FUTURE OPTIONS FOR GENERATION OF ELECTRICITY FROM COAL

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND AIR QUALITY

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COMMITTEE ON ENERGY AND COMMERCE
HOUSE OF REPRESENTATIVES

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FUTURE OPTIONS FOR GENERATION OF ELECTRICITY FROM COAL

TUESDAY, JUNE 24, 2003

HOUSE OF REPRESENTATIVES,
COMMITTEE ON ENERGY AND COMMERCE,
SUBCOMMITTEE ON ENERGY AND AIR QUALITY,
Washington, DC.

The subcommittee met, pursuant to notice, at 2 p.m., in room 2123, Rayburn House Office Building, Hon. Joe Barton (chairman) presiding.

Members present: Representatives Barton, Burr, Whitfield, Norwood, Shimkus, Boucher, Allen, Waxman, Brown, McCarthy, Strickland, and Doyle.

Staff present: Bob Meyers, majority counsel; Andy Black, policy coordinator; Bob Rainey, fellow; Bruce Harris, minority counsel; and Michael L. Goo, minority counsel.

Mr. BARTON. The subcommittee will come to order. We are waiting for a minority member to arrive, but we will officially start the hearing.

The subcommittee will come to order. Without objection, the subcommittee will proceed pursuant to committee rule 4(e) which governs opening statements by members and the opportunity to defer to them for extra questioning time. Any objection? Hearing none, prior to the recognition of the first witnesses for testimony, any member when recognized for an opening statement may completely defer his or her 3-minute opening statement and instead use those 3 minutes during the initial round of the witness questioning. In other words, they will get 8 minutes instead of 5.

The Chair is going to recognize himself for an opening statement.

More than half of our Nation's electricity is generated from the combustion of coal and power plants. Our coal reserves are tremendous and should last more than 250 years given the current expectation for the use of coal. In other words, coal power is here to stay. Coal plants today are much more efficient than they ever have been and they emit much less per ton of coal consumed than they ever have before. The act of generating electricity from coal, however, is a process that can stand further comment and research.

Today the subcommittee is going to take a look at the future options for generating electricity from coal. The hearing is intended as a technical hearing on future options and we are pleased to have a distinguished set of witnesses on these technical issues. Members of the subcommittee need to be aware of the latest technology applications that are available to electricity generators today, what might be available in the future.

We have witnesses today to discuss coal gasification, advanced combustion boilers, environmental controls and other new concepts. Some of our witnesses can discuss the process that a generator will go through when making a decision on these future options.

Congress has a role to play in this debate. H.R. 6, the House Energy bill which passed the House back in April and which is pending in the Senate, many Members of both political parties embraced the Clean Coal Power Initiative. Leaders of that initiative are on this subcommittee: Mr. Shimkus, Mr. Boucher, Mr. Whitfield, Mr. Strickland, Mr. Doyle and others.

The Clean Coal Power Initiative provides for continuation of public/private partnership in finding improved methods to produce electrical power from coal, including an emphasis on coal gasification technology. We have also identified tax credit provisions that will encourage utilities to employ these new technologies. I have talked with a number of members about an enhanced clean coal program to aggressively implement retrofits and entirely replace some of the old existing coal plants with next-generation facilities. This particular idea is not in a pending bill that is in the Senate, but it is an idea that could be if there is enough support for it.

I will work with all members in the energy conference on the clean coal section, the tax title and other conference items, incorporating, to the extent possible, lessons that we learned from today's hearing.

Since committee consideration of H.R. 6, the Department of Energy has announced a new initiative regarding the future generation from coal. This FutureGen Initiative calls for public/private partnership which design, construct, and operate a 275-megawatt prototype plant that produces both electricity and hydrogen with near zero emissions and with sequestration of carbon dioxide emissions.

Our hearing today will offer the opportunity to review this proposal for interaction with other clean coal initiatives and the projected benefits and costs of such technology. I want to welcome all of our witnesses today and encourage you to give us an honest picture of what you think the future of coal use in the United States looks like. I expect we can explore what kind of power plants will be available to power generators in the next few years and what kind of power plants will be feasible in the longer term.

We can also examine the congressional role in authorizing such activity, in providing for the conditions which will lead to adoption of new coal-based electric power plants for the private sector.

Finally we also want each of the witnesses to explain to us what they think will work and what doesn't work and what efforts Congress should support or not support. These answers are important. This hearing will have a great impact on the positions that members of the Energy and Commerce conference committee take in the discussions we have with our Senate comrades when they pass their bill, hopefully sometime this month or perhaps in July or even September.

We should not and will not take coal off the table either directly or through an overly burdensome regulatory structure. We should and can continue the evolution of coal generation into the 21st century. When we talk about abundant reliable and affordable energy, coal today is a major part of that debate, and should be for the rest of our lives and our children's lives. The question is how best to do this. Where are the currently available technologies, the technology that will become available in the near term, and the future technologies which can best utilize our Nation's most abundant conventional energy resource.

With that I would like to recognize Ranking Member Boucher, for an opening statement and thank him for helping put this hearing together. Many of the witnesses today are here because of his suggestion that they attend.

Mr. BOUCHER. Thank you very much, Mr. Chairman, and I want to express my appreciation to you and the members of your staff for the outstanding cooperation you have provided in scheduling this hearing and assembling outstanding witnesses for us today. And I want to say a word of welcome to each of our witnesses.

At a hearing before the full committee earlier this month on the topic of natural gas supply and demand, we heard from the Energy Information Administration that by the year 2025, it is estimated that an additional 450 gigawatts of new electricity generation capacity will be needed in order to meet rising demand. Even with far higher prices for natural gas in recent years and the related concerns regarding the long-term availability of a stable supply of natural gas, it is still predicted that 80 percent of the new power plants to be constructed between now and 2025 will be powered with natural gas. One of the reasons that natural gas is so widely used for electricity generation is the fuels environmental performance.

But at the same time, it should be noted that advances in clean coal technologies, both recently achieved and on the horizon, are ensuring that future coal-fired electricity plants will be able to operate with little environmental effect.

Coal is the Nation's most abundant fuel, with reserves sufficient for the next 250 years in the United States alone at current consumption rates. It generates electricity at less than one-half the cost of the fuel alternatives. In fact today, coal delivered to the power plant costs $1.25 per million BTUs as compared to natural gas that costs $4.50 per million BTUs. $1.25 for coal, $4.50 for natural gas. Natural gas prices are predicted to remain at this level or to rise in the foreseeable future, while it is estimated that coal prices will fall even further.

It is clearly in the energy security interest of the Nation to use coal, an abundant domestic resource, and consumers clearly get the best prices for electricity when they purchase electricity generated through the combustion of coal.

We are also mindful of the harm to the national economy that will occur with the rapid rise of gas prices, which would be a certain consequence of the deployment of hundreds of new gas-fired electricity-generating units. More than one-half of homes are heated today with natural gas. Products throughout the economy are manufactured in natural gas consuming and intensive processes. A dramatic increase and the demand for natural gas occasioned by an overreliance on gas for electricity generation will cause serious economic harm. Accordingly, we should be doing everything we can to encourage fuel alternatives to natural gas. We simply cannot tolerate the use of natural gas as the fuel for 80 percent of the new electricity-generating units to be built over the next 20 years.

Several of us, members of this committee, have suggested a path to a solution, and I was pleased that the chairman mentioned that effort in his opening remarks. We had hoped to make possible the greater use of coal for electricity generation and relieve the pressure on natural gas pricing that will occur unless Congress takes positive steps.

Earlier this year, I was pleased to join with several colleagues on this committee, including the gentleman from Kentucky, Mr. Whitfield and the gentleman from Illinois, Mr. Shimkus, and other members in introducing the Clean Coal Power Act of 2003. Our legislation acknowledges the value to the Nation of coal use and takes appropriate steps to assure the protection of air quality where coal is burned. Our legislation makes a substantial Federal investment in coal research and development and also provides tax benefits to promote the use of coal in both new and retrofitted electricity-generating plants that agree to use advanced clean coal technologies.

Today we will hear from a number of witnesses regarding the successes of clean coal technologies and what future technologies will further advance the use of coal, and I look forward to their testimony on this topic.

I want to take just a moment, Mr. Chairman, to say a special word of welcome to two of our witnesses. Dr. Roe-Han Yoon is a world leader in coal research and development. He is a department head and professor at Virginia Tech, which happens to be in my congressional district. He is here not because he is my constituent, but because of the expertise that he possesses in a wide range of research and development fields relating to clean coal technology. He serves as executive director of the Center for Advanced Separation Technologies, a consortium of a number of universities focusing on more efficient use of coal through precombustion separation technologies.

I also want to say a word of welcome to Mr. Brian Ferguson, chief executive officer of the Eastman Chemical Company. His company is a chemical producer, a very large one at that, which operates the Nation's first commercial coal gasification facility. The Eastman experience in the commercial use of coal gasification is clearly of relevance to our focus today and may suggest a positive direction for this committee to consider, and I want to welcome Mr. Ferguson as well.

Mr. Chairman, you have assembled an excellent panel of witnesses. I thank you for scheduling this hearing and I look forward to the testimony of those who come before us.

Mr. BARTON. It is easy to do when we ask the people you ask. Works pretty well that way.

Mr. BARTON. Does the gentleman from Georgia wish to make an opening statement?

Mr. NORWOOD. Thank you, Mr. Chairman, and I want to thank you and Mr. Boucher for putting this hearing on and I plan to do a lot more listening than talking.

Mr. BARTON. Then you will have an additional 3 minutes on your questions.

Does the gentleman from Ohio wish to make an opening statement?

Mr. BROWN. I will have more talking than listening.

Mr. BARTON. The gentleman is recognized—we are not going to put the clock on you, but supposedly you are supposed to talk for 3 minutes.

Mr. BROWN. I thank the witnesses for what I expect will be informative testimony. I am particularly pleased that we are joined today by two witnesses with close ties to my State of Ohio. Babcock & Wilcox headquartered in Barberton Ohio leads the industry in production of boilers for coal-fired power plants and the emissions control systems designed for single pollutant and multipollutant applications. B&W is researching a promising advanced combustion technology called oxyfuel that may make conventional coal combustion much more compatible with greenhouse gas emissions control. We are proud to have B&W and proud to have Larry McDonald, the company's director of Design Engineering Technology here today.

Powerspan is a valued partner to First Energy which is headquartered in Akron, Ohio in my district. Powerspan's electrocatalytic oxidation technologies produce promising test results as an effective and cost-effective multipollutant control technology. Emissions reductions of 80 percent to well over 90 percent in an economic package clearly merit further study. Along with our colleague Ted Strickland, a member of this committee, I support Powerspan's production scale tests at First Energy's plant near Shadyside, Ohio. I am pleased that Powerspan's CEO, Frank Alix, was able to appear here today.

So as I consider coal's future as a source of electric power, the dynamic seems grounded in three fundamental points: One, coal is here to stay. Two, coal can and must be an environmentally responsible source of fuel for the generation of electric power. Three, the Federal Government must support research and require the market to develop innovative, effective, and affordable pollution control technologies.

Coal is here to stay because it is an affordable, readily available source of domestic energy. This committee's recent examination of natural gas prices illustrates abandoning coal would compromise our energy security and our industrial competitiveness. As this committee's ongoing interest in manipulation of western energy markets amply illustrates, failure to maintain a diversified fuel mix invites abuse in the marketplace, sometimes with disastrous results.

The economic stakes are much too high for Congress to offer less than a total commitment to the continued viability of coal. Coal can be cleaner than it is today. There are already well-established pollution control technologies of Babcock & Wilcox as well as the promising efforts of Powerspan to offer significant improvements in the environmental performance of traditional coal-fired power plants.

The first thing the Federal Government must do is maintain and expand upon the sponsorship of promising research. Like the chairman and Ranking Member Boucher, I enthusiastically support the Clean Coal Power Initiative and I believe we must maintain the effort to improve the emissions performance of existing coal-fired plants. As Powerspan and B&W have both demonstrated, we can achieve meaningful improvements.

Congress should continue to support promising research to make America's existing coal-fired plants cleaner. It is essential that Congress, in addition, sponsor research to develop tomorrow's low-end, zero emissions, coal-fueled generating technologies. Coal gasification research has been encouraging to date and the clean coal program should continue to explore this technology.

In addition, although I rarely agree with President Bush on some of his energy policies, I couldn't agree more with the Energy Department's FutureGen proposal. FutureGen offers a government/industry partnership to address the challenges of developing coal-based fuel cell power plants. Ohio's power companies have already committed to this project. Ohio's universities are doing leading edge technology research on fuel and fuel cells. Congress should provide the resources necessary to take zero emissions technology from the drawing board to the production line.

Mr. Chairman, today's hearing offers valuable insights into one of the most important energy issues confronting our Nation.

Mr. BARTON. We may let you Chair this hearing, you know, supporting the President and all this. That is front page news, you know.

Does the gentlelady from Missouri wish to make an opening statement?

Ms. MCCARTHY. I have a lengthy one, so let me just list from it briefly so that we can proceed with our witnesses.

I want to thank you for having this hearing. Missouri—82 percent of our electric power out in Missouri comes from coal. And I just want to brag a minute about what happened in my district, Kansas City, because Kansas City Power and Light Hawthorne generating station was old, was in need of either tearing down or improving, and as a result of efforts to change the way we do business, it has become one of the cleanest coal-fired plants in the United States. This facility, that was rebuilt, has 88 percent lower nitrogen oxide, 99 percent lower particulate matter, and 92 percent lower sulfur dioxide emissions than any other uncontrolled facility. And the Hawthorne generating station is a model of clean coal technology that can be used for the rest of our Nation.

So, Mr. Chairman, I join my colleagues in supporting the Clean Coal Power Initiative and to make sure that Congress keeps funding initiatives like the Hawthorne plant and that we do the continuing research for FutureGen and other ways in order to provide the energy needed across our country, but also do so in an environmentally friendly way. I welcome the experts here today and look forward to their testimony and yield back.

Mr. BARTON. Does the gentleman from Kentucky wish to make an opening statement?

Mr. WHITFIELD. Yes, I do Mr. Chairman.

Mr. BARTON. The gentleman is recognized for 3 minutes.

Mr. WHITFIELD. Mr. Chairman, thank you very much. And I want to thank you and Mr. Boucher for having this very important hearing on our most abundant and inexpensive resource that we have in America today, and that is coal.

The timing of the hearing couldn't be better. We have heard in the last few weeks from administration officials, including Federal Reserve Chairman, Mr. Greenspan, and we have read countless market analyses who are telling us the same thing: that natural gas prices are going to continue to go up and that the demand is not there to meet the needs of our country.

But as the price of natural gas and the rate that it is used for electric power generation rises, coal-fired power generation has decreased. Even though coal continues to be our country's primary electric power source, the share of power generation has dropped from 56 percent in 1997 to 49 percent last year. In that same time period, gas-fired power generation doubled from 9 to 18 percent. The same uncertainty about environmental regulations that cause this decline is also responsible for the fact that over the last 8 years, only 3500 megawatts of new coal capacity have come on line. This fact is particularly alarming because the Energy Information Administration estimates that by 2025, America will need an additional 1.9 trillion kilowatt hours per year. Basically what this means is that we have an artificially induced market for natural gas primarily because of a lot of environmental regulations.

But the value of coal as a power source for our country is almost infinite. A four-county area in my district alone has 15 percent more energy in coal reserves than the Nation has in proven reserves of natural gas. Still, the economic impact of coal to my State and a number of others is massive. In 2000, Kentucky's coal industry's impact on the State economy totaled almost $7 billion.

I am delighted that we are having this hearing today. We are going to hear from a number of experts, that we can and should better utilize existing clean coal technologies and invest in future technologies that will do more of what is already being done, and that is reduce harmful emissions.

Congressman Boucher, Mr. Shimkus, Mr. Strickland, Ms. Cubin, and I co-authored a bill, the Clean Coal Power Act of 2003. This forward-looking legislation addresses our Nation's increasing electricity demand by enhancing the research, development, and early commercial application of advanced clean coal technologies. Our bill would include short, medium, and long-term programs to improve efficiency and further reduce emissions while also ensuring that we will have the coal-generating capacity required to meet the increased demands of the future. It is both beneficial to the environment and critical to our future economic and electrical needs.

Mr. Chairman, I look forward to the testimony of our witnesses, and I do want to emphasize once again that we must be more aware of our most abundant resource and do everything that we can do to continue to provide electricity at an affordable rate, and the best way we can do that is to use clean coal technologies and burn more coal.

Mr. BARTON. Thank you.

Does the gentleman from Pennsylvania wish to make an opening statement?

Mr. DOYLE. Mr. Chairman, I want to commend you for holding this hearing and I would like to waive my opening statement and return for some extra time.

Mr. BARTON. The gentleman will get an additional 3 minutes in the first question period.

Does the gentleman from Illinois wish to make an opening statement?

Mr. SHIMKUS. I don't need to waive. I will just say that I want my statement for the record, and just talk about the whole energy bill process and what we are trying to do with the energy bill is we got to expand the grid. That is a critical component. Our hearing on natural gas proved that we have been too overreliant on one fuel. And I have always pushed for a multifuel approach in meeting our energy needs. And coal has an important and critical role at the table, especially for baseload generation. And we need to do all that to make sure that is part of our national security and energy generation. And I look forward to the hearing.

And with that, Mr. Chairman, I yield back my time.

[The prepared statement of Hon. John Shimkus follows:]

PREPARED STATEMENT OF HON. JOHN SHIMKUS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

If the past is any indication, the future is not bright for coal. The number of mining jobs related to coal continues to decrease every year. Over 90% of all new power plants are fired by natural gas. The fact that we have not given a national energy policy to the President yet, only matters worse as industry waits on some certainty from Congress.

However, I continue to believe that coal can play a vital role in our nation's energy future. We can change the future here in Congress. If we continue to focus on increasing research on ways to burn coal more efficiently and cleaner, and we stop killing coal use by regulation, coal will have a bright future.

This Administration and this Congress have started to put the resources behind finding ways to burn coal more efficiently and cleaner. The energy bill that passed the House contains over $2 billion to fund research on clean coal technologies over the next 10 years. The Administration's FutureGen proposal will lead to power plants that will burn coal without emitting pollution. Using the latest technology, they will generate electricity, sequester greenhouse gases, and provide a new source of clean-burning hydrogen.

In Illinois we have 2 projects that are harnessing new developments in coal generation technologies to burn coal cleaner, both involved different gasification technologies.

The first one at Dynegy's Wood River plant would use the Ashworth Combustor, a front-end gasification technology that provides for multi-pollutant control. On a small demonstration project, the technology achieved results which included 70%+ reduction in sulfur dioxide emissions, NO_X emissions below 0.15lb/million Btu, and mercury reductions of over 90%. The technology allows older coal plants to be retrofitted to burn cleaner, eliminating the hassle of permitting a new power plant.

The second project uses coal gasification in a 2600 MW plant which will produce almost zero emission and as a by-product, will produce over 175,000 barrels a day of low sulfur diesel fuel. The facility will also mine close to 30 million tons of coal annually.

These two projects represent the future of coal. Both would greatly reduce emissions, both continue to use coal, both would add high paying mining jobs, and both follow the vision that this Administration has put forth on a diversified energy portfolio that relies on domestically produced energy resources.

Mr. Chairman, the future of coal can be bright. But Congress needs to step up and send an energy bill to the President that includes funding for research and tax credits for implementation. I yield back the balance of my time.

Mr. BARTON. Seeing no other member present, Chair would ask unanimous consent that all members' opening statements be put into the record at the appropriate point. Without objection, so ordered.

[Additional statements submitted for the record follow:]

PREPARED STATEMENT OF HON. W.J. "BILLY" TAUZIN, CHAIRMAN, COMMITTEE ON ENERGY AND COMMERCE

An affordable and reliable electricity supply is a critical cornerstone of the American economy, providing the foundation for much of our prosperity. Even as we seek to improve the efficient use of energy and make environmental gains, the link between energy production and economic growth has been clear, with both being critical to our nation's wellbeing.

It is also clear that our economy has suffered when supplies of affordable energy have tightened. Whether it be gasoline prices sporadically and regionally above $2 dollars a gallon, $10 natural gas during the winter of 2001, or $35 dollar a barrel oil in 1981, price spikes in energy supplies have been felt in the bottom line of the American economy and in the homes of nearly all Americans.

Just two weeks ago, in this committee room, Alan Greenspan warned of the economic challenges that may lie ahead with respect to natural gas. While he expressed optimism in the long run, short term prices have exceeded $6 per million BTU and the long-term equilibrium price of natural gas has risen steadily over the last six years.

So it is of no small import that we examine future options for coal use during today's hearing. Fifty-three percent (53%) of our electricity comes from coal, and, by all accounts, coal is expected to remain a very important source of energy for decades into the future. While we have also made substantial use of electricity from nuclear, oil, gas and to a lesser extent renewable energy sources, coal remains a leading cost-effective option for electric generation.

In this vein, projections made by the Energy Information Administration indicate that coal use in the U.S. will grow about 30% over the next two decades, roughly matching the pace of growth of total energy consumption in the U.S. An independent study conducted in 2002 also concluded that in 2010, coal will contribute over $400 billion to the nation's output and be responsible for 3.6—million jobs.

So, the question might be asked, if things really look so promising for coal use, why are we holding this hearing? If the future is bright, what's the problem? The answer is that the future won't happen by itself. We as a nation will need to make several important commitments that, over the long term, will assist in the efficient use of coal in an environmentally responsible manner.

For as central as coal is to the generation of our nation's electricity, the fact of the matter is that over 90% of new U.S. power plants over the past few years have been fueled by natural gas. This surge in demand is part of the reason for higher natural gas prices, but even with this price signal, relatively few new coal units are currently being planned by the nation's utilities. There are many separate reasons for this situation; however, an important and vital part of the eventual solution is the availability of new options for coal generation that are considered to be viable in the private marketplace.

Today, we will receive testimony about clean coal technology that has to potential to revitalize, perhaps even revolutionize, the use of coal for electric power generation. Our first panel will address the Clean Coal Power Initiative and the FutureGen program that has been proposed by the President. Both of these programs are designed as public/private partnerships to explore new methods to generate electricity from coal. The FutureGen program is especially far-reaching, having a goal of a "near zero" emission coal plant.

Our second panel contains experts in coal, coal generation technology and the utilization of this technology in "test bed" facilities as well as the real world. They bring with them a wealth of professional experience and I know that the Subcommittee can benefit greatly by their insights.

Altogether, we will not answer each and every question concerning coal at today's hearing. But I believe this hearing provides an important opportunity for us to listen and learn. As a Committee with broad jurisdiction in this area, we need to assess what technologies may be viable today, what may become available in the near term, and what is realistically on the horizon. Only with this understanding can we make the best commitment of our nation's resources.

I want to welcome all of our witnesses and I look forward to their informed testimony.

PREPARED STATEMENT OF HON. RALPH M. HALL, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. Chairman and Members of the Committee—I thank you for holding this hearing today on the use of coal for electric power generation. It is, after all, our largest domestic energy source and one in which we have turned our back on in recent years. The rest of the country discovered several years ago what we have known in Texas for many years—that with current technologies natural gas is safe, reliable, and can be burned with lower overall emissions in plants that cost less to build than a comparably sized coal plant.

However, it is now clear that the time has come when natural gas will not be able to meet the incremental demands for electric power—certainly not at prices that we have come to expect. Simply put, as gas becomes more expensive, coal becomes more competitive. As a nation we need to recognize that now is the time to begin to make the big investments in research and development in technologies that will to allow us burn coal in plants that reduce air emissions to as low a level as possible.

I hope that the promise of the "FutureGen" project can be fulfilled, which is to build a plant that is essentially emissions-free. However, I am concerned that even as ambitious as the Administration's Clean Coal Power Initiative is, that—even at the funding level of $200 million a year contained in H.R.6—it may not be enough to be able to build and have an emissions free power plant in service by 2020. We need to recognize that this program is going to cost more in the out years than we're providing for today if it is to meet its goals.

As you know, I'm an oil and gas guy, but I'm also a coal, nuclear, renewables and a conservation and efficiency guy, too. My provisions in H.R. 6 establish a crash program to develop the technologies needed to drill and produce natural gas and oil in the ultra-deep and unconventional onshore areas of this country. There's huge potential—as much as 69 trillion cubic feet of natural gas alone, according to one study—enough to fill more than one-third of the gap between gas supply and demand that is expected to develop between now and 2015.

We need to fund R&D in all of these technologies if we are to maintain the quality of life and standard of living that we have come to expect. We need to stop fighting over a diminished pot of money and recognize that our national welfare demands that we enlarge the pot so that no deserving energy technology is starved out of federal R&D funding.

Mr.Chairman, I yield back the balance of my time.

Mr. BARTON. The Chair would also ask unanimous consent that a statement pertaining to the use of petroleum coke, by Dr. Hans Linhardt be put into the official record. Is there objection? Hearing none, so ordered.

[The prepared statement of Hans Linhardt follows:]

PREPARED STATEMENT OF HANS D. LINHARDT, PRESIDENT, LINHARDT TECHNOLOGY DEVELOPMENT INTERNATIONAL, INC.

The shortage of natural gas ("NG") has driven the price from 3$/MMBTU to over $6/MMBTU. Most recent Clean Power and Hydrogen Projects in the U.S. depend on NG feed, thus demanding increased product prices from the public. Increased hydrogen prices also lead to increased end product prices of gasoline and low sulfur diesel.

Recent legislation is considering to develop advanced technology for the production of clean hydrogen and power from coal via the gasification process ("FuterGen"). Also tax credits have been set aside for clean power production from coal.

Petroleum coke ("petcoke") has not been considered by the legislature and is being exported from the US. The US refineries produce about 125,000 st/d of petcoke per day with a lower heating value of 15,250 BTU/lb and an order of magnitude less ash than US coal. This would translate to 20,000 MW of clean power and/or replacement of five nuclear plants of 4,000 MW capacities.

Fig. 1 presents an overview of the petcoke production by US refineries. Petcoke production is predominant in the major population centers of the US, where clean fuels and clean power are demanded by the legislature.

Gasification is basically a refinery type of process (Shell & Texaco), that benefits significantly from integration with the petcoke producing refineries when compared with grassroots clean coal power plants (using gasification).

A typical example of the advantages and environmental benefits of petcoke gasification is the LA Basin Project, which plans to gasify about 8000 st/d of petcoke from refineries located close to the LA and Long Beach Harbor for the net production of 700 MW of clean power and 200 MMSCFD of hydrogen for production of clean fuels by the refineries.

Since the petcoke price is about constant, no price spikes are envisioned for petcoke based clean power and fuel production in contrast to the severe price spikes of NG based power and hydrogen plants.

The LA Basin Project (feasibility established; financing for Phase II depending on legislation) would significantly reduce the shipping and handling of coke to and from the LA Harbor, thus reducing serious coke dust and related health issues in the Harbor area. Of course, clean low cost power is welcomed by all surrounding communities. Hydrogen is the live blood of the refineries, assuring reliable operation and control of operating costs.

San Francisco, Houston and New Orleans would derive the same benefit as the LA Harbor, as well other communities close to refinery centers.

The feasibility of petcoke gasification has been established by Shell and Texaco and no government funding is required to build a state of the art advanced clean power plant with hydrogen co-production and control of CO2 emission. However, the tax credits currently being offered for coal should also be available for petcoke, in order to facilitate financing of projects, from $500 million to $1.6 billion. A tax credit of 1 cent/KWh for clean electricity and $0.25/MSCF of clean hydrogen would certainly be a significant incentive for developers and refineries to proceed with petcoke to hydrogen and power projects.

Mr. BARTON. We want to welcome our first panel. Let me make a brief introduction. We first have the Deputy Assistant Secretary for Coal and Power Systems in the Office of Fossil Energy at the United States Department of Energy, George Rudins. I am informed that Mr. Rudins has an excellent reputation as a technical expert and has been the manager of the clean coal program for the Department of Energy for a number of years. We appreciate your appearance. Understand that you are a professional career staffer and not a political appointee and, as such, wouldn't be able to answer any political questions for the Bush administration. Of course, you are entitled to your own opinion, and if they ask a political question you can certainly give us a political answer if you want to.

We also have Dr. Frank Burke, who is the Vice President of Research and Development at the—at CONSOL Energy. Dr. Burke is testifying today on behalf of the National Mining Association. CONSOL Energy and other National Mining Association members have been a part of various public/private partnership efforts ongoing regarding clean coal technology, including specifically the Clean Coal Power Initiative and now FutureGen. So we are glad that you are here.

We have Mr. Hank Courtright who is the Vice President for Power Generation and Distributed Resources at the Electric Power Research Institute, better named to this committee as EPRI. It is a nonprofit, collaborative research organization supported by the electric power industry. It has engaged in broad research and development efforts on behalf of the industry and the public for over 30 years. And I believe you are headquartered out in California, so we are glad to have you.

We are going to start with you, Mr. Rudins. Give you 7 minutes and give each of the other gentleman 7 minutes and then we will have some questions. Welcome to the subcommittee.

STATEMENTS OF GEORGE RUDINS, DEPUTY ASSISTANT SECRETARY FOR COAL AND POWER SYSTEMS, U.S. DEPARTMENT OF ENERGY; FRANK BURKE, VICE PRESIDENT, RESEARCH AND DEVELOPMENT, CONSOL ENERGY, INC., ON BEHALF OF THE NATIONAL MINING ASSOCIATION; AND HENRY A. COURTRIGHT, VICE PRESIDENT, POWER GENERATION AND DISTRIBUTED RESOURCES, ELECTRIC POWER RESEARCH INSTITUTE

Mr. RUDINS. Thank you, Mr. Chairman and members of the committee. In addition to offering my written testimony for the record, I have a short opening statement I would like to make.

Mr. BARTON. Without objection.

Mr. RUDINS. I am pleased to appear before the subcommittee today to discuss the role that new clean coal technologies can play in helping the Nation meet ever-increasing demands for energy in the most efficient and environmentally responsible manner possible.

With much of the Nation's attention again focused on the security of global energy supplies, it is important to remember that we remain an energy-rich country. Today, coal is an indispensable part of our Nation's energy mix. Because of its abundance and low costs, coal accounts for half of the electricity generated in our country today.

Since I joined ERDA, DOE's predecessor agency, close to 30 years ago, there has been dramatic progress in clean coal technology and power generation technology in general. The average national total cost of electricity since 1983 has come down approximately 30 percent from 9.2 cents per kilowatt hour in 1983 to 6.4 cents in the year 2000. As a result, the development of new clean coal technology I had the formidable challenge of not only striving to improve efficiency of power generation while meeting ever tighter environmental regulations, but it had to be done while keeping the cost of electricity competitive with conventional plants that were coming down in costs.

Clean coal technology development, which involved efforts by both DOE and industry, more than met this formidable challenge. New, lower-cost emission control systems were successfully developed, demonstrated and deployed. Low NO_X burners, for example, are now deployed on close to 75 percent of the plants capable of using them. The cost of SO_2 scrubbers and selective catalytic reduction systems, or SCR for short, have been greatly reduced, while the performance of these systems has been greatly increased. This technology has kept the cost of coal-based electricity to consumers low while greatly reducing environmental emissions. As a result, coal used for power generation has roughly tripled since 1970, while overall emissions have decreased by over 30 percent. And new coal power plants emissions show an even greater percentage of decrease in emissions on an individual plant basis.

In terms of clean coal power generation technologies, back in the mid-seventies, we could not even foresee the dramatic advances in technology that have already occurred and the revolutionary progress that we are now poised to achieve in the not-too-distant future. In addition to government and industry successfully developing atmospheric fluidized bed combustion plants that have become one of the work horses of the coal power industry, the investment we have collectively made over the last 30 years on gasification-based systems has taken this technology to the point that U.S. taxpayers are already starting to reap the benefits.

Two integrated gasification combined-cycle power plants, or IGCC for short, have been successfully demonstrated under the clean coal program and have entered commercial service. They are among the most efficient and cleanest coal plants ever built. The 30-year clean coal technology base that has been developed, together with these successes, will enable gasification-based technologies to make even further and more rapid advances in the future.

The average efficiency of the existing fleet of coal power plants is in the 33 percent range. The integrated gasification combined cycle plants now operating that I just referred to have efficiencies close to 40 percent, with very low emissions. In the future, IGCC plants can reach 60 percent efficiencies and even higher efficiencies in combined heat and power applications.

From an emissions viewpoint, we believe advanced IGCC systems can approach zero emissions when integrated with carbon sequestration. And if we can achieve our development goals, these systems can do so while electricity generation costs are maintained at competitive levels.

FutureGen represents the ultimate manifestation of a zero emissions plant that coproduces electricity and hydrogen. I would like to take a minute to draw you a verbal picture of FutureGen. In the FutureGen approach, we start with coal which is converted to a synthesis gas, which is basically hydrogen, carbon monoxide, and carbon dioxide in a gas-fired vessel. We run that mixture of gases through a shift reactor to change the carbon monoxide into more hydrogen and carbon dioxide. At this point, we can separate the useful hydrogen from carbon dioxide and route the carbon dioxide for disposal. The hydrogen can then be used to produce power, be converted to chemicals like ammonia fertilizer, or be used as a transportation fuel in vehicles using fuel cells. If we return to the carbon dioxide that has been routed for disposal, we can send it to a deep saline geologic structure for storage; or, if we are in the right location, we can get a further return on our investment by using it for enhanced oil recovery. In short, FutureGen provides us with technology to use coal to make a spectrum of energy products, including hydrogen, with essentially no pollution and no greenhouse gas emissions.

Achievement of FutureGen goals is a major challenge that is made more manageable by prior government and industry successes with clean coal technology. There has been much industry experience with many of the components required for FutureGen. For example, there are hundreds of operating gasifiers worldwide. There has been much experience with shift reactors, gas turbines and so on. What makes FutureGen a major challenge is that in order to achieve its goals, we must push the technology envelope for most of these components well beyond their current capability and then put them together for the first time into an integrated system with components just emerging from the laboratory, such as low cost CO_2 capture and storage technology. But the public benefit when we succeed will be enormous. In order to assure that FutureGen is successful, it will be supported by a clean coal R&D effort focused on all key technologies needed, such as carbon sequestration, membrane technologies for oxygen and hydrogen separation, advanced turbines, fuel cells, coal-to-hydrogen conversion, gasifier related technologies and other technologies. And, the Clean Coal Power Initiative, funding for which is included in the administration's 2004 budget request, will help drive down the costs of IGCC systems and other technologies critical to the success of FutureGen through demonstration of key technologies. With each technology replication, lessons are learned, refinements are made, and costs decrease for the next unit built.

In summary, I would like to suggest that successes in improving efficiency, reducing emissions, and reducing emission control costs in the coal sector is largely due to technology developed by an effective government/industry partnership, and that this same partnership can define a future for coal in which Americans can continue to reap the benefits of this abundant and low-cost domestic resource. It is technologically possible, through a continued and sustained coal R&D effort with a focus on FutureGen, to cost effectively produce hydrogen and electricity from coal with essentially zero emissions, and thereby provide not only clean electricity from coal but also clean hydrogen for a future transportation fleet. This will be a remarkable achievement for U.S. Science and technology. This would indeed be coal's Holy Grail.

This concludes my opening remarks. Thank you for the opportunity to address the committee, and I will be pleased to answer your questions.

[The prepared statement of George Rudins follows:]

PREPARED STATEMENT OF GEORGE RUDINS, DEPUTY ASSISTANT SECRETARY FOR COAL AND POWER SYSTEMS, OFFICE OF FOSSIL ENERGY, U.S. DEPARTMENT OF ENERGY

Mr. Chairman and Members of the Subcommittee: I am pleased to appear before the Subcommittee today to discuss the great potential new technology will play in helping the Nation meet ever increasing demands for energy in the most efficient and environmentally responsible manner possible.

With much of the Nation's attention again focused on the security of global energy supplies, it is important to remember that we remain an energy-rich country. Today, coal is an indispensable part of our Nation's energy mix. Because of its abundance and low cost, coal now accounts for more than half of the electricity generated in this country.

Coal is our Nation's most abundant domestic energy resource. One quarter of the entire world's known coal supplies are found within the United States. In terms of energy value (Btus), coal constitutes approximately 95 percent of U.S. fossil energy reserves. Our nation's recoverable coal has the energy equivalent of about one trillion barrels of crude oil—comparable in energy content to all the world's known oil reserves. At present consumption rates, U.S. coal reserves are expected to last at least 275 years.

Coal has also been an energy bargain for the United States. Historically it has been the least expensive fossil fuel available to the country, and in contrast to other primary fuels, its costs are likely to decline as mine productivity continues to increase. The low cost of coal is a major reason why the United States enjoys some of the lowest electricity rates of any free market economy.

America produces over 1 billion tons of coal per year. Nearly all of it (965 million tons) goes to U.S. power plants for the generation of electricity.

According to the Energy Information Administration, annual domestic coal demand is projected to increase by 394 million tons from the 2001 level of 1.050 billion tons to 1.444 billion tons in 2025, because of projected growth in coal use for electricity generation.Largely because of improving pollution control technologies, the Nation has been able to use more coal while improving the quality of the air. While annual coal use for electric generation has increased from 320 million tons in 1970 to more than 900 million tons, sulfur dioxide emissions from coal have dropped from 15.8 million tons annually to 10.7 million tons in 2000, the most current year available. In addition, particulates from coal-fired plants declined some 60 percent over the same period according to the Environmental Protection Agency.

Because coal is America's most plentiful and readily available energy resource, the Department of Energy (DOE) has directed major portions of its R&D resources at finding ways to use coal in a more efficient, cost-effective, and environmentally benign manner.

National Benefits of Clean Coal

It is not widely known how far clean coal technologies have come in reducing emissions from coal-fired power plants, or how far we can go over the next few years. For example, in 1970, overall coal-based electric power generation emission rates were 4.4 pounds SO_2/million British Thermal Units (mmBtu) and 0.95 pounds NO_X/mmBtu. In 2000, the rates were 1.0 pounds SO_2/mmBtu and 0.44 pounds NO_X/mmBtu.

The ability to meet today's emission limits, and the cost of that compliance, has been greatly improved. For example, in the 1970's, most options for significantly reducing smog-forming nitrogen oxide (NO_X) pollutant emissions were untried and expensive—in some cases, costing as much as $3,000 per ton of pollutant removed. Now, the cost of the retrofit low-NO_X burners is estimated at less than $200 per ton. Similarly, the costs of flue gas desulphurization units—or "scrubbers"—have been dramatically reduced and their reliability greatly improved.

New government-industry collaborative efforts are getting underway pursuant to both our traditional R&D program and the President's Coal Research Initiative. These programs will continue to find ways to improve our ability to limit emissions from power generation, at lower costs. The goal for future power plant designs, such as FutureGen, discussed later in my testimony, is to remove environmental issues from the fuel choice equation by developing coal-based zero emission power plants. Moreover, the focus is on designs that are compatible with carbon sequestration technology.

The Next Generation of Power Plants

In the 1970's, the technology for coal-fired power plants was generally limited to the pulverized coal boiler—a large furnace-like unit that burns finely ground coal. As part of DOE's Clean Coal Technology Program, DOE and industry have demonstrated higher fuel efficiencies and superior environmental performance. For example, rather than burning coal, it could be *gasified*—turned into a combustible gas. In gaseous form, pollutant-forming impurities can be more easily removed. Like natural gas, it could be burned in a gas turbine-generator, and the turbine exhaust used to power a steam turbine-generator. This "combined cycle" approach raised the prospects of unprecedented increases in fuel efficiency. Gasification combined cycle (IGCC) plants built near Tampa, Florida (TECO Project), and West Terre Haute, Indiana (Wabash River Project), are among the cleanest, most efficient coal plants in the world. The Wabash River Project, which is a repowering of an existing coal-fired unit, resulted in a 30-fold decrease in SO_2 and a 5-fold decrease in NO_X emissions. These projects have recently completed their demonstration phases and are entering commercial operations.

The progress to date in developing IGCC systems, especially with the two clean coal demonstration projects now in commercial service, has laid the foundation for broader application of IGCC and continuing advances in IGCC technology—the ultimate manifestation of which is FutureGen.

FutureGen—Zero Emissions From Cutting Edge Technology

Earlier this year, President Bush and Secretary of Energy Abraham announced plans for the United States to build with international and private sector partners a prototype of the fossil fuel power plant of the future called FutureGen. It is one of the boldest steps toward a pollution-free energy future ever taken by our nation and has the potential to be one of the most important advances in energy production in the first half of this century.

This prototype power plant will serve as the test bed for proving out the best technologies the world has to offer. Virtually every aspect of the prototype plant will be based on cutting-edge technology.

FutureGen will be a cost-shared $1 billion venture that will combine electricity and hydrogen production with the virtual elimination of emissions of such air pollutants as sulfur dioxide, nitrogen oxides and mercury, as well as carbon dioxide, a greenhouse gas.

The Department envisions that FutureGen would be sized to generate the equivalent of approximately 275 megawatts of electricity, roughly equal to an average mid-size coal-fired power plant. It will turn coal into a hydrogen-rich gas, rather than burning it directly. The hydrogen could then be combusted in a turbine or used in a fuel cell to produce clean electricity, or it could be fed to a refinery to help upgrade petroleum products.

It will provide other benefits as well. FutureGen could provide a zero emissions technology option for the transportation sector—a sector that accounts for one-third of our nation's anthropogenic carbon dioxide emissions.

In the future, the plant could become a model for the production of coal-based hydrogen with zero emissions to power the new fleet of hydrogen-powered cars and trucks President Bush spoke about during his State of the Union address and called for by his Hydrogen Initiative. Using our abundant, readily available, low-cost coal to produce hydrogen—an environmentally superior transportation fuel—would help ensure America's energy security.

Carbon sequestration will be one of the primary features that will set the FutureGen plant apart from other electric power projects. Engineers will design into the plant advanced capabilities to capture the carbon dioxide in a form that can be sequestered in deep underground geologic formations. No other plant in the world has been built with this capability.

Once captured, carbon dioxide will be injected deep underground, perhaps into the brackish reservoirs that lay thousands of feet below the surface of much of the United States, or potentially into oil or gas reservoirs, or into unmineable coal seams or volcanic basalt formations. Once entrapped in these formations, the greenhouse gas would be permanently isolated from the atmosphere.

The project will seek to sequester carbon dioxide emissions at an operating rate of one million metric tons or more of carbon dioxide sequestered per year. We will work with the appropriate domestic and international communities to establish standardized technologies and protocols for carbon dioxide measuring, monitoring, and verification.

The FutureGen plant will pioneer carbon sequestration technologies on a scale that will help determine whether this approach to 21st century carbon management is viable and affordable.

In April 2003, the Department's notice of request for information on the plan to implement FutureGen appeared in the Federal Register. Comments were requested by June 16, and we are currently reviewing them. The ultimate success of FutureGen depends on acceptance of the concept of sequestration by the industry that will have primary responsibility for its potential future implementation.

The Department plans to enter into a cooperative agreement with a consortium led by the coal-fired electric power industry and the coal production industry. Under the guidance of a government steering committee, this consortium will be responsible for the design, construction and operation of the FutureGen plant, and for the monitoring, measuring, and verifying of carbon dioxide sequestration.

The Federal Register notice indicates that members of a qualifying consortium must collectively own and produce at least one-third of the nation's coal and at least one-fifth of its coal-fueled electricity. In addition to collectively owning and producing a large fraction of the national coal and electricity, the consortium is expected to be:

(a) Geographically diverse by including both eastern and western domestic coal producers and coal-fueled electricity generators; and,

(b) Be resource diverse by including producers and users of the full range of coal types.

The public's interest is best served by having this broad cross-section of the coal and coal-fueled electricity industries involved in this project. The Department will require that the consortium use fair and open competition in selecting the host site and the plant components. The Department also is seeking the participation of other coal consuming and producing nations in the FutureGen initiative at this week's the Carbon Sequestration Leadership Forum. Broad involvement in the project is desired to achieve wide acceptance of the concept of coal-based systems integrated with sequestration technology.

Although the consortium will be limited to coal and coal-fueled electricity generation owners and producers, and while equipment and service vendors may participate through a competitive selection process for their goods and services, the Department expects the consortium to provide mechanisms for future participation in the project, as appropriate, of interested parties such as state governments, regulators, and the environmental community.

We also expect the consortium to be open, working to expand its initial membership to one that is inclusive and open to other coal and coal-fueled electricity owners and producers. We anticipate placing separate contracts to independently validate carbon dioxide sequestration. An affordable, reliable, and environmentally sound supply of electricity is critical to our nation's future.

Conclusion

The ultimate goal for the prototype plant is to show how new technology can eliminate environmental concerns over the future use of coal and allow the nation to realize the full potential of its abundant coal resources to meet our energy needs. Knowledge from FutureGen will help turn coal from an environmentally challenging energy resource into an environmentally sustainable energy solution.

Coal is the workhorse of the United States' electric power sector, supplying more than half the electricity the nation consumes. It is also the most abundant fossil fuel in the United States with supplies projected to last 250 years or more. The International Energy Agency projects a 50 percent increase in worldwide coal use for electricity generation over the next quarter century.

The fact that coal will be a significant world energy resource during the 21st century cannot be ignored. Coal is abundant, it is comparatively inexpensive, and it will be used widely, especially in the developing world. Global acceptance of the concept of coal-based systems integrated with sequestration technology is one of the key goals of FutureGen.

Our challenge is to make sure that when it is used, coal is clean, safe, and affordable. Technologies that could be future candidates for testing at the prototype plant could push electric power generating efficiencies to 60 percent or more—nearly double the efficiencies of today's conventional coal-burning plants.

Thus, the FutureGen prototype plant would be a stepping stone toward commercial coal-fired power plants that not only would be emission-free but also would operate at unprecedented fuel efficiencies.

This completes my prepared statement. I would be happy to answer any questions you may have.

Mr. BARTON. We now want to hear from Dr. Burke. Your testimony is in the record. We ask that you summarize it in 7 minutes.

STATEMENT OF FRANK BURKE

Mr. BURKE. Good afternoon, Mr. Chairman and members of the subcommittee. My name is Frank Burke and I am Vice President of Research and Development for CONSOL Energy, Inc., headquartered in Pittsburgh. I am appearing here today on behalf of the National Mining Association and CONSOL to discuss technologies to meet our Nation's need for clean coal-based electricity.

Mr. Chairman, NMA and I want to thank you, Mr. Boucher, Mr. Whitfield, Mr. Shimkus, our Pittsburgh representative Mr. Doyle, and others for your support of coal-based electricity. The provisions you included in H.R. 6 will, if enacted, help our Nation to continue to enjoy the benefits of coal in the future.

Mr. Chairman, there is an inscription on the facade of Union Station and it says: "Electricity, carrier of light and power, devourer of time and space, bearer of human speech over land and sea, greater servant to man itself unknown." This statement from the 19th century is still true today. Electricity is produced so reliably that to many people its source, like oxygen in the air, is unknown and taken for granted; but electricity is to our modern society and economy as oxygen is to life. Without electricity, our society would grind to a halt not within days or hours, but within minutes.

And, Mr. Chairman, coal is solid electricity, because coal is used to generate more than half of the electricity Americans need to sustain and enhance our way of life. Coal comprises over 90 percent of our domestic energy reserve, enough to last us 250 years, and we can reconcile our need for coal with our environmental and economic needs through clean coal technology to preserve our existing coal-based electricity-generating capacity and to replace and expand it as needed in the future.

First let me commend DOE's coal R&D program and the clean coal technology program. These have resulted in the development and widespread commercial use of technologies for the cleaner and more efficient use of coal that have reduced emissions while coal use has increased.

Second, the coal-related provisions of H.R. 6 are a further step in the right direction. The Clean Coal Power Initiative, provided by this bill authorizing $2 billion through 2012, will help to ensure that we can bring the products of the R&D program to commercial readiness. The allocation of funds to gasification and other technologies in this bill is appropriate. While the Clean Coal Power Initiative and the enhanced core coal R&D authorization in H.R. 6 are necessary, they are not in themselves sufficient to ensure that these technologies will achieve widespread commercial use.

In this regard, I note that H.R. 6 does not include the clean coal technology tax incentives included in H.R. 1213, which are necessary to reduce the technical and financial risk of deploying these advanced technologies. The Senate Finance Committee included these incentives in S. 597, and we hope they will be adopted by the conference committee on the energy bill.

Many of the technical challenges and opportunities for future coal generation technology are embodied in a clean coal technology road map developed by the industry and Department of Energy. This is discussed in more detail in my written testimony. The road map focuses on the power costs, efficiency and environmental performance objectives for technologies that will allow existing plants to meet anticipated future environmental restrictions such as expected mercury regulation. The road map lays out the R&D pathway for new gasification combustion and hybrid technologies for the next generation of coal-based plants which will be needed for new and replacement electric capacity. Furthermore, the road map allows us to determine the cost for the necessary R&D and demonstration work. We estimate this to be $10 to $14 billion in public and private funds between now and 2020.

Unfortunately, the Federal funding in the administration's 2004 budget for both the core R&D program and the Clean Coal Power Initiative demonstration program is low, barely half of what we need to follow the road map. Without adequate funding from the public sector, it will not be possible to meet the road map schedule.

Now let me talk about a new aspect of DOE's program, the FutureGen project. FutureGen would minimize pollutant emissions to near zero levels. This facility would be based around the coal gasification system with the capability to convert coal gas into hydrogen and to capture and sequester 1 million tons of carbon dioxide a year.

A recent report from a group called the Energy Future Coalition and the press coverage it engendered suggested that CONSOL and others in the industry had accepted the need for mandatory caps on carbon dioxide emissions. This is not true. Neither CONSOL nor the NMA believes that global climate change resulting from carbon emissions is an established scientific fact, nor do we believe that a mandatory cap on carbon emissions is justified. However, we do believe that programs like FutureGen that seek to define the cost and feasibility of possible technological options are a prudent investment for industry and the government. Furthermore, FutureGen would serve as an important research platform to test advanced power plant components as they emerge from the core R&D program.

It is important to note that FutureGen is not a substitute for either the core R&D program or the Clean Coal Power Initiative demonstration program. We need to continue the core research on new technologies that can be tested at FutureGen and elsewhere, and we need to continue R&D and demonstration projects on technologies that are not part of the FutureGen design.

It is estimated that FutureGen costs will be $1 billion, with 80 percent provided by the government. The ability of the government to commit its full 80 percent share of the funding to the project before major costs are incurred will be critical to FutureGen's success.

In conclusion, Mr. Chairman, we must continue to define and follow a technology road map that focuses on the cost, efficiency and environmental performance of coal-based electricity-generating technologies to preserve our existing infrastructure and build new coal based plants. Thank you.

[The prepared statement of Frank Burke follows:]

PREPARED STATEMENT OF FRANK BURKE, VICE PRESIDENT, RESEARCH AND DEVELOPMENT, CONSOL ENERGY INC. ON BEHALF OF CONSOL ENERGY INC. AND THE NATIONAL MINING ASSOCIATION

Mr. Chairman, my name is Frank P. Burke, and I am vice president of research and development for CONSOL Energy Inc. (CONSOL). I am appearing here on behalf of my company as well as the National Mining Association (NMA) to testify on the current and future technologies that are needed to assure that the nation has the clean coal-fired electric generating capacity required to meet our energy demands in the future.

I would like to commend you Mr. Chairman, for holding these hearings to discuss the new technologies, and improvements to existing technologies, which will allow America to continue to use its abundant coal resources to power our economy. This will be the focus of my statement to the Committee today: Why America needs coal, why it needs new technology for the production of electricity from coal, and why a federal program to support the development of new technology represents a vital investment in our nation's economic well being. Coal makes up over 90 percent of our domestic energy reserve. And, coal is electricity. It is the fuel for over 50 percent of the electricity that our citizens use to run our businesses and support our everyday lives. Coal is, and must continue to be, one of the cornerstones of our nation's energy strategy.

GENERAL INTRODUCTION

CONSOL Inc., founded in 1864, is the largest producer of high-Btu bituminous coal in the United States, is the largest producer of coal by underground mining methods, and the largest exporter of U.S. coal. CONSOL has 23 bituminous coal mining complexes in six states and in Australia. The company has a substantial technology research program focused on energy extraction technologies and techniques, coal combustion, combustion emission abatement and combustion waste reduction. As you can see from the Appendix, CONSOL has been an active partner with DOE in the advancement of many technologies and in basic research. [CONSOL is a publicly held company (NYSE:CNX) with over 6,000 employees].

The NMA represents producers of over 80 percent of America's coal, the reliable, affordable, domestic fuel used to generate over 50 percent of the electricity used in the nation today. NMA's members also produce another form of fuel—uranium that is the source of just over 20 percent of our electricity supply. NMA represents companies that produce metals and non-metals, companies that are amongst the nation's larger industrial energy consumers. In addition, NMA members include manufacturers of processing equipment, machinery and supplies, transporters, and engineering, consulting and financial institutions serving the mining industry.

ENERGY IN THE UNITED STATES—AND THE NEED FOR A BALANCED ENERGY POLICY THAT INCLUDES INCENTIVES TO EXPAND THE ELECTRIC GENERATING FLEET

Energy, whether it is from coal, oil, natural gas, uranium, or renewable sources, is the common denominator that is imperative to sustain economic growth, improve standards of living and simultaneously support an expanding population. The significant economic expansion that has occurred in the United States over the past two decades, and the global competitiveness of our industry, was in no small measure due to reliable and affordable energy.

During the summer of 2000 this began to breakdown. Prices of energy in some regions of the country—especially prices of gasoline, natural gas and electricity—increased significantly. Spot shortages of electricity occurred in California and, although the price of energy receded, the base cause of this problem—too little energy supply chasing too much energy demand—has not been addressed. Just three years later, we again see soaring natural gas prices, and the real possibility of natural gas shortages that may lead to electricity curtailment. High prices and unreliable energy supplies three years ago were followed by a slow-down in the economy, and high natural gas prices now threaten to forestall economic recovery. And, while cause and effect may not be perfectly correlated, the experiences of the last several years reinforce the relationship between affordable energy and economic growth. Enactment of a national energy policy that balances energy supply with energy demand while simultaneously encouraging efficiency and greater protection of our environment must be a priority of the Congress and the Administration to ensure our economic future.

According to the Energy Information Administration, energy use will increase by an average 1.5 percent per year or by a total of 42 percent to 139 quadrillion Btu between 2000 and 2025. Consumption of all sources of energy will increase: petroleum by 47 percent, natural gas by 49 percent, coal by 30 percent and renewable energy by 46 percent. An important part of the forecast is the statement that the economy will become even more dependent upon electricity over the next 20 years than it is now: Thus, a viable National Energy Policy must include a strong component to support expansion of our electricity supplies.

THE NEED FOR COAL—COAL IS ELECTRICITY

We learn in grade school that a person needs three things to survive: food, water and shelter. It is interesting that oxygen is not added to that list. The omission probably results because oxygen is so important and so ubiquitous, that we take it for granted. We can live for days without water, and perhaps weeks without food and shelter, but for only minutes without oxygen. I bring this up because, in the United States' economy, electricity is the equivalent of oxygen. Without electricity, the economy would grind to a halt not in days or week, but within minutes. Electricity is so ubiquitous, and the electricity generating industry and its fuel suppliers have made it so reliable, that to the average consumer, electricity must seem to come, like oxygen, from the air itself, or perhaps from that socket in the wall.

However, electricity, unlike oxygen, is not a product of nature. It must be manufactured and delivered, continuously and in ever increasing amounts. By 2025 we will need 55% more electricity than we generate today. This can only be accomplished through the creation and employment of technology, the investment of capital, and the labor of workers in three fundamental industries: fuel supply, transportation, and power generation. The industry, which I represent, is responsible, each year, for producing about 1.1 billion tons of coal a year, almost 1 billion tons of which America uses to keep more than half of its electricity flowing to homes, hospitals, schools, businesses and factories. Imagine what would happen to our economy and the well-being and aspirations of our citizens, if half our electricity were gone tomorrow. If you understand that, then you understand the importance of maintaining our existing electricity generating capacity, while providing for the new capacity necessary to supply the electricity that America will need to sustain its economic growth in the future.

As we discuss the future need for and cost of developing the clean coal technologies to upgrade and replace our coal-based generating capacity, it is important to understand what America's coal miners have already done to meet the demand of U.S. consumers for low-cost, reliable electricity. Between 1984, when the Clean Coal Technology Program was begun, and 2000, coal prices in the United States have been driven down by 55% in real dollars, because of a doubling in productivity achieved by America's miners. Had coal prices simply remained at 1984 levels, the additional direct cost to the U.S. economy would have been over $100 billion. The coal industry has done this through the excellence of its work force, development of innovative mining methods and equipment, and large capital investments in new technology. Without coal, the indirect cost, in terms of the impact of higher electricity prices on the domestic economy, would have been much, much greater

Today, more than one-half of U.S. electricity is generated from abundant, low cost, domestic coal. And, coal can play a greater role in meeting future demands, because it constitutes more than 90 percent of the United States' fossil fuel resources, enough to last more than 250 years at current consumption rates. What is needed now is the development and, more importantly, the commercial use of Clean Coal Technologies to take full advantage of the energy resource that American's coal miners are prepared to deliver.

THE NEED FOR CLEAN COAL TECHNOLOGIES

The analogy between electricity and oxygen is appropriate for another reason. One of the principal reasons for developing new coal-fired generating technologies is to ensure that electricity generation from coal does not compromise the quality of the air we breathe. Because of its chemical composition, coal poses more environmental concerns than other fossil fuels. On average, coal contains more sulfur and nitrogen, and more mineral matter, than oil or natural gas. Fortunately, the means are available to control the emission of these substances into the environment to levels that meet current regulatory limits. A wide range of technologies is already deployed on many coal-fired power stations to control emissions of these pollutants. These include particulate collection devices, such as electrostatic precipitators and fabric filters that control emissions of coal ash, flue gas desulfurization scrubbers of various designs that control emissions of sulfur dioxide (SO_2) and a variety of methods and devices for reducing nitrogen oxide (NO_X) emissions. There are no commercially available methods to control emissions of mercury or carbon dioxide from coal-fired power plants, but as I will discuss, these are the subject of active research programs.

Like those throughout the world, the United States faces the challenge of meeting our need for low cost energy while reducing the environmental impact of energy production and use. The federal and state governments are likely to impose new environmental regulations that will reduce SO_2, NO_X, and mercury emissions from existing power plants to levels well below current regulatory limits. This will require the widespread deployment of improved technology that further reduces SO_2 and NO_X emissions below current regulatory levels at an acceptable cost. Mercury will be substantially reduced as a co-benefit of this, and, in the long run, it may be necessary to develop and deploy technology to further limit mercury. In addition, there are opportunities to improve the efficiency of existing generating units. Increasing efficiency can reduce emissions, because less fuel is required for each unit of electricity generated, and efficiency improvement is the only method currently available to reduce CO_2 emissions from power production.

A recent report by the Energy Future Coalition, and particularly, a number of misleading press releases and news stories engendered by it, imply that members of the coal industry, including CONSOL, have endorsed the need for mandatory carbon emission reductions. This is not true, and I would encourage you to read the section of the report written by the coal-working group, which was the only part of the report in which CONSOL and others in the coal industry participated. The coal working group section frames the debate on this issue, but it makes assertions or recommendations regarding the need for carbon emission reductions. Neither CONSOL nor the NMA believes that climate change resulting from carbon emissions is an established scientific fact. On the contrary, many credible scientists have presented strong arguments to rebut such claims. We strongly oppose imposition of a carbon tax or mandatory limit on carbon emissions. Nevertheless, we encourage the development and deployment of technology to increase power plant efficiency, where it makes economic sense, with the concomitant result of decreasing carbon emissions. We also support research to explore other technological options for greenhouse gas management within the DOE coal research program, because we as a nation need to know their cost and technical feasibility, to inform public policy decisions-makers and as a prudent investment in preparing a technological response so that we can continue to enjoy the benefits of coal-fueled electricity should public policy ever require carbon emission reductions.

These Clean Coal systems will need to be designed and integrated in a way that achieves the expected benefits of each, without creating any unintended consequences. For example, the use of combustion modifications to reduce NO_X emissions can result in increased carbon in coal flyash, making flyash less valuable as a byproduct. Selective Catalytic Reduction, which is an effective means for NO_X control, can cause deposition that impairs efficiency in the boiler system. On the other hand, the intelligent integration of technologies can have synergistic benefits. As noted earlier, emission control devices installed for other pollutants can remove mercury from the flue gas at no additional cost. As another example, the solid byproducts from coal combustion can be converted into salable materials such as wallboard gypsum and road aggregates. Research is underway to learn how to take full advantage of co-benefits such as these, and to incorporate them into the design of existing and new power plants.

In the future, we will need new coal-fired power plants to meet electricity demand growth and to replace existing facilities as they reach the end of their economic lives. Notable among these new technologies are supercritical pulverized coal combustion, advanced combustion, integrated gasification combined cycle (IGCC), and various hybrid power systems. These technologies hold the promise of high-energy efficiency and minimal environmental impact if they are developed and successfully deployed at an acceptable cost. For example, IGCC technology is currently being demonstrated at several sites, but it must still be considered pre-commercial technology because of its relatively high capital cost. Nevertheless, IGCC systems produce the cleanest power available from coal; emissions from these systems approach the levels generated by modern natural gas-fired power plants, and research is underway to reduce the capital cost through design improvements. As with all technologies, the full benefits of potential design optimization will not be gained until a sufficient number of full-scale commercial units have been built and operated.

COAL CHARACTERISTICS AND REGIONAL DIFFERENCES

Furthermore, we need to be sure that there are Clean Coal Technologies, which work well with all coals. Coals differ in the geological characteristics of the reserves, which affects the choice of mining method, and hence the cost of production. The geographic location of the reserve affects its economic availability to specific power plant markets. It is important that Clean Coal technology users have the flexibility to select coals that meet their technical specifications and economic requirements. New Clean Coal Technologies must be developed that can accommodate, or be modified to accommodate, a wide range of coals while achieving high efficiency and excellent environmental performance. Achieving fuel flexibility must be a key objective in designing the Clean Coal Technology development and commercialization plan.

This issue arises because coal is a highly variable geologic material, and differences in individual coal types affect their performances in electricity generating units. Individual coals differ on the basis of energy content, sulfur content, ash composition, and other properties. U.S utility coals can be categorized into three groups:

1. Bituminous coals are mined throughout the U.S. They have medium to high-energy contents. Bituminous coals from different regions differ greatly in sulfur content and mineral matter composition.
2. Subbituminous coals are mined in the western U.S., principally Wyoming and Montana. They are characterized by low sulfur and low energy content.
3. Lignite coal is mined in Texas, Louisiana, and North Dakota. Lignite has the lowest energy content of U.S. coals (less than 8,300 Btu/lb), and low to medium sulfur content.

Mercury concentrations are variable across the coal regions, but tend to be somewhat lower for the subbituminous coals and somewhat higher for the lignites (on an equivalent energy-content basis). Other important coal-quality parameters, such as mineral matter composition, chlorine content, alkali content, and grindability, vary both across and within the above groupings.

THE ROLE OF THE FEDERAL GOVERNMENT IN TECHNOLOGY DEVELOPMENT

The DOE Office of Fossil Energy, through its Coal and Environmental Systems program, expends about $200 million/year to co-fund coal-related R&D, in addition to the current Clean Coal Power Initiative demonstration program. The DOE is supporting the development of new technology for mercury reduction and carbon management. The DOE coal program also includes the Vision 21 R&D program, which seeks to develop advanced, highly efficient, low-emitting energy complexes, for the production of electricity, fuels and chemicals. The federal government has had a significant role in the development of clean coal technology. The original Clean Coal Technology (CCT) program and the current Clean Coal Power Initiative support the first-of-a-kind demonstrations of new coal use technologies. These demonstrations encompass a wide range of technologies, including environmental controls, new power generating facilities and fuel processing. Forty projects were conducted in the original CCT program, with a total value of $5.4 billion, consisting of $1.8 billion in federal funds and $3.4 billion in non-federal funds (a 2/1 leverage on federal dollars).

In January of this year, the Energy Department announced the selection of eight projects to receive $316 million in funding under Round 1 of the Clean Coal Power Initiative program, the first in a series of competitions to be run by the Energy Department to implement President Bush's 10-year, $2 billion commitment to clean coal technology. Private sector participants for these projects have offered to contribute over $1 billion, well in excess of the department's requirement for 50 percent private sector cost-sharing.

Three of the projects are directed at new ways to comply with the President's Clear Skies initiative which calls for dramatic reductions in air pollutants from power plants over the next decade-and-a-half.

Three other projects are expected to contribute to President Bush's voluntary Climate Change initiative to reduce greenhouse gases. Two of the projects will reduce carbon dioxide by boosting the fuel use efficiency of power plants. The third project will demonstrate a potential alternative to conventional Portland cement manufacturing, a large emitter of carbon dioxide.

The remaining two projects will reduce air pollution through coal gasification and multi-pollutant control systems.

CONSOL has been an active participant in coal-use research since the 1940s. Our goals are closely aligned with those of the DOE coal program, and much of our research has been done in partnership with the DOE (see Appendix). We were a member of the project teams for two of the CCT projects, and we made both financial and technical contributions to these projects. We also were selected for award under the recent Power Plant Improvement Initiative program to demonstrate a multi-pollutant control technology, targeted at the smaller power plants that generate about one-fourth of our coal-based electricity.

Much of our research is directed at helping our customers deal with the consequences of environmental regulations. For example, we developed a new technology for the beneficial use of the solid byproduct of flue gas desulfurization, by converting it into aggregates for use in road and masonry construction. This technology, which we piloted in partnership with DOE, reduces the cost and the land-use consequences of solid waste disposal. It can provide a valuable source of construction materials in areas without good indigenous sources, such as Florida, and areas of high growth, such as the southwestern states. Projects like this, which are a win for the economy and a win for the environment, justify CONSOL's commitment to work in partnership with the DOE to develop technology that makes sense from both perspectives.

In some cases, research and demonstration projects, such as those conducted under the DOE Coal and CCT programs, have been sufficient to bring important technologies directly to the marketplace. For example, over $1 billion in Low-$NO_X$ burners have been installed at U.S. power plants since being demonstrated in the CCT program. However, other CCT program technologies, such as Integrated Gasification Combined Cycle systems, have not been commercialized at their current stage of development because of the technical and economic risk that remains despite these one-of-a-kind demonstrations. Nevertheless, large scale demonstrations are essential to understand the technical and economic performance of these new technologies and to provide potential owners and inventors with sufficient confidence to be able to attract financing.

The DOE is now preparing to issue a second CCPI solicitation. We believe that these large-scale demonstration projects are essential to reduce the technical and economic risks of new advanced clean coal technology. Technology demonstrations are an integral part of the Clean Coal Technology Roadmap, as discussed below.

THE CLEAN COAL TECHNOLOGY ROADMAP

The term "Clean Coal Technology" (CCT) is used to describe systems for the generation of electricity, and in some cases, fuels and chemicals from coal, while minimizing environmental emissions. This is accomplished through increased efficiency (i.e., electricity produced per unit of fuel [energy] input), equipment for reducing or capturing potential emissions, or a combination of the two. Various CCTs are commercially available, or have been demonstrated at full commercial scale, but need further commercial use for economic optimization. Other CCTs are in the research and development stage.

Currently available CCTs include the efficient pulverized-coal-fired boiler (supercritical type) equipped with a full complement of fully-developed, state-of-the-art pollution control technologies. An example of this would be a supercritical boiler equipped with selective catalytic reduction for NO_X, high efficiency flue gas desulfurization for SO_2, and a particulate collection device. It is important to realize that many coal-fired generating units are currently equipped with these CCT systems, some of which were brought to the state of commercial readiness since 1986 in the Department of Energy's previous Clean Coal Technology program.

Clean Coal Technology also refers to high-performance technologies that are well along the development path, but not yet fully demonstrated to be commercially available because of either technical or economic risks. Examples of these are integrated gasification combined cycle (IGCC) and advanced combustion power plant technologies.

"Advanced" Clean Coal Technology refers to technology concepts that are in development for future use, such as advanced IGCC or ultrasupercritical boiler technology. In this context, the term "advanced" refers to improvements in costs, efficiency, and performance that are expected at some future date, assuming successful development.

Moving advanced clean coal technologies to full commercial operation will take a continuing commitment to research, development, demonstration and a strategy to ensure that the technologies, once developed, will be deployed commercially. To provide a means of planning future research needs, and to chart progress toward meeting them, the industry, largely through the efforts of the Coal Utilization Research Council, the EPRI, and the Department of Energy, has devised a Clean Coal Technology roadmap that sets cost and performance targets and a timeline (See Tables, below) for new coal technology. It must be clearly understood that these are merely research targets and are not intended to serve as a basis for regulatory requirements. Moreover, as noted later, progress along the roadmap will depend upon adequate funding. If the roadmap were followed, technology would be available in the near term to allow operators of existing coal-fueled power plants to meet increasingly stringent environmental regulations, such as those of the Clear Skies Act. Again, were the roadmap followed, it would be possible in 2015 to design a high efficiency power plant, capable of carbon capture, with near-zero emissions; by 2020, the first commercial plants of this design would be built.

DOE/CURC/EPRI CCT Roadmap I

Roadmap Performance Targets	Reference Plant*	2010	2020
SO_2, % Removal	98%	99%	>99%
NO_X, lb/MMBtu	0.15	0.05	<0.01
Particulate Matter, lb/MMBtu	0.01	0.005	0.002
Mercury	"Co-benefits"	90%	95%
By-Product Utilization	30%	50%	~100%

*Reference plant has performance typical of today's technology. Improved performance achievable with cost/efficiency tradeoffs.

DOE/CURC/EPRI CCT Roadmap II

Roadmap Performance Targets	Reference Plant*	2010	2020
Plant Efficiency (%,HHV)	40	45-50	50-60
Availability, %	>80	>85	~90
Capital Cost, $.VkW	1000-1300	900-1000	800-900
Cost of Electricity, $/MWh	35	30-32	<30

*Reference plant has performance typical of today's technology. Improved performance achievable with cost/efficiency tradeoffs. W/o carbon capture and sequestration.

The roadmap contains considerable detail on the specific technological advances that are necessary to meet the roadmap coal. Some of these "critical technologies" are listed below.

Improvements for Existing Plants

- Mercury control
- Low-NO_X combustion at reduced costs
- Fine particle control
- By-product utilization

Advanced Combustion

- Ultra-supercritical steam
- Oxygen combustion
- Advanced concepts (e.g., oxygen "carriers")

Gasification Systems

- Gasifier advances and new designs (e.g., transport gasifier)
- Oxygen separation membrane
- Syngas purification (cleaning) and separation (e.g., hydrogen, CO_2)

Energy Conversion

- Advanced gas turbine technology using H2-rich syngas
- Fuel cell systems using syngas
- Fuels and chemicals

Carbon Management

- CO_2 capture and sequestration
- <10% increase in cost of electricity for >90% removal of CO_2 (including sequestration)
- "Hydrogen economy"

Systems Integration

- Integrated power plant modeling and virtual simulation
- Sensors and smart-plant process control

Finally, the roadmap makes it possible to estimate the cost of the research, development and demonstration programs necessary to achieve the performance targets, as shown in the table below. These values represent the total cost of the research programs, including both federal funds and private sector cost shares.

Coal Technology Platforms	RD&D Spending Through 2020 (Billion)
IGCC/Gasification	$3.5
Advanced Combustion Systems	$1.7
Innovations for Existing Plants	$1.4
Carbon Capture/Sequestration	$2.3 (?)
Coal Derived Fuels and Liquids	$1.2
Total	$10.1

The cost for carbon capture and sequestration research is shown with a question mark, to denote the relatively greater uncertainty in the estimate of the cost of research in this unprecedented area. It could be substantially higher, particularly because a number of large scale, long-term demonstrations will be needed to understand the technical, economic and environmental feasibility of carbon sequestration technology. This was one conclusion of a recent National Coal Council report, entitled "Coal-Related Greenhouse Gas Management Issues," which provides a detailed discussion of the opportunities and impediments to developing, demonstrating and implementing greenhouse gas management options related to coal production and use.

Unfortunately, current funding levels are not sufficient to meet the roadmap goals. The table below compares the funding levels required to follow the roadmap to the level in the Administration's FY 2004 budget.

(all figures in $ millions)

Technology Program	Administration FY 2004 Request	CURC Roadmap Annual R&D Budget[1]
IGCC/Gasification	51.0	125.0
Advanced Combustion	0.0	42.0
Advanced Turbines	13	16.5 (for syngas from coal)
Innovations for Existing Plants	22.0	43.0
Carbon Sequestration	62.0	30.0
Advanced Research		
Advanced Materials Only	4.65	4.0
Coal Derived Fuels & Liquids	5.0	12.8
Total R&D	**157.7**	**273.3**
Clean Coal Power Initiative	130.0	240.0
TOTAL	**287.7**	**513.3**

[1] This number is 80% of the total R&D amount required and represents the federal contribution.

Although it varies by program area, the overall R&D funding level is little more than half of that called for in the CURC roadmap. Unfortunately, this continues a pattern of past years of underfunding clean coal research. Unless research and demonstration funds are increased, it is unlikely that technology will be developed on the roadmap schedule, if at all.

Similarly the funding level for the CCPI falls well below the roadmap requirements. Furthermore, the progress of the CCPI program is hampered by the requirement for annual, as opposed to advance appropriations. Because of the necessary size and cost of demonstration projects, it was necessary for the DOE to take money from both FY02 and FY03 appropriations to be able to fund the first solicitation. Future CCPI solicitations are likely to be delayed or limited in scope for the same reason. It is even possible that some necessary demonstrations will not be done because the available appropriations are insufficient. Given this situation, it may be appropriate for the Department to consider targeted solicitations focused on the roadmap objectives, or to utilize other approaches to match demonstration priorities with budgetary limitations.

THE FUTUREGEN PROJECT

On February 27 of this year, the Department of Energy announced plans to build a prototype of a coal-based power plant of the future. Dubbed "FutureGen," this facility would be based around a 275MW IGCC system, but it would have the capability to convert synthesis gas into hydrogen and to capture and sequester up to one million tons per year of carbon dioxide. FutureGen would be designed to minimize emissions of criteria pollutants and mercury to "near zero" levels. Furthermore, the FutureGen facility would be designed to serve as a "research platform" capable of testing advanced components, such as air separation membranes or fuel cells, during the ten year duration of the project, and perhaps beyond. The Department issued a "Request For Information" with a closing date of June 16, 2003, soliciting responses from parties willing to undertake the FutureGen project. My company, CONSOL Energy Inc., is a member of a ten-company group of major U.S. coal producers and users, which submitted a response to the DOE RFI, offering to enter into negotiations to conduct the FutureGen project. In part, our submittal says that the FutureGen mission should have four key elements:

1) develop commercially competitive and affordable coal-based electricity and hydrogen production systems that have near-zero emissions
2) develop large-scale CO_2 sequestration technologies that are technically and economically viable and publicly acceptable
3) provide a large-scale research platform for the development and commercialization of advanced technology
4) provide opportunity for stakeholder involvement and education

The vision of FutureGen as a research platform is particularly significant because it means that the FutureGen facility can be used as a test site to bring promising technologies out of the core R&D program and to accelerate their testing at scales up to full commercial implementation without the need for separate stand-alone test facilities. However, it is important to understand that FutureGen should not be viewed as a substitute for either the core R&D program or the CCPI demonstration program for at least two reasons: First, the FutureGen facility will not be operating for at least five years. During that time we need to continue the research needed to bring new technologies to the state that they can be tested at FutureGen. Second, we need to continue R&D on technologies, such as combustion-based systems, that are not part of the FutureGen design. That said, as the FutureGen concept is further defined, industry and government should look for opportunities for efficiencies in the coordination of the R&D program, the CCPI, and FutureGen to produce the greatest benefits at the lowest possible cost. This coordination should be an integral part of the ongoing technology road-mapping process.

Finally, although the exact cost is not known, DOE has estimated the project cost as $1 billion, with 80% provided by the federal government, and 20%, or $200 million, provided by the industrial alliance and its partners. Both the 80/20 cost share ratio and the ability of the Government to commit its full cost share to the project before major costs are incurred are critical to the project's success.

INCENTIVES FOR CLEAN COAL TECHNOLOGY DEPLOYMENT

The foregoing discussion in this statement deals with the need for research, development and demonstration of advanced clean coal technology, and discusses technical and economic criteria that these new technologies will need to meet to achieve acceptance in the commercial marketplace. However, while the Clean Coal Power Initiative and the enhanced core Fossil Energy authorization in Sections 21501 and 21511 of H.R. 6 are necessary for the continued development of coal technology, they are not by themselves sufficient to ensure that these technologies will find their way into widespread commercial use. When they are initially introduced, they will need to be built with substantial engineering contingencies, to assure their operability and reliability, which will increase capital and operating costs. Over time, as operating experience is gained, these costs will come down. Therefore, there is a need for financial incentives to offset the increased technical and financial risk inherent in the initial deployments of advanced clean coal technologies, In this regard I note that H.R. 6 does not include the tax incentives for a limited number of commercial demonstrations of advanced clean coal technologies that were included in H.R. 1213, the "Clean Coal Power Act of 2003." These incentives are included in S. 597, the "Energy Tax Incentive Act of 2003, reported by the Senate Finance Committee, and we hope that they will be adopted by the Conference Committee on the Energy Bill.

CONCLUSIONS

Mr. Chairman, there is little doubt that coal will continue to be used in the United States and abroad as a principal fuel for electricity generation, and coal's use will grow over time. The interests of the economy, society, and the environment in coal can be reconciled if we invest now in the development and deployment of advanced clean coal technology. By working with industry to develop a coal technology development roadmap, the Department of Energy has and continues to align its program with a logical path forward to support the development of advanced clean coal technology. The coal industry remains committed to do our part to see that coal remains an abundant, affordable fuel for power generation, and to help to advance the technology roadmap to achieve its goals of societal, economic and environmental betterment.

Mr. BARTON. Thank you, Dr. Burke.

We now want to hear from Mr. Courtright on behalf of EPRI. Your statement is in the record and we ask that you summarize it in 7 minutes.

STATEMENT OF HENRY A. COURTRIGHT

Mr. COURTRIGHT. Thank you, Mr. Chairman and members of the committee. To sustain a strong energy infrastructure and resolve the energy environmental conflict, we recommend to the committee that two challenges be solved.

The first challenge, which you have discussed, is to strengthen the portfolio of generation options for the future, using a diverse base of many energy sources including fossil fuels, hydro, nuclear and renewable energy, and to adequately address fuel supply uncertainty and energy security in our Nation. Coal provides over half the electricity, as said before. By keeping coal in the mix will ensure not only that this mix will apply but will lower energy costs to the consumer. In a study published in 2002 by EPRI, we estimated that consumer benefits of keeping coal in the mix are enormous, between $300 billion and $1.3 trillion to consumers.

The second challenge is that economical technologies for sequestering CO_2 need to be developed if fossil fuels are to remain as environmentally acceptable, affordable energy sources for electricity production. EPRI, DOE, and the Coal Utilization Research Council have developed a common clean coal technology road map which includes two pathways to keep coal as a viable option and allow for the reduction for CO_2.

The first pathway involves coal gasification, using either integrated gasification combined cycle, IGCC, or hybrid coproduction systems that use fuel cells in addition to provide electricity and transportation fuels too. A possible new application of these technologies will be the FutureGen project.

The second pathway involves advanced combustion of pulverized coal that promises lower emissions, higher efficiency and fewer CO_2 emissions. I provide information on advanced combustion in my written statement, but I will focus my comments today on IGCC and CO_2 capture.

IGCC is currently the cleanest coal technology available and has been demonstrated at four plants that are currently operating: two in the U.S. and two in Europe. The economics of IGCC have been evaluated in several EPRI studies, with the following observations. The capital costs of IGCC will be slightly higher than pulverized coal, but will provide a cost of electricity very similar to the technology. If we compare IGCC through a natural gas combined cycle plant and we assume that natural gas long-term prices will be above $4 per million BTU, as they are now, the IGCC plant would provide the lower cost of electricity.

These studies also show the advantage for IGCC if CO_2 removal is required. When you look at today's known technologies and you put on the cost of CO_2 capture, transportation, storage even on IGCC, the cost of electricity goes up 30 to 40 percent. However, if you compare that to CO_2 sequestration for a conventional coal plant today, that would add 70 to 80 percent to the cost of electricity.

So the successful future of IGCC as we see it requires three things:

First, that financial institutional confidence be established in this new power technology. Financing firms are unfamiliar with this technology in most cases. We need incentives; and energy legislation should support the need for early deployment of IGCC.

We need increases in the overall system reliability of IGCC for power production operations and to document those so energy companies become confident in the use of this technology as a viable alternative in competitive marketplaces.

And third, we need further reductions in the costs of electricity produced, especially with the cost of CO_2 capture.

This research and development can be supported in the FutureGen project and the Clean Coal Power Initiative projects. It is important that we sustain sufficient funding levels for these projects over the next decade for the resolution of this pacing issue of CO_2 capture costs. Coproduction, as said by others, have the efficiency of the cycles could be as high as 60 percent. This efficiency, coupled with CO_2 capture and sequestration, would result in significant reduction of CO_2. We need to keep sufficient funding of these new hybrid cycles to move them to their commercial State.

CO_2 sequestration. The development of CO_2 capture, transportation, storage technologies, is critical to sustaining coal as an option, assuming C02 emissions will be limited in the future. At present there is no technology that is commercially available for economic capture and disposal of CO_2 from power plants. Processes used in other industries for CO_2 capture, if applied to today's conventional power plants, would nearly double the costs of electricity. Because of the low power cost value of over 300,000 megawatts of existing coal plants, there is an incentive for an R&D program to investigate cost reductions for CO_2 capture from pulverized coal plants. As mentioned earlier even for advanced systems such as IGCC adding CO_2 sequestration with the technologies we know now would increase the cost of electricity by about 30 to 40 percent. We must focus on reducing the cost and energy penalty associated with the capture of CO_2. We think this is a very high priority. The FutureGen project will help prove the long-term safety and effectiveness of CO_2 storage.

However, FutureGen by itself is not sufficient to prove storage and all applications. As stated in a recent National Coal Council report, and I quote: Given the number of possible sinks and likely regional differences in the characteristics of these sinks, there is a need for several of these large-scale, long-duration demonstrations. The challenge of funding is even made more difficult since the ongoing DOE R&D program and coal and CO_2 supports these long-term goals, too. Therefore, it would be counterproductive to cut any ongoing coal and CO_2 research programs in order to fund FutureGen and other large demos. We need to meet these challenges by funding both ongoing coal R&D programs and new programs of large-scale testing.

In summary, we must sustain a diverse energy portfolio by keeping coal predominantly in the mix through advanced systems like IGCC, coproduction and advanced combustion. And we must accelerate the research and development of efficient and environmentally sound carbon capture and storage technologies.

Thank you for the opportunity to address the committee, and I welcome your questions.

[The prepared statement of Henry A. Courtright follows:]

PREPARED STATEMENT OF HENRY A. COURTRIGHT, VICE PRESIDENT, POWER GENERATION AND DISTRIBUTED RESOURCES, EPRI

Mr. Chairman and Members of the Committee: I represent EPRI, which is a non-profit, collaborative organization conducting electricity related R&D in the public interest. EPRI has been supported voluntarily since our founding in 1973. Our members, public and private, account for more than 90% of the kilowatt-hours sold in the U.S., and we now serve more than 1000 energy and governmental organizations in more that 40 countries.

My testimony will focus on the technology pathways needed for the continued use of coal for power generation in the United States. EPRI has used a roadmapping process, in conjunction with more than 200 organizations; representing electric utilities, government, industry and academia; to address the fundamental societal concerns of the 21st century. This work identified several “destinations” to be achieved to increase electricity’s benefits to society over the next 50 years through advances in science and technology. One of these destinations is to “resolve the energy/environment conflict” with particular emphasis on carbon management. In order to resolve this conflict there are two limiting challenges that must be solved:

1. Strengthen the Portfolio of Electricity Generation Options
2. Accelerate Development of Carbon Sequestration Technologies

The electricity generation portfolio should consist of a broad range of energy sources, including fossil, hydro, nuclear and renewable energy to adequately address issues of fuel supply uncertainty, price volatility, energy security and global sustainability. Distributed energy resource technologies are also needed to enhance power system flexibility and reliability-based generation. Coal provides over half of America’s electricity and keeping coal in the generation portfolio will assure the diversity of domestic supply options and will moderate the energy cost impact on the consumer. In a study published in May 2002, EPRI estimated that the consumer benefits of keeping coal in the mix through a strong research and development (R&D) program are enormous, between \$300-\$1,300 billion[1] (in 2000 dollars). The range of values reflects different assumptions about natural gas prices and discount rates used to determine net present values. If recent gas price levels continue into the future then the high end of the range, or greater than \$1.0 trillion, is an appropriate benefit value.

[1] *Market-based Valuation of Coal Generation and Coal R&D in the U.S. Electric Sector,* EPRI, Palo Alto, CA and LCG Consulting, Los Altos, CA : 2002 1006954

Economical technologies for sequestering carbon dioxide (CO_2) need to be developed if fossil fuels are to remain as environmentally acceptable, affordable energy sources for electricity production. These technologies must include both direct methods such as capturing CO_2 from electricity generation processes and storing it in geological formations, as well as indirect methods such as managing forests.

Technology Pathways for Coal Use in Power Generation

EPRI, DOE's Fossil Energy Office and the National Energy Technology Laboratory, (NETL) and the Coal Utilization Research Council [2] (CURC) have recently compared their individual studies and collaborated to develop a common "Clean Coal Technology Roadmap" that provides performance targets, critical technology needs, development costs and benefits to society. This joint roadmap provides guidance to energy companies, equipment manufacturers and government on public/private R&D that is essential to achieve the coal performance targets. Each of the major pathways allow for reduction of CO_2 intensity of generation. The clean coal roadmap identifies two key technology pathways that can keep coal as a viable generation option. These include:

- Coal Gasification
  - Power Generation with extremely low emissions via Integrated Gasification Combined Cycle (IGCC)
  - Co-Production of transportation fuels (such as hydrogen) with electricity generation using combined cycles and fuel cells. One example of this technology is the recently announced *FutureGen* Presidential initiative to create power and hydrogen in conjunction with CO_2 capture and storage.
- Advanced Combustion
  - A number of advanced pulverized coal (PC) combustion options also promise extremely low emissions of criteria pollutants combined with higher efficiency of generation thus producing fewer CO_2 emissions per kilowatt of generation. Some of these options concentrate the streams of CO_2 to enhance its capture.

Integrated Gasification Combined Cycle (IGCC)

IGCC involves the gasification of coal with the resulting syngas being fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine. Power is generated from both the gas and steam turbines, resulting in a combined cycle with higher efficiency. IGCC using coal for power generation is currently the cleanest coal technology available and is being demonstrated at four plants that are currently operating, two in the U.S. and two in Europe. IGCC technologies control most of the pollutants as part of the conversion process, rather than the use of "backend" clean-up devices added to today's plants.

The economics of the coal utilization technologies are continuously being evaluated in EPRI studies, with the following observations:

- Currently the capital cost of IGCC is estimated to be a slightly higher than for Pulverized Coal (PC) plants but the cost of electricity (COE) from the two technologies is very similar. However, because of the limited experience with IGCC the risk-driven financing costs for IGCC may be higher initially.
- The difference in the cost of electricity (COE) for an IGCC versus a natural gas combined cycle plant (NGCC) is highly dependent on fuel costs. A NGCC plant with natural gas at $2.50/Million Btu has a slight advantage over IGCC with coal at $1.50/Million Btu. But with long-term natural gas prices expected to be above $4.00/Million Btu, the IGCC plant will provide the lower cost of electricity.
- When the costs of CO_2 capture using currently available technologies are evaluated for the various technologies, the costs for pre-combustion CO_2 removal from the syngas in IGCC are much lower than for post-combustion CO_2 capture from the large volumes of flue gases from PC or NGCC plants. The increase in COE for CO_2 capture is 25-30% for IGCC but 60-70% for PC. When the costs of CO_2 transportation and sequestration are also added, the COE increases are 30-40% and 70-80% respectively for IGCC and PC. These study results show the advantage for IGCC if CO_2 removal is required.

The successful future of IGCC requires:

[2] The CURC is a group of electric utilities, coal producers, equipment suppliers, state government agencies, and universities. CURC members work together to promote coal utilization research and development and to commercialize new coal technologies. Its 40+ members share a common vision of the strategic importance for this country's continued utilization of coal in a cost-effective and environmentally acceptable manner.

- Financial institution confidence must be established in this "new" power generation technology. Incentives in energy legislation should support the need for early deployment of this key technology.
- Further reductions in capital costs to reduce the cost of electricity produced. Research and development programs are needed to enhance the performance and reduce the cost of CO_2 capture technologies, together with demonstration of CO_2 sequestration alternatives, as envisaged in the proposed DOE FutureGen Project. DOE's Clean Coal Power Initiative projects can also provide some of this important R&D. Sustaining sufficient funding levels over the next decade is critical for resolution of this pacing issue.
- Increase in overall system reliability and availability of IGCC for power production operations. The use of two-train gasification systems that provide appropriate sparing for higher availability levels of electricity production would initially solve this concern although at increased capital cost.

Co-Production/Hybrid Cycles

Providing hydrogen for power and transportation from domestic primary energy sources, such as coal, will reduce dependency on imported energy and enhance national security.The development of advanced coal-based cycles, with near-zero emission capability, is an important long-term objective of the coal roadmap. These concepts are contained in the Clean Coal Technology Roadmap, DOE's Vision 21 effort and in the *FutureGen* initiative. These cycles may include the following capabilities:

- Gasification of coal
- Syngas firing with advanced turbines
- Hydrogen-fired turbines
- Hydrogen powered fuel cells
- Production of chemicals or liquid fuels for transportation
- Capture of CO_2 for sequestration

The efficiencies of these advanced cycles could reach or exceed 60% (Lower Heating Value or LHV). This high efficiency, coupled with CO_2 capture and sequestration would result in significant reduction of CO_2 compared to existing technologies for coal-based generation technologies.

The provision of sufficient funding, through both government programs and public/private partnerships, is needed throughout this decade and into the next decade to accelerate the development of these cycles to their commercial state and provide clean coal options for a new fleet of coal-based electricity generation plants.

Advanced Combustion

Higher efficiency in combustion and steam cycles is important to the reduction of all forms of emissions. Efficiency improvement is the most cost-effective approach for reducing CO_2 emissions until CO_2 capture and storage becomes a commercially available technology and process. Opportunities for efficiency improvements in coal-fired power plants include:

- Improved Materials for Boilers and Turbines—the development of materials to enable the move from supercritical steam cycles to higher temperature and pressure "ultrasupercritical" conditions can result in efficiencies up to 50% (LHV) for bituminous PC power plants, or an efficiency increase of 5-7 percentage points from conventional plants. A DOE/NETL funded project involving U.S. boiler manufacturers, EPRI and the Ohio Coal Development Office has been launched to provide materials for higher efficiency operation. Application of this material technology is expected to be available within a decade.
- Innovative Combustion Technologies—as mentioned earlier, the capture of CO_2 from the flue gases of PC plants with existing technology is very costly and energy intensive. Because of the importance of the 320 GW of existing coal plants in retaining low power costs there is an incentive for an RD&D program to investigate possible reductions in the costs and energy consumption for CO_2 capture from PC plant flue gases. It is also important to examine innovative combustion technologies such as combustion with oxygen and recycled CO_2 (Oxyfuel).

CO_2 Sequestration

The development of CO_2 capture, transport and storage technologies/processes is critical to sustaining coal as an option of power generation. The development of technologies for more efficient conversion of coal to electricity must be matched with a vastly expanded CO_2 sequestration R&D program.

No technology is at present commercially available for capturing and disposing of CO_2 from power plants. Processes used in other industries for CO_2 capture, if applied to existing coal-fired plants would nearly double the cost of electricity. CO_2

capture and storage for the advanced systems such as IGCC, where more concentrated streams under pressure improve capture effectiveness, still results in increases in the cost of electricity by 30-40% compared to a modern pulverized coal plant with state of the art emission controls. Reducing the cost and energy penalty associated with the capture of CO_2 is one focus of the research needed. This is emphasized in the recently released National Coal Council report[3] that identified the opportunity for the U.S. to "explore a wide range of potential capture options, applicable to both gasification and combustion systems, in the hope that breakthrough technology can be identified to reduce the onerous costs and energy penalties associated with current approaches."

In order to meet the challenge of managing CO_2 the U.S. needs to accelerate the research and funding of work on carbon sequestration. Programs like the one million tonnes per year CO_2 sequestration testing envisioned in the *FutureGen* effort will help prove the long-term safety and effectiveness of CO_2 sequestration. However *FutureGen* by itself is not sufficient to prove sequestration in all applications. As stated in the National Coal Council report "Given the number of possible sinks, and likely regional differences in the characteristics of these sinks, there is a need for several of these large-scale, long-duration demonstrations." The challenge of funding this work is made even more difficult since the ongoing DOE R&D program in coal and CO_2 sequestration supports these long-term goals. It would therefore be counterproductive to cut ongoing coal and CO_2 research programs in order to fund *FutureGen* and other large-scale demonstrations. Both ongoing R&D and the new programs of large-scale testing are essential.

The most critical needs for R&D in CO_2 sequestration include:

- Development of advanced concepts for capture
- Pilot and full scale demonstrations of direct sequestration
- Carbon disposal stability
- Support for indirect sequestration options such as forest management and modified soil utilization practices

Summary

In order for the U.S. to solve the energy/environment conflict encountered as a result of the growing demand for energy, two key challenges must be solved.

We must sustain a strong, diverse electricity generation portfolio and keep coal prominently in this mix. This will assure a secure domestic energy supply by developing and deploying cleaner, more efficient methods of producing electricity from coal.

We must accelerate the research and development of efficient, environmentally sound carbon capture and storage technologies.

Thank you for the opportunity to address the Committee and I welcome your questions.

Mr. BARTON. Thank you.

The Chair recognizes himself for the first 5 minutes of questions. This I think will be for Mr. Courtright and Mr. Rudins. Are either of you familiar with the coal gasification plant that has been working down in Florida the last couple of years?

Mr. COURTRIGHT. Yes.

Mr. BARTON. Can you enlighten the subcommittee on what it cost to build that plant, what its efficiency is today, and, if you know, what it is generating electricity at in terms of dollars per megawatt?

Mr. RUDINS. The Tampa electric plant has been a highly successful plant. It has completed its commercial demonstration phase and recently entered commercial service. It has been shown to have very reliable operation with efficiencies close to 40 percent. The approximate cost, if you take the total DOE and private dollars that went into the project and divide by the net power output, is on the order of $1,200 a kilowatt or so. Its emissions have been extremely low and its permit requirements for commercial operation have actually been even lower than for the demonstration phase, and they

[3] Coal-Related Greenhouse Gas Management Issues, National Coal Council, May 2003

have been able to meet those requirements. So it is very much a success story. I am not sure what the cost of electricity numbers are that correspond to that.

Mr. COURTRIGHT. My understanding, the cost of electricity is fairly comparable to that selling on the grid. There is probably only one point that could be enhanced there, and that is the overall availability is in the 75 percent range. I understand that is a rough number. Most plants are trying to get up in the 80 percent range. They broke into the 80's in certain quarters, to my understanding. But with improvements, that should occur.

Mr. BARTON. In terms of the costs per kilowatt, we say it is in the $5 or $6 per kilowatt.

Mr. COURTRIGHT. Megawatt.

Mr. BARTON. Kilowatt would be a lot. Just a few zeroes. So is that plant—what is the proprietary of the blueprint? Can it be replicated around the country or are there patents involved? If we wanted to say there is something very close to this and we want to order 20 of these next year, are we ready to do that?

Mr. RUDINS. A number of companies have actually been trying to develop IGCC projects based on that and to go forward. There are intellectual property rights and equipment vendors own some of those rights. Texaco owns the right to the Texaco gasifier. But in fact, the Tampa plant can be replicated under the right economic conditions and market conditions.

Mr. BARTON. It is not something—in the beginning of the nuclear power industry, each plant was totally unique; and if you built another one, you redesigned it from scratch. The basic design can be replicated fairly routinely, is that true?

Mr. RUDINS. They can be replicated, but it really depends on the customer. Historically, the utility customer wanted specific designs and imposed specific site-related requirements that had to be met, which would have required a departure, from a straight replication.

Mr. BARTON. To rephrase the question, if we were to build a plant like that in another part of the country, would it cost $1,200 a megawatt to build or can we get this economy of scale where we standardize design, where we get it down in the $400 to $500 per megawatt?

Mr. RUDINS. With each replication it is expected the cost will come down. And after perhaps two or three replications, it might approach that of a conventional coal power plant.

Mr. BARTON. What are the nonfinancial barriers in the industry to bringing this new technology into play? Is there a tradition amongst the utility management that we don't want to use these kind of plants because we haven't worked the kinks out of them, or is there a pretty good shot that with proper incentives and things like that, you find ready acceptance to this new technology?

Mr. COURTRIGHT. What you have is that, there being two plants in the U.S., both of those are single-trained gasification plants for availabilities in that 70 percent range. Most power companies are looking at this technology as their next option; either that or advanced pulverized coal and clean up on the back end. The main nonfinancial barrier, I think, is the lack of understanding of how it fits into their fleet, the development of operators to operate that plant. They don't have people who are trained in those facilities.

They are trained on current-day technology, the experience of their maintenance staff and everything else. So we need these second and third plant demonstrations and also more education and training of the future owners of these plants to be able to feel comfortable taking them on and to operate them in a competitive marketplace.

Mr. BARTON. My time has expired. The gentleman from Virginia, Mr. Boucher, is recognized for 5 minutes.

Mr. BOUCHER. Thank you very much, Mr. Chairman.

Mr. Rudins, let me ask you a couple of questions with respect to the FutureGen project. You testified at some length in your opening statement. As I understand the proposal, the Federal Government's share of the cost would be approximately $800 million?

Mr. RUDINS. That is correct.

Mr. BOUCHER. Where is that money going to come from? Is it going to be new money, we all hope, or will this be a reprogramming of money from other coal research and development initiatives?

Mr. RUDINS. As was proposed in the fiscal year 2004 budget request to the Congress, we propose to use prior-year, clean coal dollars that would be deobligated from terminated projects to get started with the project. And we would intend to work with Congress to make those dollars available.

Mr. BOUCHER. Have you asked for any new money for this?

Mr. RUDINS. Not at this time.

Mr. BOUCHER. Do you intend to?

Mr. RUDINS. The concept was to start the initial project phases with deobligated prior-year dollars, then the new dollars would be requested once these dollars would be expended.

Mr. BOUCHER. You are not anticipating any reprogramming of funds from either CCT or the CCPI programs beyond what you have already asked for in terms of reallocating money from terminated programs; is that correct?

Mr. RUDINS. That is correct.

Mr. BOUCHER. And how much have you now asked for in terms of reallocations from terminated programs? What is that dollar amount?

Mr. RUDINS. We have not formally submitted a request for a specific amount, but we have currently deobligated $185 million from one project and there could be a somewhat lesser amount from a second project if it does not go forward.

Mr. BOUCHER. And how much would that project be?

Mr. RUDINS. The total potential is in the $300 million range.

Mr. BOUCHER. So you will be asking for about $500 million in new money for FutureGen at some point.

Mr. RUDINS. That is correct.

Mr. BOUCHER. Let me ask you about a different aspect of this. All of the witnesses have mentioned to some extent the potential of FutureGen to educate us on the potential for carbon sequestration. Not only would electricity be generated, but hydrogen, potentially, could be produced that could fuel transportation; and, at the same time, the technology permits a capture of the carbon stream, and then that would be sequestered in some form. What experience do we have today, what experience directly does the Department of

Energy have with deep underground injection or other forms of sequestration, or are we entirely starting anew as we embark on FutureGen in terms of gaining experience with sequestration technology?

Mr. RUDINS. There is already an experience base that is growing as a result of our efforts under the sequestration R&D program. We are involved in a number of international as well as domestic projects, such as the Sleipner project in Norway that is injecting CO_2 underground. We are participating with the Canadians in the Weyburn project, which is also injecting CO_2 underground. We have a number of R&D activities underway to get a better handle on that.

Part of our general experience over many years is in enhanced oil recovery with CO_2 injection. While that is not done for the purpose of CO_2 storage, it gives us knowledge of underground CO_2 behavior and gives us an opportunity to move forward.

In the future, the sequestration program is going to be focusing on that element among others. In FutureGen, that will be a very strong focus of the program.

Mr. BOUCHER. Does the desire to learn about sequestration and deep injection technology drive this project to some particular part of the United States? Are you looking for the particular kind of geologic strata that would underlie the location of the plant?

Mr. RUDINS. Deep saline aquifers would be one candidate. And they're available across a fairly large number of States. But that certainly would be one consideration.

Another consideration if we are co-producing hydrogen and electricity would be the proximity of the site to an electricity grid to be able to sell the electricity generated. Another consideration, though not mandatory for co-producing hydrogen, is proximity to a refinery so that one could sell the hydrogen or excess hydrogen that is not used in the refinery process.

A third consideration would be if the process is in reasonably close proximity to an enhanced oil recovery field, some of the CO_2 could be sold for enhanced oil recovery. There are a number of features and the probability is that no one single site will have all of those but would have a number of features that would be very attractive for a FutureGen site.

Mr. BARTON. The gentleman's time has expired, but you have got it if you want to ask one last question.

Mr. BOUCHER. Thank you, Mr. Chairman. Just briefly, at what stage are you in the process of soliciting private industry participation, which would have to contribute 20 percent of the overall cost of this project? And could you describe the process that you intend to go forward with in terms of soliciting private partners?

Mr. RUDINS. We recently issued an RFI request for information laying out the concept the department would propose to use to enter into a cooperative agreement with a cross-section of the coal and power industry of the U.S., and laying out an approach that would benefit the industry as a whole.

So we would seek to partner with a representative cross-section of the industry, where they will be represented by at least 30 percent of the coal producers and at least 20 percent of the coal-based electricity generators. The contract would, as proposed in the RFI.

We would non-competitively negotiate a cooperative agreement and then would subsequently competitively procure most of the elements associated with FutureGen, including site selection and in other components.

Mr. BOUCHER. Thank you, Mr. Rudins. Thank you, Mr. Chairman.

Mr. BARTON. Thank you, Mr. Boucher.

Mr. Whitfield is recognized for 5 minutes.

Mr. WHITFIELD. Thank you, Mr. Chairman.

Mr. Rudins, you had mentioned in responding to Mr. Boucher, at least I understood you to say, $185 million would be available that had been set aside for other projects, but you are going to reprogram that money. Is that correct?

Mr. RUDINS. No. There is one project that we entered into discussions for termination by mutual agreement, from which deobligated $185 million that is available for us to apply to FutureGen.

Mr. WHITFIELD. And that is what you would like to do?

Mr. RUDINS. Yes.

Mr. WHITFIELD. I know you have asked for a request for information. What would be the next step?

Mr. RUDINS. Well, we received something on the order of 40 or more comments that we are now reviewing. The RFI closed June 16. Was it June 16? Yes, I believe it was June 16.

On the basis of those responses, we will be issuing a summary report of responses received. We will evaluate them and make a judgment as to whether the responses we received are consistent with the game plan that we laid out and whether we can proceed with the strategy as described in the RFI to go forward with the noncompetitive negotiation with the team to meet certain specific requirements.

If our conclusion is that it is yes, then we immediately intend to enter into negotiations for government and industries partnerships to pursue the project.

Mr. WHITFIELD. And when would you expect to make that decision?

Mr. RUDINS. I don't have an exact date, but that could be done fairly quickly. If our conclusion is that we do not have a basis to go forward with a noncompetitive negotiation, then we would have to do a competitive solicitation, which would delay the process by about a year or more.

Mr. WHITFIELD. I see. Okay. There was some discussion earlier about this plant in Tampa, Florida. What is the difference in the plant in Tampa, Florida and the one in Jacksonville, Florida?

Mr. RUDINS. The Jacksonville, Florida one is an atmospheric fluidized bed combustion system. The one in Tampa is the IGCC, integrated gasification combined cycle, system.

Both are very successful. Both have achieved their demonstration goals, but IGCC is the one we have been focusing on as offering the greatest potential for integration with carbon sequestration.

Mr. WHITFIELD. How old is the Jacksonville facility?

Mr. RUDINS. It just very recently went into operation. I don't recall the exact date.

Mr. WHITFIELD. And Tampa recently went into operation?

Mr. RUDINS. Tampa has been operating for several years but very recently went into commercial service operation.

Mr. WHITFIELD. Okay. Mr. Burke, one question I'd like to ask you, I noticed recently—and maybe you refer to this in your opening statement—that a report was issued by a group called the Energy Futures Coalition. And some of the press coverage of that report indicated that the coal industry and your company specifically had agreed that there is a need for a carbon cap. Is that true?

Mr. BURKE. No, that is not true, Mr. Whitfield. The energy future coalition group that I was involved in was a working group to discuss possible policy options to reconcile environmentalist concerns about climate with industry's concerns about energy supply and energy production.

We were there as a working group. We were there as individuals, not as representatives of any organization. And I think while we had some useful and profitable discussion along those lines, we didn't reach a consensus.

The working group wrote a report. And the working group report accurately reflects that. It does help to frame the discussion and the debate, but it clearly indicates that there was no consensus that was achieved.

When the full report came out, the energy future coalition full report was included with reports from other working groups. Some of the front material in that report went well beyond what we had agreed to within the working group. And that's what the press picked up on and recorded. I think, unfortunately, I was disappointed to see that because I thought the discussions that we were having had potential to be productive. And I hope that this misrepresentation of that in the press hasn't derailed that prospect.

Mr. WHITFIELD. So despite what the press said, you all did not agree?

Mr. BURKE. No. We don't agree that there is a demonstrated scientific basis for climate change based on carbon emissions. And we certainly don't agree that a carbon cap is justified.

Mr. BARTON. The gentleman's time is about to expire in 10 seconds. So you have got one quick question.

Mr. WHITFIELD. You have intimidated me, Mr. Chairman. So I will just wait until later.

Mr. BARTON. The gentlelady from Missouri is recognized for 5 minutes.

Ms. MCCARTHY. I am going to pass.

Mr. BARTON. The gentleman from Pennsylvania is recognized for I think 8 minutes.

Mr. DOYLE. Thank you, Mr. Chairman.

Mr. Rudins, welcome.

Mr. RUDINS. Thank you.

Mr. DOYLE. I just want to reiterate or just ask again for clarity purposes some of the questions that Mr. Boucher and others had asked about FutureGen. Now, am I understanding that you are looking at some $300 million in funds that are going to be de-obligated? This one program you said was approximately $185 million.

Mr. RUDINS. That is correct.

Mr. DOYLE. And then there is another program. Which program would that be?

Mr. RUDINS. These are individual projects.

Mr. DOYLE. I see. That would get up to $115 million that would give you your $300 million.

Mr. RUDINS. There are two projects in clean coal that haven't entered the design phase. And on one, we have agreed with the participant to proceed to termination by mutual agreement. And that is the $185 million one that I had mentioned. The other one, the other project, we are not to that point yet.

Mr. DOYLE. I see. I guess what many of us up here are worried about and want to make sure doesn't happen is we are not robbing Peter to pay Paul here, that we are going to see that monies aren't going to be taken from any existing programs to fund FutureGen.

So it is your intent, then, to—and I just want to reiterate this for clarity, too—seek $500 million in new money to make up the other balance of the $800 million of Federal commitment?

Mr. RUDINS. The current plan is to seek those dollars in the years that those dollars will be needed.

Mr. DOYLE. How many fiscal years do you see that $500 million being spent? You are not going to ask for it all at once. You are going to ask for it in stages. Give us an idea of what you are——

Mr. RUDINS. We anticipate the FutureGen project will require 10 to 15 years to complete, 10 years if you are an optimist, 15 years if you are a bit pessimistic on it. We anticipate that—well, we haven't negotiated the agreement with the private sector, which then will determine what the cash-flow requirements are. But $300 million is probably sufficient for the first 2 or 3 years or actually maybe even longer.

So we do not anticipate that a first appropriation of new dollars would be needed until perhaps the third year or later. And then it depends on the cash-flow requirements of the project, but if you just do a linear division of 10 years into $800 million, it is $80 million a year. And subtract from that at the front end $300 million.

The profile won't be linear because there will be construction phases and the like where there is probably a traditional bell-shaped curve or a variation on that that would be required.

Until we get down into more specific details and negotiations of project specifics, it is difficult for me to give you a——

Mr. DOYLE. You see yourself asking for this money over a 10-year period is what you are——

Mr. RUDINS. That is correct.

Mr. DOYLE. Now, I understand that there is some optimism that there are going to be some other international partners involved with FutureGen. Are you currently discussing partnership with anyone internationally?

Mr. RUDINS. There is a meeting going on as we speak associated with the carbon sequestration leadership forum, which involves the participation of senior representation from I believe approximately 14 countries, that is focused on sharing information on carbon sequestration and exploring possible future opportunities for joint projects. There will be a few of those conversations.

That may be one opportunity for getting other countries to participate. And if so, we would hope they would join the U.S. Government in pursuing the project and contributing to the $800 million government price tag.

Mr. DOYLE. Just one final question for you, Mr. Rudins. I introduced a bill back in 1999, H.R. 1753, which was the Gas Hydrate Research and Development Act of 2000, which was signed into law by President Clinton. Many of us feel if we can just get 1 percent of the gas located in hydrates that we could produce, we could really more than double our natural gas resource base.

Now, the fiscal year 2003 budget for gas hydrates was $9.5 million. And the President's 2004 budget request is $3.5 million, which is some 63 percent less than the program as endorsed by industry and Congress and many of us feel could delay the development of gas hydrates by 5 years. Why is the administration under-funding the gas hydrates program?

Mr. RUDINS. Mr. Doyle, I can't answer that question because it is not in my office area. But I would be happy to take the question back and give you an answer for the record.

Mr. DOYLE. Yes. I would appreciate that and just want to be sure that the administration is not looking at this program and others to offset funding for FutureGen. We are talking about de-obligated programs and new money for that $800 million.

[The following was received for the record:]

Methane hydrates hold great potential as source of natural gas and our work to develop this resource is important and will continue. However, in this tight budget year, we made the decision to place more emphasis on the President's Hydrogen Initiative.

Additionally, we are seeing increased interest from the private sector in methane hydrates and are actively seeking opportunities to partner with them in order to leverage the limited public dollars available.

Mr. RUDINS. Yes, sir.

Mr. DOYLE. Thank you very much.

Dr. Burke, welcome. In one form of legislation and potential regulation, there has been talk about controlling and reducing mercury admitted from coal-fired plants. I know that the reduction of NO_X and SO_X will result in mercury reduction also, as you mentioned in your testimony. And we have begun hearing about work being done to develop technology to achieve this. You also noted that work is being done to specifically control mercury. I have a couple of questions related to this.

Why is it necessary to further limit mercury beyond the reductions achieved as a co-benefit of NO_X and SO_X reductions? And could you tell me and the committee about the status of the development of that type of technology, what type of research is ongoing, what is showing the most promise, and what we should be doing to address mercury capture and reduction?

Mr. BURKE. Yes. And, to put it in context, the issue here is run by a mercury MAACT ruling that EPA is currently engaged in. The EPA lists the mercury MAACT graph rule in December of this year. That is their schedule of final rule in December of 2004 with implementation in December of 2007. We don't know what the mercury MAACT rule is going to be.

And so the regional research point of view—I think it is important to look at all potential options for mercury control. We do see mercury, as you said, as a co-benefit of SO_X and NO_X control technologies. Depending upon the specific type of coal that is burned and the specific type of unit in which it is burned, the quantities will vary. In some cases, that might be adequate to meet a mercury

MAACT rule. In other cases, it might not. And, therefore, it might be necessary to have additional technology, add-on technology.

The problem is that there is currently no commercial mercury control technology designed specifically for coal-fired boilers. We simply don't have it. And so we are faced with the potential to have to meet a mercury MAACT built in 2007. So the time is pretty short.

There are a number of options that are being explored right now to do various types of processes, including things like carbon injection, where powdered carbon is injected into the flue gas to capture mercury. Again, the efficacy of that depends a lot upon the type of coal that is being burned, flue gas conditions and so forth. So we need to know more about that.

The thing I emphasized is that time is very short. And although the Department has, I think, a good program in this area, it is going to be necessary to pursue that very vigorously in the near term so that we know what the available technology options are in time for utilities to be able to employ them to meet the 2007 deadline.

Mr. BARTON. The gentleman's time is expiring in 11 seconds.

Mr. DOYLE. Mr. Chairman, thank you very much. I yield back.

Mr. BARTON. Does the gentleman from Maine wish to ask questions?

Mr. ALLEN. No.

Mr. BARTON. Well, you have timed it perfectly.

Mr. ALLEN. Perfectly I guess from some point of view. If I could, Mr. Chairman, I will try to be very quick. We are going to just see for 1 second if I have got some things here that I would like to ask.

Mr. BARTON. Well, while the gentleman is thinking, in this coal gasification, are there any limitations on the types of coal that can be used? Are we going to get into an Eastern coal/Western coal, high-sulfur/low-sulfur coal fight, or is the technology universally applicable to any type of coal?

Mr. RUDINS. Certainly different gasifiers' operating characteristics can vary with types of coal, but my personal view is that they are not going to be constrained by types of coal. I don't know if my colleagues share in that view.

Mr. BARTON. Dr. Burke, do you agree with that?

Mr. BURKE. I think that you are going to see the same sorts of tradeoffs you have for coal using conventional systems. The higher BTU coals are going to have some advantages in terms of their energy content. Lower-sulfur coals are going to have some advantages in terms of ease of environmental compliance. There are those kinds of tradeoffs that are going to occur, but I think it is going to be pretty much the same sorts of tradeoffs that we are currently seeing.

Mr. BARTON. Any type of coal could be gasified?

Mr. BURKE. Right, given gasifiers have different sorts of configurations, different processes. And those processes will determine which coal operates the best, but there are gasifiers out there that are able to handle all types of coal.

Mr. BARTON. Does the gentleman from Maine wish to be recognized?

Mr. ALLEN. Thank you. I do, Mr. Chairman.

Mr. BARTON. The gentleman is recognized for 5 minutes.

Mr. ALLEN. I will be brief. I apologize for not being able to be here earlier. And what I ask may already have been covered. If so, just tell me that, and I'll move on.

I wanted to ask about the administration's national hydrogen energy road map. It states that 90 percent of all hydrogen will be refined from oil, natural gas, and other fossil fuels in a process using energy generated by burning oil, coal, and natural gas. The remaining 10 percent would be from water using nuclear energy.

Let me back up one moment. The statement is that that is the goal because we don't have the technologies to develop hydrogen from the sun or wind, that those technologies need further development for hydrogen production in order to be cost-effective. If we are spending a billion dollars to build a single FutureGen coal plant, isn't it clear that the technology needed to cleanly produce hydrogen from coal also needs further development?

I am just curious if maybe Mr. Rudins or others could explain why the administration isn't putting money into a research project to develop hydrogen from wind, for example. So the two-part question is how much work you need to do on coal to develop hydrogen from coal; and, second, why not a similar investment in wind?

Mr. RUDINS. Let me answer your question on a general level. My understanding of the national hydrogen initiative is, in fact, to look at diversified sources of hydrogen, including renewables, including fusion, including nuclear, including fossil sources and that, in fact, explore all pathways to a hydrogen future. That is my understanding of the overall strategy.

I can't talk to the relative funding levels. I just don't have sufficient knowledge to be able to do that.

Mr. ALLEN. Any other comments?

Mr. BURKE. Yes. The hydrogen production is chemically the separation of water into hydrogen and oxygen. Water really likes being water. It doesn't want to be separated. And so it requires a substantial investment of energy to make that happen.

It can be done by any of a variety of sources of energy. It could be electricity that is produced by photovoltaics or it could be heat that is generated through the gasification process of coal. The question is really what the cost is. And the cost of electricity from photovoltaics is relatively high compared to the cost of producing that energy or providing the energy through the gasification of coal. So that makes coal relatively more attractive.

It doesn't preclude the possibility of those other sources, but I think the issue is bringing down the cost of the energy of providing those other sources and then looking to see if it is competitive, basically providing the heat to get that chemical reaction.

Mr. ALLEN. Okay. I hear you.

Mr. COURTRIGHT. Just to add a point on the wind and on the solar aspect is the intimacy of that. You have those sources only available at certain times, which limits the amount of use you can get out of the capital investment for those for producing electrolysis of water, for producing hydrogen. So it does affect the economics of that.

Mr. BARTON. The Chair made a decision on the administration witness to bring the technical expert in DOE on coal programs, as opposed to a political appointee, who could give a little more general overview on the various ways to do some of these things. Since this was a coal hearing, I chose the gentleman who knows the coal programs, you know, absolutely coal. So if you have a specific question on the administration, if you will put it in writing, we can get you a broader answer from the political appointees at DOE.

Mr. ALLEN. Fair enough.

Mr. RUDINS. If I could give you a specific answer on coal and its attractiveness, the issue with coal historically has been it has been an abundant domestic fuel. It has been among the lowest-cost fuels available to us. The environmental issues have been always the obstacle for coal use.

The attraction of FutureGen is that if we are successful in developing these technologies, it can eliminate all environmental concerns associated with coal use, including CO_2 emissions. And if we are successful in doing that, analysis connected by mitre analysis suggests that hydrogen co-produced from coal with electricity, assuming success in achieving program goals for sequestration, could be the lowest-cost source of hydrogen.

Mr. ALLEN. That was going to be my other question. I don't know if people have dealt with the issue of carbon sequestration, but I wondered if you could give me some sense of how much there——

Mr. BARTON. Your time has expired, but I took some of it up. Your last question.

Mr. ALLEN. Quick overview of what you think the role of the coal industry should be in developing new approaches to carbon sequestration.

Mr. BURKE. Let me expound on that because I am from the coal industry. I work for CONSOL Energy. We are a bituminous coal producer. And I am here on behalf of them and the National Mining Association.

I think the coal industry has a strong interest in understanding the technical, financial, and environmental costs and implications of this technology. And clearly to reconcile our concern about environmental issues associated with carbon emissions with the high degree of certainty that the world's community will use its abundant coal resources requires some way to deal with carbon dioxide through technology. And that technology is carbon capture and sequestration. So I think from a strategic point of view from the coal industry's perspective, it is extremely desirable for us to see this technology developed.

My company is involved with the department in doing one project right now. We are looking at carbon sequestration in coal seams. And we are a member of a group that has responded to the FutureGen solicitation or FutureGen request for information. So we would put a high degree of importance on understanding what this is, where we can go with it, what it is going to cost to do it, and what it is going to look like when we get there.

Mr. BARTON. The gentleman from Georgia. Do you want 5 minutes or 8 minutes? You are entitled to 8 if you wish.

Mr. NORWOOD. Eight.

Mr. BARTON. All right.

Mr. NORWOOD. I can always give it back.

Mr. BARTON. The gentleman is recognized for 8 minutes.

Mr. NORWOOD. Thank you very much, Mr. Chairman. I am sorry I was out of the room. So I hope I am not going to ask a question that has already been asked.

My first question is to any one of you, perhaps all of you. I know all the members of the subcommittee know the answer to the question. So I will ask this for the staff. If you will explain to me and to them—do this simply if you can—how exactly the IGCC technology works versus the pulverized coal technology and how they will differ. In layman's terms, how do those two technologies differ? And what are they? How do they work?

Mr. COURTRIGHT. I think I will take a stab at it in layman's terms. In the pulverized coal, you basically take coal, crush it to a fine, almost powder substance, blow it into a boiler and ignite that. So you essentially have a large fire in a boiler where you are producing mostly super critical steam, high-temperature steam, to run a steam turbine. And that is how predominant pulverized coal plants operate. They burn coal. You are dealing with large volumes of air, large volumes of CO_2 in a very diluted sense because you have large volumes of air. And then you clean up those emissions at the back end of that technology.

In layman's terms, gasification is basically taking the solid of coal and chemically basically heating it and turning it into a gas state. You are dealing with much more concentrated streams of energy. About one-twentieth the volume I believe is the right number. So capturing emissions is a lot easier. Capturing CO_2 is a lot easier because of its higher concentrations, higher pressures. And that allows the added ability of cleanup from an IGCC.

What has been the technology challenge has been the gasification of coal in a very reliable sense as compared to the burning of coal. And that has caught up and has basically become a reliable process. Is that in a layman's enough for you?

Mr. NORWOOD. Yes. That is good.

Mr. COURTRIGHT. Thank you.

Mr. NORWOOD. Additionally, you say that it is easier to capture the emissions in IGCC than the gasification.

Mr. COURTRIGHT. Yes.

Mr. NORWOOD. Does that mean it is not just easier but you capture more emissions?

Mr. COURTRIGHT. You are dealing with more concentrated streams. So you probably can capture higher percentages, I believe, and be able to do that with the amount of equipment that you have to put on. In the pulverized coal plants, you are dealing with very large volumes of air moving through equipment and having to capture all of that through those large volumes.

Mr. NORWOOD. So it is cleaner emissions in the IGCC?

Mr. COURTRIGHT. Yes.

Mr. NORWOOD. Easier to do as well?

Mr. COURTRIGHT. Yes. That can be designed for better emission cleanup.

Mr. NORWOOD. Does that mean less expensive, more expensive because this new technology I guess you could say is more expensive?

Mr. COURTRIGHT. Well, when we get to what we think is going to be the state of costs for IGCC, we think it is comparable. Your cost for electricity out will be about the same, not counting the cap for CO_2.

Mr. NORWOOD. Mr. Rudins, on the FutureGen, do you think the number of a billion dollars in funding is adequate for that?

Mr. RUDINS. By our estimates, yes, it is, sir.

Mr. NORWOOD. If this is a good idea, what is your expectation in the private sector and their willingness to invest private capital into this?

Mr. RUDINS. At the state of where the technologies are, we are looking at FutureGen as really a large-scale research project, not a demonstration project. In commercial demonstration projects, we typically seek 50 percent cost sharing. With this being a more risky and longer-term undertaking, as is typical in a research project, we are seeking 20 percent cost sharing from the industry.

Mr. NORWOOD. Well, when might FutureGen, that type of plant, be economically competitive out there? When do you guess that might be?

Mr. RUDINS. If we achieve the goals that we have laid out for the FutureGen project and we complete it within a 10-year horizon, we hope to show the ability to cost-effectively co-produce hydrogen electricity and sequester the CO_2 within the timeframe of that project. But more than likely, as is typical for new technology, you probably would have to have a commercial demonstration of that in a full commercial-scale plant after that.

So if you are looking at time lines, about 10 years to complete FutureGen and probably another 7 years or so to do a commercial demonstration of that.

Mr. NORWOOD. So you are telling me that if we will invest in this demonstration project or whatever you want to call it, 20 years from now, Southern Company is going to say, "We don't need any help from the government. We will use our own capital. And we will be building FutureGen plants"?

Mr. RUDINS. In that approximate timeframe, give or take some years, yes.

Mr. NORWOOD. What might Congress do in any of your opinions to stimulate, I guess is the right word, the more rapid development of coal-based technology? What else do we need to do?

Mr. BURKE. I think we have laid out in this road-mapping process—it is important to recognize that different groups of people have had different technology road maps. And over the course of the last couple of years, we have really caused them to converge: the Department of Energy, industry, EPRI.

And I think the important thing is to continue to refine and develop that road map to understand where we are going, what the performance cost criteria area that we set, what we need to do in technological detail to get to those points, and cost that out and then provide the funding to be able to do it. So it is really a question I think to be able to move along that path at the rate at which we need to go, there is an indicated funding level.

As I said in my oral remarks and my written testimony, currently the funding that is in this year's appropriation, for example, is only a little over half of what we think is necessary to follow that road map schedule.

Mr. NORWOOD. That is sort of what I got out of your testimony, too, Dr. Burke, is send money, a don't bother us, send money sort of thing. And I am sort of asking, are there other things that Congress needs to consider here? I know the Department of Energy is on top of it, but are there are other things that—and you don't have to do this right now; I am just sort of thinking out of the box—other things that we might do as a Congress besides send money to stimulate this?

Mr. Chairman, I yield back.

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

The Chair would recognize the gentleman from California.

Mr. WAXMAN. Mr. Chairman, I am not sure I can complete my questioning in time to get to this vote. Could we come back? Do you know how much time we have left before the vote?

Mr. BURR. I believe the gentleman has about 7 minutes.

Mr. WAXMAN. Well, if I have that much time, let me go ahead.

Mr. BURR. I will double-check with Jim when you start. We will get you an answer.

Mr. WAXMAN. All right. If you will protect my rights here?

Dr. Burke, you testified there may be mercury reductions as a co-benefit of controls of other pollutants and "In the long run, it may be necessary to develop and deploy technology to further limit mercury." Are you testifying today that Congress should weaken the Clean Air Act so that the mercury MAACT standard will not go into effect in 2004?

Mr. BURKE. No.

Mr. WAXMAN. How would you reconcile that with the time that we are looking at for this standard, which is supposed to be prepared by the end of this year, finalized by next year, and solved by 2007?

Mr. BURKE. I think the time between now and December of 2007, we are not starting afresh today. The work on mercury reduction and mercury technology has been underway for some time. The Department has several large projects going on right now looking at different technologies for mercury control.

And we don't know what MAACT is going to be at this point. So without knowing specifically what the rules are going to be, it is hard to say how we are going to achieve it.

Again, two things, the issues, the technology if it is installed for other purposes will reduce mercury. There is a program going on between the Department of Energy, private industry—my company I think has four projects in this area—to try to develop technology and understand how to reduce mercury emissions costs effectively.

I think the most important thing is time is of the essence. And we need to make sure that that work gets done right now.

Mr. WAXMAN. I read in your testimony that there are no commercially available methods to control emissions of mercury from coal-fired power plants. I think this is a highly misleading statement, if not false.

The American Council, Coal Council, is an alliance of companies that have the objective of advancing and utilizing coal as an energy fuel source. Are you familiar with the American Coal Council? Would you consider it a credible source of technical information for the industry?

Mr. BURKE. I am familiar with American Coal Council.

Mr. WAXMAN. I would like to submit for the record an article from the American Coal Council's most recent magazine. The article is entitled "Tools for Planning and Implementing Mercury Control Technology." This article finds that recent full-scale demonstrations have proven the effectiveness of powdered activated carbons in reducing mercury emissions. Let me read to you from this article.

Mr. BURR. Does the gentleman want it in the record?

Mr. WAXMAN. I do.

Mr. BURR. Without objection, so ordered.

[The American Coal Council magazine article follows:]

TOOLS FOR PLANNING & IMPLEMENTING MERCURY CONTROL TECHNOLOGY

Michael Durham Ph.D., President, ADA Environmental Solutions, LLC

During the past few years a great deal has been learned about the capabilities and limitations of various technologies for controlling mercury for coal-fueled boilers. New operating and performance data from full-scale installations can provide guidance on determining the most cost-effective approach for a particular plant.

New data and continued analysis of available information corrects many of the early misconceptions about mercury control. For example, it was once believed that wet scrubbers could be used to provide dependable high-levels (90%) of mercury control. We have since learned that mercury removal in scrubbers varies significantly from plant to plant and is dependent upon coal characteristics and boiler operating conditions. It was also speculated that the addition of Selective Catalytic Reduction technology (SCR) could guarantee effective removal of mercury in a downstream scrubber. Recent tests have demonstrated that this is untrue.

Recent full-scale demonstrations have proven the effectiveness of powdered activated carbon (PAC) injection for reducing mercury emissions for different coals and control configurations. Results indicate that this near-term technology will be well suited to be retrofit on existing coal-fueled boilers. It requires minimal new capital equipment, can be retrofit without long outages, and is effective on both bituminous and subbituminous coals. Because of the promise shown by PAC injection to control mercury emissions from all types of coal, it appears unlikely that compliance with pending mercury reduction regulations will result in significant fuel switching.

MERCURY EMISSIONS FROM COAL-FUELED BOILERS

Coal contains trace levels of mercury that are released when coal is burned. The mercury forms various chemical species in the boiler depending on the coal characteristics and the boiler operating conditions. Elemental mercury, also referred to as mercury zero (HgO), is not water-soluble and therefore cannot be captured in wet scrubbers. Oxidized mercury, also known as reactive mercury, ionic mercury, mercury chloride, and mercury plus two (Hg++) is water-soluble and can be captured in wet scrubbers. While oxidized mercury can be captured, it may not necessarily be fully retained due to subsequent reactions leading to some re-emission of elemental mercury.

During 1999, EPA conducted an Information Collection Request (ICR) program in which approximately 40,000 samples of coal were analyzed to determine the concentration of mercury and chlorine. The ICR data demonstrated that there is not a great deal of difference in the coal types nor is there a large supply of "low-mercury" coal. Therefore, in contrast to the situation with coal-sulfur content, coal switching will not be a widespread option to meet a mercury regulation.

This data also showed that there was a significant difference between the chlorine content of Eastern and Western coals. The Western coals, both bituminous and subbituminous, have very low chlorine levels with most having less than 100 ppm. The Eastern bituminous coals have very high chlorine levels, many exceeding 1000 ppm. Because of this the speciation of mercury in Western fuels favors the elemental form whereas the Eastern coals have a higher concentration of the oxidized forms of mercury.

EMERGING REGULATIONS

New air pollution control regulations that include limitations for mercury emissions from coal-fueled boilers are coming from a variety of fronts. EPA announced in December of 2000 that they would proceed to develop a Maximum Achievable Control Technology (MACT) Standard for the industry. A draft regulation will be submitted by December 2003 with full implementation in 2007. The MACT process does not allow emissions trading, and could establish different limits according to the type of coal and type of air pollution control equipment at each plant.

Several bills are being debated in the Senate and the House that would require reducing mercury emissions. The bills differ in the level of mercury reduction required (50 to 90%), the timing of the reduction (2008-2018), and whether emissions trading will be permitted. In addition, several states have either passed new regulations for mercury control or are in the process of drafting regulations. The most aggressive have been the New England states where mercury control will be required in Massachusetts and New Hampshire by 2006.

MERCURY CONTROL IN EXISTING EQUIPMENT

The ICR program also provided insight on the capabilities of existing Activated Powdered Carbon (APC) devices to control mercury and the impact of coal characteristics. For every type of APC device, mercury capture was higher for bituminous coals than for subbituminous coals.

The ICR program also provided insight on the capabilities of existing APC devices to control mercury and the impact of coal characteristics. For every type of APC device, mercury capture was higher for bituminous coals than for subbituminous coals. This is due to the higher levels of oxidized mercury, higher concentrations of HCI, and higher levels of carbon in the ash. It also showed that fabric filters enhance the capture of mercury compared to electrostatic precipitators (ESPs),

The ICR tests confirmed that wet and dry scrubbers, which are located on 25% of the power plants, could be effective for removing mercury from some coals. However, scrubbers are only effective at removing one form of mercury, mercury chloride, and cannot remove elemental mercury. Because of this limitation, mercury control with scrubbers varies from less than 10% up to 90% removal. They work best on bituminous coals with high chlorine levels and they are quite ineffective on western subbituminous coals. This will severely restrict fuel flexibility at plants that depend upon scrubbers for mercury control. Following the ICR tests, additional test programs have been sponsored by EPRI and U.S. Department of Energy (DOE) to determine if SCR catalysts installed for NOx control are effective at oxidizing mercury to enhance removal in scrubbers. Their results show that while fresh catalysts can oxidize some elemental mercury to mercury chloride, performance depended upon coal characteristics. The test also demonstrated that the amount of oxidation decreases as temperature and gas flow increase, was inhibited by the addition of ammonia, and decreased rapidly over time at normal operating conditions. Several full-scale SCR units showed no appreciable mercury oxidation.

One of the most difficult applications for controlling mercury will occur at plants that burn Western fuels and use dry scrubbers for S02 control. Analysis of units using fabric filters has shown that for subbituminous coal, the mercury removal on plants with spray dryers (~5-39%) was lower than for plants without spray dryers (~55-82%). This inhibition of mercury removal appears to be caused by the elimination of HCI from the gas stream. Tests conducted by EPRI confirmed that these trends also occur when activated carbon is added to enhance mercury capture. For example, at a PAC feedrate sufficient for 90% mercury capture, mercury removal was reduced to 50% by the presence of a spray dryer.

Tests have shown that iodated carbon is capable of 90% mercury removal in this application. Although the iodated sorbent is prohibitively expensive, it does indicate that the problem might be solved with modified sorbents. EPRI has performed full-scale tests adding chloride compounds to the gas stream with some limited success. issues related to corrosion and deposition must be addressed for this to be a viable approach.

ACTIVATED CARBON INJECTION

Injecting a sorbent such as powdered activated carbon (PAC) into the flue gas represents one of the simplest and most mature approaches to controlling mercury emissions from coal-fueled boilers. This technology has been used for decades to control mercury emissions from boilers burning waste. Figure I is a photograph of the sorbent silo and feed train designed to inject PAC to treat a 150 MW boiler. The gas phase mercury in the flue gas contacts the sorbent and attaches to its surface.

The sorbent with the mercury attached is then collected by the existing particle control device, either an electrostatic precipitator (ESP) or fabric filter (FF).

The most commonly used sorbent for mercury control has been activated carbon. Activated carbon is carbon that has been "treated" to produce certain properties such as surface area, pore volume and pore size. Activated carbon can be manufactured from a variety of sources, (e.g. lignite, peat, coal, wood, etc.).

FULL-SCALE DEMONSTRATIONS OF ACTIVATED CARBON

Under a cooperative agreement from the DOE National Energy Technology Laboratory, ADA-ES worked in partnership with PG&E, We Energies, Alabama Power, Ontario Power, TVA, First Energy, EPRI, Hamon, Arch Coal and Kennecott Energy on a field test program of sorbent injection technology for mercury control. The test program took place at four different sites during 2001 and 2002.

Figure 2 presents full-scale data from three test sites, one with a FF on a bituminous coal, and two with ESPs, one bituminous and the other PRB. This plot also includes reduced-scale FF tests conducted by EPRI on a PRB coal. In all cases, mercury removal increases with increased rates of carbon injection. The best results occur on units with fabric filters as removal levels as high as 90% are achieved at much lower sorbent rates than that required for an ESP. It also shows that the performance in a FF appears to be independent of the type of coal.

With the ESPs, there does appear to be somewhat different results for bituminous and PRB coals (i.e. up to 90% removal in the bituminous case). However, because of the costs associated with the higher sorbent rates for ESPs, the practical limit for PAC injection with ESPs for all coals is 50 to 70% removal.

These tests also demonstrated that for all coals and both APC devices, collection efficiency was nearly identical for both elemental and oxidized mercury. These results validate the capability of PAC to capture all forms of mercury from both bituminous and subbituminous coals.

The data presented in Figure 2 can be used to estimate the impact of various mercury control regulations. The only practical way of assuring 90% mercury removal would be to inject PAC upstream of a FF. However, currently only 10% of existing plants have FFs. Thus 90% regulations would require most plants to install these devices at a capital cost of $40/kW. However, a regulation requiring 50-70% removal could be met by many plants with PAC injected upstream of existing APC equipment.

MERCURY IN COAL COMBUSTION BYPRODUCTS

Since the purpose of controlling emissions from coal-fueled boilers is to reduce potential buildup of mercury compounds in lakes and streams, the stability of mercury captured is a critical component of the, overall control scheme. In addition, there is a concern over the impact of PAC on ash being sold for use in concrete.

Currently there are a number of programs being conducted by DOE, EPRI and the Environmental Protection Agency (EPA) to evaluate the stability of mercury captured in flyash and scrubber sludge. These programs are establishing a number of new protocols to evaluate the susceptibility of these materials to leaching and volatilization of mercury compounds under "worst-case" environmental conditions. To date results have been very promising, as the captured mercury appears to be unlikely to reenter the biosystem.

Although the ash appears to be stable, tests have confirmed that the presence of even trace amounts of PAC rendered the ash unacceptable for use in concrete. This would not be an issue for the two/thirds of the plants that landfill their ash, but is an important economic factor for those plants that do sell their ash.

Several approaches are being considered to insure that the ash remains marketable such as separation, combustion and chemical deactivation of the PAC in the ash. One straightforward approach that is currently commercially available is the arrangement in which PAC is injected upstream of a secondary baghouse located downstream an ESP. With this configuration, the ash is collected upstream of the carbon injection and remains acceptable for sale. ADA-ES has begun work on two long-term full-scale demonstration programs of this configuration at the Alabama Power Gaston Station burning bituminous coal, and at the We Energies Presque Isle Station burning PRB coal

CONCLUSIONS

The power industry in the US is faced with meeting new regulations to reduce the emissions of mercury compounds for coal-fueled plants. These regulations are directed at the existing fleet of nearly 1100 existing boilers. A reliable retrofit technology is needed for these plants that minimizes the amount of new capital equipment while providing continued flexibility in fuel selection. However, mercury removal in wet scrubbers has been proven to vary significantly from plant to plant and is dependent upon coal characteristics and boiler operating conditions. It is also becoming more obvious that the addition of an SCR does not guarantee effective removal of mercury in a downstream scrubber. On the other hand, recent full-scale demonstrates have proven the effectiveness of activated carbon injection for reducing mercury emissions. This technology is simple and near-term and provides the capability of removal of all species of mercury from both Eastern and Western coals.

Additional information on mercury control can be found on the NETL (www.netl.doe.gov) and ADA-ES (www.adaes.com) websites.

ADA Environmental Solutions, LLC (ADA-ES) is an environmental technology and specialty chemical company headquartered in Littleton, Colorado. The company brings 25 years of experience to improve profitability for electric power and industrial companies through proprietary products and systems that mitigate environmental impact while reducing operating costs. ADA-ES is a subsidiary of Earth Sciences, whose common stock trades on the OTCBB under the symbol ESCI.

Mr. WAXMAN. "The results indicate that this near-term technology will be well-suited to be retrofit on existing coal-fueled boilers. It requires minimal new capital equipment, can be retrofit without long outages, and is effective on both Eastern and Western coals. It appears that in combination with a fabric filter, this technology will reliably remove 90 percent of mercury from either Eastern or Western coal." Dr. Burke, do you have information that this evidence from the American Coal Council is incorrect?

Mr. BURKE. I think that refers to pilot plant tests of mercury carbon injection. They are relatively short-duration tests of some specific coals and some specific boilers.

I don't dispute that. I don't know the source. I don't know the information except that that is true. There have been a number of tests. And they have shown some promising results.

What I was referring to in my technology was the lack of application of that commercial-scale across the wide spectrum of the existing coal-fired utility plants.

Mr. WAXMAN. Well, I am going to submit this for the record. Perhaps you can also look at it and respond to us further for the hearing record. If there are additional issues to address, won't the industry will have an opportunity to comment once EPA issues a proposal at the end of this year?

Mr. BURKE. Yes, that is my understanding.

Mr. WAXMAN. Okay. Thank you. Thank you, Mr. Chairman. We will make this part of the record. I would like to submit it for comment.

Mr. BARTON. Is it acceptable to you, Mr. Waxman, if we let this panel go?

Mr. WAXMAN. I have no problem.

Mr. BARTON. We are going to thank you gentlemen for your participation in this issue and ask for our second panel to come forward. Thank you.

If the subcommittee could come forward? If our panelists could get located? If we could be reseated? We would like to begin. Is Mr. Olliver here in the room? We have got a name place, Dick Olliver. All right. We are going to start without Mr. Olliver.

We are going to start with Mr. Brian Ferguson, who is the Chairman and Chief Executive Officer of the Eastman Chemical Company. He is testifying at the request of Congressman Boucher. I am sure if Mr. Boucher were here, he would say some nice things about you. We will give him that opportunity when he returns.

Your testimony is in the record. We are going to recognize you for 5 minutes to elaborate on it. Hopefully by that time, we will have some other Congressmen back. Welcome to the subcommittee, Mr. Ferguson.

STATEMENTS OF J. BRIAN FERGUSON, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, EASTMAN CHEMICAL COMPANY; CHARLES R. BLACK, VICE PRESIDENT, ENERGY SUPPLY, ENGINEERING AND CONSTRUCTION, TAMPA ELECTRIC COMPANY; RANDALL RUSH, POWER SYSTEMS DEVELOPMENT FACILITY DIRECTOR, SOUTHERN COMPANY; RICHARD A. OLLIVER, GROUP VICE PRESIDENT, GLOBAL ENERGY INC.; LAWRENCE E. McDONALD, DIRECTOR, DESIGN ENGINEERING AND TECHNOLOGY, THE BABCOCK & WILCOX COMPANY; DAVID G. HAWKINS, DIRECTOR, CLIMATE CENTER, NATURAL RESOURCES DEFENSE COUNCIL; ROE-HAN YOON, DIRECTOR, CENTER FOR ADVANCED SEPARATION TECHNOLOGIES, VIRGINIA TECH; AND FRANK ALIX, CHIEF EXECUTIVE OFFICER, POWERSPAN CORP.

Mr. FERGUSON. Thank you, Mr. Chairman.

I very much appreciate the opportunity to appear before you to share the enthusiasm that Eastman has for the production of electricity through coal gasification.

Eastman is a pioneer in the coal gasification business. In the early 1980's we had two large ChevronTexaco coal gasification units at our Kingsport, Tennessee chemical manufacturing complex. This system was completed in 1983, and we have made continuous process improvements since then.

Now, as we celebrate the 20th year milestone, Eastman is widely recognized as the leading coal gasification operator in the United States. To leverage this leadership position, Eastman recently formed a subsidiary to help other gasification project owners achieve faster startup, maximize their plant values, and improve long-term performance.

In a related development, we have signed a cooperative agreement with ChevronTexaco, which allows us to provide operation, maintenance, management, and technical services to other ChevronTexaco gasification licensees.

As Eastman has marketed its gasification expertise, we have repeatedly encountered three questions about coal gasification-based electrical power plants. I've heard those questions again here today. Those questions are how expensive are they to build and operate, are they reliable, and what are the environmental benefits? I would like to elaborate on each of those a little bit in turn.

Question one, how expensive are coal gasification power plants to build and operate? Mr. Chairman, based on our 20 years of operating experience, we believe that coal gasification can be competitive right now. We strongly believe this. And it is becoming more cost-competitive with each passing day. Let me cite some specifics.

According to data compiled by Eastman, ChevronTexaco, General Electric, and others, the capital costs of coal gasification power plants are currently projected to run around $1,200 to $1,400 per kilowatt of capacity. I think that was testified to in the earlier panel. And they are trending downward over time, as you asked about. This compares favorably with the newest generation of pulverized coal power plants, which have projected capital costs in that same range but are trending upward as additional pollution control restrictions are required.

Although operation and maintenance costs are somewhat higher for coal gasification plants, these costs are offset by lower fuel costs from the higher efficiency that was testified to and by lower environmental treatment costs and subsequent waste disposal costs. In addition, the coal gasification process produces saleable byproducts, such as elemental sulfur that we produce from the capped sulfur dioxide. As additional commercial-sized coal gasification plants are built, the cost competitiveness of this environmentally superior technology should become more evident.

Question two, how reliable are gasification power plants? Mr. Chairman, this is also a question that Eastman is uniquely qualified to answer. Our system with its dual gasifiers has achieved onstream availability of 98 percent since 1984 and an estimated single gasifier availability of 90 percent. That compares to the 70 percent numbers you heard earlier being demonstrated in the TECO facility. Perhaps most remarkably, our forced outage rate is only about 1 percent.

With respect to performance, Eastman has continuously improved the performance of our gasification system. For instance, the time between gasifier switches,—this is a time for moving between one gasifier to another—is now about once every 2 months, which is a 6- or 7-fold improvement from where we were 20 years ago. Another useful measure of performance is maintenance costs. In the last 6 years alone, annual maintenance costs for our gasification systems have declined by over 40 percent.

Question three, what are the environmental benefits of coal gasification? Mr. Chairman, let me answer that simply and directly. The principal environmental benefits associated with coal gasification, as compared to coal combustion processes, are: in the short term, significantly lower emissions of serious air pollutants, such as sulfur dioxide, NO_X, and I should say almost virtual removal of volatile mercury. And in the long term, we have more cost-efficient and cost-competitive carbon dioxide capture technologies available if they are chosen.

There are many more environmental benefits of coal gasification, but all that you need to take away from this hearing is the simple fact that it is by far the cleanest of the clean coal technologies.

Before concluding, let me express Eastman's support for both FutureGen and the clean coal power initiative. The electric industry is highly regulated and, hence, conservative when it comes to embracing new technologies. So, even though Eastman believes that coal gasification is ready for further commercialization right now, some additional market incentives, such as the CCPI and the proposed clean coal tax credits, are useful and necessary inducements. We thank the members of this subcommittee for your leadership on these specific issues and on advancing coal gasification in general.

Mr. Chairman, let me summarize my testimony. We believe that gasification is economically competitive with other clean coal processes now. It is the environmentally superior coal-based technology.

And, as Eastman has proved through 20 years of experience, coal gasifications can be operated at maximum efficiency with a high-degree of reliability. And we would invite any interested members in this room to come see that with their own eyes at their convenience.

Thank you for this opportunity to appear before the subcommittee this afternoon. I have offered extended remarks for the record. And I would be happy to answer questions.

[The prepared statement of J. Brian Ferguson follows:]

PREPARED STATEMENT OF J. BRIAN FERGUSON, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, EASTMAN CHEMICAL COMPANY

Mr. Chairman and members of the subcommittee, I appreciate the opportunity to appear before you to share the enthusiasm that Eastman has for the production of electricity through coal gasification. Eastman, as you know, is a pioneer in the coal gasification business. Our coal-to-chemicals facility in Kingsport, Tennessee, has just reached the 20-year milestone, so we have a lot of knowledge and credibility with respect to coal gasification generally. But before I turn to the specific topics you asked me to address, let me take a few minutes to provide some background information about Eastman Chemical Company.

Eastman: A Proud History and an Exciting Future

Eastman is a global chemical company founded in 1920 by George Eastman to provide chemicals for Eastman Kodak Company's photographic business. We became independent from Kodak in 1994, and have grown substantially since the spin-off. Revenues in 2002 were $5.3 billion.

Eastman supplies billions of pounds of chemicals, fibers, and plastics each year to customers around the world who, in turn, manufacture thousands of different consumer products. We serve many diverse markets, including pharmaceuticals, textiles, packaging, cosmetics, electronics, paint and coatings, and photography.

Eastman's most visible asset today is arguably our large portfolio of products, but certainly one of our most valuable future assets is an expanding portfolio of ideas. After 82 years in the chemical industry, we have amassed an impressive body of technological and intellectual assets and multi-faceted capabilities. These assets have the potential to be developed into new technology-oriented service businesses that are based on higher-value business models. This strategy is an important part of Eastman's growth platform and a top priority for senior management.

In that regard, a key business objective for Eastman is to use our two decades of coal gasification experience to help other companies design, build, and operate similar facilities for the production of electricity, chemicals, or other end-products, such as hydrogen.

Eastman's Coal Gasification Experience

Many of the chemicals that Eastman produces at our Kingsport complex are created through chemical reactions involving, at the front-end of the process, simple molecules such as hydrogen ($H2$) and carbon monoxide (CO). To produce these molecular building-blocks in the large volumes required in subsequent steps of the manufacturing process, our facility has always required great quantities of hydrocarbon raw materials.

For many decades we relied upon petroleum as our principal hydrocarbon feedstock. However, severe price increases associated with two events during the 1970s—the oil embargo and the Iranian crisis—encouraged Eastman to turn to coal as an alternative.

In the early 1980s we obtained a license from Texaco (now ChevronTexaco) and installed two large coal gasification units using the Texaco technology. The installation was completed in 1983 and we have made continuous improvements to this system over the last 20 years.

Many experts consider Eastman to be the world's leading gasification operator for the following reasons:

1. Ours was the first commercial coal gasification project built in the United States.
2. We have the world's best operating performance. For the last 19 years we have enjoyed an on-stream rate of 98 percent (it was 91 percent in the initial startup year). And our annual forced outage rate is now less than one percent.
3. We have an enviable safety record. Our Kingsport site has an OSHA recordable rate of 1.0 and no lost time accidents in the last 11 years.

4. We have exceptional environmental performance. Our system removes more than 99.9 percent of the sulfur in the synthesis gas (syngas created from coal). We have a patented sulfur-free gasifier start-up process. And we remove nearly *all* of the volatile mercury present in the syngas stream.
5. Our continuous process improvements have resulted in a 40+ percent reduction in annual maintenance costs over the last six years.

Eastman has such faith in the future of gasification that we have formed a subsidiary—Eastman Gasification Services Company—to help other gasification project owners achieve faster start-up, maximize plant value, and improve long-term performance. In a related development, we have signed a cooperative agreement with ChevronTexaco, which allows us to provide operation, maintenance, management, and technical services to other ChevronTexaco gasification licensees.

Mr. Chairman, I am very proud of the fact that Eastman is widely-recognized as the premier coal gasification operator in the United States. And I am honored to appear before you today to share some insights based upon our two decades of operating experience.

Three Key Questions about Coal Gasification

As Eastman's gasification services team has marketed its expertise to potential clients here and abroad, we have repeatedly encountered three fundamental questions about coal gasification-based electrical power plants:

1. How expensive are they to build and operate?
2. Are they reliable?
3. What are the environmental benefits?

These are the three essential questions, which Eastman and other coal gasification proponents must answer convincingly if we hope to see rapid and widespread deployment of this exciting technology.

Question 1: How expensive are coal gasification power plants to build and operate?

When discussing the merits of coal gasification, it is tempting to start by describing the environmental benefits of the process, since those benefits are substantial. However, if you start such a discussion with electrical power plant developers, they inevitably stop you in mid-sentence. "That's great," they always say, "but how do the life-cycle costs compare with other technologies?"

The answer to that question is one Eastman can uniquely address. Based on our 20+ years of operating experience, we believe that coal gasification can be competitive *right now* and is becoming more cost-effective with each passing day. Consider these facts:

• **Capital Expenses.** According to data compiled by Eastman, ChevronTexaco, GE, and others, the capital costs of coal gasification power plants are currently projected to run between $1,200 and $1,400 per kilowatt of capacity and are trending downward. This compares favorably with the newest generation of pulverized coal power plants, which have projected capital costs in this same range.

What has happened to make gasification competitive? Pulverized coal capital costs have risen in recent years as the result of ever-tightening federal air pollution and other environmental regulations. Coal gasification, on the other hand, has fewer potential environmental side-effects, and the capital costs of such plants are decreasing as the electric power industry gains more familiarity with the technology.

• **Operational Costs.** Although operation and maintenance costs are somewhat higher for coal gasification plants, these costs are offset by lower fuel costs (from higher efficiency) and by lower environmental treatment costs and subsequent waste product disposal costs. In addition, the coal gasification process produces saleable by-products, such as elemental sulfur.

Mr. Chairman, total variable costs—O&M, fuel, waste product disposal, and by-product credits—are currently better for coal gasification than any other fossil fuel-based electric power generation technology, *including* natural gas. Moreover, the costs associated with the removal of volatile mercury and with carbon dioxide capture and sequestration (if and when such removals are required) are much less for gasification than for competing technologies.

• **Fuel Costs.** In general, coal gasification is competitive with natural gas when natural gas prices are in the range of $3.50-4.00/million Btu. Many energy experts now predict that natural gas prices will remain above $5.00/million Btu through most of this decade.

Sustained natural gas prices at that level would continue to harm America's chemical industry, and at Eastman we hope that this scenario will not occur. Unfortunately, a prolonged period of natural gas prices in the $5.00-6.00/million Btu range seems likely.

In summary, when comparing capital costs, operational costs, and fuel costs, we believe the generation of electricity from coal gasification can be competitive right now. As additional commercial-sized coal gasification plants are built, the cost-competitiveness of this environmentally superior technology should become more evident, especially if the best practices Eastman has developed over the years are incorporated into future designs and operations.

Question 2: How reliable are coal gasification power plants?

Mr. Chairman, this is also a question that Eastman is uniquely qualified to answer. As I mentioned earlier, we have successfully operated a coal gasification system for the last 20 years, which is longer than any other company in the United States.

Of course, some might argue that there is big difference between running a coal-to-chemicals manufacturing facility and a coal-to-electricity power plant. They'd be right. Running a chemical facility is a *lot* more complicated. But the basic coal gasification process is the same regardless of whether the ultimate end-product is chemicals or electricity.

Based upon our two decades of operating experience, I offer the following observations about the reliability and performance of our coal gasification facility:

- **Availability.** Eastman's gasification system has achieved on-stream availability of 98 percent since 1984. Even during the initial startup year we were on-stream 91 percent of the time. Perhaps most remarkably, our forced outage rate is only about one percent. While this extraordinary performance is due in part to that fact that we have two gasifiers, with one unit always serving as a "hot standby," even our single unit availability rate is estimated to be 90 percent.

How critical is gasifier availability to Eastman? Let me put it this way: losing the ability to generate synthesis gas can shut down a significant portion of our Kingsport facility, which relies heavily on syngas production. The potential cost of such a shutdown is incredibly high.

- **Performance.** Eastman has continuously improved the performance of our gasification system during the last two decades. In 1983, for example, we were switching between gasifiers about once a week. In 2002, on the other hand, we averaged 62 days between switches. Another useful measure of performance is maintenance costs. In the last six years alone, annual maintenance costs for the gasification system have decreased by over 40 percent.

Question 3: What are the environmental benefits of coal gasification?

Mr. Chairman, let me answer that question simply and directly. The principal environmental benefits associated with coal gasification are: (1) significantly lower air pollution emissions in the short-term; and (2) more cost-efficient carbon dioxide (CO_2) capture and sequestration in the long-term.

In the future, America's electricity requirements may be met primarily by renewable energy sources such as wind and solar or perhaps even by nuclear fusion. It is prudent for America to explore those options. However, it is obvious to anyone who has studied our nation's energy situation in depth that coal can and must continue to play a leading role over the next several decades (at a minimum).

Unfortunately, there are two major environmental issues which the public associates with traditional coal combustion processes and even with much newer (and cleaner) coal combustion technologies:

1. When coal is burned it produces certain air pollutants, most notably sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), and mercury (Hg). In coal-fired power plants these pollutants must be removed from the exhaust (stack) gases using expensive and often relatively inefficient processes.
2. The combustion of coal also produces substantial quantities of CO_2. If and when CO_2 capture and sequestration is eventually required, it will be difficult and prohibitively expensive for coal-fired power plants to meet such requirements.

By contrast, coal gasification is a chemical process. As such, it is possible to remove the sources of SO_2 and Hg and the CO_2 from the synthesis gas before combustion, when it is much easier and thus less expensive to remove. Also, because the syngas is much cleaner than the raw coal itself, lower quantities of NO_X and PM are produced during the combustion process.

There are many more environmental benefits of gasification such as minimal solid waste generation, nominal water consumption, and the generally pleasing aesthetics of facilities and operations. These benefits have been adequately documented by both private and public sector experts. All that you need to take away from this hearing concerning the environmental benefits of coal gasification is a simple fact: *it is by far the cleanest of the clean coal technologies.*

FutureGen and the Clean Coal Power Initiative

Mr. Chairman, I am pleased to publicly express Eastman's support for FutureGen and the Clean Coal Power Initiative (CCPI), two research, development, and demonstration programs initiated by the Bush administration. Since you have asked the witnesses at this hearing to address both FutureGen and the CCPI, I would offer the following observations:

• **FutureGen.** Eastman supports this program because we believe that the government must lead the way in demonstrating both the feasibility of large-scale hydrogen production from coal and the sequestration of carbon dioxide from coal-based power plants. If properly conceived and executed, FutureGen could help achieve these two purposes while accelerating the commercialization of coal gasification. However, we are concerned that budget constraints in future years will make the 80 percent federal funding commitment to FutureGen difficult to sustain.

If forced to choose between funding for FutureGen and the Clean Coal Power Initiative, we would choose the latter. The CCPI program—with its biennial competitive solicitations—provides a long-term source of support for a diverse array of technologically promising but commercially risky coal gasification process improvements. While the goals of FutureGen are laudable, the CCPI is more important, in our opinion, for the future of coal gasification.

Also, if the FutureGen project does go forward, Eastman agrees with our colleagues on the Gasification Technologies Council (GTC) that this project ought to be designed and executed in close collaboration with the gasification industry.

Mr. Chairman, I have attached to this statement a copy of the comments submitted by the GTC to the Department of Energy on the FutureGen proposal, and I ask that you make these comments a part of today's hearing record. The position of the gasification industry on the FutureGen project is set out in detail in this document.

• **Clean Coal Power Initiative.** Eastman supports the CCPI program and we thank the members of this committee for including a nine-year, $200 million per year, authorization for the CCPI within H.R.6, the omnibus energy bill passed by the House of Representatives earlier this year.

As you know, the CCPI authorization in H.R.6 includes a requirement that at least 60 percent of the CCPI funds "shall be used only for projects on coal-based gasification technologies, including gasification combined cycle, gasification fuel cells, gasification coproduction, and hybrid gasification/combustion." Eastman believes that this 60 percent minimum should be increased to 80 percent as is the case in the bill presently pending before the Senate. (This position was recently supported by a report from the National Research Council.)

Given the serious federal budget limitations that lie ahead and in light of the fact that gasification is the cleanest of the clean coal technologies, we urge you and your colleagues to accept the Senate position on this matter when the joint House-Senate conference committee meets to iron out the differences in the two versions of the energy bill.

The electric power industry is highly regulated and hence conservative when it comes to embracing new technologies. Thus, even though Eastman believes that coal gasification is ready for further commercialization right now, some additional market incentives such as the CCPI and the proposed clean coal tax credits are useful and necessary inducements. We thank the members of this subcommittee for your leadership on these specific issues and on advancing coal gasification in general.

Concluding Thoughts

Mr. Chairman, the gasification services team at Eastman Chemical Company has spent a lot of time contemplating the barriers—both real and perceived—to widespread acceptance of coal gasification by the electric power industry. Many of the perceived barriers have been addressed at this hearing, and I hope that I have conveyed to you what we firmly believe at Eastman—

1. Gasification is economically competitive with other clean coal processes.
2. It is *the* environmentally superior coal-based technology.
3. And, as Eastman has proven through 20 years of experience, *coal gasification plants can be operated at maximum efficiency with a high-degree of reliability.*

Mr. BARTON. Thank you, Mr. Ferguson.

We would now like to hear from Mr. Charles Black, who is Vice President for Energy Supply, Engineering and Construction, Tampa Electric Company. Your statement is in the record in its entirety. We ask that you summarize it in 5 minutes.

STATEMENT OF CHARLES R. BLACK

Mr. BLACK. Thank you, Mr. Chairman.

I appreciate the opportunity to testify here today. I am pleased and encouraged that the committee is including coal in its evaluation of generation options for our future.

I believe that the development of coal-based generation options is essential to provide security of our fuel supply, reduce volatility and fuel prices, and to provide long-term savings in the real cost of electricity. One technology that can help achieve these objectives is integrated gasification combined cycle technology, commonly known as IGCC. I am here today to share Tampa Electric's experience with IGCC technology and our view of what is required to move IGCC to the next level.

Tampa Electric's Polk IGCC plant was initiated in 1989. The project was awarded funding as part of the Department of Energy's third round of the Clean Coal Technology Program. The plant was cited through a process using an independent site selection committee, which recommended that this plant be cited in an unreclaimed phosphate mine in Polk County, Florida.

By proactively working with all of our constituents, the plant was issued all of its permits without any intervenors or any challenges. The project was placed into service in September 1996. And a detailed description of the technology is provided in the written testimony that I have provided.

The Polk plant is an important part of Tampa Electric's generation system. We depend on Polk to meet our customers' energy needs. From our perspective, the Polk IGCC plant is a commercial plant. The availability of Polk has increased to about 80 percent, which is consistent with our design point for availability.

Our Polk unit has operated reliably and efficiently for almost 7 years. We have demonstrated over 15 types of coal as well as blends of petroleum coke and biomass. At Tampa Electric, we continue to rely on IGCC technology to effectively produce electricity from coal.

IGCC technology benefits include extremely high fuel flexibility, superior environmental performance. The technology is well-suited for CO_2 and mercury removal. It also has the potential for higher cycle efficiencies than other coal-fired technologies.

While Polk has demonstrated many of the technology's advantages, barriers still remain before broader commercialization of the technology can occur. Some of these barriers include: the technology's high capital cost, high operations and maintenance cost, the perceived technical complexity of the plants, a perception that IGCC has lower availability relative to other coal options, and uncertain future environmental regulations. I believe the Department of Energy can play a key role in overcoming these barriers.

The Department of Energy's role in the Polk project has demonstrated the effectiveness of public and private partnerships. Specific funding of technology development can be executed effectively using these public-private partnerships. New funding specifically for IGCC technology development should be done in a comprehensive way, addressing both specific technology development as well as integrated demonstration facilities.

I believe such a comprehensive approach can help to resolve both the technical and the financial issues associated with IGCC. Successful development of IGCC technology will form a good foundation for an integrated approach to maintain coal as a viable option for producing electricity in our future.

Thank you again, Mr. Chairman, for the opportunity to be here today and offer our thoughts. I would be glad to address any questions.

[The prepared statement of Charles R. Black follows:]

PREPARED STATEMENT OF CHARLES R. BLACK, VICE PRESIDENT, ENERGY SUPPLY, ENGINEERING & CONSTRUCTION, TAMPA ELECTRIC COMPANY

Mr. Chairman, on behalf of Tampa Electric Company, we appreciate the opportunity to testify at this important hearing. Coal is an important part of our nation's electricity generation mix, and we support the Committee's review of future options for the use of coal.

HISTORY:

Tampa Electric Company planned, engineered, built, and operates the Polk Power Station Unit #1 Integrated Gasification Combined Cycle (IGCC) Power Plant. The project was partially funded under the U.S. Department of Energy's (DOE) Clean Coal Technology Program pursuant to a Round III award. This project demonstrates the technical feasibility of commercial-scale IGCC technology.

Tampa Electric Company began taking the Polk Power Station from a concept to a reality in 1989. The project received an award under Round III of the DOE Clean Coal Technology Program in January 1990 based on older gasification and combined cycle technology to be located at a different site. The project concept was soon revised to incorporate newer more efficient gasification and combined cycle technology. Meanwhile, an independent site selection committee consisting of community representatives selected the current site, which was an abandoned phosphate mine in southwestern Polk County Florida. The DOE Cooperative Agreement was modified in March 1992 to incorporate these improvements. Detailed design began in April 1993, permits were issued without intervention, and site work began in August 1994. The power plant achieved "first fire" of the gasification system on schedule in July 1996. The unit was placed into commercial operation on September 30, 1996. Since that time, the plant has met its objective of generating low-cost electricity in a safe, reliable, and environmentally acceptable manner. The plant continues to operate base loaded as a key part of Tampa Electric Company's generation fleet.

PLANT DESCRIPTION:

Polk Power Station is a nominal 250 MW (net) IGCC power plant, located southeast of Tampa, Florida in Polk County. The power station uses an oxygen-blown, entrained-flow coal gasifier integrated with gas clean-up systems and a highly efficient combined cycle to generate electricity with significantly lower SO_2, NO_X, and particulate emissions than existing coal-fired power plants.

The air separation unit (ASU) cryogenically separates ambient air into its major constituents, oxygen (O_2) and nitrogen (N_2). Most of the O_2 (approximately 2175 tons per day at 96% purity) is needed in the gasification plant for the production of fuel gas. 2.5% of the available O_2 is used in the sulfuric acid plant. Most of the N_2 goes to the power plant's combustion turbine to dilute the fuel gas for NO_X abatement. This diluent N_2 also increases the combustion turbine's power production by 15% (25 MW) as it expands through the turbine.

The gasification plant produces clean medium BTU fuel gas and high-pressure steam for electricity production from 2500 tons per day of coal combined with other solid fuel such as petroleum coke and biomass. Coal from the 2 silos on-site is mixed with recycled water plus fines and ground into a viscous slurry which is pumped to the gasifier. The gasifier is a Texaco slurry fed, O_2 blown, entrained gasifier operating between 2400°F and 2700°F. High pressure steam is produced by cooling the syngas in a radiant syngas cooler and two parallel fire tube convective syngas coolers. Particulates are removed in an intensive water-scrubbing step. The gas is then further cooled in a way that almost all of the remaining heat is recovered by preheating the clean syngas fuel and boiler feedwater. This improves the plant's overall efficiency. Finally, the sulfur is removed from the gas by first converting any carbonyl sulfide compounds to hydrogen sulfide. The hydrogen sulfide is then removed by a circulating amine (MDEA) solution, and the clean gas is reheated, filtered, and delivered to the combustion turbine. The sulfur removed from the syngas is sent to the sulfur recovery system, which generates medium pressure steam and produces 200 tons per day of 98% sulfuric acid, which is sold to the local phosphate industry. Fines containing unconverted carbon from gasification are separated from the slag and water and are recycled to the slurry preparation section. The slag can be sold as aggregate for shingles and blasting media or for use in cement manufacture. Dissolved solids are removed from the zero discharge process water system in a brine concentration unit so the water can be recycled.

The power block is a General Electric combined cycle, slightly modified for IGCC. The combustion turbine is a GE 7F which generates 192 MW on syngas plus diluent N_2 or 160 MW on distillate fuel. A heat recovery steam generator (HRSG) uses the 1065°F combustion turbine exhaust gas to preheat boiler feedwater, generate about ⅓ of the plant's high pressure steam (⅔ comes from the gasification plant's high temperature heat recovery section), generate low pressure steam for the gasification plant, and superheat and reheat all the plant's steam for the steam turbine.

The gross power production is typically 315 MW (192 from the combustion turbine and 123 from the steam turbine). The oxygen plant consumes 55 MW, and other auxiliaries require 10 MW, so the net power delivered to the grid is 250 MW.

PLANT PERFORMANCE:

The Polk Power Station IGCC Project has met the key objectives of the plant owner/operator and the Department of Energy since beginning operation in 1996. Multiple technologies from many different suppliers were successfully combined into a highly integrated efficient power generation plant. Synthesis gas is used to fuel an advanced combustion turbine without adverse effects. Multiple coals and other low cost solid feedstocks have been successfully utilized. Very low emissions are being achieved with these solid fuels. After overcoming several initial problems, the unit is now demonstrating good availability.

Low air emissions, while using low cost solid fuel feedstocks, is the main driver for IGCC technology. Polk's emissions of SO_2, NO_X and particulates are lower than other coal fired options. SO_2 removal is typically 98% with emissions at 0.06 lb/mwh. NO_X emissions have recently been reduced by the addition of syngas saturation and are currently averaging 10 ppmvd corrected to 15% O_2. Particulate emissions are extremely low at 0.04 lb/mwh.

SO_X and particulates are more effectively removed in IGCC than in conventional coal combustion systems since the pollutants are removed from IGCC's high-pressure fuel gas stream rather than from the exhaust gas generated by total combustion. Removal of pollutants from the fuel also makes the removal of trace elements such as mercury more feasible and cost effective. IGCC plants are currently more efficient than other coal technologies and their CO_2 emissions are correspondingly lower. Should CO_2 capture and sequestration be called for, IGCC will have a significant advantage since CO_2 can be removed from the fuel stream prior to combustion.

The reliability and availability of Polk's IGCC unit has improved steadily since entering commercial service. The unit had some problems with heat exchangers and other items that led to lower than expected initial reliability. These problems have been addressed and the availability of the gasifier now in the 80% range, which is consistent with its design. Polk's gasifier availability is somewhat lower than would be expected for the next generation IGCC plant due to the lack of redundancy of some critical equipment. The combined cycle portion of the plant can also be operated on distillate oil. This capability to run on a back up fuel, increases the overall availability of the unit to the mid 90% range which is better than any single fuel, coal fired technology. Availability information is presented in the chart below.

The efficiency of Polk's IGCC unit, or heat rate, is approximately 9,500 btu/kwh on a steady state basis which is better than most other coal fired technologies. Other IGCC units are even more efficient. The Polk gasfier loses some efficiency due to lower than expected carbon conversion and changes in heat exchanger configuration. Both of these issues would be addressed in the next generation IGCC plant.

The cost to construct the Polk IGCC unit was about $2000/kW net of DOE funding. This is somewhat higher than future plants since it was one of the first of its kind. Today's direct cost for a new single train 250 MW IGCC plant on the Polk site in Polk's current configuration incorporating all the lessons learned is estimated to be about $1650/kW. A new plant built with economies of scale could reduce capital costs to $1300/kW or below. This is significantly higher than a natural gas combine cycle plant. The cost of fuel however is much lower for IGCC.

HOW IS IGCC CURRENTLY PERCEIVED:

The IGCC demonstration project at Polk Power Station has attracted a great deal of attention from industry, government and academia. Since it's inception, the plant has hosted over 2500 visitors from over 20 countries. The reason for the interest in the project is varied, but typically focuses on the technology used, environmental performance, system reliability and capital cost.

Many of our visitors are in the process of evaluating IGCC as an option for generation expansion. Their interest stems from the advantage of using coal, or other solid feedstocks, as a secure, low cost, fuel for power generation. The IGCC process achieves the use of coal in an environmentally acceptable manner.

Typical conclusions as to the benefits of IGCC include:

- Polk has demonstrated the flexibility of using a number of different solid fuels including over 15 coal types, petroleum coke and biomass. This is seen as a major advantage over natural gas from a price, volatility and security of supply standpoint.
- Polk has demonstrated superior environmental performance regarding SO_2, NO_X, and particulate matter versus other coal technologies.
- IGCC is well suited for mercury and CO_2 removal.
- Polk has demonstrated the use of IGCC in a commercial size for power generation.
- IGCC generally has a higher cycle efficiency than other coal fired technologies.

The typical concerns regarding IGCC technology include:

- IGCC has a high level of capital investment required versus Natural Gas Combined Cycle (NGCC) plants. There is general agreement that capital costs will be lower for the next generation of IGCC, but the uncertainties of returns in future power markets have made it difficult for potential users to select the high capital cost option.
- The environmental superiority of IGCC is financially unrewarded. Other coal-fired technologies may be able to meet current environmental regulations and there is no economic benefit for the additional environmental performance of IGCC. The potential benefits of future mercury and CO_2 removal are difficult to monetize.
- Existing IGCC plants have been engineered and constructed as an assembly of individual process units. The process unit suppliers will offer performance guarantees at their boundary limits, but no guarantee is typically available for the overall IGCC plant. The assumption of the overall plant performance risk has made financing and ultimately the selection of IGCC technology more difficult.
- There is the perception that IGCC has a lower equipment availability than NGCC and perhaps other coal fired technologies. As a demonstration plant, Polk's availability has been lower than the next generation plant would be. Based on the lessons learned here and at other demonstration plants, the next IGCC plants will incorporate improvements in equipment/material selection, operating procedures and level of redundancy. An important point, which is undervalued by many is that the overall availability of the plant, including operation on backup fuel in combined cycle mode, is very high. Gasifier availability can be engineered to be as high as the particular project economics dictate.
- Operation of an IGCC plant requires different technical skills than those with which power-generating utilities are generally familiar. The Polk project has demonstrated that a modest size utility, with expertise in coal-fired generation, can build and operate an IGCC plant. Tampa Electric paid careful attention to personnel selection and training to make this project a success.

A common position taken by other electric utilities is that they would like to see someone else take the risk in building the next IGCC plant. The "risk" being quoted seems about equally split between a perceived availability risk and an economic risk. We believe that the demonstration plants, including Polk, have shown that the availability issue can be effectively managed, particularly in the next generation of plants. The economic risk is a bit more complicated. The higher initial costs for IGCC can be offset by long-term fuel savings. In the last few years, a litany of external factors such as deregulation, power market pricing, California, ENRON and most recently stock devaluation have impacted the risk tolerance of potential users. At this point, it seems everyone would like to see multiple successful IGCC plants in service before they move forward.

STEPS NECESSARY TO MOVE FORWARD:

The DOE has been, and continues to be, very supportive of IGCC process. Numerous programs being discussed envision IGCC as a key core technology. Polk Power

Station is an outstanding example of how IGCC has been taken from concept to commercialization through a public/private partnership. Tampa Electric believes strongly in the value of IGCC and its future. Polk is the only gasification unit currently using coal for the generation of electricity in the country. Through this experience, the company has learned a great deal about the feasibility of IGCC and its future commericalization opportunities. As previously noted, while there are great opportunities, barriers exist to moving from the current atmosphere of perceived risk to the widespread use envisioned by the DOE.

These barriers include:

- Higher capital cost
- Higher operations and maintenance cost
- Perceived technical complexity
- Perceived lower availability
- Uncertain future environmental regulations

One path to overcome these barriers is to build on the DOE successful application of public-private partnerships. The success and necessity of this approach has been demonstrated at Polk. Elements of this public-private approach must include funding for technology development and demonstration. This funding could be provided as grants, tax credits or other means. It is important that the funding support a comprehensive effort addressing all aspects of the technology. The gasifier, the capital costs associated with technology development and, operations and maintenance costs all need to be addressed before production incentives can be realized. In addition, the ability of long-term financing absolutely depends on full sized integrated demonstration plants. Public-private partnerships are the most expedient way of taking the next steps toward commercialization of IGCC, but funding targeted toward IGCC specifically is crucial.

A comprehensive approach, utilizing a proven public-private partnership can provide the momentum necessary to achieve zero emission coal-fired technology for the 21st century.

Again, Mr. Chairman, thank you for the opportunity to participate in today's hearing.

Mr. BARTON. Thank you, sir.

We now want to hear from Mr. Randall Rush, who is the Power Systems Development Facility Director for the Southern Company. He is in Wilsonville, Alabama. Your statement is in the record. We ask that you summarize it in 5 minutes.

STATEMENT OF RANDALL RUSH

Mr. RUSH. Thank you, Mr. Chairman.

I appreciate the opportunity to appear before you today and talk about the future of coal and electricity generation.

America stands at a significant energy crossroad primarily for two reasons. First, there is an increasing imbalance between usage rates and available fossil energy resources. We currently use natural gas to produce 17 percent of our electricity. Yet, natural gas accounts for only 10 percent of our known fossil energy resources. Natural gas usage is projected to increase, but at current usage rates, we only have an estimated 60-year supply. Coal makes up 85 percent of our fossil energy reserves. And we have more than a 250-year supply. But it only provides a little more than 50 percent of our electricity. This imbalance between usage and available resources will eventually increase the price of natural gas directly and the price of electricity indirectly.

The second reason we stand at an energy crossroad is because coal is seen by many as a dirty fuel. Yet, coal use for power generation has tripled since 1970 while overall emissions from power plants have decreased by over 30 percent. These improvements are a direct result of the research, development, and demonstration investment made in clean coal technologies over the last 30 years by private industry and the Federal Government.

Environmental standards are stringent and becoming more so. There are increasing pressures to control CO_2 emissions to address concerns many have about global warming. DOE and industry have prepared a clean coal technology road map that outlines what is necessary to develop technology by around 2020 to produce electricity at 10 percent above today's costs while meeting these more stringent standards and capturing and sequestering CO_2.

Several technologies are addressed in the road map, but let us briefly take coal gasification as an example. Of the available technologies for converting energy from coal into electricity, gasification is seen as the most economic if CO_2 capture and sequestration are required.

I am a strong proponent of gasification. The past 10 years of my career have been spent developing advanced energy systems, including new coal gasification technology. In order to meet the 10 percent electricity cost increase goal in the road map, the capital and operating cost of gasification must be reduced substantially and its reliability must be increased.

Because current gasification technology does not perform well on the high-moisture, high-ash, low-rank coals that make up 50 percent of the U.S. and world supplies, further gasifier development and new gasifier designs are needed. Examples of these coals in the U.S. are lignite and much of our sub-bituminous reserves.

Pursuing developments like these can easily consume the careers of an entire generation of engineers and scientists. I manage a team that has, among other things, been developing the first truly new coal gasification technology in over 50 years. From the first discussions about the project until today, it is 15 years. The earliest of the first-of-a-kind commercial plant based on this technology can come on stream is 2009. So the earliest anyone can be in a position to make a decision to build a second plant is around 2011.

It is possible to use coal consistent with environmental expectations while meeting the goal of a 10 percent increase in the cost of electricity, but to reach this goal would require $14 billion of combined Federal and industry R&D, about half from each sector.

The Federal Government must show its commitment by taking the lead. Without such commitment, the industry cannot justify a significant investment because the timeframe to success is too long. When one compares the administration's fiscal year 2004 budget request for coal R&D with the annualized needs for Federal funds from the road map, there is a shortfall of over $200 million. This shortfall isn't new. DOE R&D today has only one-third the purchasing power it had in 1976. It will be impossible to meet the goal of clean, affordable energy from coal, including carbon capture and sequestration, if this trend is not reversed.

EPRI recently completed an estimate of the value of future clean coal technology development using a technique called real options. This technique is used by several major corporations to estimate the value of physical assets in a volatile marketplace. As Mr. Courtright indicated, EPRI's estimate of the value of clean coal technology to consumers was between $360 billion and $1.4 trillion by mid century.

In summary, our secure supplies of domestic coal can continue to be the engine that fuels the U.S. economy if we make the investments needed to ensure the timely development of advanced coal-based technology. But to do so will take time and a consistent, significant investment in R&D.

We need a national consensus that allows an effective balance among energy needs, environmental quality, economic prosperity, and overall quality of life. This national consensus must support expansion of all energy options, including both energy uses, such as conservation and efficiency, and energy sources, including fossil fuels, renewables, and nuclear.

Thank you, Mr. Chairman.

[The prepared statement of Randall Rush follows:]

PREPARED STATEMENT OF RANDALL E. RUSH, DIRECTOR, POWER SYSTEMS DEVELOPMENT FACILITY, SOUTHERN COMPANY GENERATION AND ENERGY MARKETING

Good afternoon Mr. Chairman and Members of the Committee. I am pleased to appear before you to discuss Future Options for Generation of Electricity from Coal. I am employed by the Generation and Energy Marketing arm of the Southern Company as Director of the Power Systems Development Facility (PSDF) located in Wilsonville, AL. Southern Company provides electricity to 4 million customers in the Southeastern U. S. We operate 40,000 megawatts (MW) of electric generating capacity of which over 22,000 MW is coal-fired. Southern Company's energy businesses include electric utilities in four states, a competitive generation company, an energy services business, and a competitive retail natural gas company.

The PSDF is a key national asset for ensuring continued, cost-effective, environmentally acceptable coal use. Operation of the PSDF is currently sponsored by the U.S. Department of Energy's (DOE) Office of Fossil Energy / National Energy Technology Laboratory, Southern Company; the Electric Power Research Institute (EPRI); Kellogg, Brown and Root; Peabody Energy; The Burlington Northern and Santa Fe Railway Company; and Siemens Westinghouse Power Corporation. Foster Wheeler Corporation (FW) is a significant past sponsor.

DOE conceived the PSDF as the world's premier advanced coal research and development (R&D) facility. Work there has fulfilled this expectation. As an example, a new, more efficient, less expensive, and potentially more reliable coal gasifier developed at the PSDF is ready for commercial deployment. In addition, the PSDF was instrumental in advancing the design of the FW advanced circulating pressurized combustion concept. As a result, of work there FW changed the concept and a proposed $400 million commercial demonstration plant was reconfigured to avoid significant problems. Proposed future testing at the PSDF includes, among other things, integration of gasification with advanced air separation technology, the use of coal-derived synthesis gas in fuel cells, and evaluation of advanced hydrogen/CO2 separation technology. A summary of major accomplishments to date and plans for testing during the next five years at the PSDF are contained in Enclosure 1.

Summary of Testimony. There is a growing imbalance between the availability of the secure domestic resources that fuel electricity generation in the U. S. and the rates at which they are being used. Natural gas accounts for about 10 percent of domestic energy reserves, but is currently used to generate 17 percent of our electricity. At current use rates natural gas reserves are projected to last approximately 60 years, but usage is projected to increase and gas production in the lower 48 states has not increased in over a decade in spite of a quadrupling of exploration. On the other hand, coal accounts for 85 percent of domestic energy reserves and generates approximately 56 percent of our electricity. At current use rates domestic coal reserves are estimated at more than 250 years.

Natural gas is a remarkably versatile fuel and like electricity is used extensively in residential, commercial, and industrial applications. Coal is a less flexible fuel and is rarely used in residential and commercial applications. Its primary current use is in generating electricity. The continuing depletion of the natural gas resource will eventually increase both its price and the price of electricity. The result will be a reduction in U. S. competitiveness in the world and in the Nation's economic well being.

Current DOE coal research, development, and demonstration (RD&D) programs, if adequately funded, will assure that a wide range of electric generation technology options continue to be available for future needs. Further, the continued use of coal in an environmentally acceptable manner will contribute to continued economic prosperity by ensuring that both electricity and natural gas prices remain low. Prior DOE clean coal research has already provided the basis for $100 billion in consumer benefits at a cost of less than $4 billion (Enclosure 2). Funding the advanced Clean Coal Technology Roadmap that industry and DOE have jointly developed can lead to additional consumer benefits of between $360 billion and $1.38 trillion (Enclosure 3).

There are enormous competing needs for Federal funding, but few things go more directly to the root of economic prosperity than secure, affordable, clean energy. The U. S. has always been the world leader in energy research, but if the current funding trend for advanced coal-based energy system RD&D is not reversed the U. S. will take the wrong turn at the crossroad we face. Down that road lies increased energy prices, increased dependence upon overseas energy supplies, and decreased economic prosperity. The alternative is to reverse the trend in RD&D spending for advanced coal technology and take the more rational road toward a more secure, prosperous energy future.

Electricity is at the Core of the U. S. Economy. In fact, electricity drives the U. S. economy. Figure 1 shows the strong relationship over the last 30 years between the U. S. Gross Domestic Product (GDP) and electricity use.

Electricity has been referred to by some as the currency of the information age. It is used extensively in residential, commercial, and industrial applications and sales nationwide are over $230 billion/year. Consequently, the price of electricity directly affects the competitiveness of U.S. manufactured goods in the world market, and the Nation's economic well being.

Using Abundant Low Cost Coal for Electricity Generation Instead of the Diminishing Supply of High Cost Natural Gas. Coal is used to generate approximately 56 percent of the electricity in the U.S. and accounts for 85 percent of known U. S. fossil energy resources. Coal reserves are estimated at over 250 years at today's usage rates. With the repeal of the Fuel Use Act in 1987 an ever increasing amount of our electricity has been generated from natural gas. Natural gas currently generates 17 percent of the Nation's electricity, but it accounts for only 10 percent of known U. S. fossil energy resources. Natural gas usage is projected to increase, but at current use rates reserves are estimated at only around 60 years. Natural gas is a remarkably versatile fuel and like electricity is used extensively in residential, commercial, and industrial applications. Coal is a less flexible fuel and is rarely used in residential and commercial applications. Its most valuable characteristics are its domestic abundance, its ready availability, and its low cost as a fuel source for affordable electricity.

Current indications are that supplies of natural gas in the lower 48 States are not increasing to meet the increased demand. Figure 2 shows that in the decade since 1992 production has remained constant despite a quadrupling of drilling rigs.

As shown in Figure 3, two consequences of this flat production have been significant short-term increases in natural gas prices (reaching to near $10.00/MBtu) combined with a substantial increase in its long-term price trend. These trends are expected to continue. Coal's price has remained steady during the same period that natural gas prices have been volatile and coal's long-term price is projected to remain below $1.50/MBtu well into the future.

This increasing imbalance between the Nation's usage rates and available resource levels of natural gas and coal has major long-term consequences. Because natural gas has become a significant fuel for electricity generation the continuing depletion of the natural gas resource will eventually increase its price directly and the price of electricity indirectly.

Coal is Wrongly Perceived as a Dirty Fuel. Figure 4 shows that although coal use for power generation has tripled since 1970, overall emissions from power plants have decreased by over 30 percent. Further reductions are expected within the next 5 to 10 years as additional technology required under the 1990 Clean Air Act is brought into service. These improvements are a direct result of the RD&D investment made in clean coal technologies over the last 30 years by private industry and the Federal government.

The coal used in electricity production is a major source of the carbon dioxide (CO2) emissions that are seen as a significant contributor to global warming. Currently available coal-based technology cannot simultaneous fulfill the objectives of providing low cost electricity and achieving near zero-emissions (including carbon dioxide). However, our secure supplies of domestic coal can continue to be the engine that fuels the U. S. economy, if as a Nation, we will make the RD&D investments needed to ensure the timely development of acceptable coal-based technology.

Coal is an abundant fuel throughout the world. It fuels more than one-third of global electricity production, and growth in energy demand is particularly strong in coal-dependent areas such as China and India. The increase in coal use expected in the U.S. in the next few decades is dwarfed by the increase in coal use expected in other countries. Over the next 30 years, China and India alone are expected to account for two-thirds of the increase in total world coal demand, principally for electricity generation. Advanced technologies that allow the economic use of coal consistent with environmental expectations have the potential to be deployed not only in the U.S. but around the world as well. The opportunity to deploy these technologies internationally only heightens the need to adequately fund RD&D of advanced coal technology.

For Coal to Remain a Viable Alternative for Electricity Generation a Long-Term Commitment to RD&D is Needed. The Coal Utilization Research Council[1] (CURC), EPRI, and DOE recently completed extensive discussions that led to the creation of a common "Clean Coal Technology Roadmap" that lays out specific pathways and achievable goals for improvements in the efficiency, cost, and emissions of coal-based energy by 2020. There are specific targets for emissions of sulfur dioxide, nitrogen oxides, particulate matter and mercury, carbon dioxide management, by-product use, water use and discharge, efficiency, reliability, and cost (capital and production) that advanced clean coal technologies can achieve over the next 20 years if RD&D is adequately funded.

The Roadmap seeks to identify the critical technologies that must be successfully developed, as well as the timelines for when that development must take place, if our Nation is to have highly efficient, near-zero emission, coal-base energy production facilities available for commercial deployment by 2020. If the Roadmap is followed, by 2015 designs for high-efficiency, near-zero emission power plants can be ready for application and by 2020 the first of these advanced plants can be commercially introduced.

The Roadmap also identifies the RD&D cost to achieve these goals. From now until 2010 $6.5 billion is needed with approximately $3.5 billion needed over the following decade. Further, it is estimated that an additional $4 billion will be required by 2020 for extensive carbon sequestration research—for a total of around $14 billion. The share between industry and government will vary among projects and phases of development, but based on historical precedence about half of these funds will come from industry and half from the Federal government. The ongoing industry cost sharing in DOE research programs, numerous projects executed under the Clean Coal Technology (CCT) program, and the recent large response to the Clean Coal Power Initiative (CCPI) affirm industry's willingness to fund its share of advanced energy RD&D.

The Roadmap includes both advanced combustion-based systems and advanced coal gasification. Both technologies need substantial improvement before becoming a significant part of the Nation's electricity generation capability. Take coal gasification as an example. Gasification will be the core technology of the FutureGen project announced recently by President Bush. Of the available technologies for converting energy from coal into electricity, gasification is currently seen as being the most economic if CO2 capture and sequestration are required—sequestration is the long-term disposal of CO2 in deep underground repositories. Even so, CO2 capture and sequestration are estimated to increase the cost of electricity from coal gasification by 30 to 40 percent. And, gasification is currently 5 to 10 percent more expensive than pulverized coal technology for electricity generation. By comparison the goal in the Roadmap is for only a 10 percent increase in the cost of electricity while capturing and sequestering CO2. As described in the FutureGen announcements, gasification is also projected to be the most economically viable technology for advancing the U.S. towards the hydrogen economy, where coal-based hydrogen fuel reduces transportation-based carbon dioxide emissions and lowers our national dependency on foreign oil.

In order to realize practical hydrogen production from coal and meet the 10 percent electricity cost increase goal, the capital and operating cost of gasification must be reduced substantially and its reliability must be increased. Specifically, the reliability of equipment in the power generation train must increase to the near 100 percent levels typical of current power generation technology. This will require improved materials of construction and temperature measurement instrumentation, improved fuel rate monitoring technology and increased fuel injector life. In addition, less expensive gas cleaning technology (including CO2 and hydrogen separation

[1] The CURC is an ad-hoc group of electric utilities, coal producers, equipment suppliers, state government agencies, and universities. CURC members work together to promote coal utilization research and development and to commercialize new coal technologies. Its 40+ members share a common vision of the strategic importance for this country's continued utilization of coal in a cost-effective and environmentally acceptable manner.

systems) that can handle multiple contaminates must be developed. The cost of air separation technology must be lowered by at least 25 percent. Coal preparation and feed systems for high pressure environments must be substantially improved. And, because the current commercial gasification technology does not perform well on the high moisture, high ash, low rank coals that make up 50 percent of the U. S. and world coal reserves, further gasifier development and new gasifier designs are needed.

The world's scientists and engineers have only recently turned to solving these problems. With increased attention in the technical community these goals can be met. But, it takes time and money and without sufficient funding it will take even more time.

Southern Company estimates that past DOE research related to large-scale, coal-based power generation will provide over $100 billion in benefits to the U.S. economy through 2020 at a Federal cost of less than $4 billion—a benefit cost ratio of 25 to 1 (Enclosure 2). EPRI recently used the modern financial technique called "Real Options" to estimate the value of advanced coal RD&D[2]. The major conclusion is that the value to U. S. consumers of further coal RD&D for the period 2007-2050 is at least $360 billion and could reach $1.38 trillion (Enclosure 3).

The technique of real options analysis is being used increasingly by businesses to assess investments in physical assets, particularly in fluctuating markets. Leaders include Chevron, Hewlett Packard (Business Week, June 7, 1999), Shell and IBM. Also discussed in: "Real Options: A better way to make decisions about power plants", Global Energy Business, March/April 2001.

However, the long-term nature of the necessary RD&D program and high risk associated with it means that industry cannot afford to make this investment alone. The Real Options analysis also showed that industry as a whole cannot justify investing more than $5-6 billion on advanced coal-based energy technology development. The cost and time scales are simply too large for individual companies or even individual industries to make significant progress alone. Moreover, the major beneficiaries of improved coal-based energy systems are consumers.

The Real Options analysis makes it clear that major public investment designed to supplement private investment in advanced clean coal technology can provide significant economic benefits to consumers, but the Federal government must take the initiative. However, the trend in Federal RD&D funding is disappointing. In real dollars, the amount the Federal government currently spends on advanced coal research is only a third of that spent in 1976. As an example, the Roadmap calls for $500 million in annual Federal funding for RD&D of coal-based energy systems. Actual annual appropriations fall short of this figure by more than $200 million.

There are enormous competing needs for Federal funding, but few things go more directly to the root of economic prosperity than secure, affordable, clean energy. If current funding trends for advanced coal-based energy systems are not reversed the U. S. will take the wrong turn at the crossroad we face. Down that road lies increased energy prices, increased dependence upon overseas energy supplies, and decreased economic prosperity. The alternative is to reverse the trend in Federal RD&D spending for advanced coal technology and take the more rational road toward a secure, prosperous energy future.

Mr. BARTON. Thank you, Mr. Rush.

We now want to hear from Mr. Dick Olliver, who is the Group Vice President for Global Energy Incorporated, White House Station, New Jersey. Your statement is in the record. We ask that you summarize it in 5 minutes.

STATEMENT OF RICHARD A. OLLIVER

Mr. OLLIVER. Thank you, Mr. Chairman.

Global Energy is pleased to have the opportunity to testify on the important topic of future options for generation of electricity from coal.

Global Energy is an independent international energy company with a primary strategy of utilizing gasification technology in the development of its own power generation projects or licensing our

[2] Market-Based Valuation of Coal Generation and Coal R&D in the U.S. Electric Sector, May 2002, EPRI-LCG.

proprietary technology to others. We are the owner and licensor of E-GAS gasification technology, originally developed by Dow Chemical. Additionally, we own and operate the Wabash River Limited gasification facility in Terre Haute, Indiana, which since 1995 has gasified high-sulfur coal and petroleum coke using the E-GAS process, providing synthesis gas and steam to our neighbor utility, Cinergy, for the net production of 262 megawatts of electricity. Of significance to this hearing, Wabash River Energy is the cleanest coal-fired power plant in the world.

Global Energy is a member of the Gasification Technologies Council, the preeminent trade association of the gasification industry. I currently serve as a member of the Board of Directors of the GTC and recently served as Chairman of the organization. The GTC members provide technologies for gasification, industrial gas supply, gas cleanup and conditioning, sulfur recovery, power generation and others, as well as equipment and technical services. These components form the core of industry know-how of current and future gasification-based power, fuels, and chemical plants in the U.S. and around the world.

Reflecting again on the Wabash River gasification facility, I request that the comments of my Global Energy colleague, Mr. Phil Amick, be included with my written statement for this hearing.

The Wabash River project was a repowering using gasification of a 1953 vintage pulverized coal plant and resulted in dramatic reductions of SO_X, NO_X, PM_{10}, and CO_2 emissions.

The Wabash River facility and the Tampa Electric Polk power station in Florida are the first of a new class of coal-based electrical generation plants with superior environmental performance compared to other technologies such as pulverized coal and fluidized bed boilers. Wabash River has been operating since 1995 with emissions lower than coal-based power plants that are now being permitted for operation in 2005. Accordingly, it is our strong belief, pertinent to the subject of this hearing, that coal gasification is ready today as a clear and worthy option for power generation in North America.

E-GAS and other prominent coal gasification technologies described here today, have already been successfully demonstrated in power generation modes as well as for commercial production of chemicals and are ready to be implemented in the next round of power plant capital expansion.

Recently I reviewed the public record of other hearings held by your committee relative to today's topic. We commend the committee and this subcommittee on their vision and initiatives to highlight and increase public awareness of important related topics, including national energy policy, hydrogen, and natural gas issues.

Remarks made before this committee on March 14, 2001 by Richard Abdoo of Wisconsin Energy outlining four basic principles of energy policy for power generation emphasized the use of domestic resources, particularly coal, for power generation. His comments are perhaps more profound today as the problems of energy supply have, in fact, become more acute, presenting immediate and serious threats to our economy and national security. To amplify this point, I request that a copy of the article in The Wall Street Journal, article of June 18, 2003, titled "Gas Prices Rock Chemical Industry," be included with my written statement.

Similarly, on June 10, 2003, during this subcommittee's hearing on natural gas supply and demand, the honorable Alan Greenspan described today's reality in the U.S. of tight supplies of natural gas along with sharply rising prices and identified new capacity of imported LNG as a promising mechanism for "creating a price-pressure safety valve" and improved "widespread natural gas availability in North America." While we agree that LNG is indeed a worthy option to the natural gas supply issue, we strongly suggest that coal gasification be added to the list of worthy solutions.

It is noteworthy that coal gasification is in a state of commercial readiness today, thanks to the vision and support of the U.S. Congress and the Department of Energy initiating and implementing valuable programs including clean coal technology, Vision 21, Clean Coal Power Initiative, and others, along with the enthusiastic participation of private industry and public utilities.

Accordingly, we wholeheartedly commend and extend continued support for the DOE programs embracing coal gasification for power and consistent with Vision 21 for the co-production of chemicals and other products.

Specifically on the topic of FutureGen, we commend——

Mr. BARTON. Could you summarize very quickly? You are about a minute over.

Mr. OLLIVER. We fully support the FutureGen program for DOE. And I ask that our letter from the GTC be included as a matter of record with my testimony.

Mr. BARTON. Without objection.

Mr. OLLIVER. This concludes my remarks. Thank you very much and look forward to questions.

[The prepared statements of Richard A. Olliver and Phil Amic follow:]

PREPARED STATEMENT OF RICHARD A. OLLIVER, GROUP VICE PRESIDENT, GLOBAL ENERGY, INC.

Mr. Chairman. Global Energy is pleased to have the opportunity to testify on the important topic of "Future Options for Generation of Electricity from Coal."

Global Energy is an independent international energy company with a primary strategy of utilizing gasification technology in the development of its own power generation projects, or licensing our proprietary gasification technology to others. We are the owner and licensor of E-GAS™ Gasification Technology, originally developed by Dow Chemical. Additionally, we own and operate the Wabash River Ltd. gasification facility in Terre Haute, Indiana, which since 1995 has gasified high sulfur coal and petroleum coke using the E-GAS™ process, providing synthesis gas and steam to our neighbor utility, Cinergy, for the net production of 262 MW electricity.

Of significance to this hearing, Wabash River Energy is the cleanest coal-fired power plant in the world.

Global Energy is a member of the Gasification Technologies Council (GTC), the pre-eminent trade association of the gasification industry. I currently serve as a member of the Board of Directors of the GTC, and recently served as Chairman of the organization. The GTC members provide technologies for gasification, industrial gas supply, gas cleanup and conditioning, sulfur recovery, power generation and others, as well as equipment and technical services. These components form the core of "industry know-how" of current and future gasification-based power, fuels, and chemical plants in the U.S. and around the world.

Reflecting again on the Wabash River gasification facility, I request that the comments of my Global Energy colleague, Mr. Phil Amick, be included with my written statement for this hearing. Wabash River is a repowering of a 1953 vintage pulverized coal plant, one that was operating on compliance coal, and had precipitators but was unscrubbed. Compared to the performance prior to the repowering, based on 1990 data for the older plant, the new facility makes almost six times as many megawatt hours of electrical power, yet reduces emissions of SO_X by over 5500 tons per year, NO_X by 1180 tons per year, and PM_{10} particulates by 100 tons per year. It produces 20% less CO_2 per megawatt of production because it is 20% more efficient than the original plant.

Mercury removal is about 50%, through the cleanup processes for other pollutants. An IGCC facility can be designed for up to 95% mercury removal.

The Wabash River facility, and the Tampa Electric Polk Power Station in Florida, are the first of a new class of coal-based electrical generation plants with superior environmental performance compared to other technologies such as pulverized coal and fluidized bed boilers. Wabash River has been operating since 1995 with emissions lower than coal-based power plants that are now being permitted for operation in 2005.

Accordingly, it is our strong belief, pertinent to the subject of this hearing, that Coal Gasification is ready today, as a clear and worthy option for power generation in North America. E-GAS™ and other prominent coal gasification technologies described here today, have already been successfully demonstrated in power generation modes, as well as for commercial production of chemicals, and are ready to be implemented in the next round of power plant capital expansion.

In preparation for this hearing, I reviewed the public record of other hearings held by your committee relative to today's topic. We commend the Energy and Commerce Committee and this sub-committee on their vision and initiatives to highlight and increase public awareness of the important related topics including Comprehensive National Energy Policy, The Hydrogen Economy, and Natural Gas Supply and Demand Issues.

In that regard, it bears repeating today excerpts from the statement made before this Committee on March 14, 2001 by Richard Abdoo of Wisconsin Energy, outlining four basic principles of energy policy for power generation:

- A balance of economic, environmental and energy supply goals
- A need for fuel diversity
- A commitment to long-term solutions
- An emphasis on domestic resources—particularly coal

These observations are perhaps more obvious and more important today as the problems of energy supply have in fact become more acute, presenting immediate and serious threats to our economy and national security. To amplify this point, I request that a copy of the article in The Wall Street Journal of June 18, 2003, titled "Gas Prices Rock Chemical Industry", be included with my written statement for this hearing.

One of the current concerns discussed by this committee on June 10, 2003, highlighted Natural Gas Supply and Demand Issues. On that occasion, the Honorable Alan Greenspan described today's reality in the U.S. of tight supplies of natural gas along with sharply rising prices, and identified new capacity of imported LNG as a promising mechanism for "creating a price-pressure safety valve" and improved "widespread natural gas availability in North America".

While we agree that LNG is indeed one viable and worthy option to the "natural gas supply issue", we strongly suggest that Coal Gasification be added to the list of viable and worthy solutions.

It is noteworthy, that Coal Gasification is in a state of commercial readiness today in this time of obvious need, thanks to the vision, commitment and support of the U.S. Congress and the Department of Energy (DOE), initiating and implementing valuable programs including Clean Coal Technology, Vision 21, Clean Coal Power Initiative, and many others, along with the enthusiastic participation of private industry and public utility entities.

Accordingly, we whole-heartedly commend and extend continued support for the DOE programs aimed at furthering and improving the use of Coal Gasification for power generation, and consistent with DOE Vision 21, for co-production of chemicals and other useful commercial by-products.

Specifically on the topic of FutureGen, we commend the DOE for proposing this bold initiative which recognizes that Coal Gasification must provide the technological foundation for the U.S. power generation industry, if coal is to have a long-term future in this arena. Furthermore, I request that the comments recently submitted by the GTC on the proposed FutureGen project be included with my written statement for this hearing.

This concludes my remarks. I thank you for the opportunity to appear before this Committee and would be pleased to answer questions.

PREPARED STATEMENT OF PHIL AMICK, VICE PRESIDENT, COMMERCIAL DEVELOPMENT, GLOBAL ENERGY, INC.

My name is Phil Amick and I am Vice President, Commercial Development for Global Energy Inc., headquartered in Cincinnati, Ohio. I would like to thank the Chairman and the other members of the Subcommittee for allowing me to submit this statement for this hearing.

Global Energy owns and operates the Wabash River Energy Ltd. gasification facility in Terre Haute, Indiana. The affiliated power generation plant is owned and operated by Cinergy. This 262 MW facility powers about 250,000 homes while utilizing local high sulfur coals, and even petroleum coke feedstocks, with sulfur content of 5.5% and more. More to the point for this hearing, it is the cleanest coal fired power plant in the world, of any technology.

The Wabash River IGCC is a repowering of a 1953 vintage pulverized coal plant, one that was operating on compliance coal and had precipitators but was unscrubbed. Compared to the performance prior to repowering, based on 1990 data for the older plant, the new facility makes almost six times as many megawatt hours of electrical power yet has reduced emissions of SO_X by over 5500 tons per year, NO_X by 1180 tons per year and PM_{10} particulates by 100 tons per year.

The Wabash facility, and the Tampa Electric Polk Power Station in Florida, are the first of a new class of coal-based electrical generation facilities with superior environmental performance compared to other technologies such as pulverized coal and fluidized bed. Wabash has been operating since 1995 with emissions lower than coal plants that are now being permitted for operation in 2005.

Wabash is a power plant using high sulfur coal that has SO_2 emissions as low as one fortieth of the Clean Air Act Year 2000 standard. Sulfur is chemically extracted from the syngas and sold for use in the fertilizer industry, about a railcar per day of pure sulfur that used to go into the atmosphere.

It's a coal power plant where the coal ash products emerge as a vitrified black sand byproduct and are marketed as construction material. There are no solid wastes from the coal gasification process—no scrubber sludge, fly ash or bottom ash.

In this plant, the wastewater stream from the chemical process meets current National Drinking Water Standards.

Carbon dioxide emissions are 20% lower than conventional unscrubbed coal fired plants because of the inherent efficiency of the gasification combined cycle process. The plant, with no additional special equipment, also has a mercury removal rate of about 50%.

One of the keys to this superior environmental performance is the fact that the gasification process takes place at high pressure. This facilitates the chemical processes that remove the pollutants.

High pressure operation also will facilitate additional carbon reduction and mercury removal measures on future plants. Department of Energy and industry studies indicate that significant reductions can be achieved with much less cost and performance impact than possible with coal combustion technologies that operate near atmospheric pressure.

While carbon dioxide emissions already 20% less than conventional units, this emission can be reduced more than 75% by shifting the syngas to hydrogen. This technology, already in use at some hydrogen production facilities, can be retrofit to a gasification facility for as little as 2 % of the original capital cost. The plant output reduction for this additional process step is a fraction of what would be seen in a conventional technology plant. In a gasification facility, it can be retrofit at any time in the future.

Mercury removal is also much simpler in the gasification process. A plant like the Wabash River facility could be upgraded to 80% or better mercury removal by the addition of a single carbon bed vessel, at a cost of less than $1 million dollars. Other facilities, such as the Tennessee Eastman gasification plant for chemical feedstock production in Kingsport, Tennessee, achieve better than 90% mercury removal to meet their process constraints, and have been doing it for nearly two decades.

Gasification technology for coal based power generation is being commercially marketed by ourselves and others. We feel that it is the most environmentally friendly solution for diversifying the fuel mix of new electrical power plant capacity. Through repowering, much of the existing, aging coal generation base can be upgraded as well, as was done at Wabash River.

Thank you, Mr. Chairman, that concludes my oral statement. With your permission, I have additional materials that can be included in the record.

Mr. BARTON. Thank you, Mr. Olliver.

We want to now hear from Mr. Larry McDonald, who is Director, Design Engineering and Technology, The Babcock and Wilcox Company in Barberton, Ohio. Your statement is in the record. We ask that you summarize in 5 minutes.

STATEMENT OF LAWRENCE E. McDONALD

Mr. MCDONALD. Thank you, Mr. Chairman.

I am responsible for the design, engineering and technology at the Babcock and Wilcox Company, a major supplier of technologies for coal-based power plants. Approximately 40 percent of the installed coal-based electrical generation capacity is B&W equipment. I appreciate the opportunity to speak with you this afternoon.

Our testimony is mainly about the need for and promise of an advanced combustion development program. A major goal of this program would be to make it possible to capture carbon dioxide emissions from coal combustion. This would facilitate sequestration if or when it may be needed in response to public policies.

From today's hearing, it should be clear that much of the planning of government-sponsored coal-powered generation R&D is weighted toward gasification. A major reason for this is that IGCC systems have the ability to produce a concentrated stream of carbon dioxide, thus enabling sequestration.

By contrast to the emerging gasification complexes, the flue gases of conventional coal combustion power plants are diluted with nitrogen from the combustion air. This dilution effect is the greatest impediment to affordable separation of carbon dioxide from the combustion plant flue gases.

Currently power generation technology providers, especially boiler manufacturers, are developing a variety of advanced combustion technologies to produce concentrated streams of carbon dioxide potentially amenable to sequestration. Our company is most actively engaged in the combustion of coal with oxygen, rather than air. We believe that the oxygen fuel-fired boiler approach is closest to commercialization.

Using oxygen, rather than nitrogen containing air, to burn coal precludes the dilution of the flue gas by nitrogen. The flue gases become largely carbon dioxide with other products of combustion. This makes separation of a concentrated stream of carbon dioxide much easier.

In addition to facilitating carbon management, this approach promises an important secondary benefit. By not firing with air, much less nitrogen is introduced into the furnace. As a result, much less NO_X may reduce the need for additional add-on NO_X controls to satisfy emissions requirements. We have been actively working on this approach since 1999. Currently we are conducting work at the B&W research lab with a pilot facility that simulates full-scale boilers.

We plan to continue development of the technology toward full-scale system design. Presuming success with our research and development plans, we can foresee being ready for a full-scale demonstration around 2008.

Ultimately the marketplace will decide the technologies that are utilized for future power generation. Our country's interest will best be served by having available many different responsible options. Advantages of some of the advanced combustion systems exemplified by oxy-fuel combustion include potential applicability to some of the existing fleet as well as new power plants, near to mid-term availability, relative simplicity of overall system designs, potentially lower costs for carbon dioxide capture, and electrical generation efficiencies comparable to current gasification systems.

Government support is warranted for the creation and funding of a substantial development and demonstration program in advanced combustion systems. The clean coal power initiative provides appropriate opportunities for large-scale, first-of-a-kind demonstrations of new technologies. CCPI program rules should enable demonstration of a wide range of technological approaches. Future CCPI solicitations should not be arbitrarily weighted toward gasification, essentially impeding demonstrations of other responsible potentially lower-cost options.

FutureGen is intended to be a major showcase and test bed for the combination of coal-based electricity generation, hydrogen production, and carbon dioxide sequestration. These are laudable goals. The planned $800 million government cost share for the projected $1 billion total project cost is a large commitment in an environment of severe budget constraints. It is critical that the funding for FutureGen be provided as additions to the DOE budget and not by reducing or redirecting funds otherwise intended to support CCPI or other important clean coal R&D and demonstration programs.

The development and commercial use of clean coal technologies will enable the responsible use of coal, addressing priority pollutants and coupled with sequestration, greenhouse gas emissions. Timely advance in clean coal technology will require significant cost share funding for research and development projects and demonstrations of emerging technology and tax incentives to reduce the risks and encourage early development and refinement of the new technologies.

I thank you for your attention.

[The prepared statement of Lawrence E. McDonald follows:]

PREPARED STATEMENT OF LAWRENCE E. MCDONALD, DIRECTOR, DESIGN ENGINEERING AND TECHNOLOGY, BABCOCK & WILCOX COMPANY

Chairman Barton, Ranking Member Boucher, and members of the subcommittee; Babcock & Wilcox Company is pleased to have the opportunity to provide testimony for the hearing of the Energy and Commerce Subcommittee on Energy and Air Quality on "Future Options for Generation of Electricity from Coal". Our testimony is primarily focused on the need for and potential benefits of an advanced combustion development program as an important dimension of our nation's approach to its energy future.

Babcock & Wilcox Company is an operating unit of McDermott International. McDermott International, Inc. is a leading worldwide energy services company, providing engineering, fabrication, installation, procurement, research, manufacturing, environmental systems, and project management for a variety of customers in the energy and power industries, including the U.S. Department of Energy.

For over 135 years, the Babcock & Wilcox Company has earned a reputation of excellence, setting the standards for the power generation industry and supplying innovative solutions to meet the world's growing energy needs. With power generation systems and equipment found in more than 800 utilities and industries in over 90 countries, we are truly powering the world. More than 10,800 employees around the globe make up the B&W team. And because of our forward-thinking, talented and dedicated employees, we continue to reach new levels of success.

SUMMARY

A primary technical impediment to sequestration of exhaust gases from conventional coal-fired power plants is the dilution of the flue gases by the nitrogen that is contained in the combustion air that is supplied to the boilers. Air is about 21 percent oxygen, which is needed for combustion of the coal, and about 78 percent nitrogen. Development efforts are envisioned and/or underway by boiler technology suppliers to define practicable ways to create, through advanced combustion systems, concentrated streams of carbon dioxide from flue gases—thus facilitating subsequent sequestration if/when needed to respond to public policy imperatives.

Babcock & Wilcox Company is exploring a variety of alternatives to produce concentrated streams of carbon dioxide from coal combustion systems; and is most actively engaged in oxy-fuel boiler system development. Through studies and pilot scale tests conducted to date, we are encouraged that the oxy-fuel system will be ready for large scale demonstration around year 2008. Assuming success, the concept would benefit new power plants and potentially have some application to the fleet of existing power plants.

The U.S. economy will be favorably served by maintaining a variety of energy supply options. The government's coal power plans for the future are predominantly based on the presumption that gasification approaches will be the most viable options. It is possible that many of the gasification-related RD&D initiatives, such as FutureGen, will prove to be valuable. On the other hand, the variety of attributes of oxy-fuel combustion and other coal combustion based approaches leads us to anticipate greater potential marketplace viability for advanced combustion technologies. Advantages of some of the advanced combustion systems, exemplified by oxy-fuel combustion, include potential applicability to the existing fleet as well as new plants, near- to mid-term availability, relative simplicity of overall system designs, lower costs for capture of carbon dioxide, and comparable electricity generation efficiencies to gasification systems. Government support is warranted for the creation and funding of a substantial development and demonstration program in advanced combustion systems.

GENERAL COMMENTS

U.S. economic growth depends upon low cost plentiful supplies of energy, which can best be achieved through an energy marketplace with a variety of responsible options.

Coal will continue to be a major part of the energy supply mix for many decades to come. It makes up 90 percent of our domestic energy reserve, and 90 percent of the coal mined is used to generate approximately 50 percent of the electricity used in the country today. We are gratified that there is a growing recognition that coal will continue to be a major fuel source for our nation's electrical generation for the foreseeable future.

Energy policies are likely to be affected by increasing priorities on carbon management. The challenges of natural gas availability, reserve depletion, prices, and price volatility are well known. Policies that encourage fuel switching to natural gas from the higher carbon content coal for generation may not be in the best interest of our country.

The development and commercial use of clean coal technologies will enable the responsible use of coal; addressing priority pollutants and, coupled with sequestration, greenhouse gas emissions. Timely advances in clean coal technology will require significant cost-shared funding for research and development projects and demonstrations of emerging technology, and tax incentives to reduce the risks and encourage early deployment and refinement of the new technologies. These issues are addressed by industry groups such as the Coal Utilization Research Council and Electric Power Research Institute.

Regarding carbon management technologies, until recently, approaches to carbon dioxide reductions in coal fired electrical power generation have been mainly focused on efficiency improvements; i.e., producing more electricity from each unit of coal burned, through development of advanced steam cycles with higher operating pressures and temperatures, improved operating controls, etc. This important cross-cutting work needs to continue.

Much of the focus of government funded R&D for the future utilization of coal is weighted toward gasification. A principal attribute associated with integrated gasification combined cycle is the ability of the system to produce a concentrated stream of carbon dioxide, thus enabling sequestration. Gasification offers considerable potential, however, there are significant technological and economic hurdles that must be overcome in order to realize the benefits of these complex systems.

Currently, power generation technology providers, especially boiler manufacturers, are focusing on developing advanced combustion approaches that would also produce concentrated streams of carbon dioxide potentially amenable to sequestration. The efforts to develop combustion alternatives to gasification create a dynamic scene; some of the advanced combustion systems are being defined and still others are emerging. Babcock & Wilcox is actively engaged in advanced combustion approaches which we are cautiously optimistic will prove to be viable options for concentration and capture of carbon dioxide in the near to mid term future. Some of the approaches should potentially be applicable to some of the existing power generation fleet as well as new facilities.

The Coal Utilization Research Council, through its road-mapping process has determined that an Advanced Combustion Program needs to be an important part of the DOE's fossil energy R&D program. This has been conveyed to Congress and to the DOE. It is imperative that a suite of technologies be developed and that the marketplace be allowed to decide which are best suited based on site and economic conditions.

We offer the following comments on the major planned demonstration programs, namely the Clean Coal Power Initiative and FutureGen.

The Clean Coal Power Initiative provides appropriate opportunities for large-scale, first-of-a-kind demonstrations of new technologies. CCPI program rules should enable demonstration of a wide range of technological approaches. Future CCPI solicitations should not be arbitrarily weighted toward gasification, essentially impeding demonstrations of other responsible options.

FutureGen is intended to be a major showcase and testbed for the combination of coal-based electricity generation, hydrogen production, and carbon dioxide sequestration. These are laudable goals. The planned $800 million government cost share for the projected $1 billion total project cost is a large commitment in an environment of severe budget constraints. By way of comparison, the entire CCPI demonstration program will require $2 billion in government cost shares over its entire 10-year duration, presuming full funding. It is critical that funding for FutureGen be provided as additions to the DOE budget; and not by reducing or redirecting funds otherwise intended to support CCPI or the other important clean coal research, development, and demonstration programs.

Ultimately, the marketplace will decide the technologies that are utilized, and we repeat that our country's interests will be best served by providing many different responsible options. As the National Coal Council stated in its May 2003 report "Research And Development Needs And Deployment Issues For Coal Related Greenhouse Gas Management", ". . . Given the time before wide-scale sequestration is likely to be practiced, there is an opportunity to explore a wide range of potential capture options, applicable to both gasification and combustion systems, in the hope that break-through technology can be identified to reduce the onerous costs and energy penalties of current approaches."

OXYGEN COMBUSTION

In a conventional power plant, coal is burned with air to produce heat and generate steam that is converted to electricity by a turbine-generator. The flue gas streams are, as a result, diluted with large quantities of nitrogen from the combustion air. Air contains 78% nitrogen; only the oxygen in the air is used to convert the fuel to heat energy. Prior to the last few years, conventional wisdom was that practicable carbon dioxide separation was not attainable in conventional coal fired plant designs. Currently, the domestic boiler suppliers are active in advanced combustion systems research aimed at carbon management. Combustion of coal with oxygen rather than air is one of the promising approaches. Oxy-fuel combustion is the approach that Babcock & Wilcox is most actively pursuing—the approach that we believe is closest to commercialization.

Progress in B&W's Oxy-Fuel Combustion Program

In the oxygen-fuel fired boiler concept, combustion air is replaced with relatively pure oxygen. The oxygen is supplied by an on-site air separation unit, with nitrogen and argon being produced as byproducts of the oxygen production. For the oxy-fuel boiler system, a portion of the flue gas is returned back to the burners, and the nitrogen that would normally be conveyed with the air through conventional air-fuel firing is essentially replaced by carbon dioxide. This results in the creation of a flue gas that is primarily a concentrated stream of carbon dioxide, rather than nitrogen, and other products of coal combustion. The volume of carbon dioxide-rich flue gas leaving the plant is about one fourth of that of a conventional air-fired plant. This concentrated stream of carbon dioxide would then be available for subsequent sequestration.

Figure 1 schematically compares a modern conventional plant, Figure 1A, to an oxy-fuel power plant, Figure 1B.

In 1999 Babcock & Wilcox joined an international consortium consisting of utilities, industrial gas companies, and a research & development organization, to sponsor oxy-fuel combustion in a bench-scale combustor at CANMET. The bench-scale work showed that concentration of carbon dioxide is feasible. Some of the developmental issues could not be addressed at the small bench-scale facility, e.g., equipment for introduction of oxygen into the burner, potential need for boiler heat transfer surface modification, etc. Additionally, we are conducting a U.S. DOE-sponsored review entitled "Evaluation of Oxygen Enriched Combustion Technology for Enhanced CO2 Recovery."

A larger 5MBTU/HR proof-of-concept pilot-scale evaluation of the technology is being performed at the Babcock & Wilcox Research Center in a facility known as the Small Boiler Simulator (SBS) that simulates full-scale coal-fired boilers. The SBS has recently been modified for the oxygen-firing of coal with recycled flue gas under a program sponsored by the State of Illinois. Partial substitution of combustion air (up to 80%) with oxygen-enriched flue gas has been demonstrated and plans are in place to replace all of the combustion air with oxygen this year. A layout of the modified SBS facility appears in Figure 2.

In addition to pilot scale testing, B&W has been working on initial studies to evaluate the application of oxy-fuel conversion of existing plants firing different coals as well as the impact on the design of a new oxy-fuel plant with a high efficiency state-of-the-art steam cycle. These studies have provided significant insights into the impact of equipment arrangement options and oxygen and carbon dioxide purity on both performance and cost; and have provided an opportunity to develop many of the design tools and establish some of the key parameters needed to proceed to a full scale demonstration. This study validated the expectation that nearly all of the major equipment and emissions control systems in an existing coal-fired plant could be directly utilized if the plant were converted to oxy-fuel firing. It has also reinforced the need for an inexpensive source of oxygen to make this option economical. Considerable opportunity exists for further refinement of this work toward the goals of optimized performance and cost.

In portions of our oxy-fuel program, we have worked in collaboration with an international consortium state agencies supporting coal usage, USDOE, industrial gas companies providing oxygen, and utilities.

Future Opportunities, Challenges, and Plans

Preliminary assessment of the impact of oxy-fuel firing on the design of a new plant with a high efficiency state-of-the-art steam cycle has revealed potential opportunities for significant cost reduction. A higher efficiency advanced supercritical steam cycle reduces the amount of coal burned per megawatt generated which, in turn, reduces equipment sizes and oxygen required, as well as the amount of emissions, including carbon dioxide, produced. Current work has assumed the same amount of flue gas will pass through the boiler as in conventional units using air instead of oxygen. Reduction of the amount of flue gas recirculated to the boiler may be advantageous, further reducing new plant boiler size and associated cost significantly.

An important secondary benefit of oxy-fuel firing of coal in a boiler is that, in addition to facilitating carbon management, it also significantly reduces nitrogen oxide (NO_X) emissions. In a conventional plant using air, NO_X is produced from two sources; a small amount of nitrogen in coal (fuel-NO_X) and a larger amount of nitrogen in from the air used for combustion (thermal NO_X). By using relatively pure oxygen and replacing the nitrogen with recirculated flue gas, much less NO_X is produced since there is much less nitrogen is available. Furthermore, some of the NO_X in the recycled flue gas will be reduced by reactions within the flame to molecular nitrogen. This may reduce the requirements for add-on NO_X controls, such as selective catalytic reduction, to satisfy emission standards.

We plan to continue development of the technology toward full-scale system design and demonstration. The following areas require further development work.

Burner Development: A pulverized coal burner capable of introducing coal and oxygen into the boiler while minimizing the likelihood of an in-duct coal fire is critical to the successful implementation of the concept. The mixing of flue gas, coal, and oxygen, especially in the pulverizer and primary air lines, is an important safety-related design uncertainty. Other combustion systems such as cyclone firing may offer additional benefits not only to the fuel handling and combustion system but also by reducing boiler size. Burners can be developed for safe oxygen introduction that would reduce NO_X, carbon monoxide, hydrocarbons and unburned combustibles in the fly ash.

Full-scale Demonstration: A full-scale demonstration will be a critical event in establishment of commercial viability. It will provide the information and experience needed to allow plant suppliers to properly design and plant users to gain confidence in the technology's costs and ability to achieve the desired performance and reliability. In addition to the "normal" operating scenario, a full-scale demonstration would address such transient events as system start-up/shut-down and unplanned upsets. To minimize the full-scale demonstration costs and risks, the first application would likely involve conversion of an existing coal-fired plant to oxy-fuel firing, utilizing the existing equipment to the greatest extent possible. Since only a few new components would need to be purchased and installed, the most significant being the oxygen supply system, the project cost would be minimized. Risks also would be significantly reduced because most of the plant equipment would have already been operated; and, although some modification would be needed, the controls would be in place and proven.

New Boiler Applications: One advantage of the oxy-fuel technology is that it can be retrofitted to the existing units allowing application to the coal-fired fleet. We anticipate that, based on the experience of the first (probably retrofit) application, opportunities will be identified for significant improvements toward optimization of subsequent retrofits and new plant applications.

Oxygen Production: The cost of oxygen is a major economic hurdle for both oxy-fuel combustion and gasification technologies. Efforts are needed to minimize the cost of oxygen to improve economic viability for these oxygen-based technologies.

Integration with Carbon Sequestration Process: As carbon sequestration approaches are identified, it will be necessary to evaluate the suitability of the oxygen-fired boiler flue gas. Even with good control over boiler air infiltration, and high efficiency SO_X and NO_X removal systems, the flue gas will still contain some N_2, SO_X, NO, NH_3, etc. The impact of these contaminants will need to be evaluated before an integrated process can be defined.

Schedule and Cost

Costs for remaining research and development activities are anticipated to be about $1 million. The full-scale demonstration cost will be highly affected by site and program specific factors. As a premature and preliminary estimate, the demonstration might cost about $15 million.

Mr. BARTON. Thank you, Mr. McDonald.

We now want to hear from Mr. David Hawkins, who is the Director of the Climate Center for the Natural Resources Defense Council headquartered here in Washington and a frequent testifier. Welcome to the subcommittee. Your testimony is in the record. We ask that you summarize it in 5 minutes.

STATEMENT OF DAVID G. HAWKINS

Mr. HAWKINS. Thank you, Mr. Chairman.

You should have in front of you some slides to illustrate the points I would like to make. There are two messages I would like to convey to the subcommittee today. The first is that we need to accelerate carbon capture and storage technical systems if we are going to harmonize the use of coal with protecting the climate. The second is that the current policy mix is not going to get the job done on time.

The first point is that U.S. coal plants are aging. The graphic shows that in 2015, which is just 3 years after the President's intensity checkpoint, over nearly a third of U.S. coal capacity will be over 50 years old. And 10 years later, two-thirds of U.S. coal capacity will be over 50 years old. The question is, when those units start to retire, what products are going to be available to replace that power? If we don't have coal technology that can capture carbon, then the market is going to choose something else or we will make a commitment to a high-carbon future that is equally problematic.

On the second slide, this shows the global context, which is in the next 30 years, there are going to be 1,400 gigawatts of coal capacity. That is nearly five times the current U.S. coal capacity that is going to be built. That is a challenge and an opportunity. It is a challenge because if we build all of that in a way that can't capture its carbon, we are going to have a legacy that will be a huge problem for the Twenty-First Century. If we design it so that it does capture carbon, we are going to be on our way to being able to solve this problem.

And the U.S. plays a key role. We have the resources. We have the technology. We have the capability of proving our technology that can become a global market.

The subsequent slide simply shows that each decade, large new amounts of capacity are being built. The first decade, the one we are in, we probably aren't going to be able to affect the design, but we have got 500 gigawatts coming at us in the next decade and 700 gigawatts coming at us in the decade after that. If we get going, we can have a product that will let that new coal capacity be designed in a way that can protect the climate.

The next couple of slides illustrate the challenge in a U.S. context. This is drawn from a national energy technology laboratory, DOE carbon sequestration road map. I would like to make just two points about it.

First is that the road map contemplates significant amounts of actual capture of carbon commencing around 2020. That is 2 years after the President's Clear Skies Act second stage compliance date. Yet, there is no mention of carbon in that act, as you know. There seems to be a policy disconnect there. If we want the industry to be capturing carbon in 2020, shouldn't we be telling them about that now in order to create the market signal?

The second point about this example is simply that there is a large amount of capacity that will need to be deployed. And it still under this scenario puts the United States in a position where we will be giving up the option to stabilize global warming concentrations at what I regard as a prudent level. That is a major commitment for future generations. And we should be looking very hard to figure out ways to preserve options to stabilize at lower levels. We are not going to be able to return to lower levels once we rush by them.

And then, turning to the last slide on this, the point here is that policy matters. This illustrates what has happened to refrigerator energy consumption in the last 50 years. For 25 years, energy consumption of refrigerators went steadily upward year by year as volumes increased. And then in 1975, it reversed course. And even though volumes increased and serviceability increased, energy efficiency went down.

What happened? Policy happened. We adopted reasonable design standards. We adopted financial incentives. American industry responded, and it responded in a terrific way so that today's refrigerator uses about one-third the electricity of one that you could buy 20 years ago. It has more volume, is more consumer-friendly.

We can do the same thing with electricity services. We need to do two things. One is more focus on the existing financial incentives, both the RD&D and the tax incentives. And, second, put a policy in place that sends a signal to the private sector.

And, in conclusion, I would just like to read from the National Coal Council report of last month. Quoting, "IGCC may only become broadly competitive with PC and natural gas combined cycle plants under a CO_2-restricted scenario. Therefore, vendors currently do not have an adequate economic incentive to invest R&D dollars in IGCC advancement. Similarly, power companies are not likely to pay the premium to install today's IGCC designs in the absence of a clear regulatory direction on the CO_2 issue." That is the coal industry speaking. We agree with that proposition. And we need policies that will send that signal.

Thank you, Mr. Chairman.

[The prepared statement of David G. Hawkins follows:]

PREPARED STATEMENT OF DAVID G. HAWKINS, DIRECTOR, NRDC CLIMATE CENTER, NATURAL RESOURCES DEFENSE COUNCIL

SUMMARY

Coal's future as an option for the generation of electricity will be determined in large part by how societies respond to the problem of global warming, caused predominantly by emissions of carbon dioxide from the combustion of fossil fuels like coal.

A perception that coal use and climate protection are irreconcilable activities has contributed to a policy impasse on confronting the issue of global warming. This impasse will protect neither the coal industry nor the planet. While energy efficiency and greater use of renewable resources should remain core components of a comprehensive strategy to address global warming, development and use of technologies that capture carbon dioxide and store it permanently in geologic repositories could enhance our ability avoid a dangerous build-up of this heat-trapping gas in the atmosphere.

However, because of the long lifetime of carbon dioxide in the atmosphere and the slow turnover of large energy systems we must act without delay. Current government policies are inadequate to deliver economically attractive carbon capture and storage systems in the timeframe we need them. To accelerate the development of these systems and to create the market conditions for their use, we need to focus government funding more sharply on the most promising technologies. More importantly, we need to adopt reasonable binding measures to limit global warming emissions so that the private sector has a business rationale for prioritizing investment in this area.

Further delay in adopting serious efforts to reduce global warming emissions is a decision to commit the next generation to a large and effectively irreversible build-up of heat-trapping gases in the atmosphere. Given what we already know such a decision would not be responsible.

INTRODUCTION

Mr. Chairman and members of the Subcommittee, thank you for inviting me here today to testify on behalf of NRDC, the Natural Resources Defense Council, on the subject of "Future Options for Generation of Electricity from Coal."

Coal is an abundant fuel both in the U.S. and in a number of other countries. We have used coal to our economic advantage in the U.S., fueling our industrial growth from the first years after the War of Independence and in the past century helping to bring electricity to nearly every home and hamlet in our country. There is no denying that our use of the coal that eons of biological and geological processes bequeathed us has brought great benefits.

There is also no denying that our use of coal has caused great harm to the health of workers, the general public and the environment. As a society we have decided to tackle many of the health and environmental problems caused by coal's use and we are doing a good job addressing a number of these problems. Indeed, the U.S. leads the world in addressing many of the problems caused by coal's use. But there is one problem from coal that we as a society have not yet decided to take on in a serious manner.

I refer of course to the problem of carbon dioxide emissions resulting from coal as it is used today. As you know, carbon dioxide or CO_2 is the principal global warming gas. Because CO_2 has a long lifetime in the atmosphere, dramatically increased use of coal and other fossil fuels since the industrial revolution has caused a buildup in concentrations of this heat-trapping gas in the thin layer of life-giving atmosphere that surrounds our planet.

Our current policy regarding global warming is dysfunctional: it will not protect the use of coal and it will not protect the planet from global warming. The coal industry must acknowledge, like it or not, that the problem of global warming cannot be denied or wished away. Environmental advocates must acknowledge, like it or not, that the use of coal cannot be wished away. Denial of these facts is not a strategy for success for either group's priorities or for society's interests.

Today I would like to describe why we must not delay in acting to address the problem of global warming. If we wait longer we will eliminate the option for our children to avoid risky levels of global warming gases in the atmosphere—levels that will persist for a century or more after we have decided to do something to lower them. If we act now to chart a reasonable program of clear binding limits on global warming emissions, combined with financial incentives for advanced technologies for energy sources, including coal, we can avert the worst of global warming and provide a more plausible basis for the continued use of coal as a major energy resource.

THE PROBLEM

Despite the chaff that is thrown up when global warming is discussed as a political matter, the basic science is well understood. President Bush' Science Advisor, Dr. John Marburger provides an accurate, though not comprehensive summary of our knowledge:

> "Concentrations of greenhouse gases, especially carbon dioxide, have increased substantially since the beginning of the industrial revolution. Careful studies show that around 1750 the concentration of carbon dioxide in the atmosphere was 280 parts per million (ppm) and the concentration today is 370 ppm. The National Academy of Sciences indicates, in a report prepared at the request of the White House, that the increase of carbon dioxide is due in large part to human activity, although we cannot rule out that some significant part of these changes is also a reflection of natural variability. And the carbon dioxide increases are expected to result in additional warming of the Earth's surface." [1]

Dr. Marburger describes what we know about what we have done to the atmosphere already. More problematic is what lies ahead. Growth in global population and affluence means large and continuing increases in CO_2 from energy use unless we succeed in deploying energy resources that do not emit CO_2. Figure 1, taken from current forecasts from the U.S. Energy Information Administration and the International Energy Agency, shows that U.S. CO_2 emissions from energy will grow by 40 per cent in the next 25 years and global emissions will grow by nearly 70 per cent in the next 30 years.

Absent very large changes in world energy systems, we are on our way to doubling CO_2 concentrations from pre-industrial levels before a child born today or a coal power plant built today, retires. A child's retirement may seem like a long way off but given the inertia in energy systems and persistence of global warming emissions in the atmosphere, it is not. If we are to have clean energy resources in place at the required scale and when we need them, we must set the economic and policy forces in motion now.

Managing global warming emissions is a problem of logistics. We understand from the history of armed conflict that large amounts of personnel and materiel cannot be assembled and deployed overnight: months, sometimes years of mobilized effort are required to place these resources where we want them when we want them. Supplying clean energy resources for a growing world is even more challenging.

Figure 2 shows the required "build-rates" of clean energy resources, starting today if we are to keep global temperatures from increasing by more than 2 degrees Centigrade due to manmade emissions of global warming gases.

The results, published recently in the magazine *Science,* are sobering: globally we should be building between 400 and 1300 megawatts of zero-carbon-emitting capacity per day between now and 2050 to meet the world's energy needs in that year and avoid a commitment to warming unprecedented in the history of modern human

[1] "The President's Carbon Intensity Reduction Initiative," keynote address by Dr. John Marburger Director, Office of Science and Technology Policy, Executive Office of the President at USDOE Conference on Carbon Sequestration, Alexandria, Va., May 6, 2003

civilizations.[2] Yet the forecasted "clean energy—build rate for the next 30 years is a fraction of that need: only 80 megawatts per day.

I hope this fact demonstrates the basic policy irrelevance of the argument over how rapidly the climate will warm due to manmade emissions. The Science study shows that even if the climate only warms at the slowest warming rate in the literature, we are not building anywhere near enough low-carbon energy resources to avert a change in the earth's climate that is potentially calamitous.

THE OPPORTUNITY

Secretary of Energy Abraham has said the following about our options to address this problem:

> "Until a few years ago, there were basically only two ways to address the challenge of global climate change. One was to produce and use energy more efficiently. The second was to rely increasingly on low-carbon and carbon-free fuels.
>
> We have made great strides in energy efficiency. We have made substantial progress in bringing down the costs of renewable energy, and we are working to reestablish the nuclear power option. But when you look at most credible projections for escalating energy use around the globe in the next century—and you predict the rising levels of carbon emissions likely to result—you come to an inevitable conclusion: energy efficiency and alternative energy, alone, may not be enough to stabilize global concentrations of carbon dioxide. Not unless you assume that all nations of the world—developed and developing—undertake a massive overhaul of their energy infrastructures in a relatively near—and relatively quick—time frame.
>
> I'm not here to offer a detailed assessment of the practicability of those assumptions, but I'm inclined to think the odds are strongly against them."[3]

There is much in Secretary Abraham's statement I would agree with: energy efficiency and renewable energy resources are the core components of a successful strategy to keep global warming emissions from spiraling out of control. We need to do much more to meet our growing energy requirements by increasing our use of these resources. But a clear-eyed look at the deployment rates for renewable and efficiency resources to date raises a serious question whether we will in fact use them at the scale and in the time frame required to keep global warming emissions from becoming a runaway problem.

That concern alone causes me to believe it would be wise to rapidly determine how much we can rely on capture and geologic[4] storage of CO_2 from fossil energy resources like coal as a third tool to cut global warming emissions—a third horse in a troika if you will. There would be technical and policy benefits from proving out the approach of CO_2 capture and storage (CCS). Supplementing efficiency and renewable energy with CCS to meet growth in energy needs has the potential for avoiding the otherwise enormous forecasted increases in global CO_2 emissions. CCS also has the potential for decoupling the politics of coal from the politics of global warming. It is understandably difficult for the producers, shippers and users of coal to acknowledge the reality of global warming if they believe that doing so is a death sentence for their current line of business. And leaders of nations like the U.S., China, India, Russia, Australia, to mention just a few, that have large coal reserves, have resisted effective measures to curb global warming, in part due to concerns about the economic and energy implications of limiting the use of their coal resources.

If we want to make CCS available as an option we need policy action to make it happen. While the components of CCS all have been demonstrated technically in first or second generation form and are in limited commercial use, mostly outside the electricity sector, the private sector today does not have an adequate economic rationale for making the investments to optimize capture technologies, to prove out the viability of geologic storage, or to incur the costs of storing CO_2 once captured. I believe a combination of publicly-funded financial incentives and a schedule of market-based limits on CO_2 emissions is the policy package needed to achieve these

[2] K. Caldeira et al., "Climate Sensitivity Uncertainty and the Need for Energy Without CO_2 Emission," *Science* **299,** 2052 (2003). To put a 2 degree Centigrade warming in context, recall that the global average temperature during the last ice age was only 5 degrees cooler than today.

[3] Remarks of Energy Secretary Spencer Abraham to the National Coal Council on November 21, 2002.

[4] Other concepts, such as biomass storage and ocean disposal, apart from presenting large ecosystem risks, do not prevent fossil carbon from being added to the total carbon in the biosphere thus inevitably increasing atmospheric carbon levels.

objectives. The current policy approach of an expensive but still limited research, development and demonstration program will not give us the results we need in the time we need them.

THE IMPERATIVES OF TIME AND SCALE

For CCS to play a significant role in avoiding carbon emissions in the next few decades we need to do a lot in a short amount of time, compared to the usual pace of energy system development. Growth in global demand for energy, commitments to new coal-fired capacity, and the aging U.S. coal fleet all place a premium on accelerating our efforts to deploy commercially viable energy plants amenable to CO_2 capture and to conduct numerous, rigorously monitored full-scale geologic storage demonstrations.

Consider the issue of new coal plant construction. As figure 3 shows, today's global coal-fired electric generating capacity is about 1000 gigawatts (one gigawatt is 1000 megawatts: the size of one very large power plant). U.S. coal-fired capacity amounts to just over 300 gigawatts of this total. The International Energy Agency (IEA) forecasts that between now and 2030 over 1400 gigawatts of new coal capacity will be constructed.

The IEA forecast is a challenge and an opportunity. If all of this forecasted capacity is built using conventional technology it would commit the planet to total carbon emissions approaching 140 billion metric tonnes over the lifetime of these plants, unless one assumes that they are backfit with carbon capture equipment at some time during their life. To put this number in context, it amounts to half the estimated total cumulative carbon emissions from all fossil fuel use globally over the past 250 years! If we build any significant fraction of this new capacity in a manner that does not enable capture of its CO_2 emissions we will be creating a "carbon shadow" that will darken the lives of those who follow us.

Yet a forecast is not destiny. We can avoid this very large carbon commitment by a combination of efficiency, renewable energy and designs for new fossil plants that are capable of capturing their CO_2. Because these plants are not built yet, we have more options than we do with existing plants. Yet, as with all market opportunities, the market does not wait for the product. If the CCS product is not proven in time, the market will choose something else. As figure 4 shows, the rate of new capacity will grow every decade between now and 2030. We are likely already too late to shape the design of much of the new capacity being built in this decade. But by stepping up our efforts now, we can influence the market choice for the nearly 500 gigawatts of new coal capacity in the next decade and 700 gigawatts of additional capacity in the decade that follows that.

Next consider the issue of aging U.S. coal capacity. It too represents a market challenge and opportunity. As figure 5 shows, by 2015 (just 3 years after the current administration's carbon intensity checkpoint), nearly one-third of the current U.S. coal fleet will be more than 50 years old; about one-tenth will be older than 60 years. In 2025 two-thirds of today's coal capacity will be older than 50 years.

We don't have any experience with running large plants longer than 50 years, so prediction of retirement is difficult. But it is likely that as these plants age an increasing fraction of this capacity will be replaced with something new. Both the coal market and our ability to control global warming depend greatly on the answer. If we do not develop CCS technologies in time to meet this market demand, we will be playing a game of technological chicken that either the coal industry or the planet's climate will lose. On the one hand this capacity could be replaced by renewable energy or natural gas; an outcome that would help protect climate but not one that the coal industry would like. On the other hand the coal industry might succeed in replacing this capacity with new carbon-emitting coal plants. Though I consider it unlikely such plants could receive financing, this outcome would exacerbate global warming.

Finally, consider the scale of deployment of CCS needed to get the U.S. on a path consistent with stabilizing global warming emissions at levels less than double pre-industrial levels. DOE's National Energy Technology Lab (NETL) has published a Sequestration Roadmap that assesses the contribution that CCS could make to an emissions path that gradually slows and then stops growth in U.S. global warming emissions.[5]

NETL's Roadmap scenario assumes a path for U.S. global warming emissions that meets the administration's "carbon intensity improvement" goal between now and 2012, then grows at one-half the EIA reference case forecast until 2020, and then flattens from 2020 to 2050, the end of the NETL scenario period. Figure 6 shows

[5] NETL, *Carbon Sequestration, Tehchnology Roadmap and Program Plan,* March 12, 2003.

U.S. CO_2 emissions under the NETL Roadmap: in 2020 about 200 million metric tonnes of carbon reductions are needed and by 2050, over 1.6 billion metric tonnes of reductions from reference growth projections are needed.

To achieve this level of reductions NETL assumes a combination of enhanced efficiency and renewable energy use, storage of CO_2 in forests and soils, and a significant amount of geologic storage of CO_2 captured from industrial gas streams. As figure 7 shows, under the NETL Roadmap CO_2 reductions from CCS amount to about half of the achieved reductions in 2020 and avoids over 1 billion metric tonnes of CO_2 by 2050 compared to the reference case.

As I will discuss below, to preserve the option of stabilizing global warming emissions at prudent levels, we will need even more than this amount of reductions from U.S. reference case forecasts. Yet, given the policies now in place, it is very questionable that even the reductions assumed in the NETL Roadmap will occur. Capturing and storing the amounts of CO_2 assumed in the NETL Roadmap will require building a significant amount of coal-based generating capacity that is equipped with CCS technology. There are large benefits to be gained by accelerating the use of CCS as is assumed in the Roadmap but to cause that to happen, it will be necessary to adopt new policies to engage the private sector in making the significant investments required.

Figure 8 shows the amount of coal-based generating capacity that would need to be equipped with CCS technology after 2020, assuming those sources provide the bulk of the captured carbon after that date. In 2020 about 20,000 megawatts (about 60 medium-sized generating units) of CCS-equipped coal capacity would be needed: a modest amount compared to what is required in the following decade but large considering that DOE is proposing a $1 billion effort to build one such plant (FutureGen) that would come on line toward the end of this decade. Going from one plant operating around 2008 to perhaps 50 operating in 2020 is likely to happen only if supported with a combination of government financial support and government policies that provide a business incentive, by limiting CO_2 emissions on a reasonable but clear schedule.

Even more striking in figure 8 is the amount of coal-based capacity that would need to use CCS in the years following 2020: 200 gigawatts by 2030 (two-thirds of today's coal plant total) and over 300 gigawatts by 2040.

If we are to create this future we need to send the policy signals now. I submit there is a policy disconnect between the DOE program for CCS and the administration's proposal for addressing air pollution from existing power plants.[6] As you know, the administration's Clear Skies Act contemplates compliance schedules extending to 2018 for these plants. Yet the administration is seeking funding for a DOE program plan that contemplates significant activity to capture CO_2 from this sector in the same time frame. If we want coal-based plants to be using CCS systems by phase 2 of the Clear Skies Act would it not make sense to incorporate carbon management policies into that Act?

Finally, let me observe that the deployment schedule for CCS systems would need to be more rapid than assumed under the NETL Roadmap if planners are to count on it to replace aging U.S. coal capacity. As shown in figure 5, nearly 90 gigawatts of coal capacity will be more than 50 years old in 2015, an amount much greater than the assumed 20 gigawatts of CCS penetration by 2020 in the NETL Roadmap.

COMMENTS ON CURRENT POLICY

Current policy to promote development and deployment of CCS systems consists of federal RD&D funding and proposed federal tax credits. I would like to make two points about these provisions. First, the existing and proposed RD&D and tax provisions need more focus on the most promising technologies to enable CCS in the near term. Second, and most important, these publicly-funded financial incentives need to be accompanied by policy measures that will give CO_2 a value in the marketplace in order to assure a timely return on the public's investment and to create incentives for the required private sector investments.

Research, Development and Demonstration

The House Energy bill, H.R. 6, contains proposals for significant expansion of funding for fossil energy RD&D, including a $2 billion 10-year authorization earmarked for the "Clean Coal Power Initiative." A major issue in the CCPI is the degree to which Congress should ensure this sizable funding program is focused on systems that are capable of capturing CO_2. Given the dominant role that coal use

[6] I will mention the Clear Skies Act only in passing in this testimony, with the hope that NRDC will be afforded an opportunity to present our substantial concerns with this legislation in greater detail at a future hearing.

plays in producing global warming emissions and the potential benefits of perfecting methods to capture carbon from coal-based technologies, I would argue that the top priority for federal coal RD&D should be early deployment of carbon capture systems at full commercial scale. But the current provisions are not structured to achieve this objective.

There is a substantial difference in the readiness of different coal conversion systems to employ carbon capture technology. As noted by the National Research Council, gasification technologies produce a stream of comparatively concentrated CO_2 that is amenable to capture at costs and energy penalties that are substantially less than currently known methods applicable to conventional coal combustion technology.

In recognition of this fact, last year's House CCPI provisions required that 80 per cent of the authorized funding be used for demonstration of gasification-based systems. In contrast, this year's bill provides that at least 60 per cent of the funds be used for gasification approaches. While we should not rule out attention to carbon capture from combustion-based coal systems, it appears they are much farther from commercial deployment than are gasification-based approaches. Accordingly, NRDC urges that more of the $2 billion CCPI authorization be dedicated to gasification systems.

The tax credit provisions in pending House legislation, such as H.R. 1213, are even more problematic. Very substantial investment and production tax credits are authorized for coal-based generation plants. Yet, the eligibility conditions for these tax credits are structured so that substantial amounts of the available funds are directed toward existing coal plants that make only modest improvements in efficiency and control of conventional pollutants. The problem is that such investments will not advance the technology needed to harmonize coal use with global warming concerns. These funds can only be spent once. Allocating funds to patch up existing units rather than buying down the costs of carbon capture technologies is akin to buying aspirin to treat cancer.

Part of the rationale for these tax credit provisions is to keep older, smaller coal plants running to avoid losses in coal production currently going to such plants. Yet, if the public policy purpose is to maintain this production, why not develop a proposal that would repower such older capacity with systems that demonstrate and buy down the costs of carbon capture technology? Such an approach would assure that limited funds are not diverted from the country's top priority needs to provide a short-term palliative.

Policies to engage the private sector

The central flaw in the current policy suite to promote use of low-carbon energy resources, including coal with carbon capture and storage, is the absence of any market-based policy driver

to rationalize private sector investments at the scale required to produce timely solutions to the problem of global warming. As long as government policy is confined to public subsidies and exhortations for voluntary efforts, there is little to no business case to be made for private sector investments at the requisite scale.

Academic economists have recognized that voluntary approaches are inherently less effective in driving improvements, affecting the behavior of only one segment of industry and weakly at that.[7]

Moreover, the National Coal Council, in its May 2003 report to the Secretary of Energy on *Coal-Related Greenhouse Gas Management Issues* acknowledges the lack of private sector incentives under the current policy structure:

> "IGCC may only become broadly competitive with PC and NGCC plants under a CO_2-restricted scenario. Therefore, vendors currently do not have an adequate economic incentive to invest R&D dollars in IGCC advancement. Similarly, power companies are not likely to pay the premium to install today's IGCC designs in the absence of clear regulatory direction on the CO_2 issue."[8]

It is obvious that some mandatory global warming emissions control programs can have adverse impacts on the coal industry. It is less obvious but equally true that the status quo policy is likely to have adverse impacts on the coal industry by failing to create a business case for the technologies that are required to permit continued coal use in a carbon-constrained world. The policy question I hope this Subcommittee and Congress will address without delay is not whether to adopt a bind-

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[7] *See, eg,* Lyon, *Voluntary versus Mandatory Approaches To Climate Change Mitigation,* Resources for the Future Issue Brief 03-01, February 2003

[8] National Coal Council, *Coal-Related Greenhouse Gas Management Issues* at 65. May 2003. IGCC means integrated gasification combined cycle; PC means pulverized coal; NGCC means natural gas combined cycle.

ing program to limit global warming emissions but what program to develop. Further delay will not protect the coal industry and certainly will not protect the planet from global warming.

CONCLUSION

In conclusion let me return to the NETL Roadmap to make a final point about the cost of delay. While the Roadmap is ambitious in the current policy context, it is much less ambitious than required to preserve options to stabilize global warming concentrations at prudent levels. As shown by figure 9, we will need to do more than stop U.S. emissions growth in 2020 if we are to retain our ability to stabilize concentrations at levels less than double pre-industrial concentrations.[9] Unfortunately, if we cannot do better than the NETL Roadmap we will forfeit the ability to stabilize concentrations at 450 and make it close to infeasible to meet a 550 ppm (double pre-industrial concentrations) level.

Current debate on global warming assumes that we have ample time to wait for more evidence about the speed of future warming and then decide whether and how much to limit emissions. I hope the NETL Roadmap persuades you of the error in this assumption.

We do not have more time to decide the path we will take. If you wait, you are making a decision: you are deciding today to commit the next generation of Americans to a doubling or more of global warming concentrations, with whatever consequences that entails. By not acting you will commit us to that path today. I ask you to ask yourselves, are you confident today that such a future will be benign? If you are not, then the prudent policy is to take reasonable steps that can preserve our ability to follow a safer path.

Thank you for the opportunity to testify. I am pleased to answer any questions you may have.

Mr. BARTON. Thank you, Mr. Hawkins. And thank you for making do. We understand that if we had been in the big room, you had a PowerPoint that was going to be up where people could see and having to give a testimony without that technology is a credit to you. We do appreciate. I did follow along in your written testimony.

We now want to hear from Dr. Roe-Han Yoon from Virginia Tech, who has testified for us before. Your testimony is in the record in its entirety. And we ask that you summarize it in 5 minutes.

STATEMENT OF ROE-HAN YOON

Mr. YOON. Thank you, Mr. Chairman and members of the committee.

It is a great honor for me to be here today. I would like to use the opportunity to address the technological need of the U.S. coal industry, which has been supplying the most reliable fuel for power generation.

According to the 2003 annual energy outlook, fuel costs accounted for 76 percent of the operating expenses at coal-fired power plants in the year 2000. Therefore, utilities strive for reducing fuel costs.

The U.S. mining industry did an excellent job in meeting the demands of their customers; that is, providing low-cost solid fuels for power generation. In 1979, the price of coal was $52 per ton in 1996 dollars. In year 2000, it was reduced to $22 per ton. The 58 percent reduction in price was made possible because of the nearly 400 percent increase in productivity.

[9] Figure 9 compares the BAU or reference case emissions to 2050 with the NETL Roadmap and, in the three lower curves the U.S. emissions consistent with stabilizing concentrations at 650, 550, and 450 ppm respectively.

This remarkable achievement was realized through technology innovation. It appears, however, to be approaching a limit. In central Appalachia, the large reserve blocks amenable for large-scale operations are becoming increasingly difficult to find.

In 1997, the EIA estimates coal reserves in central Appalachia to be approximately 17.6 billion tons. In 2003, John T. Boyd Company of Pittsburgh estimated it to be 7.1 billion tons, but the coal companies operating in the region reported only 5.2 billion tons of reserves.

These reserve estimates include the coal that could be mined in the foreseeable future, perhaps at higher prices. At today's prices, however, only limited portions of the reserves are recoverable according to a study conducted by the John T. Boyd Company. The reasons given by the company included: one, less favorable geological conditions, such as seam thinning, which caused operating costs to rise; and, second, difficulty to offset the rising cost through technology innovation.

Coal companies are also losing a significant amount of coal during coal-cleaning operations due to the lack of advanced separation technologies. Of course, loss of coal contributes to increased cost.

A recent report from the National Research Council suggested that approximately 70-90 million tons of ultra fine coal is being discarded annually to 716 impoundments. Since coal is cleaned in water, the ultra fine coal is being discarded along with processed water, posing the possibility of spillage.

In year 2000, a 72-acre coal waste impoundment in Kentucky accidentally released 250 million gallons of coal sludge to the environment. To help the U.S. mining industry, we have recently formed a Center for Advanced Separation Technologies. It is a seven-university consortium with expertise in coal cleaning, minerals processing, and environmental control.

I would like to conclude my testimony by showing what university research can do. We developed under the sponsorship of DOE a technology known as Microcel, which was designed to process fine coal. A coal company in southwest Virginia has been using this technology to recover the ultra fine coal that had been discarded over the years.

Exhibit 1 in my written testimony shows the pond full of fine coal sludge. Exhibit 2 shows the same pond after 10 years of operation. The pond is now almost empty.

More recently, we have developed a novel dewatering technology, which has been tested on a coal sample from a very large impoundment in southern West Virginia. As a result of the successful pilot plant test work conducted as part of an ongoing DOE-sponsored project, Beard Technology Company in Pittsburgh is planning to build a 200-ton-per-hour recovery plant. We are hoping that this plant will be a showcase for using advanced technologies to transform an environmental liability into a valuable resource.

Mr. Chairman and members of the committee, I hope that I have conveyed a message to you that the U.S. coal industry needs advanced technologies, ocean mining, and separation.

Thank you again for the opportunity to be part of this distinguished panel.

[The prepared statement of Roe-Han Yoon follows:]

PREPARED STATEMENT OF ROE-HOAN YOON, DIRECTOR, CENTER FOR ADVANCED SEPARATION TECHNOLOGIES, VIRGINIA POLYTECHNIC INSTITUTE AND STATE UNIVERSITY

SUMMARY

Many power companies opted to meet the requirements of the 1990 Clean Air Act Amendment by switching to low-sulfur coals, and Central Appalachia has been the major source of compliance coals. Recently, the coal companies operating in this region have been experiencing difficulties due to high operating costs and low prices of coal. The price of coal had been declining between 1980 and 2000. During the same period, the productivity of underground coal mining operations increased 3.6 times. Thus, the industry combated the difficult market condition by increasing productivity. However, further increases in productivity are becoming difficult due to adverse geological conditions, stringent environmental regulations, and shortages of trained workforce. It is, therefore, necessary to develop advanced technologies for increasing mining productivity and improving the efficiency of separating coal from waste materials. The coal industry has been producing large amounts of waste at mine sites, creating public concerns and contributing to increased production costs. These problems can be minimized by developing advanced mining and processing technologies. In this testimony, examples are given to show that advanced technologies developed through research can be used to transform environmental liabilities, such as fine coal impoundment, to a valuable resource. Developing advanced mining and processing technologies will be the key to assuring a steady supply of low-cost fuels in an environmentally acceptable manner for the U.S. power industry.

THE COAL INDUSTRY IN CENTRAL APPALACHIA

The 1990 Clean Air Act Amendment called for the reduction of sulfur dioxide (SO2) emissions in coal-burning power plants. Of the various options the industry had, the following three were considered most viable, namely, i) fuel switching, ii) purchasing emission allowances, and iii) installation of scrubbers. Most of the coal-burning power plants chose the first two, with about 25% choosing scrubbers. There are two major sources of low-sulfur coals in the U.S., i.e., western subbituminous coal and central Appalachian bituminous coal. In 2002, the coal industry produced 550 million tons of western subbituminous coal and 248 million tons of bituminous coal from central Appalachia.

In 1997, the Energy Information Administration (EIA) estimated that central Appalachia has approximately 17.6 billion tons of recoverable coal reserves, which is defined as the coal that can be recovered "economically with the application of extraction technology available currently or in the foreseeable future." According to this definition, the EIA estimate includes coal that can be minable in the future using more advanced technologies. On the other hand, the John T. Boyd Company has recently estimated the recoverable reserves in Central Appalachia to be about 7.1 billion tons (Bate, 2003), while the major coal companies operating in the region reported 5.2 billion tons of reserves. Noting that much of the reported coal reserves included the coal seams that are more difficult to mine, the John T. Boyd Company "guesstimated" that only 10-15% of the estimated 7.1 billion tons may actually be economically recoverable at today's coal prices.

If the price of coal increases in the future, however, the economically recoverable reserve base in central Appalachia should increase. On the other hand, coal prices have actually been declining in real dollars between 1980 and 2000. The U.S. coal companies combated this problem by increasing productivity. During the same 20-year period, underground coal mining productivity increased 3.5 times from 1.2 to 4.2 tons per man hour. This remarkable achievement was made possible through technology development, particularly the longwall mining method. This technology was introduced to the U.S. coal industry in 1960s. In 1987, the mining industry made a complete transition from using medium voltage (1000 V) to high voltage (2400-4160 V) equipment, which allowed for the development of much larger equipment. This and other innovations such as self-advancing roof-support systems allowed companies to mine coal seams at wider face widths and deeper web cutting depths, resulting in substantial increase in productivity. However, the large reserve blocks that are conducive to present-day longwall mining technology are becoming depleted, and companies must now mine thinner coal seams. Furthermore, they have to deal with various regulatory hurdles and lack of trained workforce. All of these factors have contributed to increased costs of producing coal from central Appalachia. The combination of high production costs and low coal prices caused financial difficulties for the coal companies operating in central Appalachia, and a large number of them have filed bankruptcy proceedings since 2000.

Most of the coal mined in central Appalachia is cleaned of its impurities such as ash-forming minerals and inorganic sulfur before combustion. Typically, more than 50% of the run-of-mine (ROM) coal is separated from waste at coal cleaning (or preparation) plants. In general, the larger the amount of waste generated, the higher the operating costs, which are eventually passed on to utility companies. According to the 2003 Energy Outlook, fuel costs accounted for 76% of the operating costs for electricity generation in 2000. For this reason, utility companies are striving to reduce their fuel costs. Developing advanced mining and coal cleaning technologies would help coal companies provide low-cost compliance coals to utilities for power generation.

ADVANCED MINING AND PROCESSING TECHNOLOGIES

The U.S. is the largest mining country of the western world. In 2001, the U.S. produced a total of $58 billion of raw materials, which consisted of $39 billion from minerals and $19 billion from coal. The mineral processing industries increased the value of the minerals to $374 billion, while coal was used to produce 52% of the nation's electricity and uranium 20%. The dollar value of the electricity produced from the two mining products was estimated to be $177 billion in 2001. Thus, the U.S. mining industry contributed a total of $551 billion to the nation's economy, which accounted for 5.4% of its GDP. According to the 2002 Mineral Commodity Summary, major industries further increased the value of the processed mineral materials (not including coal and uranium) to $1.72 trillion, which accounted for 17% of the GDP.

Despite the large contributions made by the U.S. mining industry, the research and development expenditure in mining and processing research is miniscule when compared to that being spent for coal utilization. The lack of interest in these areas of research stems from the perception that the technologies used in the mining industry are mature and there is little room for further improvement. This is far from the truth. The longwall mining method, for example, was originally developed in Europe in the 17th century (Lucas and Haycocks, 1973). The technology continually advanced during the last 20 years, and has been the main reason that the U.S. coal industry has been able to increase its productivity. I would hope that development of advanced mining and processing technologies would become an integral part of the FutureGen project so that the coal industry can be a steady and reliable supplier of low-cost fuel for power generation.

It is my understanding that the FutureGen project is to address environmental issues in coal utilization. It is important to recognize that environmental problems also exist at mine sites. On October 11, 2000, near Inez, Kentucky, a 72-acre coal waste impoundment accidentally released 250 million gallons of slurry into nearby underground mines, creeks, rivers, and schoolyards. This incident caused Congress to appropriate $2 million for the National Research Council (NRC) to conduct a paper study to identify causes of the incident and suggest possible ways of preventing future incidents. According to the report published as a result of the NRC study, there are 713 impoundments, mostly in Appalachia, and the coal industry is still discarding 70-90 million tons of fine coal annually. A recent study suggested that the fine coal discarded in the various impoundments in the U.S. may amount to 2.5 billion tons. This is a significant amount in view of the depleting coal reserves in Central Appalachia. It is unfortunate that the U.S. mining industry is forced to discard significant portions of the coal after mining it from deep underground at high costs.

There are two main reasons for discarding fine coal to impoundments. First, the separation of coal from ash-forming minerals is difficult when particle sizes are smaller that approximately 45 microns. Second, the fine coal retains large amounts of water due to the large surface area, which makes it difficult to handle and increases shipping costs. Virginia Tech has been developing technologies that may be used to address these problems. Two years ago, I had the privilege of testifying in front of this Committee. I talked about a coal company in Southwest Virginia that was using an advanced separation technology, known as Microcel, to recover fine coal from an impoundment. The median particle size of the coal recovered was about 20 microns, which was the reason that it had been discarded in the first place. Exhibit 1 shows the impoundment when it was filled with fine coal waste, and Exhibit 2 shows the same pond that is nearly empty as a result of the remining operation. This is an example of turning an environmental liability into "gold" using an advanced separation technology.

The pond recovery project in Southwest Virginia was made possible because the company had an old thermal drier that could be used to dewater the coal cleaned by the advanced solid-solid separation technology. Many other companies do not have the luxury of using thermal driers, which are costly to install and operate. In order to address this problem, we have also been developing advanced dewatering technologies, which include dewatering chemicals and a hyperbaric centrifuge. The former, which is designed to improve the filtration processes that are currently used in industry, is close to commercialization, while the latter is being tested at bench-scale. The dewatering technology has recently been tested on a very fine coal recovered from a large impoundment in southern West Virginia. The coal sample taken from the impoundment was cleaned first to 5% ash using the Microcel technology. The product was then dewatered to 16-18% moisture using the novel dewatering aids. Based on pilot-scale test work conducted by Virginia Tech as part of a project sponsored by the U.S. Department of Energy, Beard Technologies is planning to build a 200-ton per hour recovery plant.

CONCLUSION

There is a need to develop advanced mining and separation technologies that can be used to reduce the cost of producing solid fuels (coal) in an environmentally acceptable manner for the U.S. power industry. They can also be used to cleanup waste coal impoundments, thereby minimizing public concerns for the environmental problems created at mine sites.

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Mr. BARTON. Thank you, Doctor.

Last, but not least, we have Mr. Frank Alix, who is the Chief Executive Officer of Powerspan Corporation in New Durham, New Hampshire. I think you, too, had a PowerPoint presentation. You are going to try to do as good a job as Mr. Hawkins did of elaborating on it without actually having the visuals. Your statement is in the record. You are recognized for 5 minutes.

STATEMENT OF FRANK ALIX

Mr. ALIX. Thank you, Mr. Chairman. That is a tough act to follow.

Powerspan is a clean energy technology company headquartered in New Hampshire. Over the past 5 years, we have been working to develop a technology called electro-catalytic oxidation, which is focused on cost-effectively reducing dioxide, nitrogen oxides, mercury, and fine particulate matter, principally from existing power plants. Several leading power generators are investors in the company or partners in development.

Since we have been pilot testing the technology at a plant owned by FirstEnergy near Shadyside, Ohio, the first slide talks about the results we have achieved, consistently SO_2 reductions on the order of 98 percent or better, NO_X reductions of 90, fine particle reduction $PM_{2.5}$ greater than 95 percent, and mercury removal from an Eastern bituminous coal on the order of 80 to 90 percent. Those are good results.

We are moving now to a commercial demonstration of that technology. The next page will show you what this technology looks like on a conventional power plant. It shows a boiler, an electrostatic precipitator.

A conventional scrubber module, the real magic to our process is what we call the ECO reactor, which is upstream of the scrubber. And it replaces a selective catalytic reduction device and a bag house in carbon for mercury. So it really is one small device that replaces two larger ones in conjunction with the scrubber. That is why our costs are lower and our space constraints needed are much smaller.

The next slide down shows what our co-product is of our process. Obviously the waste from pollution abatement at power plants is a big issue, whether it is ash or scrubber sludge. We produce a fertilizer co-product that avoids the need for disposal of waste.

We actually treat the effluent with activated carbon as well to remove mercury so that the resulting ammonium sulfate nitrate fertilizer is below minimum detectable levels of mercury. This slide shows a pile of actual fertilizer produced from a coal-fired power plant. And I think the purity that is evident by the eye is quite striking.

The next slide shows a picture of the commercial demonstration unit we will be installing also at the Burger Plant. It is a 50-megawatt unit. We have actually broken ground in the last month. We expect to have the construction done by the end of the year.

You can see a little individual standing down there next to the scrubber, near the stack. So you can see in scale, it is quite a large unit. It is about a $20 million project. It is a 50-megawatt electric unit. It is a slip stream from a 156-megawatt boiler.

We want to demonstrate ECO commercial components and reliability over the course of the next year. And we expect operation to begin early in 2004.

The next slide will talk about the benefits of ECO. I have already mentioned the high removal of four major pollutants. But it is also more readily installed on a space constraints site. You could see the photograph of the Burger Plant up against the Ohio River. Typically where pollution control equipment is installed is on the river side of the plant and stack.

You can see there is very little room there, even though it is a small photograph. This is not unusual. A lot of the existing plants, in fact, have great space constraints in terms of installing the pollution control equipment we like on them today.

Also, we think it is going to be adaptable to most different types of plants and coals. As I mentioned earlier, the fertilizer co-product is a big benefit. And reducing all of these emissions in a single installation is also a big benefit.

We have had a cost comparison done by an outside engineering firm. I refer you to the next slide. It shows that capital costs are about two-thirds of conventional equipment or on a 500-megawatt base-loaded plant, we could save on the order of $50 million.

Fixed O&M, variable O&M, when you add those up, again, about a one-third savings and two-thirds the cost. So the money that could be saved on retrofitting existing coal-fired plants with this technology could be significant.

We have a number of strategic partners that are mentioned in the following slide, most of them utilities who own coal-fired generating plants. We have plants in 11 different States and Ontario, Canada. Also, in the last slide, we show some of our commercial partners that are well-known in the power, engineering, and construction field.

So, in summary, I think we have a technology that can have a big impact on the future of coal generation for electricity. And our concern is that there is some regulatory policy over the next several years that develops and gives both the generating plant owners and technology developers, like ourselves, long-term certainty so we can obtain the capital in the time necessary to prove this technology and deploy it.

Thank you, Mr. Chairman.

[The prepared statement of Frank Alix follows:]

PREPARED STATEMENT OF FRANK ALIX, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, POWERSPAN CORP.

Chairman Barton and distinguished members of the House Subcommittee on Energy and Air Quality, thank you for the opportunity to share Powerspan's perspective on future options for generation of electricity from coal.

My name is Frank Alix and I am the Chairman and Chief Executive Officer of Powerspan Corp.

Powerspan is a clean energy technology company headquartered in New Hampshire. Our company was founded in 1994 and has grown to employ 40 scientists, engineers and other high-tech workers. In order to fund technology development, the company has raised over $50 million to date from private, institutional, and corporate investors.

Over the past five years, we have focused our resources on developing and commercializing a patented multi-pollutant control technology for coal-fired electric generating plants called Electro-Catalytic Oxidation, or ECO®. Our ECO technology is designed to cost-effectively reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury (Hg), and fine particles ($PM_{2.5}$) in a single, compact system. Several leading power generators are investors in the company or partners in ECO development. These include FirstEnergy, American Electric Power, Cinergy, AmerenUE, Allegheny Energy Supply, and Ontario Power Generation. In 2001 the National Energy Technology Laboratory of the U.S. Department of Energy awarded Powerspan $2.8 million under a cooperative agreement to demonstrate the mercury removal capabilities of ECO under various conditions.

Over the past 16 months, we have successfully pilot tested our ECO technology in a 2-megawatt slipstream at FirstEnergy's R. E. Burger Plant near Shadyside, Ohio.

During this testing, ECO technology reduced emissions of:

- SO_2 by 98%,
- NO_X by 90% based on typical inlet NO_X conditions,
- Mercury by 80-90%,
- Other heavy metals by more than 96%,
- Total particulate matter by 99.9%, and
- Fine particulate matter less than three microns in diameter by more than 95%.

These pilot test results indicate that ECO is capable of providing Best Available Control Technology—or BACT—removal levels in a single, multi-pollutant control system. Furthermore, ECO produces a commercially valuable fertilizer co-product, avoiding the need for large, new landfill disposal sites to accept flue gas desulfurization waste. Finally, a commercial cost estimate for a 500-megawatt (MW) plant prepared by an outside engineering firm indicates that ECO capital and operating costs will be two-thirds of the combined costs of the separate control systems currently required to achieve comparable reductions in SO_2, NO_X, and Hg emissions. For a 500 MW plant, this equates to a reduction of about $60 million in capital cost and $5 million in annual operating and maintenance costs. I want to emphasize, however, that the technology is still in the development phase. There could be unforeseen hurdles in moving to commercialization. Nevertheless, based on the evidence to date, we are optimistic.

Powerspan has begun installation of a commercial ECO demonstration unit at FirstEnergy's Burger Plant. The demonstration unit will treat a 50-megawatt slipstream of flue gas, and the plant will burn Ohio coal with 2-4% sulfur content. The project is being co-funded by Powerspan, FirstEnergy, and a $4.5 million grant from the Ohio Coal Development Office within the Ohio Department of Development. Successful completion of this demonstration in 2004 will allow Powerspan to offer full-scale commercial ECO systems with standard industry guarantees.

As you consider future options for the generation of electricity from coal, I would like to focus on the importance of new technology in preserving the economic viability of the existing fleet of coal-fired generating plants. Although many had hoped that new natural gas-fired generation could replace older coal-fired plants, thereby boosting the efficiency of our electric generating fleet and significantly reducing air emissions, it is now clear that this strategy poses great risk due to the limited supplies of natural gas. Likewise, while coal-gasification technologies promise to reduce emissions and boost the efficiency of coal-fired generating plants of the future, the existing fleet of coal-fired plants cannot be economically retrofit with gasification technologies. Therefore, a significant portion of the existing fleet of coal-fired plants, that today provides over 50% of our nation's electricity, need to remain economically viable for at least the next 20-30 years.

So when considering the future of electricity generation from coal, it is important to ask what threatens the economic viability of existing coal-fired generating capacity; where is new technology needed; and what can Congress do to help? We believe that environmental regulations, and the uncertainty regarding them, pose the greatest threat to existing coal-fired plants, and may even inhibit development of the technology needed to support them.

There is consensus among coal-fired generating plant owners, employees, investors, regulators and electricity customers that more should be done to reduce emissions. The environmental and public health benefits of further reductions in SO_2, NO_X, and PM emissions are well documented. The power generating industry, and the investment community that supports it, have demonstrated their willingness to invest in new control systems for SO_2, NO_X, and PM where the regulations are clear and the cost and performance of emission control technologies are well known. But while regulating and controlling SO_2, NO_X, and PM emissions has proceeded without threatening the viability of coal-fired electricity generation, pending regulations for Hg emissions could be more troubling.

Today, air pollution equipment providers cannot supply Hg control systems for coal-fired power plants with guaranteed removal rates under all conditions an operating plant might experience. This is where technology development is most urgently needed. Although our industry is optimistic in our ability to provide commercial Hg control systems at some point in the future, more research and testing is required. The point at which Hg control technology would be available to support specific reduction goals for Hg emissions is not yet certain. Still, environmental technology development is driven by environmental regulations, and without some clear indication that Hg reductions will be required, Hg control technology will not be commercialized—leaving us with the classic chicken and egg dilemma.

So what can Congress do to help?

Both the electric generating industry and the environmental technology community need long-term certainty in environmental regulation. For the capital-intensive electric generating industry, long-term regulatory certainty allows financial markets to provide sufficient capital for the orderly improvement of generating assets without threat to the availability of electricity supplies. For the technology community, regulatory certainty provides the incentive and time to deploy resources to develop and commercialize new technology that will meet the regulatory goals in the most cost-effective manner possible. Therefore, regulations that set achievable emission reduction goals for SO_2, NO_X, PM, and Hg over a period of 10-15 years will be most effective at both providing the environmental and public health benefits we all desire, while maintaining the economic viability of the existing coal-fired fleet.

You also asked for my thoughts on the proposed FutureGen program and the Clean Coal Power Initiative. As a clean coal technology developer, we certainly support federal funding of research and development activities to enhance the generation of electricity using coal. However, we believe it is important to examine the extent to which such federal programs support the near term needs of the existing coal-fired generating fleet. FutureGen, as it's name implies, is focused on the next generation of coal-fired plants that may have to operate in a carbon-constrained environment. As such, this program is properly focused on coal-gasification and CO_2 sequestration technologies. However, this provides little or no direct benefit for existing coal-fired plants.

The Clean Coal Power Initiative (CCPI) is more focused on the near term requirements of coal-fired generating plants. However, 75% of the $316 million awarded in the first round of the CCPI program was for projects involving coal-gasification and circulating fluidized bed projects. These technologies represent less than one-half of one percent of our present coal-fired generating capacity, and cannot be economically retrofit to existing coal-fired plants. So even though a great deal of federal funding has been appropriated to accelerate the commercial deployment of technologies for coal-fired generation, it is not clear that the proper balance has been struck between funding the near term needs of the existing fleet and developing the next generation of coal-fired plants.

In summary, I believe that it is possible to produce more electricity from coal and to significantly reduce or even eliminate the environmental and public health impacts of that production. Our ECO technology could make an important contribution to that objective. When evaluating future options for the generation of electricity from coal, it is important to consider the existing fleet of coal-fired generating plants and ensure that clean coal technology programs strike a proper balance between serving the needs of existing plants and providing for the next generation. Likewise, we should not allow our desire to reduce air emissions to permit us to issue regulations that threaten the viability of existing coal-fired plants. These plants are vital to our economic health and well-being. However, air emissions from coal-fired plants can and should be significantly reduced from present levels. Given time and the right regulatory framework, the technology community will find an economical way to achieve the desired environmental benefits. History has demonstrated this time and again. And there are many companies like Powerspan full of talented individuals who are dedicated to this goal.

Thank you.

Mr. BARTON. Thank you, Mr. Alix.

The Chair recognizes himself for the first 5 minutes for questions.

Mr. Black, your company is operating the pilot program in Tampa, the gasification project. I asked the DOE witness for cost comparisons and cost per kilowatt to generate electricity. Could you elaborate on that a little bit?

Mr. BLACK. The cost of the plant itself, the capital cost, was roughly $511 million net of the contribution that we received from the DOE. To put that cost in context a little bit, this was a new site that we had to develop. There were a lot of site development activities, a lot of transmission costs included. There were a lot of things that are not normally considered in this kind of exercise.

Mr. BARTON. Right.

Mr. BLACK. But as I stated in my written testimony, when you just divide the total cost by the megawatts out, it was about $2,000 a kilowatt.

Mr. BARTON. And when we replicate it now that we have kind of worked the bugs out, what would the cost be compared to a conventional coal plant?

Mr. BLACK. We feel that the numbers that Mr. Rudins of the DOE represented of about $1,600 a kilowatt are reasonable.

Mr. BARTON. And how does that compare to a conventional power plant if you wanted to build one of those today?

Mr. BLACK. There are some site-specific considerations, but conventional coal-fired plants are in the order of $1,000 a kilowatt hour.

Mr. BARTON. That's 60 percent more. What about your cost to generate electricity per kilowatt hour, just your variable cost? What kind of a number can you give us on that?

Mr. BLACK. The variable cost, the incremental cost, which is basically just the cost of the fuel necessary to generate a kilowatt hour of electricity, is somewhere between 2 and 2.5 cents.

Mr. BARTON. Okay. Mr. Rush, you represent a company that certainly is one of the biggest users of coal outside of the TVA. How competitive does the gasification of the fluidized bed technology have to get for your company to look at this to actually build a new coal plant? Where does the cost breakout need to come down to?

Mr. RUSH. Very similar to what Mr. Black said, we see cost differences in the 40 to 50 to 60 percent range in capital costs.

Mr. BARTON. How much does that have to narrow before the environmental benefit offsets the——

Mr. RUSH. Generally speaking, we wouldn't agree that there is a significant environmental benefit for gasification of pulverized coal.

Mr. BARTON. Oh, you would not?

Mr. RUSH. We think a new pulverized coal-fired plant can be built for less money than gasification at efficiencies comparable to or even greater than gasification and that emission rate is essentially the same as gasification.

Mr. BARTON. Mr. Alix's technology, would that be used on a pulverized coal plant?

Mr. RUSH. That's primarily what it would be used on.

Mr. BARTON. So you would, say, use his technology on a traditional plant, as opposed to the gasification technology that Mr. Black's company has developed in the pilot program?

Mr. RUSH. I wouldn't say use Mr. Alix's technology. There are many types of technologies to control existing power plants on the back end. The technology that Powerspan is developing is just that, still in development. There are commercial plants that you can buy to give you the same levels of performance that he is talking about.

I just iterate again we are very much proponents of gasification going forward. We are trying very hard to find a way to make——

Mr. BARTON. If it was your nickel, you wouldn't order a gasification plant today. You would order a pulverized coal plant?

Mr. RUSH. Unfortunately, that is the situation we are in.

Mr. BARTON. Mr. Hawkins, I recognize that you don't represent the entire environmental community, but you are the only one brave enough to come forward and say some semi-positive things about coal, which we give you great credit for doing that. I don't want to put words in your mouth, but I am going to kind of do that.

Would it be safe to say that the environmental community generally would oppose any new coal plants being built but they might accept a coal plant that used this gasification technology or something that had the capability to capture and sequester carbon, carbon dioxide?

Mr. HAWKINS. I will speak about NRDC's position, which is that NRDC would oppose a new conventional plant being built if it were not equipped with technologies capable of capturing carbon.

And we would work with project developers. We are not going to impose our will on a particular local community, but we would work with project developers of technologies using coal that are capable of capturing carbon. We think that is the way to harmonize these 2 objectives.

Mr. BARTON. And does your organization have a view on the technology of the pulverized coal plants versus the gasification plants?

Mr. HAWKINS. Well, Mr. Chairman, I am a lawyer, not an engineer. So I can only go by what I read.

Mr. BARTON. Well, I am an engineer, not a lawyer. I can only go by what you tell me since it is your testimony.

Mr. HAWKINS. This is a dangerous situation.

One of the things that most of the reviews have been done indicate that gasification is much closer to being able to capture carbon in an economical fashion than other systems. There are pilot and bench-scale activities for combustion-based systems, but they are I would say at a minimum several years, perhaps a decade behind where we are with respect to gasification.

So if you are talking about building new coal plants in the next decade and you want to preserve your ability to capture carbon, I think that gasification is the technology of choice at the moment. If combustion systems catch up, that will be a development to be applauded.

Mr. BARTON. Okay. Mr. Alix, my time has expired, but I want to give you the last word on this if you care to take it.

Mr. ALIX. I would agree with both testimonies earlier that systems available for pulverized coal today are much more economical. And there are other technologies to rule emissions besides ours. Ours perhaps will be the most cost-effective ones commercially available.

I think as well their removing CO_2 from a highly concentrated stream, as represented by coal gasification, is an easy task. There are technologies, however, that can be deployed, at least in the developmental stage, to remove CO_2 from a PC boiler. And one of the companies we're working with, Fluor Daniel, is looking to test some of that in Canada.

So there are technologies moving along that front. How far they are from commercialization, whether that's 5, 10, 15 years away, I can't comment.

Mr. BARTON. My time has expired. The gentleman from Virginia.

Mr. BOUCHER. Thank you, very much, Mr. Chairman. I want to thank all of the witnesses for taking the time to inform the committee today with your very carefully prepared testimony.

Mr. Rush, let me begin with you and ask if you have had an opportunity to look at the tax credits that are provided in the Senate version of our comprehensive energy bill that are directed toward encouraging electric utilities to acquire and deploy a new generation of clean coal technologies.

The bill contains investment tax credits. It contains production tax credits. These credits are along the lines of the measures that have been recommended in the House by Mr. Whitfield, who until just a moment was here; Mr. Strickland; Mr. Doyle; and myself.

Our goal is to, first of all, encourage the development and the use of the clean coal technologies, but, even more broadly, the goal is to encourage electric utilities to use coal, instead of natural gas in a large number of the new electricity-generating plants that will be built over the next 25 years.

With that background, would you care to comment on how well these tax credits might achieve those goals? Should they be enacted and make their way into the final energy bill?

Mr. RUSH. Well, since I was familiar with the tax credits from 2 or 3 years ago, before they came into their final form, and I have not looked at the current form in any great detail, my general understanding is that the form that they were offered in 2 or 3 years ago was more aggressive in terms of the tax credits than are in either the House or Senate bills.

I think that the more aggressive proposals of 2 or 3 years ago would go a lot further toward incenting new technology than those that are on the table today. But those that are on the table today are better than nothing.

Mr. BOUCHER. Would we achieve the goal of encouraging your company, for example, to use coal, instead of natural gas, in new plants?

Mr. RUSH. I think the fair answer is I have not analyzed the new numbers. I have only observed that the percentages have come down. And it would have been a push at the higher numbers 2 or 3 years ago.

Mr. BOUCHER. Okay. Well, thanks for your honesty. I am hopeful that we will come out with final numbers that will achieve the goal. If you would care to take a look at those tax credits and tell us whether you think they will achieve their goal, at least in terms of the way your company would respond, I think that would be extremely helpful.

Mr. Ferguson, I know that when you built your coal gasifier about 20 years ago and it has been in commercial operation since, it was constructed without government assistance. This was done entirely with private sector dollars.

Your goal in building this gasifier was, in part, I guess, to generate electricity for your internal use and also to derive chemicals from the process that can be utilized in your chemical operations. And it has been a success, as I understand it. Is that correct?

Mr. FERGUSON. That is correct.

Mr. BOUCHER. And it is a commercial success for you today.

I know that you also support a government role in developing clean coal technologies and that you would support a government role in developing coal gasification technologies. Why do we need that government role, given the fact that you have an example of a commercially successful technology that hasn't required government funding?

Mr. FERGUSON. Good question. The primary purpose that we built our gasifiers for was to provide raw materials for making chemicals, primarily chemicals for Eastman Kodak at that time that are used in photographic purposes. That is, frankly, one of the reasons why we had to have all the mercury removal capabilities over those years.

It was very economically attractive for the purposes of generating raw materials compared to other sources of electrical generation. It has just recently emerged with the ever-rising costs of natural gas and the dislocation of costs between natural gas and coal.

I guess maybe the primary reason, though, I think we need the incentives is that it befuddles us that people refer to this as a new technology. It's another day at the office for us. I think for most of the power-generating community, this is a new technology; therefore, it has perceived risk.

We have operating factors that are not demonstrated anywhere else in the industry. And without faith in those kinds of operating factors, there is a perceived risk that has to be overcome before the gentlemen on my left are willing to invest in gasification.

So we believe that it needs a little kick-start through that process to reweight the risk-reward proposition for the early days. At the end of the day, if we can demonstrate the kind of operating factors that we have had in our company, we are quite certain that it will be able to stand on its own and be very successful, as we have been since starting 20 years ago.

Mr. BOUCHER. Well, thank you. And congratulations on the success of a technology that I believe the sole example of a stand-alone commercial gasifier in the U.S. really is your facility in Kingsport, Tennessee. Congratulations on that success.

Dr. Yoon, in the brief amount of time I have remaining, which is none, I would like to just ask one question of you. Please be as brief in your answer as I am in asking the question.

Your technology enables the recovery of fine coal particles that in the absence of your technology would be discarded as waste. Can you talk just a little bit about how that technology contributes to the overall competitive position of coal and why would an electric utility or a coal company have an interest in using the technology that you have developed that achieves that result?

Mr. YOON. Whatever coal you lose after mining will be a big factor in determining the final price of the coal. So recovering fine coal or not losing any coal you have mined, spending your own investment money, is very important in reducing the price of coal for power generation.

Mr. BOUCHER. Thank you very much.

Mr. Chairman, my time has expired. I thank you for your indulgence.

Mr. WHITFIELD. Yes, sir. Thank you.

First of all, I would like to ask unanimous consent to enter into the record the National Coal Council report that I believe Mr. Hawkins referred to. If there is no objection, I would like to enter that into the permanent record.

[The National Coal Council report is available at: http://www.nationalcoalcouncil.org/Documents/May20001report-revised.pdf]

Mr. WHITFIELD. Mr. Olliver, in your testimony, you I believe said that your plant was the cleanest coal-using plant in the world. Is that correct?

Mr. OLLIVER. Yes, it is.

Mr. WHITFIELD. Is there unanimous agreement in that? There is no question about that, I take it? Is that correct?

Mr. OLLIVER. I would hope so. It's a matter of public record by the Department of Energy analyzing the performance of all of the clean coal projects that have been built and operating.

Mr. WHITFIELD. How much did it cost per kilowatt hour to build that plant?

Mr. OLLIVER. Well, as was mentioned by my friend from Tampa Electric, the actual costs, capital costs, of those projects were higher than would be expected. I think roughly between $1,500 and $2,000 a kilowatt installed would be valid for our plant. The current plants that are envisioned for new technology, new operating plants, again it is estimated between $1,200 and $1,400 per kilowatt.

Mr. WHITFIELD. Is your company currently planning to build or operate any new gasification plants?

Mr. OLLIVER. Yes. We have 2 projects that are in project development in the United States. One is the Kentucky pioneer project in Trapp, Kentucky and another project in Lima, Ohio, which will incorporate our E-GAS technology for the gasification of coal.

Mr. WHITFIELD. You said in Trapp, Kentucky?

Mr. OLLIVER. That is correct.

Mr. WHITFIELD. I am delighted to hear that.

Mr. Hawkins, I am not sure you said you were speaking for your organization or not, but you all really do not have any problem with these gasification plants. Do you feel comfortable with those? Is that correct?

Mr. HAWKINS. Well, I am speaking for my organization, Congressman Whitfield. And I would say that we favor clean energy resources. We can do a lot more with renewable energy than we are currently doing. I think we can do a lot more with energy efficiency than what we're currently doing.

With respect to fossil fuel facilities, we recognize that coal is an abundant resource. And if there are going to be additional capital commitments to new coal projects, we think they should be ones that are designed to capture carbon. And gasification appears to be able to do that.

Mr. WHITFIELD. And Mr. Rush had indicated that pulverized coal is something that his company is certainly using. And if you were going to be building in the future, you would feel quite comfortable in continuing to build those plants. Is that correct, Mr. Rush?

Mr. RUSH. Yes, that is correct. I think there is sort of an issue of semantics here. All fossil-fired power technology is capable of CO_2 capture. The issue is not technically, can you do it? The issue is, can you afford to do it?

Mr. WHITFIELD. Right.

Mr. RUSH. With the current technology, if you project CO_2 capture and sequestration onto the technologies we have today, you get about a 40 percent increase. With gasification, you get about a 60 to 80 percent increase with pulverized coal.

But, as David has heard me argue a number of times, the world's scientists have only within the last 5 or so years really turned to CO_2 capture. We're using technology that was developed by the petroleum industry for use on a very high value end product. Electricity is a commodity product. In the next 10 years, I am quite confident, given my 30 years in R&D that the probability of developing cost-effective CO_2 capture technology for atmospheric combustion systems is quite high.

Mr. WHITFIELD. Periodically you will read various scientists, this fellow who wrote the book, skeptical environmentalists, and others. And they talk about CO_2 emissions that are primarily natural occurring versus manmade CO_2 emissions. Some people make the argument that the manmade emissions are simply not that serious of an issue compared to that made by nature.

I was wondering if any of you had any comment on that. Mr. Hawkins?

Mr. HAWKINS. Yes. If you look at the amount of carbon on the planet, before we started burning fossil fuels, there were about 600 billion tons of carbon in the atmosphere. The estimated fossil reserves are 5 trillion tons. If we take those 5 trillion tons out of an isolated fossil reservoir and put them into the atmosphere, there is going to be a change. That is not a trivial contribution. We are talking about a factor of 10 additional carbon.

Not all of it will stay in the atmosphere. Some of it will cycle into the ocean over time. But basically the carbon you put up into the air today, if you put 100 tons in the air today, 40 tons are there 100 years from now. And 15 tons are there 1,000 years from now. So if we don't change the rate of fossil fuel consumption and release of the fossil carbon to the atmosphere, we will have a phenomenal impact. And all analyses indicate that it will be a phenomenally negative impact.

Mr. WHITFIELD. Anyone would like to make a comment to that?

[No response.]

Mr. WHITFIELD. Okay. I am going to ask one other question, then Mr. Strickland. Certainly China and some other what we might call developing countries are using more and more coal. And so many of these international environmental agreements that we have give them a lot more leeway than we do our own companies. From the position of the NRDC, how would you all approach that? What can we do to ensure that some of these countries are using more and more clean coal technology?

Mr. HAWKINS. Thank you for asking that question. I tried to address it briefly in my testimony. Basically we need a strategy to engage with the developing countries, as my testimony points out. Huge amounts of new coal capacity will be going into China and India.

The Department of State and the Department of Energy today are hosting a conference across the river—I spoke at it yesterday—getting together the major coal-consuming and using countries of the earth.

I think what we need as a strategy is something that says there is technology that allows you to use your resource and allows you to protect the climate as well. Carbon capture and storage is such a technology. I think that if we take the leadership, we can essentially make a strategic investment.

We can show that developing countries do not have to choose between taking a path that will be dangerous to the planet's climate or a path that is conducive to their economic development. And this kind of technology is a strategic opportunity.

It also has the advantage of putting us in a position to capture the global marketplace because a carbon-constrained world is coming. If we get out there with the technologies, we will have a market. And we should take advantage of that apart from the advantage of engaging these developing countries.

Mr. WHITFIELD. Do any of the other panel members have any comments on that relating to the transferability of this technology and so forth? Mr. Ferguson?

Mr. FERGUSON. Because of our long history in gasification and the interest of the Chinese in using gasification as a source of raw material to make chemicals, particularly fertilizers, we have been approached often by the Chinese in their interest in the concept of polygeneration, plants that would manufacture fuel, manufacture town gas to substitute for natural gas, which they could distribute in pipelines, material that would make fertilizer for their chemical purposes.

I am in agreement with Mr. Hawkins on his point that this will be a big deal in the Asian economy, especially the Chinese economy. And someone will fill that void for them. We have been approached very, very often about our ability to help them on those projects.

Mr. WHITFIELD. Anyone else?

[No response.]

Mr. WHITFIELD. Okay. Mr. Strickland?

Mr. STRICKLAND. Thank you, Mr. Chairman.

Mr. Alix, I represent Shadyside, Ohio, and I drive by the plant frequently. I did over the last weekend. The question I have is, when do you expect this electro-catalytic oxidation technology to be commercially available? Do you have an estimate?

Mr. ALIX. Well, our first commercial unit will begin operating first quarter 2004. That is always a bit of a risky endeavor. We, of course, as technology developers, tend to be quite optimistic and expect that it will come up and run well and people will line up to order that within a few months.

What typically happens is it comes up and you identify areas where you can improve the performance and reliability, may go through a few months of changes, and then you begin the long cycles of running, where one developer who has got a particularly acute problem may say 6 to 12 months after seeing this run reliably and produce results, "I would be willing to give you an order." Now, that order might take 2 to 3 years to generate a commercial unit. So commercially available, probably 2007 is the right timeframe when you could actually see it operating on a commercial plant.

Mr. STRICKLAND. Do you expect this technology to work equally well with older plants that may be retrofitted with the technology as well as a new plant that is built with it? Do you have any reason to believe that there is likely to be less of a positive benefit using an older plant?

Mr. ALIX. No. We see the technology really has been operating. As you know, Shadyside, the Burger Plant is a mid-1950's vintage. Certainly we have targeted the older plants that need retrofit, but I think it could work equally well on either.

Mr. STRICKLAND. I have a question that is sort of a general question for the panel. We are aware that the EPA is moving to propose new standards for mercury emissions this December, to promulgate those rules by December of 2004, with compliance for existing facilities to take place in December of 2007.

I raise this issue because coal-fired electric power plants, according to EPA data, account for approximately one-third of the total U.S. mercury emissions.

So I really have three questions. What technologies are available to the industry today to begin to prepare for the mercury MAACT rule? In your opinion, will industry invest in these technologies at projected costs or will coal plants likely shut down under a mercury MAACT rule absent a clean air bill this Congress or next? And, third, if plants may cease to operate under new mercury regulations, what should Congress do to ensure that we do not lose an affordable source of electricity? Would any one or more of you like to respond to that?

Mr. HAWKINS. I would like to, Congressman Strickland. The requirement of the Clean Air Act is a technology-based requirement.

So EPA is not in a position to adopt rules that are technically or economically unfeasible. That means that the prospect of power plants, coal-fired power plants, shutting down because of the mercury rule is quite slim, if not nonexistent.

Congressman Waxman read from a recent report published in the coal industry trade association magazine indicating that technologies have, in fact, been demonstrated that can achieve on the order of 90 percent mercury control from different types of coal, Eastern and Western, and do so with minimal capital costs and minimal operating costs.

The response to that from some of the industry witnesses was, well, that hasn't been done on a widespread basis. Well, that's not a surprise. It hasn't been required. And companies are not in the business of volunteering to control pollutants that they haven't been asked to control. That's just an unfortunate fact of life.

With these standards adopted, I think we will see the deployment of that technology. And that will provide a tremendous benefit because we are talking about something that is a brain toxin that accumulates in the environment. And the faster we get about cutting back on major controllable sources in this country, the greater improvement we will see. We will also see that technology deployed worldwide, which will also be an enormous benefit because some of the mercury that falls in the United States comes from coal plants in other countries.

If we do it, we will get the rest of the world to do it, just as we did when we took lead out of gasoline. We did it, and the rest of the world followed. We've got a great opportunity here.

Mr. STRICKLAND. If I could just say a word before I ask if anyone would like to respond? You seem very sure that if we do it, the rest of the world will follow. I would be interested in knowing how you can be so sure that will happen.

You act as if you would like to respond. So I will give you a chance to respond, sir.

Mr. HAWKINS. Thank you. I would point to two examples. We cleaned up automobiles in this country, and the rest of the world has followed. We took lead out of gasoline in this country, and the rest of the world is following.

When we show that the technology is there, people around the world have an aspiration for a healthier environment. The only reason they're not pursuing it is because the technologies don't seem to be available.

We can lead in this respect. We have done it in the past, and we have got real-world examples where the world has followed.

Mr. STRICKLAND. I don't want to be argumentative because you very well may be right. You know more about I guess the history of this than I do. But you just said that in this country, industry is not going to do it unless they are forced to. And it seems that you've said that other countries will do it simply because it is the right thing to do. And that seems like it's a contradictory judgment to me.

Mr. HAWKINS. The other countries adopt policies when those policies appear to be economically and technically feasible. What we have done in this country using the resources we have and the ingenuity we have is to show the rest of the world those policies are economically and technically feasible. And then they adopt those policies. And then the industries comply with those policies.

Mr. STRICKLAND. Mr. Chairman, could I ask for an additional minute to give anyone else on the panel to respond if they would like to because I think I saw indications that some would like to respond?

Mr. RUSH. Yes. It's unfortunate there have been a number of questions about mercury here today. Southern Company's expert on mercury testified before a congressional committee within the last 2 or 3 weeks, Dr. Larry Monroe. Would it be appropriate to enter his testimony in the directorate of this committee?

Mr. WHITFIELD. Without objection, yes, sir.

[The prepared statement of Larry S. Monroe follows:]

PREPARED STATEMENT OF LARRY S. MONROE, PROGRAM MANAGER OF POLLUTION CONTROL RESEARCH, SOUTHERN COMPANY, BEFORE THE SENATE ENVIRONMENT AND PUBLIC WORKS COMMITTEE, SUBCOMMITTEE ON CLEAN AIR, CLIMATE CHANGE AND NUCLEAR SAFETY, JUNE 5, 2003

My name is Larry S. Monroe and I am the Program Manager of Pollution Control Research for Southern Company. Southern Company is a super regional energy company serving customers in Alabama, Florida, Georgia, and Mississippi. Southern Company is the second largest user of coal in the utility industry with some 21,626 megawatts of coal-fired generating capacity. I hold a Ph.D. in Chemical Engineering from MIT, and have been involved in research on pollution control for coal-based power plants for over 20 years in university, not-for-profit research institute, and corporate settings. At Southern Company, I manage a research group that evaluates, develops, demonstrates, and troubleshoots technologies to control particulates, SO_2, NO_X, and hazardous air pollutants, including mercury, from fossil-fired power plants.

For the last 2 years, I have been engaged in the national effort to develop technologies to control mercury emissions from coal-fired power plants, resulting from EPA's decision in December 2000 to develop Maximum Available Control Technology (MACT) mercury regulations for coal plants. I serve as the utility co-chairperson of the EPRI program tasked with developing and evaluating mercury control technologies. I have also directed Southern Company's efforts, along with our partners including other utilities, EPRI, the Department of Energy, and the Environmental Protection Agency, in an attempt to develop cost-effective controls of utility mercury emissions.

I have been representing Southern Company and the industry on the Utility MACT Working Group, a subcommittee formed under the Clean Air Act Advisory Committee to provide advice to the Environmental Protection Agency. As a member of the MACT Working group, I have been intimately involved in the discussions with all of the stakeholders—including the environmental community, the state/local/tribal regulatory agencies, and the industry stakeholders—on the form of the regulation and its impacts on the industry and the price of electricity. As a part of this effort, I have been the leader of the industry stakeholders on advising EPA on our view of the performance and cost of the available mercury control technologies.

Working with EPRI, DOE, and EPA, Southern Company is one of the leading utilities in the national effort to develop mercury controls. We hosted the first full-scale power plant testing of mercury control ever performed in the United States, and are just starting a long-term follow-on test at the same site. Southern has also established a unique program to explore the fundamentals of mercury chemistry in coal power plant flue gas, partnering with EPA, TVA, EPRI, and several other utilities.

Today I am also testifying on behalf of the Edison Electric Institute (EEI). EEI is the association of U.S. shareholder-owned electric companies, international affiliates and industry associates worldwide. EEI's U.S. members serve more than 90 percent of all customers served by the shareholder-owned segment of the industry, generate approximately three-quarters of all of the electricity generated by electric companies in the country, and serve about 70 percent of all ultimate customers in the nation.

State of Technology

The state of technology development for control of mercury emissions from coal-fired power plants is very much in its infancy. Some early efforts at measuring the mercury emissions from power plants were attempted in the mid-1990's, but the sampling techniques used were not adequate, and much of that data is questionable. The mercury content in typical coal-fired power plant flue gas is very low, measured at the parts per trillion level. A good analogy that describes the low concentration of mercury in coal-fired power plant flue gas is to imagine a pipe, one foot in diameter, built from the earth to the moon. If this pipe, all 238,000 miles long, were to be filled with coal-fired power plant flue gas, and the mercury all magically brought to one end, it would only take up the first 18 inches of this pipe. If we compare the mercury in coal-fired power plant flue gas to the other criteria pollutants (e.g., particulates, NO_X, and SO_2) you find that the mercury is one million times less concentrated than those other species. The low concentrations of mercury, along with the propensity of mercury to react in the sampling equipment, contribute to the difficulties in accurately measuring and controlling mercury emissions at cost effective levels.

The state of knowledge of mercury chemistry and mercury emissions from power plants has been so scarce that, in 1999, the Environmental Protection Agency (EPA) required all power plants to sample their coal supply and test for mercury content, and required a selected number of power plants to sample for the different mercury species before and after the flue gas entered existing pollution control devices. Southern Company participated in that effort by tracking every coal to every one of our power plants and further by sampling two of our plants for mercury species and emissions. Unfortunately, this EPA Information Collection Request (ICR) database, while suffering from some flaws in data collection and power plant selection, remains the best publicly available database of mercury emissions, with and without controls, and of mercury chemistry for U.S. power plants.

There are currently no commercial technologies that are available for controlling mercury from coal-fired power plants. That is, there are no vendors that are offering process systems that are supported by guarantees from the vendor for mercury control performance under all the conditions that an ordinary power plant is expected to encounter over the course of normal operating conditions and timelines. Of course, there are vendors that will offer their best guess at how a particular technology will perform, but the risk of non-performance rests with the utility. The reliance on vendor warranties is standard practice within the utility industry, and the inability of the vendors to issue guarantees is indicative of the pre-commercial status of all mercury control technologies.

The most promising two technologies for mercury control in power plants are co-control by flue gas desulphurization (FGD) processes and the use of activated carbon injection (ACI) processes. To understand the co-control of mercury by FGD processes and the possibility of increased mercury control by NO_X control processes, namely selective catalytic reduction (SCR) systems, a basic understanding of mercury chemistry is needed. First, coal is no different than any other solid material dug from the earth's crust when it comes to the mercury content. In other words, coal is not enriched in mercury compared to ordinary rocks. The mercury in coal is there mainly as a sulfide compound, at a concentration that averages 50 parts per billion by weight. These sulfur-mercury compounds are the most common form of mercury found in nature and they tend to be very stable solids, only dissolved by a mixture of strong acids. Most everyone is familiar with mercury, the metal that is a liquid at room temperature and used widely in thermometers and blood pressure instruments seen in a physician's office.

It is not a surprise that a metal that is liquid at room temperature would boil at much lower temperatures than ordinary metals, and mercury boils at only 674°F. Similarly, when coal burns in a utility boiler, mercury in the coal vaporizes and produces the vapor of the metal in the high temperature zones of the flame. This form of mercury is commonly referred to as elemental mercury, meaning that it exists in a form that is not combined with any other element. It is also known as "mercury zero," a reference to the chemist's shorthand of referring to the electron state of a pure element as zero, or Hg^0.

As the temperature of the coal flue gas is cooled by the process of making and superheating steam, the elemental mercury vapor can react with other elements to form compounds. Our best knowledge of mercury chemistry suggests that mercury vapor can react with either chlorine or oxygen to produce mercury chloride ($HgCl_2$) or mercury oxide (HgO). Since the electronic state of the mercury atom is now "plus two," this form is sometimes called "mercury two," ionic mercury, or oxidized mercury. These are all equivalent terms that describe the chemical state of the mercury. Finally, either of these two forms of mercury, the elemental or the ionic, can attach to solid particles, either fly ash or partially burned coal particles, and is typically referred to as "particulate mercury," which is a physical description of the mercury form. To summarize, we generally classify the mercury in coal flue gas as being one of three forms: elemental, ionic, or particulate.

The proportions of the three chemical forms of mercury have a great influence over the behavior of the mercury in the flue gas in pollution control processes. The particulate form of mercury is the easiest form to remove, with high efficiency capture being normal along with the coal ash in electrostatic precipitators (ESPs) or bag houses. Unfortunately, in most power plants, the fraction of mercury contained in the particulate form is only a minor amount of the total mercury.

Flue Gas Desulphurization (FGD)

The most common method to remove sulfur dioxide (SO_2) from coal-fired power plant flue gas is a wet scrubber. This device is a large tower, where the flue gas enters the tower near the bottom and flows upward, exiting through the top. When the flue gas is flowing, hundreds of nozzles spray a mixture of powdered limestone and water. The flue gas essentially flows up through a rain storm of these limestone-water droplets. Since SO_2 is an acid, it reacts with the alkaline limestone solids and is neutralized.

The acid and base chemistry is so fast that the performance of the wet scrubber is dependent on the mixing between the flue gas and the droplets. Therefore, it is necessary to use multiple, large pumps and a large number of nozzles to produce the small droplets needed. The combined limestone-SO_2 product from the scrubber is typically calcium sulfate, better known as gypsum—the white powder found inside wallboard (also called sheetrock). Gypsum is a naturally-occurring compound, mined both for fertilizer and wallboard.

In this common FGD process, the wet limestone scrubber, the form of the mercury in the flue gas entering the scrubber appears to be the most important factor in the efficiency of mercury capture. The ionic form of mercury, that which has reacted with oxygen or chlorine, tends to be soluble in water and is therefore captured along with the SO_2, while the elemental mercury, being insoluble in water, passes through most of these processes. Therefore, our best understanding of the co-control of mercury with SO_2 control processes suggests that the efficiency of mercury capture by these processes is related to the amount of the mercury that has converted from the elemental form to the ionic form. Anything that would help convert the elemental mercury to the ionic form will presumably increase the overall mercury control in plants equipped with wet scrubbers. (NO_X control processes using selective catalytic reduction systems appear under some circumstances, and with some coals, to increase the amount of ionic mercury, and this will be discussed later.)

The biggest influence on the eventual form of mercury in the flue gas, and the apparent subsequent capture efficiency, appears to be the chlorine content of the coal. Coals with higher chlorine levels, when burned in a power plant, produce flue gas that is typically higher in the ionic form, the form which is most easily captured in an SO_2 scrubber system. In general, the domestic coals found east of the Mississippi River tend to be much higher in chlorine content than the coals found in the West.

More specifically, the rank of the coal tends to be a good predictor of chlorine content. Coal rank is an indicator of the age of the coal and there are four major classifications of coal rank, listed in the order of high rank (or older coal) to low rank (or younger coal): anthracite, bituminous, sub bituminous, and lignite. Most coal found in the Eastern U.S. is bituminous coal, although there are some lignite deposits found in the Alabama-Mississippi coastal plain. These lignite reserves are not important to the coal-fired utility industry, however. Conversely, most of the coal found in the Western U.S., including Texas, is either sub bituminous or lignite rank coal. The exception in the West is some bituminous coal found in Colorado extending into New Mexico. All of the coals in the Western U.S., including the Western bituminous coals, are characterized by low chlorine contents, while the bituminous coals in the Eastern U.S. have much higher chlorine contents. Therefore, the expected amount of ionic mercury and consequently the expected capture in a scrubber will be much higher for coals from the Eastern U.S. than from those in the Western U.S.

Typical coal-fired power plant flue gas produced from combustion of the bituminous coals found in the Eastern U.S. would contain the following proportions of the mercury species: 60% ionic mercury, 38% elemental mercury, and 2% particulate mercury. The particulate mercury would be removed in the power plant's electrostatic precipitator. We would expect the scrubber to remove 90 to 95% of the ionic mercury, and none of the elemental mercury. The overall mercury removal in this simple example would then be 56% (90% of the ionic and nearly 100% of the particulate mercury removed). This example is in good agreement with recent testing where, at three bituminous-fired power plants studied by EPRI, the FGD system removed 43 to 51% of the mercury.

However, most of the coals from the Western U.S. when used in a power plant produce much less ionic mercury, with typical estimates of: 25% ionic, 74% elemental, and less than 1% particulate. A scrubber on this power plant would then only be expected to remove 90% of the ionic and the electrostatic precipitator or bag house to remove nearly 100% of the particulate mercury. Therefore, the total mercury removal would be only 23.5%. The ICR database shows that power plants burning low rank coals ranged from near zero to 38% mercury capture without wet scrubbers, and 11 to 56% on those plants with scrubbers.

A problem with capturing mercury in wet FGD scrubbers has been discovered through analysis of the EPA Information Collection Request database. In some power plants that were tested for mercury species and also had wet SO_2 scrubbers, the apparent high capture of ionic mercury was offset by an increase in the amount of elemental mercury as the flue gas moved through the scrubber. So, while the ionic mercury appeared to be captured at efficiencies approaching 95%, some of the ionic mercury, after being captured in the scrubber, was converted back to the elemental form, which evaporated from the scrubber and was then emitted as elemental mercury.

An example may help explain the effect. Say that, before the scrubber, there are 10 micrograms (one millionth of a gram or 2 billionth's of a pound) of mercury in one cubic meter (about 35 cubic feet) of flue gas. Furthermore, let's say that 60% of that is ionic and the balance is elemental, or 6 micrograms per cubic meter ionic and 4 micrograms per cubic meter of elemental mercury. In a power plant that shows this mercury release phenomena, we might see less than 0.1 microgram per cubic meter of ionic mercury at the stack exit, an apparent capture of 98.3% of the ionic mercury. But, we see the stack exit containing maybe 5.5 micrograms per cubic meter of elemental mercury, an increase of 37.5%.

The elemental mercury is not being captured but is actually *increasing* across the scrubber. When looking at the total mercury, the 10 micrograms per cubic meter at the scrubber inlet is reduced to only 5.6 micrograms per cubic meter (5.5 elemental and 0.1 ionic) at the stack, a total reduction of only 44%. The only logical explanation to explain these example numbers is that some of the captured ionic mercury is being re-released as elemental mercury. In this case, the ionic mercury is only being captured at 73%, when the re-released mercury is included.

This scrubber mercury re-release is not well understood at this point. An analysis by EPRI notes a correlation between an increase in the amount of fly ash captured in the scrubber and an increase in the mercury re-release. Further work by EPRI on a bench-scale scrubber shows that this phenomenon is transient, and it is not easy to predict when it will occur. Additionally, private testing by Southern Company at our DOE-sponsored flue gas scrubber at Georgia Power's Plant Yates, south of Atlanta, has shown that this effect is present at some times, and not present at others. The significance of this effect is that the overall capture of mercury by a wet scrubber may be less over time than a short test period would indicate. Further research of this phenomenon is needed.

Most of the previous discussion assumes that the FGD process used is the wet limestone, forced-oxidation scrubber. Another process for SO_2 control, used widely for low sulfur Western coals, is a lime-based spray dryer followed by a bag house that collects both the reacted lime along with all of the coal ash. The EPA Information Collection Request testing in 1999 indicates that this spray dryer-bag house FGD process may give very high mercury removals with bituminous coals. However, this is a rare application of this technology, and unfortunately is not widely applicable to all bituminous coal applications. The technology is only effective for SO_2 control for low sulfur coals, is more expensive than the alternatives, and creates a large waste stream that has to be carefully handled for disposal. While this approach may be used in a few power plants burning Eastern bituminous coal for combined SO_2 and mercury control, I do not expect it to be very widely selected because of these limitations.

Ironically, the best application of this FGD process is for Western coals, but there it appears to make the mercury control worse than just particulate control alone. That is, the use of a spray dryer-bag house system on most low rank coals (sub bituminous and lignite) is normally the best engineering and low-cost FGD solution for plants burning these coals for SO_2 control, but the evidence suggests that it may worsen the mercury collection efficiency as compared to the use of a bag house alone. For example, EPA states that sub bituminous coal plants in the ICR database with only bag houses average 72% mercury control, while those with a bag house and a spray dryer for SO_2 control average only 24% mercury removal.

Various technologies are being investigated to attempt to further oxidize elemental mercury to ensure higher removal in a FGD system. Chemical injection, plasma discharges, and dedicated catalysts are all being tested and developed. These approaches are all under development, and only slow progress is being made.

Selective Catalytic and Non-Catalytic Reduction (SCR & SNCR) NO_X Controls

One of the most intriguing possibilities is the ability of NO_X control selective catalytic reduction (SCR) systems to enhance the amount of ionic mercury in the flue gas. A report on research done by a large German utility company in the early 1990's claims that the catalyst used in a SCR system was effective in converting a high fraction of the elemental mercury to the ionic form, which was then captured in FGD equipment. The German claim was that the SCR catalyst changed the chlorine chemistry, making it more likely to convert elemental mercury to ionic mercury.

Based on this German research, EPA originally assumed that any power plant equipped with a SCR and FGD, burning any type of coal, would see: (1) almost all of the elemental mercury converted to ionic; (2) the ionic mercury captured in a scrubber in a high proportion; and (3) no mercury re-released from the FGD process—all adding up to an estimate of an overall 95% reduction in mercury emissions from those plants. A 95% mercury capture would require that the SCR catalyst be 97.5% effective in converting elemental to ionic mercury. Furthermore, the FGD system would have to be 97.5% effective in removing the ionic mercury—that is, not only does the scrubber have to perform at least as well on mercury as the SO_2 (even though the mercury is one-millionth times as concentrated), but no re-release of mercury can occur. EPA's assumptions were highly optimistic and recent power plant testing has shown these assumptions are not always true.

SCR catalyst degrades over time in its performance to reduce NO_X, requiring replacement every three to five years. The catalytic activity is reduced by exposure to flue gas, either by poisoning of the catalyst active ingredient from the chemicals in the flue gas or by physical plugging of the catalyst surface by ash particles. It is not known, at present, how this catalyst deactivation affects its ability to oxidize mercury. The mercury oxidation of the catalyst could be reduced at the same rate as the NO_X reduction, or it might be slower or faster. EPRI testing has only looked at two power plants and only in two ozone seasons (May 1 to September 30). So we have limited information, both in the number of plants tested and the time between tests. Therefore, any estimate of the long-term potential for co-benefits of SCR and FGD for mercury reductions must consider the possibility of catalyst aging and the subsequent potential loss in mercury oxidation.

For the lower rank coals, and particularly those found in the Western U.S., this SCR mercury oxidation does not appear to occur. Given the German claim of the effect being based on higher chlorine content, this is not much of a surprise. The low rank coals are typically low in chlorine, and to make matters worse, the ash of these coals is alkaline, so that whatever chlorine that is present, being an acid, is usually neutralized by the fly ash before it can ever reach the SCR catalyst. Testing in an EPRI program sponsored by utilities (including Southern Company) along with the Department of Energy (DOE) and the EPA has shown that mercury reduction in low rank coals do not seem to be helped by the addition of a SCR system. Since the majority of the mercury in the flue gases from these coals in the elemental state, the addition of any type of FGD system does not appear to control mercury emissions to any significant degree. In other words, for low rank coals (typically Western U.S. coals), we do see modest benefits on mercury control by adding wet FGD systems, but do not see any mercury co-benefits from adding an SCR to the power plants burning these coals. EPA has also seen the results of the testing, and we think that they have revised their assumptions about co-benefits for lignite and sub bituminous coal to reflect this new knowledge, that is, there are only modest mercury reductions based on co-benefits of NO_X and SO_2 reductions for these coals.

At the beginning of the MACT development process, EPA had assumed that selective non-catalytic reduction (SNCR) systems would contribute to increased mercury removal, and explicitly had assumptions about its performance in their models. SNCR uses ammonia injection at elevated temperatures (1900-2400°F) to reduce NO_X without the use of a catalyst. Two years of testing have shown that this NO_X reduction technology has no influence on mercury control in any plant with any coal rank. Finally, we think that the Agency has conceded this point and we hope that they no longer count SNCR as having any influence on mercury control.

Summarizing the current state of knowledge of controlling mercury via co-benefits of SO_2 and NO_X reductions, there are only a handful of power plants that have been tested for short time periods. Given this limited amount of data, we think that for bituminous coals the mercury reductions with a SCR and FGD will probably be between 80-90% for the best case, and that for sub bituminous and lignite coals the reduction will be a modest 20%. These estimates are optimistic taking into account the previous discussions of catalyst aging in SCR systems and mercury re-release for FGD systems, and are likely to be reduced even further in the future. We think that EPA is currently using an estimate of 90% for bituminous coals and something less than 90% for lignite and sub bituminous.

Activated Carbon Injection

The second near-commercial technology for mercury control from coal-fired power plants is activated carbon injection (ACI). Activated carbon is a specially prepared product of coal or biomass that is able to adsorb many chemicals from gases or liquids. One of the primary uses of activated carbon is the treatment of drinking water. Water filtering systems sold for home use in home improvement stores are typically cartridge systems that include activated carbon as part of the filter. Activated carbon is being used currently to remove mercury from the flue gases from municipal, medical, and hazardous waste incinerators. In those applications, activated carbon can routinely collect over 90% of the mercury from the flue gas. However, the mercury concentrations in the stack after the activated carbon treatment in these incinerators are typically higher than that found in coal flue gas before treatment. That is, the amount of mercury in every cubic foot of incinerator stack gases after the control system using activated carbon is typically 5 to 10 times the amount in untreated coal flue gases from power plants. Another way to look at a comparison between incinerators and power plants is that most every power plant would meet the incinerator mercury regulations without any control technologies. Simply, incinerator mercury control by activated carbon stops where power plant flue gases begin. Therefore, it is not useful to use the experience of activated carbon in incinerators to inform the debate on its use in power plants.

The design of activated carbon injection for mercury control relies upon the existing equipment used to remove fly ash from the flue gas to also remove the added activated carbon. There are many side issues associated with the use of activated carbon in this mercury process approach, including contamination of the fly ash with carbon and interruption of the normal fly ash control by the added load of activated carbon. The injection ahead of electrostatic precipitators, which are in use by about 80% of the U.S. coal power plants, may require large amounts of activated carbon to achieve reasonable mercury control. The carbon will contaminate the fly ash making it unusable for recycling and may threaten the performance of the electrostatic precipitator for its intended use of removing fly ash. Injection of activated carbon in a bag house will not need as much activated carbon as an electrostatic precipitator, but will also contaminate the fly ash.

There have been only a handful of tests on the use of activated carbon to control mercury from coal-fired power plants. The very first test at full-scale in the United States was performed at a Southern Company power plant, Alabama Power's E.C. Gaston Unit 3, located in Wilsonville, Alabama. This was the first in a series of four power plant tests in a sequence performed by ADA-Environmental Solutions of Littleton, Colorado. The test program was sponsored by DOE's National Energy Technology Laboratory (NETL) with significant co-funding by participating utilities and vendors. All of these four sites are somewhat unique, and unfortunately do not well represent the nation's power plant fleet.

Gaston Unit 3 is one of only four power plants in the U.S. that have an advanced particulate control system that consists of a small bag house installed downstream of the existing electrostatic precipitator. This arrangement, known as COHPAC™, is a patented EPRI invention. The activated carbon can be injected between the electrostatic precipitator and the bag house. The electrostatic precipitator collects over 95% of the fly ash, while the bag house collects the remainder of the ash and the activated carbon. This approach to activated carbon injection avoids contamination of the fly ash and does not jeopardize the operation of the electrostatic precipitator with additional carbon loading. The bag house is a large filter, which has hundreds of fabric bags that separate the solid ash and carbon from the flue gases, much like the paper bag in a household vacuum cleaner. Because the activated carbon can sit on the surface of the bags for several minutes and see a substantial amount of flue gas, it can effectively collect more mercury from the flue gas than injection into an electrostatic precipitator.

The activated carbon injection testing at Gaston, which burns an Eastern U.S. bituminous coal, ended with a seven-day test of mercury control, where the average mercury reduction over that time period was just under 80%, with a high of over 90% and a low of only 36%. This was a short-term test and probably does not reflect the ability of this system to always perform at this level. We found in this testing that the bag house at Gaston is not big enough to accommodate the amount of activated carbon needed to consistently achieve 90% mercury control for even just one week of testing. The testing was promising and DOE/NETL has funded a follow-on project that will test the mercury control at this location for one calendar year. This length of testing will allow a better estimate of the potential mercury control from this technology over the course of that one year. We are just starting this longer term testing, and the initial results were presented at an international pollution control conference sponsored by DOE, EPA, and EPRI just two weeks ago here in Washington. The initial results are not encouraging—we cannot repeat the performance of the seven-day test performed in 2001. The electrostatic precipitator ahead of the bag house at Gaston Unit 3 is not performing as well as it was during the earlier testing, and we cannot inject much activated carbon into this system without causing damage to the bag house. Two conclusions can be drawn from the first few weeks of operation of the long-term testing: (1) the bag house at this unit is simply not big enough to handle both the fly ash and carbon loading over all operating conditions, and (2) the 80% average mercury control seen in the earlier one week test cannot be sustained over the long term. It may be possible to achieve levels higher than 80% in other power plants with this configuration, assuming that the additional capital investment is made to build a large bag house. Again, this is a test at a power plant burning Eastern bituminous coal.

The three other tests of full-scale mercury control using activated carbon in the joint industry-DOE project all involve the injection of activated carbon into the inlet of an electrostatic precipitator. The first electrostatic precipitator injection test was performed at Wisconsin Electric's (now We Energies) Pleasant Prairie Power Plant, which burns a Western U.S. sub bituminous coal from the Powder River Basin in Wyoming and Montana. This unit has a large electrostatic precipitator that is likely to be able to handle the additional particle loading from the activated carbon. The test that occurred over one to two weeks was able to achieve a mercury control of between 60 and 70%, but notany higher, regardless of the amount of carbon injected into the system. The logical conclusion from the testing seems to indicate that there is a chemical limitation on the amount of mercury control from low rank coals like lignite and sub bituminous, and maybe for Western U.S. bituminous coals from Colorado and New Mexico. It appears that, similar to the SCR oxidation of mercury, the activated carbon needs sufficient chlorine in the flue gas to collect the mercury. Again, this result was over a very limited time span test and may not be repeatable over a yearlong period. Longer term testing of this approach in several power plants needs to be performed before any judgment of the mercury performance can be reliably made.

An additional consequence became clear during the test at We Energies' Pleasant Prairie Power Plant. This site is able to sell all of the fly ash it produces for recycling into concrete. The activated carbon made the ash not usable for this purpose during the test period, but also contaminated the ash for about four weeks after carbon injection was discontinued. Southern Company declined a similar test at one of our sub bituminous coal plants, due to the expense of lost ash sales plus the added ash disposal costs.

The other two tests of activated carbon injection into electrostatic precipitators for mercury control were both performed in Massachusetts, at PG&E National Energy Group's Salem Harbor and Brayton Point power plants. Salem Harbor is peculiar in that it produces a large fraction of unburned coal particles that persist into the electrostatic precipitator, possibly a result of the large amount of South American coal being burned there. This high level of carbon produced seems to remove a significant amount of mercury, with a baseline removal ranging from 87 to 94% with one coal, but dropping to 50 to 70% with a second coal, all even before activated carbon injection. The activated carbon injection was able to increase the mercury capture to over 90%. Of course, this testing has shown that a change of coal supply can dramatically change the mercury baseline performance and the subsequent increased capture by activated carbon injection.

Brayton Point is also a peculiar arrangement with two electrostatic precipitators in series. In the DOE test, activated carbon was injected between the two electrostatic precipitators, much like the injection between the ESP and bag house at the Gaston station. The baseline mercury removal, that is, the removal before activated carbon injection started, was 90.8%. This is very high as compared to historical data from that unit that recorded baseline mercury removals of 29 to 75%. The results in the ten days of testing suggest that, for short periods, the injection of activated carbon can increase the mercury removal from a baseline of 90.8% to 94.5% with the addition of activated carbon (10 pounds carbon injected for every million cubic feet of flue gas). Again, the short time of the test and the potential change in behavior with a change in coal supply makes it hard to extrapolate this performance much beyond the actual period of testing.

All of the electrostatic precipitator tests of activated carbon injection to date have involved relatively large, oversized equipment where the additional burden of collecting the injected activated carbon did not impact the operation, at least in the tests of under two weeks duration. For the same mercury collection efficiency as a COHPAC™ bag house, the added carbon cost is substantial enough to justify the capital investment to build the bag house.

Another—potentially large—problem with this technology is that the supply of activated carbon is currently not sufficient to support any significant use for utility mercury control. I have publicly stated that, due to current uncertainties, Southern Company may use anywhere between 500 tons per year to 100,000 tons per year of activated carbon. The major U.S. manufacturer of activated carbon, Norit Americas, based in Atlanta, Georgia, have told us that they could supply an additional 20,000 tons per year with their existing capacity. Without long-term commitments from buyers, the activated carbon suppliers will very likely not make the needed investments to ensure that a large demand from the U.S. utility market could be met. In the 1970's, the activated carbon industry built capacity in anticipation of clean water regulations and those investments resulted in a severe price decrease caused by oversupply, when the demand did not appear. The activated carbon suppliers are not likely to make the same speculative capital investments today. Add to this reluctance to invest ahead of demand the fact that it will likely take at least five years to design, finance, permit, and build activation carbon production facilities, and it becomes apparent that, if activated carbon injection becomes the technology of choice for power plant mercury control, the supply will not be available at the beginning.

There may be foreign supplies of activated carbon. As discussed at a recent conference, there may be about 50,000 to 60,000 tons per year available from a major European supplier. Also, China has started supplying activated carbon into the U.S. market, but initial experience with this material has shown quality control problems with its performance. All in all, there may be sufficient carbon available to supply a small part of the industry with today's global supply, but there is not enough supply for any major use across the nation by the utility industry.

In early modeling efforts by EPA on the performance of activated carbon, the assumptions made about performance and the actual amount of activated carbon were grossly optimistic. The Agency used some estimates made by DOE in 1999, and the subsequent testing at full scale power plants has demonstrated that the performance is not as good as the earlier estimates. We think that the current set of performance and cost numbers offered by the Utility Air Regulatory Group in the MACT Working Group are the best estimate for mercury control processes using activated carbon.

In summary, the limited testing of activated carbon injection for power plant mercury control does not represent the average configuration of the U.S. power plant fleet, and the short-term tests that have taken place only represent what a well-controlled and well-managed test period performance could be—in other words, are likely to be close to the best case. Additional testing at the Southern Company plant has already shown that the earlier performance cannot be matched at this moment. Certainly additional testing, including long-term tests of at least eight months are needed to understand what the actual performance of activated carbon injection over longer times would be, with the wide variety of coals in use today. At this moment, the DOE/NETL is evaluating a number of proposals from utilities, vendors, and research contractors to test activated carbon for longer periods of time on a variety of plants, especially those that burn low rank coals.

With sufficient capital investment to build a COHPAC™ bag house large enough to handle both the fly ash and activated carbon, short-term performance of 90% mercury removal with bituminous coals may be possible, but, across the industry, an average removal of 80% is more likely to be achieved with today's technology. This estimate is based on only one power plant, tested for only seven days, however. It appears that low rank coals, such as lignite and sub bituminous coals, may have a limit of 60-70% mercury removal, regardless of the amount of activated carbon used or whether a bag house has been installed. Again, only one power plant has been tested for less than two weeks to establish this estimate. Under certain circumstances, activated carbon injection into a large ESP may be able to get incremental mercury control, but only two power plants have been tested for less than two weeks. Finally, the supply of activated carbon is not sufficient today to accommodate a substantial demand from the utility sector and it may take five years to bring new activated carbon production facilities on line.

Other Technologies

There are other technologies that show some promise in controlling mercury emissions from power plants, but they are all still research projects and are nowhere close to commercialization. Some of the multi-pollutant processes being developed do claim that mercury control is also removed along with SO_2, particulates, and NO_X. While this may be true, there are large questions about the costs, reliability, and long-term performance of these technologies. Most of these multi-pollutant processes make either fertilizer or acid chemical feedstocks from the NO_X and SO_2, and the ability to sell either of these waste streams in the future is questionable. The larger the penetration of these technologies into the utility market, the more of the byproducts that are produced, quickly over-saturating any potential market.

Possible future technologies that are being researched include capture of mercury by gold-plated surfaces, the use of chlorine addition to low rank coals to increase the mercury oxidation, injection of sulfur compounds to change the elemental and ionic mercury gases to solid sulfides that can be captured in the existing particulate control devices. Additionally, a large number of alternative sorbents to replace activated carbon, either with a less costly material cost or improved performance with less material injected, are under development. Unfortunately, we cannot predict whether these efforts will succeed, and we cannot base national energy policy on the hope that something is invented in time to produce the perceived needed level of mercury control.

Timing of Mercury Reductions

The timing of mercury reductions required, whether by regulations under a MACT provision or by a legislative process, needs to take under consideration both the state of knowledge about mercury control and the ability of the nation's utility industry to install the required controls. Already, in the installation of NO_X controls for the 2003 summer ozone season, we have experienced some labor shortages and tight supplies of steel, cranes, and auxiliary equipment such as fans, pumps, electric motors, switchgear, etc. If mercury control proceeds under a MACT regulation, every coal-fired power plant will have to meet the stated emissions requirements, and depending on the technologies being used, we expect shortages of steel, bag house bags, labor, and auxiliary equipment, not to mention the activated carbon supply issues discussed earlier. Southern Company estimates that the time required to install mercury controls under MACT would be at least seven years, and the time needed for the additional NO_X and SO_2 controls in Clear Skies would take probably eight to nine years.

Estimates of Benefits of Utility Mercury Reductions

EPRI and EPA are both engaged in research to attempt to predict the net effect on human health from reductions in emissions from U.S. coal-fired power plants. EPRI has just published their initial findings, and we think that EPA is working on similar model predictions. In the EPRI study, mercury deposition on the continental U.S. is predicted using a global mercury source and deposition model. The results indicate that the majority, around 70%, of the mercury falling on the U.S. is from sources outside the U.S. Additionally, this study predicts that U.S. utility emissions are estimated to contribute less than 8% of the mercury depositing in the U.S. This result is significant, because it indicates that reductions of mercury emissions from domestic utility sources will have a limited response on the amount of mercury depositing. In other words, since most of the mercury falling on the U.S. comes from overseas, controlling domestic utility emissions can have only a limited impact. The EPRI study goes on to estimate the change in human exposure from significant reductions in utility mercury reductions. The only significant route of exposure to humans is through the consumption of large fish, captured in the wild. By estimating the change in U.S. deposition from reductions in utility emissions, the change in mercury in aquatic systems, and subsequently in fish, can be found. Taking the analysis one step further, EPRI has estimated the change in exposure to humans in the U.S. from utility mercury reductions.

The EPRI study looked at mercury reductions in a Clear Skies Act approach and in a mercury MACT regulation scenario. The results indicate under the Clear Skies approach, in the year 2020, mercury deposition in the continental U.S. would be reduced by an average of 1.5%, exposure of women of childbearing age to mercury would be reduced by 0.5%, and the fraction of the population above the reference dose for mercury would be reduced by only 0.064%. In the MACT approach, also for the year 2020, mercury deposition would be reduced by 1.2%, exposure of women of childbearing age to mercury would be reduced by 0.4%, and the fraction of the population above the reference dose would be reduced by 0.055%. Since U.S. utility emissions are only a small contributor to mercury in the environment, it is not surprising that significant reductions in those emissions will not greatly affect human exposure. One significant difference in the two approaches is that the present value incremental cost for mercury controls by 2020 is estimated to be about $6 billion for CSA and $19 billion for MACT.

Summary

There are no commercially available technologies for mercury controls for coal-fired power plants. There are systems in use in the waste incinerator industry, but the EPA requirements for mercury control for incinerators allow emitted concentrations to be five to ten times higher than uncontrolled coal power plant emissions. In an engineering sense, the low concentrations mean that you have to work that much harder to get each molecule of mercury. NO_X and SO_2 stack concentrations are one million times higher than mercury, so you have to work one million times harder to collect mercury as compared to either NO_X or SO_2.

There are two near-commercial mercury control technologies at present: co-control by FGD systems, with possible beneficial mercury chemical changes from SCR systems on plants burning bituminous coals, and the injection of activated carbon into existing or new particulate control devices, either ESPs or bag houses.

Plants burning bituminous coal from the Eastern U.S. which have installed SCR systems and wet scrubbers are likely to have between 80 and 90% mercury control in the beginning. There are large uncertainties about the potential adverse scrubber chemistry that could re-release captured mercury and also about the extent of SCR catalytic mercury oxidation over time, so it is likely that these estimates may decrease as we learn more.

For low rank coals such as sub bituminous and lignite (along with bituminous coal from the Western U.S.), the SCR systems do not appear to have any beneficial effects on mercury chemistry, probably due to the low chlorine content of the coals. Additionally, the addition of a wet FGD scrubber system may increase mercury control slightly, say by 20%, but the addition of a spray-dryer FGD system may even decrease the mercury removal as compared to the pre-FGD mercury removal performance.

Activated carbon tests to date have been short, less than two weeks, and have shown some promise, but also some difficulties. The only long-term test that is being performed is at Southern Company's Plant Gaston, and the year long test is just beginning. The limited data from this one short test suggests that activated carbon injection into a COHPAC™ bag house installed at a plant burning bituminous coal may be able to achieve short-term performance of 90% mercury removal, but an average across a year is more likely to be around 80%. We do not know what operation problems may occur after an extended period of activated carbon injection, but even at the beginning of the year long test, we are not able to match the previous short term performance.

Activated carbon injected into an electrostatic precipitator at a plant burning Powder River Basin sub bituminous coal has shown mercury removal of 60-70%, but only for a short test, and with serious consequences for ash sales and disposal. The chemistry of low rank coals like these may limit the final mercury removal that can be achieved with activated carbon. Again, based on this one power plant test for a short period, it is likely that a bag house and activated carbon injection would still only achieve 60-70% mercury removal on these coals.

Activated carbon supply is also an unanswered question. Activated carbon vendors have estimated the U.S. utility market may be between 500,000 and 1,500,000 tons per year. Between domestic supply and spare European capacity, there may be up to 150,000 tons per year available today. Without firm commitments, the suppliers are unwilling to make the investments to increase the supply, indicating that widespread use by the utility industry may create a worldwide shortage of activated carbon. Given that it takes roughly five years to bring a new activated carbon production facility on line, the prospects for widespread availability of activated carbon may be questionable.

In addition, the shortages encountered during the installation of NO_X controls over the last several years have shown that shortages of labor, steel, cranes, and auxiliary equipment can occur, and installation of mercury controls under a MACT regulation or installation of more NO_X and SO_2 controls will surely cause even greater material and labor shortages. The only way to alleviate the shortages is to extend the required performance date to install the equipment. These shortages could spill over into other industries and cause price increases across the board.

There are other technologies under development for mercury control, but they are all very much still in a research stage. Various multi-pollutant processes are being touted, but they suffer from questions about performance, cost, and waste disposal issues. Other processes to specifically affect or capture mercury are also under development, but are at least eight to fifteen years away from deployment, if they work at all.

More tests and longer tests are needed to be able to reliably estimate performance and design the appropriate equipment and processes for mercury reductions in power plants with different equipment installed and burning different ranks of coal.

The Department of Energy is currently evaluating a number of proposals from the utility industry, vendors, and research organizations to test a wide variety of plants and coals for mercury control, over a longer test period. The electric power industry, along with EPRI and equipment vendors, is engaged in a large, coordinated effort to develop and optimize cost-effective mercury emission reduction processes.

EPRI modeling suggests that U.S. utility emissions of mercury are only a small contributor to deposition of mercury in the continental U.S. Significant reductions of those emissions, either under a CSA or MACT approach, will only reduce deposition in the U.S. by 1.5%, and will only decrease exposures of the most sensitive population of women of childbearing age by 0.5% in 2020, as compared to 1999.

The utility industry does not have proven technologies to reduce mercury emissions, but we know that some reductions will occur as SO_2 and NO_X control systems are installed, either under Clear Skies or business-as-usual. The industry does not hold the position that mercury reductions should not occur, but asks that right timeline should be followed, one that considers the practical aspects of the cost and impact of making these reductions. Mercury emission reductions that are required before the technology has been fully developed will lead to significantly increased costs, to likely fuel switching from coal to natural gas, and to possible disruption of the nation's energy supply.

Mr. STRICKLAND. Thank you, Mr. Chairman.

Mr. WHITFIELD. Thank you, Mr. Strickland.

I want to thank all of the panel members for taking time from their busy schedules for joining us today on this important hearing on the future options for generation of electricity from coal. As it has been said, it is our most abundant resource. And we are going to continue to be dependent upon it. Your testimony has gone a long way in helping us focus in on some very important issues. So I want to thank you and want you to know that we may very well be coming back to you from time to time for additional comments to solve some of these problems.

So, with that, this hearing will be adjourned.

[Whereupon, at 4:51 p.m., the hearing was adjourned.]

[Additional material submitted for the record follows:]

SOUTHERN COMPANY
July 10, 2003

The Honorable RICK BOUCHER
House of Representatives
Washington, DC 20515

On June 24 when I testified before the House Committee on Energy and Commerce's Subcommittee on Energy and Air Quality you asked if the tax incentives in HR 1213 would be adequate to encourage Southern Company to build a new advanced coal-fired power plant instead of a natural gas-fired plant. I agreed to examine the question and get back to you. Unfortunately, the answer is "no" for our specific situation.

Southern Company's location, relatively close to natural gas supplies and somewhat removed from most coal supplies, makes natural gas electric generation more competitive than it may be in other areas of the country. New coal-fired generation is more competitive in locations that are nearer large coal supplies and further from natural gas supplies.

We strongly believe that tax incentives similar to those in HR1213 are needed to encourage the use of advanced coal-based power generation. My testimony and that of others before the Subcommittee outline why this is critically important. Southern Company's specific situation should not be a basis for reducing these efforts.

If I can be of further assistance please do not hesitate to call.

Sincerely,

RANDALL E. RUSH
Southern Company