an electric utility generating plant to come on line after the initial decision.

The network, the rail network, most assuredly has the necessary excess capacity. Indeed, that has been our problem as an industry now for many years. It has never been suggested by anyone that we have a shortage of capacity. We have been charged time and again by the Transportation Department and the Congress to reduce our excess capacity by consolidations and coordinations and the like.

One figure I think is sufficient to underscore the fact that seems to me to be pertinent here, and that is this: Today we are operating less than 50 percent train miles per mile of track than we did at the end of the Second World War. That gives you some idea as to the surplus capacity that we have in our network.

Now, the problems that we will have will be problems of generating sufficient capital to buy the equipment and to make the necessary track improvements. Most of our main lines in the country outside the Northeast are in good shape. That is not true of all main lines in the Midwest. It is not true of all main lines in the Northeast.

There is a $6 billion renovation program underway in the Northeast by virtue of ConRail so that it seems to us the efforts that are being expended there ought to be adequate. We will have to upgrade secondary lines. As I say, we will have to purchase the cars and locomotives that I have described.

When one is dealing with the kind of a program that represents such an important strengthening of the financial condition of an industry, we do not see any insurmountable difficulties in securing this kind of capital, even on the part of the railroads that otherwise are marginal, and that if one were looking at in terms of other programs—that is to say, other less promising programs—it might present some difficulties.

There is one problem, and now I return to my friend Mr. Jennings' point, and that is this: It has to do with the last question that I discussed; that is, the financial capacity of the industry to generate sufficient capital to make the improvements that are necessary.

We are confident that can be done, but that confidence does not extend to a situation in which coal slurry pipelines would enter the picture in any significant way; that is to say, the financial community may think one thing of a railroad like the Northwestern's proposals to build along with the Burlington Northern 110 mile new line to the Powder River basin.

They might think quite differently of that kind of proposal if what is in the picture are not necessarily existing coal slurry pipelines but the threat of coal slurry pipelines that would operate in much the way a unit train does, from one source of supply to one or to a few consumers, taking some 25 million tons of coal a year on one pipeline, with 20 to 30 year binding throughput contracts.

This is the cream of the coal business. It is the kind of business that is the most profitable for the railroads, the kind of business that we do the best. If that best part of the business is siphoned in any significant way away from the railroads, then I cannot say what the financial capacity of the industry would be to meet the challenge that is posed by the President's program.

Mr. Jennings observes that there are five coal slurry pipelines spoken about in the West now. If each of them were of the magnitude of the one that is proposed for Arkansas, we would be talking about 125 million tons a year, or over 40 percent of the increase in coal production that would otherwise go to the railroads.

I think, Mr. Chairman, that that concludes the remarks that I would like to make. I would be happy to respond to any questions that anyone might have.

[Mr. Dempsey's prepared statement follows:]

STATEMENT OF WILLIAM H. DEMPSEY
PRESIDENT, ASSOCIATION OF AMERICAN RAILROADS

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER OF THE
INTERSTATE AND FOREIGN COMMERCE COMMITTEE

ON

H.R. 6831

A BILL TO ESTABLISH A COMPREHENSIVE
NATIONAL ENERGY POLICY

My name is William H. Dempsey. I am President of the Association of American Railroads, with headquarters in Washington, D. C. The railroads which are members of the Association operate 96 percent of the trackage, employ 94 percent of the workers and produce 97 percent of the freight revenues of all railroads in the United States.

I appreciate the opportunity to appear before you today as a member of this panel to present the views of the Association and its members on Title 1, Part F of H.R. 6831, provisions of the Administration bill to establish a comprehensive national energy policy dealing with conversion to coal.

In my statement I will focus on the relationship between the railroads and the expansion of coal production--the ability of the railroad industry to carry any projected volumes of coal, and the importance of this new traffic to the railroads. I shall direct the thrust of my remarks in particular to Question 5(c) of the "Questions for Witnesses" submitted by the subcommittee, which addresses transportation constraints to increased coal production. Other material, including the statistics in the attachments to my statement, may also be helpful to the subcommittee's review of this vital subject.

On April 20, 1977, the President unveiled a new energy program which had, as one of its major features, a call for a greater reliance on coal in meeting the nation's energy needs. Among other things, the President projected a two-thirds increase in annual national coal production by 1985 and conversion to coal by utilities and other large industries. To meet the President's coal production goal of 1.1 billion tons a year by 1985, an average annual increase of 53 million tons will be needed, starting with 1978. This would represent an 8 percent average increase per year over the projected 1977 production level.

The railroads are a vital link in the coal production chain. The railroad industry hauls about two-thirds of all coal produced. The rest is divided almost equally among barges, trucks and mine-mouth generation. If the railroads maintain their present share of coal transportation, the projected increases would produce increases in rail coal tonnage of 35 million tons per year.

The railroads look forward to this growth in an important traffic. The railroads have always been an integral part of the system by which coal is ultimately converted into electric power or other usable forms of energy. Coal is the largest single commodity carried by the railroads.[1/] In 1976, it represented the following for the nation's major railroads:

- 29 percent of rail tonnage originated--407.5 million net tons.
- 20 percent of total carloadings--4.7 million carloads.
- 14 percent of gross freight revenues--$2.4 billion.

Coal traffic has historically been a profitable source of revenue to the railroads, and has thus been a crucial factor in enabling the railroads to maintain even their present extremely modest level of profitability. Net railway operating income for the industry in 1976 was $430 million, up from $351 million in 1975 but quite a bit below the pre-recession level of $763 million in 1974. The estimated average rate of return on net investment for 1976 was 1.56 percent, compared with 1.20 percent in 1975 and the pre-recession level of 2.66 percent in 1974.

Coal traffic and revenues are not now spread evenly throughout the railroad industry. As a matter of fact, seven railroad systems now account for:

- 83.0 percent of total railroad coal revenues.
- 85.2 percent of total railroad coal carloadings.
- 84.1 percent of total coal tonnage originated.

1/ Attachment A presents a number of important statistics on coal production and the role of the railroads in hauling coal, including the significance of coal traffic to rail carriers.

The total operations of these rail systems account for 54.2 percent of the industry's gross freight revenues, and these figures reflect the significance of coal traffic to each:

> Norfolk and Western--64.1 percent of its originated tonnage and 40.8 percent of its revenues.
>
> Chessie System (B&O/C&O/Western Maryland)--60.6 percent of its total originated tonnage and 35.3 percent of its total revenues.
>
> Family Lines System (SCL/L&N/Clinchfield)--33.2 percent of originated tonnage and 18.4 percent of revenues.
>
> Burlington Northern--36.1 percent of originated tonnage and 17.5 percent of revenues.
>
> Conrail--28.0 percent of originated tonnage and 13.0 percent of revenues.
>
> Southern Railway System--28.3 percent of tonnage and 11.9 percent of revenues.
>
> Illinois Central Gulf--31.4 percent of tonnage and 9.8 percent of revenues.

Projected increases in coal production in the West will mean that coal traffic will take on a new importance for a number of railroads, which have not, in the past been considered major coal-carrying roads. Among such other railroads expecting to haul significant amounts of coal are the Union Pacific; the Chicago North Western; the Atchison Topeka and Santa Fe; the Chicago, Rock Island and Pacific; the St. Louis-San Francisco; the Missouri Pacific and the Chicago, Milwaukee, St. Paul and Pacific.

A number of the more marginal railroads are among those that look forward to substantial jumps in coal traffic. The prospect of increased coal traffic forms a large part of their hope for escaping from their current marginal condition back to solid financial standing.

As Attachment A also shows, the railroads have made headway in handling this important traffic with improving efficiency. Railroads have replaced older coal cars with larger cars of improved design, achieving an increase in the carrying capacity of the average coal car of 13 percent in the last eight years alone. Unit trains devoted solely to the movement of coal, about which I shall have more to say later on, have also helped the railroads improve service to coal shippers and users while keeping transportation costs down. The percentage of coal moving in unit trains has grown from 27 percent to 46 percent in the last eight years.

Some questions have been raised about the railroads' basic ability to continue to keep pace--in terms of carrying capacity--with the increasing requirements for coal transportation. These doubts have been voiced primarily by those with an interest in doing so--such as proponents of coal slurry pipeline construction, who want to establish a case for public need of coal pipelines, in order to justify the passage of special-interest legislation to facilitate the construction of pipelines to serve a few volume users. There is, however, no plausible reason to conclude that the railroad industry does not have the inherent strength to meet the increased traffic demands coal places on the railways.

The 8 percent average annual increase in coal tonnage implied by the President's stated goals translates into an average annual increase of less than 3 percent in existing total rail tonnage of all commodities, assuming the railroads maintain their present share of coal transport. That this presents no insurmountable difficulty is suggested by the fact that the railroads handled a 5 percent increase in total traffic during 1972 and a 10 percent increase during the last pre-recession year of 1973.

The 3 percent growth in traffic that will be occasioned by the projected growth in coal output is well within capabilities of the railroad industry. In fact, the railroad industry has been gearing up for the doubling of coal production by 1985, the stated goal of the previous administration's energy program. In the last three years, new open top hopper orders and deliveries have tripled. It is estimated that the present rate of acquisition of new hopper cars is more than adequate to fulfill the nation's coal transportation needs under President Carter's energy program. In fact, the present delivery rate is probably adequate to handle a doubling of coal traffic. Because coal production has not, so far, expanded at a rate great enough to meet the projections, the industry is now ahead of schedule in expanding its open top hopper fleet to handle its share of forecasted increases. Surpluses of available coal cars have exceeded shortages by an average of 6,300 cars in recent months.

Improved utilization of coal hopper cars will also help the railroad industry meet future growth in coal traffic. The principal means for improving coal car utilization is greater use of "unit trains." The unit train is a train wholly dedicated to moving a single commodity between fixed points on a continuous basis, like a conveyor belt. It was originally developed to enable railroads to reduce their transportation costs. Since its introduction some 16 years ago, the unit train has become clearly established as generally the most efficient and economical means of handling the delivery of coal to power plants or other large industrial users. Since the unit train presents advantages both to the railroad and the customer, the emphasis in expansion of railroad coal-hauling capacity is certain to be on unit train service, particularly since the users of added coal production will be primarily utilities and other large coal consumers.

The extent to which unit trains improve car utilization is reflected by the experience of one railroad which formerly used 2,400 open top hoppers to ship 3-1/2 million tons of coal a year from eastern Kentucky to northern Illinois. It is now using 892 cars in unit train service to deliver the same amount. The train operates on "loop tracks" at each end of the run and is loaded and unloaded without stopping, thus contributing to maximum efficiency.

To handle the new coal traffic which would be generated by the President's goals, and to replace older cars used to haul existing coal traffic, from 9,700 to 13,400 coal cars must be acquired annually for the next eight years, depending on the degree of unit train operations. As Attachment B shows, the number of new coal hopper cars required to transport the prospective increases in coal production depends on whether one assumes a low or a high use of unit trains to move this coal. Since most of the coal will be used by utilities for generation of electricity, it is reasonable to assume that most of the new coal will be amenable to unit-train delivery, so that requirements will work out to be closer to the lower figure.

In recent years deliveries of new open top hoppers have averaged 20,000 annually, three-fourths of which were destined for coal service. The Railway Progress Institute, the national association of the railway supply industry, performed a survey in 1975 of the capacity of that industry to produce coal cars. It was learned that major car builders would be able to produce as many as 72,000 coal cars per year--and that additional capacity exists in railroad car-building shops.

The projected coal production increases will also require increases in the railroad locomotive fleet. Annual locomotive needs for added coal traffic over the next eight years will total somewhere in the range of 280-470 depending on the utilization rates achieved through unit train operations (see Attachment B). Again, this will be a achievable requirement, in view of the fact that new and rebuilt diesel locomotives installed averaged 1,300 per year from 1972 through 1975.

Further, it is all but inconceivable that the railroads could be caught unprepared by a surge in coal production. A new coal mine takes four to five years to bring into production. The time lag from decision to production for an electric generating plant is eight to ten years. By contrast, elapsed time between the order of a new car or locomotive and its delivery is presently about three to five months.1/ Rail can be delivered

1/ The worst lagtime in car delivery schedules experienced in the last decade has been about 18 months, and that was in a period when total rail traffic grew 15 percent in two years.

in 90 days. All of these conditions reflect the inherent ability of railroads to meet increased demand on any logically foreseeable timetable. Thus, it is extremely unlikely that a railroad could be caught unprepared to move coal.

Finally, there is the issue of the physical capacity of the fixed rail plant to serve increased coal traffic. There can be no question about the potential ability of the rail system's fixed plant to handle the projected increases in coal traffic. Total train-miles per mile of road operated are less than half what they were at the end of World War II, while the capacity of many rail lines has actually been increased since then by the installation of sophisticated electronic signalling and communications equipment. One double-track railroad with centralized traffic control, for example, has the theoretical capability of handling 300 million tons of coal per year, the capacity of a dozen coal slurry pipelines. We say theoretical because no single line of railroad, even under the most optimistic projections, will be called upon to handle 300 million tons per year.

While this enormous potential capacity exists, there are just as clearly problems with the physical condition of some segments of the rail plant. Most of the nation's mainlines outside the Northeast are in top-flight condition, ready to carry the increase in coal traffic that is forthcoming. Other mainlines in the Northeast, some areas of the Midwest, and secondary rail lines throughout the nation are not presently in a physical condition in which they could handle large increases in coal traffic while continuing to serve other shippers. Twenty years of diminishing rail traffic on these lines and inadequate rail industry profits generally have required that prudent management not demand that these lines be maintained to the standards of more heavily used track. The deferred maintenance that has occurred on these lines is well known to us all.

The forthcoming growth in coal traffic may be expected to require that some of these lines be upgraded. This restoration of these lines will require substantial capital funds which the industry must raise and justify on the basis of its overall earnings. Nevertheless, of the physical ability of the industry to upgrade these lines--and to do so quickly, well in advance of any actual surge in coal traffic--there is no question.

I believe I have demonstrated that the carriage of vastly increased coal tonnages is not beyond the physical or operational capabilities of the railroad system. But, it might be asked, what of the financial capabilities? With optimum implementation of unit train operations, the eight-year cost for acquiring sufficient locomotives and freight cars to retain the railroads' current 67 percent share of coal production would amount to $4.3 billion--costed at 1976 prices--or $540 million per year, as shown in Attachment B. This includes an addition of 5,600 open top hopper cars and 280 locomotives per year to haul the additional 283 million tons of coal expected to be generated by 1985 at a cost of $310 million per year; and it includes purchases of 4,100 coal cars and 205 locomotives annually to maintain the industry's current 442 million ton coal-hauling capacity at a cost of $230 million per year.

Should the 67 percent increase in coal traffic come about in a manner that would not utilize unit trains as the preponderant method of movement--which is unlikely--the equipment requirements could escalate. Under such a conservative scenario, additional coal traffic and replacement for existing traffic would require as high as 13,400 new cars and 670 locomotives per year for a total cost of $5.9 billion--again at 1976 prices, or $740 million per year, of which $510 million per year would be for fleet expansion.

These amounts are clearly manageable when seen in the context of what the railroads are currently spending for replacements and additions to the equipment fleet. Expenditures on new cars and locomotives by railroads, leasing companies, private car lines, and shippers have been running in the range of \$1.6-\$2.0 billion per annum during the past three years. Thus a boost of \$300 to \$500 million in equipment spending (depending on extent of unit train operations) to accommodate the growth of coal traffic amounts only to an increase of 20 percent or so in the current level of equipment outlays.

Where the financial capabilities of some railroads to handle the expected growth in coal traffic may be called into question is in the area of fixed plant improvements. Many of the major coal haulers--like the Chessie, the Norfolk & Western and the Burlington Northern--are in relatively sound financial condition. They should have little or no trouble financing the improvements to their secondary lines needed to handle new coal traffic where the profit potential of that traffic warrants.

Once long-term increases in coal traffic are almost assured--traffic that historically has been profitable to the railroads--the financial community should have fewer qualms about providing investment funds for increased coal-carrying capacity. Railroads that might have difficulty obtaining financing for other worthy purposes should not encounter such difficulty in obtaining capital for profitable operations.

You need not rely on my word or the opinion of the railroad industry as to its ability to handle projected growth in the coal traffic. A number of independent studies have upheld the railroads' contention that they can easily develop the needed coal-carrying capacity.

The accounting and consulting firm of Peat, Marwick, Mitchell & Co., in a report for the Federal Energy Administration, the Commerce Department and the Department of Transportation in 1974, made assumptions of far greater coal production than is now anticipated and their estimates of railroad equipment needs to match those assumptions indicated no significant difficulty for the industry.

An information circular entitled Long-Distance Coal Transport: Unit Trains or Slurry Pipelines released by the Bureau of Mines in 1975, concluded that: "The capacity of the railroads to cope with substantially more western coal does not seem to be an unduly serious matter."

A 1976 study by the Hudson Institute agreed, stating: "We feel railroads should be able to haul initial requirements with little effort and given investment in cars and motive power, should be able to increase haulage as fast as the mines can increase production."

A fourth report prepared in April 1976 for the Department of Transportation, entitled Rail Transportation Requirements for Coal Movement in 1980 involved a survey of a number of major railroads in each of the three regions in the United States.[1/] In the report, it was predicted that increased coal traffic could help rather than hinder the movement of other commodities, noting that "the majority of the railroads are planning for projected total traffic, including anticipated increases in other commodities, on their systems. All of them indicated that they

1/ By Input-Output Computer Services, Inc.

would be able to absorb the anticipated coal traffic without any adverse effect on movement of other commodities." The report stated that: "The anticipated coal traffic increases, even though affecting individual railroads unevenly, would not place unmanageable strain on rail capacity."

The Federal Power Commission just completed in January of this year the most extensive study ever undertaken by a federal agency on new coal supply for new electric generating units. A survey of utilities that was part of this study showed that most foresaw no significant problem in the railways' capacity to move the new coal traffic of over 350 million tons.

One study of the subject did call the railroads' ability to move greatly increased coal tonnages into question. That study was one performed by Manalytics, Inc., and published by the Electric Power Research Institute.

That study's ultimate conclusions rest upon a series of assumptions about coal production and the nature of coal traffic, beginning with the notion that coal consumption will increase by 156 percent between 1973 and 1985. A further assumption was that the railroads would handle 100 percent of all coal production, diverting all of the coal which now moves via barge, via truck and even the 11 percent currently being used at the mine-mouth. It is also stipulated that all coal must move in only partially loaded cars by the shortest available route--even if an alternative route is only a few miles longer or a superior operating route.

This combination of extremes results in projected increases of 359 percent in rail carloadings and 573 percent in ton-miles of rail coal traffic, compared with 1973 levels. The conclusion, under these circumstances, was that potential trouble cannot be ruled out on 15 percent of the critical rail links over which coal would be transported if such links remain in their present physical condition. Even under this highly unlikely set of assumptions--rougly triple the projection of the current Administration--no difficulty was anticipated for the railroads in acquiring needed equipment.

To understand the potential benefits of new coal traffic to many components of the industry, it is only necessary to recall that a problem for the railroads in recent years has been huge amounts of unused plant capacity. With total train-miles per mile of road operated 50 percent below what they were at the end of World War II, the fixed costs of maintaining and operating this plant have had to be spread over decreasing amounts of traffic, thus raising unit costs. Now, that problem may prove a blessing--because this capacity was built at a cost far lower than would be possible today.

The need for additional coal transportation gives the railroads an opportunity to turn their own national liability into a national asset. The overcapacity, which has been an increasing revenue drain on the railroad industry, is waiting to be put to work carrying coal to industrial centers and utilities throughout the country. The growth in coal traffic can be easily accommodated on the underutilized railroad system.

Fixed costs will be spread over more units of traffic, so that unit costs should go down. In this way, the growth in coal traffic should contribute to a more than proportionate growth in rail profit.

All of this will be of multiple benefit to all shippers who rely on railroads. Gains in coal traffic that lower the unit cost of fixed expenses help to hold down rail rates for shippers of all commodities. Assurance of expanded coal traffic carries with it assurance of access to financing for improvements to the fixed rail plant. New track, centralized traffic control, and other such improvements will redound not only to coal shippers but all shippers who use the rail system.

One of the reasons that I stress the importance of coal traffic and particularly the projected growth in coal traffic to the railroads is that there is a dark cloud on this otherwise bright horizon. That dark cloud is the threat to rail coal traffic posed by coal slurry pipelines. Over a dozen coal slurry pipelines have already been proposed. Even if only five of these were built, each with the capacity of the one whose planning has progressed furthest--25 million tons per annum--the traffic diversion from the railroads could be as much as 125 million tons per year. This would constitute a loss of over 40 percent of the growth in coal traffic between the present and 1985 that the railroads expect to realize by maintaining their current share of the traffic.

Just one coal slurry pipeline could have a devastating impact on individual railroads. Consider that the total coal tonnage of many railroads today is well below the 25 million tons per annum capacity of one pipeline. For example, the coal tonnages carried by some of the more marginal mid-western railroads in 1976 were:

Missouri-Kansas-Texas	1 million tons
Rock Island	2 " "
St. Louis-San Francisco	5 " "
Chgo., Milwaukee, St. Paul & Pac.	9 " "
Chicago and North Western	16 " "
Illinois Central Gulf	24 " "

These railroads would be appreciably and immediately affected by the proposed coal pipeline cream-skimming operations at a time when they can ill-afford it. The proposed coal slurry pipelines would not be operated as common carriers. They would operate more as an extenuated form of contract carriers, under 20 to 30 year contracts that may permit no new customers, carrying coal from one or a few large producers to one or a few large consumers. This is the "cream" of the coal traffic and this is the cream that would be skimmed by the pipeline operators, while railroads, as true common carriers, would be required under Federal regulation to provide service to all remaining customers, including the less desirable, low volume traffic not profitable for pipeline carriage.

It is the intention of potential pipeline operators to finance their projects by locking interested utilities into long-term commitments through the use of through-put contracts. A contracting utility would be required to use the pipeline's service or pay for it as if it had been used for the full term of the contract. No railroad rate has ever been approved that would permit such a long-term commitment.

If significant amounts of this traffic are assumed to be tied up in long-term contracts with coal slurry pipelines, the potential for growth throughout the industry may never be realized and many railroads could continue to be hard-pressed to raise their earnings to adequate levels. Further, no provident bank will finance all the needed investment in equipment and facilities for hauling coal without some assurance the traffic will materialize. Thus, the prediction that the railroads could not handle increased coal production--which, as I have shown you, is foolishness today--could be made into a self-fulfilling prophecy.

The effects of that prophecy will extend far beyond coal carriage -- since railroads, unlike slurry pipelines, carry a wide range of commodities of great importance to the public welfare. The loss of these large volumes of future coal traffic will impact immediately and forcefully on the multitude of agriculture and manufacturing interests--large and small--which depend on rail service. Furthermore, railroads are the most fuel efficient mode of transport for most commodities. If the loss of coal traffic so debilitates the railroads that large amounts of other traffic are diverted to the highways, the nation will suffer a further setback in reaching its fuel conservation goals.

In conclusion, may I observe that a national policy to significantly increase production and use of coal--and to convert utilities to coal use--does carry with it a number of problems.

I believe the government faces a difficult challenge in creating a climate in which its energy goals can be achieved in the face of valid environmental considerations that arise in connection with the mining and burning of coal.

It is the hope of the railroad industry that suitable answers to these potential environmental problems will be designed so that these problems do not defeat the solution to the energy crisis that coal offers.

Fortunately, rail transportation of coal is not one of these environmental problems. No other mode of transportation offers a cheaper, more fuel-efficient, or environmentally "cleaner" means of moving coal. And the railroads stand ready and eager to do the job.

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Attachment A

HOPPER CARS, COAL LOADINGS, REVENUES, PRODUCTION AND CONSUMPTION

Year	Open top hopper ownership and capacity -- all owners				Coal carloadings -- Class I railroads (4)	Coal tons originated -- unit train movement -- all railroads			Coal revenues -- Class I railroads	Coal traffic as related to total tonnage/revenues/carloadings -- Class I railroads		
	Total cars in open top hopper fleet 12/31 (1)	Total hopper fleet capacity (000) (2)	Average capacity per car 12/31 (3)	Average coal load per car (3)		Coal tons originated (000) (3)	Tons moved in unit trains (000) (5)	% of total coal tons in unit trains (2)	Gross coal revenue received by railroads (1)	Coal as % of total tons originated (2)	Coal as % of total gross revenues (2)	Coal as % of total carloadings (2)
1968	420 325	29 605	70.4	72.5	5 216 584	400 142	109 125	27.3	$ 1 117 138 009	26.0	11.0	18.3
1969	403 803	28 979	71.8	74.7	5 152 849	405 156	122 722	30.0	1 171 254 393	25.8	10.8	18.2
1970	398 458	28 883	72.3	76.0	5 165 469	425 920	123 288	29.0	1 341 930 453	26.9	12.0	19.0
1971	396 868	29 609	74.6	77.8	4 503 174	380 309	122 832	32.2	1 314 824 710	25.3	10.8	17.8
1972	383 242	29 329	75.9	80.4	4 558 138	399 523	136 536	34.2	1 361 205 930	25.6	10.1	17.5
1973	363 330	28 021	76.7	81.5	4 486 886	400 327	155 093	38.7	1 406 455 000	24.3	9.8	16.4
1974	356 828	27 498	77.1	83.5	4 543 964	413 632	166 000 b	40.0 b	1 924 029 316	23.3	11.2	17.4
1975	363 188	28 510	78.5	84.1	4 692 903	436 810	188 000 b	43.0 b	2 146 056 288	29.1	13.5	18.2
1976	365 528	28 985 b	79.3 b	85.3 a, b	4 699 156	436 843	201 000 b	46.0 b	2 405 000 000 b	29.0	14.0 b	19.9

Year	New open top hoppers ordered/delivered/on order as of 12/31 -- all owners (1)			U.S. coal production (bituminous and lignite) and distribution by modes (Rail share includes all railroads) (3)						Major consumers/total U.S. consumption/exports (3)				
	New cars ordered	New cars delivered	On order as of 12/31	Total production (000)	% of total moved by rail	% of total moved by barge	% of total moved by truck/wagon	% used at mine mouth	% of transported coal moving by rail	Electric utilities (000)	Steel industry (000)	Other mfg. mining ind. (000)	Total U.S. consumption (000)	Exports (000)
1968	8 439	14 712	5 731	545 245	72.3	12.2	11.3	3.7	75.5	294 739	90 743	83 034	498 830	50 637
1969	13 113	10 007	10 787	560 555	71.0	12.7	11.8	4.5	74.4	308 462	92 901	78 557	507 275	56 234
1970	11 920	14 931	9 204	602 932	67.9	13.4	12.3	6.4	72.5	318 921	96 009	83 207	515 619	70 944
1971	11 874	17 543	4 439	552 192	69.2	10.7	10.9	9.2	76.2	326 280	82 809	68 862	494 862	56 632
1972	5 387	7 059	2 725	595 386	68.2	11.7	11.0	11.1	74.5	348 612	87 272	87 294	519 778	55 960
1973	13 356	3 157	10 621	591 723	67.1	11.6	9.7	11.6	75.9	389 879	93 634	60 837	556 022	52 870
1974	27 086	7 323	28 242	603 406	66.0	11.2	11.0	11.0	74.0	390 068	89 747	64 056	552 709	59 926
1975	13 175	21 748	18 949	648 438	65.0	11.0	12.0	11.0	73.8	403 000	83 000	61 000	556 000	66 000
1976	7 515	18 160	6 646	665 000 c	66.0 c	11.0 c	12.0 c	11.0 c	74.2 c	446 000 c	84 000 c	60 000 c	597 000 c	59 000 c

Sources:

(1) AAR Car Service Division and American Railway Car Institute.
(2) AAR Economics and Finance Dept.
(3) Interstate Commerce Commission.
(4) AAR Car Service Division.
(5) U.S. Bureau of Mines.

a - Avg. coal load exceeds avg. car capacity because largest cars are used in coal service. 1976 load average is AAR estimate.
b - AAR estimate.
c - U.S. Bureau of Mines, preliminary estimate.

Economics & Finance Dept., AAR

ATTACHMENT B

HIGH UNIT TRAIN FREQUENCY
(Dollars in millions)

Item	Locos. per yr.	Cars per yr.	Annual invest.	eight-year investment
Replacement cars to maintain current coal traffic	-	4,100	$123.0	$ 984
Replacement locomotives to maintain current coal traffic	205	-	102.5	820
Cars required for additional coal traffic	-	5,600	168.0	1,344
Locomotives required for additional coal traffic	280	-	140.0	1,120
Total	485	9,700	$533.5	$4,268

LOW UNIT TRAIN FREQUENCY
(Dollars in millions)

Item	Locos. per yr.	Cars per yr.	Annual invest.	eight-year investment
Replacement cars to maintain current coal traffic	-	4,100	$123.0	$ 984
Replacement locomotives to maintain current coal traffic	205	-	102.5	820
Cars required for additional coal traffic	-	9,300	279.0	2,232
Locomotives required for additional coal traffic	465	-	232.5	1,860
Total	670	13,400	$737.0	$5,896

Mr. MOFFETT. Thank you.
Mr. Bobzien?

STATEMENT OF H. JOSEPH BOBZIEN, JR.

Mr. BOBZIEN. I am President of American Commercial Barge Line Company. I have a lengthy statement prepared for the record. However, I would like to just highlight some points in my statement.

Our company operates a fleet of over 1,300 barges and 50 towboats transporting such essential commodities as coal, grain, liquids, salt, ores, scrap, steel and newsprint. Our barging operations cover virtually the entire inland system and the Gulf Coast. Although ACBL is one of the largest common carriers on the inland waterways, our operations, particularly with respect to the transportation of coal, are quite typical of many other large carriers.

Our particular participation before this subcommittee is directed toward the ability of the transportation industry to handle a doubled volume of coal by 1985 as proposed in the national energy plan proposed by President Carter.

I can emphatically say that the barging industry can handle today's demand for river coal transportation and it can handle the projected 1985 river demand for this transportation. In fact, the industry has been waiting some time on this expected increase in demand.

The barging industry of today is composed of approximately 1,800 companies, some large, many small. The bulk of these companies are private for-hire carriers, many are engaged in transportation of their own goods and a few are common carriers. The industry is very competitive as no carrier has exclusive use of any water right of way.

On a major barging contract, such as long-term transportation of coal to a powerplant, it is not unusual for 5 to 10 responsible carriers to submit bids. The point is, despite the substantial cost advantage of barging over other transportation modes, the shipping public and the electricity user get the benefit.

Our industry in 1975 moved over 15 percent of the intercity ton miles, but received only 1.3 percent of the transportation revenues.

Our industry annually moves by water over 125,000 tons of bituminous coal and lignite, which is about 20 percent of our domestic output. In some areas, which are in heavy coal producing valleys, the coal tonnages are greater than 50 percent of the total traffic.

Even with escalating fuel costs, we move coal today for 4 mills versus 8 mills per ton mile for the railroads.

We believe we move coal to the consuming powerplants and other industrial users in a safe and environmentally acceptable manner. The goods we transport are far from densely populated areas, such as the downtown and suburban areas of our cities. We do not add to the noise pollution factor, nor to congested traffic situation, and as we are extremely energy efficient, we add less pollutants to the air than do other modes of freight transportation.

Today's river towboats, which may handle 30 barges carrying 45,000 tons of cargo are comfortable and efficient. These towboats are energy efficient. According to the Department of Transportation, a gallon of fuel will allow a towboat to push 300 ton miles. But, put the same gallon of fuel in a locomotive and you move that freight only 180 ton miles, or only 50 ton miles if you are using a truck.

The 36 largest barge companies operated about 10,000 hopper barges at the beginning of this year. About one-third of these barges are used for coal. The eight largest barge building yards now have capacity of 1,650 barges per year. The barge industry could grow at almost 20 percent per year, as far as equipment supply is concerned. We predict that neither capacity nor capability will be strained by 1985.

Another capablity that has been questioned is transloading facilities primarily from rail car to barge. Barge lines and railroads have long worked together, at arm's length, on joint movements. This is a concept, intermodal transportation, which must continue to develop and grow in order that the inherent advantages of each mode are utilized.

Our company presently operates or has under construction 14-1/2 million tons of transfer capacity, rail to barge. In addition, we have properties and completed designs for an additional 42 million tons of dumping capacity for western coal.

Other major companies have recently built large transfer facilities, and there are many more on the drawing boards, waiting on demand. These facilities will be capable of handling projected tonnages for 1985.

Lest I sound too optimistic about the ability of the water carrier industry to meet these demands, let me point out that much of the destiny of our industry and of the Nation's ability to transport coal is in the hands of you gentlemen in the Congress.

There are problems. Some of the problems are common to all modes of transportation and some are competitive problems. The first one that I want to mention has to do with keeping transportation in the private sector.

In order to do this, we must achieve adequate revenues and earnings. This means that the financial regulator of rates, the Interstate Commerce Commission, must modernize its thinking and recognize replacement costs as a valuation in determining rates rather than using historic costs.

Next we must insure a continuing level of competition. Water carriers believe the sound way to make their living is by relying on their own efficiency and not on the other fellow's inefficiency. Water carriers have regularly supported legislative programs such as the recent 4R Act designed to improve rail efficiency even though they knew that improved rail efficiency would make railroads more formidable competitors.

The underlying assumption of this position is that all modes have an important role to play in the national transport system, all are needed and all should be encouraged to maximize their efficiency.

It is natural for anyone to want to be protected from competitive pressures. Cutting off the growth of barge traffic and impairing barge efficiency would be a very significant relaxation of competitive pressure. That was apparently the initial primary motive for the opposition to Lock 26, but it is hardly a very persuasive consideration from the standpoint of the public interest.

It is detrimental to our national interest to allow our waterways system to deteriorate and create bottlenecks. Yet, we have bottlenecks at old and decrepit lock structures on the Monongahela near Pittsburgh, Gallipolis on the Ohio River, the Industrial Canal Lock at New Orleans, the Vermillion Lock on the Gulf Intercoastal Canal and, of course, the famous Lock 26 at Alton, Illinois, on the Mississippi River.

When the situation is especially bad at these bottlenecks, we see more clearly the importance of river transportation. A dramatic display was shown this past winter when the ice shut down the rivers.

On the very current topic of user taxes, and although it is not totally relevant to the issues before this subcommittee, we believe two areas should be explored and investigated. The first is that the barge industry moves primarily basic commodities, coal, oil, grain, chemicals, steel and ores at low rates, considerably lower than competitors.

These basic commodities are the foundation of our total economic system in the initial production cycle, food production, energy production and power generation. It is a widely held concept that when benefits are broadly diffused through the general population, repayment of Federal expenditures have been accomplished. A specific example is electric generation entering the grid system which is then spread through a national system.

There has never been a thorough and comprehensive study of government subsidies and aids, both direct and indirect to the transportation industry. We believe the second area of investigation should be a comprehensive transportation subsidy study which would cover the equity of all Federal transportation subsidies. Further, we support a time limit for that study to be completed and submitted to Congress.

In summary, if we are to realize the goals President Carter has outlined, we must have a solid, dependable transportation policy upon which our industry, as well as the other freight transportation carriers of our country, can rely. If this be the case, the barging industry can meet the challenge presented in the national energy plan.

Presently river barges carry 20 percent of our Nation's coal. Based on what has been presented about cost and fuel efficiency, and coupled with the fact that so much coal is produced in river valley areas, I suggest that it is in the national interest to transport even more than 20 percent of our coal in river barges.

I appreciate very much the opportunity to appear before this subcommittee.

[Mr. Bobzien's prepared statement follows:]

STATEMENT OF
AMERICAN COMMERCIAL BARGE LINE COMPANY
JEFFERSONVILLE, INDIANA

by

H. J. BOBZIEN, JR., PRESIDENT

Our company, American Commercial Barge Line Company, is one of the major common carrier barge lines operating on the inland waterway system. We operate a fleet of over 1,300 barges and 50 towboats transporting such essential commodities as coal, grain, liquids, salt, ores, scrap, steel and newsprint. Our barging operations cover virtually the entire inland system and the Gulf Coast. Although ACBL is one of the largest common carriers on the inland waterways, our operations, particularly with respect to the transportation of coal, are quite typical of many other large carriers.

Last month, President Carter presented to Congress and the nation a program entitled "The National Energy Plan." We are here today to address that subject in order that our country not suffer the fate of other great civilizations -- that of national diminishing returns and fall from influence, if not utter destruction of a way of life.

Over the last ten years, as questionnaires have been addressed to me at various times to list, among other things, the greatest crisis facing our nation, I have always listed ENERGY. Therefore, I am happy to be here to testify before this Committee today in order that the considerations of a total comprehensive energy package will take into regard the concerns of the barging transportation industry.

Our particular participation before this Subcommittee is directed toward the ability of the transportation industry to handle a doubled volume of coal by 1985 or thereabouts. I can emphatically say that the Barging Industry can handle today's demand for river coal transportation, and it can handle the projected 1985 river demand for this transportation. In fact, the industry has been waiting sometime on this expected increase in demand. Some of us are wondering if we've made capital investments for this increased demand too soon. That demand to us seems most, and worst affected by the political problem. This is summed up by the recent comment that the only two problems with coal as an energy source are that "you can't dig it and you can't burn it." The Subcommittee is, of course, dealing with those problems right now. To back up my statement that "we're ready, so where's the coal?", let's review some.

The Mississippi and Ohio River systems are the Barging Industry's coal highways. The little roads that flow into these highways include the Allegheny, Monongahela, Kanawha, Green, Tennessee, Tombigbee, Cumberland, Illinois, Minnesota, Missouri and Arkansas. (The rivers mentioned have 6,900 miles of navigable channels.) A canal runs along the Gulf Coast from Florida to the Mexican border. From the beginning, River Roads were the arteries of developing nations, as these River Roads offered the only low cost way to transport a lot of something at one time.

After settlers in the New World had moved to the head of navigation on Eastern tidewater rivers, they were blocked, until population pressure pushed them through gaps in the Appalachians, where the Ohio and Mississippi systems then allowed relatively easy development of the mid-west and the mid-south.

River geography and development located the cities of these areas, as harbor geography had already located the cities of the east coast. Pittsburgh, Cincinnati, Louisville, Nashville, New Orleans, Memphis, St. Louis, Chicago, St. Paul are all there and thriving because of some characteristic of a river.

The Barging Industry of today -- a descendant of the old river keel boats -- is composed of approximately 1,800 companies, some large, many small. The bulk of these companies are private for-hire carriers, many are engaged in transportation of their own goods and a few are common carriers. The Industry is very competitive as no carrier has exclusive use of any water right of way. On a major barging contract, such as long term transportation of coal to a power plant, it is not unusual for 5 to 10 responsible carriers to submit bids. The point is, despite the substantial cost advantage of barging over other transportation modes, the shipping public and the electricity user get the benefit. Competition guarantees it.

In 1975 the ICC showed that the waterways industry is the smallest of all transportation modes. This industry received $1 billion in total freight revenues, compared to $18 billion for railroads and $21 billion for trucking. Of all transportation revenues, nationwide, the inland waterways received 1.3%. The significant point, however, is that these figures bought over 15% of all ton-miles of transportation.

Our industry annually moves by water over 125,000,000 tons of bituminous coal and lignite, which is about 20% of our domestic output. In some areas, which are in heavy coal producing valleys, such as the Ohio, Monongahela, Kanawha, and Green River basins, the coal tonnages are greater than 50% of the total traffic.

We move this tonnage in an extremely economical manner to steel mills, other domestic industrial users, for export, and to steam-generating power plants. Coal to fire these power plants produces more than half of America's steam-generated electricity.

Our rates to move this energy-producing material remained substantially stable for almost two decades until the recent crude oil price increases caused the cost of diesel fuel to rise faster than an increase in productivity could be achieved. Even today we move coal for 4 mills per ton mile versus 8 mills per ton mile for the railroads.

We believe we move coal to the consuming power plants and other industrial users in a safe and environmentally acceptable manner. A study by the Department of Commerce a few years ago showed the barging industry to be the safest mode available for the transportation of hazardous materials. The National Transportation Safety Board has reported our ratio of deaths per ton-miles moved was the best of all movable transportation modes. The goods we transport are far from densely populated areas, such as the downtown and suburban areas of our cities. We do not add to the noise pollution factor, nor to congested traffic situation, and as we are extremely energy efficient, we add less pollutants to the air than do other modes of freight transportation.

Today's river towboats, which may handle thirty barges carrying 45,000 tons of cargo are comfortable and efficient. They have central air conditioning, color TVs, and many other refinements. The crew of a large boat may number eleven. Towboats are "sized," both in draft and horsepower, for specific areas of each river. Small horsepower boats move 4 coal barges on the narrow

Green River, shallow draft boats avoid shoal problems on the Arkansas and Illinois Rivers, and medium horsepower boats are used on the Ohio River, where tows are limited to 15 barges.

And, most important of all, these towboats are energy-efficient. Even our giant 10,500-horsepower vessels are freight transportation's Volkswagens and Vegas. According to the Department of Transportation, a gallon fuel will allow a towboat to push 300 ton-miles. But put the same gallon of fuel in a locomotive and you move that freight only 180 ton-miles or only 50 ton-miles if you're using a truck. Even the most casual observer will note that an increased emphasis on river transportation will decrease the amount of petroleum this country needs for freight transportation.

President Carter has set a target of increasing coal production by at least 400 million tons by 1985. We calculate this to be a 60% increase over 9 years, about 6% per year, compounded. As most of the increases in coal will be burned in power plants, and these plants may tend to locate on waterways, we expect that barged coal may grow in excess of 6%. Our own company expects to carry substantially more coal than 6% growth would provide. But I submit that this increase in demand by 1985 is not "staggering" by any yardstick.

The thirty-six largest barge companies operated about 10,000 hopper barges at the beginning of this year. About one-third of these barges are used for coal. The eight largest barge-building yards (including none of the coastal shipyards or small yards along the Gulf bayous) now have capacity of 1,650 hopper barges per year. The barge industry could grow at almost 20% per year, as far as equipment supply is concerned. We predict that neither capacity nor capability will be strained by 1985.

Another capability that has been questioned is transloading facilities, primarily from rail car to barge. Barge lines and railroads have long worked together -- at arms length -- on joint movements. This is a concept -- intermodal transportation -- which must continue to develop and grow in order that the inherent advantages of each mode are utilized.

Our company operates a terminal near Huntington, West Virginia which dumps 2-1/2 million tons each year from Norfolk and Western hopper cars to barges, and we are building a facility in St. Louis to dump 10 million tons a year of western coal from Burlington Northern unit trains to the river. Terminal development appears to be ahead of demand as many of us bet that the increased coal demand would be here sooner than it most obviously will be. Including our St. Louis facility, which will receive coal in January, 1979, we have terminal properties and completed designs for 42 million annual tons of western coal. These facilities will be able to dump 100-car unit trains in two hours. In addition, we are now completing a two million ton transfer facility in Louisville, Kentucky served by the L&N, and we have other terminals planned for the Upper Ohio River. To get TVA's coal on the river for barge delivery, we built and now operate a 13-mile conveyor system in West Kentucky to carry 7 million tons per year.

Major companies, such as Southern Railroad, American Electric Power, Oglebay Norton, L&N, Detroit Edison all have recently built large transfer facilities, and there are many more on the drawing boards waiting on demand. Let me again emphatically repeat that the Barging Industry can handle today's demand for river coal transportation, and it will be able to handle the projected 1985 demands.

Lest I sound too optimistic about the ability of the water carrier industry to meet these demands, let me point out that much of the destiny of our industry and of the nation's ability to transport coal is in the hands of you gentlemen in the Congress. There are problems. Some of the problems are common to all modes of transportation and some are competitive problems. The first one that I want to mention has to do with keeping transportation in the private sector. In order to do this we must achieve adequate revenues and earnings. This means that the financial regulator of rates, the Interstate Commerce Commission, must modernize its thinking and recognize replacement costs as a valuation in determining rates rather than using historic costs. It is essential for the ICC to recognize that failure to use current replacement costs in the valuation of plants and equipment creates two kinds of inaccuracy. It understates asset values in the investment base and overstates profits because of inadequate allowance for depreciation.

Next we must insure a continuing level of competition. Water carriers believe the sound way to make their living is by relying on their own efficiency and not on the other fellow's inefficiency. Therefore, paradoxical as it may seem to some, water carriers have regularly supported legislative programs such as the recent 4R Act designed to improve rail efficiency even though they knew that improved rail efficiency would make railroads more formidable competitors.

The underlying assumption of this position is that all modes have an important role to play in the national transport system, all are needed and all should be encouraged to maximize their efficiency. Stephen Ailes, President of the AAR, testifying about increased future demand for transport services, summed up the position with the comment, "There is no way this demand can be met unless all modes expand and carry a share of this increasing traffic."

Bearing in mind this kind of cooperation which benefits everyone, we were surprised in 1975 to see the western railroads take an action which seemed! to say that intermodal cooperation of the type that had been so productive for them was too civilized an idea for railroads. They seemed to be saying that cooperation is a one-way street, that railroads will accept water carrier aid in promoting needed government funding to improve railroad efficiency, but will block government navigation programs which improve efficiency in barging. I refer, of course, to the spoiling legal action which has stopped the replacement of Lock and Dam 26. As everyone knows, this action has turned out to be in the nature of extortion holdin out for the imposition of a user tax on water carriers.

It is natural for anyone to want to be protected from competitive pressures. Cutting off the growth of barge traffic and impairing barge efficiency would be a very significant relaxation of competitive pressure. That was apparentl the initial primary motive for the opposition to Lock 26, but it is hardly a very persuasive consideration from the standpoint of the public interest. It is detrimental to our national interest to allow our waterways system to deteriorate and create bottlenecks. Yet we have bottlenecks at old and decrepit lock structures on the Monongahela near Pittsburgh . . . Gallipolis on the Ohio River . . . The Industrial Canal Lock at New Orleans . . . the Vermillion Lock on the Gulf Intercoastal Canal . . . and, of course, the famous Lock 26 at Alton, Illinois, on the Mississippi River. When the situation is especially bad at these bottlenecks, we see more clearly the importance of river transportation. A dramatic display was shown this past winter when the ice shut down the rivers. Thomas Graham, the President of Jones & Laughlin Steel, said "When the rivers stopped working, we at J&L found ourselves in a critical situation. Without a steady flow of coking coal, we lost two irreplacable energy sources."

The Department of Transportation recently issued an interim report on Lock and Dam 26 which found that ". . . the impact of the proposed single 1,200 foot lock on railroad revenues does not appear to be significant." However, the DOT also made certain findings with respect to existing lock capacity which simply are unfounded. The DOT indicated that the existing lock capacity would be sufficient at least until 1990. While there may be some theoretical room for traffic growth, or while you may theoretically have an infinite number of tows waiting to be locked through in each direction all the time, it does not make sense to make such judgments without seeking actual operating data from the river carriers using the lock. Even assuming the DOT to be correct, experience has shown that the period from authorization to completion of a Lock and Dam project would span that period of time. The fact is, however, that DOT is not correct.

A review of our own company's situation at Lock and Dam 26 during 1976 will give an indication of the true situation there. During 1976, we made a total of 490 lockings, 264 of which were northbound and 226 of which were southbound. Our average locking delay during 1976 was 10.61 hours per locking. Thus, a total of over 5,000 hours was wasted in waiting for clearance at Lock and Dam 26.

At the current price of towboats and barges, a 15-barge tow with an appropriate towboat would cost in the range of 6.4 million dollars. Obviously, the point to be made is that substantial new investment to handle increased traffic available on the Upper Mississippi River and the Illinois Waterway will not be made or cannot economically be made if the artificial bottleneck of Lock and Dam 26 is to continue. Particularly appropriate to mention to this Subcommittee is that substantial movements of coal to power plants in those areas will require just such a determination.

That level of investment at today's operating costs represents a direct expense of about $290 per hour in unproductive time. Thus, on the average, a towboat with 15 barges will lose in excess of $3,000 per locking. If the nature of a water carrier's business requires the movement of empty barges to the upriver areas to take cargoes of grain southbound, then the lost time and money must be doubled and, obviously, passed on to the shipper and ultimate consumers.

Before proceeding to the obvious conclusion about why perpetuation of this bottlneck is being so strongly supported in some quarters, let us look at some comparative rates on important traffic from the Upper Mississippi and Illinois Waterways to the Gulf Coast. The grain rate last published by the regulated water carriers in WFB Tariff 7 is $6.19 per ton from the general Minneapolis - St. Paul area. The comparable rail rate is $9.30 per ton on a similar movement. From Chicago, the last barge rate was $5.78 per ton compared to $10.00 per ton by rail.

The obvious conclusion, then, must be that there is a twofold benefit to be gained by the railroads at the expense of the consuming public, in perpetuating the current situation at Lock and Dam 26. The ultimate benefit to them will occur with the failure of that system and the resultant termination of river traffic through that area. In the meantime, because the Lock has already reached its ultimate practical capacity, there is an artificial lid put on growth of river traffic so that most new traffic can be captured by them through practical necessity at substantially higher rates than the water carriers offer. If this is what the Congress wants then the effect on the water carrier industry to handle increased demands of coal transportation through that area will be severely jeopardized.

We believe the conclusion is irresistable that when all economic factors are weighed, the public interest requires solution of the navigation system problems as quickly as possible.

On the very current topic of user taxes, and although it is not totally relevant to the issues before this Subcommittee, we believe two areas should be explored and investigated. The first is that the barge industry moves primarily basic commodities, coal, oil, grain, chemicals, steel and ores at low rates, considerably lower than competitors. These basic commodities are the foundation of our total economic system in the initial production cycle, food production, energy production and power generation. It is a widely held concept that when benefits are broadly diffused through the general population, repayment of federal expenditures have been accomplished. A specific example is electric generation entering the Grid system which is then spread through a national system.

There has never been a thorough and comprehensive study of government subsidies and aids, both direct and indirect to the transportation industry. We believe the second area of investigation should be a comprehensive transportation subsidy study which would cover the equity of all federal transportation subsidies. Further, we support a time limit for that study to be completed and submitted to Congress. That transportation subsidy study should:

-- Review past, present and future subsidies of all modes of transportation. Review should include government grants, loans, loan guarantees, tax incentives, federal expenditures and all other subsidies that have been, will be or are being paid to the various modes;

-- Review the equity of those subsidies to all transportation modes; and

-- Evaluate the impact of any change in current subsidies to all modes. This evaluation should cover the impact on the producer, the shipper, the consumer and the U. S. balance of trade.

-- Evaluation of allocation of benefits for waterway expenditures for recreation, water quality, flood control, hydroelectric generation, and population dispersal.

Pending legislation adopted by the Senate Committee contains a discriminatory tax on inland waterways shallow draft carriers. It excludes any type charge for deep draft ports, lake carriers and/or deep draft vessels plying shallow waters, even up to Baton Rouge. It will increase barge rates for all coal but not affect Norfolk and Baltimore harbors, where coal is shipped all rail for export. This is hardly a desirable way of solving our domestic energy crisis.

In summary, if we are to realize the goals President Carter has outlined we must have a solid dependable transportation policy upon which our industry, as well as the other freight transportation carriers of our country, can rely. If this be the case the Barging Industry can meet the challenge presented in the National Energy Plan. Presently river barges carry 20 percent of our nation's coal. Based on what has been presented about cost and fuel efficiency, and coupled with the fact that so much coal is produced in river valley areas, I suggest that it is in the national interest to transport even more than 20 percent of our coal in river barges.

I appreciate very much the opportunity to appear before this Subcommittee and would be most delighted to have our Company work with the Subcommittee or your staff in developing such further information as may be helpful in your deliberations.

Mr. MOFFETT. The Chair recognizes the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. I have no questions, Mr. Chairman.

Mr. MOFFETT. The Chair recognizes the gentleman from Ohio.

Mr. BROWN. Thank you, Mr. Chairman.

Gentlemen, let me ask you first, I gather that there is a need for additional barges, for additional railroads, railroad cars, for plate steel. To what extent will additional barges be needed should this expansion of coal transportation be required?

Mr. BOBZIEN Presently, Congressman, there is a fairly even balance between transportation needs and barge equipment. There is some abundance of equipment at the present. The ability to build barges for additional transportation as pointed out will be no problem. The capacity in just eight of the largest shipyards equals 1,650 barges a year.

Mr. BROWN. What kind of steel is used?

Mr. BOBZIEN. Plate steel, sir.

Mr. BROWN. In railroad cars, if it is to be transported by railroads?

Mr. DEMPSEY. The numbers?

Mr. BROWN. Yes.

Mr. DEMPSEY. We will need between 9,700 and 13,400 coal cars a year over the next 8 years. That is both to replace and to add to the fleet, and we will need between 280 and 470 locomotives a year, depending upon in each case the utilization of unit trains. Probably it will be towards the lower edge of those figures because we assume most of this will move in unit trains.

We have no problem as in the case of the barge industry with respect to capacity. The car building industry can produce up to 72,000 coal cars a year, and we have our own capacity in our own shops in addition. So, it is simply a matter of spending the money. It is not a matter of having the capacity.

Mr. BROWN. Have either of you talked to the steel mills to know whether or not you can get enough plate steel to do the construction work?

Mr. BOBZIEN. Sir, at the present time the steel industry is operating at considerably below capacity, particularly in the type of steel we use. So, effectively, even right now we could come up with a considerable amount of steel to start a program.

Mr. DEMPSEY. We would not anticipate any difficulty, either. In point of fact, we have delivered on the average over the last 3 years some 16,000 freight cars, which exceeds what we are going to need during this program a year, and our new and rebuilt diesel locomotives installed average 1,300 a year from 1972 through 1975. We don't foresee any difficulty in that respect.

Mr. BROWN. Does your testimony indicate how many barges specifically you think would be needed?

Mr. BOBZIEN. No, sir.

Mr. BROWN. Would you supply that for the record, the size and so forth, so we can do some checking with the steel industry on this?

[The following material was received for the record:]

As my written statement includes, there are now presently about 3,500 barges engaged in the coal trade which transport over 125 million tons of coal and lignite annually. It would be fair for projection purposes to assume that increased tonnages of 50 percent would require a similar increase in the number of barges. Exact numbers would vary with the origins and destinations of coal movements. Thus, I would project an approximate increase by 1985 of 1,700 barges. I believe that an increase of 2,000 barges would be the maximum required even considering that new more distant markets may be involved. This growth is well within shipyard capacity as referred to elsewhere in my testimony. Today's standard river barge used for coal transportation is 195 or 200 feet long, 35 feet wide and 11 feet or 12 feet tall plus about 1 foot for the combing. Approximately 275 tons of steel including 5/16ths or 3/8ths inch steel plate and standard sized structurals are required for each such barge.

Mr. BROWN. Any plate steel required in the pipeline?

Mr. JENNINGS. I am not sure what type of steel is used in the pipeline, but I assume it is the plate type steel.

Mr. BROWN. I am not sure I know whether it is plate steel or not.

Mr. JENNINGS. There is steel. Whether it is the same type plate steel, I don't know.

Mr. ZANDI. It is not the same.

Mr. BROWN. Maybe you could inquire and find out and let us know about that. [See letter dated June 7, 1977, p. 633.]

As between the three methods of transportation represented here, I wonder if we could get a summary from each of you as to what it takes to move the produce a certain distance, whether it is a ton mile that we are talking about or anything else, in terms of consumed enery, consumed water, consumed dollars, cost—I guess that would cover it in the three areas. Anybody got those estimates?

Mr. ZANDI. Do you want me to give you an answer for the slurry pipeline?

Mr. BROWN. Yes.

Mr. ZANDI. I would be glad to. The way to calculate it is really to look at one that exists, which is Black Mesa. Some time ago we made that calculation, and it turns out that you need 465 Btu per ton-mile to carry coal via the Mesa pipeline. This is about the average of railroads.

In other words, one could say on the average these two systems are about the same. They vary because of the local conditions. In general, if you take 500 Btu per-ton mile, you are talking about .2 percent of energy content in the coal to be transported via railroad for a 100 mile distance. Every 100 miles you are going to spend two-tenths of a percent.

Mr. BROWN. And water?

Mr. ZANDI. A pipeline of 25 million tons would need about 12 gallons per million Btu. Coal transported—you can look at it in a different way. Say it is equivalent to the population of something, about 250,000 people.

Mr. BROWN. Is that used up or reusable?

Mr. ZANDI. Yes. In the coal pipeline, once the water is at the end of the line, at the place that you want to utilize it, you can dewater it. As a matter of fact, the only coal pipeline which is operating in this country uses the water for cooling of the generating systems, at the power generation plant.

Mr. DEMPSEY. Our data are not quite the same as Professor Zandi's. I assume OTA will come in with some findings in the end. But, they may be equivalent—I am not sure what the base is—I will just say what we have—so far as coal slurry pipelines are concerned, the Wyoming Department of Transportation conducted a study which involved assumptions of 25 million tons a year over a 1,000 mile pipeline, which is about what the EDSE pipeline proposal is. Their conclusion was that it would take 750 Btu per ton mile.

Now, that included the transportation and the crushing and the dewatering. It may be that Professor Zandi's figures don't include one or the other of the latter two. Railroad calculations on transportation alone, on the same assumptions, unit trains now, because we are dealing now with what would be the competitive method of transporting these movements, would be 250 Btu per gross ton mile. That, I add, however, does not include the crushing. I don't have a figure on the crushing, but I can say that adding the crushing to it would not approach the 750 Btu. It might, however, approach the 450. I am not sure.

So, if dewatering is not in the Professor's figures, but only crushing, then it may be that we come out to the same place.

Mr. ZANDI. Could I respond to these statements?

Mr. BROWN. Yes. I want to get on the record, the barge lines.

Mr. DEMPSEY. As far as water is concerned, according to the testimony put in by the coal slurry proponents in the various hearings, it would seem we are dealing with on those assumptions something on the order of 6.1 or 6.2 billion gallons per year.

Mr. BROWN. The barge lines, and then I would be glad to open it up. I would like to get an estimate from all of you based on essentially the same figures. I would like to get that in all of them or out of them or whatever.

Mr. BOBZIEN. Congressman, I can just respond roughly to what it would take to move a 1,500 ton capacity barge, loaded with 1,500 tons of coal 1 mile through the water. It would be roughly 3 gallons of diesel fuel. My figures are not in the same form as my compatriot's here.

Mr. BROWN. You can look at the record as soon as it is available to you, and perhaps conform the figures for us, in how many——

Mr. BOBZIEN. You are interested in knowing how much fuel to move a ton mile of freight——

Mr. BROWN. How much fuel, how much water, what the cost is, for moving a ton of coal a mile by the systems that you use.

Now, I know the other points, the fixed nature of the barge line, the railroad and the coal slurry pipeline and so forth. So, I don't need all those other descriptions. I am just looking at one mile to get it from one point to another.

[The following material was received for the record:]

A typical river coal tow consists of 15 barges and one towboat. My cost figures are related to that type of operation. The towboat operation consumes no water, of course. Using 1976 as a guide, the total towboat, barge, crew, fuel, etc., cost was about 4.0 mills per ton mile. Of that amount, about 2.8 mills is attributable to equipment and miscellaneous costs, about .7 mills is attributable to personnel costs including labor and fringe benefits, and about .5 mills is attributable to fuel costs. Our own experience over the past several years has yielded in excess of 500 ton miles per gallon of fuel consumed.

Mr. JENNINGS. Mr. Congressman, I would just observe the Black Mesa pipeline that I referred to has been operating since 1970. They have testified to the fact that has operated at about one-half of what the other mode of transportation would cost the railroads.

Mr. BROWN. Okay. Let me ask you about the cost of construction of facilities.

Do the barge lines estimate that the routes over which barge traffic would be obliged to move are all improved adequately, or would you have construction projects that would be obliged to move the coal that we are talking about?

Mr. BOBZIEN. As I pointed out, sir, there are four or five areas of waterway improvement that need to be accomplished.

Mr. BROWN. Can you give me some estimate of the cost of that?

Mr. BOBZIEN. Lock 26 presently is estimated to cost in the range of $400 million, to replace with a 1,200 foot lock. Now, as far as the cost on the others, I don't know offhand those numbers.

Mr. BROWN. I wonder if you could get those figures for the record and submit them.

Mr. BOBZIEN. Yes, I can.

[The following material was received for the record:]

The basic essential water routes for the movement of coal are now in existence. Actually, most of them are simply natural waterways which have been changed and improved for various purposes since the beginning of our nation. A nine-foot channel is the standard design and is maintained over most of the system. There are, however, certain bottlenecks which exist because original design capacity has been exceeded or because of age and deterioration. A list of the essential improvements in my opinion and the best cost figures I can find for them are:

LOCK 3 - MONONGAHELA RIVER

In the Corps of Engineers' present appropriation request, there is $10,000,000 to rehabilitate the present Lock 3 structure. This money will be spent only to hold the lock and dam facility together until the Corps can make a determination as to what kind of permanent structure will be needed.

GALLIPOLIS LOCK - OHIO RIVER

Originally the Corps of Engineers estimated this replacement project of an outmoded facility to cost about $300,000,000 which incuded two 1,200' locks. The Secretary of the Army returned the project to be re-evaluated using the criteria of one 1,200' lock. I would estimate the project should cost approximately $200,000,000 to complete.

LOCK 26 - UPPER MISSISSIPPI RIVER

As has been previously mentioned, this much needed replacement facility is estimated to cost $430,000,000. Costs to rehabilitate the present structure would cost nearly the same amount.

VERMILLION LOCK - GULF INTRACOASTAL WATERWAY

The total federal cost of this project was estimated last fall to be $20,600,000.

INDUSTRIAL LOCK - NEW ORLEANS AREA

Many sites have been studied for locating this vitally needed link in the navigation chain. The lock structure is part of an on-going project for the Mississippi River - Gulf Outlet. The lock and access channel would accommodate deep draft ships as well as barges. The last estimate we had for the suggested "lower site" in the Corps' plan was $266,000,000.

Mr. BROWN. The railroads, what are we talking about there?

Mr. DEMPSEY. In terms of new construction?

Mr. BROWN. New construction.

Mr. DEMPSEY. This really relates to the last point Mr. Jennings made. We don't anticipate any enormous or major new construction. Now, the Burlington Northern and the Northwestern are building a 110—I believe it is—mile line up into the Powder River basin, but that is to be connected with a long haul from then on. In a situation like Black Mesa, where you are dealing with a relatively short line, I am not sure, 100 miles or whatever it was, over difficult terrain, and if that is the only thing we were dealing with coal slurry pipelines on, we would have an entirely different picture. There is no question in a situation like that the difficulties of building a railroad line would make that option not particularly attractive.

All of the coal slurry lines that have been proposed would be in competition with the existing rail network. It is that existing rail network that needs some upgrading, Mr. Congressman. It does not need any significant additions to it.

Mr. BROWN. Mr. Jennings?

Mr. JENNINGS. I couldn't give you the exact nature. I could tell you that one pipeline that is going to be 36 to 38 inches in diameter, probably 1,000 or 1,050 miles long would cost somewhere in the neighborhood of $750 million. All this would depend on the size and the route, the terrain, as Mr. Dempsey pointed out, and the other factors, but as it stands right now, none of them can be built because we cannot get the rights of way.

Mr. BROWN. As a concluding question let me also ask for operating costs or transportation and maintenance costs. I have asked you to estimate the cost of moving a ton of coal a mile. Let's assume—well, let me not make an assumption about location. I don't want to do that. But, what is the per mile labor cost involved in these operations?

Mr. JENNINGS. Of course, that is an area in which that the pipelines really shine. Our system of transportation is capital intensive. Once the lines are put in place, that represents some 70 to 75 percent of the cost of the operation of the pipeline. There is very little due to labor from then on. The railroads are labor intensive.

I should point out also that the type of energy used is as important as the amount of energy. Pipelines use domestic energy rather than imported oil, which lends to the deficit in our balance of payments. And the domestic energy used by pipelines is available at all times in our country.

Mr. DEMPSEY. I don't think I could segregate out labor costs, Mr. Congressman. We are dealing with rail transportation costs in the range of 7 to 9 mills per gross ton mile. Mr. Jennings may wish to correct me if I am wrong, but as far as I can tell in all the discussions that have been held over costs, it is not easy to come to firm grips with the coal slurry costs because the underlying data have simply not been disclosed, not disclosed to MIT that made a study of them, of the Bechtel figures.

I have never heard it suggested that initially coal slurry pipeline costs would be lower than rail costs. I think it has always been granted, except in a case like perhaps the Black Mesa, where it is not very practical to have a railroad, but in these competitive situations I think the argument has been, all right, the coal slurry will come in at a substantially higher figure—I have seen some quotes at 12 mills per gross ton mile—but eventually we will overtake the railroads because of inflation.

That, as Mr. Jennings said, is primarily because labor costs bear a higher relation to total costs with respect to railroads than they do with respect to coal slurry. Then you have to look at all the other assumptions—the assumed inflation rate, the assumption of no increased productivity in the railroads, of absolute top efficiency in operation of the pipeline, and all of those imponderables.

All I can say is I can tell you what the rail costs are now, and I have given you those data. What the coal slurry costs are it seems to me will have to await further examination by OTA and other impartial groups.

Mr. BOBZIEN. In the case of the barge line, as indicated, our average revenue on coal is in the range of 4 mills per ton mile. Our labor costs would be in the area of 15 percent.

Mr. BROWN. 15 percent of revenue?

Mr. BOBZIEN. Yes, sir.

Mr. MOFFETT. The Chair recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman. I would like to ask that the record be kept open so that I may get a projection of the amount of coal we are going to need, say, in my part of the country, with our industries, and our complete conversion from gas and oil-fired burners to coal, which we don't have now, and submit that to each of these three gentlemen representing various modes of transportation, to get their prognosis as to whether or not they could supply that amount of coal, and by when they could do so.

If that is agreeable to the three gentlemen, I would like to get that information and send it to them.

Mr. DEMPSEY. It is certainly agreeable.

Mr. MOORE. I would like to ask the record be kept open.

Mr. MOFFETT. The Chair would make clear, however, that the witnesses still are bound by the 7 day time period. They must have it to us by that time.

Mr. MOORE. I appreciate that.

[The following material was received for the record:]

ASSOCIATION OF
AMERICAN RAILROADS
AMERICAN RAILROADS BUILDING · WASHINGTON, D. C. 20036

WILLIAM H. DEMPSEY
President and Chief Executive Officer

June 3, 1977

The Honorable W. Henson Moore
House of Representatives
Congress of the United States
Washington, D.C. 20515

Dear Congressman Moore:

Your letter dated May 31, 1977, requested certain information to supplement the hearing record of the discussion which took place before the Energy Subcommittee on Thursday, May 26.

We do not have sufficient information to comment precisely on the coal production and transportation estimates made by the Louisiana State Department of Conservation. Without knowledge of the specific plant requirements and locations, the calculation of transportation needs is simply not possible. However, some observations may be helpful in that regard.

First, the 150,000 tons per day in new coal for Louisiana translates into 55 million tons per year or 14 percent of the total annual increase in coal projected by 1985 under President Carter's energy program. This appears to be a rather high percentage and it may be that the state estimates did not reflect the exceptions to coal conversion for smaller industries and other exceptions which are implicit in the President's program.

Second, if all the new coal came to Louisiana by rail--a possibility that seems most remote due to the easy access to waterway service via the Mississippi and the Gulf--it would require 14 unit trains of 120 cars a piece each day. If there were a significant number of deliveries to smaller users of coal, the number of cars and trains would increase somewhat. However, since Louisiana already uses barge service for a very significant amount of the bulk products it produces and consumes, the volume of coal arriving in Louisiana would be split between the two modes with some of the barge coal being transloaded from rail at upper river points.

Third, the number of freight cars required for total conversion to coal, all of which was shipped by rail, would be approximately 10,000 cars and 330 locomotives in unit train operations. The lead time for this equipment is far shorter than the requirements for opening new mines or for converting or building utility plants. The actual requirements would be considerably less.

Fourth, while increases in rail equipment and higher track maintenance would be required to handle additional traffic, we see no unmanageable problems in equipment production or acquisition to deal with this problem, The Honorable W. Henson Moore -- Page Two June 3, 1977

even if it existed in similar magnitude on a nationwide basis. Various government and private studies mentioned in my testimony support this conclusion. Moreover, it should be pointed out that whether the number of new trains per day is 17, 14 or the more probable lower amounts, the increase in trains per day after the full coal conversion was completed would be less than one percent per year over a ten-year period. This traffic, in turn, would provide significantly more revenue growth--a factor that would benefit all existing rail shippers to and from Louisiana as more traffic units were spread over the high amount of rail fixed costs.

As far as coal slurry pipelines are concerned, that technology would require, for optimum operation, the consumption of 20-25 million tons of coal per year at points near the mouth of the pipeline. It is hard to imagine how such utility deployment would have application to the vast number of Louisiana areas. Even then the alleged cost advantages over rail movement would depend on high levels of inflation in rail costs in distant years.

Smaller pipelines or branchlines of large pipelines have not proven to be feasible where, as in most areas of Louisiana, there is existing rail service for most of the route over which the coal must be shipped. In any event, the approval and construction of a major pipeline would take from four to ten years, depending on regulatory and environmental clearances, and would require the utilities to agree to contracts for the ensuing 30 years under which they would pay for the full service irrespective of whether it was used. Such a commitment, which would be paid by consumers of Louisiana, seems very questionable in view of the likelihood of transportation improvements and the probable development of new fuel sources such as solar energy, clean nuclear power and coal gasification, to mention just a few, long, long before the contracts had expired.

I hope these points shed some light on your fields of interest.

Sincerely,

W. H. Dempsey

RESPONSE OF COMMERCIAL BARGE LINE COMPANY

Mr. Moore has indicated that a total amount of coal in the range of 150,000 tons per day would be required by utilities and industries in the State of Louisiana, if they were to convert to coal. On an annualized basis, this is about 55 million tons. With respect to that coal, he has posed the following questions:

Can present transportation systems adequately handle this quantity of coal to Louisiana? What improvements in present systems would be necessary? What future transportation modes, such as a coal slurry pipeline, could bring fuel to Louisiana, and how long would it be before such modes could operate?

Because of the availability of the waterway system to Louisiana, it is safe to assume that much of the transportation of coal to that area would be susceptible to movement by barges. As a matter fact, the first western coal which our Company has contracted to carry under a combination rail-barge arrangement with Burlington Northern is to a Louisiana utility located on the Mississippi River north of Baton Rouge. That movement will begin in late 1978 with the coal being transferred at our facility now under construction at St. Louis.

It is interesting to note that in my complete statement, I have indicated that our Company alone now has under construction, or has completed design work, on rail-to-barge transfer facilities to receive western coal capable of handling 42 million tons per year.

Trying to project ahead, such large tonnages would undoubtedly develop over a period of several years. For instance, the lead time for a new utility plant or new unit at an existing one is several years, normally much longer than the lead time to build floating equipment, river docks, or material handling equipment. I think it is fair to conclude that there would be no lack of ability within the water carrier industry or the shipyard industry to meet such demands. We would estimate an equipment requirement of around 53 towboats and 1,500 barges to meet such a demand. Again, this within the ability of the industry to achieve, assuming typical long-term commitments to utilize the equipment.

From the navigation of view, the basic physical system is adequate from St. Louis south along the Mississippi River. There are, of course, routine maintenance and repair problems but there are no locks or dams to contend with. I do no believe, however, that all of Louisiana's demands, or the demands of other States, will come to the river at St. Louis. Areas along the Ohio and Tennessee Rivers and their tributaries are rich in coal reserves. It is essential, therefore, that the navigation system be as completely sound as possible. With particular respect to Louisiana, both the Industrial Canal Lock and Vermillion Lock could be serious restraints on our ability to move coal depending upon the actual destination.

Mr. MOORE. The only concern I have is we are talking about a massive amount of coal. Mr. Jennings gave the example at Houston, Texas. I think my part of the country would probably double or triple that in terms of heavy industrialization and electric utilities we have generated between Baton Rouge and New Orleans, in that area, where coal is not being used.

I just wonder if anybody can ship that amount of coal down there, how long it would take to build a pipeline, the number of barges, and how long it would take to build a new rail line. I just cannot conceive the fact we can ship that much coal by the time we are talking about. I hope you are right because it looks like we may have to do that.

Mr. JENNINGS. Mr. Congressman, that is one of the great problems. It affects each mode of transportation. There is a certain amount of lead time that any mode of transportation must have before it can start making delivery. I think it is of extreme importance that we have that lead time. I know it is particularly true of the railroads, of the pipelines that we have that lead time, in order to meet the target of removing the natural gas from the boilers.

Mr. MOORE. Let me ask you this: If we started today determining we wanted to build a similar pipeline like his proposed for Arkansas, or Houston, coming out of Montana, Wyoming, down to the New Orleans-Baton Rouge area, what would be the prognosis, how long it would take us?

Mr. JENNINGS. I wouldn't hazard a guess. I would have to ask the gentleman, how long do you think it will take for us to get the right of eminent domain to get under the railroads? After having gotten past that obstacle, there is no guarantee that the customers are going to be available.

We ask only for the right to compete in the marketplace, and the marketplace is going to determine whether we build a single pipeline. If the pipelines can get beneath the railroad tracks and secure customers, then we have to go to the other end and not only obtain the coal, but we have to obtain water, which is available at the discretion of the States.

Then, after that time, we would have to design the line, get an environmental impact statement, and then build the line. My guess is that at the very best, after passage of the enabling legislation and certification of the pipeline, it would probably be about 3 years.

Mr. MOORE. We ran into some problems with the Alaskan pipeline. I am just wondering—that wasn't caused so much by the actual building of the lines. It was all the problems, environmentalists. I am just wondering if we are not facing the same thing with the slurry line.

Mr. ZANDI. I think comparing these pipelines with the Alaskan pipeline is a little bit far-fetched because the problems and conditions are so different. There were new problems associated with working in that kind of environment that is not in this type.

Mr. MOORE. I agree with you from the technical point of view. You sit in our seat and you find out there are all sorts of problems in a project like this, and people willing to create them.

Mr. DEMPSEY. Mr. Congressman, I would like to say a word about your question. I would not want to suggest by anything I say today that there won't be any problems with respect to rail capacity or ability to handle. That would be foolish. Any time you have this kind of a sharp shift in emphasis naturally we will have some problems.

But, I want to suggest to you, and give you one illustration, about the problems that the railroad industry would have in making this adjustment to the new situation would be less than you would face with respect to most other things you deal with. I don't think people really understand fully how efficient rail operations can be and what kind of capacity we deal with when we deal with a rail line.

Let me give you this illustration. One double track railroad, with centralized traffic control, can handle 300 million tons of coal a year. Now, that is an enormous amount of coal. That is a lot of cars and trains rattling down the tracks. But, that is possible with one double track central traffic controlled railroad.

Now, you would have to tell me where your plants are there, and I would have to know where the origins are. I would be willing to bet right now that plant is in place, that rail plant is in place.

Mr. MOORE. We are right on the Mississippi, used to barge traffic.

Mr. BOBZIEN. We presently have under construction, Congressman, a transfer facility at St. Louis that will handle 10 to 12 million tons of western coal—transfer from rail car to barge. We have the properties and already completed plants to construct facilities that will handle another 40 million tons.

So, in partial answer to your question, we could handle 50 million tons of western coal, and the movement down the river below St. Louis to Baton Rouge would not be a problem.

Mr. MOORE. Thank you. I have no further questions.

Mr. MOFFETT. Mr. Dempsey, we had some testimony yesterday that seemed to indicate that there is not much of a role for the railroads in carrying coal into the Northeast and New England. Would you agree or disagree with that?

Mr. DEMPSEY. On the face of it, I would disgree. I don't really know what the basis is.

Mr. MOFFETT. The contention was made that it would be done—I don't know exactly who testified to this effect. I think it was some utility people, the New England utility company, New England system. I believe that some others had the same impression, that in fact it would be more barge than anything else.

Mr. DEMPSEY. More barge?

Mr. MOFFETT. And ocean-going vessels, and so forth.

Mr. DEMPSEY. ConRail is the fifth largest transporter of coal among the Nation's railroads. It is a major hauler. I can understand concerns of utilities about the adequacy of the ConRail plant to handle large additional volumes of coal, given the experience that those utilities may have had in the past before they switched over to another mode of fuel, for example.

If the situation in the Northeast had not been improved over what it was 2, 3, 4 years ago, I would think those would be quite legitimate concerns.

Congress has taken that matter in hand and, as I mentioned before, there is a $6 billion rehabilitation project underway on ConRail. It seems to me that that should put that plant in sufficiently adequate shape to handle the additional coal traffic in the Northeast.

Now, if because of routes, things of that sort, the barges have a competitive advantage, because they are better situated to handle it, that is another story.

Mr. MOFFETT. Let's stay on the rails for a moment, and let's focus on whether or not this $6 billion is really going to help us all that much.

We are rooting for that to work. But there are many questions about whether this coal program is going to work for New England and the Northeast, and one of the big question marks revolves around transportation, and one of those question marks, of course, is on the rails.

Just to give you an example, the FEA notice of intent on April 25 to Northeast Utilities to convert to coal, some of their plants talked about transportation, and I am quoting here from page 26 where it said:"ConRail's 9,000 foot railroad spur into these powerplants requires considerable repair before it can reliably be used to supply coal. While the powerplants were burning coal as a result of the oil embargo, several hopper cars delivering coal to the powerplants derailed and fell into the Connecticut River.

The Poughkeepsie Bridge, which you may be familiar with, "which would ordinarly be used for rail shipment of the coal to these powerplants is in serious disrepair and there are no plans for its reconstruction. Therefore, coal would have to be routed around the bridge."

What this means, to route coal around this bridge, as you may or may not know, it's quite a reroute. It means you go up the New York side of the Hudson, way up to Selkirk, and way around over to Springfield and then down to Connecticut. Essentially what I am saying is Connecticut, for example, becomes a branch line under that kind of system. I have debated back and forth with ConRail about why they don't fix the bridge. The bridge was damaged by fire in May of 1974. Then there was an agreement to fix it with New

York State, and Penn Central and the U.S. Department of Transportation which has fallen through.

ConRail owns that bridge. It seems to me that if the President has a plan and he says we are going to switch to coal, and if, in fact, some of the coal can be burned in New England, then the improvement that you mention ought to be focused on fixing things like that bridge. What happens is ConRail, which we created and which we told to act like a business but which we continue to have to bail out time and time again, comes back to us in the Congress and say, gee, it would be nice if we could fix the bridge but we are a business now, and it's not worth our while to fix the bridge.

Now you may know all of this, so there are different points of view. In fact, there are some analyses which say it would be economic to fix the bridge. You would have $20 million worth of the traffic going over that bridge.

Not to belabor that point, the point is with regard to coal coming in from the West and Southwest, that bridge could be very, very important, and I am wondering, while I am rooting for the railroads to have a more prominent role in freight overall in the Northeast and New England, I am wondering if this isn't an example of why it might not work under the current system, given the fact what we are doing with ConRail, and given the fact we can't command ConRail to repair that bridge, I wonder how much we can afford to keep pouring money into ConRail talking about improvements, and yet with regard to the President's energy program not be able to deliver.

Mr. DEMPSEY. Mr. Chairman, I am sure you will appreciate I am not familiar with the particular situation you describe. It's not surprising to me, there are situations in which we all know, there are many of them in which branch lines, spur lines have fallen into terrible disrepair, but all I can say is that the program is underway. Whether it will work or not depends on lots of considerations, some of them having to do with the way Congress responds to the trimming down of the system. If the system is not to be trimmed to its most efficient contours, for whatever reason, then ConRail, in my judgment, is going to have very rough sledding, and this Congress is going to have that continuing obligation for a very long time.

Mr. MOFFETT. I understand, but trimming the system, which is worthy, may be at cross purposes with the importance of getting coal into those areas.

Mr. DEMPSEY. I would find that difficult to believe if the demand is there. Coal, as I say, is a profitable commodity. If we are dealing with a major utility, major transportation of coal, it's difficult for me to conceive of a circumstance in which that would not be profitable.

Mr. MOFFETT. Do you think ConRail in projecting abandonments, for example, takes into consideration the President's energy program and the increased production of coal, and as a result of that keeps certain lines that might otherwise be scheduled for abandonment?

Mr. DEMPSEY. Honestly I cannot respond.

Mr. MOFFETT. I have my doubts about that. Do you agree with the President's projections on increased coal production?

Mr. DEMPSEY. Do I agree?

Mr. MOFFETT. Do you agree with his projections on increased coal production?

Mr. DEMPSEY. Do I agree they are necessary?

Mr. MOFFETT. No, do you agree with the figures the President has sent up to the Congress, because we have had considerable testimony to the effect they are overly ambitious, and, in fact, way off the mark.

Mr. DEMPSEY. That they wouldn't be achieved?

Mr. MOFFETT. Right.

Mr. DEMPSEY. It seems to me that is again a function of the capacity of the coal mining industry and its labor force to gear up, and I have heard the coal mining people say that they can do it, provided that the Congress sets policies that encourage that sort of thing, and you have a clash between the environmental constraints and coal production and I am probably the last person in this room to be able to make a sound judgment as to whether those goals can be reached or not.

Mr. MOFFETT. I am not trying to pick on you but any of the transportation industry, don't you have to take a look at the President's projections for increased production and decide whether your industry agrees with those projections or not?

Mr. DEMPSEY. We are planning on the assumption that the President's program targets will be met. That is how we have been acquiring coal cars. Indeed, we were assuming President Ford's target would be met of a doubling of production, and that is why we are ahead of the game, so to speak, in getting coal cars.

Mr. MOFFETT. Is that a safe thing to do?

Mr. DEMPSEY. We can't do that very long. In point of fact, the targets have not been met, and one becomes understandably cautious.

Mr. MOFFETT. Don't you do your own assessment rather than just assuming the targets will be met? Don't you put your own economists to work and say wait a minute, the President is way off base, and we are going ahead and ordering more rail coal cars, and it really doesn't make sense?

Mr. DEMPSEY. Yes, we will do that as soon as the Congress finishes its work on the program, so we can make some sort of appraisal as to what kind of program there is going to be.

Mr. MOFFETT. It would be helpful in our deliberations if we can get some opinion from the various experts in the transportation industry involved as to whether or not the President is correct or not, and it seems to me it would be a safe assumption for us to make that a business, and an industry is going to take a look at the President's assumptions and whether they go to the Wall Street firms or whoever they go to, or they use their own economists, it seems to me they have to try and project out what their own assessment is of what coal production wil be like, and what their behavior will be in response to it.

Mr. DEMPSEY. We do, Mr. Chairman. We don't mine the coal, and we don't provide the money to mine the coal; we don't regulate clean air quality standards; we don't do any of the things that have to do with whether or not the President's program will be achieved.

We follow your lead, and the President's answer and then the coal mining industry, and the utility industry, and I guess all I can say is we feel that we are capable of doing that.

I acknowledge that there may be problems from spot to spot in ConRail, and I will be glad to take that up.

Mr. MOFFETT. I am just not sure if I were sitting where you are sitting that I would be following a), the President and his projections, and basing my business on that, or b), the projections of Congress.

Mr. DEMPSEY. We may not.

Mr. MOFFETT. I would surely have some analysis of my own as quickly as I could get it to put up against those projections.

Mr. DEMPSEY. Let me put it this way: If the President had not come in with a new program, and we are dealing under the old Ford Administration target of a doubling of coal production by 1985, I can assure you we would no longer be considering that a valid program, because it simply hasn't measured up to what the former administration said it would.

Now we have a new ball game, and we will just have to wait and see what happens to this legislation.

Mr. MOFFETT. I am sorry to report we do have a vote. I would like to thank you all for testifying and your contribution. I think you have helped us a great deal.

Thank you very much,

Mr. DEMPSEY. Thank you, Mr. Chairman.

[The following letters and attachments were received for the record:]

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June 6, 1977

Honorable John D. Dingell, Chairman
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
U. S. House of Representatives
Washington, D. C. 20515

Dear Mr. Chairman:

During a hearing of the Subcommittee on Energy and Power on Thursday, May 26, 1977, Mr. Moore asked each panelist representing the barge, railroad and slurry pipeline industries to comment on the sufficiency of transportation facilities to bring an adequate supply of coal to Louisiana.

Following that hearing, Mr. Moore advised that the Louisiana State Department of Conservation says that if Louisiana utilities and industries convert to coal, they will need 150,000 tons a day of bituminous coal. It is estimated further by the Louisiana conservation department that 17 trains of 120 cars apiece or 100 barges would be required to accommodate that amount of coal.

As one looks to the future, the magnitude of the transportation requirement for coal delivery to Louisiana becomes even greater. A study completed this year for the Division of Natural Resources in the Louisiana State Department of Conservation estimates that Louisiana will need to import between 206 and 222 million tons of coal a year by 1990.

If the railroads could transport that quantity of coal, it would require the arrival of 60 loaded coal trains of 100 cars apiece at points within the state daily. Since coal trains return empty to the mines, this would mean 120 mile-long trains entering or leaving Louisiana every day or an average of five such trains every hour.

The social and environmental impacts of that many unit trains of coal moving through Louisiana would require thorough investigation, the study notes. It also suggests that consideration be given to alternate routes around metropolitan areas to reduce the noise, traffic disruption and air pollution associated with rail transport.

The study, performed for the conservation department by Southwest Louisiana State University, also notes:

• Much of the railroad track in Louisiana is inadequate to handle large volumes of coal and that some railroads do not know how much upgrading it would require to make coal transportation possible.

- That while Louisiana has waterways available for coal transit, many barge lines are owned by energy companies and that future barge deliveries of coal may be destined for industries other than those covered by the survey.

- That slurry pipelines are silent and out of sight and offer an alternative transport method, providing competition that should be favorable to the energy consumer.

In conclusion, the report notes that "industry and utilities that are considering conversion to coal should have more than one coal transport alternative. A plant that does not have barge or slurry possibilities will not have as strong a negotiating base with the railroads as one with multiple alternatives."

Based on this report, it is apparent that the present transportation systems, especially the railroads, cannot adequately handle the quantity of coal Louisiana will require. Even with substantial improvements, rail transport is still questionable enough to indicate the need for a supplementary transportation system.

In response to your question about construction time for a slurry pipeline, I can only say, as I did at the hearing, that construction of coal slurry pipelines is dependent upon Congressional approval of the pending bill (H.R.1609) to provide the right of eminent domain for coal slurry pipelines. Without eminent domain, the railroads have demonstrated their determination to block entry of another mode of transportation into the market place by denying them passage beneath the railroad tracks.

The bill providing eminent domain for coal slurry pipelines provides for an extensive examination of each specific pipeline proposal. In addition, each pipeline builder will have to acquire his own financing, his own customers and secure, through appropriate authorities, in states near the mine site sufficient water to operate a slurry pipeline.

The planning, design and construction of a coal slurry pipeline is generally estimated to take about three years. Given prompt Congressional action on the right of way question and no undue delays in the certification process, a coal slurry pipeline should be ready for operation in the early 1980's.

Sincerely,

W. Pat Jennings

W. PAT JENNINGS
President

cc: Honorable W. Henson Moore

SLURRY TRANSPORT ASSOCIATION
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June 7, 1977

Honorable John D. Dingell, Chairman
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
U. S. House of Representatives
Washington, D. C. 20515

Dear Mr. Chairman:

On May 26, 1977, I was invited to make a statement to the Subcommittee on Energy and Power along with representatives of the rail and barge industries on the coal transportation aspects of the President's energy program. During the course of the hearing, Rep. Brown requested each panelist to respond to a series of questions with information relating to the mode of transport he represents.

The following responses are provided for coal slurry pipelines.

Question: For coal slurry pipelines, what is the consumption of-

a. Energy: Slurry pipelines and railroads are generally believed to use about the same amount of energy although pipelines do not require petroleum-based fuel.

Al H. Chesser, president, United Transportation Union, noted this comparability when he told the House Interior Committee in 1975 that "the facts show that there is very little difference between the two modes of transportation. Slurry pipelines are 96 percent energy efficient while unit trains are 98 percent energy efficient. That is, 4 percent of the energy value of the coal being transported is absorbed in the pipeline, while the comparable figure for rail is 2 percent. The Association of American Railroads has stated that railroad unit trains hauling coal use 250 BTU's per ton mile while coal slurry pipelines use about 290 BTU's per ton."

In a study financed by the Burlington Northern Railroad, the Hudson Institute also said the energy use of the two modes was essentially the same, assuming both use electricity. When the unit train is powered by a diesel engine, the Hudson Institute said, the advantage lies with the railroad, but the report noted that diesel fuel is the more precious energy.

b. Water: Coal slurry consists of approximately equal parts of water and coal; therefore it takes a ton of water to move a ton of coal.

It should be noted, however, that coal slurry pipelines use less water than energy conversion processes. A power plant takes 7-8 times as much water as a slurry pipeline; a gasification plant about twice as much.

Since the silent, underground slurry lines have less social and environmental impacts than unit trains and use less water than energy conversion processes, they offer an attractive alternative to communities in coal producing areas.

c. Dollars: Artificial barriers have limited the use of slurry pipelines in coal transportation. Operators of the Ohio pipeline (1957-63) and the Black Mesa Pipe Line (1970 to date), however, claim economic success for those pipelines. The Chairman of the Board of Southern California Edison Co., operators of the Mohave Generating Station which receives its fuel by slurry pipeline, told the House Interior Committee that his experience indicates coal has been transported to the generating plant "at a cost benefit of nearly 50 percent below that of alternative transportation costs."

The characteristics of slurry pipelines are that 70 percent of the costs are associated with capital outlays while only 30 percent go for operations. As a result, coal slurry pipeline costs are relatively insensitive to inflationary increases.

What is the cost of--

a. Construction: Experience with pipeline construction in general indicates the cost of building pipelines is largely a linear function of pipe size and costs vary widely from one area to another. In an effort to be responsive, however, we have obtained an estimate from industry sources available to the STA Technical Committee of $11,000 per diameter-inch per mile although, as noted, this will vary from job to job.

b. Operation: This is essentially the same question as c.above.

c. Transportation: Slurry transportation costs are dependent upon volume and distance as indicated by attached chart.

A study conducted by Ebasco Services Incorporated and reported to the American Power Conference last year examined the transportation of energy blocks of various sizes over distances of 500, 900, and 1600 miles. The study compared electric power transportation by transmission lines, coal transport by rail, combined rail and river barge systems and slurry pipelines.

The conclusion was "that the pipeline coal-energy transportation system, in almost all cases, is the most economic means of transporting energy."

Copies of that study are enclosed.

We have tried to be helpful and responsive to your questions, and I hope these broad, general statements will be useful to you.

The real answers to all these cost questions must come in the market-place where a user of coal energy can match specific proposals from competitiors against each other and determine which alternative is the better one. Utility executives have testified that they can save billions of dollars for the consumer of electricity with coal slurry pipelines, but these potential savings have been denied because the railroads refuse to allow construction of coal slurry pipelines. By granting the right of eminent domain, as proposed in H.R. 1609, the Congress can set the stage for meaningful studies of these questions and provide the benefits of competition in energy transportation to the American consumer.

In addition to the questions relating to costs, Mr. Brown also asked about the availability of steel. I am advised that coal slurry pipelines use carbon steel pipe, which is not the same as that used by railroads and barges.

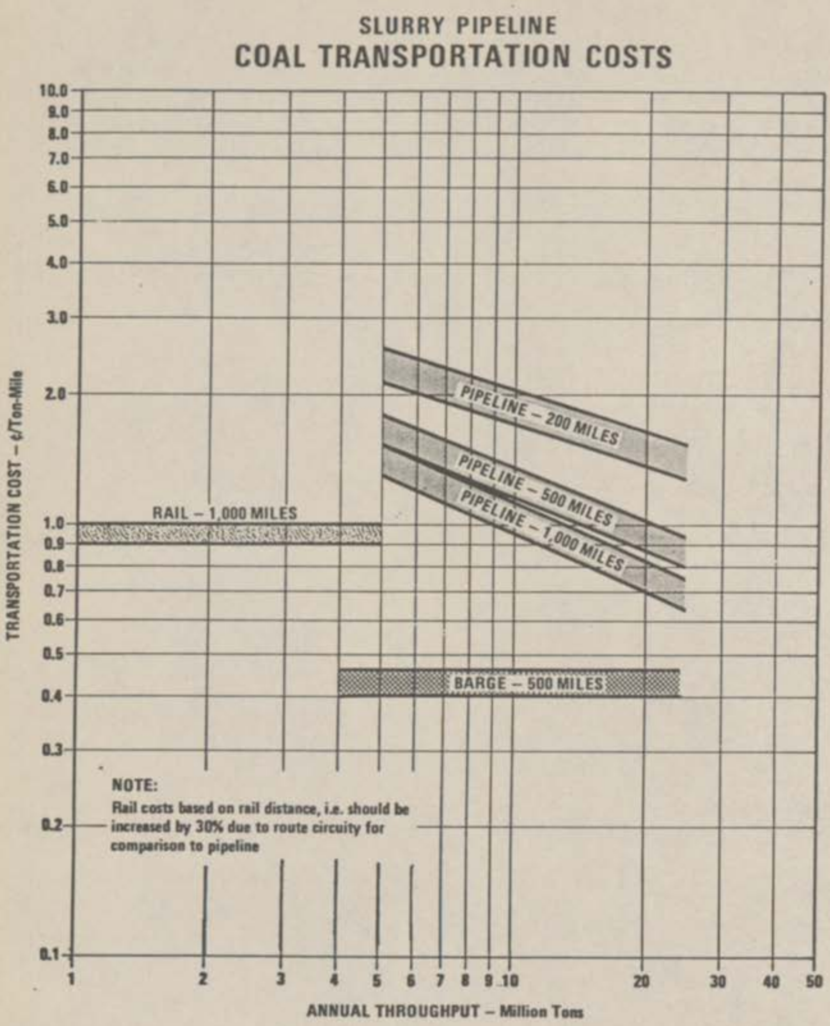
Sincerely,

Pat Jennings

W. PAT JENNINGS
President

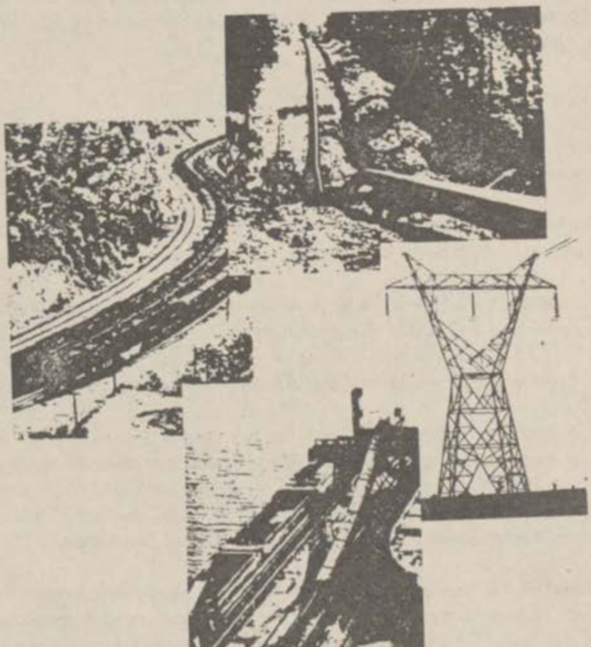
Enclosure

cc: Honorable Clarence J. Brown


SLURRY PIPELINE
COAL TRANSPORTATION COSTS
TRANSPORTATION COST – ¢/Ton-Mile
ANNUAL THROUGHPUT – Million Tons
PIPELINE – 200 MILES
PIPELINE – 500 MILES
PIPELINE – 1,000 MILES
RAIL – 1,000 MILES
BARGE – 500 MILES
NOTE:
Rail costs based on rail distance, i.e. should be increased by 30% due to route circuity for comparison to pipeline

ENERGY TRANSPORTATION

by
A.J. Banks
R.B. Leemans
Consulting Mechanical Engineers
Ebasco Services Incorporated



American Power Conference · 38th Annual Meeting
April 20, 21, & 22, 1976
Chicago, Illinois

Ebasco Services Incorporated
Two Rector Street, New York, N.Y. 10006

ENERGY TRANSPORTATION

A. INTRODUCTION

Several of our more pressing national concerns today relate to energy as a dwindling American resource, its rate of consumption, its conservation and its cost. Although most of us are not intimately familiar with the first three concerns, we are all experienced with energy cost and how it has increased over the past several years due to the recent inflationary spiral.

Transporting energy, in the form of electricity and coal, has also been subjected to these inflationary forces and is becoming of increasingly greater significance in the delivered cost of energy to the power consumer. Several alternative energy transportation systems relative to these two energy sources, have been studied and evaluated by Ebasco and are the subject of this paper. The alternatives are:

Electric power transportation by transmission lines
Coal transportation by railroads
Coal transportation by combined railroad and river barge systems
Coal transportation by slurry pipelines

This paper covers the transportation of these energy blocks in 1600, 3200, 6400 and 9000 MW increments over distances of 500, 900 and 1500 miles.

Costs are based on having a single terminal point for each transportation system. However, the 6 400 MW and 9 000 MW generating facilities could be comprised of several large stations in an energy center transmitting to a large industrial city. The transportation system would, therefore, split into several branches as it nears the terminus.

The distances selected represent probable haulage routes. For example, from the west Kentucky or southern Illinois coal fields to a plant site on the lower Mississippi would be about 500 miles. A 900-mile route would be equivalent to the distance between east Kentucky and the Dallas-Fort Worth area whereas 1500 miles would be equivalent to the distances between Wyoming and the lower Mississippi and Gulf Coast areas.

The study concludes that the pipeline coal-energy transportation system, in almost all cases, is the most economic means of transporting energy. Except for large power blocks at long distances, rail-barge transportation systems, as defined in the paper, are the second most attractive alternative. Railroads in half of the cases studied, proved to be the most expensive means of transporting energy. This is especially true when transferring large blocks of energy over great distances. In general, transmission lines are competitive with the rail and rail-barge systems when large power blocks are to be transported over long distances. They are not too competitive, however, when relatively small power blocks are involved regardless of transmission distances.

The following sections examine, review and summarize each of the alternatives studied.

B. ELECTRIC ENERGY TRANSPORTATION BY TRANSMISSION LINES

The study of this alternative requires selecting the most feasible line voltage to evaluate. Four transmission voltages have been examined to determine the appropriate system for each power level and each distance. Two of the cases are AC and two are DC power systems. The two alternating current voltage levels are 765 kV and 1100 kV. The 765 kV voltage is, of course, a proven technology, whereas 1100 kV designs have developed to a point where there is a reasonable probability of constructing a system at this voltage for a 1980 service date. A 1500 kV AC line is not included in the comparision as Ebasco is not as optimistic about its 1980 availability. The 400 and 600 kV direct current voltages are feasible.

Series and shunt compensation are assumed for the AC lines because of circuit length and loading. Bundled conductor configurations are selected as they are appropriate to the circuit loadings. All lines are single circuit construction.

Since the systems would be designed to carry rated load with one circuit out of service, a minimum of two lines is considered for all cases. Although up to five circuits were investigated for some situations, two, at the proper voltage level, were found adequate in all cases.

The transmission costs are tabulated in Figure 1. The data indicates:

1) The most efficient voltage for each energy level and distance studied,
2) the line losses experienced to each load center,
3) the investment required for each alternative, and
4) the annual owning and operating cost for each alternative.

Unlike the other energy transportation alternatives, the transmission lines require a larger power generating plant to account for the I^2R losses which will be experienced over the length of the transmission lines. The plant size increase would be slightly larger than the line losses listed in the chart. The annual cost figures, as shown in the tabulation, take into account the increase in plant investment and fuel cost associated with this alternative.

C. COAL-ENERGY TRANSPORTATION BY RAILROAD

Unit trains are dedicated freight trains made up of between 100 and 170 coal cars which are for the exclusive delivery of coal to a specific customer's plant at a special low freight rate. The number of cars varies with delivery rate and the terrain over which the train must travel.

The lower freight rate results because of the full-time utilization of the equipment. Typical railroad freight cars spend only a small percentage of their service lives moving a revenue-producing cargo. Most of the time they sit empty waiting to be taken to a loading point or even waiting in a freight yard to be made up into a train to return to its home system. Obviously, waiting is not a revenue producing activity. The unit train equipment, on the other hand, operates at a very high capacity factor.

The unit train freight rate is developed by the carrier after a detailed cost study. It takes into account track conditions, terrain, motive power, drawbar pull, coal tonnage to be moved, and length of the haul. Loading and unloading times are specified with extra charges accruing if they are exceeded. The carrier provides the motive power and train crew. The coal cars can be furnished by the carrier—at a higher rate, of course—or by the receiver, or even by the shipper. A leasing contract could also be negotiated with a financial institution. Coal-burning utilities should evaluate the acquisition of their own fleets of coal cars. The nationwide shortage of hopper cars will not be eased by the expected increase in coal usage nor by carriers in poor financial health who cannot properly maintain existing equipment and right-of-way much less invest in new fleets of coal cars.

The annual delivery requirements, based on a 65 percent generating load factor would be as follows:

PEAK LOAD – MW	COAL @ 65% LOAD FACTOR 1 000 TONS/YEAR
1 600	4 500
3 200	9 000
6 400	18 000
9 000	25 000

Costs for this method of transportation will be covered later.

D. COAL-ENERGY TRANSPORTATION BY RAILROAD AND BARGE

A combined unit train-coal barge transportation system could service power plants along a major navigable waterway, e.g., the Mississippi and/or Ohio Rivers, or along the Intercoastal Canal along the Gulf Coast.

Barge transportation is an efficient and growing industry. In the past 20 years barge lines have increased their share of intercity freight traffic from approximately 5½ percent to over 15 percent. Single tows have grown to as much as 30 000 tons of material. The so-called "Jumbo" barges (1 500 ton capacity) are rapidly becoming the standard barge size. Towboats which actually push the string of barges, are being built with 10 000 hp drive units.

Moving freight by barge is lower in cost than by train. One of the reasons for this is that the barge lines are not under the jurisdiction of the Interstate Commerce Commission as are the railroads and truckers. In addition, the barge lines' "right-of-way" is maintained and improved at no direct cost to them but by taxpayers' money, through the U.S. Corps of Engineers.

For purposes of comparison we have assumed the railroad and barge hauls would be split as shown in Table 1 below:

TABLE 1

DISTANCE – MILES			ROUTE	
Total	By Rail	By Barge	From	To
500	100	400	W. Kentucky	lower Mississippi
900	300	600	E. Kentucky	Dallas area
1 500	1 000	500	Wyoming	lower Mississippi

Thus, the coal would move from mine to river barge loading facility by unit train, and thence via the waterway to the plant barge unloading facility. Alternatively, the coal could be loaded directly into barges from a riverside mine and then be transferred to unit train for delivery to the power plant. Costs for rail-barge systems contemplate only one transfer, i.e., from rail to barge or barge to rail.

The towboats and barges are normally provided by the barge line. In order to transport the coal tonnages under consideration the barge lines would have to build or purchase new equipment requiring a considerable investment. They would demand a long-term contract which would permit them to amortize most of this investment. Conceivably, they might need financial assistance or participation by the utility.

Barge rates, analogous to unit train rates, depend on the volume, distance and the route to be traveled. The latter may dictate maximum size of tow and whether or not the tow must be broken to pass through locks. Both of these factors affect costs.

Comparative transport costs for this alternative will also be covered later in the study.

E. COAL-ENERGY TRANSPORTATION BY PIPELINE

Another method of transporting coal is in a slurry form via pipeline. The first U.S. coal pipeline, a 108-mile, 10-inch line, was built in 1957 to counteract high coal freight rates. The line serviced the Eastlake Station of Cleveland Electric Illuminating Company and, after the initial problems were ironed out, operated successfully for several years. The railroad tariff for hauling coal to the station was subsequently reduced. The line was then shut down having accomplished its purpose.

The Black Mesa pipeline was installed in 1970. It is comprised of a 273-mile, 18-inch diameter line which delivers about 5½ million tons per year to the Mohave Power Project. The plant does not have a rail facility and the line provides their only viable means of delivering coal to the plant site.

A 1 040-mile line is currently under consideration to deliver 25 million tons of Wyoming coal per year to Arkansas. An 800-mile line to deliver Wyoming coal to northwest Washington is also being studied. Another 1 000-mile line from Colorado to Texas has been proposed. As you can see, we are not dealing with a new, untried technology.

Let us briefly run through the components of a coal pipeline. It starts with a slurry preparation plant at the mine. Here the coal is crushed to particles about one-tenth of an inch and smaller in diameter and is then mixed with water to make a 50-50 coal-water slurry. This is pumped at 1 200 psi into the pipeline. Over level terrain, the line pressure drops off to about 100 psi after 70 miles at which point a pumping station is installed to repressure the line to 1 200 psi. This is repeated at 7.0-mile increments. At each pumping station a dump pond is provided with capacity to contain the pipeline volume between that station and the upstream pumping station. This permits emptying each section of the line for repair or an emergency.

The slurry moves along at 6 ft per second inside the pipe. This means, for a 900-mile trip, that the coal is in transit for nine days. A 900-mile long line delivering coal at the rate of 9 million tons per year would contain 270 000 tons of coal in transit at any one time.

The slurry is passed through centrifuges at the receiving end of the line thereby producing a coal "cake" with a 25 percent moisture content. The water removed is treated to remove additional fine coal dust and then used for plant services.

The pipe size for each of the annual coal tonnages are as follows:

COAL (10^6 Tons/Yr)	GENERATION (10^6 kWh)	LINE DIAMETER (Inches)
4.5	9 110.4	18
9.0	18 220.8	24
18.0	36 441.6	34
25.0	51 246.0	40

Figure 2 is a tabulation of the pipeline energy transportation costs for the several alternatives being evaluated.

These examples and data sound encouraging, and they are. However, if the vast amounts of western coal being projected as a future fuel supply are to be moved by pipeline, this requires performing a complete water resource evaluation study in order to produce a viable system design which is environmentally acceptable. Fortunately, this concern may not apply to the same degree to the rest of the country.

In addition to water, another problem exists; however, it is a man-made problem and is therefore more readily soluble. The coal pipeline, as yet, does not enjoy the same right of eminent domain that gas and oil lines possess. This poses a problem since a 900-mile line, for example, may involve some 30 major railway crossings. Railways are not inclined to permit such crossings to a competing mode of transportation.

Carl F. Bagge, President of the National Coal Association, addressed the House of Representatives, House Interior Committee on July 25th, last year. He advised the Committee members that:

> Pipelines offer coal much the same advantage as they do oil and natural gas. Once constructed, they are relatively inflation resistant, dependable, environmentally acceptable, and able to move large volumes of material with a minimum of disruption. Indeed, one of coal's major competitive disadvantages over the years has been the availability of pipelining technology to its major competitors, natural gas and oil.

Mr. Bagge commented further on eminent domain as a problem with coal slurry lines. He advised the Committee that:

> Today in the midst of a rapidly escalating demand, coal simply must have the option of the pipeline. And it therefore follows that the coal pipeline must be accorded the right of eminent domain to insure that such pipelines can be built where economics and technology as well as other factors indicate that they should be built.

Hopefully, his testimony will have an impact on future congressional legislation.

F. ENVIRONMENTAL AND LICENSING CONSIDERATIONS

Of the four alternative means of transporting energy, transmission lines probably have the greatest environmental impact. Railroad and rail-barge system expansions for the most part result in increased traffic along existing routes with new right-of-ways possibly only being required to connect a new mine to the nearest rail line or docking facility. However, the increased traffic on existing lines caused by mile-long unit trains may also create new additional undesirable effects, such as added noise pollution, cross-traffic tie-ups, increased coal dusting in populated areas contiguous with the railroad lines and other such public nuisances.

The coal pipeline, on the other hand, requires a very narrow right-of-way and, once installed, is invisible except for the low-profile pumping stations every 70 miles or so. In addition to obtaining approval of the Environmental Impact Report for licensing, various and sundry other type approvals must be obtained to construct the line. For example, a 900-mile line from Wyoming to an eastern area could involve as many as 130 highway crossings, 30 major railroad crossings, 25 river crossings and 10 major natural gas pipeline crossings. Obtaining approval for all these "crossings" is no small feat. However, new eminent domain regulations relative to coal pipelines could reduce these encumbrances or nuisances to a tolerable level.

G. COMPARATIVE COSTS

1. Bases of Estimates

Of necessity, many assumptions were made to determine the comparative costs of the alternative energy transportation systems. The levelized annual cost figures are calculated on a 10.9 percent discount rate for the transmission lines, 11.4 percent for the coal slurry lines, and an 8 percent rate for the rail and rail-barge systems. A 30-year amortization period and 6 percent annual escalation rate are also used. Levelizing equates a continually escalating annual cost to a uniform annual cost figure. Both values yield the *same* Present Worth Dollar Value over a specific amortization period.

The following additional basic assumptions were made in arriving at the costs for each system.

a) Transmission Lines

1. The 765 kV (AC) transmission line costs were based on American utility experience with this line rating. The 1 100 kV (AC) costs were developed from the 765 kV figures by using the cost ratios for various UHV configurations presented in a recent CIGRE paper. The 600 kV (DC) line basic design, using a bundle of four 954 kcmil conductors, was estimated as being 75 percent of the cost of a similar 765 kV (AC) line. The costs for the other DC line voltage and conductor configurations were extrapolated from this by Peterson's formula. DC terminal equipment costs are based on manufacturer's recent information. They also include an allowance for ground electrodes.

2. Right-of-way widths were chosen which would permit a collapsing tower on one line to fall clear of the neighboring line. A cost of $2 500 per acre was assumed, which included clearing, access roads, gates, etc.

3. Fixed charges were taken as 16 percent for depreciable items and 20 percent for nondepreciables. Financing was assumed at a typical utility's debt-equity rates.

4. Investment costs were escalated for a 1980 initial operation at the rate of 7.5 percent a year. Operation and maintenance costs were taken as 1 percent of the investment costs.

b) Railroad and Rail and Barge Systems

1. Existing rail lines were available to deliver coal from the mines to the plant or the barges.

2. Unit train and barge rates for such large volume movements were not available from a published tariff schedule. The rates used in this study are representative of those that Ebasco believes could be negotiated with the carriers and are based on other known unit train and barge freight rates.

3. Hopper cars costs were obtained from a manufacturer. Maintenance costs were based on published data on cars in unit train service.

4. Based on the long-term trend, rail freight rates and barge rates were assumed to escalate at the rate of 6 percent per year, as were car maintenance costs.

c) Coal Slurry Pipelines

1. Investment costs were estimated in detail by Ebasco for a specific case and then adjusted, on an order-of-magnitude basis, for the other alternatives.

2. Fixed charges were taken at the rate of 14 percent, based on 80 percent debt, 20 percent equity financing, i.e., nonutility-type financing.

3. Energy costs were based on actual utility rates. For example, the 1 500-mile line energy costs included preparation plant energy costs based on a western utility company's rates.

4. Material costs were escalated for 1980 initial operation at 6 percent per year, while labor costs were escalated at 8 percent per year.

2. Pipeline vs Transmission Line – Investment Estimates

Coal pipelines and electric transmission lines require the largest investment of the four alternatives studied. Coal transporting by rail or rail-barge requires lower expenditures. If the carrier provides the coal cars, there is essentially no investment required of the utility other than the facilities at the power station. This study is based on the use of utility-owned cars, as this option is becoming more and more predominent with the industry because of the railroads' current financial problems.

As an example, a 900-mile coal pipeline, delivering 9 million tons of coal per year to generate 3 200 MW, is estimated to cost $710 million based on a 1980 operating date. This figure is comprised of:

ITEM	INVESTMENT ($1 000)
Coal Slurry preparation plant	$ 92 000
Coal pipeline	348 000
Pumping stations (Total 12)	155 000
Dewatering plant	115 000
Total Investment	$710 000

On the other hand, transmitting 3 200 MW of electric power via two 600 kV (DC) circuits requires an investment of approximately $1 045 million. This includes:

ITEM	INVESTMENT ($1 000)
Right-of-way @ $2 500 per acre	$ 131 000
Power line terminals	380 000
Power line	534 000
Total Investment	$1 045 000

For 900 miles of rail or rail and barge transportation of 9 million tons of coal, utility investment for hopper cars is estimated to be $29 million for an all rail mode and $14 million for rail-barge transportation alternatives. The barges and towboats are assumed to be provided by the carrier.

The investment figures are important, but no finite conclusions should be made without completely evaluating these cases with regard to both investment *and* operating costs.

Two of these alternatives are heavily investment oriented (coal pipeline and electric transmission lines) but the other two are more sensitive to inflationary factors as they relate to annual costs. The latter factors include labor and transportation rates (i. e., operating labor and railroad and rail-barge haulage rates). The latter two alternatives will be discussed in the next section. It should be noted that capital investment items do not escalate once they are installed.

3. Transportation Costs

Transportation costs include investment fixed charges and annual operating and maintenance costs. In the case of rail or rail and barge transportation, the freight charges remain the major component with relatively small amounts for investment and maintenance.

Rail freight rates used in the study are shown in Table 2, based on mid-1975 conditions and utility-owned coal cars.

TABLE 2

Distance - Miles	Freight Rate - $/Ton (Mills/Ton Mile)	
500	5.50	(11.00)
900	8.50	(9.45)
1 500	13.50	(9.00)

On the same basis, the rail-barge rates used are shown in Table 3.

TABLE 3

Distance - Miles	Freight Rate - $/Ton (Mills/Ton Mile)		
	Rail	Barge	Total
500 (100 rail - 400 barge)	2.20 (22.00)	1.80 (4.50)	4.00 (8.00)
900 (300 rail - 600 barge)	4.30 (14.32)	2.70 (4.50)	7.00 (7.79)
1 500 (1 000 rail - 500 barge)	9.50 (9.50)	2.20 (4.40)	11.70 (7.79)

It is believed the rates shown are about what would be arrived at in negotiations with carriers.

Escalating these rates using the long-term trend of 6.0 percent per year results in the levelized rates shown in Tables 4 and 5.

TABLE 4

Distance - Miles	All-Rail Freight Rate - $/Ton (Mills/Ton Mile)	
500	15.82	(31.64)
900	24.47	(27.19)
1 500	38.81	(25.87)

TABLE 5

Distance - Miles	Rail and Barge Freight Rate - $/Ton (Mills/Ton Mile)	
500	11.50	(23.00)
900	20.15	(22.39)
1 500	33.65	(22.43)

In the case of the capital-intensive pipelines and transmission lines, the major component of the annual costs are the fixed charges, with operation and maintenance being relatively small. The pipeline fixed charges are about 73 percent of the annual costs, the balance is operating and maintenance costs. With 73 percent of their annual costs fixed, the coal pipelines are inflation resistant, with only a small component of the annual costs subject to escalation forces. Therefore, any evaluation of owning and operating costs which equates a capital intensive alternative equal to an operating intensive alternative, the capital alternative is the more attractive of the two, provided the state public service commission responds to rate adjustment requests on a timely basis.

Table 6 indicates the portion of the annual costs subject to escalation factors for each transportation system.

TABLE 6

System	Approximate Percent of Annual Costs Subject to Escalation
All-Rail	98.5
Rail-Barge	99.0
Coal Pipelines	27.1
Transmission Lines	24.0 to 54.3

The variations in the transmission line percentage costs are due to the I^2R line losses which vary both with electrical load and energy transporting distances. This variation does not exist with the other alternatives as the generating plants are assumed to be located reasonably close to the load centers. Because of this, additional plant capacity is not required.

Figure 3 is a breakdown of the levelized annual owning and operating costs of the alternatives studied based on a 1980 initial operating date. Figure 4 tabulates the alternative costs based on differentials over the lowest cost alternative. The chart shows that coal pipelines are the most economic system in almost all cases. Rail and barge transportation systems are the next most attractive alternative.

Figures 5, 6 and 7 are bar charts of the four alternatives owning and operating costs for the three distances studied; i.e., 500, 900 and 1 500 miles. These exhibits graphically illustrate the impact that both inflating operating costs and large capital investment equipment have on annual costs and how they vary with transportation distances and size of the power block being transported.

H. CONCLUSIONS

In summary, the study shows:

1. In all but a few cases, pipeline transportation systems are the lowest cost mode of energy transportation followed by the rail-barge systems, as defined in the study. Coal pipelines are even more attractive if rail facilities do not serve the area under consideration.

2. Barge and rail transportation systems are worthy of consideration if (a) navigable waters for barge movements are available, and (b) the tonnage, distances and split between rail and barge hauling distances are in the "right" proportion.

3. Coal pipelines are lower in initial investment cost than transmission lines for the quantities of coal involved and the distances covered in the study.

4. Coal pipelines and transmission lines are more inflation-proof than rail or rail and barge modes of transportation because of the low, overall operating and maintenance cost associated with pipe slurry and power transmission lines. This should be weighed against the high operating cost of the rail and barge system alternatives when selecting the type energy transportation to use for your new coal-fired power plant.

5. If coal pipelines are to be viable, the right of eminent domain must be available to the user. In order to accomplish this, utilities must pursue this with their legislative leaders well ahead of time as it is a politically volatile subject.

96-231 O - 77 - 42

FIGURE 1

TRANSMISSION LINE TRANSPORTATION COSTS

FIGURES FOR 1980 INITIAL OPERATING DATE

Delivered Load (MW)	Optimum Voltage (kV) Type of Power (AC-DC)	Distance (Miles)	Line Loss (MW)	No. of Circuits*	Investment $1000's	Levelized Annual Cost $1000's
1600	±400-dc	500	58	2	511 000	113 380
	±400-dc	900	105	2	795 000	180 930
	±400-dc	1 500	175	2	1 220 000	284 490
3200	765-ac	500	130	2	618 000	155 710
	±600-dc	900	187	2	1 045 000	252 400
	±600-dc	1 500	312	2	1 518 000	376 390
6400	1100-ac	500	103	2	1 107 000	238 470
	±600-dc	900	425	2	1 609 000	428 940
	±600-dc	1 500	708	2	2 229 000	623 120
9000	1100-ac	500	204	2	1 268 000	296 300
	±600-dc	900	840	2	1 884 000	612 020
	±600-dc	1 500	1 401	2	2 504 000	896 210

*Conductor Bundles Used

±400kV-dc - 4-954 kcmil
±600kV-dc - 4-954 kcmil (for 3200 MW only)
4-2312 kcmil
765kV-ac - 4-954 kcmil
1100kV-ac - 6-1590 kcmil

FIGURE 2

PIPELINE TRANSPORTATION COSTS

FIGURES FOR 1980 INITIAL OPERATING DATE

Generation (MW)	Coal Delivery Tons Per Year	Distance (Miles)	Pipe Diameter (Inches)	Investment ($1000)	Levelized Annual Cost ($1000)
1 600	4 500 000	500	18	245 000	47 070
1 600	4 500 000	900	18	520 000	99 900
1 600	4 500 000	1 500	18	725 000	139 290
3 200	9 000 000	500	24	490 000	94 140
3 200	9 000 000	900	24	710 000	136 400
3 200	9 000 000	1 500	24	1 050 000	201 720
6 400	18 000 000	500	34	1 065 000	204 610
6 400	18 000 000	900	34	1 575 000	302 590
6 400	18 000 000	1 500	34	2 440 000	468 770
9 000	25 000 000	500	40	1 500 000	288 190
9 000	25 000 000	900	40	2 090 000	401 530
9 000	25 000 000	1 500	40	2 660 000	511 030

FIGURE 3

ANNUAL LEVELIZED UTILITY OWNING AND OPERATING COSTS
THOUSANDS OF DOLLARS

Distance - Miles	500	500	500	500	900	900	900	900	1 500	1 500	1 500	1 500
Capacity - MW	1 600	3 200	6 400	9 000	1 600	3 200	6 400	9 000	1 600	3 200	6 400	9 000
Transmission	400 kV-dc	765 kV-ac	1100 kV-ac	1100 kV-ac	400 kV-dc	600 kV-dc	600 kV-dc	600 kV-dc	400 kV-dc	600 kV-dc	600 kV-dc	600 kV-dc
Fixed Charges	84 390	101 940	181 300	206 900	131 840	172 510	263 130	307 130	202 940	251 720	365 860	409 860
Operating	28 990	53 770	57 170	89 400	49 090	79 890	165 810	304 890	81 550	124 570	257 260	486 350
Total	113 380	155 710	238 470	296 300	180 930	252 400	428 940	612 020	284 490	376 390	623 120	896 210
Railroad												
Fixed Charges	1 400	2 800	5 600	7 800	1 700	3 500	6 900	9 700	2 100	4 200	8 400	11 700
Operating	73 520	147 250	294 500	413 700	114 760	228 890	458 000	637 950	181 430	362 850	725 710	1 007 970
Total	74 920	150 050	300 100	421 500	116 460	232 390	464 900	647 650	183 530	367 050	734 110	1 019 670
Rail-Barge												
Fixed Charges	500	900	1 800	2 500	800	1 700	3 300	4 500	1 800	3 600	7 300	9 900
Operating	52 380	104 550	209 100	290 390	92 360	184 510	369 010	512 320	156 490	312 980	625 960	866 950
Total	52 880	105 450	210 900	292 890	93 160	186 210	372 310	516 820	158 290	316 580	633 260	876 850
Pipeline												
Fixed Charges	34 300	68 600	149 100	210 000	72 800	99 400	220 500	292 600	101 500	147 000	341 600	372 400
Operating	12 769	25 538	55 507	78 190	27 101	37 003	82 085	108 926	37 785	54 723	127 167	138 633
Total	47 069	94 138	204 607	288 190	99 901	136 402	302 585	401 526	139 285	201 723	468 767	511 033

FIGURE 4

DIFFERENTIAL ANNUAL OWNING AND OPERATING COSTS
MILLIONS OF DOLLARS

Distance - Miles	500	500	500	500	900	900	900	900	1 500	1 500	1 500	1 500
Generation - MW	1 600	3 200	6 400	9 000	1 600	3 200	6 400	9 000	1 600	3 200	6 400	9 000
Annual Costs												
Transmission Line	113.38	155.71	238.47	296.36	180.93	252.40	428.94	617.02	284.44	376.39	623.12	896.21
Railroad	74.92	150.05	300.10	421.50	116.46	232.39	414.90	647.65	183.53	367.05	734.11	019.67
Rail & Barge	52.88	105.45	210.90	292.80	93.16	186.21	372.31	516.82	158.29	316.58	622.26	876.85
Pipeline	47.07	94.14	204.61	288.19	99.90	136.40	302.59	401.53	137.29	201.72	468.77	511.03
Differential												
Transmission Line	66.31	61.57	33.86	8.17	87.77	116.00	126.35	210.44	145.20	174.67	154.35	385.18
Railroad	27.85	55.91	95.49	33.31	23.30	95.99	162.31	246.12	44.24	165.33	265.34	508.64
Rail & Barge	5.81	11.31	6.29	4.61	Base	49.81	69.72	115.29	19.00	114.36	164.49	365.82
Pipeline	Base	Base	Base	Base	6.74	Base	Base	Base	Base	Base	Base	Base

FIGURE 5

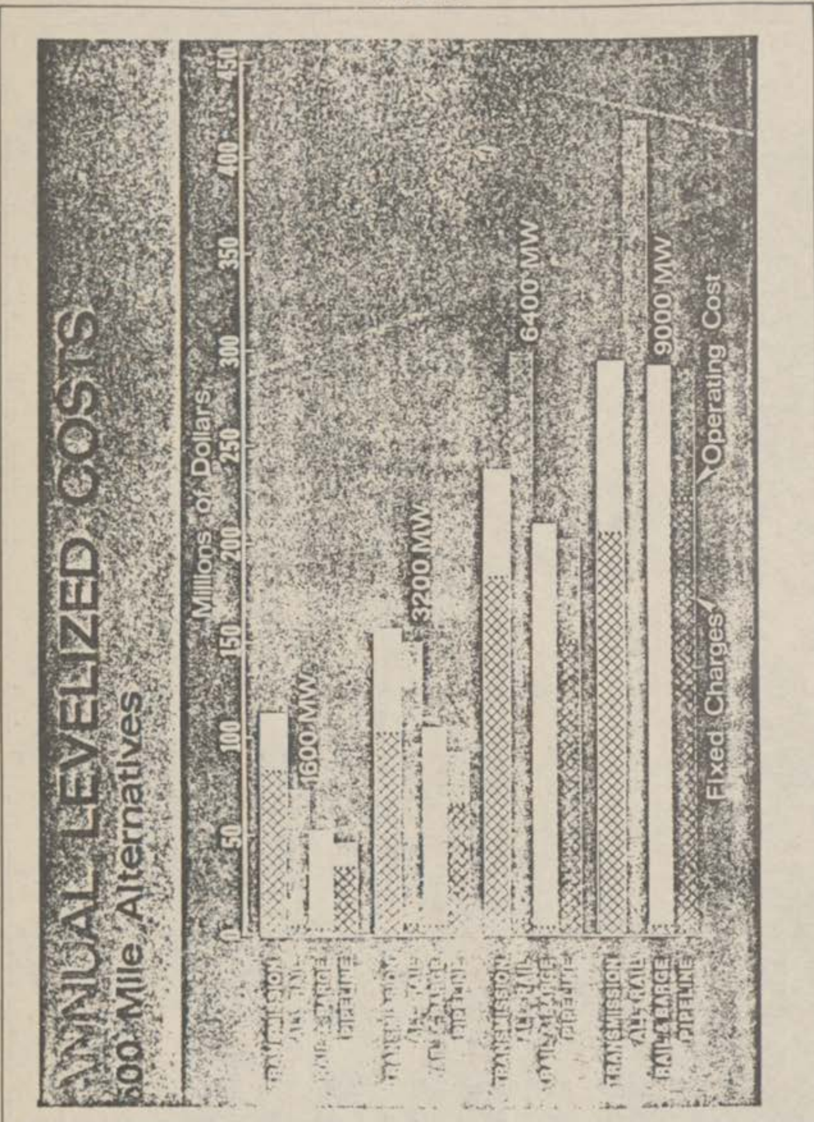

LEVELIZED COSTS
Mile Alternatives
Millions of Dollars
0
50
100
150
200
250
300
350
400
450
1600 MW
3200 MW
6400 MW
9000 MW
Fixed Charges
Operating Cost
TRANSMISSION
ALL RAIL
RAIL-BARGE
PIPELINE

FIGURE 6

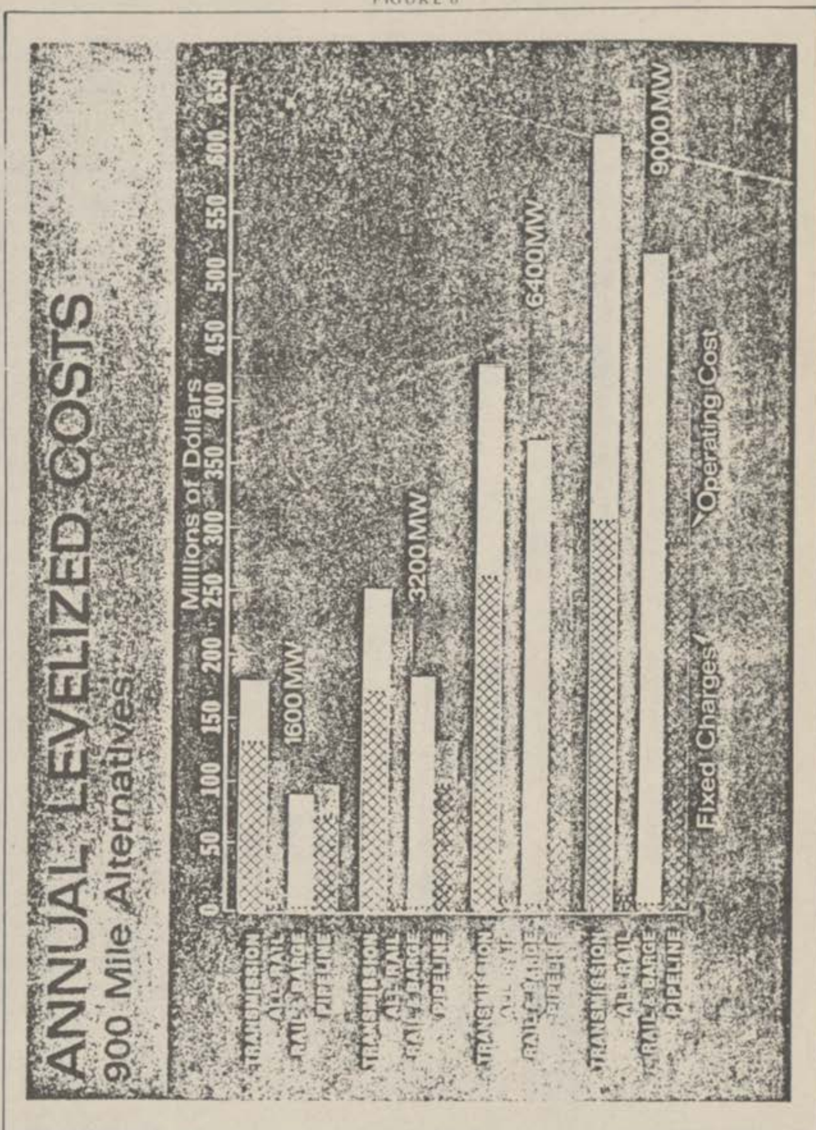
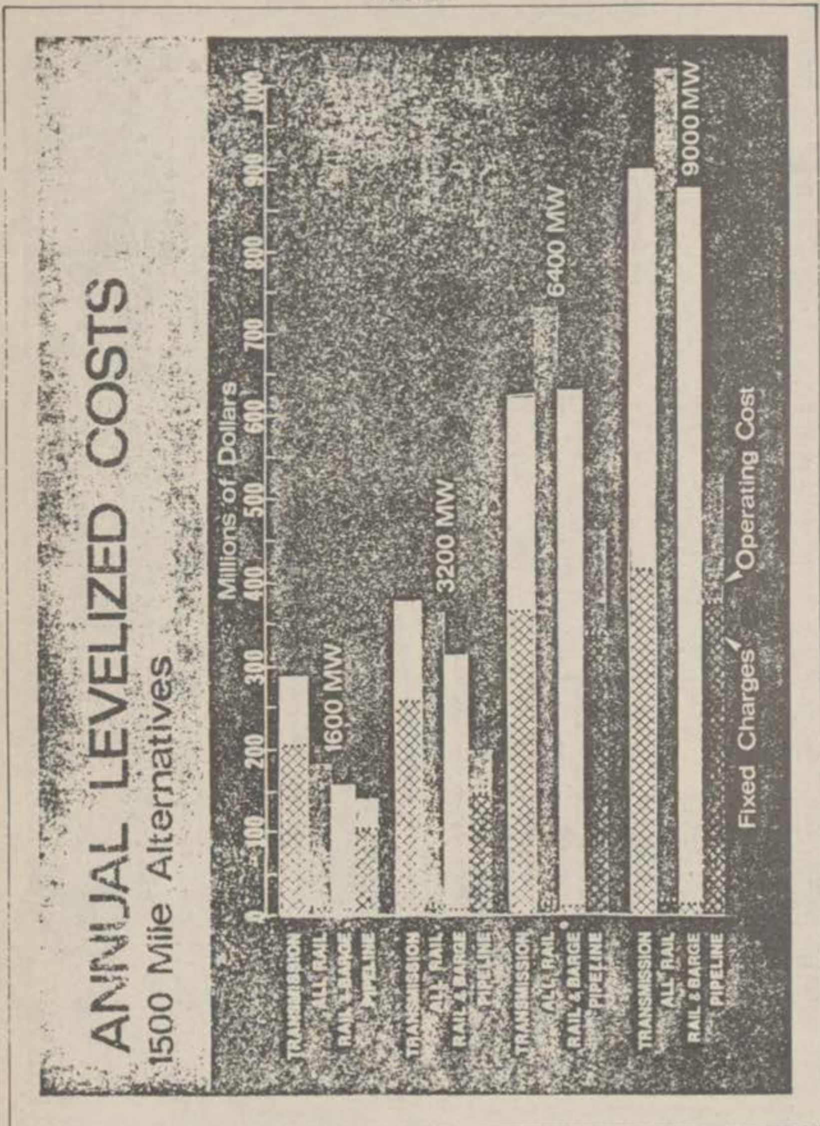

ANNUAL LEVELIZED COSTS
900 Mile Alternatives
Millions of Dollars
0
50
100
150
200
250
300
350
400
450
500
550
600
650
1600MW
3200MW
6400MW
9000MW
TRANSMISSION
ALL RAIL
RAIL / BARGE
PIPELINE
Fixed Charges
Operating Cost

FIGURE 7


ANNUAL LEVELIZED COSTS
1500 Mile Alternatives
Millions of Dollars
0
100
200
300
400
500
600
700
800
900
1000
1600 MW
3200 MW
6400 MW
9000 MW
TRANSMISSION
ALL RAIL
RAIL & BARGE
PIPELINE
Fixed Charges
Operating Cost

Mr. MOFFET. The committee will stand in recess for about 10 minutes. When we return the next panel will be addressing itself to technology issues.

[Brief recess.]

Mr. SHARP [presiding]. The subcommittee will come to order, and we will hear our last panel of the day, the panel on technology issues.

Gentlemen, we will just begin from my right and your left, and if you would we would appreciate having a summary of your testimony if it's lengthy, and we will put the entire statements into the record under any circcumstances, and if you could provide us something reasonable within the span of 5 minutes we would appreciate it. We have time problems, and afterward we will ask questions.

STATEMENTS OF CLIFFORD E. SEGLEM, MANAGER, TECHNICAL LIAISON, LONG RANGE DEVELOPMENT DEPARTMENT, GENERATION SYSTEMS DIVISION, WESTINGHOUSE ELECTRIC CORP.; ANDREW J. GRANT, PRODUCT MANAGER, ENERGY, WOODALL-DUCKHAM, LTD., BABCOCK INTERNATIONAL, INC.; DR. HENRY R. LINDEN, PRESIDENT, INSTITUTE OF GAS TECHOLOGY; DR. RAY ZAHRADNICK, PRESIDENT, RAY ZAHRADNIK CONSULTING, INC.; AND DR. MARTIN B. NEUWORTH, ACTING DIRECTOR, COAL CONVERSION AND UTILIZATION, ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION

Mr. SEGLEM. Thank you, Mr. Chairman.

I am Clifford Seglem, Manager of Technical Liaison, Long Range Development Department, of the Generation Systems Division, Westinghouse Electric Corporation.

I appreciate this opportunity to testify before your Subcommittee on Energy and Power.

My division of Westinghouse produces large heavy duty combustion turbine systems for use in electric utility powerplants and industrial installations. The technology of combustion turbines is a direct and important element in the utilization of coal in more efficient, economic, and environmentally acceptable powerplants.

I would like to summarize the status of technology for combustion turbines, coal conversion processes, and the path that can be followed for the earliest utilization of these technologies.

There are two basic coal conversion processes, gasification and liquefaction, that will provide fuel for future powerplants and industrial installations. In the first process coal is converted into a clean gas of medium or low Btu content and burned directly in the combustion turbine combined cycle power plant.

Secondly, coal also can be liquefied into a synthetic crude oil, and then refined to yield clean turbine grade fuel for direct burning in the combustion turbine powerplant. An alternative path would be to produce methanol fuel from coal. Methanol is an attractive clean liquid fuel for use in combustion turbines.

Why do we recommend burning coal derived fuels in a combustion turbine combined cycle powerplant?

According to several published studies by ERDA, EPRI and industry, burning gasified or liquefied coal in a combustion turbine combined cycle powerplant has significant advantages over burning coal directly in a steam powerplant with stack gas scrubbers. These advantages are:

(a) Lower capital cost with shorter lead times to design, manufacture and construct the modular components.

(b) A higher overall thermal conversion efficiency from coal to electicity.

(c) Compliance with the present clean air standards, lower water usage, and a reduction of disposable waste.

Coal gasification processes are ready for implementation into a demonstration plant phase. Such a demonstration program is necessary to gain operational experience of a complete powerplant and coal gasification system on a utility grid. Of particular value would be the obtaining of thousands of hours of operation of a combustion turbine with low Btu coal gas fuel, and the verification that fuel clean up and emission objectives are satisfactorily met.

Coal liquefaction is considered a longer term technology because the cost of refined liquid fuel produced from liquefied coal is not currently competitive with other fossil fuels. Technology breakthroughs must be achieved to reduce the refining and conversion costs. It should be noted that the design features of the combustion turbine combined cycle powerplant would differ very little whether it is burning a coal gasification or a coal liquefaction fuel product.

Presently the thermal efficiency of combustion turbine combined cycle powerplants burning petroleum or natural gas fuels is approximately 41 percent. New plants in operation 2 years from now should have efficiencies of 43 percent. By 1985 combined cycles burning low Btu coal gas should reach overall efficiencies of 45-46 percent including energy losses associated with the gasification process. The same plants burning coal liquid fuel would have an efficiency of over 50 percent.

By comparison, steam powerplants that burn coal directly utilizing stack gas scrubbers have thermal efficiencies of 35-36 percent, with limited potential for improvement.

The environmental benefits of the combustion turbine combined cycle powerplant burning low Btu coal gas are: (a) ash is removed as a solid during the gasification process; (b) sulfur can be recovered as pure sulfur; (c) water required for plant operation is only about one-half of that required for a conventional steam plant; and (d) nitrogen-oxide emissions are significantly reduced.

What is the development path to follow for earliest obtainment of the country's energy goals of conservation and more efficient utilization of coal?

We believe a demonstration powerplant in the 100 Mw range should be constructed on a utility site using today's gasifier technology. Major modular elements of this powerplant would consist of the gasifier, fuel clean up system, combustion turbine, heat recovery steam generator, steam turbine and condenser. Multiple replicas of these basic modules would be the basis for building larger plants.

Some Government support would be needed to minimize financial risks and to cover additional costs associated with prototype shakedown and test operations. Such a demonstration plant also could be considered for coal fired cogeneration where the exhaust energy from the combustion turbine could be used to provide process heat. Even though each modular element of such a plant can be considered to be commercial hardware, the necessary experience of operation can only be achieved by joining all elements into a power producing system.

Plans for mandatory conversion of existing oil or gas fired plants to coal should take into acount the conservation potential of interim measures when conversion may be restrained by environmental, economic or coal supply considerations. One such measure is repowering. Repowering is the conversion of a steam powerplant to a combined cycle powerplant by the addition of a combustion turbine. In a typical case, repowering may provide fuel savings of 20 percent or greater. Incentives for repowering should be considered.

Repowering also provides the most efficient approach to cogeneration. Several industrial firms have demonstrated the value of this approach over the past 20 years. Incentives for more cogeneration are extremely important since they would give such repowered plants exemption from coal conversion and thereby permit the continued use of oil in cases where marked improvement in energy utilization is achieved.

Plants granted an exemption from coal conversion if repowering and/or cogeneration is accomplished are still candidates for future conversion to coal derived fuels when the conversion processes are commercially available. Coal derived liquid fuels could be used directly, while minimum retrofit and modification would be necessary for a low Btu coal gasification process. A combined cycle powerplant utilization coal derived liquid fuels would operate at efficiencies over 50 percent.

I am including with this statement a copy of the testimony given to the Senate Subcommittee on Energy Production and Supply with regard to Senate bill S. 977, "The Coal Utilization Act of 1977," by Mr. Donald R. Jones of Westinghouse Electric Corporation. This includes a copy of "Comments of the Westinghouse Electric Corporation on National Energy Policy" submitted by Mr. Gordon C. Hurlbert, President of Westinghouse Power Systems Company, in response to President Carter's and Dr. Schlesinger's invitation to provide information regarding the formulation of a National Energy Policy.

Mr. Chairman, I would be pleased to answer any questions you might have and to provide additional information for the record.

[The attachments to Mr. Seglem's statement may be found in the subcommittee files:]

Mr. SHARP. Thank you, Mr. Seglem.

Mr. Grant?

STATEMENT OF ANDREW J. GRANT

Mr. GRANT. Thank you for the honor of addressing this committee today.

My name is Andrew Grant. I am Product Manager, Energy, for Woodall-Duckham, which is responsible for the energy interest of British Babcock & Wilcox, Limited, in the U.S.A. British Babcock is the first, I believe the only, company to be able to offer coal-fired fluidized bed boilers on a commercial basis. I shall tell you a little about what these boilers can do, their economic and environmental impact, the extent to which they can release oil and gas for other uses, and the attitudes of potential users.

Our ability to design and build boilers on a commercial basis stems from 20 years of development work, including 20,000 hours operation of test rigs. The very extensive basic data from the test rigs is the property of Combustion Systems Limited, jointly owned by the British National Coal Board, British Petroleum, and a development financing agency of the British Government.

By agreement with Combustion Systems Limited, British Babcock went ahead with the reduction of the basic technology to engineering practice, to meet the requirements of day-to-day commercial boiler operation. We did so by converting an existing industrial boiler which supplies steam to our plant at Renfrew, Scotland.

This boiler started up in May 1975, and has enabled us to conduct an extensive and successful series of trials, which are described in my prepared testimony. Besides confirming the promise of FBC as a combustion system which will accept an incredibly wide range of fuels, and will provide a simple and effective means of controlling both sulfur and nitrogen oxides, our Renfrew boiler has enabled us to identify the detailed operating problems facing routine FBC operation, and to demonstrate effective and practical techniques for reliable industrial service.

A fluidized bed boiler contains several tons of non-combustible granular material, maintained in a highly agitated and partly suspended bed a few feet deep by an upwards flow of air. This bed of inert material is maintained at a temperature in the range 1,400-1,750 degrees Fahrenheit by simultaneously burning coal, or other fuel, and removing the heat of combustion through boiler tubes immersed in the bed.

The presence of tons of inert material confers upon our boiler its first advantage over conventional units, effective combustion of high ash fuels, for example coal containing 60 percent ash. This alone makes previously unattractive coal reserves of economic value, and gives a boiler operator freedom of choice in fuel purchasing.

The second advantage of our boiler derives from the controlled low combustion temperature. At this relatively low temperature, sulfur dioxide can be retained in the coal ash to any extent desired by the addition of limestone to the coal feed. This results in an increased volume of ash contained inert calcium sulfate, and no sludge. Nitrogen oxide levels are also much reduced due to the low combustion temperature.

Capital costs of British Babcock's new FBC boilers are about the same as conventional stoker-fired or pulverised fuel boilers in the medium to large industrial size range. Below 100,000 lb/hr of steam, the capital cost is rather more than for a conventional boiler, at least for the present. The capital cost saving that can be achieved is the cost of a stack gas scrubber, which would be required to be added to the cost of a conventional boiler. This represents a most significant saving, both of capital and the managerial and operating resources required to handle stack gas scrubbing.

The operating economy of British Babcock's FBC boiler is the difference in cost between a premium steam coal and low-grade coal with no special limits on ash, sulfur, grading or consistency of properties. In major industrial areas, the difference can amount to $15 a ton or more.

While we are not yet ready to supply FBC boilers in the 200 MW to 1,000 MW range required for new utility construction, I wish to point out that the amount of oil and gas used for industrial steam generation exceeds that used for utility steam generation. Considering only those industrial steam plants in the MFBI range, the amount of oil and gas which could be released by the application of British Babcock's FBC boilers is roughly equivalent to that used today by utility power generation. Most importantly, such a program has modest capital requirements for individual boiler plants and coal suppliers, the full resources of many thousands of U.S. businesses can be applied, and no regulatory delays need be anticipated.

While talking of utilities, you may have heard reference to pressurized fluidized combustion for application to combined cycle powerplants. We are currently carrying out the initial design of such a plant jointly with American Electric Power and Stal Laval. The plant, if built, would have an eventual output of about 160 MW, but I must stress that this is developmental. The technology will not be commercially available until the early 1980's.

It is easy to identify the potential users of our FBC technology. It is even easier to convince them of its merits and reliability. But it is generally hard to convince them to take immediate action, because the incentives are not yet clear. Switching from oil or gas to coal for steam generation is a radical change for most of United States industry. They must be convinced that this action is cost-justified. Significant financial assistance will greatly accelerate the switch to coal.

[Mr. Grant's prepared statement follows:]

Babcock

PREPARED TESTIMONY

on

FLUIDIZED COMBUSTION OF COAL

to the

SUBCOMMITTEE ON ENERGY & POWER

of the

COMMITTEE ON INTERSTATE & FOREIGN COMMERCE

U. S. HOUSE OF REPRESENTATIVES

by

ANDREW J. GRANT

BABCOCK INTERNATIONAL INC.

THURSDAY, MAY 26, 1977

at

3:30 p.m.

200 Manor Oak One • 1910 Cochran Road • Pittsburgh, PA 15220 • (412) 344-6911

Babcock

FLUIDIZED BOILERS

EXECUTIVE SUMMARY

Following two years' operation of a prototype industrial fluidized bed boiler, plus over 20,000 hours operation of supporting test rigs, Babcock & Wilcox Limited of Great Britain is offering FBC boilers on a commercial basis. Both new FBC boilers, and FBC retrofits to old boilers, are offered. Coal of any sulfur content may be burned, and SO_2 removal to EPA limits can be guaranteed.

The advantages of an FBC boiler include its ability to burn almost any grade of fuel, and built-in SO_2 and NO_x control. SO_2 control is achieved at an appreciably lower cost than with stack gas scrubbers, and without their operational and maintenance problems.

Babcock & Wilcox Limited is offering its FBC boilers from 100,000 to 500,000 lb./hr. of steam, i.e. right across the industrial size range. The total use of fossil fuel for industrial steam generation is almost as much as utility consumption of fossil fuel, and at present coal accounts for no more than 20 - 25% of industrial steam generation, compared with around 50% for utilities. Therefore, the use of industrial FBC boilers can achieve a very significant reduction in gas and oil consumption. This can be achieved without any further R & D - all that is required are incentives to induce industry to make the necessary capital investment.

The capital cost of a typical industrial FBC boiler plant is about the same as that of a conventional stoker or P.F. fired unit. Its economic attractions are saving the cost of stack gas scrubbing, and permitting the use of the cheapest available B.T.U. without the usual limitations on coal characteristics.

Pressurized fluidized combustion offers a method of achieving high coal-to-bus bar efficiencies for power plants. Together with American Electric Power, and Stal Laval, Babcock & Wilcox Ltd. is designing a combined cycle power plant incorporating pressurized fluidized combustion having a total output of around 160 MW. This approach is developmental in nature, and general applicability of the pressurized technology is unlikely until the early 1980's.

Babcock

FLUIDIZED BED COMBUSTION

A. THE DEVELOPMENT OF THE B & W LTD. INDUSTRIAL FBC BOILER

1. INTRODUCTION

Interest in fluidized bed combustion has increased considerably in the past few years due to growing public concern about atmospheric pollution and problems arising from the relative cost and availability of the fuels useable on current boilers and gas turbines.

Until now boilers and their fuel preparation and firing equipment have had to be designed to suit a chosen fuel. The shape and size of boiler furnaces and their burners differ considerably, for example, for coal fired units depending upon whether the coal is anthracite, bituminous or lignite. No boiler designed for one of these types could operate on any other without considerable penalties. While boilers designed for coal firing can readily be converted to firing oil or gas and still meet design duty, the reverse is not possible. Because oil and gas are relatively clean fuels high gas speeds can be used, but conversion to coal firing would necessitate reducing these so that at most the boiler would only perform at 60% of its original capacity.

The main pollutants in flue gases from current conventional high temperature combustion systems are fuel ash, sulfur oxides and nitrogen oxides. The solid matter can be trapped by precipitators with acceptable efficiency. Sulfur oxides can be controlled by burning low sulfur fuels which are becoming more and more expensive unless they are coals of the sub-bituminous type, such as those found in the Western States, which because of their high alkali content give rise to other troubles such as severe slagging and fouling. Alternatively, sulfur oxides can be removed by expensive back end scrubbing systems. These have not so far achieved a very good reliability record and create a residual pollution problem in disposing of spent material, unless more expense is incurred in recovery of elemental sulfur which has a doubtful market value. Nitrogen oxides are generally controlled by interfering with the combustion process, again with attendant difficulties.

Fluidized bed combustion provides a system which will accept any fuel which has a net calorific value above that required to heat it and the combustion air to bed temperature. Any boiler designed for this system will accept any fuel which is available, given the above proviso, whether solid, liquid or gas. Its first advantage to the boiler industry is, therefore, the ability to standardize on boiler design and combustion system to a far greater degree than ever before, independent of the fuel characteristics. Obviously, fuel handling systems have to be provided to suit the various forms of fuel which will be fired. Secondly, it permits the use of very low grade coals without the need for expensive support fuels to ensure stable ignition. Thirdly, atmospheric pollution control can be exercised without much additional capital expenditure and with a relatively minor residual problem in disposing of spent limestone.

2. FLUIDIZED BED COMBUSTION

Fluidized bed combustion consists of blowing air through a bed of crushed material, which could be, for example, firebrick, limestone or coal ash, at a rate which causes the bed to become fluidized without excessive loss due to elutriation. Fuel is injected into the bed at a rate somewhat below its stoichiometric equivalent to the fluidizing air. Heat absorption surface is immersed in the bed and matched to the heat input so that the mean bed temperature is controlled between the chosen limits, say 1400 - 1750° F.

It will be apparent that, at a specified excess air level, the heat release per unit area of bed surface is a linear function of the fluidizing velocity (calculated on the gases leaving the bed at bed temperature and pressure). Again for a given density of the bed material, the size distribution in the bed needs to be coarser as the fluidizing velocity increases. The heat transfer coefficient of the bed material to the immersed surface is inversely proportional to the mean particle size. Hence there are two factors increasing the amount of heat absorbing surface as the heat input per unit area of bed is increased. Since for a given tube arrangement this can only be provided by increasing the bed depth, an optimization has to be made between capital cost of bed area and operating costs of increased fan power with deep beds. The design data to enable this to be done has been obtained from the test rigs operated at the British National Coal Board's Coal Research Establishment (C.R.E.) and at the British Coal Utilization Research Association (B.C.U.R.A.). These rigs have operated for more than 20,000 hours. The largest at C.R.E. was 3 ft. x 3 ft. and the largest at B.C.U.R.A. was 4 ft. x 2 ft., the latter having been operated at 8 atmospheres pressure.

Besides producing the basic design data for fluidized bed combustion, these rigs have been used to examine sulfur retention in the bed material, corrosion and erosion of the immersed tubes and the down-stream surfaces, whether they be convection tube banks or gas turbine blades, and the proportions of the coal ash which remain in the bed for a large number of coals from various sources. Encouraging results came from all these rig tests but obviously there were a large number of engineering problems which they were too small to solve. The next step, therefore, was to carry out trials on a commercial scale and it was arranged that Babcock & Wilcox Ltd., in conjunction with Combustion Systems Ltd., would convert a boiler to this system in their Renfrew, Scotland, Works. The main objectives of the trials were to obtain data on:

(a) Lateral mixing and ignition propagation patterns to establish start-up procedures and the optimum disposition of fuel and additive injection and ash withdrawal points.

(b) Range of fluidizing velocity and bed temperature which will maintain combustion, to determine the extent of load control provided by these two parameters and the rate of response.

(c) Other load control means such as compartmentation, partial bed slumping and varying bed height.

(d) Possibility of sintering and clinkering of ash, even under fault conditions, particularly with known coals which give rise to severe slagging when fired in current pulverized fuel installations. The ability of fluidized beds to retain the alkali in sub-bituminous coals from Australia, the United States and Canada is of particular interest.

(e) Thermal stresses and possibility of departure from nucleate boiling in the horizontal boiler tubes subjected to the high heat fluxes obtainable in fluidized beds. Both plain and rifled tubes have been installed in the boiler at Renfrew.

(f) Sulfur retention.

(g) NO_x production.

In addition the boiler would, of course, be used to confirm or modify the design data obtained from the test rigs.

The above program concentrates on coal firing since it is believed that that is what the market will mainly require. Arrangements are, however, in hand to install the necessary equipment to fire liquid fuels.

3. DESCRIPTION OF THE RENFREW BOILER

The boiler is the Babcock Cross Type designed for 40,000 lbs./hr. evaporation at 400 p.s.i.g. and 560°F. It was originally coal fired with a spreader stoker. Grit interceptors collected all grits above 52 BSS (295 u) for refiring and a Pratt-Daniel precipitator trapped most of the residual grits. The boiler has a Green's finned tube economizer and no air heater.

The grate was removed and a fluidized bed 10 ft. x 10 ft. installed in its place. (Fig. 1) The only alteration to the steam and water circuits is the introduction of circulating pumps taking water from the drum, driving it through the tubes immersed in the bed where saturated steam is generated and then back to the drum.

For the initial trials raw coal was dried and crushed to 95% minus 1/8 inch in a Babcock E type mill. The product was separated from the moist carrying air in cyclone separators and delivered to a service hopper. From there it was taken through rotary feeders into a line where it was conveyed by air to the injection points in the bed. Start-up is achieved by fluidizing the bed with cold air and then heating the bed by overbed burners. When the bed temperature reaches coal ignition temperature (about 950°F has been found adequate) the coal feed is started. Coal firing is steadily increased until the required boiler load is attained, the oil burners being shut off at some intermediate point.

The first trials made were at a nominal fluidizing velocity of 4.1 ft./sec. With a bed temperature of 1560° F. and 20% excess air this would permit a heat input of about 8.8 MW (30 x 10^6 Btu/hr.) which would generate about 23,000 lbs./hr. of steam on this boiler. The tube bank to be immersed in the bed was, therefore, designed for these conditions and it amounted to 10 tube loops on 178 mm x 216 mm pitch. Later, when trials were made at up to 8 ft./sec. fluidizing velocity, the number of loops increased to 24 and the pitching of the tubes halved. The anticipated heat input and steam generated then became 17.6 MW (60 x 10^6 Btu/hr.) and 46,000 lbs./hr. respectively.

Nine coal injection points were installed and three stand pipes for ash removal from the bed.

Initially the bed was formed by spreading about 15000 lb. of sand, sized to 95% less than 1/8 inch. As operation on coal has proceeded the sand has been largely replaced by residual coal ash.

4. EXPERIENCE TO DATE AT RENFREW

No difficulty has been experienced in bringing the bed up to coal ignition temperature with the overbed oil burners. Four oil burners were installed. Two burners have in fact been found adequate to raise temperature conditions at a permissible rate when operating at 4 ft./sec. fluidizing velocity. At 8 ft./sec. all four burners are needed to raise temperature.

Some difficulties have been experienced with the rotary coal feeders when firing an average quality coal on the lower load, largely because the feeders were working well below their normal capacity. When a coal having 60% ash was fired, the coal rate per feeder approximately doubled and the system worked well.

Typical coals which have been fired have the following characteristics given in Table 1, page 7.

Typical performance figures with no grit re-firing are given in Table 2, page 8.

TABLE I

		SCOTTISH COAL	IRISH COAL	HIGH SULFUR COAL
Proximate Analysis	%	Newbattle U.S.	Arigna	Temple Newsome
Moisture	%	6.5	2.0	16.0
Volatile Matter	%	29.7	13.3	
Fixed Carbon	%	45.8	25.9	
Ash	%	18.0	58.7	14.0
Gross Calorific Value				
	kJ/kg	25280	11420	
	Btu./lb.	10870	4911	9960
Sulfur Content	%			3.3

TABLE II

		SCOTTISH COAL		IRISH COAL
Steam generated at 28 bar and 270 °C	kg/s lb/hr	2.76 22,000	4.43 35,125	2.79 22,000
Coal fired	kg/s	0.345	0.556	0.851
Air to bed	kg/s	3.635	5.48	4.091
Excess air	%	27.4	14.3	19.7
Average bed temp.	°C	933	877	930
Fluidising velocity	m/s	1.34	1.82	1.38
Heat Balance				
To steam	%	79.2	79.8	70.5
To dry gas loss	%	6.3	7.0	5.6
To H_2O in stack gas	%	4.5	4.3	5.4
To unburnt C	%	3.7	4.0	10.5
To heat transfer probe in bed	%	1.9	0.6	1.7
To blowdown	%	1.7	1.5	1.5
To radiation and unaccounted	%	2.7	2.8	4.8

The tests with the Scottish coal exhibited an unburned loss of 3-1/2 - 4%. This is of the same order that one would expect with a coal of this quality burned on a stoker of this size. The indication, therefore, is that an acceptable combustion efficiency can be attained without recourse to grit re-firing.

The Irish coal has very high ash fusion temperatures. This would permit operation at higher bed temperatures which would help to reduce unburned loss.

The boiler has now operated for about 5,000 hours. There has been no erosion evident either on the tubes immersed in the bed or on any surface following the bed. A very thin shiny black enamel skin appears on the bed tubes (Fig. 2) similar to what was noted on the N.C.B.'s rigs. On analysis it was found to be:-

Silica (SiO_2)	24.0%
Iron Oxide (Fe_2O_3)	3.0%
Aluminum Oxide (Al_2O_3)	23.0%
Calcium Oxide (CaO) Magnesium Oxide (MgO)	1.0%
Sulfate (SO_3)	1.0%
Carbon (determined)	35.0%
Ignition Loss at 800°C.	47.0%

This scale breaks off while still very thin with no deterioration to the tube metal. It has no discernible effect on heat transmission rate.

5. COMBUSTION IN THE FREEBOARD

From a practical point of view the only important parameter from this aspect is what combustibles leave the freeboard and are quenched so that they appear as unburned loss in the heat balance. Gas samples have been taken, however, at 6 ft. above the bed surface. At 4 ft./sec. fluidizing velocity these showed CO and CH_4 levels which indicated that, depending on bed temperature, anything up to about 10% of the total heat release occurred in the freeboard. A very significant proportion of this is, however, absorbed by the bed so that the net effect of freeboard combustion is small.

6. LOAD CONTROL

Load control becomes simpler as the size of the boiler and number of beds it contains increases. It can be effected in ramp operation by control of bed temperature or stepwise by bed slumping.

Reduction of load can be achieved as fast as may be required. If a bed be slumped then heat transfer from the bed to the immersed surface drops to almost nothing immediately. The bed retains its heat and on reactivation, with resumption of fuel feed, load is restored very quickly. A slower, but still fast, reduction in load can be achieved by stopping the fuel feed until the new required bed temperature is achieved. Fig. 3 shows the rate of temperature loss in the bed of the Babcock boiler when operating at about 4 ft./sec. fluidizing velocity. With the air mass flow maintained, in 300 seconds the bed temperature fell from 1560° F to 1100° F.

This curve shows the measured temperatures on the Renfrew boiler which coincide almost precisely with what would be calculated from the heat given to the fluidizing air and the immersed surface. At 1100°F the heat flux to the immersed surface is just under half of that at 1560°F. Obviously, by reducing fuel feed rate rather than stopping it entirely one can make the time interval between the two conditions meet any requirement. Restoration of load in a bed which has been allowed to cool is a function of the fuel firing change rate, the combustion efficiency within the bed, the thermal capacity of the bed material and the heat absorbed by the immersed surface. There is obviously an appreciable heat requirement to take the bed material to its higher operating temperature and the deeper the bed the greater this becomes. For the same fluidizing velocity the air mass flow per unit area is inversely proportional to the absolute bed temperature. One can, therefore, reduce the time for load restoration by firing at higher rates when the temperature of the bed is low.

On the Renfrew boiler load has been restored from the reduced temperature conditions by reverting to the MCR fuel feed rate at about 5% per minute at the start of the restoration. This rate falls off, of course, as one approaches the equilibrium between heat available to the bed and that absorbed by the immersed surface.

7. EMISSION OF NO_x AND SO_x

NO_x formation is shown on Fig. 4 against bed temperatures. These figures were obtained using the chemiluminiscence method. They are well below the current limit of 525 ppm at 3% excess oxygen set by U.S. E.P.A. for new coal fired plants and are in fair agreement with rig figures from coal of similar N_2 content.

In view of the many thousands of hours of FBC rig tests carried out on sulfur retention, there was little doubt as to the performance of the 45,000 lb./hr. Renfrew boiler. Long-term corrosion/erosion tests have also been carried out on the rigs, using full-scale boiler components. Confirmation that rig tests of coal and limestone would accurately predict full scale sulfur retention for a given coal: limestone ratio was therefore the remaining requirement.

Figure 5 shows the effect of using two different types of limestone, and different limestone:coal ratios, on sulfur retention. A 3.3% sulfur coal was used, although sulfur contents as high as 5.5% and as low as 3.0% were recorded.

While the results show that remarkably high degrees of sulfur retention can be obtained, e.g. 98%, the significant result is the close agreement between the actual performance and that predicted by the C.R.E. rig.

These sulfur retention trials were carried out at approximately 1560°F, with a fluidizing velocity of 8 ft./sec., and an expanded bed height of about 3 ft.

Each point on the curve corresponds to a trial consisting of about 48 hours operation to demonstrate stable conditions and uniform bed composition, followed by 48 hours actual data gathering. Coal and limestone feed rates and ratios were continuously controlled, and monitored by two separate sampling techniques. Sulfur retention was measured by a continuous dry process, the read-out from which can be used to control the limestone:coal feed ratio. Regular wet chemical analyses were carried out on gas samples to verify the data from the continuous SO_2 monitor.

8. ASH RETENTION IN BED

With the Scottish coal with 18% ash, operating at 4 ft./sec. fluidizing velocity and a fuel feed of 95% $<$ 1/8 inch, the coal ash retained in the bed was approximately 30% of the total. When the fluidizing velocity increased to 6 ft./sec. and the coal feed size coarsened to 95% $<$ 1/4 inch, the ash retained in the bed was of the order of 25%. With the Irish coal with 60% ash, operating at 4 ft./sec. fluidizing velocity and fuel feed crushed to 95% $<$ 1/8 inch, approximately 35% of the ash was retained in the bed.

These figures represent high carryover from the bed and in fact approach what one would expect at the boiler outlet for a pulverized fuel fired plant. As the technology develops, the carryover will be reduced but it is likely that dust catchment equipment will always be somewhat more extensive than that needed for stoker firing but less than that required for P.F.

Bed depth control has presented no problems. With the Scottish coal, the bed growth corresponds to an increase in pressure drop of about 0.3 - 0.4 in. w.g. per hour. An intermittent adjustment by draining ash off into a hopper where it is air cooled has been adequate. With the Irish coal, the ash retention was equivalent to an increase in bed pressure drop of about 2.7 in. w.g. per hour. Under these conditions much more frequent ash removal is essential and a continuous system becomes desirable. With the 35% catchment the heat content of the Irish coal ash (above 59°F) becomes equivalent to 1.4% of the heat input to the boiler. Improving the ash retention will, of course, proportionally increase the heat content of the ash. This heat, however, can be recovered to a large extent fairly easily by cooling the ash with part of the combustion air.

9. COMPARISON OF BOILER PERFORMANCE WITH THAT OBTAINED WITH ORIGINAL SPREADER STOKER

Table 3 sets out performance figures on fluidized bed operation with the original spreader stoker with partial grit re-firing.

TABLE III

COMPARISON OF PERFORMANCE OF RENFREW

CROSS TYPE BOILER WITH SPREADER STOKER

V. FLUIDISED BED FIRING

		SPREADER	FBC
Boiler Output at 28 bar and 270°C	kg/s	5.06	4.43
	lbs/hr	40,200	35,125
Coal Fired	kg/s	0.689	0.556
	lbs/hr	5,470	4,420
Proximate Analysis			
Moisture	%	17.7	5.2
Volatile Matter	%	26.0	28.9
Fixed Carbon	%	43.6	44.5
Ash	%	12.7	21.4
G.C.V.	kJ/kg	23,600	24,600
	BTU/lb	10,150	10,580
Grading through 6mm	%	68	90
Gas Analysis at Economiser Exit			
CO_2	%	11.2	12.7
O_2	%	8.2	6.5
N_2	%	80.6	80.8
Air Pressure under Grate or Bed	mm.WG	28	760
Grit Collection			
Economiser hopper	kg/hr	11	NIL
Interceptors	kg/hr	Refired	142
Pratt-Daniel precip.	kg/hr	98	96
Stack	kg/hr	17	80
Heat Balance			
To steam	%	77.3	79.8
To dry gas loss at stack	%	8.2	7.0
To water vapour loss at stack	%	5.9	4.3
To unburned carbon	%	4.4	4.0
To radiation, blowdown	%	4.2	4.3
To heat transfer probe	%	-	0.6

To all intents and purpose the performance of the boiler so far as thermal efficiency is concerned is the same with the two systems when the differences in the coal moisture content and the preparation of the coal for fluidized bed firing are taken into account. With the spreader stoker the design steam temperature of 560°F was attained. With the fluidized bed firing, as was anticipated, the final steam temperature is somewhat short at 520°F. It was not attempted to correct this, however, since the steam even at that had to be desuperheated for the Works' services that the boiler serves. The grit collection figures illustrate the higher dust burden at the stack with fluidized bed operation.

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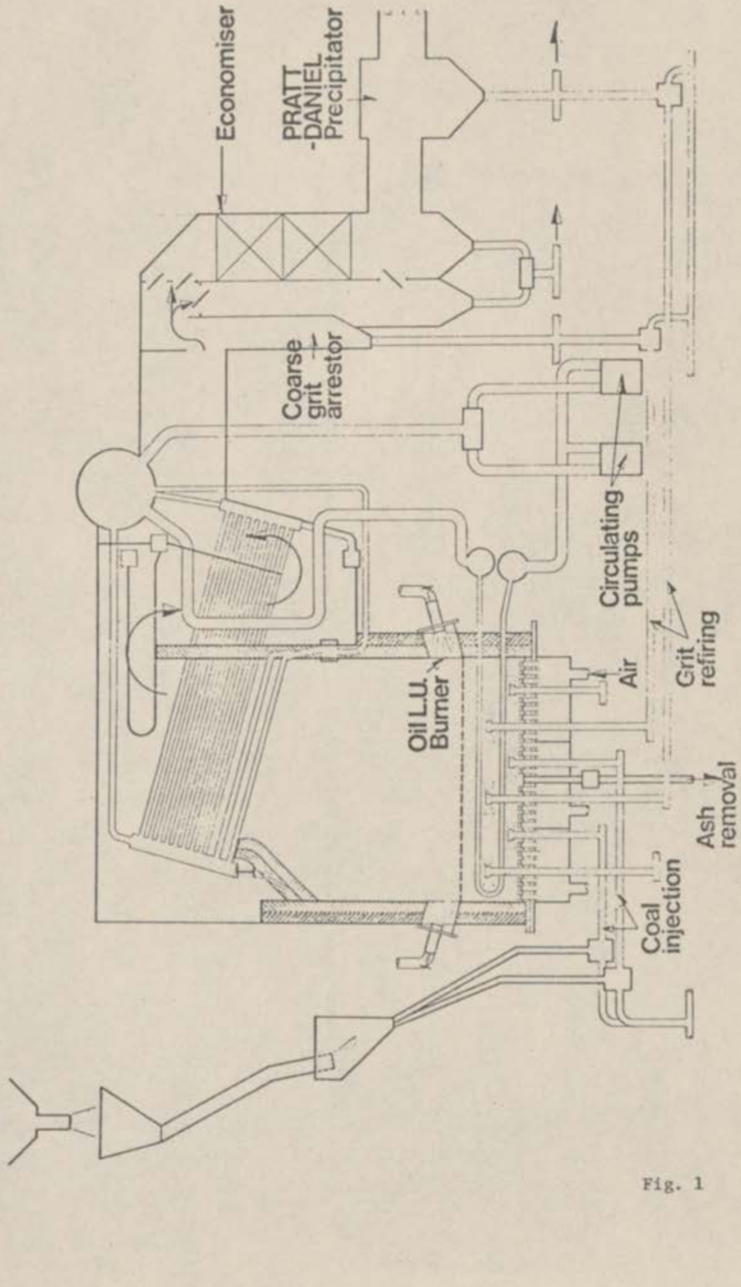


BABCOCK RENFREW FLUIDISED BOILER RETROFIT

Fig. 1

Section of bed tube showing "enamel" type deposit

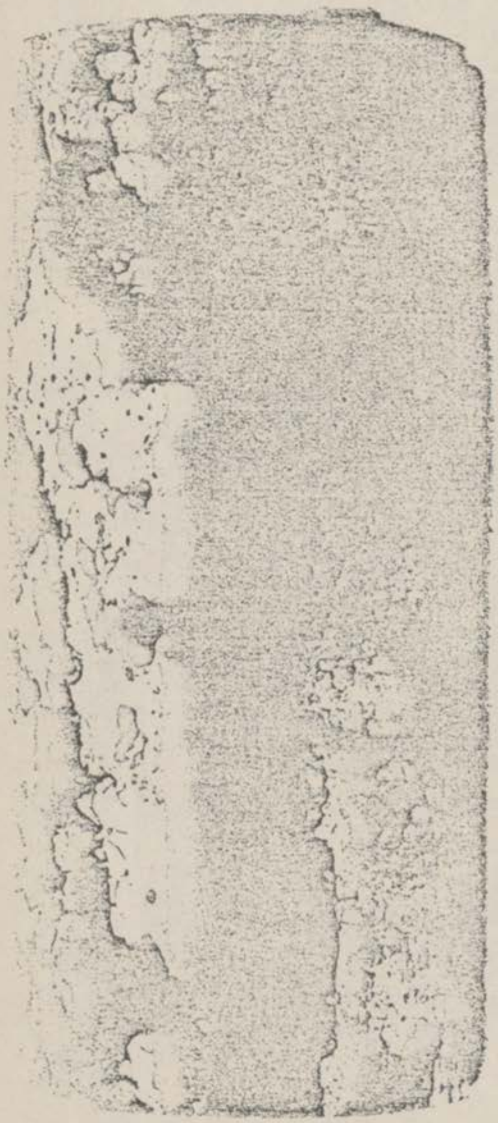
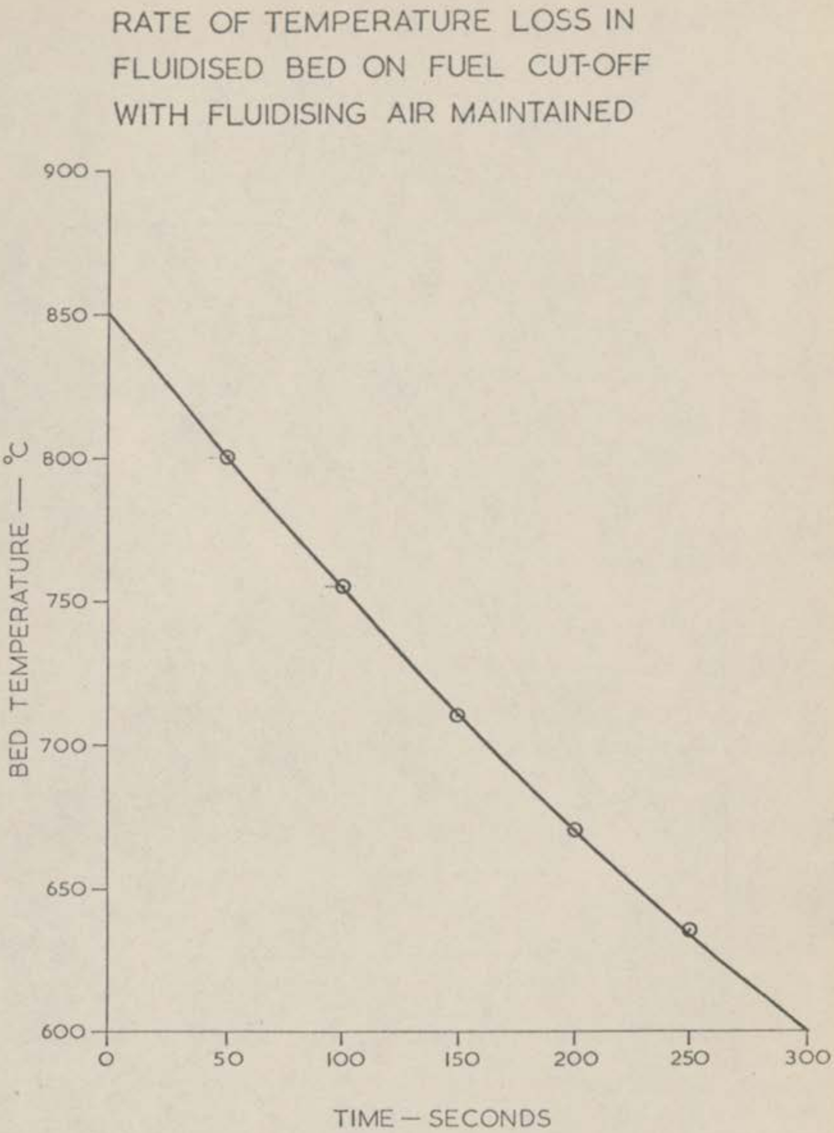
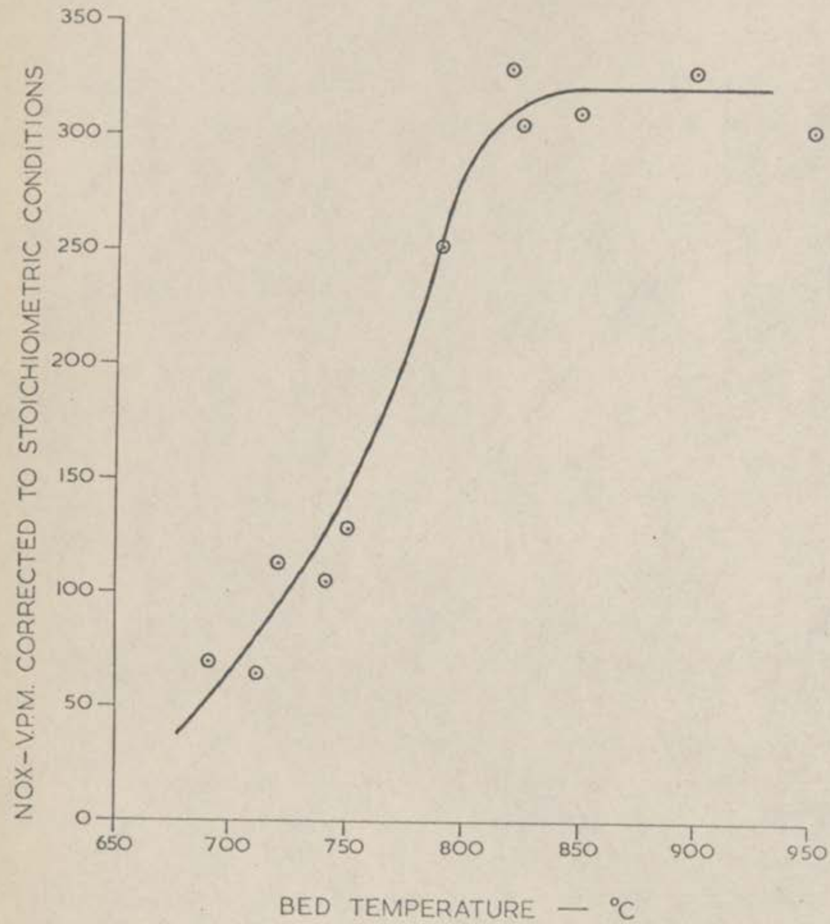


Fig. 2


RATE OF TEMPERATURE LOSS IN
FLUIDISED BED ON FUEL CUT-OFF
WITH FLUIDISING AIR MAINTAINED
BED TEMPERATURE — °C
900
850
800
750
700
650
600
0
50
100
150
200
250
300
TIME — SECONDS

NOX AND BED TEMPERATURE RELATIONSHIP
FIRING COAL WITH 1·1 % NITROGEN



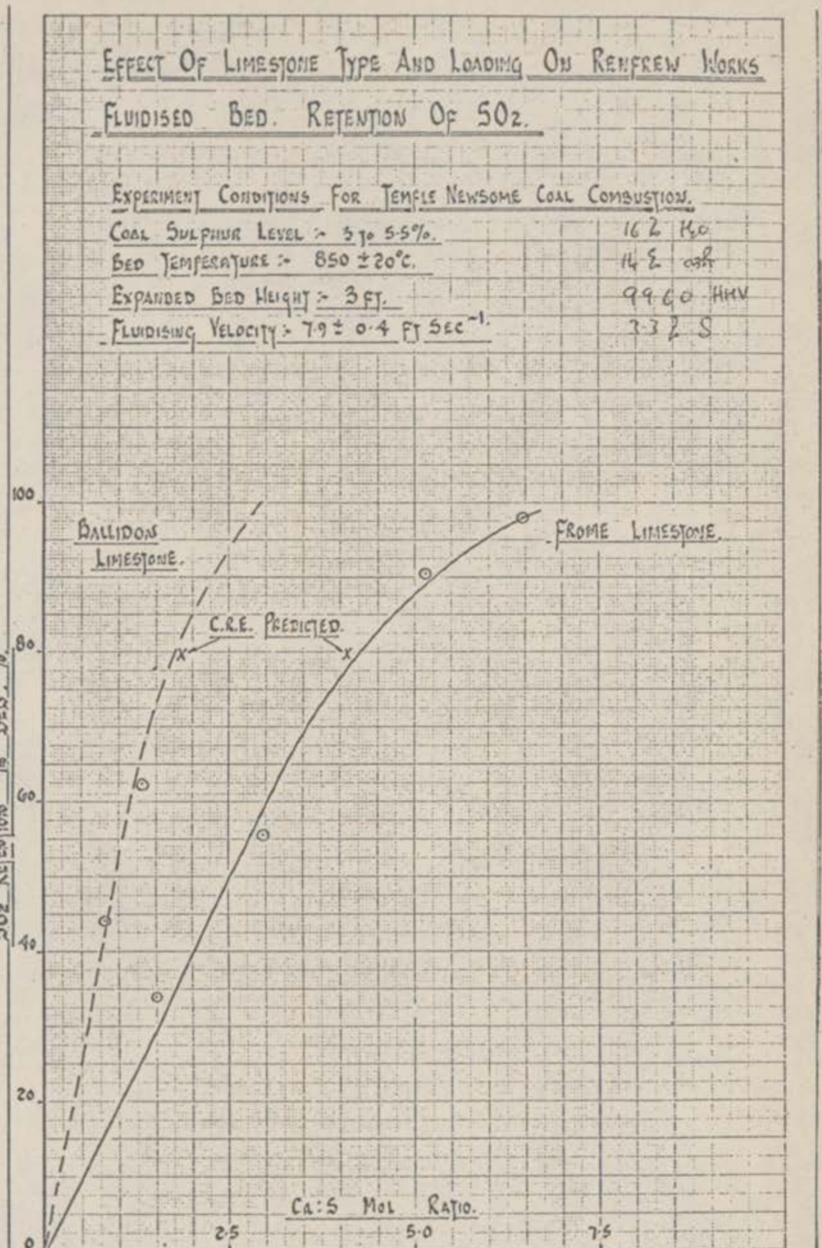

EFFECT OF LIMESTONE TYPE AND LOADING ON RENFREW WORKS
FLUIDISED BED. RETENTION OF SO2.
EXPERIMENT CONDITIONS FOR TEMPLE NEWSOME COAL COMBUSTION.
COAL SULPHUR LEVEL :- 3 TO 5.5%.
BED TEMPERATURE :- 850 ± 20°C.
EXPANDED BED HEIGHT :- 3 FT.
FLUIDISING VELOCITY :- 7.9 ± 0.4 FT SEC^-1.
BALLIDON LIMESTONE.
FROME LIMESTONE.
C.R.E. PREDICTED.
CA:S MOL RATIO.
2.5
5.0
7.5
100
80
60
40
20
0
0
0.2
0.4
0.6
0.8
1.0
SO2 RETENTION IN BED %.
EQUIVALENT LB LIMESTONE / LB 4% S. COAL.

Fig. 5

B. THE SIGNIFICANCE OF INDUSTRIAL STEAM GENERATION

Further experience with industrial-scale FBC boilers will be necessary before utility boilers, e.g. 200 MW and upwards, can be built on a commercial basis. However, substitution of coal for the gas and oil currently used to generate steam in boiler plants of 100,000 lb./hr. of steam and over would release about as much gas and oil for use elsewhere as would total conversion of oil and gas burning utility boilers. Table 4 compares the use of fossil fuels for major industrial sectors to the total useage of all sectors, and to the utility sector. Steam generation is the predominant industrial use and is almost as large in fuel consumption as the utility sector.

INDUSTRIAL AND UTILITY USE OF FOSSIL FUELS

TABLE 4

	Trillions of Btu's for base year 1968			
	All Fossil Fuels	Coal	Oil	Gas
TOTAL - ALL SECTORS	59,639	13,326	26,749	19,564
UTILITY SECTOR TOTAL	11,556	7,130	1,181	3,245
INDUSTRIAL SECTOR TOTAL	19,348	5,616	4,474	9,258
Fuel-Fired in Boilers for Steam Generation				
Process & Space Heating	10,132	2,349	1,986	5,797
Electricity Generated on Site	410	95	80	235
Fuel Used for Direct-Heat Applications (not incl. purchased electrical energy)	6,604	3,025	808	2,771
Fuel Used as Feedstocks	2,202	147	1,600	455

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About half the gas and oil used by our major fuel consuming industries - petroleum, petrochemical, paper, stone and ceramics, and primary metals - is burned to generate steam. More than 60% of this steam generation is produced in plants using 100,000 lb./hr. or more - i.e. a sufficiently large scale to justify the installation of a coal fired system.

100,000 lb./hr. of steam corresponds roughly with the lower limit of the Major Fuel Burning Installation (MFBI) definition. It is unlikely that a new coal-fired steam boiler plant will be economically attractive at much below this size, unless a coal handling plant is already in existence.

Industrial steam generation is under much greater pressure than are the electric utilities to abide by strict pollution control regulations. Also, fluidized combustion's ability to use low-grade fuel, and to switch fuel sources, is of more importance to an industrial purchasing agent than it is to his counterpart in an electric utility. The utility will generally own large coal reserves or control them under long-term contract.

An additional feature in the industrial scene is our ability to retrofit existing coal-fired boilers to fluidized combustion. Our Renfrew boiler is an example. There are many thousands of stoker coal-fired boilers in the United States, some operating on coal, some kept as stand-by units, some converted to gas or oil. While there are definite engineering limitations on the boiler types that can be so converted, retrofit of FBC is a viable method of gaining the advantages of fluidized combustion quickly and at a lower cost than a new boiler. For an existing boiler which is declared "coal-capable", FBC retrofit is likely to be an attractive alternative to either stack gas scrubbing or the use of expensive low sulfur coal.

Babcock & Wilcox Ltd. is therefore in a position, today, to release most of the gas and oil currently being used for industrial steam generation for other more valuable end-uses.

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C. AVAILABILITY AND COSTS OF FBC BOILERS

1. NEW BOILER SIZE RANGE

Up to 500,000 lb/hr of steam, either as saturated steam, superheated steam for turbine operation, or as high temperature hot water equivalent.

2. FBC RETROFIT SIZE RANGE

Boilers suitable for FBC retrofit are usually in the range lb.hr - 200,000 lb/hr. The upper limit is the largest stoker usually built. There are a very large number of such boilers in the 150,000 - 200,000 lb.hr range.

3. CAPITAL COST COMPARISON

The capital cost of a new FBC boiler plant at a typical industrial size is very close to that of a conventional stoker or P.F. fired boiler plant. The capital cost saving which can be realised is that of a stack gas scrubbing system.

4. OPERATING COST COMPARISON

Advantage can be taken of FBC characteristics to achieve fuel conversion efficiencies higher than with a conventional coal fired boiler, e.g. lower excess air rates, lower stack gas temperature because of SO_2 removal. However, these are unlikely to be of major significance in most cases. The biggest impact on operating costs is the ability to burn low grade low cost coal. In the case of a high sulfur coal, say 4-5% sulfur, the cost of limestone may be as much as \$5 per ton of coal, depending on plant location. Typical coal costs range from \$20 per ton or less for low grade coal up to \$45 per ton for low sulfur stoker quality coal.

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5. GUARANTEES

Babcock & Wilcox Ltd. is prepared to offer its normal commercial boiler guarantees for FBC boilers up to 500,000 lb/hr, plus guarantees on sulfur emission. Tests of coal and limestone are necessary to establish guarantee parameters.

6. MANUFACTURE AND DELIVERY

Babcock & Wilcox Ltd. intends to arrange for the manufacture of the major part of its FBC boilers in the United States. The smaller industrial boilers can be provided in shop-fabricated form. Supporting equipment for coal and limestone handling, water treatment, particulate collection, etc., is readily available from U.S. suppliers.

Delivery will be comparable to a conventional boiler, as the manufacturing process is basically the same. However, the smaller FBC units can be delivered to site completely shop fabricated, which may enable a total project to be completed in as little as 18 months.

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D. PRESSURIZED FBC FOR COMBINED CYCLE POWER PLANTS

Atmospheric fluidized combustion will not provide a significant increase in power generation efficiency, although it will prevent the loss in efficiency threatened by stack gas scrubbers. Higher efficiency in power generation can be achieved by combined gas turbine/steam turbine plants. At present such plants can only use oil or gas fuel.

By carrying out fluidized combustion under pressure, coal can be used as the fuel for a gas turbine. The characteristics of fluidized combustion enable the combustion gases to be clean enough for gas turbine operation - e.g. alkalies are substantially retained in the coal ash, sulfur is retained, and the ash carried over, while it must be largely removed, is much softer than fly-ash from P.F. coal combustion.

Many years of pilot investigation have led Babcock & Wilcox Ltd. to design coal-fired fluidized combustors for a 70 MW industrial gas turbine made by Stal Laval. American Electric Power has joined the project, which is currently at feasibility study stage. Current plans are to couple the coal-fired gas turbine to an existing steam turbine, thereby providing about 160 MW electrical power on a combined-cycle basis.

Unlike Babcock & Wilcox Ltd.'s FBC boilers, pressurized FBC is not yet available on a commercial basis. If the AEP project goes ahead, the design basis for commercial plants should be available in the early 1980's.

Mr. MOFFETT [presiding]. Thank you.
Dr. Lnden?

STATEMENT OF DR. HENRY R. LINDEN

Dr. LINDEN. Thank you, Mr. Chairman.

I am Henry R. Linden, President of the Institute of Gas Technology, and I have been directly involved in work relating to technical, economic and environmental problems in synthetic fuels production since 1947. My comments today concern the President's energy message and legislative proposals for substituting coal for crude oil and natural gas. The Presdent's program presents a series of sound and well-integrated initiatives to accomplish this objective. However, I am concerned that the coal program attaches low priority to the economically and environmentally most acceptable means of delivering coal energy to a majority of ultimate consumers, synthetic high Btu gas. Instead, direct combustion of coal involving several clean-up techniques for gaseous and solid pollutant, production of syncrude and solvent refined coal, and production of low Btu gas from coal are given greater prominence and urgency as a means for coal substitution. High Btu gas from coal is treated merely as a long-term substitute for declining supplies of natural gas, neglecting its near-term and generally superior capability to deliver coal to residential, commercial and even many industrial customers.

The reasons high Btu pipeline-quality gas from coal should be the preferred method of substituting coal for petroleum and natural gas in most stationary uses are as follows:

1) It is the only abundant long-term domestic source of pipeline-quality gas whose cost we know with some certainty and for which we have commercially demonstrated technology.

2) It requires no costly and time-consuming conversion of natural gas-using equipment. This consideration is vital because natural gas is still the dominant energy source for homes, commercial installations and industry. In addition, high Btu gas produced from coal can replace natural gas, and in some instances, oil, as a process feed where necessary.

3) The environmental impact of substituting coal for oil and natural gas by means of producing high Btu gas from coal at the mine mouth and delivering it through the existing underground pipeline system will be less than that of any other method of substitution.

4) It is generally at least as economical to substitute high Btu gas produced from coal for oil and natural gas as it is to substitute coal by any other method, with the exception of: a) The direct combustion of coal with stack-gas clean-up or the use of sulfur-removing fluidized-bed combustion systems for the large boiler loads where these pollution control methods are feasible, and, b) Second generation techology low Btu gas for large, high-load factor industrial uses.

The appended exhibits show the comparative economics of energy from coal and the specific environmental advantages of "coal by pipeline" versus "coal by wire." From these exhibits and other environmental considerations, it can be seen that, generally:

1) High Btu gas from coal is cheaper than coal-generated electricity for heat energy requirements even if it is assumed that the end-use efficiency of electricity may be up to three times greater than that of gas.

2) It is not practical or economical for any but the larger industrial customers or base-load central power stations to substitute direct combustion of coal for the use of oil and natural gas because of the space and equipment needs, plus the high cost and frequent lack of technical feasibility of installing the necessary environmental control equipment. Also, where gas or oil must be used for process reasons, direct combustion of coal has no role to play.

3) Based on projections from pilot plant operations, the delivered cost of solvent-refined coal and similar coal-derived, low-grade industrial fuels will be about the same as the delivered cost of high Btu gas produced from coal in second generation plants. However, as an industrial fuel, high Btu gas is much cleaner and more versatile.

4) Low Btu gas produced from coal in relatively small, dispersed industrial installations will generally be at least as costly and have a greater environmental impact than high Btu gas delivered by pipeline from central mine-mouth plants because of the high cost of delivering coal, the poorer load factor, the poorer economy of scale, and the difficulty of providing adequate environmental controls for a multiplicity of small coal conversion plants. However, large, central low-Btu gas installations, servicing a number of industrial users within a radius of 50 miles or less, which require gas or other clean fuels, should generally be the preferred method of substituting coal for oil and natural gas in areas with a high concentration of heavy industry. Better operating load factors—which could be further improved by off-peak sales to electric utilities—improved economies of scale, and centralized coal handling and pollution control, all contribute to the advantages of this approach.

Commercial technology, proven in Europe and South Africa, is available today for the production of high-Btu pipeline gas from noncaking coals. In contrast, there is no commercial technology for coal liquefaction available at present that can compete in the American energy market. Accepting the technical feasibility of producing liquids or solvent-refined products from coal by the new processes now under development, the projected economics of these processes still show them to produce fuels whose form value is far inferior to that of high-Btu gas at a price level equivalent to high-Btu gas.

Therefore, the President's energy plan, which places the urgency for coal research, development and demonstration in the areas of liquefaction, solvent refining and low-Btu gasification ahead of that for high-Btu gas, should be modified. Much greater emphasis should be placed on, one, the demonstration, under U.S. conditions and on a scale commensurate with U.S. commercial requirements, of existing (first-generation) high-Btu gas from coal technology which so far has been commercialized only overseas, and, two, the demonstration of the already far-advanced, second-generation high-Btu gas from coal technologies on a scale sufficient to allow prompt commercialization if they prove to have sufficient advantages over existing technology.

If, in the absence of other practical solutions, the new energy policy leads to the widespread substitution of coal-based electricity for oil and natural gas, the economic impact on the electric utilities and the public could be serious. The investment requirements of substituting electricity for current uses of oil and natural gas are multiples of those for substituting high-Btu gas.

Moreover, the user cost of replacing oil and gas-burning equipment with electric equipment would often be prohibitive. In addition, as shown in my exhibits, the environmental impact of increased electrification to replace direct use of oil and natural gas would be many times that of substituting high-Btu gas from coal.

As a final point, the business press has reported that, assuming decontrol, the "Nation would be awash with natural gas," at price levels substantially below the current estimates for production of synthetic pipeline gas. The presumed sources of this plethora of cheap natural gas supplies are the very substantial amounts of gas in geopressured zones, tight formations and Devonian shales, and the methane contained in underground coal deposits. We can all hope that this is so because these resources, if they could actually be recovered at these prices, would alleviate the need for many of the proposed new energy conservation measures and for coal conversion.

In fact, if methane recoverable from the geopressured brines can actually be realized at anywhere near the speculative costs, this would allow the United States to go on a total methane economy for all but transportation uses, with all this would imply in terms of consumer and environmental benefits and energy independence. Even many transportation energy needs could be met with compressed gas.

The unfortunate fallout from this sudden optimism on gas supply has been the feeling in some quarters that this will permit deemphasizing the need for deployment of commercial high-Btu gasification technology and might even justify a slowdown in the development of second-generation technology.

I must point out that the amount of gas from unconventional sources that can be produced at an economic price is not known, and years of intensive research and development are necessary before any assessment can be made of this crucial question. In contrast, we know with some certainty the cost of producing high-Btu gas from our abundant coal supplies using commercially available technology.

Because of the inherent advantages of natural gas and its substitutes, whatever their source, the objective of the Nation's energy policy should be to maximize their availability and optimize their use. These sources include not only the substantial remaining conventional natural gas supplies plus all of the unconventional supplies that can be developed, but also substitute natural gas produced from coal and petroleum, Alaskan gas, and LNG and Canadian gas imports.

In summary, the President's proposed energy policy recognizes the fundamental need to substitute coal for crude oil and natural gas in the absence of other solutions whose viability has been adequately demonstrated. However, this policy does not assign the proper role to what is frequently the most economical and nearly always the environmentally most desirable system, namely, conversion of coal to synthetic high-Btu pipeline gas for delivery through the existing transmission, storage and distribution systems to residential, commercial and industrial customers.

Thank you.

[The exhibits to Dr. Linden's statement follow:]

Exhibit 1

ESTIMATED COST OF ENERGY FROM COAL

Energy Form	At Mine Mouth	Delivered 1000 Miles From Mine Mouth: Transport Coal	Delivered 1000 Miles From Mine Mouth: Transport Product
	$/Million Btu		
1. Raw Coal	.65	1.00	——
2. Combustion and Stack Gas Clean-Up To Generate Steam for Large Installations (Commercial)	1.75	2.15	——
3. Fluidized-Bed Combustion To Generate Steam for Industrial Boilers (Not Yet Commercial)	1.90	2.30	——
4. 300 Btu/cu ft Gas			
Commercial Technology (Small Plant)	3.60	4.10	——
Commercial Technology (Large Plant)	2.90	3.40	3.60
2nd Generation Technology (Large Plant)	2.25	2.70	2.85
5. Solvent-Refined Coal (Not Yet Commercial)	3.00	——	3.30
6. High-Btu Gas			
Commercial Technology	3.75	——	4.05
2nd Generation Technology	3.05	——	3.35
7. Synthetic Crude-Pipelineable (Not Yet Commercial)	3.90	——	4.00
8. Electricity			
Mine-Mouth Plant Bus-Bar Cost	11.00	——	——
Ship Coal 1000 Miles, plus Bus-Bar Cost	——	12.00	——
Bus-Bar Cost, plus Cost to Transmit Electricity 1000 Miles	——	——	15.00

Exhibit 2

SUMMARY COMPARISON OF ENVIRONMENTAL IMPACTS OF TWO DELIVERED ENERGY-EQUIVALENT PROJECTS

	High-Btu Coal Gasification Plant (250 mmcfd)*	Kaiparowits Power Plant (3000 Mwe with scrubbers)
Air Emissions (LB/HR)		
Particulates	180	1,070
SO_2	450	4,300
NO_x	1,780	20,830
CO	90	1,200
HC	30	360
Water Requirements (Acre-ft/yr)	6,300	54,300
Solid Wastes (Tons/day)	1,400	5,100

* Million cubic feet per day.

Note: The material shown is taken from several recent studies of the Policy Analysis Group, American Gas Association.

All figures rounded. Proposed coal electric power plant at Kaiparowits was to include wet cooling towers and underground mining, both of which tended to increase its projected water use.

A.G.A. Sources: Radian Corporation, A Western Regional Energy Development Study: Primary Environmental Impacts, Volume II, prepared for the Council on Environmental Quality and the Federal Energy Administration under contract No. EQ4AC037, August 1975.

Final Environmental Impact Statement on the Proposed Kaiparowits Project, U.S. Department of the Interior, March 1976.

Mr. MOFFETT. Thank you.
Dr. Zahradnik, please.

STATEMENT OF DR. RAY ZAHRADNIK

Dr. ZAHRADNIK. Thank you, Mr. Chairman. It is a pleasure to be here today to discuss issues of importance to the Nation's energy future.

In my last appearance before this committee I was representing the ERDA. I represent myself today, specializing in services to the energy community, an activity I have been engaged in since November 1976.

The proposed National Energy Plan indicates that, "full utilization of America's coal resources has been hindered principally by constraints on demand, rather than by lack of supply." Although this is certainly true, it is by no means simple. The constraints on demand are quite complex and involve most of the aspects of the total energy situation in this country: Competition from lower priced, more convenient alternative fuels, a neglected infrastructure, environmental pressures, uncertain regulatory controls, et cetera.

A few years ago the National Science Foundation and the Department of Interior both commissioned studies on the constraints to and incentives for increased coal production. After considerable analysis, both studies concluded that increasing coal production was contingent upon a national commitment to coal and stabilized regulatory practice.

Under these two conditions all the infrastructure questions such as availability of mining equipment, adequacy of the Nation's coal transportation system, level and productivity of miners, et cetera, would adjust in a timely way to higher production rates.

The capacity to produce more coal is one side of the coin, however. American utilities and industry must be prepared to utilize this increased production if the supply and demand equation is to be satisfied. In recognition of this fact, the proposed National Energy Plan calls for an elaborate structure of user taxes and regulatory policies to encourage the large-scale conversion by industry and utilities from oil and gas to coal.

Although I am not personally aware of studies that might have been carried out to identify the limiting constraints on this conversion process, I can tell you some of industry's concerns about it. Basically they center around retrofit situations since most fossil-fired industrial and utility boilers on the drawing boards today are already coal based.

The retrofit problems, on the other hand, are many. Cost is a big factor and capital estimates for equipment needed to replace oil and gas by coal in existing boilers are of the order of tens, if not hundreds of billions of dollars. And hardware costs are only a fraction of the total system conversion cost. In many cases the physical surroundings of a plant preclude adequate coal storage and handling. Coal users are concerned about the pollution abatement equipment that will be required in the future to meet even tougher air and water quality standards.

In the light of these many concerns as well as the uncertain limit and availability of oil and gas, it is no wonder that the coal conversion issue is the subject of considerable attention. As I understand it, today's session is intended to shed some light on still another factor, namely, the effect of new technology.

For many years the development of new coal processing technology in this country has been sponsored almost exclusively by the Federal Government. In order to provide glamour to this assignment, the technology was inevitably sophisticated, operating at extreme conditions of temperature and pressure and utilizing advanced equipment and materials.

In order to ensure marketability of the product, the technology was in large measure directed towards the production of synthetic fuels and electricity, so that the existing energy distribution networks of this country—the gas pipelines and electricity transmission lines—could be used to deliver coal-derived energy to the end users in a traditional and nondisruptive way.

It was recognized that the development times and costs of this program were large, but it was felt that the ultimate payout in terms of process efficiency, improved product cost and environmental acceptability were worth it. Thus, the timeframe for commercial delivery of government-sponsored coal processing technology was and still is today well into the next decade and beyond.

The coal R&D effort of the past 15 years is thus not congruent with the coal conversion provisions of the proposed National Energy Plan. Because the coal R&D effort was directed towards existing energy distribution networks, it cannot contribute broadly to the direct utilization of coal. Because the programmed R&D delivery timeframe is a decade away, it will not spell relief to coal users in the near-term.

In actual fact, the proposed National Energy Plan places coal research in just about this perspective. The short-term options cited by the plan, coal cleaning, flue-gas desulfurization, fluidized bed combustion and production of solvent-refined coal are not a whole lot closer to commercial reality. The first two options have been supported by EPA, the atter two by ERDA.

As a matter of general information, Federal support for these technologies constituted a minuscule fraction of the Nation's energy R&D budget over the past few years. Their citation as near-term solutions emerging from R&D is analogous to the flea on a dog's tail wagging the dog. If these options are to play any significant role in increasing coal utilization, they will have to be supported quickly and fully with dedicated, mission-oriented programs involving the total commitment and attention of our national energy managers.

Lacking this full support, those industrial and utility users who wish to convert in the near-term to coal will most likely do so with "off-the-shelf" technology, technology that has been around for 20 years or more and which was developed in an era of different costs and different environmental concerns.

It is hard to accept the proposition that in spite of the time, dollars, rhetoric and work committed to energy R&D the Nation will have available in the near-term only the centuries-old option of burning coal.

Coal has been called the sleeping giant of the energy industry, the bridesmaid whose time has come, the pivotal fuel to bridge our energy needs into the 21st century. If our Nation is to make it into the next century with any kind of realization of its societal aspirations, it will have to resolve its energy questions. In virtually every future scenario, coal is expected to play a significant role.

But if the only technologically significant option is to burn coal, in the manner of our fathers, we as a Nation will have again succeeded in mismanaging the use of a valuable, nonrenewable energy resource.

Thank you, gentlemen. I will be glad to answer questions.

Mr. MOFFETT. Thank you.

Dr. Neuworth.

STATEMENT OF DR. MARTIN B. NEUWORTH

Dr. NEUWORTH. Thank you, Mr. Chairman.

My name is Martin B. Neuworth. I am Acting Director of Coal Conversion and Utilization of ERDA. I have a statement I would like to read.

ERDA's coal program is aimed at supporting the development of environmentally acceptable technology to permit the increased utilization of coal, our largest fossil fuel resource, by supporting research, development and demonstration (RD&D) on utilization and conversion of coal.

Although the coal program broadly covers coal combustion and coal conversion, I plan to limit my remarks to the status of conversion of coal to gas and liquids. Dr. Philip White, Assistant Administrator for Fossil Energy, will be a witness tomorrow and will cover the ERDA coal combustion program in greater depth.

Commercial coal gasification processes have been available for many years. The most important are Lurgi and Koppers Totzek. Both of these processes have a number of limitations including high cost, low efficiency, and use of narrow coal sizes and types. The second generation gasification processes supported by ERDA are: Hy-Gas, CO_2 Acceptor, Bi-Gas, and Synthane.

All the processes are designed to overcome some or all of the above limitations and produce synthetic natural gas at a lower cost than the first generation processes, if the pilot plant operations are successful.

The four pilot plants have been operational for different periods of time. The CO_2 Acceptor program is about complete, demonstrating technical feasibility. The Hy-Gas program is mature and an economic analysis of a conceptual commercial plant converting western coal indicates significant cost savings over the other second generation processes as well as the Lurgi process. The Hy-Gas process is a candidate for a demonstration plant.

ERDA issued an RFP for a high-Btu demonstration plant. Two awards were made to consortia, offering the slagging Lurgi process and CoGas process respectively. The CoGas process includes a coal pyrolysis step designated COED. The latter process was developed by FMC with OCR/ERDA support.

A considerable savings in the cost of synthetic gas can be effected by substituting low-Btu gas for high-Btu gas. Because of the lack of an existing market and the high cost of transporting low-Btu gas, consideration was given to projects which couple gas production to the end user. Using a PON, we have made six awards, involving small commercial gasifiers supplying low-Btu gas to commercial end users, previously served by natural gas. These projects are 50/50 cost shared in all phases and will continue to operate as commercial facilities after ERDA involvement. Success in these programs will provide a model for rapid expansion without government involvement. Operation of the gasifiers will start in 1979.

In the area of coal liquefaction, there is no corresponding commercial technology. The German processes developed during World War II were very costly and inefficient with no concern for the environment. The largest plant would be considered an oversized pilot plant by today's standards. The Fischer Tropsch process currently operated in South Africa is more expensive and less efficient than second generation direct liquefaction processes.

ERDA is supporting the development of a number of liquefaction processes. Three of these processes, SRC, H-Coal and Donor Solvent are at a pilot plant scale of testing.

The SRC pilot plant at Tacoma, Washington, processes 50 T/D of coal and has been in operation for 2-1/2 years. Over 4,000 tons of specification Solvent Refined Coal has been produced. Three thousand tons have been dedicated to full-scale boiler tests scheduled next month at an electric generation station at Albany, Georgia. Solvent Refined Coal resembles coal but it can be burned in a boiler and meets existing emission standards for SO_2 and particulates without the need for a flue gas scrubber or an electrostatic precipitator. The process will be ready for design of a commercial demonstration plant in 1978.

The H-Coal pilot plant construction will be completed in 1978 and operation of the pilot plant will be completed in 1980. In the case of the Donor Solvent project, the pilot plant construction will be completed by 1980. Both processes produce a synthetic crude oil which can be processed in a petroleum refinery to marketable products—gasoline, fuel oil and chemical feedstocks. This permits the use of the existing network of storage tanks, pipelines and other transportation facilities.

It is contemplated that successful operation of these pilot plants will permit the construction of full-scale commercial plants without the need for intermediate demonstration plants. First commercial plants could be constructed in the 1980-1985 period.

A word about the environmental aspects of synthetic fuel projects. All pilot plants are equipped with instrumentation to measure air and water pollutants associated with each process. Control systems are installed to produce acceptable effluent levels. This monitoring activity will permit us to establish emission standards for conversion plants in cooperation with EPA.

Employees are provided with changes of clothing and required to take routine physical examinations. Extensive biomedical investigations will be carried out on various streams using animal testing to evaluate potential toxicity of all streams. This will permit establish-

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ment of appropriate handling procedures to protect the health of employees and the general public.

Mr. Chairman, this concludes my statement.

Mr. MOFFETT. Thank you, gentlemen. The Chair now recognizes the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. Thank you, Mr. Chairman.

I wanted to ask Mr. Grant if he could enlighten me more in the case of the fluidized bed combustion systems. I understand you people have a contract with AEP to do a demonstration plant at 160 megawatts. That is clearly the largest effort of this system, is that true?

What I am trying to get at is that claims have been made that a fluidized bed combustion system has only been done on a small scale operation and there are many questions to be answered in going to a larger sized operation. Therefore, we don't know when we can expect to really be able to make use of the fluidized bed combustion system.

Mr. GRANT. First of all, the reference to the American Electric Power projects, a combined cycle pressurized fuel combustion development. It is certainly large, but it is developmental. We would not represent it as being ready for commercialization now, and will not before the early 1980's, and that will require a degree of good fortune.

I also discussed atmospheric fluidized combustion which we see as usable today for industrial application. They are very different technologies.

Mr. SHARP. That is a smaller one, the one commercially available?

Mr. GRANT. That is correct.

Mr. SHARP. But I think it would now presently meet many industrial uses in this country, in other words, industries who wish to switch?

Mr. GRANT. It will meet virtually any industrial requirement for steam generation, industrial requirement.

Mr. SHARP. Are there any in operation in this country that you are aware of?

Mr. GRANT. No, sir.

Mr. SHARP. How many are in operation in England or elsewhere?

Mr. GRANT. We have one that has been in operation for 2 years at our own plant.

Mr. SHARP. How quickly could industrial plants in the United States purchase and install this equipment? What is the capacity to produce it, in other words?

Mr. GRANT. The time to install a new industrial fluidized boiler of our design will range between 18 months and 2-1/2 years, depending on the size of the plants and the site of the installation. For the smaller plants it is possible to shop fabricate them and ship them to the site preassembled and this cuts down the time to get them in operation.

The larger ones have to be field assembled and this is a much longer procedure.

Mr. SHARP. But that is assuming you were into production with many orders and you have the capacity to produce. Does that capacity exist?

Mr. GRANT. The capacity certainly exists to produce them. I doubt if we will feel any capacity restraints for some time until industry generally accepts this. It is certainly going to be a period of a year or so when we can produce a darn sight more boilers than industry will buy.

Mr. SHARP. Have you already had many inquiries or contracts?

Mr. GRANT. We have had a large number of inquiries. We are currently negotiating contracts, but in Europe, since we started marketing them there earlier than we have done in the United States.

Mr. SHARP. I am trying to ge a feel of how American industry is already responding and whether or not this is something that really can develop rapidly in this country.

Mr. GRANT. It can develop rapidly, sir, and I believe there is a substantial demand for it. As I pointed out at the end of my statement, there are still unresolved financial questions on the part of our potential clients. I believe they are looking to your good selves to resolve some of these questions.

Mr. SHARP. Once they know what the energy policy is you say they will be willing to make their decisions and plans?

Mr. GRANT. Right.

Mr. SHARP. Thank you.

Mr. MOFFETT. Mr. Brown.

Mr. BROWN. Thank you, Mr. Chairman.

Dr. Neuworth, I want to ask you why the administration has opted for low-Btu coal gasification as opposed to high-Btu coal gasification, why not both? Do you feel that there is no need for transported gasified coal?

Dr. NEUWORTH. Technically we share Dr. Linden's view that certainly moving high-Btu gas ahead in terms of a demonstration plant is in our program plan. The decision to build a state of the art commercial high-Btu gas, I guess, is being considered by the administration at the moment.

I can't expand beyond that point. As I understand it, it is being evaluated right now.

Mr. BROWN. Dr. Linden?

Dr. LINDEN. My comments referred primarily to the detailed fact sheet accompanying President Carter's message on April 20th which relegated high-Btu gas to sometime in the distant future to replace dwindling supplies of natural gas rather than as a preferred option to move coal in an acceptable way to the consumer.

This interrelates with the whole issue of the gas industry's attempt to get commercial first generation coal gasification plants into being, an effort which has been unsuccessful so far because their financial viability is such that they cannot assume the risk to invest $1.3 billion in a commercial-sized installation under regulatory conditions which do not assure them the kind of rate treatment that would induce investors in this kind of project to commit their money.

So, the overall problem has been one of delay of about six announced first generation technology plants that could have, if they had been put into being, produced about 750,000 barrels a day of crude oil equivalent and, also, what I have perceived to be a slowdown in interest in developing second generation improved high-Btu gas from coal technology.

As Dr. Neuworth has mentioned, ERDA has had a vigorous program in this. But if you look at the relative budgets, they have not kept pace with other options for moving coal to the ultimate consumer.

Mr. MOFFETT. Is it really just a problem of money, though?

Dr. LINDEN. It is not only a problem of money.

Mr. MOFFETT. Within ERDA, is it a problem of ERDA not getting enough money or is there something else we ought to be looking at?

Dr. LINDEN. I would say the basic problem is that the ultimate value of moving coal to the ultimate consumer through the existing pipeline system which is running below capacity has not been fully recognized throughout the decisionmaking structure, that it needs a little push to give it more impetus.

Mr. BROWN. That is a very careful phrasing. You say it has not been recognized. Is it there? In other words, are we overlooking something that we ought to be getting into with a little bit more vigor?

Dr. LINDEN. I feel we should get into it with a lot more vigor. It requires a multiple approach, development of second and third generation technology and also deployment of existing technology which I believe can be shown to be totally competitive in meeting existing consumer needs for energy with other means. If we have 2 million housing starts a year, what are they going to buy for heating and water heating? They are going to buy electricity. We can clearly show that it is cheaper starting with the same coal source, to make high-Btu gas than to make electricity and move it to the consumer.

Mr. BROWN. What would you put the price at?

Dr. LINDEN. We have to have a base point. If we use 1976 data, the cost of making high-Btu gas from coal by existing technology is somewhere between $3.50 and $4 a million Btu which, delivered to the ultimate consumer, goes up to say $5 a million Btu. Electricity made from the same coal source and delivered will be in the order of $13 or $14 a million Btu.

So even if you have substantially higher efficiency of utilization such as with the heat pump, it is still cheaper to make high-Btu gas from coal and transport it by pipeline than to make electricity and transport it by wire.

Mr. BROWN. Would you agree?

Dr. NEUWORTH. We have no problem with his calculations. I don't think it would be fair to say that we have no continued high interest in high-Btu gasification. We have supported a very sizable research and development program on all the technically interesting and economic second generation processes. We are continually looking at third generation processes. Technically we have no decrease in interest in high-Btu gas.

Mr. BROWN. What I have some concern about here, because I am in a gas-short area thanks to Uncle Sam, is that we were gas short anyway, but we are now, really, short because of Uncle Sam. If we fix or freeze the price of natural gas at $1.75, then people in my area won't have any choice but to go to electric homes, and many of them have, to their dismay, when they get the bill, or to synthetic gas of some kind, coming in at very high prices.

Now, on the other hand, if we let the price of natural gas move in the market, then we may have a number of alternatives, including, as we have discussed in these hearings, geothermal gas or high-Btu gas or in some areas in Ohio, low-Btu gas or even intrastate natural gas from our Devonian shale. But at $1.75 we might as well burn buffalo chips again. So we have a real problem depending on the nature of the way the legislation is written.

I don't mean to get into that because I know you all sympathize with me, but I don't want you to start sobbing at the table.

The fluidized beds, can you give me some indication of what has to be done in the way of pollution problems going from fluidized beds with coal and also what the boiler impact is on fluidized beds?

Mr. GRANT. First of all, pollution control for fluidized beds will be comparable to pollution control requirements on conventional boilers. In fact, the emissions from a fluidized bed boiler fall between the pollution from a conventional stoker coal-fired boiler and the pulverized fuel boiler. So we are proposing to use the same sort of standard equipment that is used on existing coal-fired boilers.

Mr. BROWN. The same standard antipollution equipment?

Mr. GRANT. That is right.

Mr. BROWN. Scrubbers?

Mr. GRANT. No, cyclones, bag houses and precipitators.

Mr. BROWN. What about the boiler itself? The fluidized bed has to have its own specialized boiler?

Mr. GRANT. The fluidized bed boiler is a specialized boiler.

Mr. BROWN. Is the conversion directly possible or must the boiler be built for the fluidized bed?

Mr. GRANT. We are approaching two lines of attack, to supply new boilers and to convert existing boilers. This is possible. The one we have been operating for 2 years in Scotland is a conversion of an existing conventional coal-fired boiler. This is possible when it is the right type of boiler. There are many thousands of such boilers in the United States. Some of them are working on coal at present, some are mothballed and some are being converted to oil or gas.

Mr. BROWN. Can only a conventional coal boiler be converted to a fluidized bed boiler or can a natural gas or oil system be readily converted?

Mr. GRANT. For an existing conventional coal-fired boiler we can convert it to fluidized bed and achieve the original output in most cases.

Mr. BROWN. Original output of energy do you mean?

Mr. GRANT. Yes, or steam or whatever, hot water. For an oil or gas-fired boiler it is most unlikely that even if we could convert it, we would achieve more than about 60 percent of the output and maybe less.

Mr. BROWN. So we have the same problem that we have with conversion to conventional coal usage of a gas or oil-fired boiler?

Mr. GRANT. That is correct. It probably would not be worthwhile converting existing gas-fired boilers to fluidized bed coal combustion.

Mr. BROWN. Mr. Chairman, I have no further questions at the moment.

Mr. MOFFETT. I would like to ask Mr. Seglem something not necessarily directed to this hearing, but how does Westinghouse feel about the cogeneration provisions in the President's plan?

Mr. SEGLEM. We think they are pointed in the right direction to encourage that. This has been going on with certain industries for some years. That should be encouraged with incentives as I mentioned in my testimony. It is a very important path to follow to help in the conversion because if you can install cogeneration even if it is oil or gas-fired now, that could be convertible equipment to the coal processing later on. So it is a very important aspect.

We are getting inquiries now from industrial customers. The interest is already present in the country. They are hearing what was in the message and are looking at the possibilities of what they might do.

Mr. MOFFETT. Now something that is more on point to today's hearing: I know you can only speak for your own company and maybe it is even difficult to answer for your own company, but what is your view of the government's performance and particularly ERDA's performance? This is maybe a bit difficult for you to state publicly, but if you can share with us your view of how the government performs on the approach of the commercializing things as opposed to R&D.

I have comments all the time from industry people in my area that really question the ability within government to understand what it takes to commercialize something.

Mr. SEGLEM. That is a hard one to answer totally, not that I am holding back, but just to figure out how to encompass what you are asking.

I think ERDA was set up with R&D as its primary emphasis to do research and technology development. That tends to put a different flavor on the emphasis of how would you bring that into a commercial being rather than starting with a total plant system and do all the things to make that plant a commercial reality.

So I think perhaps where ERDA could hasten this process more would be to put more of their R&D in parallel with the commercialization aspects of the R&D, that you plan demonstration plants earlier and take more risks in probably not having everything verified by research and development.

That shakedown process that occurs in the operation of a plant is the most important aspect of commercialization. Until that is done, you cannot sell R&D to a utility. You can sell them a demonstrated plant. That is the part that should be strengthened and made to move faster in their programs.

Mr. MOFFETT. Do you think that there is a naivete reflected in the President's message and what you have been able to find out about it beyond the message, about the plan itself? Is there a naivete in this area, in Schlesinger's operation, for example?

Mr. SEGLEM. With respect to commercialization of technology? I think it depends upon what you start with. I think there is enough today that if you determine you should start with that for demonstration, you can bring some of this technology that is a little way out in a lot sooner. If the emphasis is there and the plans are set up to do that, then I think these things can be made to happen.

Mr. MOFFETT. One final question on this point.

From your point of view and your company's point of view, does it make sense to take ERDA and fold it into the new Department of Energy almost intact and in total?

Mr. SEGLEM. I think the portions of ERDA that we work with probably would not be very much affected by this. So from that standpoint, we probably would not see much of a change, at least as we understand the reorganization today.

Mr. MOFFETT. You mean they would not be affected in the sense that they would be incorporated into the new Department?

Mr. SEGLEM. I mean as they are planning and managing programs, the portions we would be dealing with would seem to be very little changed.

Mr. MOFFETT. But that is my point. Do you think they are wise? Are things going so well at this point where we are reorganizing the energy portions of government that we should take ERDA and just fold it right into the new Department without questioning?

Mr. SEGLEM. I think the thing the new Department does is bring together some of the conflicts that exist now between other agencies that are really dealing with energy as much as ERDA is and get them under a single hat.

Mr. MOFFETT. We applaud that and the idea of bringing these pieces together and coordinating and having some efficiency is very good. I am asking if it makes sense to pick up these pieces like FEA and ERDA. I am asking you really is the President right when he went before that government agency wherever it was, Treasury Department or something, and said no one will lose their job as a result of reorganization?

Do you think that was a good idea?

Mr. SEGLEM. I don't know if he can finally support that statement, but I believe the overall interpretation is right.

Mr. MOFFETT. I just wonder if Westinghouse ran its affairs like that, how long it would last in reorganizing?

Mr. Grant, do you have a comment on the industry view of how ERDA and other government agencies are performing with regard to commercialization?

Mr. GRANT. I believe there are only commercialization as distinct from R&D plans. Until we see them in print I am afraid I could not recall them.

Mr. MOFFETT. Would the chairman of the subcommittee like to be recognized?

Mr. DINGELL. No. You are doing a splendid job. I want the record to show that you have presided in such a capable fashion today. I appreciate the hard work that you have done. I appreciate our panel being here to assist us.

Mr. MOFFETT. For the record we should note that the chairman has not been off vacationing somewhere, but has been working very hard and had a victory of his own today.

Dr. LINDEN. Mr. Chairman, if I may comment, considering the great difficulty of commercializing government R&D for industrial uses, not internal uses such as DOD and NASA, I think ERDA has done a commendable job. It is an extremely difficult situation, especially in view of the adversary relationship one has to maintain between industry and government.

In regard to your comment on reorganization, if ERDA would indeed be moved intact into DOE, it would be better than the way it is being moved. It is split up rather severely. I think there was great merit to having a single administrator of energy R&D and demonstration in the government. Splitting it up under a lot of assistant secretaries isn't as effective for the type of integrated R&D and demonstration which involves environmental problems, involves commercialization problems, et cetera.

So I think that moving it intact would be better than the way it is being moved now.

Mr. MOFFETT. The Chair recognizes staff.

Mr. HUNT. Thank you, Mr. Chairman.

Dr. Neuworth, it is my understanding that ERDA is currently undergoing an analysis known as MOPPS, which refers to market-oriented programs and planning systems. It is my further understanding within that analysis there are certain recommendations relative to which systems seem to be the most promising relative to the conversion of coal to liquid and gaseous and solid fuels; am I correct?

Dr. NEUWORTH. That is correct.

Mr. HUNT. Would it be possible for you to provide for the record not only the conclusions of that analysis but the analytical backup that went behind the recommendations relative to one system for coal conversion versus another?

Dr. NEUWORTH. I was not part of the team that was involved in the MOPPS study and my only information on it is secondhand and it is similar to what you just quoted. As I understand it, the study is about halfway through its course. It is still several months off before the conclusions will be arrived at.

Mr. HUNT. I think it would be helpful for us to have an interim look at it.

Dr. NEUWORTH. I have not had access to it, unfortunately.

Mr. HUNT. Would you anticipate any difficulty in providing it?

Dr. NEUWORTH. I could try.

Mr. BROWN. Would the gentleman yield?

I would like you also to supply the information on the geothermal study.

Dr. NEUWORTH. I am not familiar with that at all.

Mr. BROWN. It is also being done by MOPPS. I understand they worked on it today and the day before and they have had some interesting modifications. This is now the third modification. I would like the opportunity to see that, so if you could make an effort to secure this it would be helpful.

Mr. HUNT. Further, it is my understanding that there are two processes that ERDA has undertaken to support solvent coal, one known as SRC1 and SRC2. What are the major advantages of SRC2?

Dr. NEUWORTH. Just to step back to the SRC1 process, in the course of operating the process there is a difficult separation of solids and liquids. About 5 or 10 percent of the coal plus the mineral matter does not dissolve, and this has to be separated from the liquid material. This is very difficult and very costly. By increasing the severity of the SRC process, a distillate material is produced, and this material is separated by distillation, which is a fairly conventional chemical engineering operation. That is the interest in SRC2.

While SRC1, which produces the so-called solid coal-like material has been operated for about 2 years and has produced approximately 4,000 tons of product ——

Mr. HUNT. That is the only product it puts out?

Dr. NEUWORTH. No. It produces some gaseous components and some small amount of distillate, but the major product, making up 60 percent of the coal, is the solid refined coal.

Mr. DINGELL. In what period of time?

Dr. NEUWORTH. It was about a year, roughly.

Mr. DINGELL. Four thousand, tops, in a year. Can you give us a breakdown in the relative amounts of the different constituents of the byproducts?

Dr. NEUWORTH. The major product is the solvent-refined coal which makes up about 60 percnt of the coal. About 15 percent is mineral matter and the other 25 percent is made up of gas, that is, water, ammonia, hydrogen sulfide, and then some light hydrocarbons and then a small amount of distillate.

Mr. DINGELL. Does all the sulfur come off in the last extraction?

Dr. NEUWORTH. Some of it remains in the solvent-refined coal.

Mr. DINGELL. Is the solid residue of coal a sulfur product then?

Dr. NEUWORTH. It is a product which contains about .7 of 1 percent of sulfur. Based on the Btu content, it would meet the new source performance standard.

Mr. DINGELL. That is what you call compliance coal?

Dr. NEUWORTH. Sir?

Mr. DINGELL. Compliance coal.

Dr. NEUWORTH. That is right.

Mr. DINGELL. Is there any reason why this process cannot be installed commercially?

Dr. NEUWORTH. It is our recommendation there is this burning test which I mentioned, and if that comes off as well as we anticipate, we feel the process would be ready for call up to a commercial demonstration plant.

Mr. DINGELL. What would be the production and cost of that?

Dr. NEUWORTH. The figures we have seen are around $2.75 per million to about $3.25.

Mr. DINGELL. And the cost?

Dr. NEUWORTH. That is the cost to manufacture.

Mr. DINGELL. I see. The cost would be $2.75.

Dr. NEUWORTH. $2.75 per million Btu.

Mr. DINGELL. How much coal would you run in one end and how much product at the other end?

Dr. NEUWORTH. For every ton of coal you feed in you get about 0.6 of a solvent-refined coal.

Mr. DINGELL. Two-tenths of a ton of liquids and ——

Dr. NEUWORTH. Some residue.

Mr. DINGELL. Which would run about 20 percent again, I guess?

Dr. NEUWORTH. Yes.

Mr. HUNT. If I may reverse direction for a moment. The SRC2 has a wider spectrum of fuels?

Dr. NEUWORTH. It makes a smaller quantity of what amounts to mostly naphtha and distillate fuel oil, something like No. 2 fuel oil. But I should point out ——

Mr. HUNT. When you say smaller quantity, do you mean on a proportional basis you get more liquids and gases?

Dr. NEUWORTH. No. You have to leave a larger amount of unconverted coal plus undistillable residue because this is the best the process has been able to do today. You make approximately 2-1/2 barrels of liquid per ton of coal, which is significantly smaller than the SRC1.

Mr. HUNT. In liquid?

Dr. NEUWORTH. In total available fuel.

Mr. HUNT. I am afraid it is not coming through clearly. Perhaps you could provide for the record a breakdown of not only the Btu but the inputs and outputs of both SRC1 and 2.

[The following material was received for the record:]

THERMAL EFFICIENCY OF SRC-I PROCESS
(Based on Conceptual Commercial Plant Design)
EPRI - Study by Parsons (1)
1976

Input	Quantity	MM Btu/D
Coal	30,680 T/D	768,300
Output		
Light Distillate	4,170 B/D	23,000
SRC (Solid)	17,300 T/D	553,200
Total		576,200
Thermal Efficiency		75%

(1) Adjusted to same input basis as SRC-II Design.

THERMAL EFFICIENCY OF SRC-II PROCESS
(Based on Conceptual Commercial Plant Design)
Gulf - 1976

Input	Quantity	MM Btu/D
Coal	30,000 T/D	759,700
Electrical Power (41 MW(e)		8,600 (a)
	Total	768,300
Output		
Pipeline Gas	34 MM SCF/D	44,800
LPG	7440 B/D	29,100
Light Distillate	15,000 B/D	82,900
Low-Sulfur Fuel Oil	61,200 B/D	383,100
	Total	539,900
		70.3%
Thermal Efficiency		

(a) Based on Power Plant Thermal Efficiency of 39%.

Mr. HUNT. It is my further understanding the analysis was done last year which came out with a per million Btu cost for SRC2 of $1.82 or 1.

Dr. NEUWORTH. I do not believe that is correct. I think the studies you are referring to really do not deal with the SRC2 as you are describing it. There were many studies made on conceptual conversions where they took the SRC1 and upgraded it to a distillate fuel by paper processes. The only studies I am familiar with would put SRC2 at about the same cost roughly as SRC1, which is the number I gave you previously.

The extent of time the SRC2 process has been operated is one month on one coal, and we do not consider that a pilot plant demonstration of a process. There are concerns the applicability of that technique will be limited to specific coals in contrast to the SRC1, where we have run at least six coals.

Mr. HUNT. I recognize there is a certain constraint, but is there a shortage of specific coals SRC is to run on?

Dr. NEUWORTH. I do not think we can really designate which coals are amenable and which are not. It is not at that stage of development. In other words—

Mr. HUNT. The character of coal might not enter into the decision?

Dr. NEUWORTH. It is more the chemistry of the ash which is the consideration rather than the location of the coal.

Mr. HUNT. The problem of the chemistry of the ash——

Dr. NEUWORTH. It is inherent in the particular coal you select. You have no way of catalyzing or modifying the process. You have to take the chemistry of the ash that comes with the coal you are selecting. The only coal they have run is Kentucky coal.

Mr. HUNT. So they have only tested one, so the only point is that it has only been proven on one type of coal?

Dr. NEUWORTH. We do not know if it will work on other types of coal.

Mr. HUNT. Mr. Zahradnik, you express some concern relative to the level of effort that is going into coal conversion technology at the present time in ERDA. Do you have any recommendations relative to how much in terms of dollars or manpower this might be scaled out to get a realistic program underway?

Dr. ZAHRADNIK. I do not want to answer it in terms of dollars. I think it would be difficult to get into the budget. I think you would have to analyze ERDA's accomplishments and objectives. I agree with some of the statements made earlier by my colleague from Westinghouse and Dr. Linden that ERDA has to wrestle with a very difficult problem of having a R & D component or mentality, if you will, and being pushed from all sides, and the congressional side as well, to develop some sort of commercial success overnight.

I think it is very difficult to do all of those things. I would argue that what is needed may not be a bigger budget but it may be some sort of overall commercialization plan which recognizes the diversity of its technologies, diversities in the marketplace, and tries to identify some specific mission orientation so it can address that in a very positive and aggressive way.

Mr. HUNT. Mr. Seglem indicated the critical aspects of commercialization come in the shakedown of the plant. I just put this to you as a proposition. Would there be any value in having the Federal Government warrant a particular new technology for a given period of time, say for a year or two, so that if indeed it could not be made to work properly under industrial circumstances the purchaser would be able to share some of the costs of failure?

Mr. SEGLEM. I think the areas where the risks are higher are because you are trying to move the technologies fast. Things will have to be redone. So in those areas where the investment has to be supported I think is where you would need this guarantee, but certainly a couple of those types of costs that would not end up being ones that are part of the commercial process but are necessary to find out where the commercial process really should be in terms of the equipment and the way it operates.

Mr. HUNT. Would you have any other suggestions that might ease this transition or the risk associated with this transition?

Mr. SEGLEM. I think it is really tied up in getting a valid size demonstration plant where these risks are covered. If that proves the case that it is supposed to prove, I would think then the subsequent steps should be able to be carried out by industry, that it should be on a competitive, normal risk-taking basis.

Mr. BROWN. Would the gentleman yield?

Let me ask you what you mean by competitive normal risk-taking basis. Are you suggesting if it is economically competitive, economically viable with other systems, it then is all right?

Mr. SEGLEM. Yes. It has to earn its way against whatever the other competing systems would be for energy conversion if we are talking about that process. Once it is known to be free of technological bugs and that it will work and provide reliable, maintainable type of service, then it should be directly comparable to whatever the other methods are that are providing that same type of service.

Mr. BROWN. My only concern here is that I have some enthusiasm for the ERDA process being involved in the establishment of ERDA as a member of the Operations Committee, and I think it is a great operation for pushing fringe technological development. I think they have overlooked some bets, and I will get to that when I get another chance to question. But what happens if this decision is made improperly at the governmental level? In other words, if we subsidize the process that either is not technologically productive nor maybe at a certain economic level but the other factors that the government is involved in keep it from being economically viable, the example I would give again is the whole question of the whole approach of holding down natural gas prices and then encouraging coal conversion when we wind up with the other problems of environmental limitations that actually make coal conversion uneconomic in terms of the lower natural gas prices.

A lot of people are going to find it is still cheaper economically and certainly cheaper environmentally to burn natural gas. That is what bothers me.

Our sort of unnatural approach to certain things and our discouraging them on the one hand, or encouraging, rather, cheaper methods,and then the unnatural approach on the other hand, which discourages the oncoming in a normal sense of technology, normal market sense. Do you want to address that?

Mr. SEGLEM. I think you have described it very well.

Mr. BROWN. I see heads nod but I do not know what the reaction is deeper.

Mr. SEGLEM. You described the dilemma very well. It is a real conflict.

Dr. LINDEN. I will be happy to comment on it. The test of commercial viability that ERDA has used has been willingness of industry to cost share a demonstration program 50-50, normally. It has not materialized quite that way. But if you have a situation where the economic viability is questionable but the national interest justifies going ahead because were dealing with a lead time maybe of 15, or at most 25 years of approaching disaster in terms of world crude oil supplies—and possibly natural gas supplies—and you have a discount rate which tells you anything of this sort 10 years in advance has very little present value, what do you do?

Mr. BROWN. If I may, who would have guessed 5 years ago that the price of natural gas would have gone much higher than, say, 50 cents? It is now, by the decision of the Federal Power Commission, three times higher than that, and by the market in Texas four times higher.

If one holds down the price of natural gas as the President's legislation proposes, to $1.75 from now on for some time, then what we are up against is the prospect that either high or low Btu coal, gasified coal, is very unlikely to be brought in, even though we force feed the development of the technology, because you are never going to get that price down to $1.75.

Dr. LINDEN. This is another issue. A less explosive issue would be shale oil. We have a world price of $13 a barrel and a cost of producing shale oil which is not quite double that, maybe $20 a barrel. It is clearly in the national interest to get a shale oil production industry going, but the lead time involved and the risks involved in an undetermined future escalation of world oil price and regulated domestic price are such that nobody is able to do it.

What does one do? One must find a better approach than simply cost-sharing, such as government-owned, company-operated installations.

Mr. BROWN. I guess you are taking a larger separation than I am because what I am suggesting is that perhaps one more increase in the price of natural gas brings us to the price of low-Btu gasified coal, or high-Btu gasified coal almost within reach. But if we keep that price down there we will never get to that commercial feasibility that you discussed.

Dr. ZAHRADNIK. I would like to comment on that. I guess I agree with Henry's analysis. I would just like to add a couple of historical perspectives. In 1948 Congress passed the Synthetic Fuels Production Act which gave the Bureau of Mines the authority to produce synthetic liquids from coal. That operation lasted for over 5 years, processing nearly 8 or 10 American coals at about a level of 200 barrels a day. It was finally closed down in 1953 for the lack of economic viability because at that time it was a penny a gallon more expensive than the fuels that were produced in the Middle East.

I expect that difference would have grown as time passed, but nonetheless it failed the test at that time of economic viability in 1953.

We have been chasing economic viability in this country for coal conversion processes since the Office of Coal Research was established in 1960. I make a prediction we will never catch it by analysis, by projections, by conjecture and by sitting around trying to contemplate what we really ought to be doing.

I would argue you are never going to be able to prove on paper that coal conversion is going to be better than any natural product. I told a committee in the House eight months ago if we had an extensive transportation system in this country to deliver coal, I could make synthetic coal from petroleum but it would cost a lot more than natural product. I think we are always going to be faced with that kind of dilemma. You cannot artificially bring natural gas up or down in order to justify some synthetic economic viability.

Mr. BROWN. The price of $1.75 makes coal gasification a lot less viable than the marginal price of natural gas, which in February was coming in at $2.45. The Federal Power Commission has been asked to look at the pricing of natural gas on the basis of those two cost figures.

If natural gas moved to $2.45, then the prospect of gasified coal being commercially feasible becomes a lot closer, does it not, and you begin to get a payout of the kind of investment the government has made.

I have no objection to the idea of going ahead with shale oil development projects. As a matter of fact, I want to go ahead with most of these efforts, but I think we are idiotic to put Federal money into them on the one hand and then try to hold down in an artificial sense the price of the natural products we have, on the other hand, because we guarantee that Federal money, like your coal and liquefaction project you talked about in the '40s, is going to be wasted and that was not held down artificially. It was perhaps a little premature but it would have been wasted if you held the price down artificially.

Dr. ZAHRADNIK. I agree. I think I am saying similar things from a different perspective. I have the feeling that cost projects have a way, at least at ERDA, of waivering sometimes and going up or down depending on the circumstances. I have a feeling that it would be far more prudent to get something going in this country irrespective sometimes of the cost system, which are just a best guess of a lot of people with regard to technology that the world has never seen before.

I am not suggesting we throw them out of the window. I suggest if we made other matters in proper perspective such as our pooling of resources, national security, and the inevitability of this kind of technology, then we ought to get on with the job and quit looking for a lot of justifications in price or economic protection or any other incentive. I think it is a job we have to do. I do not see why we do not do it.

Dr. LINDEN. Also we cannot get on a learning curve until we commercialize, so we have to get on with commercialization now.

Mr. GRANT. I would like to corroborate your point on the effect of natural gas prices on industry's decision to go ahead and do things. One of the cheapest ways of converting coal is Btu gasification—old-fashioned technology. About the lowest price you can do this on a reasonable industrial scale is about $2.50 per million Btu. Right now the gas prices are set a bit too low to encourage people to do that.

Mr. BROWN. That is right. The problem afflicts me and I wish it would afflict the other members of the committee. We have had testimony that in order to convert utilities in the South to coal, natural state coal, and put all the air pollution devices on, and so forth it will increase the cost of the electricity by 300 percent. We are about to force that on them from natural gas to that hard coal-burning process with the scrubbers and the whole business. About the time we get all those conversions made, then the market price of natural gas will have achieved the price of gasified coal and we will have the Federal objective to switch them back so they can burn some kind of gas because it saves money for consumers who will still be paying for those coal scrubbers and boilers and everything else.

To me that does not make very much sense. That is what I am getting at. I just do not think we ought to be running around pushing the pendulum artificially all the time when we could go into the artificial development, let the pendulum catch up with us, and then maybe be able to move on to the next developmental generation.

Mr. GRANT. I think one of the points to make here is if we are trying to release oil and gas, particularly natural gas for domestic consumption, the way to do it effectively is to seek out the cheapest existing utility use of that gas which can be converted to coal. Do not do it most expensively. Take the guy who will cost least to convert to coal. That is going to be the cheapest gas to put into the domestic pipeline. Maybe you are right—putting a power plant in Texas on high-solvent coal with scrubbers may be a bit more expensive way of generating that gas, putting in the Texas homewowner's pipe, than gasifying the coal and putting it in there.

Mr. BROWN. May I just ask one other question. I do not mean to attack ERDA in this question and I do not mean to drag any of you into an area outside your competence because I recognize this is a technology panel within the coal area of the bill. I have been somewhat distressed with the fact that ERDA, since its existence as ERDA, has tended to support what I would call the big and dramatic way-out-in-the-future kinds of projects and not address itself to somewhat more refined and limited breakthroughs in technology that would help the whole energy industry.

I mean by that, materials for transmission of electric power, electric motors, batteries, the kinds of things that are collateral to the energy area.

Dr. NEUWORTH. I should point out those are not in the prerogative of the fossil energy area. Those are, I believe, conservation programs in most of the areas you mentioned. I cannot really describe them in detail but that is their mission, and they are working on batteries and motors and energy conservation techniques.

Mr. BROWN. I grant it is not the fossil energy area, but I am not sure it is getting the attention which might well be devoted to it. Maybe that is not fair.

Dr. NEUWORTH. I would say our breakthroughs have been very limited.

Dr. LINDEN. They have made a very commendable effort in terms of near-term R and D in tertiary recovery of oil and recovery of gas from Devonian shale. They are now getting into geopressured zones. They have done quite a bit of near-term work to maximize the utilization of oil and gas resources. This is a new initiative that came with Dr. White that has been very successful and is moving ahead very well. They have made major efforts to get into more of this.

Mr. BROWN. Do you feel generally we are devoting that time and effort and money in what I would call the fringe areas of all the various technologies?

Dr. LINDEN. You can always use more money. It is difficult to organize these programs. I think in particular in the areas of tight formation gas, geopressured zones, Devonian shale and oil shale, more money should be spent by ERDA, specifically because these are near-term efforts that could pay off much more quickly than many of the other programs.

Mr. BROWN. Do you have comments in that area?

Dr. NEUWORTH. I can never quarrel with having more money.

Mr. HUNT. Dr. Linden, in your testimony on page 2 you make note in the fourth point near the bottom of the page that low-Btu gas installation serving a large number of industrial users within a radius of 50 miles or less might have a cost advantage basically over high-Btu gasification. Do you have any estimate as to what percentage of the industry might be covered by concentration of heavy industrial areas we have in this country?

Dr. LINDEN. I would say a very substantial share of major industry use of clean fuels, especially high form value fuels such as gas. Detroit is one of the ideal areas, and the advantages of centralized pollution control, centralized coal handling, the economies of scale and particularly the load factor that you could obtain would make low Btu gas installations serving a large industrial complex a very competitive thing.

The problem that we are faced with in these small dispersed installations is that they have not sold because——

Mr. HUNT. Under those circumstances then it would be basically possible to extend our supplies of high Btu natural gas and perhaps save those areas which would not be served——

Dr. LINDEN. For most industrial uses there is no need to make high Btu gas from coal. I am simply saying under the existing circumstances, what we have here and now—we have the logistic system for delivery of coal to the consumer, we have got a pipeline system that is not running full. It is running 30 percent empty. We have coal, we have existing technology. We ought to do something to encourage that, especially when you look at the hidden costs of conversion from gas to other things.

Mr. HUNT. The conversion from high Btu gas for industrial uses to your medium Btu gas is a neglible conversion cost.

Dr. LINDEN. That is correct. We are dealing here with a very marginal difference between centralized low Btu gas and high Btu gas. This margin will increase as low Btu gas technology develops further.

Mr. HUNT. Another question. It is my understanding that the Institute for Gas Technology has done some rather pioneering research in the area of conversion of Devonian shale.

Dr. LINDEN. We have done work on conversion of eastern shales generally, which is based on our concept that the way to get the most out of shale, out of oil shales generally, is to treat them in a hydrogen atmosphere under pressure in a very systematic way, and we have shown—and we have testimony to this effect, and exhibits to this effect—that we can get pretty much the same yields in gallons per ton from eastern shale as one can from western shale.

Mr. HUNT. Rather than in gallons per ton, you mean in total Btu per ton of usable liquids and gaseous fuels?

Dr. LINDEN. Eastern shale and the typical Colorado shale have about the same carbon content. The eastern shale is much lower in hydrogen. When you retort it by the conventional way, simply heating it up, most of this carbon just carbonizes and you get 10 gallons of liquid per ton.

By hydro-retorting eastern shale, you can get up to 30 gallons per ton. There is no question that this is a do-able thing. The economics, of course, are always in question. It is certainly something that ought to be looked at very carefully because it does make an incredible additional amount of hydrocarbons.

Mr. HUNT. The Fisher assay has been misleading?

Dr. LINDEN. Yes. It simply simulates conventional retorting, which gives you a very low yield with eastern shales.

Mr. HUNT. It is my understanding, and correct me if I am wrong, that the optimal size from the standpoint of costs for a fluidized bed combustion chamber running in roughly the peak as far as efficiency is about 60 megawatts, am I correct? I am afraid I am not familiar with pounds of steam output.

Mr. GRANT. I don't think there is a great difference in combustion efficiency.

Mr. HUNT. Total cost efficiency of the unit.

Mr. GRANT. Fluidized bed boilers will obey the conventional economies of scale curve, and at present we are not willing to build a boiler bigger than 500,000 pounds per hour. That is about 50 megawatts. That is simply a self-imposed limit because we don't wish to go any larger at present.

Mr. HUNT. As a generating facility, if indeed we are involved in electric generation, that is reasonably small.

Mr. GRANT. It is small.

Mr. HUNT. It would occur to me if this is a good working size installation, fluidized bed would provide an opportunity for following load growth by adding in small bite sizes as opposed to big bites, which seems to be the common practice in this country. Very, very large generating stations.

Mr. GRANT. That is correct, but the capital costs per installed kilowatt would certainly be higher at 50 megawatts, a lot higher than 1,000 megawatts. The utility would have to face up to this fact.

Mr. HUNT. Yes, but I would suspect that there might be offsetting savings from the duration of time the material would be in construction and hence you wouldn't have as long a capital carrying cost.

Mr. GRANT. I am sure you could find a set of circumstances, a particular utility, a particular site, which this would be true. Maybe several such.

Mr. HUNT. We have heard testimony in this committee within the last month that indeed it is delays and long building times that have been one of the major contributing factors to the high costs of very large facilities. I thought perhaps the smaller unit size of fluidized bed combustion chambers might offer an opportunity to break out of that.

Mr. GRANT. Yes. I am not sure the average utility would be willing to go in for such small plants. I am not aware of the circumstances they are considering, which might compel them to do so.

Mr. HUNT. Fine, thank you very much.

Dr. NEUWORTH. Could I say something on that. The problem you have with the utilities, if you are trying to build a boiler of the appropriate size, a single fluid bed boiler can only be built so large. If you put sections alongside of each other, the land requirements become prohibitive. You have a problem of stacking these units, and this is one of the issues in building a utility boiler. Can you vertically stack them and still feed them successfully? This is one of the issues that we have to address in scaling the fluid bed boiler to a utility application.

Mr. HUNT. Althugh it may not be reflected in the United States experience, it is my understanding that the square footage required for a fluidized bed combustion chamber is considerably smaller than that in the typical normal combustion chamber, a factor of a third, I think.

Dr. NEUWORTH. The situation is that the Rivesville boiler is the largest single installation in the world.

Mr. HUNT. Which one?

Mr. GRANT. Rivesville, West Virginia.

Mr. HUNT. That is what?

Mr. GRANT. Thirty megawatts. But the point is you could not continue to do that to get up to 1,000 megawatts. The land requirements would just be prohibitive, to build cells of that size. If you build them much larger, it is not clear that you could uniformly operate them.

Mr. HUNT. Do you have an analysis to that extent?

Mr. GRANT. I think there have been some analyses made.

Mr. HUNT. I would greatly appreciate it if you could provide one.

Dr. NEUWORTH. We cannot just extrapolate them geometrically and not get into difficulty.

Mr. HUNT. I look forward to receiving the analysis.

That will be all, Mr. Chairman, I believe.

Mr. DINGELL. Gentlemen, you have been here a long time. The committee is grateful to you for your time. The Chair observes Mr. Ain of our staff also has a question. The Chair will recognize him at this time.

Mr. AIN. Mr. Seglem, you submitted some very interesting testimony to the committee today. In the testimony of Mr. Jones, on page 6 of that testimony, Mr. Jones indicates that in looking at section 208C of the Senate bill, we can look to a 20 percent or greater improvement in operating efficiency of existing facilities through the application of repowering, as described in his testimony.

I guess my question to the panel is, looking at conversion to coal, should we not carefully focus on some standards for new industrial facilities that will be minimum efficiency standards for the use of oil and gas as opposed to prohibitions on the use of coal?

Mr. SEGLEM. I think you can set standards for new plants. This testimony of Mr. Jones was directed more at the conversion problems you face with existing plants, in that you cannot place an absolute level of efficiency on those, but you can get this incremental gain, depending upon what the nature of the plant was that you started with before you began the conversion.

Certainly on new plants you can set standards there because you are not trying to make existing equipment work in a way that it may not be designed to be worked.

Mr. AIN. If the legislation would require conversions of existing industrial facilities from oil and gas to coal, would it be reasonable to allow an exemption from that if they met certain improvements in efficiency of this type mentioned in your testimony?

Mr. SEGLEM. Yes, that was the intent. That would be a way of trading and keeping an existing facility operating at a higher conversion or conserving more energy than to have one that is not convertible to coal and having to scrap it.

Mr. AIN. The costs of converting to coal, and the new boiler, versus the energy savings from the retrofit of the existing plant, can you compare the costs?

Mr. SEGLEM. I don't think I could give you a specific cost just off the top of my head.

Mr. AIN. Take a medium-sized industrial boiler that uses oil or gas, and you are going to either retrofit it to improve its efficiency by 20 percent, or convert it to coal.

Mr. SEGLEM. Mr. Jones is behind me, so I understand that is what he had submitted in testimony. We find that these industrial conversion cases are very specific to the plant that you are looking at, and hence you cannot really generalize levels of performance or costs and so on until you look at that plant, and what the situation would be for it.

The studies we have made on adding repowering to get this efficiency gain indicates that the incremental costs of the conversion are at a very cost effective level as far as the user would be concerned. The incremental costs are, I would say, very competitive.

Mr. AIN. Unfortunately, I haven't had a chance to read all of your testimony today. We were under a tight schedule. I was wondering if you could provide for the committee within the next 7 days some examples of different existing oil or gas burning facilities, of different sizes, in the industrial sector, and what the cost would be of converting them to the use of coal or applying a repowering technique to them, so we could see the differences there.

Mr. SEGLEM. I think the one on the use of coal would be probably beyond what is available as data now because those are just being really studied.

Now, in the case of converting by repowering, this has been done and studies have been made there. We have one study probably that we could draw data from that would indicate what these costs are if you convert an existing facility to being repowered, and thereby get this gain in efficiency, and increased power output.

[The study referred to, Repowering as a Solution to Lower Generating Costs, may be found in the subcommittee files.]

Mr. DINGELL. The Chair observes Mr. Jones making a comment. Why don't you pull a chair up to the table, identify yourself, and we will hear your comment. I think that is the proper way to do it.

STATEMENT OF DONALD R. JONES, LONG-RANGE DEVELOPMENT MANAGER, GENERATION SYSTEMS DIVISION, WESTINGHOUSE ELECTRIC CORPORATION

Mr. JONES. I am Donald R. Jones. I am the Long-Range Development Manager of the Generation Systems Division of Westinghouse Electric Corporation. The comments that we made were specifically intended to be for electric utility repowering.

When we referenced cycle improvement, it is referencing the Btu or performance, percent performance, of utility operating systems. When you look at an industrial system, it is extremely difficult to set performance levels because the integration of process energy with power generation and/or process mechanical drive energy is synonymous, they are one and the same. You cannot break them apart.

So, we referenced that performance improvement to utility cycles where you are only generating electrical power. In that case, a 20 percent improvement using natural gas or oil type cycles is very obtainable. Since most of the utility applications on natural gas were originally conceived when gas was 10 to 20 cents a million Btu, the complexity of the cycle is very immature because it was not economically justifiable from a cost standpoint. Hence, the cycle efficiency of most natural gas plants in the Southeast and Southwest is between 10,000 and 13,000 Btu.

By repowering, or making a combined cycle, you can get a 20 or even 30 percent improvement in performance. We thought that rather than have these plants go to coal, it would be a good step to try and conserve the utilization of natural gas, and/or oil.

Mr. AIN. What is the availability of the equipment involved in the repowering?

Mr. JONES. The availability—is it commercially available, you mean?

Mr. AIN. Yes.

Mr. JONES. Ys, it is. There are like four or five manufacturers in the United States that produce combustion turbines that could be used for this conversion. They vary in size from 5,000 to 90,000 kilowatts.

Mr. AIN. So the application could be almost across the board from the lowest end of the spectrum all the way up?

Mr. JONES. I think that is true in utility service, yes.

Mr. AIN. And industrial service?

Mr. JONES. Industrial service, because you are generally dealing with capacity sizes below 100,000 kilowatts, you are tending to use the lower end of the spectrum. If you talk cogeneration, very definitely, where you are just trying to match a heat sink rather than trying to match the characteistics of kilowatt usage of the industrial.

Mr. AIN. Thank you very much.

Thank you, Mr. Chairman.

Mr. DINGELL. The Chair recognizes Mr. Hunt for one more question.

Mr. HUNT. Mr. Seglem, in your statement you indicated that by going to a liquid fuel on the combined cycle, that you could raise the efficiency to 50 percent. Why are you so constrained on doing so with either low Btu or natural gas?

Mr. SEGLEM. What was the last part?

Mr. HUNT. Either low Btu or natural gas, on your combined cycle. Why does the liquid have that great advantage that it will boost you to 50 percent?

Mr. SEGLEM. If you used natural gas, you would get about the same efficiency. The reason that distinction was made was in the case of the low Btu combined cycle using gasification. There we considered the conversion efficiency of the low Btu gasification process.

Mr. HUNT. So it is the conversion loss at the front end?

Mr. SEGLEM. Yes. That represents a difference.

Mr. HUNT. Thank you.

Mr. DINGELL. Gentlemen, the committee thanks you all for your assistance to us. The Chair would like to make one particular observation.

Not only has this panel been a panel of extraordinary quality, for which we commend and thank you, but I want to welcome Mr. Zahradnik back here.

Dr. Zahradnik, I hope all things are well with you.

Dr. ZAHRADNIK. Very well, Mr. Dingell, thank you.

Mr. DINGELL. I would like to have it known that you have earned the particular respect and affection of this committee by reason of your ability and courage and your integrity.

Dr. ZAHRADNIK. Thank you.

Mr. DINGELL. I would like the record to show that I, as chairman of the subcommittee, am particularly pleased to see you back before us. I have had you before this committee in other occasions when you were with the government, and I regarded you at that time as a public servant of extraordinary quality and decency and ability and courage. I would like to have it known that I feel all the more honored that you are back with us again, and that I express to you not only my pleasure that you are with us, but also my hope that things go well for you.

Dr. ZAHRADNIK. Thank you very much, Mr. Chairman. I want to say how pleased I am to be here as well, and that I too hold the committee in high regard and high esteem. I want to give you my personal assurance if there is anything I can do for you in the future, just call at any time. I would be happy to help.

Mr. DINGELL. You have demonstrated extraordinary qualities of public service. I am just very much pleased you are back with us, and I thank you for your kindness to the committee, and rejoice that things are well with you.

Gentlemen, we express our thanks to you all for your assistance to us. You have been an outstanding panel.

The committee will stand adjourned until 9:30 tomorrow morning.

[Whereupon, at 5:50 p.m., the subcommittee adjourned, to reconvene at 9:30 a.m., Friday, May 27, 1977.]

NATIONAL ENERGY ACT

FRIDAY, MAY 27, 1977

House of Representatives,
Subcommittee on Energy and Power,
Committee on Interstate and Foreign Commerce,
Washington D.C.

The subcommittee met at 9:35 a.m. pursuant to notice, in in room 2123, Rayburn House Office Building, Hon. John D. Dingell, chairman, presiding.

Mr. Dingell. The subcommittee will come to order.

We are glad to welcome our panel of witnesses. We are also glad to see our former colleague, Brock Adams, a very close friend of mine.

The Chair would also like to express welcome to Mr. O'Leary, Mr. White, Mr. Costle and Mr. Woodworth, whom I have known for years on Ways and Means, an extremely fine public servant.

The committee commences its last day of hearings on the coal conversion provisions of the administration's bill, H.R. 6861.

I believe the Nation should halt or severely cut back its use of natural gas for boiler fuel purposes. A significant reduction in the use of petroleum products for this purpose appears to be not only sound, but necessary.

Three years ago, the Congress recognized this need and enacted the ESECA coal conversion program, one which has been characterized by not having worked and can be most kindly called a very severe failure.

A basic problem has been the past failure of FEA to administer the program effectively but the complexity of the law also has not helped.

A less complex law is needed. However, the testimony we have heard to date shows the coal conversion provisions of the bill are not much of an improvement over existing law. The bill seeks to shift the burden of proof by a series of exceptions and exemptions to be considered by FEA.

I will observe that appears to be a bad way for the law to be administered. The criteria for granting or denying them appear to be quite vague. This vagueness may result in mounds of paper work, extensive litigation and of benefit only to the legal fraternity.

I am particularly concerned about the proposal to have determined in the law that a denial of an exception or exemption is not a "major Federal action" requiring an environmental impact statement.

As the chief sponsor and the author in the House of the National Environmental Policy Act of 1969, I want it clearly understood I do not look with any kindness at all on proposals to in effect water down or convert exemptions on the National Environmental Policy Act, one of our very important environmental protections and one of our major decisionmaking tools in terms of protecting the environment.

More importantly, I do not think such a blanket finding is in the public interest and I want it made clear that I intend to oppose it, particularly when one realizes that the ratepayer must pay the cost of the conversion.

If a NEPA statement is required by law and if it will improve the decisionmaking within the government, FEA, EPA and the other agencies concerned, why should the Congress decide otherwise in order to foster what might be a conflicting policy in some cases? Furthermore, the Chair has had some difficulty procuring the necessary assistance from the executive agencies in terms of making the decision-making papers available to the Congress, so that we might have a full understanding and appreciation of what went into the decisionmaking process, as Mr. Costle well knows. As a matter of fact, this committee had to go to another subcommittee, the Oversight and Investigations Subcommittee, to procure the assistance in achieving the information that we need to arrive at some decisions with regard to legislation just on the floor yesterday.

The administration sought with some diligence to prevent the committee from having that information.

Few of our witnesses have supported the program. No one has endorsed the legislation in its present form. A number of witnesses have expressed concern about the environmental impact of this program and the lack of adequate data as to effects of increased coal use on air pollution.

The EPA analysis of the effects of coal conversion and the best available control technology on industrial and utility emissions suggests that increased use of coal "will not result in significant national increases," in emissions over projected 1985 levels. However, one undated EPA memorandum to Mr. Costle from Mr. William Drayton, an EPA Special Assistant, states as follows:

> National emission loadings can only provide a crude assessment of the effect on air quality of coal conversion and the energy plan. While this analysis suggests that national emission loadings are not a cause of environmental concern, further analysis of the emission increases in AQCR's above and near the NAAQS, is needed to address the question of whether increased coal use will represent a threat to public health.

The memorandum adds that "national emission loadings are only a crude indication of air quality problems." A more detailed analysis of the specific areas is needed.

The memorandum states that such a study is underway and should be available "before final energy legislation is passed."

The Chair will request that it be made available to the committee as soon as possible so that we may consider it as part of our affairs.

I note we begin mark-up of the coal conversion part of the bill in mid-June. The availability of such important data weeks later will not be of great help and unfortunately it appears to be Congress is being called upon in many instances to act on judgments of the administration before the supporting data is made available to us so that we might more properly come to a full and an informed decision on the matter.

Another EPA memo states that the nitrogen oxide emissions are anticipated to "increase significantly even in the absence of the administration's conversion program."

The memorandum shows the increase of 24 percent in 1985 over 1975 emission may be expected "due to industrial and utility growth alone."

The coal conversion program "would increase this percentage by 6 percent."

The memorandum then states, "Frankly, there has been a real problem in developing adequate control technology. At this time controls on large boilers, over 25 megawatts, can be required which can reduce emissions by only 10 percent. When this is compared to our ability to control particulate levels up to 99 percent, the progress we need to make in this area are phenomenal. Technological advances will not be achieved for another 5 to 10 years, and we will not see the benefits of additional controls for at least 10 to 15 years.

We have a significant effort underway to better develop NOx technology for stationary sources. Mr. O'Leary has said, "All new facilities, including those that burn low sulfur coal, should be required to use the best available control technology."

But the bill does not appear to require such a technology and the Chair wonders whether or not there has been coordination between the air quality programs of the administration and the coal conversion programs and, if there has been coordination, which of the two will prevail.

What if the technology does not exist as in the case of nitrogenoxide emissions? What about existing plants that are required to convert? What technology will they be required to use? We will examine these and other issues today with the hope of reaching not only some consensus, but some information on the proposal.

The Chair observes that our old friend, Mr. Adams, has indicated that he has to leave and he will leave members of his staff here to respond to questions, so, Mr. Adams, we will recognize you first at this time for the reading of your statement.

STATEMENTS OF THE HON. BROCK ADAMS, SECRETARY, DEPARTMENT OF TRANSPORTATION, ACCOMPANIED BY CHESTER C. DAVENPORT, ASSISTANT SECRETARY OF TRANSPORTATION FOR POLICY, PLANS AND INTERNATIONAL AFFAIRS, JOHN SULLIVAN, ADMINISTRATOR DESIGNATE, FEDERAL RAILROAD ADMINISTRATION, AND WILLIAM COX, FEDERAL HIGHWAY ADMINISTRATOR; HON. JOHN O'LEARY, ADMINISTRATOR, FEDERAL ENERGY ADMINISTRATION, ACCOMPANIED BY ROBERT HANFLING, DEPUTY ASSISTANT ADMINISTRATOR, ENERGY RESOURCE DEVELOPMENT; PHILIP C. WHITE, PH.D., ASSISTANT ADMINISTRATOR FOR FOSSIL ENERGY, ENERGY RESEARCH

AND DEVELOPMENT ADMINISTRATION; LAURENCE N. WOODWORTH, ASSISTANT SECRETARY FOR TAX POLICY, DEPARTMENT OF THE TREASURY; HON. DOUGLAS M. COSTLE, ADMINISTRATOR, ENVIRONMENTAL PROTECTION AGENCY

Secretary ADAMS. Thank you, Mr. Chairman. I appreciate very much the Chairman's willingness to indulge the problem that I have.

I have a prepared statement, Mr. Chairman, which I would ask be included in the record in full. I would like to summarize briefly from it and then I would be most happy to answer questions.

Mr. DINGELL. I think that is entirely appropriate and without objection it is so ordered.

Secretary ADAMS. Thank you, Mr. Chairman.

Mr. Chairman, as you know, the Department of Transportation's role in the President's energy plan is extremely important, particularly with regard to coal conversion, so we have moved immediately to address the problem.

First, it is necessary to know whether our present transportation system is capable of moving the necessary supplies of coal from the areas where it will be produced to those places where it will be used.

As you know, Mr. Chairman, the President's energy plan calls for an increase in coal production of at least 400 million tons by 1985. We have started an examination of the capacity of the transportation system to carry this increased production. My first comment is that the great bulk of this coal transportation, Mr. Chairman, in the early years of this plan, will be carried by rail, which is its traditional method of movement. We, therefore, need to examine carefully the supply of rail coal cars and locomotives.

Mr. Chairman, of the over 365,000 open hopper cars currently in use, about 250,000 are used for coal movement. Hopper cars ordered in the last 3 years have averaged about 16,000 a year.

If the trend continues toward more unit train operations, which we anticipate, the annual requirement for hopper cars in the short range will not increase above that number. In any case, we have consulted with the railway car builders and they have indicated that they have several times that amount of hopper car production capacity.

We have also examined the supply of locomotives. There is a productive capacity of approximately 1,600 locomotives per year. The new fleet additions and rebuilt power units can be available to meet the short term or immediate line-haul power needs.

We do have a problem, Mr. Chairman, and I know that the members of this committee are very well aware of it, and that is the ability of the marginal railroads to secure the financing necessary to make the necessary investments. In other words, what I have indicated, Mr. Chairman, is that we have available the productive capacity to produce these cars; but we are also aware that while the more profitable railroads have the ability to finance and to purchase them, some of the marginal roads may be faced with a financing problem. Therefore, although we do not think we will need to construct new lines, we will need to move ahead, Mr.

Chairman, with the so-called preference share program and the other aid programs which we have had in the past to aid the railroads that were unable to meet their own financial commitments.

Mr. Chairman, aproximately 10 percent of our coal shipments now go by barge over our inland waterways. We anticipate having greater intermodal movement of coal since the rail carriers and the barge carriers are making the intermodal connections. We have examined the capacity of the inland water system and for the short run it does have sufficient capacity to move the coal to meet the President's energy demands.

Another concern, Mr. Chairman, is with respect to trucks, partcularly in the eastern part of the United States. A great many people are not aware of the fact that we use a large number of trucks to bring the coal from the mine to the basic washing plants and the railroad or barge loading facilities. Unfortunately, we have a very badly deteriorated short haul system of roads for the coal trucks.

In this connection, are looking at the feasibility of trying to centralize coal preparation and storage facilities in Appalachia.

I want to touch briefly on coal slurry pipelines. We are at this time within the administration working to establish a position among several Departments to present to the Congress. The coal slurry pipeline operation involves the environmental impact of moving large amounts of water from one place to another. We also understand the problems of eminent domain. We believe that the construction of these pipelines must be very carefully considered since they will have significant impacts on the transportation system and we are very concerned about redundant capacity and economic efficiency.

Mr. Chairman, I have indicated to you that we have examined and are satisfied that we have the short-term capacity to move the coal production that is required by the energy bill, but knowing that we are going to step up into enormously heavy utilization of coal facilities, I have established within the Department of Transportation a Coal Transportation Task Force. It was established over 10 days ago, when we were working on the energy plan, determining the best way to marshal our efforts.

The chairman of this task force will be Mr. Chester Davenport, who is the Assistant Secretary for Policy, Plans and International Affairs. He is here and will be available to the committee when I leave so you can ask him questions on the specifics of our long-term planning and where it is going.

I also have available, Mr. Chairman, the designee for Administrator of the Federal Railroad Administration, Mr. John Sullivan, and I also have the Federal Highway Administrator, Mr. William Cox. These two are the principal participants in the Coal Transportation Task Force, along with the Assistant Secretary for Policy, Plans, and International Affairs.

This task force's immediate assignment, Mr. Chairman, is to identify the gaps in our coal transportation system, to analyze the areas where we may need additional movement and where capacity is not available.

The task force will also be examining the necessity for the establishment of a road system and railway system for eastern coal and finally the tying together of the western railroads and the barge lines in order to supply coal into the midwestern and eastern markets. We anticipate having our recommendations long-term, Mr. Chairman, available for presentation to the President and then to this committee, by the end of this summer.

As I say, if we come to the conclusion that our original estimates were in any way incorrect that the present capacity is not available, we will, of course, move immediately to take appropriate action. Our present identification of the segments indicates that we have the line—haul capacity and the immediate production capacity of equipment to meet the needs of the increased coal production, at least for the short term.

Mr. Chairman, that completes my statement. I would be most happy to answer your questions and then I would like to ask that Mr. Davenport, the chairman of our Task Force, together with the Federal Highway Administrator and the Federal Railroad Administrator designee, participate in the morning's discussion.

[Secretary Adams' prepared statement follows:]

STATEMENT OF BROCK ADAMS, SECRETARY OF TRANSPORTATION, BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER OF THE HOUSE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE REGARDING THE NATION'S COAL-HAULING CAPACITY, FRIDAY, MAY 27, 1977.

Mr. Chairman and Members of the Subcommittee:

I appreciate this opportunity to appear before you to discuss problems concerning the transportation of coal.

As you know, President Carter's National Energy Plan calls for a major increase in the Nation's reliance on coal as a source of energy. Oil and natural gas account for three quarters of our energy needs, yet they constitute less than eight percent of current domestic energy reserves. Coal, on the other hand, constitutes 90 percent of our conventional energy reserves, but currently supplies only 18 percent of energy consumption. As our demand for energy continues to grow, the need to stimulate greater use of coal is clear. Our failure to move in this direction would translate into reduced economic growth, an increase in dependence on foreign oil, and inadequate supplies of natural gas for residential use.

A salient feature of the President's Plan is to increase coal production by two-thirds, to more than one billion tons per year. In large part, this would be brought about by increased demand resulting from the conversion of industries and utilities to coal. That conversion would be encouraged by taxes on the use of oil and natural gas, and a regulatory program prohibiting industries and utilities from burning natural gas and petroleum products in new boilers or in new major fuel-burning installations other than boilers. Also, existing facilities with a coal-burning capability would be prohibited from burning gas or oil where the burning of substitute fuels would be feasible.

In calling for an increase in annual coal production of at least 400 million tons by 1985, the President's Plan has understandably caused questions to be raised about the adequacy of the Nation's transportation system to deliver vastly increased quantities of coal. In addition, increased movements of coal raise a number of significant transportation policy questions.

The Nation's railroads will play a central role in determining our ability to achieve the President's coal production goals. Presently, the great bulk of coal transportation in the United States is by rail. Therefore, we must first concern ourselves with the ability of our rail system to respond to a large-scale increase in coal demand. Among the factors to be considered are the line-haul capacity for moving coal, especially western coal. We will be looking at the need for line expansion in the West and in the traditional Eastern and Midwestern mining areas, and the need in those areas for improved track and signal systems.

We will also have to look into the supply of rail coal cars and locomotives. That supply will have to be enhanced to handle at least a two-thirds increase in rail coal loadings. Of the over 365,000 open hopper cars currently in use, about 250,000 are used for coal movement. Hopper cars ordered in the last three years have averaged about 16,000 per year. If the trend continues toward more unit train operations, the annual requirement for hopper cars probably will not increase above that number. In any case, railway car builders have indicated that they possess several times that amount of hopper car production capacity.

Similarly, locomotive needs do not appear to present a problem. With an estimated productive capability of 1,600 locomotives per year, new fleet additions and rebuilt power units can be readily phased in to assure line-haul power needs.

To the extent that constraints on the shipment of coal by rail do emerge, they are likely to involve the ability of financially marginal railroads to secure the financing required to make the necessary investments. I should point out that the bulk of the investments in question would be for improved signalling systems,

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rolling stock, and lengthened sidings or intermittant double tracking. We are not likely to be faced with the need to construct whole new rail routes.

Slightly more than 10 percent of all coal shipments move via our inland waterways. Increases in the use of barge lines for transporting vastly increased volumes of coal, however, face certain restrictions due to the inland waterway system's limited geographic coverage and capacity constraints. At this time, virtually all segments of the inland waterway system, including the segment around Alton Locks and Dam, have sufficient capacity to handle increased coal traffic. We need to continue to evaluate the need for waterway capacity expansion. At this time, however, I believe the role of the Nation's inland waterway operators with respect to coal shipments will remain significant but limited.

Trucks are also an essential part of the coal transportation system. They are particularly important in the Eastern United States where they are used to move coal short distances from the mine to washing plants and to railroad or barge loading facilities. Trucks are used most intensively in areas typified by small mining operations that cannot consistently meet the production levels necessary for the efficient use of rail or barge service.

In this connection, we are looking into the feasibility of centralized coal preparation and storage facilities to serve small mine operators in Appalachia. We believe that modern facilities for the blending and preparation of coal for utility customers will foster a coordinated truck-rail intermodal service, combining the flexibility of truck service from the mine with the economies of unit train loading of high quality, uniform coal to destination.

The trucks used in Appalachia are frequently operated on roads that are structurally and geometrically unsuited for travel by large, heavy vehicles. Deteriorated road conditions and high maintenance costs caused by coal truck traffic have placed and will continue to place a significant burden on these coal producing states. There may also be significant costs associated with access roads for workers and equipment to mines and power plants. In addition, increased movements of Western coal may give rise to the need for numerous railroad/highway grade crossing separations and line relocations. Severe environmental and social impacts may result from the movement of large volumes of coal through the streets of small towns. The movement of 20 or 30 large unit trains a day could create serious problems at such locations.

The need for energy-related highway improvements must compete for funds with many other highway projects required to help meet other national goals such as improved highway safety. At the same time, reduced consumption of fuel in automobiles on a state-wide basis will cause a reduction in state tax revenues normally devoted to highway maintenance and construction. We are well aware of these problems and we are focusing on them very closely. In order to ensure that critical coal transportation needs on and off the Federal-aid highway system can be met, it may be necessary to provide special Federal assistance.

Slurry pipelines are another potential means of transporting coal. Although only one such pipeline is currently in operation in the United States, slurry pipelines have been used for years in many countries as a means of transporting large volumes of crushed solids. The construction of additional pipelines would require the commitment of large amounts of scarce financial and natural resources. The decision to move forward with the construction of these pipelines must not be taken lightly, for they are likely to have significant impacts on the economy and environment. We must consider carefully the issues of redundant capacity and economic efficiency.

The Department has already devoted a considerable amount of time and effort to these coal transportation matters but, in view of the heavy emphasis the President has placed on this and the need to marshal our efforts in the most effective manner, I have established within the Department a coal transportation task force. It will be the duty of this task force to pull together what has already been accomplished, to identify gaps in the analyses conducted to date and to conduct further analyses and develop proposals and recommendations for my consideration.

Chester Davenport, Assistant Secretary for Policy, Plans and International Affairs, will chair the task group. Among the most important participants on the task force will be representatives from the Federal Railroad and Federal Highway Administrations.

We intend to complete our broad task force study and report our recommendations to the President before the end of the year. If we conclude that legislation is necessary to carry out any of our recommendations, we plan to provide those proposals to the Congress early in the next session. Of course, if we find that there is a need for immediate action before completion of the entire study, we will make our recommendations known at once.

Mr. Chairman, that completes my prepared testimony. Now my colleagues and I will be happy to answer your questions.

Mr. DINGELL. That will be quite appropriate.

Mr. MOFFETT. Mr. Chairman, before Mr. Adams leaves, there is just one thing that arose time and time again in my mind as we had the hearings in the last 2 or 3 days and that was the question of— number one, the transportation analysis coming after the plan is submitted and supposedly it is going to be complete some time off in the future, and along with that the question of, for example—I know in our own area, which you are very familiar with, the question of how the energy policy relates to what ConRail, for example, is doing right now in terms of abandonments, to abandon rail lines, for example, or to refuse to repair something like the

Poughkeepsie bridge because it doesn't seem to be a good business decision, if that is made in the absence of the need to transport coal, for example, I think it is unfortunate. We may look back in 5 or 10 years and regret that that happened.

Secretary ADAMS. We are very much aware of these concerns. As I indicated, we needed first to establish the energy policy and determine what the scope of the conversion from oil to coal might be. This has been done. That having been done, we have now analyzed to determine, in answer to your question, whether the transportation facilities are available to the particular areas where they will be required to meet coal conversion needs. We have made that examination and determined that they are adequate at this point.

Now, as we move in with the task force, we will be examining with groups such as ConRail and other eastern carriers, such as the Chesapeake and Ohio, and the Norfolk and Western, the means by which they intend to take coal from the mine mouth into the New England area. If we find those decisions are wrong in terms of what individual utilities or industries may have been doing, then we will take appropriate action to correct that.

As of right now, our system is functional and we have to follow closely the location of converting plants and see that the transportation facilities are available at the time or conversion. We are trying to avoid, incidentally, abandonment of specific lines that we know are going to be necessary for coal movement. That is a very difficult change in policy, particularly in the New England area.

Mr. DINGELL. Mr. O'Leary

STATEMENT OF JOHN F. O'LEARY

Mr. O'LEARY. Mr. Chairman and members of the committee, I am pleased to be here today to discuss the important and critical subject of coal utilization. I know this is a subject that you have been personally interested in for quite some time and I feel confident that the proposals incorporated in the National Energy Plan will remedy some of the problems experienced under the current legislative authority as well as provide a clear, consistent and comprehensive approach to the long-term achievement of several national objectives. The proposed program involves three of the major aspects of the President's national objectives: Coal utilization, conservation of our scarce resources, and maintenance of our environmental objectives. I firmly believe that these objectives are not mutually exclusive and can realistically be achieved to the satisfaction of all interested parties.

Demand for energy is increasing while the available domestic supply of oil and natural gas has been, and will continue to be, declining. To meet increasing demand, the United States has turned more and more to imports, which has resulted in increased vulnerability to supply interruptions. The principal oil exporting countries will have severe difficulties in supplying all the increases in demand which will occur in the United States and other countries through the 1980's. In 1976, the 13 OPEC countries exported 29 million barrels of oil per day. If world demand for exported oil continues to grow at the rate of recent years, by 1985 demand for OPEC production could reach or exceed 50 million barrels a day. Thus, it is essential that this nation reduce its dependence on imported oil by the mid-1980's and be assured that a return to increased dependence on imported oil will not occur thereafter.

The energy problem should be addressed comprehensively. Levels of domestic energy demand, domestic supply, and oil imports should be consistent with goals of public policy such as economic growth, security from supply interruptions, and protection of the environment. A comprehensive energy program must address the relationship between the use of imported oil and the use of other fuels. For example, since every additional barrel of oil the Nation burns is imported, initiatives directed at establishing rational gas prices and reducing industrial use of gas could result in increasing the use of oil and consequently our level of imports. Similarly, it was therefore necessary to develop our natural gas policy keeping in mind a number of important related objectives and limitations.

First, we need to move towards bringing supply and demand in the natural gas market back into balance. Second, the natural gas policy had to be designed to reduce the use of natural gas without driving up oil imports. Finally, the natural gas policy had to protect the consumers from higher natural gas prices while assuring the availability of adequate supplies and avoiding unnecessary producer profits from known reserves.

The coal use policies we are proposing are specifically designed to achieve these objectives through the related mechanisms of the natural gas pricing provisions, the new oil pricing policy and the oil and gas consumption taxes.

To achieve these multiple objectives, the plan has four major features:

Conservation and increased fuel efficiency.

Rational pricing and production policies.

Substitution of abundant energy resources for those in short supply.

Development of nonconventional technologies for the future.

Each of these four features is embodied in the three-part program that constitutes the proposed National Energy Plan for coal use. The three parts of this program are regulation, oil and gas consumption taxes, and financial incentives. Although this committee is interested primarily in the regulatory measures, I feel it is important to present the integrated program in order to explain fully each of the three parts of our approach.

Current and projected consumption of oil and gas by industry and utilities indicates the magnitude of the problem. In 1975 the Nation's industrial and utility consumption of oil was nearly 4.2 million barrels of oil per day and 11.9 trillion cubic feet of gas per year, for a total of 10 million barrels a day of oil equivalent. This represented approximately 25 percent total consumption of oil and 60 percent of gas in 1975. If there were no additional Federal programs, this consumption level would increase by 1985 to nearly 13.4 million barrels per day of oil equivalent.

The administration's proposed coal program will save approximately 3.3 million barrels a day of oil equivalent by 1985. The program deals with new and existing electric utility facilities, new and existing large industrial facilities, and takes into account the differences between existing facilities that are currently capable of burning coal and those that are not capable of burning coal.

The first area of consideration is new facilities. With respect to utilities, there are basically no new base load oil or gas plants currently being projected. I am concerned that needs created by any delays in planned coal or nuclear facilities would be filled by oil units. To assure that the current utility plans are in fact fulfilled, and additional combined cycle facilities held to a minimum, the administration has proposed that a blanket prohibition against new oil and gas electric utility facilities be placed in effect. There would be limited exemptions or exceptions from this blanket prohibition based on the use of the facility, unique economic conditions, and maintenance of reliability of service. In addition, there are some areas of the country where environmental conditions may preclude the conversion to coal.

In the industrial sector, only 10 percent of new boiler orders are being placed with coal capability while an additional 20 percent are designed to burn non-oil or gas fuels, such as wood chips. Our approach in this area is to have a blanket prohibition with certain exceptions and exemptions on the use of oil and gas in new industrial boilers but to have a case-by-case or categorial prohibition authority for non-boilers or combustors, such as furnaces, kilns and process heaters. It is the combustor area where we feel that more information and flexibility are required prior to fashioning an appropriate prohibition.

In the area of existing electric utility facilities, we plan to continue the existing coal conversion philosophy of focusing the regulatory process on only those facilities that are capable of burning coal. However, all facilities, with limited exceptions, would be required to cease the use of gas by 1990. It is felt that the 1990 timeframe is achievable with minimal economic disruption.

Similar prohibitions are provided for the large industrial users except that no finite date for eliminating the use of gas is included. In addition, there are no regulatory provisions for eliminating the consumption of oil in non-coal capable units. It is anticipated that the tax and rebate process will be adequate to accelerate the replacement of those facilities under the rational pricing system embodied in that tax approach.

The administration intends to achieve its energy goals without endangering the public health or degrading the environment. Utilities and industrial facilities will be asked to convert to coal without sacrifice of air quality standards. It is recognized that, in areas with serious air pollution problems, it may be necessary to continue burning oil in order to protect public health. A strong but consistent and certain environmental policy can provide the stability needed to encourage investment in new energy facilities. The administration has taken a position that all new facilities, including those that burn low sulfur coal, should be required to use the best available control technology.

As I stated earlier, although this committee is not primarily interested in the tax and rebate portions of the proposal, I feel it is important to discuss how this fits in with the overall objectives of the proposed coal program.

As we have learned from the current regulatory process, it is extremely difficult to determine solely by regulation what facilities would economically be switched to coal and over what timeframe this should be done without significantly injuring the economic viability of the company.

Industry, however, will generally act in an economically rational way if there is some degree of certainty in economic projections. Thus, it is very easy for a computer to decide to switch from oil or gas to coal in the middle 1980's if the computer has been told what prices it can expect for oil and gas at that time. It is this basic future determination of fuel value that underlines this oil and gas consumption tax concept; that is, the government would establish today a reasonable degree of certainty of future oil and gas values for use as a boiler or combustor fuel.

The program recommends that, starting in 1979 for industry and 1983 for utilities, a tax be placed on natural gas that over several years will be equal to the difference between the Btu equivalent of distillate oil and the price paid by the user for natural gas. In addition, a flat tax would be placed on oil of $1.50 per barrel for utilities. For industry, it would eventually reach $3 per barrel.

The tax would be imposed only on large users of oil and gas—those consuming more than one-half trillion Btu's per year. This will include only 2,000 industrial firms out of 100,000 in the Nation. It is estimated these 2,000 companies consume about 90 percent of all industrial oil and gas in the United States. As with other parts of the National Energy Plan, these taxes would be returned as rebates for qualified investment costs incurred in switching to coal or other fuels.

Utility companies and industrial firms would therefore have to raise sufficient funds to pay the oil and gas taxes. Having done so, firms would then decide whether to pay the taxes or use the money to make qualified investments, and the decisionmaking process in board rooms would be changed from whether to invest in coal facilities or not, to a new decision of whether to pay the Federal Government taxes or use these funds to invest in facilities to reduce or eliminate the use of oil and gas. For example, if a given company incurred $10 million of oil and gas tax liability in 1982 and expended $12 million in qualified investments in that year, the company would pay no taxes and would be able to carry the remaining $2 million over into the subsequent year to be used as a credit against that year's tax liability. However, if the company expended only $8 million in that given year, it would be required to pay $2 million in oil and gas taxes. Thus, companies aggressively making adequate investments would not pay any taxes but would, over a reasonable period of time, reduce their oil and gas requirements to a bare minimum.

An alternative financial incentive for industry would be the selection of an additional 10 percent investment tax credit, for a total of 20 percent, in lieu of the rebate. This option would probably be selected by new companies or single boiler companies.

In the utility area, a comparable rebate system would be developed whereby utilities accelerating the replacement of existing oil and gas facilities would receive rebates based on oil and gas taxes collected.

The administration's three-part program—regulation, consumption taxes, rebates—should go a long way in ensuring a proper balance between Federal regulation and free market decisionmaking. This program will also permit the Nation to reduce its dependence on oil and gas as a boiler fuel in a way as economically and environmentally sound as possible. The program is designed to encourge the use of new technologies such as low and high Btu coal gasification, fluidized bed combustion, and other technologies to burn coal in an environmentally and economically practical way It is established in a manner to return some certainty to the coal industry and to provide adequate lead time such that the necessary infrastructure can be developed consistent with the Nation's increased coal requirements.

Mr. Chairman, I look forward to working with you, the other members of the committee, and your staffs on the complex task that lies before us. The energy crisis is probably the most important domestic problem we will have to address during the next several years. It is a problem that will test our vision, our creativity, and our courage.

Future generations, including our own children and grandchildren, will look back at what we did in facing this problem. They will inquire whether we made effective use of the time available to us. It is, therefore, essential to have close cooperation between the administration and the Congress now while we still have time to deal with the energy problem in an orderly manner.

Mr. Dingell. Thank you, Mr. O'Leary.

The Chair now recognizes Mr. White.

STATEMENT OF PHILIP C. WHITE, PH.D.

Mr. White. The principal objectives of ERDA's coal program are to accelerate the development of environmentally acceptable technology for converting coal to liquid and gaseous fuels; and to develop improved methods for the direct combustion of coal; to foster the rapid development of advanced power conversion systems including magnetohydrodynamics for generating electricity from coal.

Coal conversion programs develop processes to convert coal into products that substitute for those derived from oil and natural gas. These substitutes include crude oil, fuel oil and distillates; chemical feedstocks; pipeline quality (high Btu) and fuel (low and intermediate Btu) gas; and other by-products, such as char, that may be useful in energy production. The liquefaction, high Btu and low Btu subprograms address the development of these products and their use in the market.

Coal gasification processes have been available as off-the-shelf technology for many years. However, today's technology is high cost and, in many cases, limited in the kinds and sizes of coal that can be processed. Therefore, this technology's capability to proceed to commercial applications is limited or nonexistent.

Second generation gasification technology is well under development at both the pilot plant and demonstration plant level. Low Btu gas is nearly economically competitive for certain applications with the direct utilization of coal where scrubbers are required for the generation of power.

The object of coal utilization programs are to develop processes in compliance with environmental regulations, to permit increased utilization of coal by direct combustion in electric powerplants, industrial/institutional boilers, and process heaters. This objective may be attained through improved direct combustion systems, advanced power systems with gas turbines, and magnetohydrodynamic electric power.

The direct combustion projects are aimed at developing methods for burning cleanly all ranks and quality of coal and, at the same time, improving the economics, efficiency, and reliability of converting coal to electricity. Advanced power systems involve improved turbine technologies which if successful will impact utility new plant equipment in the midterm (1985-2000). MHD projects are concerned solely with generating electricity via advanced techniques with potential impact in the 1990s.

In the short term, most coal will continue to be burned directly. The immediate priority is the development of more effective, economical methods to meet air pollution control standards. Some flue-gas desulfurization systems, or scrubbers, are already in commercial use. Work is continuing on overcoming generic operating problems.

In addition, increased research will be devoted to developing alternative means to control the fine particulate, sulfur oxide, nitrogen oxide and hydrocarbon emissions associated with coal burning. In many situations, front-end coal cleaning by grinding and washing can reduce the free sulfur and ash content and thereby reduce the cost of meeting environmental standards.

At the same time, research into fluidized bed combustion systems for the direct burning of coal in an environmentally superior manner is being expanded. The advantages to the fluidized bed boiler are: Sulfur dioxide and nitrogen oxide emissions are well within EPA standards; flue gas cleaning equipment is not required; low quality high sulfur coal can be burned; the heat release and heat transfer coefficients are high, reducing boiler size, weight and cost; multicell design lends itself to mass production; the overall operating efficiency of the plant is projected to be higher than a conventional coal-fired plant with stack-gas cleanup systems; the waste is a dry ash which is easier to dispose of than the wet sludge associated with present scrubber systems.

The principal projects in the direct combustion research and development subprogram are the fluidized bed boiler (30 MWe), the atmospheric fluidized bed component test and integration unit, and industrial applications.

The Rivesville facility is the first major step toward the commercial size central station power program. The combustor for Rivesville represents a building block for scaleup to 200 MWe and eventually to 800 MWe and is an essential activity supporting a planned direct combustion demonstration plant.

The atmospheric fluidized bed Component Test and Integration Unit (CTIU) will be located at the Morgantown Energy Research

Center to test new atmospheric fluidized bed combustion systems and components at an intermediate size scale and to act as an investigative facility for problems developed in the 30-MWe boiler test project.

Fabrication and field erection will start in fiscal year 1977 and operations will begin in fiscal year 1979. The CTIU will test improved solids handling systems, develop technology for vertical stacking of multiple beds, and serve as a boiler development laboratory to test tube bundle geometries and materials in operating fluidized bed combustors.

The industrial applications project will consist of feasibility studies and preliminary designs for industrial application of the atmospheric fluidized bed concept. This will be followed with design, construction and operation of prototypes on industrial sites for such purposes as captive in-plant generation of power, use of surplus heat for manufacturing processes, waste disposal, et cetera.

Five contractors, or groups, have been selected to test industrial heaters using atmospheric fluidized bed combustors at coal use rates ranging from 3/4 to 5 tons per hour. The objectives of these projects are to: Conduct evaluations to determine the applications in which fluidized bed combustion is technically, economically and environmentally feasible; and demonstrate the prototype boilers and heaters to establish the practicality of burning high-sulfur coals and other fuels for industrial applications. The data obtained from these efforts will assist industry in scaleup decisions for plant-size installations.

Other important projects in the development of technology for the direct combustion of the relatively abundant coal fuel resource include research into advanced closed cycle turbine design and projects to identify the problems and develop the procedures for the retrofit of current industrial oil burners for coal and coal/oil mixture burning.

In addition, a conceptual design for a direct combustion demonstration plant for base load central station application is underway.

To assist this subcommittee in this review, I have attached a table which shows the ERDA budget resources dedicated to coal technologies from fiscal year 1976 to fiscal year 1978.

[The table referred to follows:]

FOSSIL ENERGY DEVELOPMENT
COAL PROGRAM
FY 1976 - FY 1978 TOTAL FUNDING LEVELS
BUDGET AUTHORITY
(Dollars in Millions)

Operating Expenses	FY 1976	TQ	Estimate FY 1977	Estimate FY 1978
Liquefaction	$ 97.9	$ 26.4	$ 73.0	$ 107.0
High-Btu Gasification	53.4	9.3	44.0	51.2
Low-Btu Gasification	24.5	6.7	33.0	73.9
Advanced Power Systems	10.0	3.5	22.5	25.5
Direct Combustion	46.1	13.5	51.9	53.2
Advanced Research & Supporting Technology	35.4	8.8	37.1	40.0
Demonstration Plants	27.9	7.8	53.0	50.9
Magnetohydrodynamics	33.5	7.8	35.0	45.8
Total Operating Expenses	328.7	83.8	349.5	447.5
Plant and Capital Equipment				
Liquefaction				
Analytical Research Chemistry and Coal Carbonization Laboratory				$ 6.6
Demonstration Plants				
Clean boiler fuels demonstration plant	$ 33.0	$ 8.0	$ 30.0	
High-Btu synthetic pipeline gas demonstration plant			10.0	29.0
Low-Btu fuel gas industrial demonstration plant			7.3	36.0
Low-Btu fuel gas small industrial demonstration plants (2)				6.0
Fluidized Bed direct combustion demonstration plant				2.0
Solvent refined coal demonstration plant				2.0
Magnetohydrodynamics				
Component development and integration facility			5.0	4.2
Energy Research Centers				
Modifications and Additions			6.9	3.0
Other Capital Equipment			.3	2.4
Total Plant & Capital Equipment	$ 33.0	$ 8.0	$ 59.5	$ 91.2
TOTAL COAL PROGRAM	$361.7	$ 91.8	$409.0	$538.7

Mr. WHITE. We will be pleased to respond to any questions which you have.

Mr. DINGELL. Thank you very much, Mr. White.

Our next witness will be Mr. Woodworth.

STATEMENT OF LAURENCE N. WOODWORTH

Mr. WOODWORTH. Mr. Chairman and members of the subcommittee, I am before you today to discuss one of the most important aspects of the National Energy Plan. The coal and alternative energy conversion program.

Let me begin by describing the major aspects of the oil and gas consumption taxes and associated rebates. The program calls for excise taxes to be imposed—beginning in 1979 for industrial use and in 1983 for utilities—on business use of oil and natural gas. Oil will be taxed at a rate that will start at a relatively low level and will increase gradually until 1985. For industries generally it starts at $1.12 a barrel in 1979—in current dollars—and goes to $5.15 a barrel in 1985. For utilities it is $2.30 a barrel starting in 1983 and increases to $2.58 by 1985.

Now, these figures differ from figures you heard earlier but that is because I have expressed them in current dollars and I think the figures previously presented were expressed in 1975 dollars, so that accounts for the difference.

Mr. DINGELL. This is a more rational way that it should be done.

Mr. WOODWORTH. This is the figure that is more likely to be in existence when it is imposed.

Mr. DINGELL. These are the figures business would use to make judgments, am I right?

Mr. WOODWORTH. Yes. An inflation rate has to be assumed and it has generally been assumed at 5.5 percent.

Mr. BROWN. Could you also put these in total economic impact dollars? That is, how many billion dollars this amounts to?

Mr. WOODWORTH. I get into that to some degree a little later, Mr. Brown.

The tax on natural gas also will start at a low rate and gradually increase. The tax on natural gas will be geared to the difference between the user's average cost of natural gas and the price of number 2 distillate oil. When the tax is fully phased in in 1985, the effect will be to make the industrial cost of natural gas equivalent to the cost per Btu of number 2 distillate oil not including the oil conservation tax. Thus the tax will (1) eliminate the sometimes artificially low price of gas relative to oil and (2) gradually make both oil and gas more expensive relative to coal and other energy sources.

An integral part of the coal conversion program is the rebate of taxes on coal conversion investment. To encourage conversion to nonoil and gas fuels and also to lessen the economic impact of the oil and gas consumption tax, a business may offset investment in specified energy property—such as coal-fired boilers—against the oil and gas consumption taxes paid during the year. In effect this treats the taxpayer's investment in the specified energy property as a payment of his oil and gas consumption taxes for the year. The amount of investment treated as a payment of oil or gas consumption taxes may not exceed the taxes imposed for the calendar year. However, any excess investment not applied to offset taxes may be carried over and used to offset taxes in the next year.

As an alternative to the rebate, an industrial taxpayer may choose an additional 10 percent tax credit on his investment.

The basic rationale for the program is to provide an incentive for business users of oil and gas to switch to more plentiful energy sources such as coal. This will free up oil and gas for residential use where economic and environmental considerations often preclude conversions away from oil or gas use.

At the time the decision was made to impose the oil and gas taxes and rebates, it was recognized that the program would present problems for many taxpayers. As a result, first we have designed a program that will take effect gradually and mitigate any adverse effects. Second, we have provided a generous plan for the return of the taxes to the extent of investment in conversion equipment.

Third, we have provided a number of exemptions from the tax in the case of businesses that we feel will not be able to convert to more plentiful fuels. One of the exemptions provides that no tax will be collected for taxpayers using less than 500 billion Btu's of oil and gas per year, and the full tax is not levied until 1.5 trillion Btu's per year are used.

A second exemption is provided for gasoline or lubricating oil. Another is provided for fuel supplies for vessels or commercial aircraft. A fourth exemption is provided for taxes imposed on farming, or the production of ammonia for fertilizer. Finally, no tax is applied to the use of oil and gas in the production of refined petroleum products except when used as a fuel.

We estimate the net effect on receipts of the program to be a cumulative revenue gain, 1979-1985, of $40.9 billion. This figure is net of rebates—$44.2 billion—and reduced income tax liability due to the deductibility of the excise taxes—$5.4 billion.

I have been asked to comment on the economic impact of the coal conversion program and on its impact on specific industries. Secretary Blumenthal in his May 16 testimony before the Ways and Means Committee commented on the price impact of the program on various regions and industries. At that time he indicated the price impact on the six most energy intensive industries: paper, 1.7-2.6 percent; chemicals, 3.6-5.4 percent; petrochemicals, 6.2-9.3 percent; petroleum, 1.7-2.5 percent; aluminum, 4.7-7.0 percent; and steel, 1.7-2.6 percent. He also mentioned the impact on prices in the Northeast to be 1.0-1.5 percent and in the Southwest as 3.6-5.4 percent.

This material was supplied to the Treasury Department by the White House Energy Policy and Planning staff and by FEA.

Mr. DINGELL. Did I understand you to say the Treasury Department was the recipient of figures with regard to the economic and financial impact on different regions of the country from the White House?

Mr. WOODWORTH. From the energy staff in the White House, yes.

Mr. DINGELL. Isn't that a little curious? Isn't it usually traditional that the White House asks the Treasury for this information?

Mr. WOODWORTH. The energy staff did the basic research in that regard.

Mr. DINGELL. I am sure that is very nice, but it is a little at variance with the traditional practice, is it not? Don't they usually come to you and ask about the economic impact?

Mr. WOODWORTH. Of course, I wasn't in this position at the time the last energy bill was undertaken, but it is my recollection at that time that the FEA was the primary source of production figures with respect to the energy program. I think this is a straight continuation of that policy.

Mr. DINGELL. I will ask you at this time to submit that information to us that you received from the White House.

Mr. WOODWORTH. That is what I did right here in the statement.

Mr. DINGELL. I would like to have it in its whole form rather than bits and pieces. I would like to have you also submit to us for inclusion in the record the Treasury Department's analysis of these things so that we can understand what the Treasury says the facts are and I want you to understand that you were expressly instructed that you will submit to us the information directly and not through the tender hands of the Office of Management and Budget, or the White House.

I happen to have some distaste for the cooking of figures. We seem to be getting too much of that these days. It would be appreciated if you will make the information directly available. We would like to have the impacts as you see them and not what someone somewhere else might tell you you should see in them.

Mr. WOODWORTH. We will gather together what we can in that regard.

[The following material was received for the record:]

ECONOMIC IMPACT OF COAL CONVERSION

QUESTION: What is the economic impact of the coal conversion program? What effect will it have on the Northeast and the Southwest?

ANSWER: The coal conversion program will increase the overall level of industrial prices by 1.5 to 2.0 percent by 1985. Most of these increases will be concentrated in six energy intensive industries which account for nearly 70 percent of total industrial oil and gas consumption. The projected price impacts from these industries are summarized below:

Industry	*Price Increase in 1985*
Paper	1.7 to 2.6%
Chemicals	3.6 to 5.4%
Petrochemicals	6.2 to 9.3%
Petroleum	1.7 to 2.5%
Aluminum	4.7 to 7.0%
Steel	1.7 to 2.6%

The price impacts will be somewhat higher in the Northeast and the Southwest. It is estimated that industrial prices in the Northeast will increase 1.0 percent to 1.5 percent by 1985. The projected increase in the Southwest is 3.6 percent to 5.4 percent. The associated regional price impacts for the energy intensive industries are summarized below:

	Price Increase in 1985	
Industry	*Northeast*	*Southwest*
Paper	1.5 to 2.2%	5.2 to 7.8%
Chemicals	1.5 to 2.3%	5.3 to 8.0%
Petrochemicals	Insignificant	N/A
Petroleum	Insignificant	4.7 to 6.7%
Aluminum	Insignificant	13.6 to 20.4%
Steel	Insignificant	7.6 to 11.4%

The coal conversion program together with all other initiatives (i.e., rate reform) will reduce *utility rates nationwide by 1.5 percent*. The most heavily impacted regions would be *New England (1.0 percent increase)* and the Southwest *(4 percent increase)*. It is important to note that the conservation, peak load pricing and load management measures in the Plan tend to reduce rates.

Mr. WOODWORTH. It is not really possible to separate out the macroeconomic effects of the coal conversion program from the other elements of the National Energy Plan. We estimate that the plan as a whole will have no significant effects on gross national product or employment. The price effects of the plan are estimated as .3-.4 percent in 1978 and 1979 without the standby gasoline tax and .1-.3 percent in 1980 and 1981 on the same basis. The gasoline tax would add an additional .2-.3 percent to the rate of inflation.

That the oil and gas consumption taxes and rebate are significant elements in the National Energy Plan can be shown by the effect on imports. Of the 4.5 million barrels of oil per day saved by the entire energy program in 1985, 2.8 million barrels per day are directly attributable to the oil and gas consumption taxes and rebate.

Thus, the coal conversion program goes a long way towards achieving our goals of a less than 2 percent annual growth in energy demand by 1985, and a reduction of crude oil imports.

[The attachments to Mr. Woodworth's statement follow:]

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Estimated Revenue Impact of the Energy Program on Fiscal Year Receipts

($ millions)

		Fiscal Years								1978-1985
		1978	1979	1980	1981	1982	1983	1984	1985	
1.	Auto efficiency tax (effective September 1, 1977)	500 1/	500 1/	500 1/	700 1/	900 1/	1,200 1/	1,300 1/	1,900 1/	7,700 1/
2.	Crude oil equalization tax net of rebates (effective January 1, 1978)	499 2/	1,177 2/	1,914 2/	2,108 2/	2,053 2/	1,986 2/	1,919 2/	1,860 2/	13,516 2/
3.	Standby gasoline tax (effective January 1, 1979)	3/	3/	3/	3/	3/	3/	3/	3/	3/
4.	Residential energy credits (effective April 20, 1977 through December 31, 1984):									
	a. Thermal efficiency (insulation, etc.) 4/	-360	-445	-469	-494	-520	-550	-581	-517	-3,936
	b. Solar energy	-32	-68	-73	-59	-68	-86	-81	-99	-548
5.	Business energy credits (effective April 20, 1977 through December 31, 1982):									
	a. Thermal efficiency	-306	-307	-349	-428	-488	-317	--	--	-2,195
	b. Cogeneration 5/	-32	-62	-106	-157	-214	-139	--	--	-730
	c. Alternative energy 6/	-4	-9	-19	-33	-46	-28	--	--	-139
6.	Oil and natural gas consumption taxes -- rebate for investment in alternative energy facilities:									
	a. Tax, net of rebate: electric utilities (effective January 1, 1983)	--	--	--	--	--	86	123	101	310
	b. Tax, net of rebate: other businesses (effective January 1, 1979)	--	1,403	3,444	4,169	4,918	6,329	8,278	11,862	40,603
7.	Tax incentives for certain energy resource supplies (effective April 20, 1977):									
	a. Expensing of intangible drilling costs, geothermal discovery and development	-5	-10	-17	-21	-20	-20	-32	-54	-179
	b. Limitation of minimum tax on intangible drilling costs to amount in excess of net related income	-19 7/	-32	-37	-42	-48	-56	-65	-74	-373
8.	Aviation fuels tax revision (effective October 1, 1977)	44	47	50	55	61	66	71	76	470
9.	Revision of tax on gasoline for use in motorboats (effective October 1, 1977)	1	4	4	4	4	4	4	4	29
10.	Repeal excise tax on buses (April 20, 1977)	-13	-9	-9	-9	-9	-9	-9	-9	-76
	Total, excluding standby gasoline taxes	253	2,189	4,831	5,793	6,523	8,686	11,127	15,050	54,452

Office of the Secretary of the Treasury, Office of Tax Analysis

May 26, 1977

1/ Taxes shown will be fully rebated on the expenditure side of the budget.
2/ Taxes shown are net of refunds and income tax rebates and offsets and will be fully rebated on the expenditures side of the budget.
3/ Tax collected, if any, will be fully rebated. Collections after income tax rebate each year will range between zero and the following maximum allowable amounts: 1979, $0.9 billion; 1980, $2.0 billion; 1981, $3.2 billion; 1982, $4.4 billion; 1983, $5.6 billion; 1984, $6.8 billion; and 1985, $8.0 billion.
4/ In order to achieve the desired level of conservation, it may prove necessary to have mandatory standards affecting homes sold. The absence of any experience with the insulation incentives provided by this bill makes it difficult to estimate the level of insulation investment. The estimates presented here are relatively conservative. It is assumed that mandatory standards, effective January 1, 1980, would give rise to the following tax loss:

	Fiscal Years						1980-1985
	1980	1981	1982	1983	1984	1985	
Additional revenue effect	-43	-302	-395	-532	-835	-835	-2,942

5/ Includes effects of elimination of declining block rates.
6/ Coal conversion and solar equipment.
7/ For calendar year 1977, or fiscal year 1978, this provision is included in "The Tax Reduction and Simplification Act of 1977."

Oil and Natural Gas Consumption Taxes 1/

Relationship of Tax without Investment Rebate to Final Tax

($ millions)

	Fiscal Years							1979-
	1979	1980	1981	1982	1983	1984	1985	1985
Tax without rebate for qualified investment	2,745	7,555	10,499	12,467	16,467	19,235	21,566	90,534
Qualified investment rebate	-1,201	-3,675	-5,736	-6,880	-8,974	-9,700	-8,040	-44,206
Reduced industry income tax 2/	-141	-436	-594	-669	-878	-1,134	-1,563	-5,415
Net effect on receipts	1,403	3,444	4,169	4,918	6,615	8,401	11,963	40,913

Office of the Secretary of the Treasury
Office of Tax Analysis

May 13, 1977

1/ Industry and utility taxes.

2/ Results from less than full pass-through of tax to prices.

Crude Oil Equalization Tax

Relationship of Gross Excise to Energy Credits and Payments

($millions)

	Fiscal Years								1978-
	1978	1979	1980	1981	1982	1983	1984	1985	1985
Gross crude oil equalization tax collections	2,833	7,199	11,866	13,539	13,193	12,770	12,337	11,956	85,693
Refund for residential heating oil	-48	-362	-667	-957	-937	-909	-878	-849	-5,607
Reduced refiners' income tax 1/	-306	-968	-1,651	-2,038	-1,989	-1,927	-1,862	-1,803	-12,544
Estimated per capita energy credits	-1,980	-4,692	-7,634	-8,436	-8,214	-7,948	-7,678	-7,444	-54,026
Net effect on receipts	499	1,177	1,914	2,108	2,053	1,986	1,919	1,860	13,516
Amount available for energy payments (outlays)	499	1,177	1,914	2,108	2,053	1,986	1,919	1,860	13,516

Office of the Secretary of the Treasury
Office of Tax Analysis

May 26, 1977

1/ Results from less than full pass-through of tax to prices.

Mr. DINGELL. Thank you very much, Mr. Woodworth.
The Chair now recognizes Mr. Costle.

STATEMENT OF DOUGLAS M. COSTLE

Mr. COSTLE. Mr. Chairman and members of the subcommittee, thank you for the opportunity to appear before this subcommittee to present EPA's views on part F of the National Energy Act. We are, of course, primarily concerned with the environmental impact that any conversion program might have. Since Mr. Edward F. Tuerk has already provided the subcommittee with a technical discussion of potential environmental impacts, I will limit my statement to a brief discussion of the environmental policy implications of the plan.

The U.S. Environmental Protection Agency strongly supports the National Energy Plan, with its emphasis on both conservation and increased coal production. One of its basic principles is that increased utilization of domestic fuels must be accompanied by strong efforts to conserve energy and by stringent enforcement of environmental controls.

The adoption of the National Energy Plan would substantially increase coal usage—from approximately 600 million tons per year at present to about 1.2 billion tons per year in 1985, compared to expected coal use of about 1 billion tons without the National Energy Plan. With the increased coal use expected even without the Plan we would need to ensure that both new and old coal-burning facilities are sufficiently controlled to prevent an unacceptable increase of emissions. The further increase in coal use under the National Energy Plan will make vigorous and effective control even more urgent.

In the copies of this testimony that I have distributed, you will find three charts showing the effects on national emisions loadings the National Energy Plan and the administration's proposed Clean Air Act Amendments will have. These tables address the changes in emissions of the three pollutants whch will be most substantially affected by coal conversions: Particulates, sulfur dioxide, and nitrogen dioxide.

Mr. DINGELL. Without objection, these charts will appear in the record at the appropriate place

Mr. COSTLE. Thank you, Mr. Chairman.

While coal conversion would tend to increase emissions, the administration's energy plan also encourages energy conservation. Together with the administration's proposed changes in the Clean Air Act, these conservation measures would result in compensating decreases in emissions.

The energy conservation measures include peak load pricing, mandatory insulation standards for new buildings, mandatory standards for new appliances, financial incentives for energy conservation in existing buildings, and oil and gas pricing policies.

As shown in the table, if the plan's energy conservation measures and the Clean Air Act changes are enacted, nationwide emission levels will not be much different in 1985 than they would have been in 1985 without the adoption of the President's energy plan.

These conclusions are based on several critical assumptions regarding pollution controls.

First, as stated, best available control technology must be required on all new facilities.

Second, existing facilities must install equipment needed to meet current emissions limitations.

Third, the pollution control equipment must be operated and maintained properly. Basically, in order to avoid aggravating existing pollution problems through increased coal use, it is necessary to take measures to assure that stringent controls are installed and operated properly wherever possible.

Thus, the administration supports amendments to the Clean Air Act requiring the use of best available control technology [BACT] on new sources, requiring prevention of significant deterioration, disallowing credit for tall stacks as a means of meeting air quality standards, and establishing noncompliance penalties to eliminate any incentive to delay compliance or to operate or maintain pollution control equipment inadequately.

EPA specifically supports the House provision on BACT to reduce emissions from new coal-fired units. A new 1,000 megawatt coal-fired powerplant meeting the currently required new source performance standards [NSPS] would emit more than 28,000 tons of sulfur dioxide per year. If the same plant were to use locally available low sulfur coal to meet NSPS, and then also adopt BACT, emissions would be reduced by an additional 90 percent relative to the NSPS requirement. For a plant using 3.5 percent sulfur coal, the BACT requirement would reduce emissions by an additional 50 percent beyond the level resulting from the NSPS requirement. Particulate emissions for a plant using NSPS would be 2,300 tons per year. Using BACT those emissions would be reduced by at least 50 percent or 1,150 tons.

BACT controls will reduce the emissions from each facility, tending to mitigate the effect of any increases resulting from increased coal use. BACT controls will also increase the capacity to accommodate new industrial growth within the limits of air quality standards in areas that are in compliance with national ambient air quality standards.

The President also supports provisions requiring the prevention of significant deterioration [PSD] in areas of the country with air quality that is cleaner than now required by air quality standards. Specifically, this includes support for a three-tiered system for allowing industrial growth by different increments. The PSD approach supported by the administration will not place unreasonable constraints on new source growth, but it will provide pressure for more stringent controls on new sources. As with the BACT requirements, the stringent controls induced by the PSD requirement will tend to mitigate the effects of increased coal use in some areas.

The noncompliance penalties supported by the administration would provide needed incentives to install and properly operate and maintain required pollution control equipment. This incentive is needed to insure that the emissions reductions projected to result from the Clean Air Act and its proposed modifications actually occur so that increased emissions from increased coal use are minimized or offset.

The costs of these controls are reasonable in view of the environmental protection they will provide. EPA estimates that they will add a total of about $5 billion to the cost of new coal-fired powerplants by 1985 and about $12 billion in 1990. This cost will increase utility capital costs between 1975 and 1985 by about 2 percent and will result in average rate increases of about 1 percent nationally by 1985, with higher increases in some regions. The incremental capital costs of the BACT requirement for other industrial facilities will be about $4 billion in 1985.

The national emission loadings shown in the charts do not tell us very much about how coal conversion would affect the attainment of air quality standards in specific areas of the country. In some areas additional use of coal could make it difficult to reach the health standards. The National Energy Plan was developed assuming that significant coal conversions would not occur—, and should not be allowed—, in some areas due to environmental constraints.

The administration's coal conversion program provides adequate safeguards for conversions in nonattainment areas.

First, it allows exemptions from requirements to burn coal for new and existing units which cannot meet environmental requirements.

Second, it allows units now burning coal to burn petroleum if the State certifies that the fuel switch is necessary to meet air quality standards.

Third, it allows exemptions from requirements to burn coal for units for which the costs—including the cost of meeting environmental requirements as well as the costs of converting boilers—are excessive.

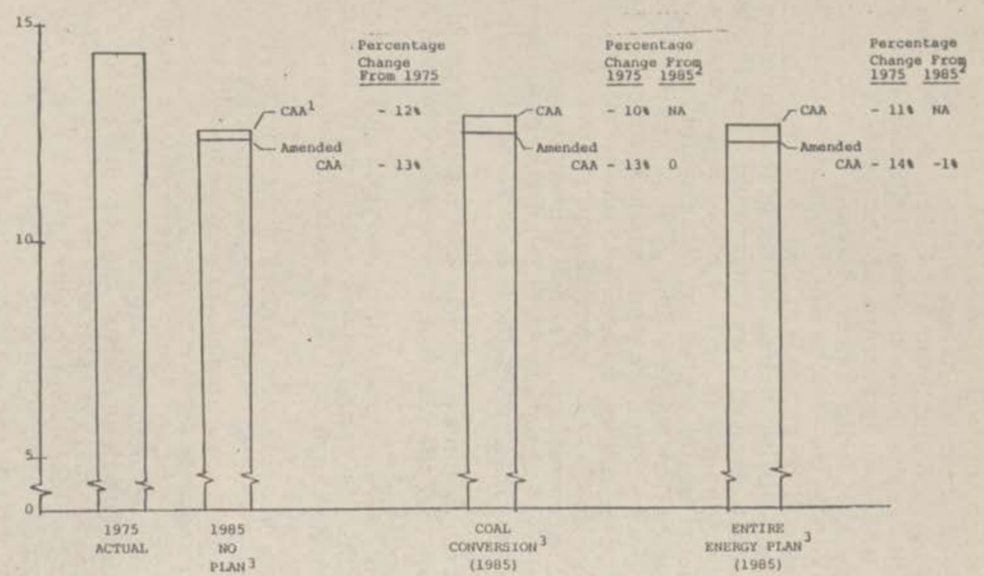
In addition, since about 90 percent of the sources affected by the coal conversion program will be required to undergo new source review, most of those in nonattainment areas will have to obtain offsetting emission reductions.

In conclusion, I believe tough environmental controls and environmental waiver provisions are absolutely necessary to protect public health. With those controls the potential for conflict between increased coal use and the environment can be minimized. I believe we can work together within the administration, with the State and local governments, and with Congress to ensure that the potential conflicts are worked out.

This concludes my prepared statement. I will be happy to answer any questions you may have.

[The charts referred to follow:]

TABLE 1 -- PARTICULATE EMISSIONS FROM INDUSTRY AND UTILITIES (National Loadings)



1/ CAA = Current Clean Air Act
2/ 1985 Assuming Amended CAA
3/ Assumes full compliance with applicable emissions limitations; comparisons with 1975 actual emissions may be misleading since the 1975 figure includes delayed compliance and the 1985 figures do not.

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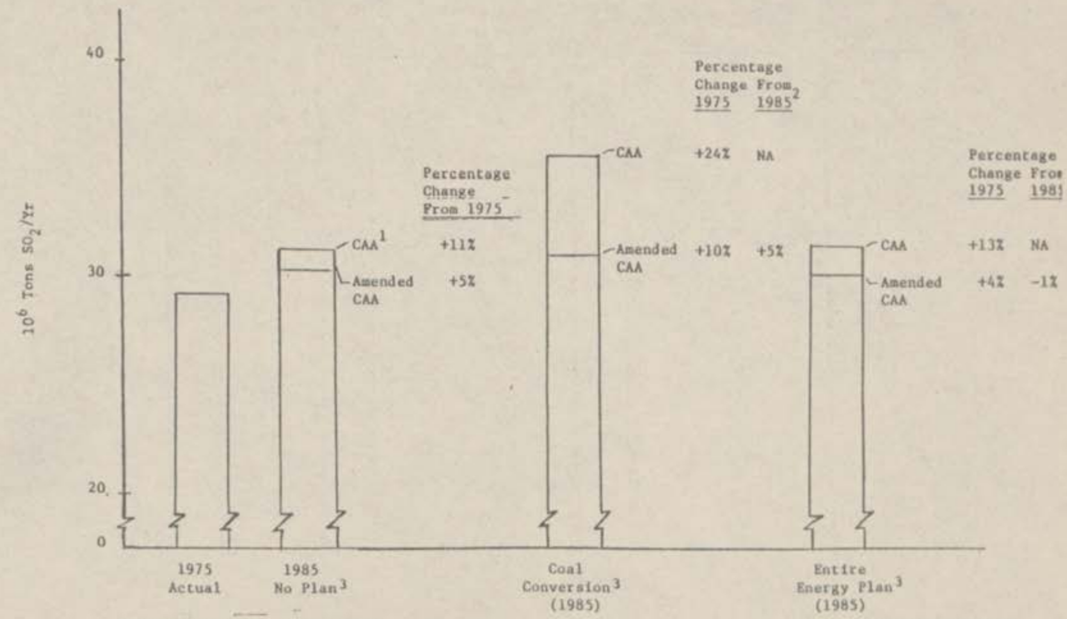
TABLE 2 -- SO_2 EMISSIONS FROM INDUSTRY & UTILITIES
(National Loadings)



1/ CAA = Current Clean Air Act
2/ 1985 Assuming Amended CAA
3/ Assumes full compliance with applicable emissions limitations; comparisons with 1975 actual emissions may be misleading since the 1975 figure includes delayed compliance and the 1985 figures do not.

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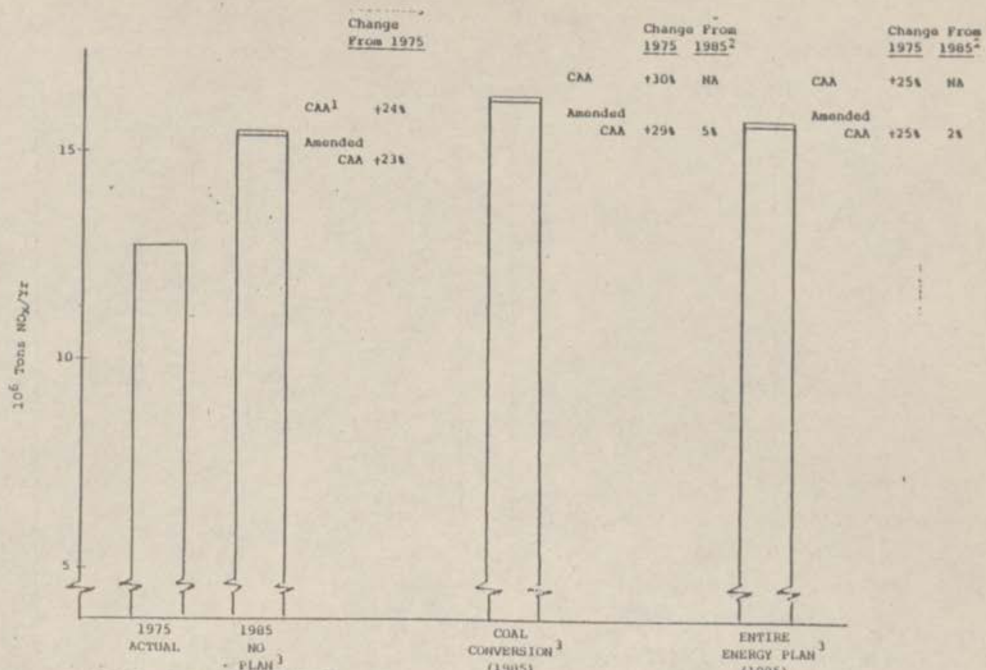

1/ CAA = Current Clean Air Act
2/ 1985 Assuming Amended CAA
3/ Assumes full compliance with applicable emissions limitations; comparisons with 1975 actual emissions may be misleading since the 1975 figure includes delayed compliance and the 1985 figures do not.

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Mr. DINGELL. Thank you, Mr. Costle. The Chair will recognize my colleagues for questions now, in the order they appeared.

The Chair observes the gentleman from Indiana, Mr. Sharp, was the first to arrive. The Chair also observes the stopwatch we usually use is not available, so we are using a device we borrowed from across the hall. I am told the bell rings very loudly.

Mr. SHARP. Thank you, Mr. Chairman.

Mr. White, I wonder if you could provide us, perhaps it should be in writing, a clear indication of each of the technologies you are supporting as to what the status is. You have given us some indication on one item that we can expect something by 1977 or 1979 but we would like to know whether or not we are talking about 15 years out or 20 years out on a real return on this; or whether it will be next year.

On fluidized gas yesterday we had a gentleman who was for industrialized boilers being used. He indicated they are available for industrial use but industry has not yet become accustomed with this. How does this square with your knowledge?

Mr. WHITE. They are available. These are small industrial boilers of the size we are using in the program, as I mentioned last in my statement. The basis of that program was to take clearly available units and show they could be operated and could handle different types of coal. They could also meet required standards and illustrate what the operating problems were.

There is an attempt in that program to familiarize industry with the applicability of this technique.

Mr. SHARP. If I were in industry and I wanted that information, when could I come see you people or get information from you with respect to this?

Mr. WHITE. I think I indicated those units are being designed now and will be operating, I believe, in 1979. It will be that long before the operation results are available.

Mr. SHARP. It would be in the early 1980s before anything is on line?

Mr. WHITE. There is no reason why one would not order one of these. Certainly by 1981 it could be put on line by anybody making a decision based on the information available in our program.

Mr. SHARP. There was a statement strongly urging greater attention to the high Btu gas projects and suggesting there has been a lack of commitment there.

Do you have any comment you would like to make about that?

Mr. WHITE. I can assure you we in ERDA are definitely committed to pursuing that plant. The contract for the first two design efforts on a demonstration plant is to be signed today and we are pushing to see what we can do in justifying a larger commercial-size demonstration as soon as we can.

Mr. SHARP. That decision is under consideration in the administration as to whether or not to go to a commercial size?

Mr. WHITE. Yes.

Mr. SHARP. That takes legislative action, does it not?

Mr. WHITE. Yes; it does.

Mr. SHARP. I would like to ask Mr. O'Leary this question.

One of the concerns raised in our hearings was that the utilities tax may well be passed right on to the ratepayer because of the few adjustment clauses which exist in some States and may not produce the incentive to conversion that you are hoping for.

What is your response?

Mr. O'LEARY. That is a concern and a legitimate one, Mr. Sharp. I think, however, that the pressure on the utility systems from public service commissions which realize the potential for pass through and can vote to stem this. Pass through combined, with the tax it receives will provide an effective incentive we have decided, although it is a theoretical concern. It will be a decision of the State utility commissions.

Mr. SHARP. Thank you, Mr. Chairman.

Mr. DINGELL. The Chair recognizes the gentleman from Connecticut, Mr. Moffett, for 5 minutes.

Mr. MOFFETT. I would like to direct my first question to Mr. Costle.

Your record in our State of Connecticut, with which I am well familiar, was one of doing everything within reason to prevent the air quality from being damaged. You are now in a position where you are assessing national impacts. I am glad you are, but one of the problems I have is that it seems to me that the EPA'a analysis thus far has been national only. We have heard testimony from EPA witnesses to the effect that what increased pollution or air quality damage may occur from the coal conversion program would be washed out by the benefits from conservation, such as the peak load pricing, etc. Those are voluntary, first of all.

I wonder how we can assess what those benefits will be if they are voluntary and where are the regional analyses and when will we see those analyses in order to make a determination as to how our individual regions are going to fare?

There is an EPA memo which has been cited by the chairman, from Mr. Drayton to you, which says: "We are currently planning to initiate a more detailed analysis of the nonattainment problem and coal conversion in several specific areas. These two study efforts should provide EPA with a detailed assessment of the air quality consequences of the energy initiatives before final energy legislation is passed."

The EPA is testifying as to impacts, pollution impacts of the coal conversion program. I am not sure from what I have seen, that there has been a regional analysis done nor am I sure that it is wise to make policy then determine the feasibility afterwards.

Mr. COSTLE. Mr. Moffett, if you recall, also, the basic—one of the basic underpinnings of the energy plan is that it will not require conversions where that detailed site-by-site analysis is done which indicates you can't do it without violating public health standards.

The ultimate protection is there, even though the analysis as to region is not available. They are going on. EPA is doing a lot of it and FEA is also separately doing work in this area.

There is no question but that there will be regional differences. One of the things we have discovered is that a lot of the whole AQCR's are located in nonattainment areas.

If you take the analysis down one more cut you may find within a 10-, 15-, or 20-mile radius you could locate a coal-burning source with adequate controls—that is terribly important—and it still would not violate an applicable health standard.

Mr. MOFFETT. As I recall, the bill calls for FEA to do all of that, not in consultation with EPA.

Mr. COSTLE. As to conversion, the particular problems which are unique, FEA does do that analysis. We can assist but we are and will be doing, along with the States, the requisite air quality analyses as to the impact of——

Mr. MOFFETT. The legislation doesn't assure that. Let us make that clear.

Mr. COSTLE. I am not aware that it is that ambiguous.

The legislation says that you have to meet all applicable air quality standards. Implicit in that is we have to analyze the conversions, that, in fact, those standards are met.

Mr. MOFFETT. I would just like to make the point, maybe I am missing something, but I don't understand how all this being done afterwards makes any sense. I think I, as a member, and most of the members are trying to bend over backwards to cooperate with the President's plan, but it is becoming difficult.

In looking at my region I find there is very little, if any, study being done as to impact on my region. I am being asked to go into markup on a very important portion of the President's plan without benefit of that knowledge; without a guarantee that this is being done.

It goes to the transportation question and my good friend, Brock Adams, I don't think he answered my question very well. I did not have a chance to tell him that, but I am troubled. It is becoming difficult to keep our enthusiasm to try to respond to portions of the plan.

Has my time expired, Mr. Chairman?

Mr. DINGELL. Your time has expired; but you were doing so well, I did not want to interrupt.

The Chair will request each of you, at your convenience, to submit the following information:

1. What consultation was made with you and your agencies by the White House staff in preparing that particular proposal;

2. What consultation took place between each of you and/or with the White House staff;

3. What information did you submit to the White House with regard to these matters;

4. What studies are ongoing in your agencies with regard to the points involved; and

5. When these studies will be completed and available to the committee.

I expressed the same concern as Mr. Moffett did, as you recall I had some trouble getting information on automotive emissions awhile back.

[The information requested may be found in the subcommittee files:]

Mr. DINGELL. The chair recognizes the gentleman from Michigan, Mr. Stockman.

Mr. STOCKMAN. It seems to me in the utility sector the factors are easy enough to undestand. The issues are pretty clear because you are dealing with a relatively low level of emissions and the economics really aren't all that complicated. There are large economies of scale of direct coal combustion when you consider the handling, and so on.

But it seems to me when you get to the industrial sector, the situation is different. I have read all the testimony we have received so far; I have looked at the information we have gotten from the administration and it still appears as one big black box to me as far as energy use. You are dealing with thousands of installations producing thousands of products. You are dealing with hundreds of end uses or applications for energy. I find in talking to industry people, the real cost is not on the purchase cost but it varies with the application and the requirements and calibrations needed in the end use. I want to give you one little example.

I visited a small foundry in my district sometime ago. Their end use is a cycle-firing process for a small melting furnace. They were in the process of analyzing whether to go with gas or electricity or combustion furnaces.

Gas was much cheaper as a fuel acquisition cost, but the problem they have is it is a cycle-firing process. They have to have a very high temperature. Since gas is a lot less flexible, they have to use a lot more units, even though the acquisition cost is low.

With the electric furnace, their problem with that is reliability. The technology has not been completely demonstrated. There is the trade-off use for fuel at a lower cost or less fuel at a higher cost with less reliability.

When you put all that together you have a complicated decision to make. This is a small foundry out in the hinterlands in my district.

Another thing most of the industries are involved in is a process which has a very complex mixture of fuels, again based on a complex set of economic decisions. I have a medium-sized foundry in my district that makes all kinds of products, primarily for the automotive industry. It uses 800 billion Btu's of energy per year. It breaks down to 36 percent natural gas, 34 percent coke, 35 percent electric, 3 percent oil, 5 percent propane, 1 percent gasoline. They have various types of equipment in just this one medium-sized foundry plant.

I bring all this up because that is how complex the real world is in terms of energy consumption. From what I know right now, I would hate to vote on anything which would give you the power to intervene with wide discretion in the industrial sector when we know so little as to what will happen and the kind of problems we will confront. So what I am asking for is a much more detailed and analytical base of data before we are even in a position to start marking up the bill.

I am wondering what you might have available that might help us in that regard.

Mr. O'LEARY. These were driving motivators behind the form of approach we took in the plan. With regard to existing industrial users of gas unless there is coal capability, they are not affected by the plan until 1990, at which point they have to be off the gas unless they meet an exceptions criteria. With respect to the processors, we don't have enough information to make a sensible regime. There is a blanket prohibition on——

Mr. STOCKMAN. You also use the word "combustors." It is not in the bill, yet you have strict regulatory authority as to this.

Mr. O'LEARY. That applies to equipment such as furnaces and heaters. In my prepared testimony this is mentioned.

Indeed, we share the same concerns that you do and feel we have to know a great deal more and approach this on a case-by-case basis before we can sensibly handle that part of the problem.

Mr. STOCKMAN. Wouldn't it be better to put a stay in that and give you more time to study that area so we can determine as to what areas we should delegate legal authority to the agency?

Mr. O'LEARY. No. We would rather have the authority now. The transition into abstract areas would simply postpone the effective date of the action. If we were to go into a 1-or 2-year study now, there would be a great deal of uncertainty with the final statutory role. I would rather have a rather broad mandate process to develop the regulations on a very broad basis of consultation as you may very well understand and, again, you must understand we have no intention, no desire, but absolutely no intention, as I think is manifest throughout the plan, of disturbing things. The principal thing which is the tax setup. We have adopted that approach after looking at two broad situations, one was to go into an intricate and highly complex system and attempt to regulate them.

The other was to take the broader approach and use the tax price to get the market working and get these billions and millions of decisions made on the basis of economic criteria. If you look at it in those terms, I think you will find it is really an acceptable and balanced package.

Mr. DINGELL. The chair recognizes the gentleman from Colorado, Mr. Wirth.

Mr. WIRTH. Mr. Costle, in your testimony you made reference to the fact that we need to be very careful we do not violate public health standards. I would assume there is a definition of what is an acceptable level of pollution in the air, how much at any time.

Mr. COSTLE. It is predicated on those ambient air quality standards.

Mr. WIRTH. But there generally is an acceptable level beyond which we can't dump any more stuff into the atmosphere, is there not?

Mr. COSTLE. What we are still wrestling with is whether the standards in some instances should not be tightened even more.

Mr. WIRTH. Given that basic minimum standard, will you do an analysis of the impact of yesterday's decision on the floor of the House on automobile emissions, the impact that it will have on the administration's coal conversion program?

Mr. COSTLE. Yes, sir, I will.

Mr. WIRTH. What is your hunch at this point as to what that impact will be?

Mr. COSTLE. The thing that concerns me the most about that is if the evidence which has been developed holds up, we will need a short-term standard for NOx, if it shows the real basis for a short-term standard is the peaking phenomenon associated with the automobile, as to NOx, that we have lost a measure of control over NOx at least in respect to an area where we know it can be controlled by essentially having relaxed our expectations in terms of what will be expected in NOx controls.

Mr. WIRTH. Can you convert that into numbers of tons per year of coal? When we relax the NOx standards to a certain point, that means we will burn less coal; we can't burn more coal to put more sulfur dioxides, in the air.

Mr. COSTLE. I could not speculate on figures off the top of my head but I will try to develop those figures and lay out all the information we have. There has to be some element of assumption in areas such as this.

Mr. WIRTH. Without the plan to increase to 10 billion tons a year. We are talking about a difference of 200 million tons a year. Would that 200 million tons by 1985 be made up for, or the reverse of that, by the decisions made yesterday on the floor of the House?

Mr. COSTLE. I couldn't tie to the 200 million tons. I would not speculate.

Mr. WIRTH. We may well be wasting our time in talking about this if the decision was made yesterday that we were going to go to auto emissions to get us up to capacity and we can't do any more with coal conversion. We may be stuck with that, or we may have to depend on the President to veto the bill so we can proceed with a long-term plan without the auto provisions we came up with yesterday.

It seems as though this committee and the administration have to develop that information as soon as possible between now and the time that bill arrives on the President's desk.

Mr. COSTLE. That is a question we have to look at and I will endeavor to provide the figures you request.

It is no secret I was worried as to the auto emissions decision yesterday. One principle you stated is important. That is we are dealing with a phenomenon where the air has the capacity to absorb only so much of the waste we put into it. We have to be sure we are not allowing a particular industry to prevent that capacity to absorb waste. I would have preferred to have seen a much tougher set of auto standards.

Mr. DINGELL. Have you any studies on the point you have just last been addressing, with regard to the automotive problems you have just been addressing? Are there any studies at EPA with regard to this matter?

Mr. COSTLE. I believe we have made available to the committee all the studies we do have.

Mr. DINGELL. With some difficulty.

Will you submit to us the studies on this particular point that you deem relevant to the discussion you just had with Mr. Wirth?

Mr. COSTLE. I will be glad to.

Mr. DINGELL. I have had some distress with your agency in bringing forth studies later to justify decisions already made.

The Chair recognizes the gentleman from Ohio, Mr. Brown.

Mr. BROWN. As I understand the National Environmental Policy Act, a major action such as this legislative proposal has to be accompanied by some kind of impact statement with reference to the environment to satisfy the law under the National Environmental Policy Act. Is there an NEPA statement on the coal conversion program?

Mr. COSTLE. No. I would like to point out I am not the final arbiter as to when there should or should not be NEPA statements. A legal opinion was asked of the legal counsel on environmental quality as to whether a statement would be required and the answer was no.

Mr. BROWN. Could we get that opinion for the record. Because it seems to me the coal conversion program is a major environmental policy decision by the Federal Government and the nature of the NEPA statement would be interesting and even more interesting would the decision that one was not necessary.

I would ask that opinion be inserted in the record at this point.

Mr. DINGELL. Without objection, the document referred to will appear in the record at this point.

[The information referred to had not been received at the time the record was closed.]

Mr. BROWN. In your statement you mention figures as to coal usage between utilities and industries. I am curious to know how much more is this in each category than would have been consumed without the program? In other words, without the legislative proposal here.

I will let you deal with your staff there.

Mr. White, I notice your interest in high Btu coal gasification. Last year President Ford proposed, and I supported, a synthetic fuels commercial demonstration program. Unfortunately, the rule was defeated, as I recall, by one vote.

What concerns me is that the budget authority attachment to your statement indicates a real decrease in high Btu gas. In view of your interest, why is this?

Mr. WHITE. That is our oldest program in energy. The pilot plants which were constructed out of operating expenses because they are transitory facilities, have been essentially completed.

Mr. BROWN. We have no more to learn on that subject.

Mr. WHITE. The funds required are significantly less than they were originally when we were building pilot plants a year or so ago. Two or three major pilot plants are now finished and are running.

Mr. BROWN. But is there no more to be learned?

Mr. WHITE. There is more to be learned.

Mr. BROWN. Are we ready to go to commercial usage?

Mr. WHITE. We feel the second generation work which has come out of this program is ready for demonstration. And we are having design work done on several of these approaches for demonstration plants which will be only about a tenth of the size of a full commercial plant. The only thing ready for the commercial plants is the existing technology such as Lurgi. It is the nature of the program. We can continue to learn and advance rather rapidly.

I have two tables that I would like to submit for the record.

Mr. DINGELL. Without objection, the papers will be received.

[The tables referred to may be found in the subcommittee files:]

Mr. O'LEARY. In the utility sector there will be a net saving entirely attributable to the program in the utility sector of the equivalent of 1.0 million barrels a day in the industrial sector.

Mr. BROWN. Million or billion?

Mr. O'LEARY. Million, and in the industrial, 2.3 million barrels for a total of 3.3, in my statement. Of that we will derive from existing facilities a saving of 1.5 and of facilities to be built between now and 1985.

Mr. Chairman, taking a look at it——

Mr. BROWN. I don't know how that squares with the limitations placed on new coal-fired plants under the present Clean Air Act.

Mr. O'LEARY. These are changes which are consistent with our perception of the air quality requirements, both State and Federal, over time.

The sectorizing is a 16 million tons of coal use, 177 million tons in the industrial sector for a total of 199 million which we have rounded to 200 million tons.

Mr. DINGELL. Mr. Costle, yesterday the counsel, at my direction, asked EPA witnesses to provide data concerning the amount of gas and oil used to incinerate sewager sludge. 1.2 billion Btu's of gas is burned in one area I know, for purposes of incinerating sewage sludge.

Earlier I wrote you about this and requested data on this so I would be able to have judgments as to whether or not we should be able to address this problem in the legislation before us. Can you tell me when the information on that will be made available?

Mr. COSTLE. It is my hope to get that information to you certainly by the end of next week. We have had to go to each of our 10 regional offices and collect and aggregate the information. Since I have put that information out, I have not gone back and cracked a whip on it, but I will do that.

Mr. DINGELL. Can you give me any horseback estimate as to the amount of gas and oil used to incinerate sludge or garbage in the country?

Mr. COSTLE. I can't.

Mr. DINGELL. Mr. O'Leary, do you believe we should use natural gas or oil for the purpose of incinerating sewage and sludge?

Mr. O'LEARY. I don't know enough about the technology to answer it.

Mr. DINGELL. Sewage has 8,000 Btu's a pound and coal 12,000 and if properly dried it can be burned nicely. Has any study ever been done as to this by EPA?

Mr. COSTLE. I don't know. But I will check. We have some experiments going on now. We have a sludge-burning operation in California. Sludge, in general, is a very difficult problem, as you, particularly, are aware. We do need to have a much closer way of looking at that.

Mr. DINGELL. Have any studies been made of this problem by EPA?

Mr. COSTLE. I am told there have.

Mr. DINGELL. Will you submit that information, please, so we can have those studies?

[The studies referred to may be found in the subcommittee files:]

Mr. DINGELL. Mr. Costle, what is the policy of EPA with regard to energy use? Do you have any written policy as to energy use within your agency?

Mr. COSTLE. It is not what I would call blanket policy.

Mr. DINGELL. Have you issued a policy statement on it?

Mr. COSTLE. I have not issued a policy statement.

Mr. DINGELL. Have any of your predecessors?

Mr. COSTLE. I will have to check the record.

Mr. DINGELL. Will you check the record to see if there is a policy statement in place, by yourself or any of your predecessors?

Mr. COSTLE. I will.

Mr. DINGELL. Can you inform us as to whether your agency should have a policy in place?

Mr. COSTLE. I certainly do.

Mr. DINGELL. What should that be?

Mr. COSTLE. I think in all that we do now—not just us, but the same phenomenon everybody is experiencing—we have to be more sensitive as to what the energy costs may be and they should be factored in.

Mr. DINGELL. Do you have a specific policy as to how this is factored into the judgments and decisions made by your agency?

Mr. COSTLE. I think I have answered that, Mr. Chairman.

Mr. DINGELL. Your agency is exempt by the National Environmental Policy Act which would require consideration of energy questions. Should your agency continue to be exempt from the consideration of energy questions?

Mr. COSTLE. Mr. Chairman, as I understand it, in our decisions now, when we make them, we do make an effort to lay out what the energy implication is as we think them to be.

Mr. DINGELL. You say you do lay them out now.

Mr. COSTLE. Yes, and I certainly asked that question myself.

Mr. DINGELL. Do you consult with FEA in making major decisions?

Mr. COSTLE. Frequently.

Mr. DINGELL. Do you do it at all times? "Frequently" indicates you do it some of the time and some of the time you don't.

Mr. COSTLE. Mr. Dingell, I obviously speak for myself. We have been working very diligently to develop a close working relationship with FEA since Mr. O'Leary and I have assumed our present positions.

Mr. DINGELL. Do you have a memorandum of understanding between your two agencies with regard to consultation.

Mr. COSTLE. I am not aware we have a written memorandum.

Mr. O'LEARY. No. We have no written memorandum.

Mr. DINGELL. Do you have a policy with EPA with regard to energy questions?

Mr. O'LEARY. From the very time we have entered office we have had a policy of consultation.

Mr. DINGELL. Who does the consulting?

Mr. O'LEARY. It is done at all levels in the organization.

Mr. DINGELL. You have told me you have no written policy, how do you know this is carried out?

Mr. O'LEARY. I am in constant touch with Mr. Costle and his staff and he with me and my staff. I continually interrogate my staff as to the degree of consultation they are having and I feel we are having a greater degree of consultation than at any time in the past.

Mr. DINGELL. Yesterday, the Washington Post contained an article, Mr. Costle, entitled "EPA: Coal Use Need Not Boost Pollution."

You indicated that industrial pollution from industrial coal burning could be offset by energy conservation measures. Mr. Costle, what is your view? Can we increase coal use without boosting pollution, or not?

Mr. COSTLE. You are looking at the aggregate loadings in the atmosphere. I think the President's plan does essentially manage that increment of increase. By load management, at least from the figures I have seen, they suggest by depressing the need for excess capacity and peaking power, production will, in fact, result in a net overall decrease in total atmospheric loadings.

As I said in my statement, Mr. Chairman, and I think as you pointed out in your opening statement, you can't finally decide where you can or can't burn coal until you get down to site-by-site analysis. Air quality region by region, State implementation plan by State implementation plan. That is the ultimate protection this plan affords. The plan does suggest in areas where it is clear we can't go to coal without causing damage to public health, those facilities should be exempt from going to coal.

Mr. DINGELL. In your statement you mention environmental constraints, et cetera. How was the decision made as to the areas affected and where studies should be made?

Mr. COSTLE. I think all we can honestly say is we used antidotal evidence and best judgment. For example, I would imagine it would be very difficult in downtown New York City to get an equivalent emissions control over coal sufficient to allow you to go to coal without a net increase in air pollution problems.

Mr. DINGELL. I wouldn't quarrel with that judgment but let me ask you, Mr. Costle, you indicated we can't allow this conversion in certain areas. If you don't know what those areas are, how are you to know whether we can meet our goal in coal consumption and coal use without information as to how you will increase fuel consumption in other areas.

Mr. COSTLE. You can't know precisely until you do that more detailed analysis. It does not, in my judgment, preclude some reasonable calculation and estimation. I testified to this fact before Senators Jackson and Muskie this week, that we think these are reasonable estimates, but at no time have we said we think they are concrete and absolute. We have conceded, frankly, from the outset, without the detailed site-by-site analysis, you can't pin the numbers down.

Mr. DINGELL. What you are saying is you don't have the information in this matter?

Mr. MOFFETT. Will the Chair yield?

Mr. DINGELL. Yes.

Mr. MOFFETT. Yesterday, as you may know, Mr. Ayres testified representing the environmental point of view. He attached a chart showing the increased emission. He said: "This is only a small sample of the conservation that would be required under the President's program, but these are the only ones we have data for and we can see from the environmental impact statements filed by the Federal Energy Administration on those programs that you would have a 108 percent increase in the Hartford-Springfield-New Haven area for sulfur oxide, 387—percent increase in Boston; 271 percent in the New York, New Jersey, Connecticut metropolitan area, and for particulates, as you can see, much larger increases yet."

Do you disagree with those figures?

Mr. COSTLE. In terms of what they sound like to me, assume plants only have to meet national air quality, the NAAQS. If you have to go back and realize also they have to meet applicable State implementation plans which look at all sources in an area and adopts a program, that could wash that increase from powerplants out.

Mr. DINGELL. The Chair recognizes Mr. Sharp.

Mr. SHARP. No questions.

Mr. DINGELL. Mr. Moffett, for 5 minutes.

Mr. MOFFETT. For a moment, if we could focus on the question I asked earlier, Mr. O'Leary.

Since there are some benefits we hope to achieve from the conservation plan to balance out the air pollution increases, which are voluntary, how do we assess those impacts?

If we are making the contention, as I understand it has been made, that the air pollution damage will be balanced out by conservation benefits, how do we get to that point?

Mr. O'LEARY. We are making estimates as to the penetration of coal into markets previously occupied by oil and coal and we are making estimates of the reduction of overall requirements attributable to the conservation program. These are made to the best of our ability and they do come up with the result that we have come up here, that you get a wash on the overall loadings. As Mr. Costle has indicated, there are uncertainties with regard to this. For instance, we would not know with absolute precision, as to whether or not we can cite a given plant in a given location until the two agencies have done the analytical work in both parts of the country. We can affect the changes as to coal. The bottom line on that is that we must do that without violating either Federal law or regulation or State law or regulation. If we did not have that kind of a restriction, the sky would be the limit; if we were not bound by constraints, we could put the whole country onto coal tomorrow morning. But we are faced with restraints.

Mr. MOFFETT. Mr. Stockman, I believe, expressed it pretty well earlier, how can we make decisions on what is best for our constituents in our particular areas and regions if we don't have the data in advance? I am not saying right down to every little detail, but I am at a loss; I don't understand how we can be expected to make those judgments unless we have a better idea as to how it will impact on our areas.

Mr. O'LEARY. The overall bound on that is the absolute imperative, that we not invade the areas which are required by the State implementation plans and the Federal standards. What that means is that in order to load additionally into your area, for example, there will have to be some other reduction in there, that will be a State decision and we simply can't analytically predict how the State will handle that problem.

So what we are saying is you have an absolute safeguard as regards air quality. We will not go into an area where we are in violation with either State or local law. In the inevitable role of the States you can't have the degree of certainty that either you or we would like.

Mr. MOFFETT. My problem is FEA ordered eight in Connecticut to convert, eight in Massachusetts to convert. If, in fact, the air quality impact is requesting to be so severe there is an enormous amount of cost in the meantime, which is passed on to consumers, we are going through what could be an exercise, do we have any estimate as to the cost of the industries fighting the plans for Northeast Utilities, as Mr. Costle and you well know, is now fighting the conversion orders. Is this a process which will go on and on through the exemption and exception stage inflicting a great deal of cost ultimately on consumers when, in fact, perhaps a determination could have been made in advance if we had taken a little more time to analyze the terms of the coal conversion proposals?

Mr. O'LEARY. We ran through 29 plants on notice of intent. When we went to the policy level with EPA, Mr. Costle had grave reservations with regard to the conclusion, because the staff had been working on the basis of existing SIPs and we knew there would be changes in the SIPs over the time of the conversion. That is the conclusion of the analysis. We dropped several plants out of the ordering series, where we are with regard to the orders now is both FEA and EPA believe we can go effectively to the conversion with some investment, of course, in clean-up equipment, in order to burn that coal acceptably, without doing any violence to the clean air requirements which are imposed by the State or Federal Government.

That is the absolute criteria. That is now being tested in hearings. The orders are not out on those plants. They will be out prior to June 30, depending on what we learn in the hearings now proceeding.

Mr. MOFFETT. Is it justified as to cost?

Mr. O'LEARY. It is required under the ESECA program that we have an understanding. Costs will actually decrease to consumers as a result of the conversion from $2 per million Btu fuel, to fuel costing roughly $1.25. There will be substantial fuel savings, offset to some degree by capital cost in equipment.

Mr. MOFFETT. Is there a cost analysis in this bill?

Mr. O'LEARY. There is a cost analysis required under our regulations and under the legal advice we have received.

Mr. MOFFETT. Not under the legislation.

Mr. O'LEARY. If not, I believe implicitly there is that kind of testimony, we certainly couldn't go in willy-nilly without it. We would be willing to review that with you.

Mr. MOFFETT [presiding]. The chair recognizes Mr. Stockman.

Mr. STOCKMAN. On the question of the impact of auto emissions by going to the more reasonable NOx standards that we adopted yesterday for tailpipe controls, whether we are going to sharply constrain the amount of coal conversion which can take place because of the ambient NOx loadings are a function of two variables of which I am sure you are aware. No. 1, the emission per mile of the tailpipe and, No. 2, the number of total miles traveled for the total fleet, for the total year. No. 1, you can maximize tailpipe controls and put our environmental and energy controls in conflict, because there will be fuel penalties and higher costs. The second alternative strategy would be to minimize vehicle miles traveled. When you do that, you put the two objectives in harmony. You will avoid fuel penalties and extra costs to consumers for the capital addition to the powerplant.

I want to suggest to you that on the basis of your data in the March 21 study, I did some crude calculations. I think they are in the right range. The early 1970 auto fleet was putting out about 4.1 billion kilograms NOx per year. If we went to a .4 NOx standard, as in the committee bill, by 1990, and assuming we had a historic growth rate of 3 percent through 1990, or 2.3 billion kilograms of NOx—a 44-percent reduction, that is important. That gives you some health benefits and room for other sources. However, you could get the same result with the NOx standards in the Dingell bill in combination with the 1 percent growth rate. The annual loading into the atmosphere would go down 35 or 40 percent.

I am not talking about reducing only the growth rate in NOx. The fact is, there would be some additional gains from it. You would save about $20 billion to $30 billion to consumers in the economy. You would save about 880,000 barrels a day of oil because you would have less consumption by the vehicular fleet. You wouldn't have fuel penalties; and, finally, you would avoid a lot of inequity in the country.

The ultrastringent approach to tailpipe control is supposedly to deal with the NOx problem. But that is a thinly disguised effort on the part of highly congested urban areas to impose the cost of their environmental control and their privilege of traffic congestion and sprawling suburbs on the rest of the country, where we don't have the NOx problem.

I would like to ask whether your agency can provide for us some alternative scenarios for 1989 and 1990, based on tailpipe strategies and the loadings into the environment, so we could see the health benefits and, also, the room we would open up for emissions from stationary sources.

What I would also like to ask is how this interfaces with the administration's gasoline strategy.

It seems to me if your program in that area works as intended, we are going to have an automatic reduction of loadings because of the lower vehicle mile growth rate. Qualitative indications on the policy would be necessary in order to bring about various vehicle mile growth rate. These are things we can do to constrain traffic.

I wonder if you have any comment now and if you can supply some of this information for the record?

Mr. Costle. My own judgment is that particularly as to the NOx problem, the National Academy of Sciences requires that there be a short-term NOx standard to deal with the peaking problem.

Mr. Stockman. That is a function of differance in amounts of travel.

Mr. Costle. I have a strong hunch, and I will do these calculations, that you are going to effectively need to have both in order to deal with the problem. In other words, neither strategy by itself would be wholly effective.

I would also point out, if you take the existing tailpipe technology and you try to ram that through tighter and tighter, you are going to suffer a fuel penalty. If you are talking about advanced technologies with fuel electronics, three-way catalysts, you are not necessarily talking of a fuel economy penalty.

In fact, in terms of the cost of that technology, many of the components that would have to be a part of that technology package, in our judgment, would essentially be components required for fuel economy purposes, in any event, so it's not so black and white on the cost or the fuel penalty.

The other thing that distressed me about the numbers that were adopted yesterday is that you have to make some pretty Herculean assumptions about end use compliance, and quite frankly the auto companies aren't measuring up in terms of end use performance as to what is going to be required for those numbers, in fact, to achieve the increments to clean up we would hope.

Mr. STOCKMAN. I realize my time has expired, Mr. Chairman, but isn't it true that the tighter the tailpipe control you go to the greater the problems you are going to have with end use compliance, because you are going to have far more sensitive equipment, you are going to require much great calibration of the air-fuel mix, and so forth, so the tighter you go the greater your compliance problem. I think the point you raise is exactly pertinent to the general issue I am talking about, in fact, it reenforces the position that there are certain economic and other limits to going down to the bottom line on tailpipe controls. Isn't that true?

Mr. COSTLE. I am inclined to think at least on the engineering studies I have seen that electronics is not, in the case of the automobile, is not some exotic outer space kind of technology, and I frankly think there has been a little bit of overselling on the complexity of what they will be asked to do.

That is not to say they would have been asked in our proposals to do something simple, and it's not to say they shouldn't be given a fair opportunity and time to do it, but I guess my judgment is that we didn't ask them to do enough yesterday.

Mr. MOFFETT. The gentleman's time has expired.

The Chair recognizes the gentleman from Colorado.

Mr. WIRTH. Thank you.

Mr. Costle, I think it's fair to say I agree completely with what you have said this morning related to yesterday's decision, and I think what is coming out in the discussion between you and Mr. Stockman and you and Mr. Moffett, and my earlier question, is that the decision yesterday is going to come back again and again and again as we focus on a national energy policy; as we focus on the need for coal conversion and on the economics of the issue, and I would hope other industries in this country are going to recognize the fact that one industry has gotten away pretty clean in this operation and the burden is going to come to rest on others, much more sharply than I think we would like to see, and we are going to maybe see a litte bit of breaking of ranks on that when they come to recognize what happened yesterday, if, in fact, that decision holds.

When I asked you briefly before the statement you made earlier, Mr. Costle, on coal conversion, that if the Federal Government requires in certain areas States to pollute more or to allow more pollution, that means State standards on other effluents are going to have to come down; right?

Mr. COSTLE. That is correct.

Mr. WIRTH. What if States can't do that or refuse to do that? What do we do then?

Mr. Costle. Then I think we are between a rock and a hard place.

Mr. WIRTH. Is there then an authority to require a State to do that or what do we do at that junction? We have let the one trade off the hook, over here we are requiring coal conversion and somehow the public service company in Colorado has to cut way back in an impossible way.

Where are we at that point? Who has the authority to step in?

Mr. COSTLE. I think those are precisely the kinds of issues, along with individual cost factors in a given plant, there are a whole range of issues that are likely to be, and are, in fact, drawn into this plan to be required to be considered before you make final decisions to convert.

I don't think the plan is attempting to ram a conversion through, it's attempting to provide a process by which you can look at all these factors and recognize right now we don't know enough about every street corner in America to say a plant could or could not be converted and located on that street corner.

Mr. WIRTH. I think that is a fair statement.

Let me ask a follow-up question on the exchange between I believe you and Mr. Moffett related to costs.

As we look at the analysis of yesterday's decision on the floor of the House in relation to clean air standards, you were going to supply us with some of the trade-offs in terms of air pollution, and the other variables that were going to be involved in that, and how much coal might be prohibited from burning because of yesterday's decision.

Could you also give us a sense of what the economic costs are going to turn out to be? I mean, there is much ballyhooed discussion about the costs of controlling tailpipe emissions, as if that is going to provide a horrendous cost to the American consumer.

I think what Mr. Moffett was trying to get at was what are some of the other costs that are going to be entailed now that we have made the decision not to impose those costs on tailpipes, what is the trade-off going to be in terms of higher utility rates and so on?

What are some of those other variables that we can understand at this point? It seems to me it's terribly important that you and Members of this Congress understand those trade-offs as well as the enviromental trade-offs. So, would it be possible for you as quickly as possible to put together that kind of information? I think that is consistent with what you were asking for, Mr. Moffett, as well.

Mr. COSTLE. We will certainly endeavor to pull that together.

I can't anticipate what difficulty we will have trying to make those computations, but I would like to see them too.

Let me make one observation if I can, Mr. Wirth. There is no question that the costs of controlling NOx from a tailpipe is going to be cheaper than a controlling of NOx from stationary sources.

Mr. WIRTH. Could you repeat that?

Mr. COSTLE. My understanding of it is the cost of controlling NOx from the tailpipe is cheaper than the cost of trying to control NOx from industry, industrial sources.

Mr. WIRTH. Do you have data that backs that statement up?

Mr. COSTLE. It's possible to make some rough calculations, and as I say, I am expressing my judgment on this and I will try to supply actual figures.

Mr. WIRTH. In other words, the American consumer, who was threatened yesterday by all kinds of discussion on the floor of the House about how much more expensive his automobile would be, is, in fact, ill-served by the decision made yesterday, in your opinion?

Mr. COSTLE. In my opinion.

Mr. WIRTH. And, in fact, would be better served by controlling pollution on the automobile than by controlling it as we are going to be forced to do it now in industrial fashion; is that correct?

Mr. COSTLE The basic problem we have in trying to control it in industrial sources is we don't know how in industrial sources, and the kind technologies that might emerge over the next 5 to 10 years, are likely to be, or could certainly be very expensive kinds of technologies.

Mr. WIRTH. Mr. Chairman, might we leave the record open to have that information provided to members of the committee as quickly as possible as well?

Thank you very much.

Mr. MOFFETT. Without objection, it will be left open.

[The information had not been received at the time the record was closed.]

Mr. MOFFETT. The gentleman from Indiana, Mr. Sharp.

Mr. SHARP. Thank you, Mr. Chairman.

I would like to ask Mr. Costle, doesn't fluidized bed combustion provide a way of handling NOx in many instances in the utilization of coal in industrial boilers?

Mr. COSTLE. Mr. Sharp, as I understand it, that is probably the one parameter in combustion that we have the most difficulty with in going the fluidized bed combustion route. In terms of SO_2 particularly there are really substantial gains to be had, and I think that is a promising technology. I think it may be possible in the case of fluidized bed to improve the NOx situation.

As I understand it—and I would have to check this to be absolutely sure—my impression from conversations I have had with the engineers on this is NOx is still a bit of a problem in the case of fluidized bed and I could not tell you off the top of my head, frankly, what the problem would likely be with say low Btu gas in that area.

Mr. SHARP. This is very important.

Mr. COSTLE. If you are talking about the application of stacked gas controls for NOx, we just don't have technology.

Mr. SHARP. I understand that. We are talking about the potentiality of new systems of combustion here, new ways of doing that. That is the same thing we are talking about with the automobile, new ways of doing things, and you are making the claim, and if it's a wise one we would like to know about that, that there is a major trade-off in costs here. That is what the gentleman from Colorado has indicated, that is what you have agreed to, and what we would like to see is some documentation on what can and cannot be done in the industrial sector with stationary sources on the question of NOx vis-a-vis what can be done on the automobile.

The question is coming down to the trade-offs among various sections of the economy on this issue, the question is coming down to trade-offs between air quality questions and energy and very complex, in very complex ways, and one of the difficulties we have with which we are confronted is the most incredible conflicting claims and very little data.

It's getting down to where we make the judgment and that may be the nature of things, we will never have the data, but if that is the case then I don't think the authority of every governmental agency ought to come down on the side of something on the presumption there is a major analysis and data behind it.

Mr. Stockman. Will the gentleman yield?

Mr. Sharp. Be happy to yield.

Mr. Stockman. Just to reenforce a comment about conflicting claims, if my memory is correct, last year's task force on motor vehicle goals indicated a cost per ton of NOx reduction of $2,300 per ton for tailpipe controls, and $100 per ton for new utility boilers, which is exactly the opposite of what has just been indicated. So, it seems to me we have mass confusion and contradiction on this issue. In supplying this information, and I would hope the gentleman would agree, maybe you could provide a critique of those numbers from the previous work that was done by the task force, and say why they are wrong.

Mr. Costle. I certainly will, and if I have misspoken on that I will state that clearly, but what I have in mind is the fact NOx is a problem for virtually every fuel burning source, and the costs are going back to deal with every industrial source in some gross application of control technology. I think it's going to turn out to be exceedingly expensive, if we even knew how to do it. That is probably the threshold question.

Mr. Brown. Will somebody yield?

You say you don't know how to do it in the stationary sources. But you do know how to do it in the mobile sources. Yet, this legislation encourages a move to stationary sources that have an increased NOx emission, isn't that correct? I mean, the one we are talking about right now, the coal conversion?

Mr. Costle. That coal conversion program adds only incrementally, and if I recall the figures——

Mr. Brown. But coal has more NOx in it than gas does, doesn't it?

Mr. Costle. In moving the emission loading, the increment, without the energy plan, without the President's coal conversion program, is a very substantial increase in NOx emissions. It's on the order of 25 percent. Coal conversion adds incrementally to that under the President's plan.

Mr. BROWN. Four times per Btu, isn't that right?

Mr. COSTLE. The basic point here about NOx—and it's one we are going to be dealing with for years ahead—is we have, irrespective of the energy plan, we have a base problem of increasing NOx emissions that are not being controlled in the industrial arena, and it's on the order of 25 percent, forgetting the national energy plan.

Mr. BROWN. With the national energy plan there will be more, I guess that is what I am trying to say.

Mr. COSTLE. The additional increment is on the order of 4 or 5 percent.

Mr. BROWN. Four times on any plant for Btu, any plant you convert from gas to oil?

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes now the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Just as the other gentleman tried to help you, Mr. Costle, with the information about moving sources, I want to help Mr. O'Leary with some information about the costs Mr. Moffett is asking about of conversion.

Testimony before this subcommittee from boiler industries estimated that the cost of conversion required by this legislation of boilers and the testimony came from the American Boiler Manufacturers Association, would be $50 billion, exclusive of pollution controls.

In the paper industry I think there have been 15 plants for 10 companies that have already had notice of intent that they have to be converted, and the cost there will be something like $700 million just for those plants, so that is a beginning on providing the figures to Mr. Moffett on what the cost of conversion will be.

I think there is a generally held misconception that you can take a gas fired or oil fired burner and just simply take out the gas and put the coal under it, and produce electricity or whatever it is, heat with coal. You have to undo and redo the boiler system too, and that cost is rather massive.

The Mississippi Public Utility, which testified before us, I think yesterday or the day before, indicated that the impact of this will be to increase the cost of electricity to consumers in Mississippi something like 300 percent, so the cost of this, never mind all of the hokey-pokey with the taxes and the rebates as they might be passed or might not be passed by the Congress, is going to be rather impressive.

I would hope we can get those figures.

Let me just say to Mr. Costle I think he misspoke to one of the other gentlemen on the panel. The previous law, ESECA, which is in effect now, I should say, put the burden on the Administrator of FEA to prove the need for conversion from gas and oil to coal. The present law puts the burden of proof on the plant, the present law proposed puts the burden of proof on the plant to prove that it need not convert.

Isn't that correct? The present law before us, the proposal before us does this?

Mr. O'LEARY. Yes.

Mr. BROWN. In effect, if we pass this bill, the Administrator will have the power to make the conversions and then the individual industry, or whatever it is, has to prove they don't have to.

Now, I want to go to Mr. Woodworth, if I can, and ask what are you going to do with all of the money left over from all of these taxes?

I understand from Mr. Blumenthal testifying before the Ad Hoc Committee that when all of the taxes are in place the gross taxes will be something like $100 billion a year, the equivalent of a 25 percent tax increase.

For instance, what is the justification for the tax increase on processed users of natural gas? I understand that this may be as high as 35 percent of all of the industrial use of gas. Obviously, the taxpayer is going to pay for the boiler conversion, because the company will get some kind of a rebate for the boiler conversion if the taxes and rebates are all passed. That is a conversion. On new boilers, of course, the consumer will pay.

If Mississippi has to add a new boiler for a new plant, there is no tax rebate, and of course, if you tax processed gas, by then the taxpayer, consumer, is going to pay for that and the additional cost of the product processed by that process system, I guess that shows you are going to get about $12 billion a year out of it. I mean the Federal Government is by 1985, I assume, from those people who cannot convert; is that right?

Mr. WOODWORTH. The figure as to the amount that does obtain from these taxes by 1985 is close to around $12 billion, yes. The problem, however, overall, does balance out, which is I think actually the figure of $100 billion you mentioned in terms of gross is small, it's quite a bit bigger than that.

Mr. BROWN. Can you give me the figure?

Mr. WOODWORTH. I can't offhand, but I can supply that figure for the record.

Mr. BROWN If you would, because now that comes out of somebody's pocket first sort of like how much we all pay on April 15, we may not think of it in terms of how it comes back to us, and in terms of subsidies for mass transit or local public works facilities or revenue sharing or something else, but what we pay as taxpayers, as individual taxpayers, is $250 billion out of our pockets, and I guess in terms of these additional taxes we are going to pay plenty, and I would like to know what that is.

Mr. WOODWORTH. A very large proportion is rebated under one system or another directly back to the taxpayer.

Mr. BROWN. With all due respect, Larry, I have a great deal of respect for you and I understand your disclaimer on page 2 that these figures came from somebody else. But I would sure like to know what the total take is, and then what the total rebate plans are. No place in the months since this system has been proposed—a month and several days—have I seen a total tax take figure, and a total discussion of how much money is put back.

That is what worries all of us who have to vote on this, just as the gentleman from Indiana indicated. We get a lot of fancy footwork but we have some difficulty getting the facts, and I understand the problem that you are in, I think, but I would sure like to have a balance sheet on the total program and nobody has presented that.

I asked Mr. Blumenthal for the gross figure. He said he couldn't give me that, that he could only give me the net, and my question was how do you get the net without knowing the gross? Now, I would ask you the same question. I don't know where he went to business school but when I was trained you had to get the gross before you figured out the net, I just don't understand that.

Mr. WOODWORTH. I have no trouble getting the gross figure.

Mr. BROWN. I think that is the way the Ways and Means Committee used to operate when you were counsel. I would like to get the gross and net and explain to me in between and maybe I can understand, but I sure don't understand the way it has been submitted.

Mr. DINGELL. The Chair observes the time of the gentleman has expired. I am sure I want everybody to understand that is how this subcommittee runs. We are going to try to get the gross and net in the proper order.

Mr. Woodworth, if you will make the necessary submission at this point, the record will be held open.

Mr. WOODWORTH. I will be glad to do so.

[The following information was received for the record:]

The total gross revenue impact of the tax aspects of the program would be $132.0 billion for the period 1978 to 1985.

This number is arrived at by using the figures in the summary table [1] for items 1, 3-5, 7-10, and adding $85.693 billion gross tax for the crude oil equalization tax and $46.328 billion for the oil and gas consumption taxes (tax net of rebate). Since the netting of the oil and gas consumption taxes and rebates for investment in alternative energy facilities is done by the taxpayer, the Treasury would never see more than the $46.328 billion excise figure. This assumes no impact for the standby gasoline.

Mr. DINGELL. The Chair has a few questions here I want to ask and then we are going to ask counsel.

Mr. Costle, you indicated you have no in-house policy statement with regard to energy conservation.

Mr. COSTLE. That I am aware of, Mr. Chairman.

Mr. DINGELL. Can you advise us how you are going to establish an energy policy without some, on this point, without some statutory direction, in view of the large number of other programs which fall withing the purview of your agency?

Mr. COSTLE. Mr. Chairman, I think throughout a lot of the law we now administer we are required to look at certain things, and increasingly these laws are being amended to specifically require consideration of energy.

For example, in BACT, which you voted on yesterday, as I recall we are specifically directed to consider cost and energy in determining what the BACT is.

Mr. DINGELL. But for purposes of your administration of your agency, I think if you are to do this you ought to have some mandate as to how you are going to conduct your affairs with regard to energy conservation, should you not?

Mr. COSTLE. I would suspect we could go through the law and there is probably sufficient mandate there.

Mr. DINGELL. We have been functioning a great deal of late on suppression, and I am trying to have this committee function on fact, and I hope you don't differ with me on the idea we should do that.

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[1] See tables attached to Mr. Woodworth's prepared statement, p. 746.

What I am asking you is this: Do you have any objection to having a clear mandatory instruction that your agency and all other Government agencies should consider energy impacts as you go forward?

Mr. COSTLE. No, I don't object to that, Mr. Chairman. I think it's already there.

Mr. DINGELL. I function a great deal on faith, hope, and charity, but when I deal with Government I don't have too much of any of them.

I would like to direct this question now to Mr. O'Leary.

Mr. O'Leary, do you feel that there should be a general mandate to Federal agencies that they should consider energy questions in connection with the judgment they are making?

Mr. O'LEARY. Mr. Chairman, I think that is an appropriate element of any policy, and I think it has now risen to the point where if there are significant energy potentials or significant energy impacts, that they are, in fact, considered.

Mr. DINGELL. One thing that troubles me is I find no such statement in the legislation before us. It strikes me such should be put in there, that, and a policy statement. Do you disagree with that as a basic assumption?

Mr. O'LEARY. Mr. Chairman, with regard to the policy statement, I think it's a fair thing to do. I think it simply places, in writing, what is already being observed. I would have some difficulty, I think, in formulating a statute that would require some balancing. I am not, for example, enthusiastic about the net energy theory of conducting our affairs.

Mr. DINGELL. We will seek to accomplish this follow-up here.

This question to Mr. Woodworth and Mr. O'Leary.

Gentlemen, you have indicated that the administration's proposal will tax utilities. What assurances are there that an additional fuel cost wouldn't be passed through via the fuel adjustment clause? Is there any assurance you can give me?

Mr. WOODWORTH. I don't believe there is any assurance that can be given on that in the case of existing law.

Mr. DINGELL. Could either you or Mr. O'Leary give us an assurance that it won't transpire, and then cite the particular authority whereby you make that statement.

Mr. O'LEARY. Mr. Chairman, I think there will be passed through those additional costs. That, of course, is a matter for the judgment of the public service commission regulating the utility. I believe when the public service commission realizes this, they will put a great deal of pressure on the companies to make the appropriate investment rather than simply make the pass-through with no gain from the standpoint of the national economy to the customers.

Mr. DINGELL. You will permit my taking small comfort from your comment, because I have lived in two States that have fuel adjustment clauses, and I have discerned very little benefit from the fuel adjustment clauses in electric power either in the State of Virginia or in the State of Michigan.

Can either of you gentlemen give us any assurances that these rebates will pass through to the consumers. Is there anything in the bill that would require that event to take place?

Mr. O'LEARY. No; the rebates you are talking about, the surtax that you are discussing here, will not pass through to consumers, Mr. Chairman. It will go back in as a compensation for the utility for making an investment in a replacement facility.

Mr. DINGELL. Let me ask this question: If we have a large industrial plant which is in the early planning process and there is an order to convert that plant and that order would take place unless the plant would incur substantial financial hardship, if such financial hardship would occur and FEA can't order the plant to convert, it will then burn gas and oil.

Now the question is as follows: Why is there no investment tax credit or other mechanism to move that kind of plant to coal? Could either Mr. O'Leary or Mr. Woodworth address that?

Mr. O'LEARY. Mr. Chairman, right now so far as the utility sector is concerned, all of the orders of which we are aware, all of the recent orders are for coal or nuclear fired generation. In fact, the utility industry is not buying oil or gas fired generation at the moment.

Mr. DINGELL. I am aware of that.

Mr. O'LEARY. With regard to the industrial sector, about 70 percent of the new capacity is going to oil or gas, 10 percent to coal and about 20 percent to nonfossil fuels, to wood chips and what have you. That prospectively, of course, would come under the ambit of the administration bill. We would have a blanket provision on the ordering of new industrial boilers that were not coal fired.

Mr. DINGELL. With regard to new plants, once they make these contracts, get themselves tied into gas, they have created a situation whereby there is substantial hardship, and the plants then have the ability to bootstrap themselves into use of natural gas, even though our national policy might be that they should go towards coal.

Do you want to give us a comment on that?

Mr. O'LEARY. Yes. I think what you are saying will be forbidden for plants that go into construction after the bill is passed.

Mr. DINGELL. Please give us the citation in the statute proposed to accomplish that end?

Mr. MOFFETT. Mr. Chairman, would you yield for a question?

Mr. DINGELL. My time has expired, but I will yield to the gentleman.

Mr. MOFFETT. To go back to the question of user tax and whether it's passed on or not, you responded, Mr. O'Leary, to Mr. Sharp earlier in the hearing that this would essentially be left to the States, and your answer to Mr. Dingell is not inconsistent with that, except you seem to say, you went a little farther and said you thought it would be passed on. At the same time, as I heard it, you indicated that the rebate to the utilities would not be likely to be passed on. So the consumers have the user tax passed on, the rebate is not passed on, and essentially aren't we saying here the consumers are then financing construction work in process through the fuel adjustment clause?

Mr. O'LEARY. I think this is the way it would work with regard to utilities. The surtax is not implemented until 1983. In between now and then we expect that the utility industry will make substantial investments and create, thereby, large banks, which will be drawn down by the tax incidence, and we suspect that in most cases the tax will, in fact, never be paid.

We are now in discussions with the utility industry to get a further understanding of that. What we are trying to do is get a very strong economic prod on the utility industry to make these replacement investments that, of course, they don't want to make.

We think that once this is enacted into law they will then begin the orderly staging in, taking into account this tax impact. As I have said before, if they find themselves with a necessity to raise money one way or another, and particularly if the local public service commissions begin to make a distinction between this kind of tax and other fuel costs, it seems to me what they will say is, well, we will raise the money and make the conversion rather than raise the money and pay the additional tax.

I think by the time this is all shaken down, we will not, in fact, see that tax implemented in very many cases.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. I wanted to ask Mr. Davenport, in the Secretary's testimony he indicated that the task force would be making a report at the end of the year. Close to those remarks was his statement about the coal slurry pipeline. It was not clear to me whether that is a major part of this task force responsibility and whether or not the administration position on the coal slurry pipeline, in other words, will wait until December when this report is made.

Mr. DAVENPORT. No. The administration's position on the coal slurry pipelines will not wait until the end of the year. Administration position is under active consideration now by the White House and by the various agencies affected, including DOT.

What Secretary Adams was referring to is since we are looking at all possible modes of transporting coal, we will obviously consider the coal slurry pipelines. But the coal slurry pipeline legislation, as you know, is moving rather rapidly, and the administration hopes to have a position rather soon on that.

Mr. SHARP. I see. Am I correct that it is important that we decide this issue one way or the other in the very near future, because it will shape railroad investment and other decisions that are critical for how we are going to ship this coal within the next couple of years?

Mr. DAVENPORT. We feel that it's important that we get this behind us, yes.

Mr. SHARP. Fine.

Mr. DINGELL. Would the gentleman yield briefly?

Mr. SHARP. Be happy to.

Mr. DINGELL. Mr. Adams indicated when he was testifying here that the industry proposed to add to the fleet 16,000 railroad cars each year. What is the ordinary level of additions to the fleet of railroad cars?

Mr. DAVENPORT. Let's see; I have the Federal railroad people with me.

Mr. DINGELL. Would you do this for me? Submit to us the following: 1) The normal level of additions to the fleet of railroad cars, particularly with regard to coal categories, coal carrying categories; 2) what is the level which is required to carry the additional coal which will be required by the shift of our national energy policy to coal of the additional? What will be the capital costs there from, and investment costs there from, and do so, if you please, by region and by railroads. I have reason to think some railroads may be, are able to do it, and some may not be, by reason of capital inefficiencies and other difficulties with which the railroad industry is known to be afflicted.

Mr. DAVENPORT. We will be more than happy to do that, Mr. Chairman.

[The following material was received for the record:]

RAILROAD EQUIPMENT REQUIREMENTS FOR COAL

AAR figures show that during 1974-1976, open top hopper car orders averaged about 16,000 per year. Because the railroads have already begun expanding their fleets to handle increasing coal traffic, this level is significantly higher than the historical average. During the previous six years (1968-1973), orders for open top hoppers averaged only 11,000 per year.

The AAR has estimated the equipment acquisitions which would be necessary for the railroads to handle the two-thirds increase in coal traffic that is projected for the next eight years (1978-1985). This additional coal traffic would require from 5,600 to 9,300 new open top hopper cars per year, depending upon the degree of unit train operations. The average annual requirement for locomotives would range from 280 to 465, again depending upon the usage of unit trains. It is estimated that the railroads will require an additional 4,100 coal hoppers and 205 locomotives per year to replace retirements during the eight years. Thus, the total annual equipment requirements to handle the expected coal traffic will be 9,700-13,400 cars, and 485-670 locomotives.

At 1976 price levels, an open top hopper car costs about $30,000, and a typical locomotive about $500,000. Thus, the equipment acquisitions to handle current plus expected growth coal traffic will cost from $533.5 million to $737.0 million annually. During 1975, about $2 billion was expended for 74,000 freight cars and 840 locomotives. Coal traffic is not spread evenly through the industry. Seven railroad systems currently originate 85% of the total coal carloads. These are the Chessie System (C&O/B&O/Western Maryland), Norfolk and Western, Conrail, Family Lines (SCL/L&N/Clinchfield), Burlington Northern, Southern and Illinois Central Gulf. The spectacular increases in Western coal production will cause coal to take on a new importance for a number of railroads, including the Union Pacific; the Chicago and Northwestern; the Atchison, Topeka and Santa Fe; the Chicago, Rock Island and Pacific; the St. Louis - San Francisco; the Missouri Pacific; and the Chicago, Milwaukee, St. Paul and Pacific. While these roads differ in financial strength, we are confident that they will be able to obtain the necessary cars and locomotives to handle new profitable traffic. Equipment trusts are widely used to finance purchases of rolling stock and are readily available. In addition, it is estimated that perhaps one-third of the equipment requirements discussed above will be supplied by utilities and coal producers. This arrangement offers the advantage of lower capital outlays for the railroads and better control over equipment—plus better rates—for the private owners.

Beyond the broad estimates of rail coal equipment needs for the industry as a whole, no meaningful estimate of each carrier's requirement is possible at this time, due to the need for firm origin-destination and routing information. Accordingly, where multiple routes are involved it is not possible to presently estimate each carrier's projected share of such equipment needs.

Mr. DINGELL. Mr. Sharp, do you have further questions?

Mr. SHARP. Thank you, Mr. Chairman, I have no further questions.

Mr. DINGELL. The Chair recognizes the gentleman from Michigan, Mr. Stockman.

Mr. STOCKMAN. Mr. Costle, I wanted to go back to the discussion we were having before, because I am very concerned that your statement to this committee indicating that the cost of removing

NOx would be much lower on the tailpipe end as opposed to industrial end seems to contradict the data that is available.

I was quoting some numbers off the top of my head, but I have since obtained the report of the Federal Interagency Task Force on Motor Vehicle Goals from September 1976, and here are the figures that they have.

I certainly don't stand behind these figures or swear for them. They could be totally wrong and erroneous; there could be an automobile point of view implicit in those studies. The thing that concerns me is what you said completely contradicts the best available evidence that seems to be on the record, and what certainly EPA would have been aware of.

Here are the figures: The cost per ton of NOx reduction for new utility boilers, $100, if you are going to 25 and 50 percent control.

For the cost of new industrial boilers per ton of emissions removed, $150; for existing utility boilers that would have to be converted or retrofitted, $225 per ton.

Now, when you get to light duty motor vehicles, the cost per ton of NOx removal by going from 2.0 NOx on the tailpipe to 1.0 is indicated at $450 per ton, and then when you go from 1.0 to .4, the figure they have is $2,300 per ton.

So you have a spread there of 23 to 1, and particularly you have a very sharply rising marginal cost on tailpipe NOx control when you go below 1.0.

So I am hoping, I don't expect you would have any response now, if you do that is fine.

Mr. COSTLE. I would like to respond, Mr. Stockman. I may have misspoken, and I want to be sure if I have I will immediately correct the record.

My understanding is that the cost figures as laid out in that have changed, and I don't know whether it has changed enough to make very much difference.

What I was particularly reflecting on was the fact that the ability to go out and put controls effectively on stationary sources is going to be a very difficult and expensive business, when we don't know what the technology really ought to be.

Now, it may turn out to be fluidized bed. I have some questions in my own mind about whether we can have fluidized bed combustion on large utility boilers, for example, much before the mid-1980's, and I think we can see it on smaller, and I think we will see it sooner in industry than in utilities.

Everyone I have talked to has said there is some real questions about whether we can get fluidized bed and there are still problems with NOx, as I understand it.

Low Btu gas cost, comparability of both low Btu gas and fluidized bed, according to the data I have seen, suggests it is not much different than the cost of flue gas desulfurization. There is some suggestion it may be 10 percent better, the comparison of fluidized bed to flue gas desulfurization. With that, the scaled up experience, I think my hunch, if prudent, may be saying this 10 percent may evaporate. We just don't know. So my point was simply where we know we can control, we ought to be controlling, and particularly if we are referencing a peaking problem, then I think you deal with the source of the peaking problem.

In any event, as several members of the committee this morning have pointed out, we are seeing a very substantial base load growth quite apart from the energy plant and the overall problem with NOx.

Mr. DINGELL. Would the gentlemen yield?

Mr. STOCKMAN. I yield to the chairman.

Mr. DINGELL. Have you had any studies on mass transit, if you have a peaking problem, how about mass transit as a solution? Have you given any study to that?

Mr. COSTLE. Mr. Chairman, I think I am all for mass transit. I think the question that this Congress will address, is, in fact, the question of what the future of the mass transit program of this country will be.

Mr. DINGELL. I get the impression——

Mr. COSTLE. I understand there is a question of availability of funding now, for what kinds of systems those funds shuld be spent, those are all questions coming right before the Congress at this session.

Mr. DINGELL. I get the distinct impression you good folks down there are a little like a doctor that has a patient coming in with cancer and you treat him for fallen arches, and he may have both, but the problem that is going to get him is the more serious and you are applying a totally different treatment, and I thank the gentleman.

Mr. STOCKMAN. The only additional comment I wanted to make was yes, we have to go over the sources we can get to now, but we are dealing with a long run problem, and I think we all agree we have to cost control strategy because we are dealing with many years, and you can take some very precipitous steps in the short run that could amount to a very high cost strategy for reduction. That is why I am concerned about this, because these numbers vary so widely that if we don't have an accurate or even a plausibly solid data base, we are going to make a totally wrong fundamental strategy decision. So we would appreciate anything that you could supply for the record now and over time, because this, as you said, will be a continuing issue of contention.

Mr. COSTLE. I think that is a very legitimate concern, Mr. Stockman, and I will review those numbers personally and if I have misspoken I will correct the record.

Mr. STOCKMAN. Thank you.

Mr. DINGELL. The Chair recognizes now the gentleman from Colorado, Mr. Wirth.

Mr. WIRTH. Thank you, Mr. Chairman.

I think your reference to fallen arches was absolutely appropriate. I think that is what we were doing yesterday; focusing on fallen arches, and not the cancer factor all around us.

Mr. DINGELL. If the gentleman will yield, there is no evidence about cancer from automobile emissions.

Mr. WIRTH. I will disagree but I guess what you see depends on where you sit.

Mr. Costle, I would just like to review the bidding, if I might, from the earlier exchanges. The first exchange you agreed you were going to send to me your best analysis as quickly as possible on what the impact of yesterday's decision on coal conversion might be.

Mr. COSTLE That is correct.

Mr. WIRTH. The second thing we talked about was then what the economic impact on the consumer might be, assuming we no longer geared the flexibility and the freedom of focusing on auto emissions in terms of air quality. The burden then gets shifted to other industries. What was our consumer cost going to be; that was our second agreed upon set of data. It seems to me there is a third to complete the loop, if I might, and that is the cost to other industries.

I think many of us in the process of yesterday's discussion received from our friendly local chambers of commerce and National Associations of Manufacturers and so forth, urging that we vote for the Dingell-Broyhill substitute. I suspect that many of those industries that did write to us were not as aware as they might have been of what costs are going to be incurred by them in picking up the difference now that the automobile industry no longer has to.

We have talked a little bit about this in discussions between yourself and Mr. Moffett and yourself and me. I was wondering if you could supply me with any data you might have on that issue of costs that we now are going to have borne by other industries.

Mr. COSTLE Yes. I will endeavor to make that available.

Mr. WIRTH. Mr. O'Leary, let me jump to another issue, which I think will be welcome. Thinking briefly about the conversion from say natural gas to coal—and I want to get around to ultimate cost figures on the consumer and find out what kind of data you all may have put together, perhaps with the Department of Transportation—it's my understanding that the cost of natural gas to the consumer, say the cost when you turn the value on in the kitchen, is about 25 percent the wellhead price of the natural gas, and that about 40 or 45 percent is transportation pipeline costs, and about 40 percent is local distribution costs.

Is that a generally fair assumption?. Isn't that correct?

Mr. O'LEARY. I think you would find that the wellhead price, that was true sometime back, the wellhead price is now a larger proportion because there have been insignificant increases, it might be 30 to 35 percent.

Mr. WIRTH. Let's say it's a third, and one-third for purposes of convenience.

Mr. BROWN I wonder if the gentleman would submit for the record that assumption.

Mr. WIRTH. Yes, I would like to have that.

Mr. O'LEARY. I will be pleased to expand on that now. Average price of gas in interstate commerce right now is about 65¢ at the wellhead, and the average cost to the consumer, as I recall it, residential consumer, is something under $3, something in that range.

Mr. WIRTH. Let's assume that becomes part of the answer. I would like you to submit that to us, if I might.

Mr. DINGELL. Without objection, the documents and information will be received and placed in the files of the subcommittee.

Mr. WIRTH. Thank you, Mr. Chairman.

Now, if we go about the process of converting from natural gas to coal, therefore, the hope would be that we would be using less natural gas, and therefore, that we will be shipping less natural gas; correct?

Therefore, pipeline costs, as a percentage, would go up; is that correct?

Mr. O'LEARY. No; not correct. The overriding factor with regard to the movement of natural gas will be its availability. All of the gas that is producible will be consumed, if this is a sectoral shift, not an absolute reduction in the amounts of gas that will otherwise be available.

Mr. WIRTH. So the variable of the pipeline cost as a percentage of what the consumer pays remains the same; is that correct?

Mr. O'LEARY. The variable there is a producibility of the industry, not the shifts going to be injected into the system by the President's program.

Mr. WIRTH. If you are shipping less gas through a pipeline, you are converting say in State X, right from the use of natural gas to coal, you are going to be shipping less gas from the producer State to States X. Is that correct?

Mr. O'LEARY. No, Mr. Wirth. The producibility, so far as we can predict between now and 1985, will go down. That has nothing to do though with——

Mr. WIRTH Let's stay with that. If the producibility goes down, the pipeline cost——

Mr. O'LEARY. ——go up, except that the pipeline costs are being amortized on generally a 20-year schedule, so they are roughly tracking one another.

Mr. WIRTH. Could you provide in answer to my question and that of Mr. Brown, the percentage factors in the price of natural gas to the consumer, and could we also look at what your projection is as to what might happen to the pipeline cost of that? I think this is very important, because we hear so much discussion about what would happen with the deregulation of natural gas at the wellhead, and, in fact, that is a very small percentage of the price.

Mr. O'LEARY. The key, Mr. Wirth, the key point here is that the coal conversion program has nothing to do, repeat, nothing to do, with producibility of gas. Consequently, nothing at all to do with the amount of gas on gross terms that is going to be taken through the Nation's transportation system.

That is a function of the finding and development of new gas resources, not of the coal conversion program. So they are simply not associated.

Mr. WIRTH Okay. Then, if we might, Mr. Chairman, leave them disassociated, you can give us the analysis that relates to productivity and those factors that go into the consumer bill.

Mr. O'LEARY. I will.

Mr. WIRTH. Thank you very much.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Ohio, Mr. Brown.

Mr. BROWN. I would like to continue precisely on that point with Mr. White, but I would like to observe my previous question about high Btu gas and gasification of coal, and the fact we are not going to go into the production of it does bear on the fact you don't produce anything of pipeline quality that could supplement natural gas through pipeline systems.

Mr. White, did ERDA participate in the drafting of policy on coal in this legislation? If so, how?

Mr. WHITE. There was some contact. I was not personally involved in it. Mr. LeGassie was working with the Energy Policy Office at the White House.

Mr. BROWN. If you can tell us how and when, I would appreciate it. FPC said they got notification only 2 days before the bill was submitted to the Congress, so I would like to know when.

Mr. WHITE. I will be glad to put that in the record.

Mr. BROWN. How does the great push toward coal in the program square with the work being done by ERDA in the MOPPS study groups, which is, I understand, indicating now the United States has massive amounts of geothermal natural gas, which might be brought in, and priced slightly above current natural gas supplies.

Mr. WHITE. The purpose of the MOPPS study from the start was to look at the impact of new technologies as they would satisfy demands of the various consuming markets.

Mr. BROWN. Related to price?

Mr. WHITE. As an approach to better orient our programs. It was obvious that one of the first things we had to do, in terms of when solar or coal gasification might come in, was to know what was the likely prospect of the conventional sources, oil or gas, as they might be more attractive and more available in the future than the new technologies.

There have been estimates made in that study group. The results that have been so widely publicized were very preliminary results, produced in the early stage of the study. We feel they are not as valid as some of the later results.

Mr. BROWN. Be careful, but you go too far, because I understand there have been meetings for the last 2 days out at ERDA with people from industry and people from the U.S. Geological Survey and academicians, and that they may be revising their position somewhat back toward that original study rather than the second version of it.

I am going to ask you, if I might, to receive from you the rules of that current colloquium that is going on at ERDA on this subject.

Mr. WHITE. You certainly will.

Mr. DINGELL. The Chair at this time would request both of the studies, the current and the new study from ERDA as to both coal conversion and with regard to natural gas. We hope we will receive them promptly.

Mr. WHITE. I will supply them.

[The studies referred to may be found in the subcommittee files:]

Mr. BROWN. I said the colloquium is going on at ERDA. It's at USGS.

Now, I want to continue on the point and I must say I understand that the last day or two that the results of that study, unlike Mr. O'Leary's comments to Mr. Wirth, have indicated that there is a vast amount of gas available, and that the price figures may be somewhat closer to the original price figures cited in the Wall Street Journal, for instance, those that were later revised by a second study of the first MOPPS results.

If I may go on just for a minute on this point, today in the Journal there was an observation, and I quote: " The more you induce Octopus Oil to invest in gasification or LNG at $3.75, the harder it will be to unleash competition," in the gas field, "at $2.25."

We have a number of companies in this country with billions of dollars invested in LNG from foreign fields which would hate to see United States produced gas in large quantities come in at $2 or $2.50 or $2.75, because they have got a lot of bucks on the line in on a higher price.

If we then do have $2 or $2.50 gas available in quantity, your own study group at ERDA, which has, I understand, again this week found that we have about 500 trillion cubic feet of gas available, check figures, okay, and that if we can get 1 percent of that out, we can put 25 percent of our natural gas from that source into the pipeline.

They cite specifics. They talk about Exxon with a rather heavy investment in synthetic natural gas from coal; El Paso which has $1 billion in liquid natural gas tankers; Mobil which has immense natural gas holdings in Indonesia, which, of course, they would like to bring in; Phillips, which has a big investment in oil in the North Sea, then also in Indonesia.

If you could give me those studies of the last few days, which I understand are supposed to be available about the first of June but won't be printed for a couple of months, it would be very helpful.

Mr. WHITE. Excuse me; it is our intention, Mr. Brown, to put out by the end of next week for public criticism—June 6 is our target date—the results of the studies at Reston, both the second curve and the first curve, so people can see what these are and can comment on them.

Mr. DINGELL. The time of the gentleman has expired.

We would apprciate receiving those at your earliest convenience in order they may be reviewed by the staff in connection with the matter now before us.

Mr. BROWN. Mr. Chairman, could I ask also the usual question of whether or not they will be reviewed first by the Office of Management and Budget or FEA or some other agency?

Mr. WHITE. The FEA participated in the Reston study and we don't expect there will be any further need. When we bring them out we will ask FEA's comments.

Mr. BROWN Just so they are uncensored by the CIA, FBI, and OMB, that is what I am interested in.

Mr. DINGELL. The time of the gentleman has expired.

Mr. BROWN. Mr. Chairman, I do have a few other questions I would like to submit for the record if we are not going around again.

Mr. DINGELL. The questions will be received.

Mr. DINGELL. Mr. O'Leary, were you briefed on this matter?

Mr. O'LEARY. I am sorry.

Mr. DINGELL. Were you briefed on the matter just discussed?

Mr. O'LEARY. Yes, indeed.

Mr. DINGELL. Do you have some comments?

Mr. O'LEARY. Mr. White was kind enough to bring over some of these and we spent a long evening about 2 months ago.

Mr. BROWN. After the first MOPPS study and before the second one?

Mr. O'LEARY. This ran to the entire question of the non- conventional sources of gas. In addition, we have had more briefing on the MOPPS study. This preceded the MOPPS study briefing by at least a month and a half.

Mr. DINGELL. Do you have any comments on the MOPPS study?

Mr. O'LEARY. I will be pleased to see what comes out of the Reston analysis. I take a deep interest in this myself.

Mr. DINGELL. In other words, you are saying you are reserving judgment and comments until you get a chance to review it.

Mr. O'LEARY. Thus far I haven't seen anything in the analysis to be sanguine about to be sure, on Mr. Brown's views that there is a great low cost source of gas out there. I think there is a great source of gas, but I think it has high costs associated with it, and some very, very severe technological problems associated.

Mr. BROWN. I wonder if I could ask the chairman to yield?

Mr. DINGELL. I am glad the gentleman asked me; yes, I will be glad to yield.

Mr. BROWN. To ask if you have had any chance to talk to a Doctor Joseph Rene of the United Nations and the United Nations study, and his experiences and studies and predictions on the natural gas availability, and on geothermal and the cost predictions.

Mr. O'LEARY. No, I have not, but I will make it a point.

Mr. BROWN. I wish you would. I hope to get him before this committee and perhaps before the Ad Hoc Committee. He is an international authority in the area and he is somewhat more sanguine.

Mr. DINGELL. The Chair thanks the gentleman, but I can't yield my time further.

The Chair is going to declare my time at an end, and the Chair is going to recognize Mr. Finnegan for purposes of questions.

Mr. FINNEGAN. Thank you, Mr. Chairman.

Mr. Costle, your staff provided to us a copy of a report entitled, Industrial Coal-Using Program, Energy and Other Impacts, dated May 19, 1977. It has an index which indicates there are a great many parts to it. However, the report that you provided to us only covers from page 16 on. Could we get the entire report for the record?

Mr. COSTLE. Of course. I have no idea why you didn't get pages 1 through 16, but I can't imagine why. Yes, definitely.

Mr. FINNEGAN. Mr. O'Leary, in the bill itself, it defines the term "nuclear powerplant," and uses in the subparagraph A with respect to which an order was issued pursuant to section 2(c) of ESECA. When you speak of an order, do you mean a final order or a proposed order?

Mr. O'Leary. When we speak of an order, Mr. Finnegan, we speak of an order that is a good deal less than final. Actually the final order is the NOE, which follows on hearings and appeals and what have you. We go to an ordering at a more or less intermediate point in the process, and the order is not final.

Mr. FINNEGAN. At this point in time, isn't the order subject to a great deal of procedural steps within both FEA and elsewhere?

Mr. O'LEARY. There is a very substantial procedural burden on getting the order and a very substantial procedural burden beyond the order, Mr. Finnegan.

Mr. FINNEGAN. Aren't you in effect finalizing using this language to essentially finalalizing that order?

Mr. O'LEARY. The language there we would hope to some degree would facilitate the ordering process. It is now pretty cumbersome.

Mr. FINNEGAN. I see, but what effect and impact will that have on the people who have received that order?

Mr. O'LEARY. I would like to think that through and submit a comment for the record.

Mr. FINNEGAN. Fine. In relation to that, let me go one further: During the previous questioning there were questions raised about the relationship between EPA and FEA, and you indicated that you could consult with the EPA on these orders and all of these matters.

Do you have any objection to providing in the bill, in those places where there were determinations on environmental factors, that they be required to consult with the EPA on this matter?

Mr. O'LEARY. I think that simply puts into formal language the current practices. We are, in fact, doing that consultation now. So long as the statement of the bill does not run beyond consultation, I have no objection to it.

Mr. FINNEGAN. I see. On that point, on April 25 of this year, the Acting General Counsel of the FEA issued a notice of intention to issue prohibition orders for some plants in the New England areas. Just prior to that, in a letter dated April 21, 1977, Mr. O'Leary, Mr. Costle wrote to you in which he expressed some concern about several plants.

He said: "In particular, our preliminary analysis indicates that conversion of the following five plants may result in violations of the preliminary standards." However, those five plants or at least some of them are included in that proposed order.

Mr. Costle, may I ask why this letter was sent only 4 days before the order was issued and did FEA receive it before the notice of intent was issued?

Mr. COSTLE. I am sure the FEA did receive it before the order was issued.

Mr. FINNEGAN. What was done as a result of it?

Mr. COSTLE. There is no special explanation. We did have notice of FEA's interest in issuing conversion orders. We asked for time to do some analysis. We got that time. Then I wrote that letter to Mr. O'Leary saying here is what it looks like to us on the basis of the preliminary analysis we have done.

Mr. FINNEGAN. What did you do then, Mr. O'Leary?

Mr. O'LEARY. You are alluding to a portion of the letter.

Mr. FINNEGAN. That is true. I have not read the entire letter.

Mr. O'LEARY. The letter of April 21 referred to five plants in the may-violate category, and nine plants in the will-conflict category. Our reaction to that was to drop our plan to put out NOIs on the nine plants that Mr. Costle had indicated would in all likelihood not be convertible, and to go ahead with the ordering procedure, the process, in order to test his theory that the additional five plants may not be convertible.

Mr. FINNEGAN. But you still issued the proposed order for those five plants.

Mr. O'LEARY. Yes, because in the first category, the nine plants, he said quite clearly, these, in his judgment, would not be convertible. We said, well, there is no point in following the ESECA pattern down a line that will ultimately be frustrated. That is a waste of resources. On the others where he said they may be convertible, or they may not be convertible, the obverse, we thought in that case, in order to carry out the clear mandate of ESECA, we had no choice but to issue the NOIs.

Mr. FINNEGAN. Even though there is a possiblity of violation of the primary standards?

Mr. O'LEARY. Indeed, even though there is a possibility. Now, in the first case there was clearly a strong probability of a violation. In that case, I think that proceeding with the ordering process would have been an exercise in futility. In the second one, we intend to test in close coordination with EPA the thought that they may violate the primary standards.

Mr. FINNEGAN. How will that work? Mr. Costle, are you satisfied with that approach? How will that all work out?

Mr. COSTLE. I think the call is close enough in those five that I think we cannot be sure until we look at the whole data set and the utility submissions and the air quality modeling. I think obviously the cost factors are going to sharpen when they come forward.

Mr. FINNEGAN. Are both agencies satisfied with the interpretation of the statute that you are in fact required to do this?

Mr. O'LEARY. Yes, I think if we had not proceeded with these, that we would certainly not be fulfilling our responsibilities under ESECA to proceed with the coal conversion program. There is a possibility that they will not be convertible. There remains a strong possibility they will be convertible.

You recall, Mr. Finnegan, that the bottom line of this is we cannot convert them if they do in fact breach the standard. I think the only way in this intermediate field, the five plants we are focusing on now, to determine that is by going on with the process. So, that was quite a conscious decision.

Again, I think I had no choice but to proceed with those five plants under my interpretation of ESECA.

Mr. FINNEGAN. In the chairman's opening statement he made note of your statement, Mr. O'Leary, that the best available control technology should be available for new plants. What about existing plants, and what will happen in those cases?

Mr. O'LEARY. Clearly this is not simply my statement. This is the President's statement as incorporated in the national energy plan. Clearly for new plants coming on, with a long service life, best available control technology makes an enormous amount of sense.

With regard to any existing plant, it seems to me we have to take into account a variety of factors—the fitability of the retrofit, the remaining service life of the plant. If the plant is 1 minute old, for example, it seems to me you have one case in a 30-year potential life. If it is 29 years old, it is quite a different case.

So, here, it seems to me, we cannot establish sweeping policy. There have been some indications that, some viewpoint that BACT should apply to all conversions.

My own view is that doesn't take into account the full public interest, which should keep a very close eye on economics. So, I think we should have a flexible policy with regard to existing facilities.

Mr. FINNEGAN. Wouldn't it be better to provide——

Mr. DINGELL. If counsel would yield, would you give us your comments on that, please, Mr. Costle? Are you in accord?

Mr. COSTLE. What Mr. O'Leary has just testified to is essentially what the current policy of the Federal Government is. It is pretty impossible, except on a plant-by-plant basis, to determine just what is a cost effective way of reducing emissions. Clearly that would mean in some older plants, particularly with respect to a life of 15 years or more, you get a judgment called on the question of whether scrubbers, for example, ought to be applied or not. There are judgment calls.

I think I share Jack's concern that we not have just sort of a blanket on older plants. Frankly, I think it is going to turn out to be a lot easier to deal with this problem in terms of new plant, where you can build these systems right in—the cost figures are going to come out a lot better. One thing I would point out is that the President's energy plan really relies only on 10 percent of this to come from conversion of old plants, and essentially 90 percent on new.

Mr. FINNEGAN. Wouldn't it be better to state in the legislation that best available control technology be required except where it is shown that it cannot be done because of cost or whatever other factor? In other words, there would be a burden of showing at least as to why it has not been utilized.

Mr. COSTLE. No—I am answering off the top of my head. It is not consistent with what we are now doing, but it sounds about right.

Mr. FINNEGAN. Mr. O'Leary?

Mr. O'LEARY. I would like to consider that. I am not sure it wouldn't distort the burden, Mr. Finnegan. I think that you could just as easily say that it shall not apply, if you want to go into this, except where a clear showing can be made where it should apply. I really don't like the implications of who makes the showing on this—the burden of proof argument which we have discussed before in the context of ESECA.

So, I would really like to think about it a little bit. In principle, I have no difficulty with it because it really is consistent with policy. Whether in law it would work out so that it was tempered—that is to say, intermediate, neutral in the application of that language—I am not sure. So, I would like to look at it.

Mr. FINNEGAN. Would you object to it being put in as a requirement for new plants?

Mr. O'LEARY. The BACT as a requirement for new plants? Insofar as our policy runs it is a requirement for new plants above a certain level.

Mr. FINNEGAN. So it could be in the legislation?

Mr. O'LEARY. As far as I am concerned.

Mr. FINNEGAN. Mr. Costle, I hope the two of you would get together and we hear from you very shortly as to what your views are on all of these points because it is very important.

Mr. COSTLE. Fine.

Mr. FINNEGAN. Mr. Costle, have you considered the problems of what you do with the disposal of the ash? We have noted a number of witnesses have raised this problem.

Mr. COSTLE. We have in a general sense.

Mr. FINNEGAN. Particularly in a more urban environment.

Mr. COSTLE. That is exactly right. We have not done site-by-site analysis. But, without any question at all, increased coal use is going to increase the land use impacts, resulting from ultimate disposal of waste ash.

While the ash disposal requirements nationwide may not appear to be excessive, significant sites, specific problems, could arise. These problems can only be addressed, I suspect, on a case-by-case basis. In general, land use impacts can be mitigated by reducing the volume of waste to be disposed of through recycling and reclamation. The use of white waste ash, for example, as a fill or building material is increasingly being accepted as a recycling measure.

I think the experience, for example, they are having in Japan, I am told, in terms of getting reusable product out of this sludge is fairly positive.

Mr. FINNEGAN. How far away is that in this country, and how much is it being used in this country at this time?

Mr. COSTLE. It is not very far away. In fact, I think it could be done right now.

Mr. FINNEGAN. Is it being done here in this country?

Mr. COSTLE. Not at the present time. But, that is not a function of technology as much as it is a function of the fact utilities refuse to go to scrubbers.

Mr. FINNEGAN. Is that true for the ash itself? What about the ash? The ash is not a scrubber problem as I understand it.

Mr. O'LEARY. Mr. Finnegan, ash was an enormous problem 20 years ago, and since then has become an article of commerce. Great use has been found for it. I think it is useful to think in terms of the product that comes out of the scrubbers as a problem of about the same magnitude as ash.

I really don't think that is going to be a stumbling block over time. We will be able to handle that.

Mr. FINNEGAN. Isn't it a product of commerce if it is found or located in an area where there is transportation to get it to commerce?

Mr. O'LEARY. Yes. So are loads. You find that coincidence of the ash and the marketing fairly closely related.

Mr. FINNEGAN. The last question, in the considerations of exemptions and so forth, what do you do where there is a State law or State court action such as there is with Vepco, I believe, in Virginia, where the court has ordered the company to use oil—I believe it is oil—how do you take that into consideration as to whether you grant them an exemption or exceptions under this language?

Mr. O'Leary. Mr. Finnegan, I would like to supply that answer for the record. I don't know offhand how we would handle that, who would pre-empt.

Mr. Dingell. I think you ought to give us an answer on that. We are not pressing you to give us an answer at this moment. We just want a good answer because pretty obviously somebody like that is caught between two forces, the Federal Government on the one flank and the State agency on the other flank, or the State court.

The question is do we pre-empt. If we pre-empt, how do we pre-empt and when? I would like both your judgment, Mr. O'Leary, and Mr. Costle's, too, please.

Mr. O'Leary. Mr. Finnegan, I would assume if that is in fulfillment of a State imposed obligation with regard to air quality——

Mr. Finnegan. In this case I believe it is an action by the local community, county attorney, against Vepco, as our testimony was yesterday. I suggest that you might have your staff take a look at that testimony and consider that.

Mr. Finnegan. Is it really necessary, Mr. O'Leary, to include the provisions concerning NEPA in this bill? Why is it in the bill?

Mr. O'Leary. May I ask Mr. Hanfling to address that, Mr. Finnegan. There is a good reason for it.

Mr. Dingell. If you please, give us your full name and responsibility for the purposes of the record.

Mr. Hanfling. Mr. Chairman, I am Robert Hanfling, Deputy Assistant Administrator, Energy Resource Development, FEA.

The reasons that we suggested in the proposed bill to call for the elimination of a major Federal action should an exemption or exception be denied is the fact that we find one of the major problems under the current legislation to be a lengthy environmental impact statement process that will then subsequently be duplicated by another environmental impact statement required for the construction of the facility.

So, the purpose of not having a major Federal action for a rejection of the request is primarily to avoid the duplication of environmental review—not in any way to shorten or circumvent that necessary review. In effect, the words in the proposed legislation specifically state that that elimination of a major Federal action would not hold if there is a situation where no other agency other than the FEA would be responsible for that environmental review.

Mr. Finnegan. Where would be the requirement for a NEPA statement in the construction?

Mr. Hanfling. In most cases, for new plants, and that basically would hold in reality for new plants.

Mr. Finnegan. It is not limited as I recall——

Mr. Hanfling. No, the bill doesn't. But, the way that bottom part of the phrase—let me give you two specific cases. In a new plant, most generally the facility would have to go to the Corps of Engineers or some other Federal Government agency to get some sort of a permit. An environmental impact statement is done at that point for the construction of the plant.

Mr. Finnegan. That gets to the site location problem. But the issue here is whether or not it is in the interest of the environmental quality to go ahead and grant an exception or exemption, isn't that correct? Isn't that a fairly serious decision that ought to be looked at in the total analysis?

Mr. HANFLING. What the recommendation is—and again, let me just go to the existing facilities. The existing plant is at a particular point, it is already there. There would probably be no other agency looking at the environmental impact of making a switch from oil and gas to coal. In those cases it is appropriate, and there is nothing in there at least as we drafted it that would negate FEA's going into the environment assessment, or environmental impact statement.

On a new facility, what we wanted to try to avoid is the following case. In new facilities, the bill recommends a blanket prohibition against use of oil and gas, and there would be a programmatic environmental impact statement. You can conceive of two instances. One is where a builder would go ahead and say, all right, I am now going to build a new coal plant. He goes ahead and does an environmental impact statement on the coal plant.

The second individual could say, well, I will go in for an exception. That exception will now force FEA to do an environmental impact statement. Even if they are going to reject it, that will drag out the process by another 2 or 3 years. After that process is done, an additional environmental impact statement will then have to be performed, just as would have been done in Case A.

So, the purpose of that is to avoid a duplication and reduce the bureaucratic and regulatory burden.

Mr. FINNEGAN. When you say no other entity, do you mean no other Federal entity?

Mr. HANFLING. No other Federal entity.

Mr. FINNEGAN. Thank you.

Mr. DINGELL. The Chair is going to recognize Mr. Barrett for a question.

Mr. BARRETT. Mr. O'Leary, we have been told without the administration plan coal usage in 1985 would be approximately 1 billion tons. With the administration plan, it would be increased by some 200 million tons, to about 1.2 billion.

Now, of this 200 million increase, the majority is in the industrial area, something on the order of 180 million tons.

Mr. O'LEARY. 177, as I recall the number.

Mr. BARRETT. This would bring industrial usage from something like 205 million tons without the plan to something like 385 million tons with the plan.

Mr. O'LEARY. It brings it from 206 in the base case to 383.

Mr. BARRETT. So it is approximately 180 million in the industrial area increase. Last year industrial usage was something on the order of about 61 million tons.

Mr. O'LEARY. It was 146, Mr. Barrett.

Mr. BARRETT. Your 146 figure is including metallurgical coal?

Mr. O'LEARY. That is the total industrial use, and I would assume it includes metallurgical coal.

Mr. BARRETT. What is the basis for this conclusion that we can raise it to 205 million or to 385 million? Are there some studies that would support this?

Mr. O'LEARY. What we are doing is making a projection with regard to the rate of industrial expansion; that is to say, the addition of new large burners in the economy, and making the assumption that the bulk of those will go to coal. That is the predicate for this.

Mr. BARRETT. My question was, is there a study that has been performed that is the basis for these conclusions?

Mr. O'LEARY. Yes, there have been studies. There have been statistical studies that indicate the expansion, the deployment of new boilers, and the proportion of that that we would anticipate will be captured by coal with and without the plan. They are not elaborate studies.

Mr. BARRETT. What I am asking is, is there a Learner study or Learner report, performed by EEA, that would have formed the basis for some of these conclusions?

Mr. O'LEARY. No, I don't think so. I think these are straight statistical extrapolations. We apparently are in the process of developing the back-up for this, and will have it available for the committee next week.

Mr. BARRETT. At the present time the report is not completed.

Mr. O'LEARY. Yes, that is true.

Mr. BARRETT. Thank you.

Mr. DINGELL. Gentlemen, I am advised that the Japanese are going to need a billion tons of coal by the year 2000. Is that correct?

Mr. O'LEARY. You are advised what?

Mr. DINGELL. That the Japanese propose to import about a billion tons of coal by the year 2000. Am I correct on that?

Mr. O'LEARY. That would sound, Mr. Chairman—we will check that—that sounds a little high to me. I would suspect their base now is something in the range of 100 to 150 million tons of imports at the moment. Most of that is metallurgical, as you know.

Mr. DINGELL. Can you advise us where they are going get it? Is it going to come from this country? What does that do to the calculations with regard to coal production?

I think in fairness to you, Mr. O'Leary, you better submit this to us.

Mr. O'LEARY. Mr. Dingell, I would imagine what they would do is go to closer sources. There are substantial resources, if this is steam coal, and I can only conceive of this volume of imports as a surrogate for oil or for nuclear, steam coal—they could get it, for example, from Australia. There are enormous deposits in Malaysia, Indonesia, and I would imagine that they would not look upon the United States as a principal source of that coal.

Mr. DINGELL. I am advised they have bought a large number of mines in this country already.

Mr. O'LEARY. Yes. They have been systematically getting a position here in metallurgical coal, Mr. Chairman.

Mr. DINGELL. Let me ask Mr. Davenport—can you give us some information as to whether or not these figures will skew your estimates on the transportation capability of this country, both with regard to trucks and also with regard to railroads, which are obviously methods in which the coal would be transported. If you could submit that information for the record, I think it would be appreciated.

The Chair would also like you to submit us some appreciation of the impact on trucking and the capital needs of the trucking industry with regard to coal conversion.

[The following information was received for the record:]

Railroad Export Coal Requirements

FEA projects that coal exports will increase from the current level of approximately 65 million tons annually to about 80 million tons in 1985. All of this coal will come from the Eastern U.S., and nearly all of it will be exported through Norfolk-Newport News, Cleveland and Baltimore. It will primarily be metallurgical coal. This relatively small increase in coal traffic has already been incorporated into railroad plans, and can be met with little difficulty.

The Japanese will import more than 25 million tons of metallurgical coal from Eastern U.S. fields. They will be able to obtain satisfactory steam coal from sources much closer than the U.S., so we do not expect to export any steam coal to Japan.

This Department has seen no evidence that any potential problem will arise in connection with the capital needs of the trucking industry for hauling coal.

According to data collected in the 1972 Census of Transportation, there were then 210,000 dump trucks classified as heavy-heavy (capacity of 7 cubic yards or more). It is estimated that about 10 percent, or 22,000 of these were engaged in the mining sector. According to Bureau of Mines data, there were 3,600 trucks (presumably all dump bodies) engaged in 1969 in hauling coal from the mines to a transloading facility (1969 was the last year in which these data were collected). These figures suggest adequate excess capacity in the mining sector alone to transport increased amounts of coal. And there were in 1972 almost 190,000 more heavy-heavy dump trucks available whose major use was in another industrial sector.

The Truck Body and Equipment Association informed us that more than 60,000 dump truck bodies have been produced yearly, and that the industry is capable of continuing at that level.

Although there is no way to separate dump truck chassis production from the production of all truck chassis, we have been assured by an industrial expert in the Census Bureau that there is room for expansion of production, since heavy truck manufacturing plants are now operating much below capacity. In their study, "Kentucky Coal and Its Transportation Impacts," the Kentucky Department of Transportation estimated that the number of trucks in that State utilized principally for coal hauling would increase from 2,890 in 1973 to between 5,254 and 6,268 in 1984. They expressed no concern about the availability of the trucks, but did express concern about the harmful effects this increased number of heavily laden coal trucks would have on the highways over which they would travel.

And this capability of the highway system is the segment of the coal-hauling-by-truck problem that we have been thoroughly investigating. A study that we shall be submitting to the Congress will report that approximately three-fourths of the costs of all energy-related highway improvements that the States estimate will be needed between now and 1985 would be incurred in building or rebuilding roads used for the hauling of coal. And almost 90 percent of these estimated costs of needed coal-haul road improvements were submitted by the Appalachian States. (This study was called for in Section 153 of the Federal-Aid Highway Act of 1976–P.L. 94-280.)

Mr. Dingell. Gentlemen, we have kept you all overlong. We do apologize to you. I think you will agree that the questions have been meaningful. We have been trying to get some information on which we can proceed on the legislation before us.

Gentlemen, we thank you all. The subcommittee will stand in recess until 2:30 p.m..

With our thanks, we excuse the panel.

[Whereupon at 12:50 p.m., the subcommittee recessed, to reconvene at 2:30 p.m.]

AFTER RECESS

[The subcommittee reconvened at 2:30 p.m., Hon. John D. Dingell presiding.]

Mr. DINGELL. The subcommittee will come to order.

This is a continuation of the hearings of the subcommittee on the National Energy Act, title I, part F, amendments to the Energy Supply and Environmental Coordination Act.

Our panel this afternoon is a panel on the impact of conversion: Mr. William B. Marx, Mr. Daniel F. Twomey, Mr. Loren V. Forman, and Mr. James Price.

Gentlemen, we have done you an unkindness by having our panel this morning persist rather longer than was our intention. I express to you our apologies in the hope that we have not inconvenienced you.

Gentlemen, would you please, starting on your left, and on my right, identify yourselves each, please.

STATEMENTS OF JAMES U. PRICE, DIRECTOR OF CORPORATE ENGINEERING, M. LOWENSTEIN & SONS, AND CHAIRMAN, FINISHERS ENERGY CONSERVATION SUBCOMMITTEE, AMERICAN TEXTILE MANUFACTURERS INSTITUTE; ACCOMPANIED BY JAMES A. MORRISSEY, SECRETARY, ATMI ENERGY POLICY COMMITTEE; LOREN V. FORMAN, VICE PRESIDENT, ENVIRONMENTAL RESOURCES, SCOTT PAPER COMPANY, ON BEHALF OF THE AMERICAN PAPER INSTITUTE; DANIEL F. TWOMEY, DIRECTOR OF TRAFFIC, CHEMICAL GROUP, CELANESE CORP.; AND WILLIAM B. MARX, EXECUTIVE DIRECTOR, AMERICAN BOILER MANUFACTURERS ASSOCIATION; ACCOMPANIED BY ROBERT WELDEN, FOSTER WHEELER ENERGY CORP.

Mr. PRICE. James Price.

Mr. FORMAN. Loren Forman.

Mr. TWOMEY. Dan Twomey.

Mr. MARX. I am Bill Marx. I would like to introduce Mr. Welden and Mr. Meyer with me, sir.

Mr. DINGELL. Gentlemen, you are all welcome.

Now that you have identified yourselves each, if you would begin. I think in the interest of time we will insert each of your statements in the record in full and recognize you for such summary.

Counsel advises me another gentleman desired to be heard, Mr. R. Timothy Columbus. Is he present in the room? He is not.

Then, gentlemen, without objection, his statement will be placed in the record.

Mr. DINGELL. Gentlemen, we will hear you, commencing first with Mr. Price.

STATEMENT OF JAMES U. PRICE

Mr. PRICE. Thank you, Mr. Chairman.

My name is James U. Price, of M. Lowenstein and Sons, a major textile manufacturing and finishing company and chairman of the Finishers Energy Conservation Subcommittee of the American Textile Manufacturers Institute. I am accompanied by James A. Morrissey, who is secretary of the ATMI Energy Policy Committee.

My appearance here today is on behalf of the American Textile Manufacturers Institute, which is the central trade association for the U.S. spinning, weaving, knitting and finishing industry. The membership of ATMI accounts for about 85 percent of the U.S. textile production. Our industry employs nearly 1 million people in 47 States.

We certainly appreciate this opportunity to offer the comments of the textile industry on Title I—Conversion to Coal and Other Fuels of H.R. 6831, the National Energy Act.

Since 1973, the American Textile Manufacturers Institute has conducted an active energy program, the basic thrust of which has focused on conservation. ATMI members are participating in the voluntary energy reporting program under the Energy Policy and Conservation Act. Our first report to the Commerce Department under this program comparing 1976 energy consumption with 1972, shows an 11.4 percent reduction in the amount of energy needed to produce a pound of fabric.

Textile manufacturers believe very strongly that reliance on the free market mechanism and voluntary conservation measures must be the foundation of a fair, equitable and effective national energy policy. Our industry strongly supports deregulation of oil and natural gas so that the free market might then encourage development of domestic resources and at the same time permit market prices to allocate fuel and encourage conservation and conversions. Government intrusions into the free market are chiefly responsible for the situation in which we find ourselves today.

Realistic pricing of natural gas and oil, at the true replacement cost, would bring about the fuel conversions voluntarily that would be mandated by the legislation you have before you today.

In the face of energy price increases and the natural gas shortages that already have been experienced, the textile industry is converting from oil and natural gas when it is technologically and economically feasible. On May 12, the Daily News Record, a publication which covers the textile industry, carried a round-up on the extent to which some companies already are converting to coal. With your permission, I would like to submit a copy of the article for the record.

This summary and additional conversions we know of illustrate that the textile industry is moving toward greater use of coal.

While we support greater utilization of coal, we are concerned that this bill does not adequately address three basic problems in connection with a major conversion to coal from oil and natural gas. These are (1) environmental impediments to greater use of coal, (2) problems associated with the transportation and handling of coal and the disposal of coal waste in and around plants that have been built to use oil and natural gas, (3) the tremendous economic impact of a major conversion to coal.

In addition to these general problems, the bill is based on the erroneous assumption that conversion to coal from gas and oil is simple. This is not the case in the textile industry. Most of our boilers were originally designed for gas and oil and are not physically suited for conversion to coal.

The textile industry has additional problems in the conversion of boilers to coal, even when the boilers were originally designed to burn coal. Some of them were built and installed in the early 1900's. Manufacturers of the original equipment no longer make parts needed in order to make conversions. Areas that were once used to store and handle coal and ash have now been utilized for additional production buildings and facilities. The utilization of this space for these buildings eliminates the possibility of having adequate on-site storage for coal.

The conversion to coal from gas and oil will require additional energy consumption per pound of steam produced and per pound of finished textile product. This additional energy consumption will be in the form of additional coal, cinder and ash handling equipment, air pollution control devices as well as the reduced efficiency of utilizing coal in converted boilers. The estimates on the additional fuel requirements range from 4-1/2 to 10 percent.

Capital formation is another major problem. Most manufacturers want to convert to coal where it is economically, environmentally and technologically feasible. However, mandated conversion without proper regard for individual company capital needs and without tax incentives would result in tremendous financial burdens.

The bill calls for a ban against the construction of new gas or oil burning installations with a design capability of consuming fuel at a rate of 100 million Btu per hour or greater or a combination of boilers with a capability of consuming 250 million Btu. In addition, the Administrator would have authority to order conversion of certain existing boilers with the same capacity.

We question whether the Administrator should have authority to lower the threshold for boilers as provided in section 102(7)(c).

The textile industry uses a number of package boilers with a capacity of 100 million Btu or smaller. There is no technological or economic way to convert these boilers to use coal. If their conversion were to be mandated they would have to be scrapped. This would be wasteful and the amount of natural gas or oil saved would not be worth the cost of the economy.

In view of the significant economic costs to the Nation involved in ending boiler fuel use of natural gas and oil, we believe the inflationary aspects of fuel conversion could be reduced significantly by distinguishing between new and existing boilers. Conversion also should focus on those boilers which have the capability of being converted at reasonable costs. Large field boilers in the area of 300 million Btu per hour should be built or converted to use coal first.

The American Boiler Manufacturers Association has estimated that total replacement cost for units at the 120 million Btu per hour and above level would be $49 billion exclusive of the cost of pollution control equipment. If this threshold were raised to 300 million Btu per hour, the replacement cost drops to $24 billion, less than half that of the lower threshold. Yet, boilers in the 100 to 300 million Btu per hour range use only about 8.6 percent of the total industrial and utility boiler fuel gas and oil consumed. Obviously, the return, in terms of gas and oil conservation, is infinitely better by focusing on the large boilers.

The National Coal Association has testified before this and other committees of Congress to the effect that a good deal of coal is already committed under long-term contracts to electric utilities. A massive program converting both new and existing boilers in the 100 million Btu range in the proposed timeframe would result in very serious shortages and skyrocketing coal prices. This could lead to Federal coal allocation and price controls.

The national interest would be better served by permitting a phased conversion to coal based on economic incentives and the forces of free market pricing.

In closing, let me say that the textile industry has a deep and abiding commitment to conserve energy and to use fuel in the most efficient manner. We share with the Congress and the administration a great sense of urgency to get on with the job. It is particularly important that uncertainties be removed where coal conversion is concerned.

Many decisions are being postponed because industrial consumers do not know what is going to happen. We hope we can work closely and cooperatively with you to develop a national energy policy which will be fair and equitable to all consumers of energy and provide the resources needed for a strong and growing economy.

I would also like to submit for the record an article that appeared in the Wall Street Journal on May 26, yesterday, which points up this fact in some detail.

[The newspaper article referred to follows:]

Switch to Coal New Burden for Textile Mfrs.

BY RALPH REYNOLDS

CHARLOTTE, N.C. — The switch or, in certain cases, the return to coal-fired boilers is viewed as inevitable by the major supplier of natural gas to textile companies in the Piedmont Carolinas. And it adds another burden in the form of pollution control expenses for the textile companies.

The posture of various textile firms varies, with some well along the way in establishing long-range conversions from other fuels to coal; others are still in the early planning stages. But regardless of their programs' status, all agree the expenses involved are high, whether for pollution control of stack emissions or investments in new coal-fired boilers.

Most textile executives agree one of the effects of the shift in national energy policy should stimulate some growth in various sectors of the industrial fabrics market from filters to baghouses to higher demand for heavy belting fabrics as a result of stepped up coal-mining operations. But they are reluctant to even estimate in terms of general figures at this time.

They feel projections are somewhat premature, dependent on the ultimate national energy policy approved by Congress.

Forrest L. Collier, vice-president of Piedmont Natural Gas Co. here, finds "no fault in the suggestion of coal for boiler fuel. It's something that had to come sooner or later. Actually it is wasteful to use a premium fuel in boilers, but no one ever paid much attention to it until now.

"So it does make sense not to use gas as a boiler fuel when others are available. We should save the premium fuel for premium uses, as in those operations, say in textile finishing, where the gas flame is essential.

"From our standpoint, the use of coal to fire boilers does not affect us, since for the past two years, we haven't sold the huge volumes of gas that we did five to ten years ago for major industrial users to fire their boilers. There hasn't been that amount of gas available. None in the winter and very little in the summer. So we and they have been weaned away purely and simply because of the shortages. The combination of the shortage of gas available coupled with the coldest winter in 80 years proved that point," Collier said.

Following alphabetically are summaries of the status of some major textile firms on their energy conversion and conservation programs.

At **(Burlington Industries)**, William A. Klopman, chairman, president and chief executive, characterized that firm's posture at the annual shareholders meeting earlier this year, and company spokesmen indicated it has remained essentially the same.

Klopman reported the firm had recently installed five new large coal-fired boilers and plans to continue putting in coal boilers until about 1980 when the company will be providing over 50 per cent of its steam capacity from coal.

Burlington has equipped many of its plants with multiple fuel burning systems to protect itself from shortages of natural gas, he noted. And recently the company entered into contracts with two outside gas exploration firms to explore natural gas deposits, scoring two hits.

In discussing capital expenditures for 1977, Burlington listed some $200-$225 million, with approximately $7.5 million earmarked for projects designed to reduce energy costs and provide alternate sources for steam and processing, including additional coal-fired boilers.

At **Collins & Aikman Corp.**, Leigh Woodall, manager of energy conservation, said, "We are in the process of formulating our long-range plans in view of the national energy policy as now proposed. We do have one of our larger units now on coal for boiler steam and are planning at least a couple of conversion projects, mostly from combinations of gas and No. 6 fuel oil. But as yet we haven't established the target date for conversion.

"At the present time, we are using mechanical collectors for fly ash and with the future conversions to coal, we haven't completely decided on the route to go for pollution control," Woodall noted.

At **Cone Mills Corp., Greensboro, N.C.**, Lewis S. Morris, chairman and chief executive, commented at the annual shareholders meeting of the firm's three larger boiler operations, one had been converted to coal; the other two use fuel oil. "We are presently in the middle of a detailed study of what would be involved in switching back to coal."

Of the three large boiler installations at Cone, one exceeds 250,000 million BTU output per hour. It is not on coal, but is equipped to use coal with the exception of air pollution devices.

The cost to install pollution control devices to meet existing regulations at Cone's largest boiler site would be in the neighborhood of $2.5 million. The estimated cost of air pollution control devices on all the company's boilers should be approximately $4 million.

"We have made preliminary studies on each boiler at each location and determined which can be converted and which ones should be replaced. The pace at which this will be done depends a great deal on legislation and the national energy policy," Morris said.

The cost of a new coal-fired boiler with 125,000-pound capacity is about $2 million, he pointed out.

At **Graniteville Co., Graniteville, S.C.**, Jerry R. Johnson, vice-president operations estimated "about 75 per cent of our boilers are on No. 6 fuel oil, 25 per cent on coal.

"We can convert another 100,000-pound boiler to coal at not much expense. This was originally coal-fired, and we converted to gas, so we will be going back in the other direction.

"Two other boilers in that same plant complex are coal-fired now so our immediate plans there are to wait and see what happens," Johnson said.

"Another thing to consider is what this will do to the boiler manufacturers. I don't think they'll be able to meet the tremendous demand that could occur," Johnson observed.

At **Springs Mills, based at Fort Mill, S.C.**, coordinator of energy conservation and supply, William S. Hood, explains his company's position this way.

"The Grace Bleachery plant in **Lancaster, S.C.**, has its own coal-fired steam and electricity generating facility. Since dyeing and finishing accounts for some 60 per cent of total corporate energy consumption, the Grace operation is a tremendous factor as far as energy is concerned.

"All of the electricity and steam consumed is generated from coal. So we have 65 per cent of total energy at Grace already on coal. Companywide, about 30 per cent of our energy is purchased electricity and the remaining 70 per cent is made up of fuels of various types from natural gas, fuel oil and coal. Of that type, 70 per cent already is coal.

"Several years ago we installed electrostatic precipitators on our power plant at Grace. So we are in good shape as far as those pollution control standards go," Hood said.

At **J. P. Stevens & Co.**, assistant director of the manufacturing services division, W. A. L. Sibley, Jr., based at Charlotte, assesses his company's status "as not now having 50 per cent of our boiler capacity on coal but undoubtedly we would approach at least that with some near-term plan.

"With incentives to move toward coal, we are assessing the present situation with respect to gas and oil-fired boilers and putting together a priority schedule that makes the most sense to convert those back to coal, if, in fact, it is necessary, through phaseout and replacement.

"We have quite a number of coal-fired boilers throughout the company, and a number fired by oil and natural gas. We are concerned not only with the conversion from oil and gas, but we also have to face the pollution problem in respect to coal.

"At this time, we don't have baghouses or electrostatic precipitators but use multiclones, the cyclone device, to filter out particulate matter," Sibley said.

"Fabrics associated with coal production undoubtedly would receive some impetus from the national energy policy. With baghouse fabrics, it seems these are more a function of the environmental equation and whatever Congress sees fit to relax pollution standards, or in fact, make them tighter as more coal is burned," Sibley said.

Mr. DINGELL. I just want you to know, Mr. Price, the subcommittee finds ourselves very much impressed with your statement, particularly some of the suggestions you have given with regard to using things like refuse, bark, and that sort of thing in connection with construction.

I would like to get your comments on those matters after we hear the other panel members because I think they will be most helpful to us all.

Mr. Forman?

STATEMENT OF LOREN V. FORMAN

Mr. Forman. My name is Loren V. Forman, vice president of Environmental Resources and Chairman of the Corporate Energy Committee at the Scott Paper Company. I appreciate this opportunity of appearing before you today on behalf of the American Paper Institute. This is the trade association of the pulp, paper and paperboard industry.

The testimony which was submitted carries all the statistics, composition and so on, on the American paper institute. I will skip over that.

The paper industry is very proud of its energy achievements and it is anxious to make further positive contributions to resolving the Nation's energy dilemmas.

Since this statement has been submitted for the record, I am going to assume that the members have either read it or will read it, and I recommend that, and therefore I will not go over it in detail. I will just try to hit two or three of the highlights and leave time for discussion, if you wish.

I would like first to call your attention to one of the major differences between the pulp and paper industry and some of the other industrial segments.

While we rank up in the top five of the industrial categories in terms of the total energy consumption, we are unique because we supply 45 percent of our own needs from nonfossil fuels, from bark and hogged wood and process wastes and that sort of thing.

I want to emphasize the contribution of these process waste fuels because they are renewable; they are not finite, as all of the fossil fuels are. Therefore, this puts them in a preferred category in terms of saving our fossil fuels.

We actually believe at least in our industry that the conversion to more of these nonfossil fuels and maximizing the use of these nonfossil fuels really deserves a higher priority than the conversion to coal because of the reasons that I just stated.

It is not an easy thing to do. These are more expensive routes to go. These are more expensive boilers, more expensive to operate. But, in conserving the total finite fossil energy supply, here is a way to stay current with the solar energy being turned into wood substance—the raw materials which we use.

Mr. BARRETT. Excuse me, you mean by that more expensive in the initial investment?

Mr. FORMAN. And in the operation—in most cases. Hardwarewise, certainly.

At this point we would simply make the observation that if we must convert to coal, according to arbitrary sequences and procedures, that we can see a lot of problems, which we have detailed in our written testimony. These vary from availability and cost of coal to the equipment, and other things. But, I would like to highlight particularly the last one in the list in the testimony, which is the question of the environmental conflict with the coal conversion that we see down the road.

We believe that we are going to be encountering the nondegradation problem, the nonattainment problem, and that the present procedure, as I understand it, for the NOI and NOE conversion sequence doesn't really get into the meat of the environmental conflict until you are well down the road.

If there is any one suggestion that I would make, apart from the written testimony here, it is that I believe it would serve all parties better if we could move that—the environmental decision—up earlier in the process so that we don't waste time on something which is going to be tossed out on account of the cost of environmental compatibility.

We then have mentioned in our testimony the experience of one company in our group who received NOI's recently. Fifteen of the 24 NOI's came to the pulp and paper business, and some of us got more than one. Scott Paper Company got two, and there are two boilers at each location. I could discuss those with you if you wish, but for the moment I will just say I pretty well document and agree with the testimony written here about another company, I would expand it just a little bit to point out that the method of choosing which boilers should be candidates for coal conversion by the FEA is something we don't understand yet. We are not yet on the same beam, and not moving in the same direction.

I might take just a minute to explain our procedure. Our Corporate Energy Committee has been working on this for some time and it is going to be 6 months to 1 year before we get it thoroughly sorted out. We are paying attention to two or three things in the first rank of priority.

One is to look at the overage boilers in the company. There are quite a few. Most companies of any size have boilers of all ages, and they have some that are pretty old. Boilers are like people. They don't all live the same length of time. It seems to me that we all pretty well agree that when we replace old boilers, they will be replaced with, in our case, either nonfossil fuel boilers or coal boilers, wherever that is feasible.

There is certain merit in doing that in a first-rank priority before converting the younger boilers that seem to be the focus of the present NOI program in FEA. One reason is that these are very expensive things to install. The capital limitations require some degree of scheduling. If you sequence the replacement of your old boilers in an orderly fashion, it would seem as though it will work out better than if we ignore those old boilers, focus on the younger ones, and convert them, and suddenly also have to replace the old ones with both replacements pyramided in a given year when the capital is very short.

A second reason is this: We in our business do a lot of electric generation as a part of the in-house energy consumption. We burn the fuel, we make the steam, we make some electricity from the steam, and we also use the steam in the process. By doing that, we get about twice the efficiency out of the use of the fuel that some utilities get when they use condensing turbines and simply make steam, spin the turbine and condense the exhaust steam which heats the water—the condenser water.

Therefore, for the Nation as a whole there seems to be a compelling reason to move in the direction of cogeneration of steam and electricity, both in utilities and also in industry. We would like to do this. This takes, however, putting in boilers of a little higher pressure.

So, back to where I started. As you replace the older boilers, you would put them in for higher pressure. This would give you the opportunity in many cases to do some electric generation. That would be very positive.

Similarly on the other side, although this is out of my field, I would suggest that the siting of utilities near people who could use some steam, by-product steam, would certainly be helpful in the overall picture.

In our case, without going into details, I just want to mention a brief point about each of the two NOI's. They are too fresh to have been thoroughly digested or understood. But, we do know this—that the boilers chosen would not be in the first or second rank of our priority choosing. There are others that seem to make more sense, which would use more coal per million dollars cost of conversion, and that sort of thing.

In the case of one of our mills, the two boilers identified are burning wood. We have been led to believe that wood boilers would not be involved in coal conversion, at least not early on. We certainly would think that it might be better to hold off a little on those, and to convert boilers which are 100 percent on gas or oil, and will go 100 percent to coal, so that you will have the maximum return on the cost of this conversion.

Of the four boilers involved only one has ever burned coal, and that was some 25 years ago. All the coal handling equipment is gone. I think the criteria, as it is being applied by FEA on coal burning capability, has been made a little bit too all-inclusive—to just look at the design of the boiler box itself, if that is what they are doing, and that is what it seems like.

In the case of the other NOI the mill is near an urban location. For example, in this location there are some old boilers that to me would make more sense to be converted, that is, replaced, first, sometime in the next 10 years. We are on our own moving out of gas first and then replacing oil with the nonfossil fuels where possible, and then going to the coal where this is feasible.

There are a few boilers which did burn coal within the last 10, 12 years, and probably could be converted at a minimum cost, and this will be considered as we prioritize these things.

This urban location, if we would convert now, would cut us off from the possibility of the alternative routes which are indeed very attractive and wise routes. One of these is the use of municipal waste. We are seriously considering providing the energy requirements for this mill from the combustion of the combustible portion of municipal wastes. If these two boilers are converted to coal now, as the NOI sequence has started rolling, that option will be excluded. We cannot do that.

Secondly, for a long time we have been interested in this possibility of cogeneration, with a very large utility nearby. In our investigation of that,3 , 4, 5 years ago, we found no interest on the part of the utility because it felt that its regulatory requirements prevented it from doing much in that direction.

Mr. DINGELL. You say you found no evidence of interest from them because of the regulatory requirements? What regulatory requirements are you referring to?

Mr. FORMAN. This was a foreign thing to their way of thinking.

Mr. DINGELL. No regulatory bar from state or Federal Government?

Mr. FORMAN. I cannot give you the details. My impression was they felt their regulatory restrictions focused them on the delivery of electricity, not steam.

Mr. DINGELL. Not steam?

Mr. FORMAN. That was my impression, and we would like to buy both.

Mr. DINGELL. In what State was this?

Mr. FORMAN. This is Pennsylvania.

Mr. DINGELL. Is there any requirement in Pennsylvania law on this point that bans them from doing this?

Mr. FORMAN. I can't answer that. But, I can tell you the point of my story is they are now interested. This is good news for us. We are going to investigate it. I don't know if it will work, but it is an alternative here which would be a very desirable one, which would be ruled out if we go ahead and convert at this point. That is my message.

So, to wind it up, we are trying, as you are, to sort this thing out and get the most effective, most economical, and most efficient way to proceed with it. Our industry indeed stands ready to work with you and FEA, if we may, to help you and to help us find the right solutions.

Thank you very much.

[Mr. Forman's prepared statement follows:]

STATEMENT OF AMERICAN PAPER INSTITUTE, INC.

INTRODUCTION

I am Loren V. Forman, Vice President, Scott Paper Company. I appreciate this opportunity of appearing before you today on behalf of the American Paper Institute, the trade association of the pulp, paper and paperboard industry.

The 200 member firms of the Institute produce more than 90% of the pulp, paper and paperboard manufactured in the United States. Net sales of the paper and allied products industry in 1976 were $39 billion. The industry employs about 680,000 people in approximately 6,000 facilities. Last year, its outlay in wages, salaries and benefits amounted to over $11 billion, and it paid approximately $2 billion in federal, state and local taxes.

The industry welcomes the efforts being made by the Administration and the Congress to develop an effective national energy program with emphasis on energy conservation and reduced dependence on imported petroleum fuels.

With due respect to these considerable efforts, however, we believe that inadequate attention has been given to stimulating domestic supplies of appropriate fuels, and to the multiplicity of problems for industry in a program which would add to the regulatory role of government.

However, the paper industry is anxious to make a positive contribution to resolving the nation's energy dilemmas and I feel that I can be most helpful by giving you briefly some background on what our industry has achieved to date in its conservation of energy and in its efforts to shift away from petroleum-based fuels. I then plan to point out how the proposed amendments to the Energy Supply and Environmental Coordination Act of 1974 would affect the paper industry and suggest certain changes.

THE PAPER INDUSTRY'S PATTERNS OF FUEL USE

While the paper and allied products industry ranks among the top five manufacturing industries in total energy consumption, it is unique because it generates 45% of its energy requirements from non-fossil, self-generated, waste fuels. These fuels include bark, hogged wood (chipped residues from forest and manufacturing operations) and spent pulping liquors from which chemicals as well as energy are recovered.

I want to emphasize the contribution of these process waste fuels because they are renewable, being derived from trees which themselves utilized solar energy.

The self-generated proportion of the industry's total energy requirements has been increasing - from 42% in 1972 to 45% last year. Over recent years, the industry has been substituting wood-waste fuels for oil and natural gas. This substitution has been made in response to market forces. We believe, also,that this is in line with the intent of the Administration's proposed program. In 1976, the substitution represented an equivalent annual saving of 8.4 million barrels of oil.

This trend has been revealed by API's monthly Energy Monitoring System in which 85% of the industry's capacity regularly participates. The system has also revealed other trends in fossil fuel and purchased energy use between 1972 and 1976. For example, the industry's use of natural gas has declined from 20% to 15%, fuel oils have increased from 23% to 24% and purchased electricity from 4% to 5%. We estimate electricity needs, approximately 75% of which was cogenerated, that is, generating electricity as a by-product of process steam production.

Since coal is the subject on which your Subcommittee is concentrating today, let me report that the paper industry's use of coal declined from 10.5% in 1972 to 9.1% in 1975, partly as the result of environmental requirements but also because, for many mills, it was simpler and cheaper to use natural gas or fuel oils. Natural gas was particularly attractive because government regulations had kept its price artifically low in interstate markets, and it is unquestionably the cleanest of all the fuels. By 1976, however, API's data show that the contribution of coal had begun to move up to 9.5%. A number of companies apparently concluded that, in the longer term, coal would be a more reliable source of energy than natural gas and oil.

As another indication of the industry's shift away from imported fossil fuels toward using more of its own wastes, we would call your attention to the following table, based on information compiled by the American Boiler Manufacturers' Association (ABMA).

BOILERS ORDERED BY PAPER AND ALLIED PRODUCTS INDUSTRY, 1974 - 1976 - BY FUEL TYPE

FUEL TYPE	NUMBER OF UNITS	CAPACITY (lbs. Steam/hr)	% of Total
Spent Pulping Liquor	20	7,200,000	43%
Bark & Hogged Wood	15	4,085,000	24%
Fuel Oils	27	3,947,000	23%
Coal	4	983,000	6%
Natural Gas	13	729,000	4%
TOTAL	79	16,944,000	100%

These figures are further evidence that with a total of only 27 percent of new boilers being based on fuel oils and natural gas, there has already been a considerable movement in the direction of the industry's own wastes and to some extent toward coal as energy sources.

PROBLEMS WITH COAL

Expanded use of coal by the paper industry involves a number of broad aspects which raise grave questions that this Subcommittee and the government should consider.

a) Does the national interest warrant the mandatory use of coal by those pulp and paper plants in states which are remote from existing coal mines?

b) Will the nation have the capability to produce the enormous amount of equipment needed to mine, transport, handle, burn and clean up the air emissions from coal?

c) Is it realistic for the Administration to expect the nation to almost double its production of coal between 1976 and 1985 - from 7.9 to 14.5 millions of barrels of oil equivalent per day?

d) Will the environmental consequences of expanded use of coal add substantially to the industry's already heavy burden of capital investments required to meet present and future air and water standards?

e) Will many of the plants thought to be capable of conversion to coal be permitted to effect the change because they are located in non-degradation and non-attainment areas?

FEA'S CONVERSION ORDERS AND THE PAPER INDUSTRY

Under existing legislation, the Federal Energy Administration recently issued Notices of Intent, the first step in implementing its authority to prohibit oil and natural gas use in certain existing industrial boilers and to require that new boilers be built with alternative fuel-burning capability. Of the 24 existing facilities, 15* are owned by pulp and paper companies, representing 11% of the industry's 1977 total paper and paperboard capacity.

It is ironic and totally contrary to the efforts designed to reduce dependence on imported fuels that at least two of these fifteen facilities are multifuel or combination boilers using bark for the major proportion of their fuel.

The ten pulp and paper companies that have been served with the 15 NOI's to convert to coal have individually estimated their costs of converting and meeting expected environmental standards. The combined total exceeds $400 million. These additional and usually non-productive expenditures will seriously inhibit the ability of a significant proportion of the industry to add new capacity to meet the nation's future needs of pulp, paper and paperboard.

One API member company has been served with coal conversion NOI's for four of its 18 existing primary pulp, paper and paperboard mills. In public hearings earlier this week, this company pointed out that, on the basis of a cost-effective analysis, it has concluded that FEA has not selected the mills most appropriate for coal conversion. These conclusions were based on such factors as locations unfavorable to coal, approaching obsolescence and the availability of waste fuels. This company also expressed its determination to develop a strategy to systematically reduce its oil and natural gas requirements and to identify appropriate conversion opportunities. Obviously, more careful and expert analysis on the part of the FEA is called for in its current efforts to achieve expanded industrial use of coal.

*These 15 facilities are located in:

Alabama (1)	Michigan (1)	South Carolina (1)
Arkansas (1)	Mississippi (1)	Tennessee (1)
Georgia (2)	North Carolina (1)	Texas (1)
Maine (2)	Pennsylvania (1)	Virginia (2)

THE POTENTIAL OF WOOD WASTES SHOULD BE RECOGNIZED

In its efforts to achieve a switch away from oil and natural gas by the pulp and paper industry, the Administration should not regard coal as the only major alternative fuel. Energy legislation should clearly and specifically recognize the potential of wood and the manufacturing wastes of the forest-based industries as logical, economic and environmentally acceptable alternatives.

We would suggest the following:

1. Any legislation which the Congress enacts as a means to encourage a larger degree of energy independence should contain provisions which allow for the specific use of non-fossil, renewable fuels such as bark, hogged wood and spent pulping liquors. Municipal solid wastes could also qualify as an appropriate alternate fuel to oil and natural gas in many boiler applications. Our industry favors the maximum economic recovery and recycling of the paper component of solid waste before the combustible component is burned.

2. Current legislation and proposed amendments, in our view, give the Federal Energy Administrator unnecessarily broad authority to prohibit industrial use of oil and natural gas as well as to require conversion to alternative fuels. Experience with recent NOI's clearly indicates that the FEA does not have the best available information as a basis for valid decisions in this area, especially in regard to the paper industry's combination boilers capable of burning non-fossil, process wastes. We would recommend that such combination boilers be exempted from prohibition orders if their average annual use of non-fossil, waste fuels is 75% or more on a BTU basis.

3. Expanded use of waste fuels and coal in the pulp and paper industry could be accelerated by appropriate incentives, particularly in the tax area. The API testified to this effect before the House Committee on Ways and Means on May 18, supporting the proposed 10% additional investment tax credit for energy-related facilities which would use more of the industry's own wastes.

THE PAPER INDUSTRY WANTS TO MAKE FURTHER CONTRIBUTIONS

Let me repeat my earlier statement - the pulp, paper and paperboard industry is anxious to make further contributions to resolving the nation's energy dilemmas and reducing our dependence on foreign sources of energy.

We feel that this can be done by the regulatory agencies working more closely with industry in order to develop sound information on which to base the nation's overall energy programs.

Business must make its decisions largely on the basis of free market influences and the government should recognize that its regulations add a high degree of uncertainty to those decisions concerned with energy.

Finally, let me reiterate the paper industry's strong preference for the free market mechanism rather than price controls on oil and natural gas. Much of our present problem is the direct result of past controls on natural gas. We believe that a free market approach to all the fuels available to industry will assure impressive results by bringing to bear on the problems the innovative and creative abilities that have brought this country to its enviable level of economic and social development.

Mr. DINGELL. You have given us a very helpful statement which we wish to pursue further.

Mr. Twomey?

Mr. PRICE. Excuse me, Mr. Chairman. May I be excused. I have a plane to catch. Mr. Morrissey, with the ATMI, will be here to take any questions.

Mr. DINGELL. I apologize for our having held you.

Mr. PRICE. I am sorry I can't stay.

Mr. DINGELL. You go with the thanks of the committee. Thank you.

Mr. PRICE. Thank you.

Mr. DINGELL. Mr. Morrissey, would you identify yourself.

Mr. MORRISSEY. I am James Morrissey, secretary of the Energy Policy Committee of the American Textile Manufacturers Institute.

Mr. DINGELL. All right. We recognize Mr. Twomey.

STATEMENT OF DANIEL F. TWOMEY

Mr. TWOMEY. Mr. Chairman, members of the committee, my name is Daniel F. Twomey, Director of Traffic, Chemical Group, Celanese Corporation, a diversified producer of petrochemicals, fibers, plastics, coatings, and specialty chemicals.

As a result of the Texas Railroad Commission Docket 600, Celanese is converting its Pampa, Texas, plant from gas-fired boilers to coal-fired boilers in 1979 at a cost in excess of $70 million. The conversion will not increase our production capacity. Of this $70 million, $20 million will be for coal handling facilities, and $4 million will be for the purchase of coal hopper cars. We will be obtaining our coal from Wyoming or Colorado, where the railroads have a virtual monopoly in transportation.

Mr. DINGELL. You are talking about your company receiving its supply of coal from Colorado or Wyoming, regardless of where the plant is located?

Mr. TWOMEY. The plant is located in Pampa, Texas. We conducted a 2-year study for source of coal and zeroed in on these two areas.

Mr. DINGELL. You are talking just for one of your plants.

Mr. TWOMEY. Right, Mr. Chairman.

Our concerns in the transportation area relate to, one, obtaining a sufficient number of coal hopper cars to move 600,000 to 800,000 tons of coal annually, from 700 to 990 miles.

Secondly, maintaining these cars in first-class operating condition.

Thirdly, obtaining an equitable unit train freight rate for the movement of coal.

The number of coal hopper cars we will require will depend on the source of the coal. Inasmuch as we have been unable to obtain a realistic freight rate from the railroads, we are still at this late date unable to place an order for the cars.

With respect to the acquisition of these coal cars, the Carter energy legislation contains a provision for a tax credit for equipment used for unloading and transferring coal. We believe this provision should be broadened to include an investment tax credit for the substantial capital which will be dedicated to coal car acquisition.

Our second area of involvement, insuring that the rail cars will be maintained in first-class operating condition, has been very difficult and very time consuming for us. We have two choices. We can install our own maintenance facility at Pampa, or we can try to have the work done by an outside contractor. As of this date, we have been unable to find anyone willing to do this for us.

Our problem lies in the nature of the unit train movement. It is unlike anything Celanese has experienced in the past. For example, we have been operating a large tank car fleet for many years. Ask us anything about tank car maintenance costs, and we can almost answer you to the dollar. We have a detailed historical record filed to draw from on tank cars, which travel an average 24,000 miles a year.

But, these coal cars will travel 130,000 to 140,000 a year, or six to seven times as far as a tank car, and no one has any meaningful long-term historical maintenance data on them.

Under the circumstances, we think we have done the best we possibly can do. We have visited with railroads, shippers, receivers, car builders, and car component builders to discuss their maintenance experiences, limited though they may be.

On this basis we are projecting a maintenance cost of 4 cents per running mile on these cars or approximately $5,500 per year per car. A new tank car could be maintained for less than 1/10th of this cost.

Our third area of involvement and the most frustrating involves our efforts to obtain an equitable freight rate. We believe our rate should approximate the level of rates now in effect to such points as Amarillo, Texas, which is only 48 miles from Pampa, San Antonio, and Welsh, Texas, Pueblo, Colorado, and other points. After all, the

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transportation characteristics of our movement are basically the same as those I just mentioned. But the railroads tell us that they don't make unit train rates like this any more. They tell us they have a new rate level for us, and this is what they are trying to put over on us.

Well, this is exactly what they told the San Antonio Public Service Board. San Antonio took them to the Interstate Commerce Commission and the ICC recently prescribed a rate in line with what San Antonio had felt they were entitled to. The railroads appealed this action in Federal court, but the court upheld the ICC.

Since this time, Arizona Electric Power Cooperative and Houston Light and Power have filed similar complaints which are now pending before the ICC.

Furthermore, I understand Central Power and Light at Corpus Christi, Texas, is about to file a similar complaint. If we at Celanese cannot resolve our differences with the railroads very shortly, we will be doing the same thing.

We are being asked to pay artificially high freight rates by the railroads because they know they have no competition for the movement of western coal. In our opinion, this is a short-sighted attitude on their part, and it will hasten the day of the coal slurry pipeline which Celanese favors. When this happens, their so-called captive traffic will begin to disappear.

This concludes my statement, Mr. Chairman. Thank you very much for the opportunity to appear before you.

[Mr. Twomey's prepared statement follows:]

STATEMENT
BY
CELANESE CORPORATION
PREPARED BY
DANIEL F. TWOMEY
BEFORE THE
SUBCOMMITTEE ENERGY AND POWER
OF THE
INTERSTATE AND FOREIGN COMMERCE COMMITTEE
CONCERNING
THE TRANSPORTATION ASPECTS OF THE COAL CONVERSION OBJECTIVES
OF THE
PRESIDENT'S NATIONAL ENERGY PROGRAM

May 27, 1977

Mr. Chairman, members of the Committee, my name is Daniel F. Twomey. I am Director of Traffic, Chemical Group, Celanese Corporation, an independent petrochemical company. In my present capacity I am responsible for ensuring that the raw materials which we receive and the chemicals which we produce at Pampa, Bishop, Bay City and Clear Lake, Texas, Rock Hill, S.C. and Newark, N.J., move via the most economical means consistent with our service requirements and those of our customers.

I appear before you today in connection with "Title I - Conversion to Coal and Other Fuels" of H.R. 6831, the National Energy Act.

As a result of Texas Railroad Commission Docket #600, gas contracts for boiler fuel cannot be made, extended or altered after December 17, 1975 without having an exemption granted by the Texas Railroad Commission. Therefore in order to ensure the continued operation of our Pampa, Texas plant conversion to coal is necessary before the expiration of our current gas contract.

Our Pampa, Texas plant which manufactures a variety of chemicals such as Acetic Acid and Anhydride, Methyl Ethyl Ketone, Methyl Acrylate, 2 Ethyl Hexyl Acrylate, Propionic Acid and Formic Acid currently generates its required steam in gas fired boilers. Gas is currently supplied under a contract calling for decreasing volumes up to its expiration in 1980. It is our intention to replace these gas fired boilers at Pampa with coal fired boilers in 1979.

When this complex project is completed we will have spent in excess of $70 million dollars to convert from gas to coal and we will not have increased our production capacity. Of this total amount approximately $20 million dollars will be for coal handling facilities and approximately $4 million dollars will be for coal hopper cars to transport the coal.

Celanese is a major user of railroad services throughout the country. As a matter of fact 64% of our transportation bill is paid to the nation's railroads who transport 51% of our tonnage. Our interest in a financially sound railroad network is second to none, and the economic well-being of each of our plants is highly dependent upon safe, efficient, economical railroad service.

As receivers of coal from the west, Celanese will be responsible for selecting the transportation mode to be used (in this case we have no viable alternative to rail service in the next few years).

The Carter Energy legislation contains a provision for a tax credit for equipment used for unloading and transferring coal. We believe that this provision, should be broadened to include an investment tax credit for substantial capital which will be dedicated to coal car acquisition. We also believe that the credit should be made effective from the date of the President's proposal.

We will be responsible for supplying the coal hopper cars necessary to transport the coal and paying the applicable freight charges - if we can ever negotiate an equitable unit train freight rate with the railroads.

Let me briefly describe to you the transportation aspects of Celanese Pampa coal conversion project, our areas of responsibility concerning the project and where we are after nine months of effort.

Our primary areas of concern are:

1) Securing the necessary rail cars to transport from 600 thousand to 800 thousand tons of coal annually over a distance of, from 700 to 990 miles.
2) Developing a preventive maintenance program for the cars in order to ensure safe operation of the unit train.
3) Obtaining an equitable unit train freight rate to cover the transportation of the coal.

As a result of past practices with respect to unit train movements of western coal, the railroads require the shipper and/or the receiver to furnish the necessary coal hopper cars. We are now in the process of obtaining a sufficient number of suitable hopper cars to handle coal from one of two places: the Powder River Basin area of Wyoming or the area around Hayden, Colorado. Firm quotations have been received from only five of the twelve car construction companies to whom we submitted bids.

Although we requested a purchase and full service lease price from them, four firms quoted a purchase price only and one firm offered to submita full service lease proposal.

The number of cars required for our movement will depend on the source of the coal. Inasmuch as we have been unable to obtain a realistic freight rate from either source under consideration, we are still, at this late date, unable to place an order for the required coal cars.

Our second area of involvement, recommending a preventive maintenance program for the cars will require a decision on our part to:

1) Install a maintenance facility at Pampa to perform running repairs on the cars in order to protect the integrity of the unit train
or
2) Evaluate the feasibility of having the maintenance done for us by an outside contractor.

At the present time, no contract repair facility exists between the Colorado origin and Pampa, Texas nor are we aware of any plans to construct such a facility.

Developing a preventive maintenance program responsive to our needs has been and will continue to be very difficult and very time consuming. The movement of these coal cars will be unlike anything Celanese has experienced in the past. While the average tank car in our fleet travels approximately 24,000 miles in any given year, these coal cars will travel approximately 130,000 miles per year or 140,000 miles per year depending on the source of the coal. In other words, these cars will be getting six to seven years wear and tear on them in one year when compared to a tank car.

As a result of this and the fact that no one around has any meaningful historical maintenance data covering unit train operations for movements this long, we are contacting any and all railroads, shippers and receivers of unit trains of western coal in order to assist us in projecting maintenance costs and sizing our fleet of coal cars. Based on the information we have obtained thus far, we are using a figure of 4¢ per running mile as a maintenance cost on these cars. A new tank car could be maintained for less than one tenth of this cost.

Last but not least insofar as our areas of involvement is concerned has to do with our efforts to obtain an equitable unit train freight rate to cover the transportation of our coal requirements.

Quite frankly, the negotiations which commenced in September of 1976 have been rather frustrating. Basically, our position has been that the rates we should have from Colorado and Wyoming should approximate the level of unit train rates now published to other consuming points such as Amarillo, San Antonio, and Welsh, Texas; Pueblo, Colorado and Kaiser, California, giving due consideration to the different distances involved. On this basis, we believe a rate in the area of $8.00 per ton should apply from Wyoming and something in the area of $6.00 per ton should apply from Colorado.

The final offer we received from the railroads is substantially higher than these figures. As a matter of fact we consider it completely unrealistic. We will have one more meeting with the railroads and if we are unable to make significant progress towards obtaining an equitable unit train rate, we will be forced to file a formal complaint with the Interstate Commerce Commission as was done by the San Antonio Central Public Service Board, the Arizona Electric Power Cooperative and the Houston Light and Power Company.

The development of vast new coal deposits in the west - much of which will be marketed in the Texas area - represents a tremendous new business opportunity for the railroads to significantly increase their earnings without having to rebuild their existing plant - much of which is today under-utilized. On the other hand the almost total reliance of shippers and receivers on transportation by rail makes it absolutely essential that the pricing of railroad transportation services be free of monopolistic pricing tendencies.

Please do not misunderstand me. This is not to say that we espouse freight rates which are set so low as to deprive the railroads of a fair rate of return on their investment. Nothing could be further from the truth. As I previously mentioned the economic well-being of our plants and those of all shippers for that matter, depends on a financially sound railroad system.

What we do vigorously object to - and what we are experiencing today - are attempts by the railroads to set unit train freight rates at an artifically high level - in the absence of any meaningful intermodal competition.

Mark my words. If the current monopolistic - you have no alternative - pricing policies of the railroads persist and prevail, the day of the coal slurry pipelines will be upon them much sooner than they expect. In fact their "captive" shippers and receivers will become the driving force behind their construction. And sad to say, the glowing promise of heretofor undreamed of increases in their earnings for decades to come, will be irretrievably lost to the railroads.

Mr. DINGELL. Thank you very much, sir.
Mr. Marx.

STATEMENT OF WILLIAM B. MARX

Mr. MARX. Thank you.

I am William B. Marx, executive director of the American Boiler Manufacturers Association.

I think that I will, if it is all right with you gentlemen, run through our statement rather informally, highlighting the portions that seem to me to be of interest in light of this testimony, what I heard this morning.

Mr. DINGELL. Very well.

Without objection, your full statement will be inserted in the record, and we will recognize you then for the summary.

Mr. MARX. Thank you, Mr. Chairman.

On page 1 we make some basic points about conservation, conservation to us meaning taking an existing boiler which is burning one fuel and equipping it or redesigning it, rebuilding it, retrofitting it, to build another.

You will see we make the point that gas and oil-fired units are relatively convertible back and forth, but that neither one is convertible to coal unless in fact that unit had been designed originally with coal in mind.

If you will excuse this informality, I have some pictures here which I wish I had on a full scale. The first two are utility boilers. We have two basic designs, those for utilities and those for industrials. The first one is of a coal-fired unit and then page 2 is of a gas-fired unit. Those two happen to be fairly much on the same scale. Those ar exactly the same capacity.

I think you can visualize the inability of taking the second one and making it into the first one. In other words, we would have to burn much more fuel in that smaller unit, and it just simply cannot be done.

If you go to the next two, pages 3 and 4, and they are not to comparable scale–if they were it would be even more dramatic–the first unit is a coal-fired boiler, and the second unit an oil-gas-fired boiler for industry, and I think you can see the impossibility of making that unit on the fourth page into what you see on the third page. This point has been made by them and I guess it is beginning to be accepted, but I thought maybe looking at those, and I will be glad to leave those books with you.

I think the last two are as pertinent as any, and those show the relative total area required for a steam plant. The next to the last sheet in the book shows you the area which is required for a typical oil or gas-fired boiler plant. It is about 14 acres. The last page shows you the same size boiler plant coal-fired. Now, this is a worst case situation. We are exaggerating, but it could be this great. That is 300 acres.

In other words, you need 20 times the space in some situations. In any situation it would be at least five times. That, as I say, is perhaps every bit as important or more so than the boiler difficulty.

If I may, to go on to item B. On page 2, I will briefly touch on capital costs. We have first cited the example of a relatively large industrial boiler, a 250,000 pound an hour unit. This is a unit of roughly 25 megawatts if you put it in electrical terms. You can see the difference in cost between the coal-fired unit and an oil or gas-fired unit, $10 million as opposed to about $3.5 million, and this comparison does not include the flue gas desulfurization system. If you include that you are looking at $5 million, or something awfully close to a five-to-one ratio. This is a typical large industrial situation such as I think perhaps Mr. Forman might find himself involved with, this kind of capacity in a large energy-intensive industry such as paper, chemical, and refining.

On the next page we give some relatively different costs for utility units. Here we are, of course, assuming coal. Our order books show that in 1974 there were like one or two small noncoal-fired utility boilers ordered. There was one ordered in 1975, and there was none ordered in 1976. So these are just coal. We have cited the cost of a 600 megawatt unit, and if this were placed on order today, and these are 1977 dollars, you would have commercial operation about 1985. These figures, incidentally, do include scrubbers, $425 million for 600 megawatts, $500 million for an 800 megawatt, and $700 million for a 1,200 megawatt, and I have made the point that as you double in size you save about 20 percent in unit cost, that is, unit size cost. These are enormous figures and you can see, and that is on a unit basis, if you build a plant within let's say two-1200 megawatts units you would have a plant at a site with an excess of a billion dollars invested.

Item C, marketplace data. Here I have made the point that not only have utilities stopped buying oil-fired units but our industrial customers here at this table insofar as large units are concerned have ceased to buy them too. You will note down at the very bottom of the page in 1973 we sold 45 large industrial oil or gas-fired boilers. In 1974 we sold 54; in 1975, 21, from 1973 to 1975 down to 21. Last year none. Whereas the ordering rate of industrial coal-fired boilers has been essentially flat in recent years, and that is true. It runs at about 7 percent, and it is running that way this year.

To back up what Mr. Forman emphasized, a significant increase in the total of non-oil or gas-fired boilers, that is, those firing coal and by-product and waste fuel as well as coal, has occurred. From a 1972 figure of 22.7 percent of industrial boiler sales, these units are now up over one-third. And I made the point that our oil inquiries for industrial boilers show that the inquiries for coal and refuse-fired units run about two-thirds of the total. And in corroborating this trend a leading boiler consulting firm in the industrial field reported to me about a month ago that he had no gas-fired boiler inquiries on his books, and only 10 percent oil-fired boiler inquiries, with of course the obverse being 90 percent for refuse or coal.

There has been a lot of talk about the capacity of boiler service to respond to a boiler program, and that is why I include this next statement on page 3:

While an exact determination to total U.S. steam generator manufacturing capacity has never been made, industry estimates range from 20,000-30,000 megawatts coal-fired utility units and 6,000-7,000 megawatts coal-fired industrial units. We believe this capacity is adequate to respond to any credible national coal conversion schedule, and we have looked at this in some detail. In fact, one company projection I saw looking at coal-fired utilities boilers through about 1993 as I remember showed that in the peak year orders would run no more than 26,000 megawatts. So we sincerely believe that our industry's capacity is there right now.

There was some conversation this morning on new technologies in fluidized bed, and I think it is important to realize that these technologies are in the future. Perhaps the one which will come most rapidly is fluidized bed. Depending in our industry whether you are a bull or a bear, we think they will be offered on a commercial basis to industry in something like 3 to 5 years, but in the utility area we don't see them being purchased until 12 to 15 years from now.

Mr. DINGELL. Can you parenthetically tell us why so long, that 15-year period?

Mr. MARX. Well, yes, I will. ERDA has a number of projects that they are pursuing in the fluidized bed area and in the boiler field I guess they are probably in the neighborhood of seven to eight, and our member companies are involved in all of them. The largest unit and, interestingly enough, the one which is the closest to commercial operation, is in a utility plant in Rivesville, West Virginia, the Monongahela powerplant. It is 30 megawatts. This is somewhere towards the top of the line, so to speak, or the top size of an industrial unit, and although it is in a utility plant, and although at the time that project was conceived they were looking for utility impact, I think the perception of all of us is now that the result of the test of that unit will have quickest application to industry.

To go to utility size unit is going to require tremendous scaling up, and even when we were dealing with known technology as we were back, oh, perhaps in the early 1960s and so on we got into a fair amount of trouble when our utility customers were extrapolating average sizes at a great rate.

So I just think that it is going to take a number of steps in terms of size I believe to get to that point. I also think that utilities are going to be a little bit cautious about making the huge investments required, and I think they will be watching of course very carefully the results of the industrial sector, coupled of course with the fact, Mr. Chairman, of the extremely long lead time for a conventional unit. You start out with something like 5 to 8 years from date of order to commercial operation to begin with with existing technology.

I would like to make just one or two final points. There has been a lot of discussion about where the size limit should be. We have not stated for the record our opinion on that but I would like very, very strongly to say that wherever that comes out we would hate to see FEA be given the authority to reduce that limit in a given situation, and that was my point four on page 4. Otherwise the uncertainty syndrome will be perpetuated. Our orders are down where they haven't been this low for 40 years.

Mr. DINGELL. You have emphasized this point of certainty and uncertainty. That seems to be a major part of the problem. You have indicated that uncertainty with regard, I assume to Government policy, although you didn't say that is the major part of the problem we have in terms of getting the transfer. Is that right?

Mr. MARX. Yes.

Mr. DINGELL. Would you like at this time to address yourself with a little more force please to that?

Mr. MARX. Yes. The uncertainty of course exists in the marketplace, our marketplace, among our industrial customers and utilities customers, and I think there are two major ingredients here. On the utility side I believe the fuel picture is quite clear. As I have indicated, utilities are buying strictly coal, although I am sure they have concerns about perhaps being forced to retrofit in difficult situations. But they are concerned with environmental considerations, and whether or not they are going to be forced to put flue gas desulfurization systems on the back end of a steam generator even though it is firing low sulfur coal.

I think the capital costs associated with these scrubbers, they are tremendous, but when you get down into industrial sizes this factor becomes even more prominent. The unit cost goes up something like four times when you scale down from a utility size unit to an industrial unit. So that the cost of a scrubber in an industrial plant will generally exceed the cost of the boiler itself, and an awful lot of industrial firms I believe are waiting to see whether or not they will be forced to put this piece of equipment on the back end of their units, and I think many of them if they are forced to will not build new coal-fired units.

Finally—I pointed this out before, but I would like to read the summary—conflicting and confused signals from Washington in the closely related energy and environmental areas have cast a pall of uncertainty over U.S. industry and utilities; inaction is the inevitable result. New orders for steam generators in 1976 and so far in 1977 are running less than one-third of normal, i.e. at about the level of the 1930's. This means the Nation's coal conversion program is stalled. Legislation enacted must, therefore, reflect a policy which is clear, consistent and predictable over the period it is designed to affect. To prolong this uncertainty will cause grave damage to the Nation's energy supply.

I thank you very much, gentlemen.

[Mr. Marx's prepared statement follows:]

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Written Statement

on

(H.R. 6831) National Energy Act

"Title I - Conversion to Coal and Other Fuels"

Subcommittee on Energy and Power
(Committee on Interstate and Foreign Commerce)
House of Representatives

May 27, 1977

A. DESIGN

1. Gas-to-Oil Conversion

Most gas-fired boilers can be readily converted to oil at reasonable cost. Changes must be made to the fuel burning equipment and controls; modification of the internal boiler pressure parts may be required; and oil storage facilities, oil handling equipment, boiler cleaning equipment (soot blowers) and additional heat transfer surface will have to be installed in most cases. Little or no unit derating, however, is required.

In short, an oil-fired boiler is very similar to a gas-fired boiler although pollution control equipment will have to be added to the larger units.

2. Gas-to-Coal Conversion;

3. Oil-toCoal Conversion

If the unit was not initially designed for future coal-firing, gas-to-coal or oil-to-coal conversion of an industrial or utility boiler is virtually impossible and totally impracticable, both as relates to economic feasibility and boiler capacity, which can be reduced as much as 60%. All design parameters are radically different:

a. Coal furnace usually twice as large;

b. Much more liberal boiler tube spacing required;

c. Boiler hoppers are needed;

d. Added plant requirements:

   1. Extensive and expensive pollution control equipment;
   2. Ash handling equipment;
   3. Coal handling equipment;
   4. Coal pile area, etc.

THIS SITUATION REALLY MEANS BOILER REPLACEMENT.

4. Coal-to-Oil (gas)-to-Coal Conversion (Unit originally designed for coal-firing later converted to oil or gas)

In most instances a coal-fired unit later converted to oil or gas can be reconverted, depending upon how drastically the initial conversion was carried out. If the new coal differs greatly from the design coal, however, severe operating and capacity limitations could be encountered.

5. <u>Plant and Site Factors</u> (coal versus oil or gas)

a. Five to twenty times the total plant space is needed; this includes coal pile area, coal and ash handling equipment, larger boiler and auxiliaries, and in many cases, a buffer zone; the site often will be located in an urban or suburban area where a plot of the needed size may not be available;

b. Additional operating personnel are required;

c. Higher operating costs are incurred;

d. Fuel costs will be lower but differences will vary.

6. <u>Upgrading and Modernizing Equipment; Increased Efficiency and Reliability</u>

In order to increase the efficiency of an existing steam generator the following can be added:

a. Increased heat transfer surface; (economizer or air heater)

b. New components; (superheater, burner, tighter boiler enclosure, etc.)

c. Soot blowers; (ash cleaning equipment)

d. Blowdown recovery system;

e. Modern combustion control system.

By-product and refuse fuels firing or waste heat utilization can sometimes be added to an industrial or utility boiler plant. (See Exhibit "A")

B. CAPITAL COSTS (New Units)

The natural gas shortage will continue to force the use of alternative fuels whose selection will be governed primarily by availability and equipment costs. For example a recent survey of 300 large industrial steam users showed two-thirds more concerned with reliability of fuel supply than with cost.

The capital cost barrier can be great; an industrial coal-fired boiler plant of 250,000 pounds of steam per hour capacity will cost approximately $10 million with a lead time of up to three years from order to commercial operation. In addition, if a flue gas desulfurization system ("scrubber") for the burning of high sulfur coal is required, $5 million must be added to plant capital costs. <u>This amount is one-third greater than the total boiler equipment cost of $3.75 million</u>.* (See Exhibit "B") On the other hand, an oil-fired unit costs approximately $3.5 million and could be placed in operation within 9 - 12 months from date of order. Thus, the economic impact caused by mandating gas and oil industrial boiler replacement by coal must be considered as it could affect the financial viability of an entire enterprise.

*This is underscored by the same survey which showed the principal coal-firing constraint to be environmental problems associated with boiler emissions.

Capital costs for a utility coal-fired plant are enormous. A 600 megawatt unit ordered this year for commercial operation in 1985 will cost about $425 million, including flue gas desulfurization; an 800 megawatt unit, $500 million; and a 1200 megawatt unit, $700 million. (Note a unit saving of about 20% with a doubling of size.)

C. MARKETPLACE DATA

Industry statistics show that utilities have virtually ceased buying oil or gas-fired units. Exhibit "C" shows that from a 1970 peak of 60% for these two fuels, 1974 - 75 purchases of oil and gas-fired boilers were insignificant and none were ordered in 1976.

Whereas the ordering rate of industrial coal-fired boilers has been essentially flat in recent years, a significant increase in the total of non-oil or gas-fired boilers, i. e. those firing coal and by-product and refuse fuels,has occurred; from a 1972 figure of 22.7% 1976 sales of these units were up to 34.0% (See Exhibit "D") Furthermore, not a single large (input greater than 300 million Btu per hour) industrial oil or gas-fired boiler was sold in 1976.* Looking to the future, industrial boiler inquiries of oil and gas-fired units are running only about one-third of the total. In corroborating this trend a leading industrial boiler consulting firm reports <u>no</u> gas-fired and only 10% oil-fired boiler inquiries.

While an exact determination of total U. S. steam generator manufacturing capacity has never been made, industry estimates range from 20 - 30,000 megawatts coal-fired utility units and 6 - 7,000 megawatts coal-fired industrial units. We believe this capacity is adequate to respond to any credible national coal conversion schedule.

D. NEW TECHNOLOGY; TIMETABLES

The need to reduce our dependence on oil and gas as boiler fuel, whether it be for power generation or industrial steam production, has precipitated a drive to develop advanced coal burning technologies and coal-derived synthetic fuels. Active research and development projects are underway in the following fields:

a. Fluidized bed combustion;

b. Coal/oil slurry mixtures;

c. High Btu coal gasification;

d. Low and medium Btu coal gasification;

e. Liquefied coal, solvent-refined processes.

*Note: A large number of these units have been sold in recent years:

1975 - 21
1974 - 54
1973 - 45

We believe it will be at least 3 - 5 years before sufficient data from demonstration plants is available to indicate which of these processes, if any, are practical for commercial steam generation. It could be another five years before a substantial number of these high technology units were installed.

For the next five or six years, then, we must depend on existing coal technology, i. e. the use of stoker and pulverized-coal firing.

TECHNICAL CONSIDERATIONS

Fuel Oil and Natural Gas Consumed in Boilers

Heat Input, MKB	Barrels of Oil (or oil equivalent) Per Day
10 - 100	2.0 million
101 - 300	0.6 million
Over - 300	1.6 million
Total Industrial	4.2 million
Total utility	2.8 million
GRAND TOTAL	7.0 million

1. New utility boilers should be designed to burn coal;*

2. Below a specified size industrial boilers should be designed to burn oil; if individual plant economic and environmental considerations permit, an installation should be designed for coal firing;

3. Above this size industrial boilers should be designed to burn other than oil or natural gas; this will be coal, industrial by-product fuels and refuse;*

4. WE STRONGLY URGE THAT FEA NOT BE GIVEN THE AUTHORITY TO LOWER THIS LIMIT IN SPECIFIC INSTANCES FOR "PUBLIC INTEREST" REASONS; OTHERWISE, THE UNCERTAINTY SYNDROME WILL BE PERPETUATED.

5. Operators of utility or industrial boilers should be encouraged to convert from gas to oil-firing, but smaller industrial users should retain their gas capability for the following reasons:

a. Maintenance plant operation in the event of oil embargo;

b. Non-availability of oil in some areas;

c. Capability to use synthetic gas if it becomes available.

6. Consideration should be given to extension of the 1990 oil-use cut off date to 1995, permitting a more deliberate phasing-in of coal as a boiler fuel.

*We believe the utilization of industrial by-product and refuse fuels should be strongly encouraged not only to reduce oil and gas consumption but to conserve the Nation's coal resources as well. While a majority of these applications will be in the industrial sector there will be utility applications, too.

SUMMARY

Conflicting and confused signals from Washington in the closely related energy and environmental areas have cast a pall of uncertainty over U. S. industry and utilities; inaction is the inevitable result. New orders for steam generators in 1976 and so far in 1977 are running less than 1/3 of normal, i.e. at about the level of the 1930's. THIS MEANS THE NATION'S COAL CONVERSION PROGRAM IS STALLED. Legislation enacted must, therefore, reflect a policy which is clear, consistent and predictable over the period it is designed to affect. To prolong this uncertainty will cause grave damage to the Nation's energy supply.

Therefore, we urge rapid enactment of reasonable coal conversion legislation.

Exhibit "A"

Available industrial fuels—gas, liquid and solid

Gas	**Btu/cu ft, as-fired**	**Liquid**	**Btu/lb, as-fired**	**Solid**	**Btu/lb, as-fired**
Natural gas	1000	Gasoline	20,700	Coal	7000-14,000
Coke-oven gas	500-600	Naphtha	20,250	Bagasse	3600-6500
Blast-furnace gas	85	Naphthalene	18,500	Bagasse	3600-6500
CO gas	20-30	Industrial sludge	3700-4200	Bark	4500-5200
Refiner gas	1200-1800	Black liquor	4400	General wood wastes	4500-6500
Waste organic gases	Variable	Sulfite liquor	4200	Sawdust, shavings	4500-7500
		Dirty solvents	10,000-16,000	Coffee grounds	4900-6500
		Spent lubricants	10,000-14,000	Nut hulls	7700
Liquid	**Btu/lb, as-fired**	Paints and resins	6000-10,000	Rice hulls	5225-6500
Crude oil	19,200	Oil waste, fuel-oil		Corn cobs	8000-8300
Residual oil	18,500	residue	18,000	Municipal refuse	4500-6500
Distillate oil	19,300	Waste organic-liquids	Variable	Industrial refuse	6600-7300

Exhibit "B"

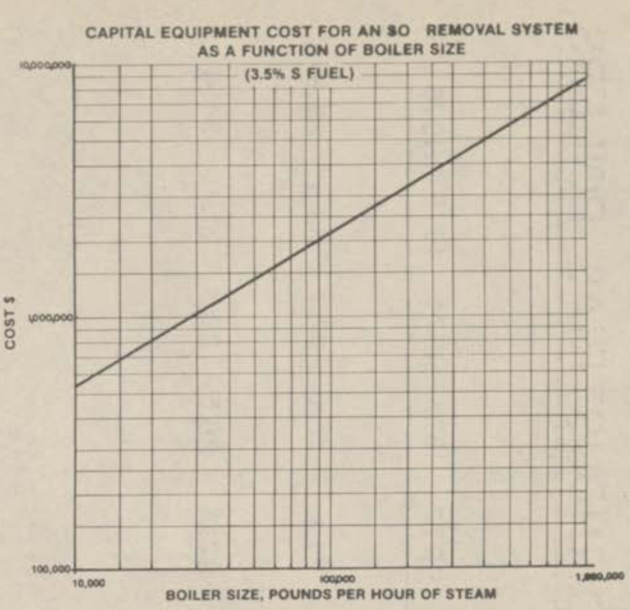


Exhibit "C"

NEW UTILITY UNIT PURCHASES
DISTRIBUTION BY FUEL

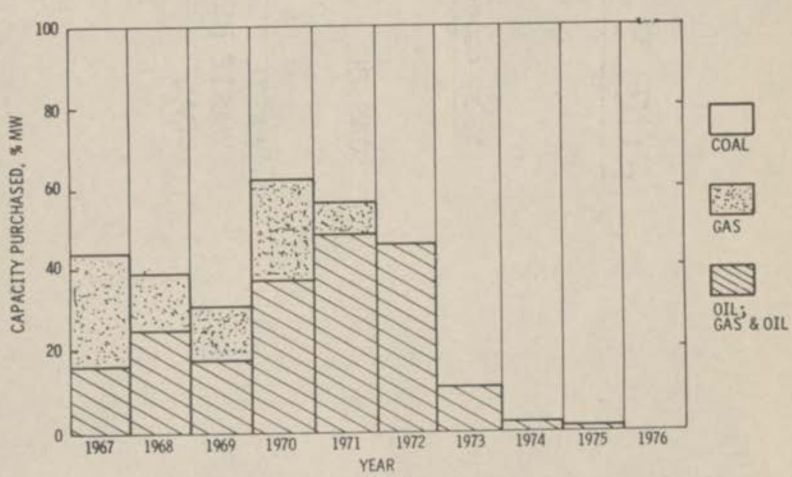


FIGURE 1

Exhibit "D"

FUELS FIRED, INDUSTRIAL BOILERS

% by capacity	1972	1973	1974	1975	1976
GAS, OIL	77.3	71.5	73.7	68.3	65.6
WASTE FUEL, WASTE HEAT, COAL	22.7	28.5	26.3	31.7	34.4

Mr. DINGELL. Thank you, sir.

The Chair recognizes the gentleman from Michigan, Mr. Stockman.

Mr. STOCKMAN. Mr. Forman, I would just like to clarify one thing for the record before we get started because I must have misunderstood you or not heard you correctly, but did you indicate that the FEA has issued a NOI which would require you to convert a wood-fired boiler to coal? Did I misunderstand you, or is that what you said?

Mr. FORMAN. FEA has issued us a NOI for two boilers at one plant, and one of these boilers burns wood all the time to the extent of its capacity with, say, maybe 20 to 25 percent of supplemental fossil fuel which used to be gas and now is oil.

[The following clarifying note was received for the record:]

(It is not presumed that FEA would ask Scott to diminish or to eliminate the amount of wood and bark burned in these boilers and to replace it with coal, but rather to replace the supplemental oil or gas with supplemental coal. The conversion of the supplementary fuel would have an extremely high cost and provide very little benefit).

Mr. STOCKMAN. But the baseload on it is wood?

Mr. FORMAN. In effect it is full of wood practically.

Mr. STOCKMAN. Did they ask you for information about that boiler before they issued a NOI or what did they base it on?

Mr. FORMAN. Two or three times.

Mr. STOCKMAN. And you indicated it was 75 percent wood-fired?

Mr. FORMAN. Yes. Wood is the primary fuel.

The second one at that same installation, just to make it abundantly clear, is not burning wood most of the time, but when boiler number one, the wood boiler, goes down, as it must for many days a year, the other one has to pick it up or we would be covered up in bark. It is very essential to have that boiler 100 percent available.

Mr. STOCKMAN. So that is really the way you dispose of your waste product, to keep it moving into your boilers?

Mr. FORMAN. Right.

Mr. STOCKMAN. I indicated this morning to Mr. O'Leary that I had some concern about his unleashing his agency into the industrial sector of the economy to make all kinds of orders on what types of fuels ought to be used for what end uses and processes, and perhaps we have a fairly good example here of the danger that some of us anticipate.

Mr. FORMAN. I do not understand why this was issued.

Mr. STOCKMAN. Thank you.

Another area that I wanted to get into was this with Mr. Marx. We had one of the leading environmental experts in the Nation here this morning, the head of the Environmental Protection Agency, and he seemed to indicate that NOx control for large utility and industrial boilers was pretty much a frontier area as far as scientific and technological understanding was concerned, and so we really didn't have much of a basis for estimating costs or coming to any conclusions as to how feasible NOx control would be from stationary sources.

You are in the business, in the industry, and I wonder whether or not that is an accurate reflection of the state of affairs and whether or not there is some information you could provide either for the record or now which would add to what we know?

Mr. MARX. No, I don't believe that is accurate, Mr. Stockman, and to respond to that I think in a litle more detail I would like to call Mr. Robert Welden of Foster Wheeler.

Mr. DINGELL. Would you please identify yourself?

Mr. WELDEN. My name is Robert Welden. I am with Foster Wheeler Energy Corporation. In the present state we are controlling NOx from large coal-fired units. I think one of the main problems is that we don't know what some of the side effects of it might be, but right now we can meet compliance with the .7 pounds per million Btu. Costwise for a unit designed today to meet the environmental .7 pounds per million Btu it did not add a tremenedous amount to the cost, but as I say, we still do not know what the side effects may be in the long term and, therefore, it may be that we will have to reduce the output of a steam generator in order to comply without getting the steam generator into other difficulties.

Mr. STOCKMAN. Maybe you can give a little more background on that specific point. As I understand it, NOx is a product of the combustion process rather than the fuel unit used. I would presume then when you are trying to control NOx you are really trying to calibrate the combustion process some way. Is that what you are referring to?

Mr. WELDEN. Yes.

In other words, with oil and gas firing the largest percentage of your NOx formed is the thermal NOx which is a nonorganic form of nitrogen oxide formation. In coal firing the largest percent formed is from the fuel in the nitrogen in the fuel itself which is an organic form. We still do not entirely understand what the process of formation is of the fuel nitrogen. The thermal emissions from coal firing are relatively low so that this can be very easily controlled by the same process as we use on oil and gas.

Right now we are all working, I believe, to modifying the type of combustion in order to limit the transformation of the fuel nitrogen to NOx, but this is definitely not in a very progressive state right at the present time. We have had mixed experience with it.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Ohio, Mr. Brown, for five minutes.

Mr. BROWN. Thank you, Mr. Chairman.

Gentlemen, the U.S. Chamber of Commerce points out that there are three types of costs imposed by this program that has been known as the National Energy Act. First is direct taxes, and that some of these will be rebated. Second is inflation taxes, as inflation due to the program pushes people into higher tax brackets and the Government is going to be collecting somewhere between $15 billion and $20 billion a year more from individuals by 1984, but there is no plan to rebate that tax. Then, finally, the slower growth of the gross national product will reduce the growth of wages over the years, and the sum total of lower wages and the inflation taxes come to about $1,000 per worker each year by 1984, and then goes up after that.

Can you speak to the figures that were given by the Treasury Department with reference to various industries, particularly the paper industry? They gave quite a broad range there of what that inflationary impact would be. Do you concur with that? I am trying to find that. I think it was 2.7 to 7.0 or something like that in terms of inflation percentage.

Mr. FORMAN. I am sorry, I cannot comment on that personally, but I am sure the American Paper Institute could supply an answer to that later.

Mr. BROWN. I wonder if we could get that for the record because I am concerned specifically about whether those inflation figures or impact figures given by the Treasury were rational in terms of impact on the industry.

Mr. MORRISSEY. In connection with our testimony before the Ways and Means Committee we took the oil tax the user surcharge on the man-made fiber, and then the user tax that would be levied on the manufacturing of our textile products and we come up with a figure of $430 million.

Mr. BROWN. The figures for the paper industry were 1.7 to 2.6. I guess it was in the aluminum industry it was 4.7 to 7.0, and the petrochemical industry was 6.2 to 9.3.

Does anybody want to comment further on those?

Mr. MORRISSEY. We had simply a gross dollar figure as to what it would cost the textile industry.

Mr. BROWN. Can you try to quantify some of those figures into percent? Let's see what they say about the textile industry here. They don't list it—

Mr. MORRISSEY. We are not among the top six. We are among the top ten. I think they listed the top six.

Mr. BROWN. Yes. I wonder if you could get us figures for yours and any other appropriate industry? I wonder if the petrochemical industry could?

Mr. TWOMEY. I don't have the information, but I will get it for you.

Mr. BROWN. In terms of the feedstock versus boiler fuel figures, do any of you have a percentage for the total industrial use of natural gas, as to how much of it is feedstock and how much of it is boiler fuel?

Mr. MORRISSEY. We are in the process of developing that for the Ways and Means Committee which also requested it, and we would be happy to supply it to your committee. We are currently running a survey of our industry to find out exactly what our process use is and what our boiler fuel is and we should have that by next week.

[The following information was received for the record:]

An informal survey of textile manufacturers indicates that most of the natural gas being consumed is for process use for which there is no substitute. Consumption of natural gas by individual companies varies, depending upon the products being made, and the availability of natural gas. Process use amounts to anywhere from 30 to 100 per cent. There is some nonprocess use, particularly during summer months, simply because natural gas has been available. However, this situation is changing as gas supply becomes tighter and manufacturers need to save what gas is available for those processes for which there is no substitute.

Mr. BROWN. I wonder if you could also provide it for us and then if you could also give us the impact of the process fuel use in terms of product price increases. Do you have that in the various industries, any of you have it in the various industries represented? Because that tax apparently will be passed right on through to the consumer directly and there is no prospect of it being rebated. Isn't that the way the program will work? Petrochemical, do you want to comment on that?

Mr. TWOMEY. Again I cannot comment but I can obtain the information.

Mr. BROWN. Isn't that the way the program will work?

Mr. TWOMEY. Yes.

Mr. BROWN. In other words, you will be taxed for the natural gas usage. That you cannot avoid, can you?

Mr. TWOMEY. Right.

Mr. BROWN. Is there any way you can avoid or cut down natural gas usage in any of your processes in the petrochemical industry that you can think of?

Mr. TWOMEY. I cannot speak with a great deal of expertise on that point.

Mr. BROWN. Has the industry done any study, and I might ask that also of the textile industry.

Mr. MORRISSEY. We have some and we are doing it where it can be done. In one case, for instance, there has been a recent breakthrough where we find that we can use No. 2 fuel oil where we were formerly using natural gas, but because the user charge applies to fuel oil as well as natural gas we still face the user charge on No. 2 fuel oil.

Mr. BROWN. Aren't you out of the frying pan into the fire?

Mr. MORRISSEY. In that case certainly, yes. Then we have certain processes where we need an open flame such as singeing, and we have no choice but to keep using gas and pay the surcharge.

Mr. BROWN. Finally, I wonder if you would submit for the record in each of the industries represented the trend of construction of plants in gas-available areas and gas-short areas? I am particularly interested in the petrochemical industry and the paper industry, and I wish the glass industry were represented, to know whether they are tending to move south in order to get an assured, although more expensive, supply of natural gas for their process uses.

[The following information was received for the record:]

There is no trend as yet in the textile industry toward locating plants because of energy considerations, although as supply becomes more critical this could become a future consideration.

Mr. BROWN. Does anybody want to speak to that?

I am finished.

Mr. DINGELL. The time of the gentleman has expired. Without objection the information requested will appear in the record at the appropriate place.

The Chair recognizes counsel for purpose of asking questions.

Mr. BARRETT. Mr. Forman, I understand from your testimony that perhaps the FEA picked the wrong plants to issue the NOI's to. Are you going to offer to trade them?

Mr. FORMAN. We are just entering the hearing stage on these. One was yesterday, and one is coming up next week, and we hope to learn there why they picked these plants. I don't know.

Mr. DINGELL. It does strike me on the plants in question they could have done rather better.

Mr. BARRETT. Mr. Twomey, you mentioned that Texas Railroad Commission Docket No. 600. Does this requirement to use fuel other than oil and gas relate to refineries as well as to normal processes?

Mr. TWOMEY. Only for the firing of the boilers.

Mr. BARRETT. But it does apply to refinery boilers as well?

Mr. TWOMEY. Yes.

Mr. BARRETT. On page 2 of your statement you talk about the complex where you spent something in excess of $70 million to convert from gas to coal, and you haven't increased your productivity or your production capacity?

Mr. TWOMEY. Capacity.

Mr. BARRETT. Have you increased the life of the facility at all?

Mr. TWOMEY. I suppose you could say that because they are new boilers, but not the manufacturing process themselves.

Mr. BARRETT. Could you give us an indication of how long you might have increased the life? Is it 10 percent, 20 percent, or is it quantifiable?

Mr. TWOMEY. I cannot say that. I can check it for you though and let you know.

Mr. BARRETT. Would you please?

Mr. TWOMEY. Sure.

Mr. BARRETT. Does this $70 million figure include scrubbers?

Mr. TWOMEY. No, it doesn't.

Mr. BARRETT. That would be another increment, something beyond that?

Mr. TWOMEY. Yes.

Mr. DINGELL. Does it include any other pollution control or safety equipment?

Mr. TWOMEY. Those to be in compliance with the Texas Air Quality Board.

Mr. DINGELL. It does include.

Mr. TWOMEY. Yes.

Mr. DINGELL. I see.

Mr. BARRETT. Mr. Marx, when you convert a boiler from oil to coal essentially you have to rebuild the boiler as I understand it. In the process of rebuilding do you end up derating the boiler?

Mr. MARX. Well, if you were to go that route you would have to derate, yes. What we say is the derating could be as much as 70 percent and the cost could be as much as 75 percent, the cost of a new unit, so it just doesn't make sense. That is why we said it is really a boiler replacement, going from either gas or oil-fired to coal-fired.

Mr. BARRETT. You lose that much.

Mr. MARX. There is one point perhaps should be mentioned here that wasn't talked about this morning by the ERDA witness, and that is ERDA has a program, and they recently let something in the area of five or six contracts to study the combustion of coal-oil slurry. This is a mixture of up to I guess as high as 50 percent coal and 50 percent oil with some sort of a stabilizing agent so that it is a mixture which remains stable and can be handled like oil. Preliminary indications are—this will be pulverized coal—that the boilers operate very well, that the flame is very much like an oil flame, and a couple of the problems that the boiler manufacturers foresaw with the limited experience to date may not be too serious, so this might be a way for certain smaller industrial boilers of the type that I described as being nonconvertible to burn some coal. It is a little too early to make any judgments, but the indications so far are somewhat favorable. I think there should be some reference to coal-oil slurry in your record here.

Mr. BARRETT. You did testify with respect to the 100 million Btu limit and expressed some concern that the FEA could reduce that limit further. I am concerned about the 100 million to some upper number like 300 million. How realistic is 100 million Btu's as a lower limit for a boiler? How many people would be employed in the plant that would use that kind of a boiler, for instance?

Mr. MARX. It would depend on the type of plant, but let me go back. We don't have unanimity of opinion in the Association on this point, the reason I didn't put it in here officially, but our consensus is, and I believe that this is in agreement with most of the industrial users that I have spoken with, that an input something in the area of 250 million to 300 million might be appropriate.

I want to make the distinction between what is done by Government requirement and what is done in the natural economic course of events. We hope to see a lot of coal-fired units and sizes below 250 or 300, below 100, below 50, and so on, and there are indications where this is possible it is happening. We have a list, for example, of 12 companies that makes stokers, coal-firing equipment, for industrials, that we had either never heard of or we thought had gone out of business that are back in business. We have three companies in ABMA who manufacture very small boilers, much smaller than what we have been talking about here, where there is appreciable market for these coal-fired units. In the case of one firm 40 percent of their shipments are for coal-fired units, so I am trying to draw the line between what we perceive to be happening and perhaps about to happen in the free marketplace.

There will be a lot of small coal-fired units we think, but in terms of legislation and FEA, I would think that our consensus would be a limit of 250 or 300 million floor per unit, and I don't particularly like the idea of a combination criterion of *x* size per unit and *y* size per plant, because then you do what you want to do while using multiple units. I don't think that really makes a lot of sense, so I would think a one unit designation would be appropriate.

Mr. BARRETT. Well, if you had an overall plant size, a maximum or minimum, such as 300 million would you prevent somebody from putting in five units of 95 million Btu?

Mr. MARX. Yes, but, for example, if you had 100 million per unit, as I think is in the bill, and 250 per plant, your steam requirement is anywhere in between those two extremes, for example, suppose I have a requirement for 240 million. I can put in three 80 million units. I am below the 100 per unit, and I am below the 250 per plant, so the guy is making the decision. If you are going to do that, why not let him do it in the first place? That was my point.

The other point you should make is it is a little bit hard to draw any correlation between the size of the boiler unit and the number of people employed. You have to know what kind of industry you are in. The gentlemen represented here at this table are people whose plants basically are process plants, and they use a lot of steam, and it doesn't mean that there are a tremendous number of people in the plant. Auto assembly lines, like General Motors, many of their plants are below 100 million, but of course in some cases they have tens of thousands of workers and that is because their load is strictly heating. They have no process requirements.

Mr. BARRETT. We heard testimony the other day that would indicate there was as much as a 7-year backlog on industrial boilers. Does that sound realistic?

Mr. MARX. It is totally false. We can produce in the industry, using the historical fuels pattern, and recognizing a coal-fired boiler is larger, therefore, in terms of megawatt or input capacity, we can produce fewer or less aggregate capacity coal-fired than oil or gas-fired, so taking the traditional fuel pattern we have produced up to 90,000 pounds of steam per year in aggregate industrial boiler capacity. That was in 1973. In 1974 our orders ran 74 million. In 1975 they dropped down to around 50 million. In 1976 they were 38 million. This year they are running at an annualized rate of about 40 million. So you can draw your own conclusions. We are down about two-thirds of our normal capacity. So somebody is very badly misinformed.

Mr. BARRETT. Thank you, Mr. Chairman.

Mr. DINGELL. Mr. Brown.

Mr. BROWN. Mr. Chairman, I would like to ask, we are sitting here discussing the wisdom of the FEA of requiring Scott Paper to change a wood-chip boiler to coal-fired—is there anybody else here from Scott? I would like to find out from the record or maybe ask counsel or ask FEA what opportunity there was for the paper company to appeal that decision. If any of you were obliged to change your boiler by FEA, would you have the choice to take it to an appeal or what would you do? Take it to court? How would Scott have been able to avoid that decision which seems to me to be, on the face of it, ridiculous, to be kind.

Mr. MORRISSEY. As I understand it, this is a notice of intent. There is a hearing procedure where they can bring in their case and point up the criteria on which it is based. There is a notice of intent, an opportunity for a public hearing and an order to do so if they find it is justified. So there is an administrative procedure which permits you to be heard but it is a rather long and expensive procedure when you see they are hitting a boiler they should not have been looking at. The boiler is already in place and in use. They are questioning as to why that was looked at.

Mr. MARX. If I may call on our association counsel, Mr. Miron.

Mr. MIRON. You have a company who is being regulated, then having to go through a regulatory process, then ultimately through a judicial process in order to purchase a piece of equipment. This goes to this issue which was brought up earlier today as to where the procedural burden should be. As it is under the law now, the burden is upon the agency to take the would-be purchaser.

Mr. BROWN. At present?

Mr. MIRON. Yes. The existing law would change that. It would require going to court to justify buying a piece of equipment which would be an extraordinary procedure considering most of the time you don't have a lot of lead time. And you would have to get some kind of injunction under some kind of threat that if it were wrongfully issued, you might have to tear out the equipment. You have put your finger on an important procedural part of the program.

Mr. BROWN. You have a lot of little companies which would wind up being part of bigger companies if they had too many of those legal procedures they had to undertake. It is awfully tough for a small business to do that kind of battle with a monstrous agency like FEA.

Mr. MIRON. We have been talking in terms of utilities in industrial companies but it should be remembered that the customers for steam generating equipment in the lower ranges of 100 million Btu content in universities, hospitals, in buildings such as the Capitol of the United States——

Mr. BROWN. I think we could hold out.

Would you give us that breakdown—do you have that—of the customers for the different sizes of boilers at different levels? The kinds of people involved?

Mr. MARX. I would rather get the information and submit it for the record.

Mr. BROWN. Yes. I would also like to ask you for some detail on the study that brought you to the conclusion—I beg your pardon. This is the testimony of American Textile Manufacturers Institute citing their study that the American Boiler Institute has estimated the total replacement cost for units would be $49 billion, exclusive of the cost of pollution control equipment.

Mr. MARX. We will submit that for the record.

Mr. Dingell. Without objection.

Mr. BROWN. I assume, therefore, that you have a fairly extensive study that has different statistical data.

Mr. MARX. We have a matrix which shows the material you refer to.

Mr. BROWN. Thank you, Mr. Chairman.

Mr. DINGELL. Mr. Stockman.

Mr. STOCKMAN. Mr. Marx, when we were discussing before the fluidized bed process, you estimated it would be 10 to 15 years before it was adopted in the utility sector. The reason was there was a scaling-up time involved and the chairman asked you what that was based on and you said, "Our experience with conventional boilers has shown that." Would you submit some data showing the historical process in terms of the growth and boiler size so we can see over what time period this scaling-up is for the utility boilers we have today. Obviously, it took a lot of operating experience, testing and experimentation to get those large size boilers. Would you comment on that?

Mr. MARX. I will put the data together for the record. But one point that should be made, that is the extreme variability of fuel. As you go out and use the newer coals out west, that situation worsens. So you have appreciable differences in fuel that comes out of the same mine.

Mr. STOCKMAN. What you are saying is that when you get to low-quality fuel, you have all kinds of problems with very large boilers and combustion processes.

Mr. WELDEN. You spoke of before the extrapolation of the first steam generators. Yes, this has been rapid, in fact, too rapid. Right now the utilities are under the pressure of FEA and so forth in an effort to improve their reliability. In the fluidized bed it is a relatively new technique and we still do not know what the broad range of characteristics will have on it. There is a great deal of experimentation that has to be done.

Mr. MARX. It is an entirely different combustion process in itself.

Mr. STOCKMAN. If we could go back to conventional boilers and total coal combustion processes. When you take into account waste disposal and so forth, it seems to me it is an important thing to know whether you could get very large economies and that would call for direct coal combustionn, but if you get to the lower end and the cost rises rather steeply you might want to consider more ways to put more gas into the pipelines. Is there any good information available on that? Can you give us some comments or maybe submit something for the record?

Are there economies of scale in coal combustion treatment or emission control? As I understand it, when you are talking about the stack scrubbers you are really talking about a mini-chemical plant. For fairly small boilers, I am wondering whether you could even put on a stack scrubber which could be justified in any sense in terms of cost factor ratios. If there are economies of scale for both, do they coincide?

Mr. MARX. One of the basic things when you speak of putting a scrubber on a boiler, it takes as much manpower to operate a small boiler as it does a large one.

In coal handling equipment, it is very similar. There is a certain amount of basic expense associated with it. The coal piling and handling facilities, the preparation of fuel, the pulverizing and so forth and a stoker-fired unit has limited capacity, so when you get into the 5 million Btu and above you are forced to go to pulverization in the fuel. The stoker-fired jobs require less equipment but the first costs may be quite high. It is also true the steam generator and all the other equipment is definitely more proportionate, the smaller you get. There are certain basic costs so the 500 megawatt steam generator as compared to a thousand watt, is cheaper.

Mr. STOCKMAN. Would you submit for the record something which would show the output capacity in terms of power and steam and the costs both capital and operating costs.

Mr. DINGELL. The Chair recognizes the minority counsel.

Mr. VLCEK. Mr. Twomey, with respect to your trying to obtain transportation of coal to certain areas, we have testimony from the Association of American Railroads in which they indicated they felt they had the full capacity to handle this coal movement and they have been told up to 72,000 coal cars per year could be built.

Have you perceived in your attempt to arrange to purchase these coal cars that perhaps this capacity is not there? Perhaps there may be some problems?

Mr. TWOMEY. The other seven firms said they would decline to bid on the trains for the coal.

Mr. VLCEK. Any reason?

Mr. TWOMEY. Most had little or no experience in building the car. They are automatically unloaded and automatically closed. They didn't have the experience for this type of car but this is the car which will be used to haul most of the western coal. It will be used in unit trains. It is a rapid discharge car. The bottom gates pass through a beam and they are automatically unloaded. The train itself never stops moving. It passes over a trestle and when it passes the beam it is automatically unloaded.

Mr. VLCEK. If this coal is to be moved by unit train, it may be that the experience to move these cars may not exist.

Mr. TWOMEY. That is right.

Mr. BROWN. What are the cars made of?

Mr. MARX. Steel.

Mr. VLCEK. What kind of steel?

Mr. MARX. The alloy——

Mr. BROWN Is there any problem in getting the steel for boilers, including the tubing?

Mr. MARX It is basically tubular and plate products.

Mr. BROWN. You mean plate steel?

Mr. MARX. Yes. Very, very heavy plate up to 10 or 11 inches in thickness.

Mr. BROWN. The reason I worry is that it takes plate steel to make railroad cars, to make barges, boilers, mining equipment, drilling equipment.

Mr. MARX. The kind of plate we use comes from users not in the markets you mention. The speciality people who make our plate, which is very heavy, are not involved in making the kind of plate you are talking about, by and large.

Mr. BROWN. How many producers? If you could find out and let us know for the record and ask them whether there is any problem with that, I would appreciate that being submitted for the record.

[The following letters were received for the record:]

A B
M A

AMERICAN BOILER MANUFACTURERS ASSOCIATION

SUITE 317 AM BUILDING 1500 WILSON BOULEVARD, ARLINGTON, VIRGINIA 22209 703/522-7298

June 3, 1977

Congress of the United States
House of Representatives
Subcommittee on Energy and Power of the
Committee on Interstate and Foreign Commerce
Washington, D. C. 20515

Gentlemen:

I have checked our data for boilers with a capacity in excess of 80,000 #/hr steaming capacity (equivalent to an input of 100 MKB) with the following results:*

Oil and Gas		Coal and Waste
50%	1977	50%
53%	1976	47%
60%	1972	40%

* On a capacity basis

I would like to have this information included in the record of the hearings on H. R. 6831.

Sincerely,

Wm. B. Marx

William B. Marx/
Executive Director

WBM/rd

A B
M A

AMERICAN BOILER MANUFACTURERS ASSOCIATION

SUITE 317 AM BUILDING 1500 WILSON BOULEVARD, ARLINGTON, VIRGINIA 22209 703/522-7298

June 3, 1977

Congress of the United States
House of Representatives
Subcommittee on Energy and Power of the
Committee on Interstate and Foreign Commerce
Washington, D. C. 20515

Gentlemen:

I would like to have the following American Boiler Manufacturers Association data included in the record of the hearings on H.R. 6831.

Average Size Industrial Boilers by User Industry, June 2, 1977

Sales of Industrial Type Watertube Steam Generators -
Distribution as to Markets - 1972 through 1976

Increased Size Electric Utility Generating Units, June 2, 1977

Sincerely,

Wm. B. Marx

William B. Marx
Executive Director

WBM/rd

P. S. Enclosed also is: Boiler Plants Designed for Oil or Gas Firing
Other Than Electric Power Plants, June 3, 1977

AB
MA
AMERICAN BOILER MANUFACTURERS ASSOCIATION
SUITE 317 AM BUILDING 1500 WILSON BOULEVARD, ARLINGTON, VIRGINIA 22209 703/522-7298

AVERAGE SIZE INDUSTRIAL BOILERS
BY USER INDUSTRY

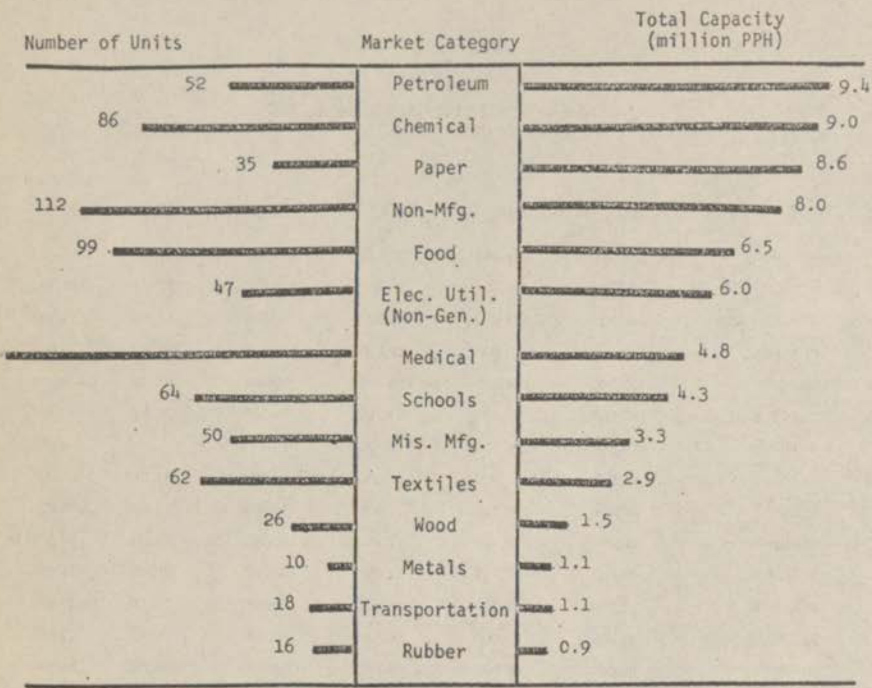
	1976	1975	1974	1973	1972	AVER.
PAPER	220,000	247,100	193,800	151,700	245,700	211,700
PETROLEUM	94,700	248,600	183,800	168,500	180,800	175,300
PRIMARY MET	200,000	144,000	148,000	96,600	110,000	139,700
CHEMICAL	139,100	111,800	160,800	117,900	104,700	126,900
WOOD	127,300	285,700	75,600	80,300	57,700	125,300
ELECT. UTIL. (non-gen.)	93,500	114,300	131,250	105,500	127,700	114,500
RENTAL	91,700	90,000	106,400	- *	- *	96,000
TRANSPORTATION	66,700	133,300	95,000	65,500	61,100	84,300
FOOD	100,000	91,700	75,000	76,600	65,700	81,800
SCHOOLS	50,000	90,000	72,200	53,100	67,200	66,500
MISC. MFG.	59,000	66,700	57,600	82,700	66,000	66,400
NON-MFG.	58,100	46,400	65,800	55,400	71,400	59,500
TEXTILES	69,200	55,600	45,800	60,600	46,800	55,600
RUBBER	45,000	60,000	55,600	60,700	56,250	55,500
MEDICAL	29,200	27,800	37,500	31,700	32,700	31,400
AVER. IND.	85,800	96,500	103,100	88,400	81,800	91,100
AVER. COAL	100,000	118,200	144,700	171,800	280,000	162,900

* Included in non-manufacturing classification.

rd

1972 SALES OF INDUSTRIAL TYPE WATERTUBE STEAM GENERATORS

DISTRIBUTION AS TO MARKETS



Total Number of Units 824 Total Capacity 67423 thousand PPH

Note 1: This section includes all industrial type units, steam, packaged and field-assembled, regardless of use, both domestic and export.

Note 2: Schools includes schools and colleges; medical includes hospitals, medical centers and related facilities. These categories were formerly included in the Non-Mfg. group.

A B M A

AMERICAN BOILER MANUFACTURERS ASSOCIATION

SUITE 317 AM BUILDING 1500 WILSON BOULEVARD, ARLINGTON, VIRGINIA 22209 703/522-7298

INCREASED SIZE
ELECTRIC UTILITY GENERATING UNITS

	TOTAL UNITS	TOTAL CAP. X 10^3	AVG. SIZE X 10^3	COAL UNITS	COAL CAP. X 10^3	AVG. SIZE COAL X 10^3
1961	82	98,390	1,200	45	59,780	1,328
1962	84	76,937	916	44	53,000	1,205
1963	71	110,629	1,558	32	49,500	1,546
1964	86	134,394	1,562	30	52,600	1,753
1965	77	169,637	2,203	47	127,700	2,717
1966	73	164,169	2,249	42	117,500	2,798
1967	72	198,306	2,754	32	109,700	3,428
1968	79	189,559	2,399	29	102,400	3,531
1969	55	198,931	3,617	29	139,200	4,800
1970	79	234,122	2,963	22	83,000	3,773
1971	54	141,525	2,621	21	64,000	3,048
1972	58	153,618	2,649	20	68,200	3,410
1973	70	243,129	3,473	50	200,700	4,014
1974	90	276,929	3,077	72	263,600	3,661
1975	32	115,643	3,614	28	114,200	4,079
1976	19	49,827	2,622	13	47,500	3,654

Note:

1962 to 1969 Average size of all units increased 294%

Average size of coal units increased 306%

B
A
AMERICAN BOILER MANUFACTURERS ASSOCIATION
SUITE 317 AM BUILDING 1500 WILSON BOULEVARD, ARLINGTON, VIRGINIA 22209 703/522-7298

BOILER PLANTS DESIGNED FOR OIL OR GAS FIRING
OTHER THAN ELECTRIC POWER PLANTS

Lower Plant Specified Heat Rate Level (1) (Million Btu Input)	120	300	Over 300
Non-Solid Fossil Fuel Consumed Per Day - Million Bbl Oil Equivalent (2)	2.2	2.0	1.6
Estimated Number Units Requiring Replacement (3)	17,000	4,000	400
Cost Coal Fired Plant $/1000 Btu	80	57	40
Costs Coal Fired Plants $/Plant	8 million	14 million	21 million
Estimated Number of Plants Requiring Replacement	7,000	2,000	300
Total Replacement Costs Coal Fired Plants $	56 billion	28 billion	6.3 billion

(1) Boilers installed in what might be considered combinations

(2) Consumption as boiler fuel; excludes other non-boiler uses

(3) ABMA Analysis

Revised 6/3/77

CELANESE
CHEMICAL COMPANY

DFT-6-132-77

June 17, 1977

Mr. John D. Dingell
Chairman
Subcommittee on Energy and Power
U.S. House of Representatives
Room 3204 - Annex #2
2nd and D Streets, SW
Washington, D.C. 20515

Dear Congressman Dingell:

On Friday afternoon, May 27th, I appeared before your Subcommittee as an industrial transportation expert on a panel of witnesses drawn from major industrial users of energy. Following the panel's testimony, members of the Subcommittee raised several questions which although related to the petrochemical industry were outside the scope of my transportation specialization. I have since discussed the questions with responsible individuals within Celanese in an attempt to be responsive to the members' questions.

On information and belief, I know of no industry figures which support Dr. Laurence N. Woodworth's testimony, which testimony, I believe, is based on White House information that the inflationary impact of the President's coal conversion program would be between 6.2 and 9.3 percent.

A Subcommittee member asked for comment on his observation that natural gas for feedstocks is non-substitutable and hence, feedstocks use by petrochemicals is not like boiler fuel use of natural gas which is substitutable. The member is correct. Petrochemical feedstocks are unique and technology unfortunately does not permit petrochemicals to be made out of some feedstock other than oil and gas. In existing plants, only the feedstock for which the plant was designed can be used. For new plants, a limited shift to crude oil fractions for feedstocks rather than gas is possible. But the use of coal as a feedstock is, perhaps, 20 years off, if then.

A member brought up the trend in plant construction asking if new plants were going into gas short or gas normal areas. We cannot speak for the rest of industry but only for ourselves. Because of the importance to our industry of raw materials from natural gas processing plants and refineries, the heaviest concentration of petrochemical plants is along the Texas and Louisiana Gulf Coast. Although regional raw material availability is an important consideration, feedstock costs have been and will continue to be determinate in locating petrochemical complexes either here or abroad.

Very truly yours,

Daniel F. Twomey

DANIEL F. TWOMEY
DIRECTOR OF TRAFFIC
CHEMICALS GROUP

DFT:dmm

Mr. DINGELL. Gentlemen, you have been here for a long time. We thank you.

The committee stands adjourned until Wednesday morning at 10 o'clock.

[The following memorandum, statements, and letters were received for the record:]

NINETY-FIFTH CONGRESS

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CONGRESS OF THE UNITED STATES
HOUSE OF REPRESENTATIVES
SUBCOMMITTEE ON ENERGY AND POWER
OF THE
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
WASHINGTON, D.C. 20515

May 25, 1977

M E M O R A N D U M

TO: Chairman John D. Dingell

FROM: Subcommittee Staff

SUBJECT: Coal Conversion Program

On March 25, 1977, you asked the staff to evaluate the performance of the Federal Energy Administration's coal conversion program, conducted under authorities granted by the 1974 Energy Supply and Environmental Coordination Act (ESECA), as amended by the 1975 Energy Policy and Conservation Act (EPCA). The review you requested was occasioned by the fact that authority to issue prohibition orders under these statutes is scheduled to expire June 30. Subcommittee investigators subsequently obtained and analyzed more than 400 documents generated by FEA and the Environmental Protection Agency (EPA) over the three years of the coal conversion program and interviewed 23 present and former program officials at both FEA and EPA. In addition, one Subcommittee staffer attended an FEA regional hearing on coal conversion in Boston and, while there, interviewed officials of utilities affected by coal conversion orders.

Because ESECA stands to be superseded by an expanded and revised coal conversion program included in President Carter's new energy bill, it was determined that a detailed report on the implementation of ESECA would not be relevant at this time. A "Who Struck John" analysis of ESECA implementation would be of little value to the Subcommittee in its consideration of the President's program. Thus, this memorandum deals in broad brush strokes with types of problems experienced in ESECA that could crop up again unless care is taken to avoid them. Some of these problems call for tightening of the President's bill by the Congress, while others require imposition of better management procedures on the part of the Administration.

Overview

Some three years after ESECA's enactment, the country has yet to save a single drop of oil or a cubic foot of natural gas by way of an ESECA conversion order. In fact, only one utility prohibition order has been put into effect. Its upshot: merely to prohibit a utility power plant that already burns coal from burning natural gas that it might otherwise burn this summer on an interruptible, as available, basis. (For specific program procedures and actions taken, see Appendix 1, p. 20).

In terms of practical payoff, the ESECA program has accomplished little or nothing. This is not to say, however, that the program is a total failure. Although the staff feels that FEA took far too much time to develop the program's methodology, that methodology has yielded considerable data underlying coal conversions which should be useful to FEA in implementing the President's program, if and when it becomes law. Although mismanagement was rife in the ESECA program, future program managers can benefit from their predecessors' mistakes, particularly in regard to attainment of unified control of FEA's portion of the program, which has been fragmented in the past. As a result of their own internal review, FEA's current management is moving to correct the shortcomings of the ESECA program management structure. For example, FEA Administrator John F. O'Leary endorsed the following management principles for the ESECA program in a May 16 memorandum to the program's principal officials:

- The program must have a clearly defined management and decision-making structure.

- Concerned individuals must have every opportunity to present their views on issues of interest to them before the responsible officials make their decisions on the issues.

- Timely program milestones must be established, given high visibility, and followed.

- Subversion of decisions made by responsible officials by continuing the pre-decision debate after a decision has been made, or by ignoring the decision, must be avoided.

In fairness to program officials, it must be said that ESECA was not -- by any stretch of the imagination -- an easy statute to implement. As passed, ESECA was a compromise between proponents of massive coal conversion and advocates of rigid compliance with air quality standards. Consequently, the statute is a hybrid approach to coal conversion. Although ESECA's mandate for coal conversion is clear, there are numerous caveats, including vaguely defined requirements that the conversions be economically practicable and that coal (not specified by the type that a particular boiler needs) be available for conversion candidates within the time frame that they convert to coal burning. Internal wrangling over the meaning of these provisions -- particularly between lawyers and non-lawyers, was inevitable. In view of the statutory deadlines for issuing conversion orders and enforcing schedules for installation of pollution control equipment, however, prolonged debate over methodology was a luxury FEA could ill afford. "It seems clear that FEA could properly have adopted different, less time-consuming procedures," said an April 22, 1977, evaluation of ESECA by John N. Harmon, Acting Assistant Attorney General, Office of Legal Council. While Harmon considered FEA's approach a legal one, he added that "This is not to say, however, that FEA is precluded from adopting more flexible procedures." After a period of say, one year, FEA should have terminated its internal debate and produced the best methodology possible within the time available. Undoubtedly, some irate conversion order recipient would have challenged the order in court. But that is happening now anyway. Had FEA's methodology been thrown out of court two years ago, the problems of implementation would have been visible to the Congress and Congress could have dealt with those problems. Had Congress not cared to continue with coal conversion, it could have revoked the program and saved the $4.1 million that has been spent on implementing the program in the past two years. (In all, $12.6 million will have been spent on ESECA implementation through fiscal 1978). Termination of the program also would have saved utilities and environmental groups a great deal of effort.

Mismanagement

In the staff's opinion, ESECA -- though difficult and confusing -- is a workable statute. Much of the delay in implementing the program has been attributable to the dispersion of management control over the program to a variety of co-equal offices within the FEA.

On paper, the bulk of management authority appears to be vested in the Office of Coal Utilization (OCU), formerly the Office of Fuel Utilization. In reality, however, FEA's Office of General Counsel (OGC) has been a co-equal in management decisions. (Some even argue that the OGC has dominated the program). The OGC performs an independent legal review of all program decisions that have legal ramifications, including the methodology behind prohibition and construction orders, methodologies for performing environmental analyses, and the environmental statements themselves. In addition, still other entities within the FEA have had a piece of the environmental action.

From the beginning, turf battles among these various entities have hobbled the ESECA effort. OCU -- the office most readily identified with success or failure of the program -- has opted for a pragmatic approach to ESECA. By contrast, OGC has demanded a rigorous interpretation of the statute. Proposal after proposal by OCU, including methodologies for various types of conversion orders and for environmental review of the orders, has been rejected by the General Counsel's Office as inadequate. Timetables for issuing prohibition orders slipped and slipped again as the disputes dragged on. In the environmental area, the debate was compounded by the inclusion of two other offices -- the Office of the Assistant Administrator for Conservation and Environment (C&E) and a separate environmental assessment office under the Assistant Administrator for Energy Resources Development -- the official to whom the OCU director reports.

Despite this fragmented management structure, the program slippage could have been avoided had top level management of the agency monitored the disputes and imposed deadlines for their resolution. There is no evidence in any of the files reviewed by the Subcommittee staff that the Administrator or Deputy Administrator -- or even any of their special assistants -- ever umpired one of these disputes during the Ford Administration. Nor is there any evidence that anyone ever asked them to. "Coal conversion simply had a low priority at FEA during the last Administration," said Robert Hanfling, who has served as Deputy Assistant Administrator for Energy Resource Development during both the Ford and Carter Administrations.

<u>Major Disputes</u>

Disputes over interpretation of ESECA have bogged down progress of the program in three major areas:

1. Development of the methodology for determining that coal supply is available to conversion order recipients in the time frame of the conversions;
2. Development of a methodology for the environmental analysis that is required before orders may be issued; and
3. Development of methodology for determining that coal conversions are practicable.

Coal Finding -- Pragmatism reigned in the first phase of the FEA coal conversion program, when prohibition orders covering 74 utility powerplants at 32 sites were issued on June 30, 1975 -- the last day they could be issued under authority provided by the original ESECA Act. The Round 1 coal finding was based on a market survey that matched demand for coal of a certain Btu and sulphur content with the expected uncommitted supply of such coal in a conversion order candidates' geographical region.

Assuming that this coal finding would hold up, Judith M. Liersch, the then director of OCU, announced in an August 5, 1975 memorandum to her branch chiefs that they should be prepared to issue Round 2 prohibition orders by October 1, 1975, providing that Congress extended the order issuing authority by that time. (It was extended on December 22, 1975). Before the Round 2 orders could be issued, however, the OGC found the Round 1 coal finding inadequate and demanded extensive revision prior to OGC signoff on Round 2 orders. The debate went on for 18 months before the two offices could agree on a revised finding in March 1977. The new methodology required FEA not only to find that uncommitted coal of a given sulphur and Btu content was available on a regional basis, but also to prove that available coal met other characteristics, including moisture, ash, volatility and ash softening temperature. The staff regards the additional characteristics as important ones and thus does not consider the revised finding unreasonable. At best, however, it would appear that a two-month debate over the proposed revision would have been sufficient. Top level management of the agency should have moved in to break up the impasse -- one way or another -- long before the 18 months it took the combatants to reach agreement on their own.

Environmental Review -- While the debate over adequacy of the coal finding delayed Round 2 utility prohibition orders, internal wrangling on another track was holding up Notices of Effectiveness (NOEs) on the Round 1 orders. This debate centered on the agency's strategy for compliance with environmental requirements of ESECA and the National Environmental Policy Act (NEPA).

OCU's initial environmental strategy was to produce a strong programmatic environmental impact statement for the ESECA program, which would obviate the need for a full-blown environmental impact statement for each conversion order. This strategy was endorsed by Stephen D. Jellinek, Staff Director of the President's Council on Environmental Quality (CEQ), in a February 27, 1975 letter to Judith Liersch.

OCU's strategy began to unravel, however, as soon as the programmatic was drafted. Numerous other offices got into the act, including the Office of Environmental Analysis under Assistant Administrator for Energy Resource Development, William G. Rosenberg (an office detached from OCU in November 1975, only to have some of its functions reassigned to OCU in June 1976), the Office of the Assistant Administrator for Conservation and Environment (C&E), and the Office of General Counsel. Both C&E and OGC criticized OCU's draft programmatic environmental statement (prepared for OCU and later for Rosenberg's environmental office by an outside contractor) and demanded a hand in its revision as well as in the broader role of shaping overall ESECA environmental policy. C&E sought to impose its own "Guidelines" on ESECA's environmental methodology and OGC demanded that extensive site specific analysis be done with respect to each conversion order. The debate continued from August 1975 to January 1977, when a format embodying the OGC site-specific approach was finally agreed on. At a minimum, Environmental Assessments (EA's) were to be prepared for each site. But where there was a significant potential adverse impact on the environment, full-fledged Environmental Impact Statements (EIS's) were to be prepared.

As the environmental debate dragged on, the Round 1 prohibition orders hung in limbo. No Notice of Effectiveness (NOE) putting conversion into effect by a date certain could be issued prior to completion of a site-specific EA or EIS. As of May 24, 1977, only five Environmental Assessments and no Environmental Impact Statements had been completed, and only one Round 1 NOE out of the 74 electric powerplant units affected by Round 1 prohibition orders had been issued. Among the plants whose conversions were delayed were 22 dual gas- and coal-fired plants consuming about 57 billion cubic feet of gas a year. The 22 units already had a secondary coal burning capability and could have switched to coal on an exclusive basis soon after the conversion orders were made effective.

There were other casualties too. With respect to about half the Round 1 utility prohibition orders, the slip in NOE issuance meant that the date for commencement of coal burning slipped past January 1, 1979, the date on which the Environmental Protection Agency's authority to enforce compliance schedules expires. EPA claimed that unless coal burning was projected to begin before January 1, 1979, the agency had no authority to enforce increments of progress toward meeting air quality standards, e.g., the installation of air pollution control equipment on a timetable that would ensure its readiness by the time coal burning was to commence. "Without enforcement of the scheduled increments of progress, utilities could sit back and do nothing until their prohibition orders become effective in 1979 or later," said K. Gary Moore, a former executive assistant to the OCU director. "When the time for coal burning comes, they could say, 'Oh, we can't burn that coal in compliance with air quality standards.'"

Practicability -- Protracted in-fighting also occurred over development of methodology for satisfying another requirement of ESECA -- that coal conversion be economically practicable.

In the Round 1 orders, conversion was found to meet the practicability test when the utility had the ability to pay for conversions. During the Round 2 planning process, OGC demanded a more rigorous test: that the conversion be put to a plant-by-plant cost-benefit analysis. OCU balked at this proposal. In a September 23, 1975 memorandum, Stuart M. Rosenbloom, OCU's in-house lawyer, wrote: "There is no indication in the Act that Congress intended to add a cost-benefit test to the other filters against conversion that are explained in great length in ESECA; it is also clear that Congress did not intend that we order conversion only for those candidates that would volunteer to convert because they would make a profit by it."

The crux of the issue was laid down by Jay L. Carlson and Harry M. Yohalem, two FEA Assistant General Counsels, in a December 5, 1975 memorandum to Hanfling and Liersch. The two lawyers argued that a "reasonableness of cost" finding would be necessary in addition to the financial feasibility test contained in the initial prohibition orders. Their reading of FEA's ESECA regulations held that FEA must consider the reasonableness of the additional costs of conversion on a plant-by-plant basis instead of merely considering a utility system's financial capability to absorb the costs of all prohibition orders. The lawyers called for development of a formula that would yield the cost or saving per barrel of oil saved through conversion. If the equation yielded profits, conversions would be deemed "reasonable" by definition. If it yielded a loss, FEA would have to decide at what dollar level a conversion became unreasonable.

OCU and OGC continued to debate the practicability issue until March 1976, when James Rubin, who had succeeded Judy Liersch as director of OCU, accepted OGC's analytical approach but declined to establish a dollar cutoff level at which conversions are deemed too costly. "The standard of practicability varies from site to site depending upon the age of the plant and other site-specific factors," Rubin said. The staff believes that the uneven treatment of the practicability determination may subject FEA to even greater legal problems than the original Round 1 practicability finding might have encountered.

Other Management Problems

Disputes between co-equal offices were not the only problem that side-tracked ESECA. Both OGC and OCU had their fair share of internal management problems and these problems often were translated into program delays. They included:

- Initial OCU disinterest concerning the issuance of orders for major fuel burning installations (MFBIs), followed by a last-minute rush to get MFBI orders out.
- Disruption in OCU's office routine caused by frequent changes of office directors.
- Open warfare between the director and deputy director of OCU over program methodology.
- Inadequate staffing levels at OGC to support the coal conversion program.

MFBI Effort -- Until recent months, MFBI conversion authority has been an unwanted stepchild of the ESECA program. While authority to issue utility prohibition orders was mandatory under ESECA, authority to issue both MFBI prohibition and construction orders was discretionary with the FEA Administrator. So until well into 1976, FEA placed the MFBI program on a back burner. According to Deputy Assistant Administrator (ERD) Robert Hanfling, his former superior, William Rosenberg, hoped never to have to use the MFBI authority because "he thought industry would come in here and cause a commotion about it."

Working on their own, OCU officials Gary Moore and John Dean developed an MFBI questionnaire in early 1975 and received responses from 822 potential order recipients with 6,289 MFBI combustors. "If somebody had given the word we would have been ready to go with MFBI prohibition orders by late 1975," Dean said. "It was OK to gather data, but we weren't allowed to do much else."

Additional data gathering became necessary when Congress passed the 1975 Energy Supply and Conservation Act (EPCA), which granted FEA discretionary authority to issue orders requiring that MFBIs in "the early planning process" design their boilers to burn coal as their primary energy source. A questionnaire for potential order recipients was drafted in early 1976, but it languished in the General Counsel's Office until

October. After a push by Hanfling in November, the questionnaire went out, and analysis of responses began in early April. On April 12, three days before he was to deliver draft site-specific notices of intention for MFBI prohibition orders, Dean, who had become MFBI division chief in early 1976, was relieved of his responsibility for scheduling and issuing MFBI orders. His superiors charged that Dean had "missed too many deadlines" in the past. Dean, in an interview, acknowledged that some deadlines had been missed but attributed the deadline slippage to lack of support from above. (In the Subcommittee staff's view, Dean's portion of the program was underfunded and understaffed).

Dean's removal in midstream caused unexpected problems. The staff found that in their haste to beat the June 30 deadline, OCU ignored Dean's methodology for construction order issuance, applied no set criteria to its selection of candidates and, in some cases, failed to check on the accuracy of information the companies supplied in the questionnaires.

On May 9, OCU issued notices of intent for 58 MFBI prohibition orders and 56 MFBI construction orders. Dean and other FEA MFBI analysts think the prohibition orders will be legally sound but they fear that the construction orders are defective. The Subcommittee staff believes that the entire MFBI effort, though discretionary, deserved better management support prior to its sudden popularity last November. It believes a decision should have been made by early 1976 to have all MFBI analysis completed by January 1, 1977, so as to allow adequate time for a smooth transition to order issuance in the event a decision was made to get MFBI orders out prior to expiration of the current order issuing authorities.

Command Changes -- The post of OCU director has become a revolving door - a factor that is particularly detrimental to a program as complex as ESECA. During its three-year duration, OCU has had two directors and three "acting" directors. On July 1, yet another director is scheduled to take over. The directors who have served thus far provide a contrast in philosophies and management styles. According to OCU staffers, the lack of continuity has lowered office morale and impaired performance.

Another problem has surfaced with the latest management change, in which James Rubin was replaced in April by John Schuler, who was to serve as "interim" director. Gary Moore -- a talented Rubin assistant who had been with the program since its inception -- was removed from the management process following Rubin's departure. Moore -- who could have provided continuity between Rubin and Schuler -- went for weeks without any work assignments. Finally, he took it upon himself to organize a task force of similarly displaced staffers to prepare Round 1 Notices of Effectiveness so that the NOEs will be ready for issuance when environmental analyses are completed. Officially, the office's total effort is being aimed at issuance of prohibition and construction orders that have to be out by the June 30 deadline.

Rubin-Parker Feud -- Another factor that has hurt morale at OCU has been a long-standing conflict between Rubin and his deputy, Gerald J. Parker, over program methodology.

The dispute came to a head last February 9, when Parker, in a memorandum to Rubin, accused Rubin of "guilding the lily" in his technical analyses and his toleration for OGC's legal approaches. Parker, arguing for simplicity and pragmatism, said his purpose was to put pressure on Rubin and other "obstructionists" to adopt a level of effort that would give OCU an "outside chance" of meeting the June 30 deadline. While the Subcommittee staff thinks there is a basis for Parker's criticisms of program methodology and performance, it also believes that the situation had been vastly improved by the time Parker sent his memo to Rubin. At the time the memo was written, the OGC ESECA legal staff had been reconstituted, coal conversion was getting greater OGC priority and relationships between OCU and OGC had taken a quantum jump for the better.

The results of Parker's February 9 memo are a mixed bag. On one hand, they heightened tensions in what was an already overwrought office. But on the other, they brought needed public and Congressional attention to bear on the deficiencies of the ESECA program.

OGC Staffing -- Prior to December 1976, when ESECA was given a higher OGC priority, inadequate OGC staffing levels were a roadblock for the ESECA program. Until last December, only two OGC attorneys were assigned to the program, and one of them had additional duties pertaining to legislation and general law. Since December, four OGC attorneys have seen assigned full-time to the ESECA program and there is an authorization to hire two more.

EPA Role

At the time of ESECA's passage, proponents of coal conversion feared that EPA would seek to block conversions while FEA would try to expedite them. In practice, EPA has been basically cooperative, and FEA has been the stumbling block (though the cause has been ineffective management rather than subversion of the program).

EPA's role in ESECA is to certify to FEA the earliest date that plants or installations receiving conversion orders can comply with air quality requirements. With some exceptions, EPA can issue compliance date extensions to enable conversion candidates to burn noncomplying coal provided the plant will be in compliance by January 1, 1979.

Although it getsgenerally good marks now, EPA was not always so cooperative. In fact, had FEA acted in a timely fashion to discharge its duties, EPA would have caused some delays during the second year of the program. In 1975 and 1976, it appeared that EPA was lagging in certifying compliance dates for Round 1 utility prohibition order recipients. Many of the certifications came in mid- to late 1976 -- a year after FEA issued the Round 1 prohibition orders. By April 22, 1977, EPA had issued 63 of the 74 certifications required for Round 1 orders. The stumbling block to issuing notices of effectiveness was not EPA but FEA, which had not yet completed its environmental work on the orders.

According to both FEA and EPA sources, EPA was amenable to signing a joint policy statement with FEA that, among other things, would have committed EPA to encouraging utilities now burning non-conforming oil or gas. On March 30, 1977, a draft policy statement reflecting suggested FEA changes was sent from EPA to FEA, but FEA still had taken no action to finalize the agreement by May 25, 1977.

Conclusion

Although ESECA is a complex statute, there is little if any excuse for FEA's failure to implement it in a more timely fashion. As the Justice Department's assessment of the program indicated, FEA could have opted for a more flexible approach to implementation. Instead it chose a tortuous one.

Nonetheless, if a coal conversion program is to continue, a simpler statute would be beneficial. Efforts should be made to avoid phraseology that could be subjected to conflicting interpretations by FEA.

The President's coal conversion proposals, included in his energy bill, are a good start. They certainly are more workable than ESECA. The new methodology of the President's bill would supersede the ESECA methodology in plants now under ESECA orders or notices of intent to issue orders. That methodology holds as follows: the burden of proof with regard to coal availability would be shifted to industry; however, FEA would retain the burden of proving the practicability (redefined as "financial feasibility") of conversions. If coal conversion is deemed a national priority -- as it should be -- the entire burden of proof should be shifted to industry.

No matter what the statute looks like, however, it is hoped that the Subcommittee will encourage FEA's top management to follow through on its commitment to give coal conversion more management attention. Many of the problems that beset ESECA in the past have now been ironed out, but others remain, and the old ones -- such as the OGC-OCU animosity -- could surface again as soon as the present cast of characters changes or individuals' views change. Program structure is fundamentally sound; however, inter-office disputes must be arbitrated by the Administrator's office and, where appropriate, deadlines for decisions must be imposed from above. To ensure that management improvements are carried out, it is recommended that the Subcommittee staff monitor the program periodically and conduct another full-fledged oversight review six months from now -- or earlier, if circumstances warrant.

APPENDIX I

ESECA -- Procedures and Performance

ESECA requires FEA to prohibit an electric power plant from burning petroleum and natural gas when the agency finds that: (1) the power plant had the capability and necessary plant and equipment to burn coal on June 22, 1974, or acquired it after that date; (2) conversion is practicable and consistent with the purposes of ESECA; (3) coal and coal transportation facilities will be available during the period when the order is in effect; and (4) the order will not impair the reliability of electric service in and areas served by the plant.

Other ESECA authorities provide FEA discretionary authority to: (1) prohibit major industrial generating units ("Major fuel burning installations") from burning oil or gas as their primary energy source, subject to the same criteria affecting power plant conversion (above) except for the system reliability finding, and (2) require certain power plants and installations in their "early planning process" to be designed and constructed with the capability to burn coal as their primary energy source.

The Environmental Protection Agency's role in the ESECA program is to certify the earliest date by which plants under ESECA conversion orders can burn coal in compliance with air quality standards, and subject to certain rules, to issue compliance date extensions.

There are three steps in the coal conversion process under ESECA. FEA's first move is to publish in the Federal Register a "Notice of Intent" (NOI), indicating that the agency plans to issue a prohibition order. The NOI gives the potential order recipient a chance to make a written or oral response to the FEA findings. After considering the response, FEA decided whether or not to issue a prohibition order, and then issues the order, if appropriate. After performing site-specific environmental analyses and obtaining EPA certifications, the order, if still appropriate, is finally put into effect by a Notice of Effectiveness (NOE) that sets a date certain for the commencement of coal burning.

As of the date of this report, May 24, 1977, FEA has taken the following actions under ESECA:

UTILITY	SITES	UNITS	SAVINGS OIL	PER YEAR GAS	EQUIVALENT COAL DEMAND
Prohibition Orders or NOIs	50	105	85 million bbls.	59 billion cub. ft./yr.	25 million tons
Construction Orders	97	143	810 million bbls.	0	221 million tons
MFBI					
Prohibition Order NOIs	24	58	12 million bbls.	23 billion cub. ft./yr.	4 million tons
Construction Order NOIs	32	56	20 million bbls.	0	5.2 million tons

As of May 25, a limited number of NOEs had been issued. Only one NOE had been issued with respect to utility power plant prohibition orders. NOEs affecting 30 units at 21 sites had been issued with respect to utility construction orders. No NOEs had been issued with respect to MFBI construction or prohibition orders.

STATEMENT OF THE AD HOC COMMITTEE FOR A FAIR NATURAL GAS POLICY

Mr. Chairman and members of the Subcommittee, my name is R. Timothy Columbus and I am here today on behalf of the Ad Hoc Committee for A Fair Natural Gas Policy. The Ad Hoc Committee deeply appreciates this opportunity to share with you its concern over certain aspects of the proposed legislation presently under consideration by the Subcommittee.

The proposed amendments to the Energy Supply and Environmental Coordination Act of 1974 presently under consideration reflect, as do other portions of this legislation, an attempt to provide the government with the tools necessary to achieve a goal, with which my client's members, all of whom are participants in the fuel oil business agree, i.e., to reduce this Nation's unnecessary consumption of imported petroleum. However, my client believes that as presently drafted, this proposed legislation ignores and, if enacted, may aggrevate a problem of potentially greater urgency, specifically increased and non-essential consumption of natural gas.

It is my client's understanding that domestic reserves of natural gas are being depleted at a rate which exceeds the rate of depletion to which domestic reserves of crude petroleum are subject. Given the Nation's experience during the past winter, in which hundreds of thousands of individuals' employment was interrupted as a result of inadequate supplies of natural gas for process fuel and other essential users of natural gas, my client believes that this Subcommittee should amend this portion of the bill to the extent necessary to minimize immediately the unconscionable consumption of natural gas as a boiler fuel by consumers which have the present capacity to employ an alternate fuel.

Mr. Chairman, as you and other members of the Subcommittee are aware, the availability of adequate supplies of natural gas is a condition precedent to many industrial activities. One cannot manufacture stainless steel, produce some glass, print a newspaper, or dry paint on automobiles without natural gas. Therefore, to the extent that increased supplies of this resource can be made available by limiting a class of consumers' use of natural gas without the imposition of burdensome capital costs on that class, it seems only reasonable that such action be taken, and Mr. Chairman such a class of natural gas consumers does exist.

Throughout portions of the mid-continent, consumers with dual capacity, have been consuming quantities of natural gas substantially in excess of their rate of consumption during the three year period preceding the 1975-1976 heating season. This increased consumption has coincided with severe curtailments of and interruptions in natural gas supplies to other parts of the country. While some of these consumers fall within the definition of "major fuel-burning installations" contained in the bill, most do not. In light of this fact, my client recommends that this Subcommittee require natural gas consumers, which possess the current physical capability to employ alternate fuels for non-essential uses to terminate their consumption of natural gas. At a minimum, my client urges this Subcommittee to expand the scope of these amendments to include substantial consumers which are not included in the bill's present definition of "major fuel-burning installations" and to provide the Administrator with the authority to order the conversion of such consumers from natural gas to alternate fuels. Such action by the Subcommittee would serve as a major step towards preventing the type of hardship which the country endured last winter without imposing burdensome capital costs upon any consumer.

The above described expansion of natural gas service to the boiler fuel market in some areas has resulted in other undesirable effects. As you are aware, Mr. Chairman, the boiler fuel most frequently replaced by natural gas is residual fuel oil, a product which is the inevitable result of crude oil distillation. To the extent that increased natural gas service reduces the market for residual fuel oil, the production of other, lighter products is restricted which results in supply dislocations in those products.

Many areas are currently inundated with residual fuel oil. This phenomenon is forcing some refiners to reduce their crude oil runs to stills and thus to reduce their production of lighter products during a peak period of demand.

The fundamental question which my client believes the Subcommittee must address in this area is, should the nation attempt to reduce its petroleum consumption by prematurely exhausting its very limited reserves of natural gas through their unnecessary consumption as a boiler fuel.

In light of the terrific dependence of many industries, and therefore many employees, upon the availability of natural gas, my client believes the answer to this question must be in the negative.

Once our gas reserves are depleted, the cost of their replacement is very high, i.e. either imported liquified natural gas, synthetic gas produced from petroleum, or synthetic gas produced from coal. If either of the first two alternatives is chosen, our dependence upon foreign energy sources will increase both in absolute terms and duration. At present the technology required for economic exploitation of the third alternative does not exist. If essential users, whose demand is inelastic, are compelled to consume these high priced alternatives, one must believe that serious economic consequences will result.

My client believes that logic dictates immediate action to protect the nation's rapidly depleting reserves of natural gas for e ential users if the nation is to avoid a future dependence upon foreign sources of natural gas similar to that to which we have subjected ourselves in petroleum. In light of Alaskan production's coming on stream in the near future and current and foreseeable supply conditions, adequate supplies of residual fuel oil and will be available to sustain boiler fuel demand during an orderly and economically sound program of converting our energy base to coal.

Too many times, particularly with regard to energy policy, we have addressed ourselves only to that which appears most undesirable at the time and thereby have created subsequent problems of a magnitude equal to or greater than the problem we originally sought to solve. Mr. Chairman, my client is confident that you and the other members of the Subcommittee will not let this happen again.

On behalf of the Ad Hoc Committee, I again thank the Chairman and the Subcommittee for this opportunity and will gladly respond to any questions which my testimony may have raised.

COMMENTS
of
AMERICAN PETROLEUM INSTITUTE
on
Part F. of H.R. 6381, "National Energy Act"

The American Petroleum Institute has been following the development of a national coal conversion program as set forth in S. 977 and earlier legislation proposals in the Senate, and as further defined in Part F, Revision of the Coal Conversion Program, of H.R. 6381. Because of the importance of this proposed legislation and its impact on steam boilers and process heaters used in petroleum refining, we wish to submit the following comments.

The American Petroleum Institute is vitally concerned with increasing the self-sufficiency of energy supplies in the United States. Any national energy program should provide for development and prudent use of domestic energy resources. Such a program must include continued diligent efforts to conserve energy and foster development of domestic energy resources, epsecially our abundant coal reserves. To achieve a reasonable degree of self-sufficiency, government and the private sector must work cooperatively, constructively, and expeditiously over a sustained period of time. We believe strongly that the competitive marketplace is the best means of encouraging efficient use of coal as an energy source. However, if the Congress deems it necessary to pursue the legislative route, we would like to share with you some of our concerns about the effect of proposed legislation on refining installations.

We endorse the concept of maximizing the use of coal where such use is technically, environmentally and economically feasible. Nevertheless, we consider temporary exceptions for mandatory coal use to be essential, for several reasons. One reason is the problem that may arise in obtaining and transporting the required supply of coal to the fuel-burning site. A second reason is to allow for, and encourage, advances in technology and engineering developments that will, in time, enable coal to be used for process heat.

The exceptions already contained in H.R. 6381 properly recognize the need for the Administrator of the program to consider the cost-effectiveness of coal conversion and the economic waste involved in retiring existing useful equipment prematurely. We suggest that the exceptions take into account the possible non-availability of coal supplies and the lack of adequate transportation facilities in many instances. And we suggest that the exceptions take into account the cost relationship between coal and other competing sources of energy.

Recognition, in H.R. 6381, of these factors would, in our judgment, reduce the need for many coal-conversion decisions to be made by the Administrator. Such recognition would also lighten the heavy reporting burden on both the government and industry, by reducing the number of requests that are likely to be made for exceptions to the provisions of the present bill.

In our judgment, over-reliance on the regulatory approach, rather than the market value of fuels, will result in delays in achieving the objectives of H.R. 6381. These delays will result from conflicting interpretations of the regulations by the Administrator and the regulated industries.

In Section 102, Par. (4), permission to use the heating value of waste gases and other gaseous, liquid and solid byproducts as hear sources will stretch energy resources and conserve crude oil.

In Section 102, Par. (6)(A) and Par. (7)(A), we suggest changing "...one hundred million British thermal units per hour or greater..." to read, "...two hundred and fifty million British thermal units per hour or greater...."

In Section 102, Par. (6)(B) and Par. (7)(B), we suggest changing "...two hundred and fifty million British thermal units per hour or greater..." to read, "...five hundred million British thermal units per hour or greater..."

These suggestions are based on our concern that the indicated combustor lower heat limits will create an inordinate manpower burden on both industry and government and result in delays because of the administrative complexities of developing and obtaining agreement on the basis for exception and exemptions, as well as interpretation of the law. Many refinery steam boilers are of the relatively small size of 100,000,000 Btu per hour heat rate or less. These smaller boilers typically are not convertible to coal-firing. A boiler size of 250,000,000 Btu per hour heat rate and above would be a more likely candidate for coal conversion with current technology. Increasing the minimum combustor size would reduce the number of combustors which must be considered by the Administrator, and also focus on those installations that, by their size, will be most cost-effective in terms of coal conversion and have the most significant impact on replacing oil and gas with coal.

Section 102, Par. (12), of H.R. 6381 appears to make the assumption that it is readily possible to convert boilers and other equipment to coal use, and that such conversion would be in full compliance with environmental requirements of the Clean Air Act. Petroleum engineers do not believe this assumption is correct, even if the best available technology is employed and even if low-sulfur Western coal is used. This would be especially so in the major metropolitan areas of the U.S., where 70 percent of petroleum refining capacity is located.

We therefore believe that significant conflicts will arise between the objectives of H.R. 6381 and the objectives of current and contemplated environmental legislation. To resolve these conflicts in favor of H.R. 6381's objectives might require substantial changes in existing or proposed environmental legislation and programs.

In Section 106 (a)(2) and (3), we find the language and the concept of "categories" of combustors to be an improvement over previous proposals.

The petroleum refinery's main task is not to boil water to make steam, but to heat and boil hydrocarbons to make petroleum products. Furnaces and heaters that are used to process crude oil and other projects do not -- and cannot - now use coal as a heat source.

If use of coal to heat petroleum were mandated for refineries today, furnace tubes would likely coke up or plug if the heat flux were uneven or too high. Coking and plugging can cause catastrophic failure of a tube and possible explosion and fire. Also, the fast and accurate temperature control necessary in many refinery processes is at present impossible to achieve with coal firing.

Combustor manufacturers are doing research to develop coal technology for such process applications, but in our judgment, demonstrated commercial feasibility is several years away. Such research should be expanded to include demonstration projects of commercial size. Also, the Energy Research and Development Administration (ERDA) is sponsoring research programs to develop fluidized-bed coal-firing technology. This technique offers potential advantages over conventional coal burning in the area of capital investments, operating costs, and environmental control. But even if successfully developed, the technique will not be commercially available for a number of years.

There are other factors to be considered in addition to the technical problems of coal firing. The most important factor is the location of combustors in most refineries, which would make coal conversion difficult, expensive and, in some cases, impossible.

It is important to note that most refineries consist of many close-quartered and complex operating units. Each unit contains numerous pieces of equipment. The process furnaces and other combustors are generally located very near the equipment they service. These combustors and other heaters cover a broad range of heat outputs, and each one is tailor-made for its particular job. In many instances, space is simply not available within the refinery for new combustors or to install facilities to store and prepare coal. In addition, the distribution of solid fuel to, and the handling of ashes at, the many scattered sites would be a mountainous problem.

Appendix I to these comments is a copy of the presentation made by the American Petroleum Institute on April 7, 1977, to the Office of Coal Utilization of the Federal Energy Administration. The presentation goes into some detail about the limitations of refinery process heaters and furnaces for conversion to coal.

As stated earlier, we believe coal will be cost effective for many applications in a free market environment. We compliment the sponsors of H.R. 6381 for specifying that the economics of coal conversion are to be considered in exceptions and exemptions. The interrelationships of economics with environmental, technological, and safety factors must also be considered. We submit that certain industrial processes are better served by fuel other than coal for reasons of process control, product quality, and safety considerations. Thus, we recommend that these factors be included in the decision on exceptions and exemptions.

One resource that needs to be given greater consideration as an alternate to coal is residual fuel oil. Residual oil is what is left over after the lighter products are made. It is not readily converted into lighter products. Currently, yields of residual oil from U.S. refineries average about 10 percent of the crude oil processed. It represents an attractive substitute for natural gas as a burner fuel both for petroleum refiners and industrial users. We view the use of residual fuel as an acceptable alternative to coal where space, coal supply and other conversion problems make coal unacceptable and unavailable.

In summary, the API supports the nation's efforts for the use of coal instead of natural gas and petroleum by electric power plants and industrial installations. However, we urge consideration of ways to reduce the complexity and administrative burden of the provisions of this Act by more reliance on market forces to set priorities and fuel choices, and by limiting the scope of its applicability in the initial years, as experience and technology are built up.

APPENDIX I

AMERICAN PETROLEUM INSTITUTE

COMMENTS TO FEDERAL ENERGY ADMINISTRATION

OFFICE OF COAL UTILIZATION

The American Petroleum Institute wishes to submit several recommendations regarding energy conservation and domestic energy supply development, two of the most important elements of a sound energy policy. It is clearly vital to the economic health and security of this country that immediate action be taken to accelerate domestic energy production and to increase energy conservation. To arrest and reverse the increasing dependence on foreign sources for this country's energy needs will require the best efforts, over a sustained period of time, of government and the private sector working cooperatively, constructively and with deliberate speed toward the goal of a reasonable degree of energy self-reliance. The API believes that the role of the government should be to provide workable and practical policy guidelines for accomplishment of domestic resource conservation and development. Private industry's role should be the timely development of U.S. energy resources, within the policy guidelines, operating in a free market environment with price as the incentive for supply and the restraint on demand. Together, government and private industry must speak out and work for sound national energy policies and provide the leadership and education in the energy conservation and energy development effort.

Our society, which has become accustomed to exponential growth in consumption of energy from natural gas and petroleum, has difficulty in coming to terms with the finite nature of these valuable resources. We must therefore redouble our efforts to educate the public, government and industry to conserve these two resources for higher-value uses and begin to utilize more abundant, domestically secure energy sources. Over the next 10-15 years we must count heavily upon coal as the primary domestic source to augment declining domestic supplies of natural gas and oil. The API supports the basic objective of increased coal utilization which will result both in the conservation of domestic natural gas and petroleum supplies and a reduction of imported petroleum products. Currently, there are efforts within industry and the government to foster the increased use of coal to conserve the dwindling domestic reserves of oil and natural gas. Under current rules and regulations, as defined in ESECA of 1974 and EPCA of 1975, the FEA is authorized to require the utilization of coal as a primary fuel in certain utility and major fuel burning installations (MFBI). As a mechanism to accomplish this, the FEA has recently initiated the MFBI Early Planning Process Identification Reports. These reports, along with previous identification reports, recognize that the utilization of coal in certain industrial combustors requires consideration of the interrelationships of economic, environmental, safety and technological factors. We believe in the need to promote greater use of indigenous coal resources and believe generally that coal utilization will be cost effective in a free market environment, but we do not favor the principle of greater use at any cost. Mandatory utilization of coal must be evaluated on an individual combustor basis considering all of the above factors. Care must be taken to avoid forced conversion to coal in certain industrial processes which, because of safety, process control, and product quality considerations, are best served by noncoal fossil fuels. Careful evaluation of technological factors is a key requirement in considering use of coal in certain categories of combustors. An API task force of combustor users and combustor manufacturers has reviewed existing technology for the direct burning of coal in combustors, other than boilers, used in refining. This task force, in considering the application of coal-firing technology to existing process heater design concepts, chose to categorize combustor designs by severity of process service. As discussed below, coal-firing is not feasible in certain applications but with the development of technology appears feasible in others. The task force has defined three basic categories of combustors, with stated coal-firing limitations, as follows:

1. Designs of heaters for high temperature process reactions or high pressures and elevated temperatures:
   (a) Require that metal pressure parts be at temperatures approaching the coal ash fusion point, implying severe corrosion problems;
   (b) Have metal pressure parts operating near the safe high temperature strength limit and require precise control of the heat flux to avoid overheating of these parts; and
   (c) Commonly require many small burners in order to adequately control heat flux distribution.

Limited experience is available to identify the magnitude of the corrosion problem. However, studies of the effects of the (much milder) corrosive agents in oil fuels have led to the conclusion that sulfur and many metal salts, common to coal ash, will rapidly destroy the highly alloyed materials used in high temperature and/or pressure heaters. Also, detailed knowledge of heat transfer from coal flames, as required to design for and control precise heat flux distributions in refining process combustors is presently lacking. Therefore, we conclude that it is presently, and for the foreseeable future, impractical to design for coal firing in heaters designed for high temperature process reactions or for high pressures and elevated temperatures.

Heaters falling in the above class include those for ethylene pyrolysis, steam-hydrocarbon reforming, hydrocracking, and some hydrotreating. They are to be found predominantly in the chemical, petroleum, and fertilizer industries.

2. Designs that process fluids subject to thermal decomposition require close control of the temperature of the fluid adjacent to the heat absorbing surface (known as the fluid film). Overheating of the fluid film will lead to formation of decomposition products and plugging and/or overheating of the tubes. Relatively close prediction and control of heat flux is required in order to obtain satisfactory run length and operational safety. Also, it is necessary to provide for rapid extinction of combustion for the case when thermal decomposition is detected. These factors will likely remove stoker-fired designs from consideration for these services. Since adequate knowledge of heat flux prediction and control is lacking, the application of coal firing to this class of units is presently unfeasible and should be deferred until coal-firing is developed and proven for less severe services. Services susceptible to thermal decomposition include heaters in cokers, visbreakers, thermal crackers, and vacuum flashers in the petroleum refining industry.

3. Designs for general process service are not available for installation today, but are considered as first priority candidates for development of coal-firing designs. Current and traditional designs do not satisfy the fundamental technical requirements for burning coal. In addition,

we expect that larger combustion chambers and fewer burners of greater heat release, as compared to current designs, will be required for firing pulverized coal. Vertical upward firing, as currently applied with gas or oil fuels, to give the most even heat distribution in economically-sized fireboxes will not be possible with coal fuel. Maintenance requirements on combustor, fuel, and ash systems may limit heater availability. Experience with coal-fired boilers indicates that stream factors are less than currently considered desirable in process applications.

Existing coal-fired boiler technology and features are deemed directly transferrable to process heater design in the areas of coal handling, ash or slag handling, flue gas conditioning, and maintenance facilities. Improvement of pulverized coal firing control is possibly indicated. Problem areas requiring solution before general application of coal firing to process heaters can be attempted are:

(a) Obtain detailed knowledge of coal flame characteristics and heat transfer from coal flames.

(b) Solve problems of slagging, fouling, and corrosion of high temperature pressure parts and refractory.

(c) Develop techniques for controlling heat flux distribution with coal firing. This includes consideration of fuel distribution, air distribution, and small burner development.

A review of the foregoing indicates that one is unlikely to find any existing process heaters that would be suitable for retrofitting for coal burning. Also, the auxiliary equipment (air preheater, ash collection and handling facilities, fuel facilities) requires much more plot space than is available in most plants. Therefore, we judge that no existing heaters are candidates for modification to burn coal.

Also, we judge that no existing fired heater designs readily lend themselves to revision for coal firing. Since the heater design is a marriage of process side and combustor designs this means that new designs for coal firing will probably have to include additional modifications to handle process considerations. Thus, the design uncertainties will be magnified and care in selecting initial applications is recommended.

While technical feasilibility is a primary consideration in the nation's coal-conversion strategy, it is not the only one. Guidelines concerning cost effectiveness, environmental conservation, safety, coal availability, logistics and other important factors must also be provided. A mechanism to assure cost effectiveness should be established. The most straight-forward approach would be to establish a priority order based on combustor size. Use of coal in the largest installations will, in general, be the most cost-effective use of available resources while at the same time making the most substantial impact upon conservation of oil and natural gas. Mandating coal-firing for combustors which are not cost effective, which is more likely to be the case in small installations at the threshold MFBI level of 100MM BTU/hour, will create an undue burden on human and capital resources, will be destructive to the small fuel user, and will inhibit real growth of the economy.

If implementation of coal conversion is to be timely, we believe that current environmental regulations, initiatives, and legislative proposals must be reexamined for consistency with the current MFBI regulations. This may require restructuring of existing programs and proposals. Development of coal supplies may involve environmental/energy tradeoffs to assure that coal conversion is implemented in a timely manner.

A coordinated government/industry effort is essential to assure that coal supply and logistics will be coordinated with industry's conversion to coal. Such an effort would necessitate that planning efforts to address minemouth-to-user transportation are consistent with the coal conversion timetable. Current debate between government, rail, barge and pipeline interests must be brought to a successful conclusion quickly if potential coal suppliers and identified coal users are to proceed with coal-conversion implementation.

In summary, the American Petroleum Institute believes that substantial progress can be made in reducing our dependence on foreign energy supplies through development of sound conservation practices and the dedication of human and material resources to the development of indigenous energy supplies. This can best be achieved through cooperative government/industry efforts. The government can and should provide leadership and policy guidelines for accomplishment of conservation and domestic resource development objectives. The private sector, and specifically industry, should have the responsibility, working within the policy guidelines, to achieve the conservation goals and develop the energy resources while operating in a free market environment with price as the incentive for supply and the restraint on demand.

June 6, 1977

STATEMENT BY THE COMPANIES OF
THE NORTHEAST UTILITIES SYSTEM
ON THE COAL CONVERSION PROVISIONS OF
THE PROPOSED NATIONAL ENERGY ACT

The companies of the Northeast Utilities system endorse the recently articulated national policy of reducing our country's dependence on oil and gas and increasing its reliance--insofar as electricity is concerned--upon coal and nuclear energy. We believe that we have already gone a long way toward accomplishing this national objective. Because New England was and still is at the end of the fossil fuel "pipeline", we embarked, in the early 1960's, upon a course of providing base-load capacity from nuclear power plants. We believed, and time has proven, that this nuclear expansion program would be cost-effective and environmentally sound.

This program has also accomplished our objective of reducing our dependence on imported residual oil. The total nuclear capability of our system as of May 1, 1977 was 1,958 megawatts (MW), or approximately 30% of the system's total net capability. In the crucial 1970's we reduced our dependence on residual oil to such an extent that in 1976 the Northeast Utilities system used only 50% of the oil it needed in 1973, in spite of the growth in energy consumption which had occurred during that time. From January 1974 nuclear generation has saved the NU system more than $300 million and over 50 million barrels of oil. In the month of April 1977 we supplied about 70% of our total energy requirements from nuclear power. Oil savings were approximately 8.1 million barrels in the first four months of 1977 and approximately 21.6 million barrels in the 12 months ended April 30, 1977.

Millstone Unit 3, an 1150 MW nuclear plant which is under construction and scheduled for completion in May 1982, will save approximately 12 million barrels of oil per year. Moreover, we intend to build twin 1150 MW nuclear units at Montague, Massachusetts which are scheduled for completion in 1986 and 1988 and which together should reduce dependence upon oil by about 24 million barrels per year. After these units become available, nuclear power will reduce our system's dependence on oil by almost 50 million barrels per year.

Financing a nuclear base-load expansion program which is highly capital intensive has continuously strained our ability to raise the necessary capital. However, the end result has been a modern, reliable electric supply system with a favorable generation mix, which has resulted in rates that are increasingly competitive with those in other parts of the country that have traditionally benefited from proximity to coal, oil and gas.

Now, however, we are faced with six proposed Prohibition Orders from the FEA under the Energy Supply and Environmental Coordination Act of 1974 ("ESECA"). These orders would require conversion to coal burning of The Connecticut Light and Power Company's two units at Norwalk Harbor, Connecticut, three units of The Hartford Electric Light Company at Middletown, Connecticut and Holyoke Water Power Company's Mt. Tom unit at Holyoke, Massachusetts. These six units, built between 1954 and 1964, aggregate 900 MW or about 13% of the NU system's generating capacity. We are presently engaged in proceedings before the FEA and the courts in which we are contesting these proposed orders because they will have a number of significant adverse effects on our customers, our investors, our companies and the public at large. We have presented extensive testimony before the FEA on those proposed orders. Some highlights of it are as follows:

1. Conversion of these units would require capital expenditures of $277 million (or $306 million if flue gas desulfurization equipment is required at the Mt. Tom station to meet air quality requirements). These expenditures would not increase the capability of our system to serve the growing energy requirements of our customers in the 1980's; in fact, coal conversion would reduce the peak generating capability of these units by 73 MW or about 8%.

2. In view of our present weakened financial condition, we already need substantial rate relief in order to finance our present construction programs. Because of the presently negative rate-regulatory climate in which we are operating, we have already found it necessary to reduce the construction programs of our Connecticut companies to levels below those which we believe to be the minimum required by good utility engineering practice. If the capital costs needed to convert these six units to coal are allowed to create an additional pressure upon the financing needs of our companies, our present construction programs will suffer, and we will probably be required to delay completion of Millstone Unit 3 and the two Montague units. Rate relief which would be sufficient to enable us to meet coal conversion costs as well as to satisfy the demands of our present construction programs does not appear to be available in the present regulatory climate.

3. The customers of the Northeast Utilities system would have to pay between \$2 billion and \$2.5 billion more by the year 2000 to support a program of coal conversion for these six existing units if coal conversion results in those three nuclear units being delayed by two years each. Even if sufficient financing were available so that coal conversion

did not affect our nuclear construction program, our customers would have to pay between $840 million and $1,250 million more by the year 2000.

4. A delay of two years in completion of the three nuclear units previously mentioned can be expected to increase the use of oil in New England by 72 million barrels during the period 1982 through 1990. This increase would largely offset the oil which conversion to coal of our six units would replace so that there would be no significant net oil savings from this FEA action.

5. Conversion of these units would reduce the reliability of electric service in New England below the minimum reliability criterion adopted by the New England Power Pool in several years during the 1980s. Delays in completion of our three nuclear units would worsen this situation. In addition, we envisage electricity supply problems in the Southwest Connecticut area during the conversion period if our Norwalk Harbor units and the three Bridgeport Harbor units of the United Illuminating Company are required to switch to coal as their fuel.

6. Conversion of six units to coal burning would have significant environmental impacts. Emissions of particulates and nitrogen oxides into the air would be increased. Enormous quantities of ash and sludge from flue gas desulfurization equipment would be produced. For the five Connecticut units the volume of this solid waste could be about 620,000 tons per year, enough to cover each year about 378 acres of land a foot deep. These wastes would aggravate Connecticut's already serious solid waste disposal problems. We are not aware of any disposal site for such wastes in Connecticut that would be acceptable to the state environmental authorities.

Serious as these consequences of the FEA's proposed Prohibition Orders under existing law would be, the proposed National Energy Act, House of Representatives Bill 6831, would amend ESECA in ways that would magnify these adverse effects in scope and impact. This Bill would increase our system's exposure to additional conversion orders. Up to 12 other units could conceivably be subjected to conversion orders, which would require the raising and expenditure of enormously larger amounts of capital, in the order of approximately $950 million more. It could make futile our efforts to show that the six pending orders should not be implemented by reducing the procedural and substantive requirements of the present law and empowering the FEA Administrator to shortcut the six present proceedings.

The resulting burdens and sacrifices should not be imposed on our customers and investors and the economies of our states. Our customers have already financed the high capital costs of our nuclear expansion program, and they have just begun to reap its benefits. To require them now to bear additional costs, whether under the National Energy Act or ESECA, would fail to recognize that we have already taken significant steps to meet the national objective of reducing the country's dependence on oil by implementing our nuclear expansion program.

Our concerns with the coal conversion provisions of the proposed National Energy Act center largely on proposed new Section 105 of The Energy Supply and Environmental Coordination Act of 1974 and related provisions which deal with the conversion of existing electric powerplants. However, although our present problems involve existing plants and we have no plans to install new fossil-fuel-fired plants, our analysis of the exemption provisions for new plants in proposed new Section 104(b) does indicate that these provisions are so structured as to be impossible to meet, except possibly for the exemption in Section 104(b)(3) for peaking plants, which run less than 1500 hours per year. Even that exemption for peaking plants requires much more definition and needs to take account of the fact that in New England peakload generating units may have to run much longer than 1500 hours a year in order to meet customer needs.

The provisions for existing plants in new Section 105 will provide, in our opinion, significantly less protection for the interests of utility consumers and investors than the present ESECA provisions. This is so, first, because of the new Section 105(a)(2)(A), which would permit the Administrator to issue by rule blanket prohibitions against natural gas or oil burning, without having to satisfy even the present minimal procedural requirements of ESECA. No provision is made for an EPA environmental review. The classes of plants to which such a rule could apply are apparently to be determined entirely by the Administrator's discretion. No statutory criteria are specified, except that the Section provides that one class of prohibited plants may be those for which prohibition proceedings are currently pending under ESECA. Because of this lack of statutory criteria, the Administrator would apparently be entitled to prohibit oil burning by plants, such as gas turbine peaking units, which are incapable of burning coal.

The apparent impact of this new Section 105(a)(2)(A) on utilities such as the Northeast Utilities System which have pending ESECA prohibition proceedings is particularly disturbing. We have devoted to date over 20,000 hours of employees' and consultants' time to our pending ESECA proceedings. All of this effort and the accompanying costs could be wasted if new Section 105(a)(2)(A) were enacted and the Administrator then moved to shortcut the pending proceedings by adopting a rule which would cover our plants. A mid-stream change in approach such as this seems grossly unfair to us.

The Bill would retain in new Section 105(a)(2)(B) and (C) the present procedure on issuance of prohibition orders for additional plants, but with a significant cutback in the scope of the preliminary findings that would have to be made by the Administrator. Thus, the present requirement of ESECA that a plant have in place "necessary plant equipment" to permit coal burning would be eliminated. Further, the Bill would replace the present requirement of a finding of "practicability", under which the Administrator has had to consider the comparative economics of the plant in burning oil or coal, with a new requirement that the Administrator find only that "the use of coal is financially feasible". Section 105(a)(2)(C)(ii). While the concept of "financially feasible" is not defined in the Bill, it clearly does not require a consideration of comparative economics. We question whether the Administrator would not be justified under the Bill in finding a conversion "financially feasible" so long as it does not bankrupt the utility. In any event, the concept of financial feasibility does not adequately take account of the ability of utilities such as our companies to obtain the rates needed to finance the capital costs of coal conversion. Moreover, the lack of definition vests too broad a discretion in the Administrator.

While there are provisions in the Bill on temporary exceptions and exemptions, these in our judgment do not appear adequate to protect the interests of utility consumers and investors. The only exemption of continuing application which would be available to companies which use oil like the Northeast Utilities System is that in Section 105(e)(1) of the Bill. The conditions imposed on this exemption, however, could have most unfavorable effects on our customer charges. Thus, leaving aside the question of site limitations, which do not appear applicable to use, in order to qualify for an exemption we would have to establish both that the cost of using coal would substantially exceed the cost of using imported oil and that no alternative supply of power was available.

Two significant problems exist with the way this exemption is structured. First, in analyzing comparative coal and oil costs, Section 102(14) of the Bill would require a reference to "any change in the use of existing electric powerplants in the relevant dispatching system." This is a proper way of analyzing cost. However, in New England, our generation is dispatched as part of the overall New England or NEPEX system, which will continue to be oil-fired to a major extent. Under NEPEX dispatch, if total costs of operating with coal are significantly greater than the cost of operating with oil, this would serve to increase the cost of operating our converted plants - although quite possibly not be enough to meet the "substantially exceeds" test of the exemption - and the result would be that NEPEX would reduce the level of operation of our converted plants and increase the level of operation of other New England plants, which are very likely to burn oil and are likely to be less efficient than our plants presently are. The one clear result would be to increase our customers' costs, but, because of the dispatch arrangements, such action may not produce significant oil savings and, at worst, might actually increase oil consumption.

Secondly, the question of comparative economics becomes relevant under the exemption only if "there is no alternative source of power". Section 105(e)(1)(C). Alternative sources of power will almost always be available at some price. Unfortunately, however, the cost of the alternative is irrelevant to the availability of the exemption. Thus, it is likely that even if we could demonstrate that the costs of using coal would be two or three times the costs with oil, we would not be entitled to an exemption.

Finally, the Bill fails to face squarely the issue that has been of paramount importance to us in assessing the possibility of coal conversions. This is the issue of whether we can effect the large amounts of financing required for conversion without adversely affecting our nuclear expansion program. We need a regulatory climate in which we can obtain adequate rate relief to proceed with our nuclear expansion program and bear the large additional costs which coal conversion would impose. It has been our judgment that, in view of our own present weakened financial condition and our present regulatory circumstances, we probably will have to cut back on our nuclear program if conversions are required.

We believe that we are not alone in facing this problem of a potential adverse effect on our nuclear program. In view of this, we urge that a provision be written into the Bill which will require the Administrator to credit the contributions already made to oil savings and which will be made in the future by a utility's nuclear plants, and to make a nuclear contribution like ours a basis for exemption.

We also urge that the Bill specifically require full hearings on the record, where the views and positions of all parties will be subject to the test of cross-examination. Such a requirement will ensure a full airing of the costs and benefits of a mandate to convert a plant to coal burning. In this way fairer and better decisions should be made, which will take full account of the impacts on consumers, investors and utilities. In addition, the Bill should clearly direct the FEA to make the environmental assessments which the National Environmental Policy Act requires when the FEA begins its consideration of whether or not to order coal conversion, instead of waiting until its administrative processes are nearly completed. Such a direction would ensure that the FEA properly considers environmental values and consequences and that environmentally sound decisions are made.

June 6, 1977

COMMENTS OF THE COMPANIES OF THE NORTHEAST UTILITIES SYSTEM
ON TITLE I, PART F
(Amendments to the Energy Supply and Environmental Coordination Act)
OF THE PROPOSED NATIONAL ENERGY ACT
(H.R.6831; S.1469 and S.1472)

In 1974 the Energy Supply and Environmental Coordination Act (ESECA) (Public Law 93-319) was enacted which empowered the Federal Energy Administrator to prohibit by order any power plant or major fuel burning installation from burning natural gas or petroleum products as its primary energy source. Even though very few procedural safeguards are present in ESECA, it has proven to be difficult to administer at best, and at worst has been ineffectual and contrary in application to the purpose of the Act which was to reduce petroleum and natural gas dependence by mandating coal conversion. For example, in New England because of our unique regional power dispatching system, it may well be that forcing certain power plants to shift to coal will in fact increase the region's petroleum consumption, and cost, because of substitution of less efficient petroleum-fired units to meet cycling and loss of capacity requirements.

In the same fashion the coal conversion program mandated by the proposed National Energy Act also appears to be misconceived and unlikely to achieve the purpose of meaningfully decreasing natural gas and petroleum utilization. In addition, the proposed National Energy Act would further limit due process guarantees and public evaluation of any decisions made. The Federal Energy Administrator's discretion is greatly enlarged such that orders can be based primarily upon his being satisfied as to only a few of the applicable parameters, with very little weight being given to the impact of a mandated coal conversion on

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the consumer or the economy or its adverse effect on other on-going programs to reduce petroleum and natural gas dependence, such as construction of nuclear power plants or solid waste utilization.

Northeast Utilities can speak with authority in these areas because its operating companies are now involved with the Federal Energy Administration in the consideration of six units to be converted to coal under the provision of ESECA before its extension expires on June 30, 1977. It is our inescapable conclusion that ESECA, and the coal conversion provisions of the proposed National Energy Act (Title I, Part F) do not accomplish the laudatory aim of decreasing petroleum and natural gas dependence in the production of power nor do they properly take into account the economic, social and environmental costs associated with a mandated conversion which must be evaluated on a site specific basis.

Thus, we believe it would be appropriate to repeal rather than modify ESECA. However, assuming the concept which resulted in the passage of ESECA is still deemed valid, and because of our experience under ESECA, Northeast Utilities offers the following suggested modifications to the proposed National Energy Act to alleviate the present shortcomings:

Delete Section 601(Sec.105(a)(2)(A)) in its entirety.

Explanation

This amendment would remove the ability of the Federal Energy Administrator which would be granted by this Act to establish by administrative fiat by category those existing power plants which would be prohibited from utilizing petroleum or natural gas on a blanket basis with no consideration of the individual circumstances of any particular plant within a category or any due process guarantees to identify and resolve any attendant issues such as economic or environmental effects.

Add the following at the end of Section 601(Sec.105(a)(2)(B)):

"except that any existing electric power plant which was subject to an order issued pursuant to the provisions of Section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 as in existence at the time of enactment of this Act shall continue to be subject only to the provisons of that Act."

Explanation

This amendment ensures that those utilities which are already involved in a coal conversion proceeding commenced under the Energy Supply and Environmental Coordination Act (ESECA) would not be subject to a generally duplicative proceeding under the proposed National Energy Act.

Modify Section 601(Sec.105(a)(2)(C)) as follows:

"Criteria. - The Administrator may issue an order pursuant to subparagraph (B) if he determines that -

"(i) the existing electric power plant on June 22, 1974, had or thereafter acquired or is designed with the capability <u>and has</u>

the necessary plant equipment to use coal or other fuel as an energy source;

"(ii) that the use of coal or other fuel by the power plant in lieu of natural gas or petroleum is practicable, cost effective, and consistent with the purposes of the Act to decrease natural gas and petroleum usage;

"(iii) that the prohibition under subsection (a)(2)(B) will not adversely affect the reliability and economy of service in the dispatching system of the power plant;

"(iv) that adequate and reliable sources of coal, coal transportation and waste disposal facilities will be available during the useful life of the existing electric power plant; and

"(v) that a suitable alternative plan to decrease natural gas or petroleum usage has not been developed for the system of which this plant is a part."

Explanation

The criterial for issuance of a prohibition order have been revised to reflect the types of determination which should be made to establish a reasonable and effective coal conversion program to accomplish meaningful reduction of natural gas and petroleum usage for the production of power while recognizing the necessity to consider economic and environmental impacts and the feasibility of accomplishing the same purpose through alternate construction and operation strategies.

Change the last clause of Section 601(Sec.105(a)(3)) to read:

"... unless the reliability and economy of service in the dispatching system will thereby be impaired."

Explanation

This amendment would require that a determination be made that a prohibition to increase the proportion of petroleum or natural gas used in a mixture with coal would not adversely affect either the reliability of service or the economy of service realized through a dispatching system.

Modify Section 601(Sec.105(b)(2)) as follows:

"Before issuing, modifying or rescinding an order issued under subsection (a)(2)(B), the Administrator shall give notice to the public and give affected parties the right to participate in an adjudicatory-type hearing on the record to provide and promote full disclosure of all pertinent data, views and arguments and to afford interested persons an opportunity for oral and written presentations of data, views and arguments."

Explanation

Recognizing that a correct decision is more likely to be made when parties whose interests will be substantially effected have been allowed to participate meaningfully in the decision-making process, it is recommended that an adjudicatory hearing be conducted to better provide and promote fully disclosure of all pertinent data, views and arguments.

In Sections 601(Sec.105(d)(3) and 601(Sec.105(e), delete the phrase

"to the satisfaction of the Administrator"

Explanation

These amendments would narrow the power of the Administrator to bring that power into conformance with traditional administrative principles to prevent the exercise of authority in an arbitrary or capricious manner.

Make the following modifications to Sections 601(Sec.105(d)(3)(B)) and 601(Sec.105(e)(1)(A)):

"... such as access to <u>or the availability and cost of</u> coal or coal transportation facilities <u>or waste disposal sites</u>."

<u>Explanation</u>

A specific physical factor which has not been considered as a criteria for coal conversion is the availability, accessability, and cost of liquid and solid waste disposal sites. In addition, the availability and cost of coal supplies and transportation facilities are necessary determinations in any assessment of the feasibility of a conversion to coal. These amendments would specifically require the analysis of these factors to be included in the determination of whether to grant a temporary or general exemption.

Substitute the following for Section 601(Sec.105(e)(1)(B)):

"the <u>conversion and use of</u> coal or other fuel <u>is not cost justified</u>; <u>or</u>"

<u>Explanation</u>

This amendment would clarify the provision in the proposed National Energy Act to ensure that a decision is not made without having considered a cost/benefit analysis and to remove any possible ambiguity as to the interpretation of the meaning of "substantially exceeds" as it might affect a local service area.

Add the following phrase at the end of Section 601(Sec.105(e)(1)(C)):

"there is no alternative supply of power which can be obtained without impairing reliability <u>or unreasonably increasing cost</u> of service; <u>or</u>"

Explanation

Although it is recognized that some sacrifice on the part of individual consumers or even regions of the country may be necessary to achieve a valid national energy policy, an exemption should be granted when the costs which must be borne by the customer because of conversion are excessive.

Add a new Section 601(Sec.105(e)(1)(D)):

"a suitable alternative plan has been developed to decrease natural gas or petroleum usage for the system of which this plant is a part."

Explanation

Since a major purpose of the coal conversion program is to decrease natural gas and petroleum dependence in the production of power, utilities which have already embarked or intend to embark on construction or operation programs which would reduce that dependence through means other than the increased utilization of coal should not be penalized or forced to bear further substantial capital costs merely because they choose alternatives other than coal or chose to use coal in stations other than those being subjected to a prohibition order. This amendment would credit a utility for that foresight and commitment in the determination of the necessity to order any of its plants to undergo a mandatory conversion to coal and is intended to provide an alternative ground for an exemption.

Modify Section 108 as follows:

"... because of investments or commitments made in other alternative methods to coal conversion which have or will significantly decrease natural gas or petroleum dependence."

Explanation

This amendment would authorize the Administrator to grant relief from a prohibition order directed at a particular electric power plant if the purposes of the act have or will be satisfied through the development and use of alternative methods for power production other than coal utilization at that specific plant, such as increased nuclear power, solar energy or solid waste utilization within that utility system.

Delete Section 601(Sec.112(a)(1),(2),(3) and (b) in their entirety.

Explanation

The traditional method of enforcing compliance with an administrative process is through a petition to the district courts of the United States to enjoin the violation of an administrative order. The imposition of a penalty of as much as $50,000 or incarceration for one year per violation per day is unnecessary and unwarranted to ensure compliance with this act.

Portland Cement Association
June 3, 1977

Statement Submitted to the Energy and Power Subcommittee of the House Interstate and Foreign Commerce Committee, on the Coal Conversion Provisions of H.R. 6831 (Part F)

The portland cement industry recommends that the Energy and Power Subcommittee eliminate provisions of H.R. 6831 that would mandate conversion to coal by industries now using oil and natural gas. Mandatory regulation of industrial fuel usage is inflationary, administratively burdensome, and totally unnecessary as far as our industry is concerned.

This position does not in any way dilute our strong support of essential national energy conservation programs and our recognition that such programs must be challenging. In fact, in the three years that the cement industry has participated in the Administration's voluntary industrial energy conservation program, this industry has moved dramatically -- and voluntarily -- to convert from oil and natural gas to coal as its principal process fuel.

In 1972 the cement industry utilized coal for only 38% of its fossil fuel needs. By 1976 -- under the voluntary program -- this figure had risen to 55%. In the same period, the industry's consumption of natural gas fell 41% and oil use declined 30%. These achievements were the result of management decisions that reflected both economic reality and a concern for national energy objectives. They did not result from government fiat.

A 1975 industry-wide survey conducted by the Portland Cement Association indicated that planned coal conversions will bring the cement industry's coal-burning capability to 90% of total capacity by 1980. The remaining 10% will be in localities (Hawaii, for example) where coal is not economically available or where plant sites cannot accommodate coal stockpiling facilities. With such demonstrated voluntary response, a mandatory program is obviously unnecessary.

The mandatory provision of H.R. 6831 would be administratively burdensome for both government and industry. More importantly, it would be highly inflationary. If conversion "deadlines" are mandated, industries would be forced to compete for a limited supply of coal-handling equipment. The inevitable result would be production bottlenecks and increased equipment prices. A voluntary program would minimize such disruptions. A mandatory program, by contrast, would produce small incremental benefits to the nation at an extremely high cost in inflation, equipment shortages, and added paperwork.

As a major energy user with a strong reliance on coal, the cement industry strongly recommends that the Subcommittee delete the mandatory coal conversion provisions contained in the Administration's energy proposals.

NEW ENGLAND POWER COMPANY
New England Electric System
Telephone 617 366-9011
20 Turnpike Road, Westborough, Massachusetts 01581

May 19, 1977

The Honorable John D. Dingell
Chairman, House Energy & Power Subcommittee
Room 3204
House Annex No. 2
Washington, D. C. 20515

Dear Congressman Dingell:

At the suggestion of Jim Phillips who attended the recent FEA hearings in Boston regarding the issuance of proposed coal conversion orders to a number of New England utilities, I will describe our position relative to coal burning and our objections to the ESECA process. Our basic company position is quite simple - we want to burn coal and we believe we can burn it cleanly and save money for our customers. Our basic objection to the ESECA process is also quite simple - we believe it will result in needless expense for our customers.

First, by way of general background ---

Our company burned coal as a primary fuel until the late 1960's when we converted to oil. During the early 1970's Federal and State air pollution regulations evolved and, in Massachusetts, a State Implementation Plan (SIP) was formulated on the basis of requirements that oil burners could meet without extensive plant modifications. The blessing of the SIP by EPA resulted in a stringent set of air quality rules for oil burners - and I'm sure since there were no coal burners in the state - no one envisioned the impact of that SIP on future coal burning.

During the oil embargo in 1974 we reconverted our units with coal burning capability back to coal on a crash program and in 1974 and 1975 burned 1.5 million tons of coal. Because the air quality rules had changed from our prior coal burning days, we were allowed to burn coal only under strict variance and suspension conditions - and it is important to note that at no time were primary standards violated in our area of impact. Because our variances and suspensions could not be extended beyond a statutory deadline date of June 30, 1975, we reconverted the units back to oil.

This little bit of history is significant because it points out the irony in the coal conversion dilemma. We voluntarily converted to coal, met primary standards and saved money for our customers via the fuel adjustment provision in our rates (coal was less expensive than oil). Now we are about to be ordered to burn coal, must meet a SIP designed for oil and the net result will be higher costs for our customers. The higher cost derives from a choice of burning coal conforming to the SIP - a coal cost higher than our oil cost - or installing pollution control equipment whose cost could exceed $250,000,000. I would point out that the regions in which our two major plants are located have ambient SO_2 levels only 60% and 30% of the primary standards for SO_2.

We have and will continue to work toward reasonable change in air quality regulations - with these changes we feel that some of our units can again burn coal economically. Given this condition we will voluntarily switch back to coal. In the meantime, we continue to resist forced conversion that entails needless expense for our consumers.

Regarding the ESECA process - we have objections to some provisions of the law and the FEA's actions within its framework. Rather than detailing these objections, however, it might be more useful to point to changes that should be incorporated in ESECA or follow on legislation:

1. From an environmental standpoint the target is moving so quickly (e.g. nonattainment, nondeterioration) that one is never quite sure what the rules are and converting to coal poses huge investment risks. Many of the current debates and issues will take years to resolve. To expedite and encourage conversions, potential coal burners should be permitted to burn - and environmental regulatory groups should be directed to support - the burning of as high a sulfur coal as ambient conditions will permit up to the primary standard for SO_2. In addition, new legislation must provide a period of certainty under Federal and State clean air standards for utilities making an investment in coal conversion facilities. This concept is sometimes called a "grandfather clause" and is exemplified by Section 306(d) of the Federal Water Pollution Control Act, which provides that industries meeting "new source" discharge limits shall not be subject to any more stringent standards for ten years following completion of construction. (In the case of coal conversion, the remaining useful life of the plant would be a more appropriate period). Such a provision would eliminate the substantial risk which now exists that such an investment might well be rendered worthless by constantly changing environmental standards.

2. Coal conversion should not be required where it would result in an economic cost penalty to the utility or its customers. The current standard of conversion if it is "practicable" is entirely too vague and unworkable. Any additional costs imposed by coal conversion should not be paid solely by the affected utilities and their customers but should be distributed throughout the nation through federal grants or tax write-off provisions so that the benefits of making our country "energy independent" are paid for by all of its citizens, not just some.

3. The current ESECA "two step" process, whereby FEA first issues a Prohibition Order and EPA then makes its Clean Air Act findings, is cumbersome and difficult. FEA cannot make valid cost and other findings until EPA has specified the applicable limits. The two agencies should be required to work together in advance of any conversion attempts so that all issues can be dealt with in a single proceeding which deals realistically with the problems. In addition, the required environmental impact statements should be available before the conversion proceedings begin so that environmental constraints will be known.

4. Prior to any conversion efforts, FEA and EPA should be required to make public their detailed factual findings as to the costs and benefits resulting from conversion. FEA's current attitude of releasing documents only after the proceeding is commenced, and not preparing an analysis which backs up its findings with facts, encourages shoddy government decision making and makes extensive litigation inevitable. All relevant data should be "put on the table" so that the utilities and the public may scrutinize the basis for a conversion decision.

5. Any conversion of utilities which are part of a centralized "power pool" system - as is the case in New England - should be preceded by an analysis of the effects of conversion on such system, as well as on the individual plants. Without such an analysis, the true costs and benefits of conversion can never be understood.

6. An opportunity should be provided to the utility for cross-examination of the FEA and EPA "experts" who prepare the necessary findings for conversion. A full-scale evidentiary hearing would be desirable, but even limited opportunity for cross-examination would be a vast improvement over the current law. Although it might be argued by some that such a procedure would slow down the conversion process, in fact, it will speed it up because government decisions will be made on a more realistic basis if those making them understand that their rationale is subject to a genuine critique. This will result in a more realistic approach to conversion by the regulatory authorities and, therefore, greatly reduce the litigation which is unavoidable where no mechanism exists for a thorough examination of the facts prior to a conversion initiative.

The preceding suggestions are directed toward overcoming some of the weaknesses of current mandatory conversion legislation. Of deep concern to me - after witnessing the unproductive and perhaps counter-productive pursuits under ESECA - is whether any mandatory conversion program on existing generating plants can be very effective. If we focused our attention on removing impediments to voluntary, economic conversions, I believe the taxpayer and utility customer would come out far ahead and we would see coal conversion effected more rapidly and in greater numbers.

I hope these observations are helpful and if we may be of any further assistance in this matter, please let us know.

Very truly yours

J. F. Kaslow

J. F. Kaslow
Vice President

Stauffer

Stauffer Chemical Company

Westport, Connecticut 06880 / Telephone (203) 226-1511 / Cable "Staufchem"

June 6, 1977

Honorable John D. Dingell, Chairman
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
Room 3204 Annex No. 2
2nd and D Streets, S. W.
Washington, D. C. 20515

Re: H.R. 6831, The National Energy Act

Dear Mr. Chairman:

Stauffer Chemical Company has previously reviewed the coal conversion legislation proposed by Senator Randolph, and as subsequently revised by Senator Jackson. We have worked with the Senate committees and staff in an effort to develop a bill which would give the results desired in the most beneficial and least disruptive manner.

Based on the background and experience we have gained from the above, we would like to offer the following comments on the revisions to Title I of the Energy Supply and Coordination Act that are proposed in H.R. 6831:

1. Only new industrial and utility boilers of 250 million BTU/hour design heat input and over should be required to burn coal. Only existing boilers of that size which have burned coal or are equipped to burn coal should be required to convert to coal. It is not practical to convert boilers designed to burn oil and gas so that they will burn coal.

2. Industrial combustors should not be required to burn coal. The amount of oil that would be saved is not significant, and even when technology permits the cost is prohibitive. Direct fired retorts, cracking furnaces and process heaters, particularly those depending on radiant heat, are not capable of burning coal, and in most cases cannot be designed to do so. Even when there is not direct firing, temperature control is not sensitive enough to control the process, and flame and heat release characteristics are unsuitable. The only manner in which coal could be used would be by coal gasification - clearly not the intent of this section,

entirely too expensive on a small scale, and not yet proven technology. Unlike a boiler house, process combustors cannot be centrally located, so that even when it might be technically feasible to construct equipment to use coal, the cost of multiple coal handling and flue gas environmental control make the use of coal prohibitively expensive.

3. The Federal Energy Administrator should not be given the authority to lower the size limitation adopted by Congress, or to arbitrarily rule that certain industrial equipment or processes must convert to coal or that certain installations are to be defined as MFBI's.

4. Most industrial boilers can be converted from natural gas to fuel oil to save natural gas. Not all process combustors can use natural gas, however. The present FPC regulations on end use curtailment of natural gas recognize, in FPC Order 476B that for certain process uses other fuels such as petroleum cannot be substituted. The proposed law should adopt those provisions.

5. The power plant or industry which has constructed its own pipeline to transport natural gas for its own use should be allowed to increase the price of gas sold because of a prohibition to recover the pipeline cost allocated to such gas.

6. We consider it unconscionable that the Administrator would be allowed to refuse an exemption and then allocate coal to a person when a person subject to a prohibition demonstrates in a request for an exemption that coal is not available.

We appreciate the opportunity to comment on this bill, and respectfully request that you include our views and comments in your consideration of this highly technical and vitally important section of H.R. 6831.

Very truly yours,

D. M. Greeno

D. M. Greeno
Director, Energy Management

DMG:dw

[Whereupon, at 4:20 p.m., the subcommittee adjourned, to reconvene at 10 a.m., Wednesday, June 1, 1977.]

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