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# IMPLEMENTATION OF THE PROVISIONS OF THE ENERGY POLICY ACT OF 2005

## HEARINGS

BEFORE THE

## COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED NINTH CONGRESS

SECOND SESSION

ON

COAL LIQUEFACTION TECHNOLOGY; COAL GASIFICATION TECHNOLOGY; AND LICENSING OF HYDROELECTRIC FACILITIES

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# COAL LIQUEFACTION TECHNOLOGY

**MONDAY, APRIL 24, 2006**

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington DC.*

The committee met, pursuant to notice, at 2:30 p.m., in room SD–366 Dirksen Senate Office Building, Hon. Jim Bunning presiding.

## OPENING STATEMENT OF HON. JIM BUNNING, U.S. SENATOR FROM KENTUCKY

Senator BUNNING. The full committee hearing will come to order. First of all I'd like to welcome all of you to the first of a series of Monday afternoon energy committee hearings. After years of hard work in this committee, we finally passed a comprehensive energy piece of legislation last year. Each of these Monday hearings will examine provisions of the Energy Policy Act of 2005 and discuss their implementation and benefits.

Today's hearing will focus on the coal-to-liquids or CTL technology. This promising technology transforms coal into liquid fuels such as diesel and jet fuel and while it has faced hurdles in the past, sustained higher energy prices have encouraged companies and their scientists to redouble their efforts to push this technology into the market place. With this in mind, the Energy Information Administration estimates by the year 2030, 180 million tons of coal will be used to produce high quality liquid fuels. That translates into production of between 800,000 and 1.7 million barrels per day of domestic CTL fuel. Looking at these numbers, I am proud to come from a coal State.

Kentucky is home to large deposits of America's most abundant domestic fuel as well state-of-the-art clean coal research and development. I know that the people in my State would like to become part of the solution to our addiction to foreign oil. I believe coal-to-liquids technology offers America the chance to capitalize on a domestic resource that will provide the energy for economic growth and a new level of energy security required in today's world. With such a strong potential to provide a domestic alternative to imported oil, I want to make sure the Federal Government is doing all it can to push this coal technology into widespread implementation.

On our first panel, the Department of Energy will testify about its role in the new technology. We will explore how loan guarantees granted under title XVII of the Energy Policy Act of 2005 can help develop and deploy coal-to-liquid technologies. We will also examine that institutional barriers stand, what institutional barriers stand in the way of more rapid deployment and identify opportunities for the DOE and other Federal agencies to promote this technology. The second panel will help us address the transition from CTL technology into commercial viability facilities. Private companies who are in the process of building CTL plants will share their experiences and propose models for the Government's support and involvement.

The director for the Center for Applied Energy Research at the University of Kentucky who oversees cutting edge experiments on CTL technology will discuss the state of the current research. I want to especially thank UK, for traveling here today so that we can hear their important testimony.

Finally, the environmental community will share their thoughts as we discuss how implementation of this technology can be done in the most environmentally sound manner. I look forward to the testimony of the witnesses before the committee today.

I guess you're on now, Dr. Miller.

**STATEMENT OF CLARENCE L. MILLER, DIRECTOR, OFFICE OF SEQUESTRATION, HYDROGEN, & CLEAN COAL FUELS, OFFICE OF FOSSIL ENERGY, DEPARTMENT OF ENERGY**

Dr. MILLER. Thank you, Mr. Chairman. I'd first like to express my thanks and appreciation for the opportunity to introduce the subject of coal-to-liquids. Coal is the most abundant fossil fuel resource in the United States. Recoverable coal reserves are estimated at 267 billion tons. As coal mining technology improves and additional geologic information becomes available, this reserve estimate will grow since it is based on current mining methods and the measured and indicated reserves within a total U.S. coal resource base estimated at nearly four trillion tons. These coal resources are widely distributed throughout the United States with recoverable reserves located in 33 States. Based on current annual production of nearly 1.1 billion short tons, the United States has an approximate 250 year supply.

Utilizing this resource, the production of liquid fuels from coal has a long history and significant advances made in technology over the past two decades make it a potential component of a strategy to increase domestic production of liquid fuels. In the early 1900's, this coal was first reacted with hydrogen and process solvent at high temperature and pressure and produced a coal derived liquid or synthetic crude oil. This direct liquefaction approach was later improved and used by Germany in the Second World War to fuel the Luftwaffe with high octane aviation gasoline. In the 1920's, two German scientists, Fischer and Tropsch, passed a synthesis gas consisting of carbon monoxide and hydrogen over metallic catalysts and produced pure hydrocarbons. These hydrocarbons produced by the Fischer-Tropsch process proved to be excellent transportation fuels. This overall coal-to-liquids process known as indirect liquefaction, because it first involves complete breakdown of the coal to a synthesis gas, was used commercially in the 1950's by the South African Synthetic Oil Corporation, commonly known as SASOL, to produce transportation fuels, gasoline and diesel. Since then, SASOL has built two large facilities to produce over 150,000 barrels per day of transportation fuels.

The U.S. Government, directly and through industrial partnerships and international cooperation, has, for over 30 years, supported R&D on both direct and indirect coal liquefaction technology and processes. The Government programs resulted in improved processes, catalysts, and reactors which has contributed to reduced cost and improved product quantity and quality.

Liquid fuels from coal are clean, refined products requiring little if any additional refinery processing, are compatible with petroleum products, and, therefore, can use the existing fuels distribution and in-use infrastructure. Preliminary studies indicate that a first plant cost utilizing this technology would have products in the $45 per barrel range but no U.S. commercial plants have been built making these cost estimates difficult. Still more difficult to estimate is the cost of production of subsequent plants but some studies indicate that coal liquids might eventually be produced in the $35 to $40 per barrel range as domestic construction and operational experience is gained.

However, there are significant existing impediments to deploying CTL technologies. First and foremost is the uncertainty and volatility of the world oil price. Other impediments include high capital investment for the plants, technical and economic risks associated with first-of-a-kind plants, environmental concerns associated with increased coal production and utilization, and siting and "not in my back yard" issues for new plants.

Environment concerns can be addressed by using clean coal technologies to reduce emissions of criteria pollutants and in the future to capture and sequester carbon dioxide to limit greenhouse gas emissions. At present, no requirements exist in the United States to manage carbon emissions from fossil fuel resources, however, in full recognition of the importance of carbon management an extensive research and development program is in progress to develop technology, processes, and systems to capture and store the carbon dioxide produced during the conversion process.

Although past Department efforts and some congressionally directed funding has focused on production of liquid fuels from coal, the fiscal year 2007 budget does not support these activities. Coal-to-liquids is a mature technology receiving funding from the private sector for evolutionary advances and incremental improvements and, therefore, not consistent with the administration's research and development investment criteria. However, the fiscal year 2007 budget does support production of hydrogen from coal and some funding will be used for development of liquids that while not directly applicable for conventional internal combustion engines, could be an efficient way to move fuel for hydrogen applications through the existing infrastructure. The resource exists, current technology is available, and it is possible that continued evolutionary R&D will produce advanced processes that will continue to modify the economic and environmental performance of those processes used in the implementation of a coal-to-liquid industry for the production of alternate fuels. These fuels could contribute to reducing our dependence on oil imports and significantly contribute to the Nation's energy security.

This completes my testimony and I would be pleased to respond to your questions.

[The prepared statement of Dr. Miller follows:]

PREPARED STATEMENT OF CLARENCE L. MILLER, DIRECTOR, OFFICE OF SEQUESTRATION, HYDROGEN, & CLEAN COAL FUELS, OFFICE OF FOSSIL ENERGY, DEPARTMENT OF ENERGY

SUMMARY

The United States' future economic security will remain linked to an efficient transportation system of air, rail, and highway vehicles that depend on a continuous supply of affordable liquid fuels with characteristics enabling vehicle manufacturers to meet increasingly stringent environmental regulations. In the current supply/demand situation, the Nation's transportation fuel requirements are met in part by crude oil and refined products from unstable regions of the world. Crude oil delivery and refining in the Untied States is concentrated in the Gulf Coast region, which presents concerns regarding destructive weather conditions. Additional challenges, including urban and regional air pollution, greenhouse gas emissions, and the availability and cost of transportation fuels, present unique issues that must be addressed to safeguard economic growth, social stability and public health.

Technology is now in hand for producing synthetic oil, and oil products from coal. Liquid fuels from coal are clean, refined products requiring little if any additional refinery processing, are fungible with petroleum products and, therefore, can use the existing fuels distribution and end-use infrastructure. There are preliminary analyses [Mitretek Technical Report 2005-08, "A Technoeconomic Analysis of a Wyoming Located Coal-To-Liquids Plan"] that indicate synthetic oil costs may drop into the $35 per barrel range after several initial higher cost plants are built. This estimate assumes near-zero atmospheric emissions of criteria pollutants, assumes reduced water use through air coolers instead of water cooling, and assumes carbon capture and sequestration. However, no commercial U.S. plants have been built. The primary barrier to commercial introduction of the technology has been the volatility and uncertainty of world oil prices. The private sector financial markets are best positioned to evaluate whether, when, and how to build coal to liquids plants given this market uncertainty.

THE RESOURCE

Coal is the most abundant fossil fuel resource in the United States. Recoverable coal reserves are estimated (as of January 1, 2005) at 267 billion tons. As coal mining technology improves and additional geological information becomes available, this reserve estimate will grow, since it is based on current mining methods and the measured and indicated reserves within a total U.S. coal resource base estimated at nearly 4 trillion tons. These coal resources are widely distributed throughout the United States with recoverable reserves located in 33 states.

Based on current annual production of nearly 1.1 billion short tons, the United States has an approximate 250-year supply. However, this estimate needs to be placed within the context of the projected use of domestic coal in the United States and how coal reserves and resources are defined and quantified. To the first point, the Energy Information Administration (EIA) projects a steady rise in coal consumption to 1.78 billion short tons by 2030 in its reference case forecast. The increase is largely due to the projected increase in new coal-fired power generating capacity, projected to increase at 1.7% per year through 2030. To the second point, the EIA estimates the "demonstrated coal reserve base" at 494 billion short tons. With anticipated advances in mining technology, there is the potential to access a significant portion of the reserve base, and support some degree of increased production of coal for a coal-to-liquids industry.

BACKGROUND: COAL TO LIQUIDS PRODUCTION

Production of liquid fuels from coal has a long history, and the significant advances made in technology over the past two decades make it a potential component of a strategy to increase domestic production of liquid fuels. In the early 1900's coal was first reacted with hydrogen and process solvent at high temperature and pressure, and produced a coal-derived liquid or synthetic crude oil. This direct liquefaction approach was later improved and used by Germany in the second world war to fuel the Luftwaffe with high octane aviation gasoline. In the 1920's two German scientists, Fischer and Tropsch, passed synthesis gas—consisting of carbon monoxide and hydrogen—over metallic catalysts and produced pure hydrocarbons. These hydrocarbons produced by the Fischer-Tropsch (FT) process proved to be excellent transportation fuels. This overall coal-to-liquids process, known as indirect liquefaction because it first involves complete breakdown of the coal to synthesis gas, was used commercially in the 1950's by the South African Synthetic Oil Corporation (SASOL) to produce transportation fuels (gasoline and diesel) using synthesis gas produced by the gasification of coal. Since then, SASOL has built two large facilities that produce over 150,000 barrels per day of transportation fuels. The South African government enabled these plants to be built by providing a price floor safety net for SASOL's coal liquids. In both cases, Nazi Germany and Apartheid South Africa, the primary motivation for government support of coal liquids was that the countries were not able to access world oil markets.

TECHNOLOGY STATUS

The U.S. Government—directly and through industrial partnerships and international cooperation—has for over 30 years supported R&D on both direct and indirect technology. The Government programs resulted in improved processes, catalysts and reactors. These indirect liquefaction of coal processes produce clean, zero sulfur liquid fuels that are cleaner than required under the EPA Tier II fuel regulations. These fuels are compatible with petroleum fuels and can utilize the same distribution infrastructure. Because these fuels are essentially refined products, very little if any additional refinery capacity would be needed for their upgrading. Indirect liquefaction technology has a proven track record and is technically viable. Although SASOL has successful commercial plants in operation, the integration of modem entrained-flow coal gasification with advanced slurry-phase FT synthesis has not yet been demonstrated. Preliminary studies [Mitretek Technical Report 2005-08] indicate that first plant costs would have products in the $45 per barrel range, but no commercial U.S. plants have been built, making cost estimates difficult. Still more difficult to estimate is the cost of production for subsequent plants, but these studies indicate that coal liquids might eventually be produced in the $35 per barrel range if domestic construction experience is gained. However the principal market barrier discussed would remain. China, with an increasingly large appetite for liquid fuels, scarce supply of domestic petroleum and large coal resources, is reportedly moving toward commercialization of coal-to-liquids technologies. In the U.S. demonstration plant to produce liquid transportation fuels from anthracite waste was competitively selected in January 2003 under DOE's Clean Coal Power Initiative. However, the project has been unable to obtain financing for the private sector cost share.

OPPORTUNITIES AND IMPEDIMENTS

As noted, the U.S. is endowed with over 267 billion tons of recoverable coal reserves, equivalent to 250 years supply at current usage rates. The opportunity exists to use coal-to-liquids (CTL) technologies to produce clean transportation fuels that could supplement petroleum supply if world petroleum prices remained elevated over the approximately 30-year time horizon required to pay back the significant initial capital investment.

Despite current world oil prices, there are significant existing impediments to deploying CTL technologies: first and foremost, the uncertainty and volatility of the world oil price; high capital investment for the plants; technical and economic risks associated with first-of-a-kind plants; environmental concerns associated with increase coal production and the coal to liquids industrial process; public attitude to increased coal use; siting and "not in my backyard" issues for new plants; and increasing the supply of coal given a supply chain that is already stretched to capacity. Over the long term, the capital cost of the plants could be reduced by the experience gained in the actual construction and operation of commercial facilities. It is well documented that first-of-a-kind plants are always significantly more costly than subsequent or $N^{th}$ plants. While coal liquids technology is proven, the domestic construction industry has an opportunity to reduce its costs with increased experience. Environmental concerns can be addressed by using clean coal technologies to reduce emissions of criteria pollutants, and in the future to capture and sequester carbon dioxide to limit greenhouse gas emissions. Siting issues can be mitigated by maximizing retrofit opportunities at existing coal-fired power plants.

ENVIRONMENTAL ISSUES

The technology that underlies CTL fuel production offers the potential for low emissions of criteria and toxic air pollutants, water quality, and solid wastes. Nonetheless, this promise of high performance needs to be verified during the design and initial operations of first-of-a-kind CTL plants and costs may be prohibitively expensive. Significant water demand will remain a constraint on CTL fuel production, particularly in regions with limited water resources. Other key environmental issues are the impacts on land, land use and watersheds caused by coal mining and the traffic and local development associated with CTL plant construction and operations. These considerations may prevent the construction of CTL plants in particular areas. However, coal resources suitable for CTL fuel production are widely distributed throughout the United States. The impact of site-specific environmental constraints on the development of a strategically significant CTL industry will depend in part on how environmental regulations are applied on local, regional, and national levels. Permitting delays should be anticipated, especially in view of the large size of and lack of experience in operating CTL plants. Even if the environmental risks are addressed, there is a very good possibility of public reluctance to accept the need for large new industrial facilities, particularly those using coal.

At present, no requirements exist in the United States to manage carbon emissions from fossil fuel sources. However, in full recognition of the importance of carbon management an extensive research and development program is underway to develop technology, processes and systems to capture and store the carbon dioxide produced during the conversion process. The carbon dioxide could be stored in deep saline formations or sold for use in enhanced oil recovery operations. It is possible that CTL plant emissions and the emissions from utilization of CTL products would be comparable to those associated with the production and consumption of petroleum-based fuels.

### NEXT STEPS

The greatest market barrier for CTL is the volatility and uncertainty of future world oil prices. The private sector is best positioned to evaluate market or oil price risk and respond accordingly with an appropriate deployment strategy.

Although past department efforts and some Congressionally directed funding has focused on production of liquid fuels from coal, the FY 2007 Budget does not support these activities. Coal to liquids is a mature technology receiving funding from the private sector for evolutionary advances and incremental improvements and therefore not consistent with the Administration's Research and Development Investment Criteria. Although the FY 2007 Budget does not directly support CTL technology, there are some overlapping activities directed at electricity and hydrogen generation that the private sector could apply to reducing production costs and technical risks, and improving environmental performance of coal to liquids plants. The FY 2007 Budget supports production of hydrogen from coal and some funding will be used for development of liquids that while not applicable for conventional internal combustion engines because their hydrogen content is too high, could be an efficient way to move fuel for hydrogen applications through existing infrastructure. The FY 2007 Budget promotes the goal of reducing dependence on foreign sources of oil through development of technologies consistent with the Research and Development Investment Criteria, such as cellulosic ethanol, battery technology, and hydrogen, among others. Over the mid to long term, these technologies could reduce demand for conventional sources of petroleum and ease pressures on world oil prices.

The resource exists, current technology is available and it is possible that continued evolutionary R&D will produce advanced processes that will continue to modify the private sector's analysis of whether the economic and environmental performance of the processes used in the implementation of a coal-to-liquids industry for the production of alternate fuels justify plant construction, in tandem with the primary consideration of petroleum market risk.

If economic, these fuels could contribute to reducing our dependence on oil imports and significantly contribute to the Nation's energy security.

This completes my testimony, and I would be pleased to respond to your questions.

Senator BUNNING. Thank you, Dr. Miller. First question is one about the, since we passed the energy bill and I have not seen any movement on the part of DOE to implement the loan guaranteed program. What is the status of this program and what loan guarantees—are there any for CTL projects?

Dr. MILLER. I'm afraid I don't have the information to answer that particular question but I do know that there is considerable activity in progress and the Department is supporting the efforts of the Treasury Department and other relevant agencies in the preparation of the criteria that would be used in the application of those incentives.

Senator BUNNING. Well, I suggest that you go back to your Department of Energy and find out exactly what their program is going to be to implement the provisions in the energy bill for CTL projects.

Dr. MILLER. I'll be happy to and we'll submit that back for the record for you.

[The information follows:]

The Department of Energy (DOE) has established a loan guarantee office under the Department's Chief Financial Officer. In implementing the program, we will follow the Federal Credit Reform Act of 1990 (FCRA) and Office of Management and Budget (OMB) guidelines, and we will emulate "best practices" of other federal agencies. Toward that end we are drafting program policies and procedures, establishing a credit review board, and plan to employ outside experts.

Title XVII of EPAct 2005 authorizes DOE to implement loan guarantee programs for projects that avoid, sequester, or reduce air pollutants and/or anthropogenic emissions of greenhouse gases, and "employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued." Projects that employ coal gasification or liquefaction may be eligible under the Act to apply for loan guarantees.

Title XVII allows for project developers to pay the cost of loan guarantees issued by DOE. While this "self pay" mechanism may reduce the need for appropriations, it does not eliminate the taxpayer's exposure to the possible default of the total loan amount. Therefore, DOE's evaluations of applications will entail rigorous analysis and careful negotiation of terms and conditions.

FCRA contains a requirement that prevents us from issuing a loan guarantee until we have authorization to do so in an appropriations bill. We do not believe we have authority to proceed with an award absent having the necessary explicit authorization in an appropriations bill.

Senator BUNNING. Thank you. I appreciate that. Dr. Miller, are the Department's resources sufficient to pursue rapid development and deployment of coal-to-liquid technologies?

Dr. MILLER. Mr. Chairman, we would expect that that will be the responsibility of industry. As noted in the testimony, the technology is commercial, it is being pursued by a number of potential industries that we are aware of and we would expect them to pursue and, when economic or appropriate, implement that kind of an industry.

Senator BUNNING. Then you are saying there are enough resources at DOE to assist a commercial development of CTL?

Dr. MILLER. You are correct. We are actively involved in assisting industry in doing a lot of estimates and assessments of the technology and in the application of the technology.

Senator BUNNING. When will DOE's guidance be issued and when will DOE's—DOE be accepting applications for the loan guaranteed program? What do you foresee as a timetable for this program?

Dr. MILLER. Once again, Mr. Chairman, that's an answer I'm going to have to submit to the record and it will be part of the other answer simply because the DOE is not responsible for producing the actual criteria for the implementation of those incentives. We wouldn't——

[The following was received for the record:]

We are in discussions with OMB regarding the guidelines and anticipate issuing them as soon as is practicable.

Senator BUNNING. But in the bill, didn't we specify that there would be guidelines set out by DOE?

Dr. MILLER. That is true and we are following the requirements of the EPAct precisely and in EPAct there are dates set for the delivery of each of those particular items and we're following that the Secretary has emphasized that his staff will meet those particular criteria and I know work is underway.

Senator BUNNING. As you know, the Department of Defense has expressed great interest in the CTL technology as a way to produce a secure domestic fuel source for our military. Section 369 of the energy bill provided that DOE participate in the Department of Defense Assured Fuel Program to evaluate the potential of CTL for use by the military. What is the status of that program presently?

Dr. MILLER. I do know that that report has been prepared, I do know that it has been submitted to the department's concurrence process and that is——

[The following was received for the record:]

We have been working quite closely with representatives of the Department of Defense on their Assured Fuels Program/Initiative. A draft report has been prepared in response to the requirements of Conference Report 109-360 and it does consider the status of the coordinated efforts on the initiative that have taken place between the Department of Defense and the Office of Fossil Energy.

Senator BUNNING. The Department of Energy or the Department of Defense?

Dr. MILLER. I'm sorry. To be more clear, we have—Department of Energy has completed the draft report, we have submitted it to our management structure for concurrence, and it is somewhere in that process. We will meet the date.

Senator BUNNING. But DOD, Department of Defense, does not have that report currently?

Dr. MILLER. That I can't answer. I don't know whether it's been transferred over to them for their review or not.

Senator BUNNING. Senator Thomas, would you like to get in on the questions?

Senator THOMAS. Yes, I would. Thank you.

Senator BUNNING. Thank you.

Senator THOMAS. Thank you very much. Thank you for even being here, Dr. Miller. Appreciated your being in Wyoming a week or so ago for a conference we had there. And on this very topic, as a matter of fact.

Dr. MILLER. Correct.

Senator THOMAS. So we appreciate that very much. Since I wasn't here at the beginning, I just have to share with you a thought or two that I think as Senator has pointed out, I think we have a policy in place that moves this in this direction and now our challenge is to implement that policy and I think in some cases to differentiate between those alternative sources that are out there 30 years from now or 20 years from now and those that we know how to be able to do now, if we can put into place the initiatives and the operations to do some of those things. So, for instance, the energy policy, of course, establishes a loan guarantee program which covers 80 percent of the cost associated with some of these projects, authorizes a billion dollars over three years of conversion to coal-to-liquids.

So I guess that's really what I'm interested in is how we can move a little more quickly. There's quite a bit of the private sector that's ready to go. They're out there kind of wondering how can we get the approval, how can we get involved in the incentives that are available, and just kind of holding the thing up. So do you think the structure in the Department of Energy is sufficient to pursue this? Should there be a separate program specifically designed to pursue the coal-to-liquid research development demonstration or is it lost in the bureaucracy of the total bureau?

Dr. MILLER. As I noted in my verbal testimony, we are participating, as we're being requested to by industry, in feasibility studies and in reports assessments of the technology. The Department considers that the technology is commercial and it is being pursued by a number of industries and it really is not in the investment criteria that we now are following as it is commercial and we're assuming that private sector will now make whatever technology advances are necessary to meet their goals and objectives.

Senator THOMAS. But these objectives and goals and this is a very expensive operation and one that needs to have some assurance that there's going to be a long-standing market here before making that tremendous investment. So I don't think we're talking about doing the research. I think we're talking about putting into place the incentives, the dollar incentives, whether they be loan guarantees or whether they be incentives that will give the people who already have the technology—we've got a company in Wyoming waiting to make diesel fuel but we haven't gotten the criteria for the application, for the dollars to take advantage of what's in the bill at this time and I understand it's because the Department isn't ready to do that.

Dr. MILLER. Senator Thomas, we've always, even in the R&D, we've recognized for some time that the volatility and the price fluctuations in the world oil market is a major impediment to the implementation of any coal-to-liquids industry. We've gone through this on several cycles where we have started a coal-to-liquids industry and then had the floor of the world oil price drop out and not be able to continue. We consider, and after looking at EPAct 5, we recognize that that contains the mechanism for implementing a program of incentives, we recognize that they are there and I know that the Department—I am not part of that particular activity but aware of the fact that the Department—is moving very rapidly to implement the terms and the intent of EPAct 5. And as I've already mentioned, we will be back to the Congress with a memo to the record telling or stating exactly what the progress is, what the schedule is, to the best that we can and it will be submitted for the record.

Senator THOMAS. I appreciate that but I have to tell you that particularly given what the President's saying these days with respect to the oil business and the oil shortage and so on, committed to doing something of this kind. And the fact is that times have changed pretty clearly. In the past I know we did wonder whether we would be out of the oil thing but now that we see India and China going the way they are we know that this is a permanent problem, this business of relying—and fossil fuel is our greatest resource. From a technical standpoint now one of the issues is going to be the politics of setting up these plans, I suppose, and we as you know, I've specifically said in the bill that we want to have some of this gasification at an altitude of over 4,000 feet. And I hope that we can recognize that's where the coal is and that we ought to be moving along getting—the problem now, as you know, of using coal is that you get $15 for the coal and it costs $30 to get it to the market in a railroad car.

Dr. MILLER. I would concur.

Senator THOMAS. And so one of the things we can do is take advantage of our greatest resource by being able to modernize it. So I appreciate what you're doing but I just have to close by saying that I do think there doesn't seem to be quite the anxiety to get moving in the bureaucracy as there is in the private sector and I hope we can bring those two things together.

Dr. MILLER. I think as time goes on you'll see that that feeling of urgency is also in the Department as they complete the requirements under EPAct 5 and submit the documents that are requested in that particular document. As an aside, I feel it's important to note that with respect to your concern about technology, the R&D program is well-prepared with technology that can operate and under the conditions that are of some concern.

Senator THOMAS. Thank you.

Senator BUNNING. Dr. Miller, this is only one alternative we put in the energy bill. This is one of many alternatives for synthetic fuels or other fuels to get our dependency out of the Middle East and create a situation where we can do like Brazil has done. All of a sudden they have 85 percent of their own fuel being produced domestically and then used by alternative vehicles that have been produced domestically. So I want you to make sure that we only—not only do we need this alternative that we're talking about but we need many others whether it be bio-diesel, whether it be ethanol or whatever it might be.

I gave you some information earlier about the energy information projections for coal-to-liquid technology usage for the next 25 years in my earlier statement. Do you believe these predictions of large scale CTL usage are attainable?

Dr. MILLER. I do.

Senator BUNNING. You do believe that?

Dr. MILLER. Yes.

Senator BUNNING. And that's why it's so important for the Department to get geared up so that those commercial usage people can—we're never going to have a stable oil price. You can mark it down. It's going the fluctuate between somewhere between $50 and $100. It may go over that. So unless we are positive about where we're heading with this program and the Department of Energy is ready to assist because of the instability of the price of oil. We're trying to take that instability away. That's the whole idea of the energy bill last year to make sure that we have a domestic source of something and we're not dependent on the Middle East for their petroleum. So this is very important for us.

Could you explain your current TCL research efforts and discuss why past research initiatives failed to create a sustained marketplace for CTL products?

Dr. MILLER. Yes, I can. First, Mr. Chairman, let me go back to one of your assessments in the introductory comments. You are aware I'm sure that my expertise is coal-to-liquids and has been for a number of years, however, my other duties have made me aware and I'm sure you're aware that in our Office of Energy Efficiency and Renewable Energy there is a great experimental effort going on on each of those alternate fuels, that alternate technologies for the production of alternate fuels that must be made in order to accomplish the supply of liquid fuels that are required. We're also now looking at the production of hydrogen from coal. The technology for the production of hydrogen from coal is very similar and consistent with some of the work that has to be done to improve the efficiency, improve the quality and quantity of a coal-to-liquids facility. So we are still working on those kind of advanced technologies, exciting technologies that have a great deal of opportunity to ensure that we arrive at an economic supply of alternate liquids from coal.

Senator BUNNING. My last question, I have some others I'll submit to you for the record but my last question is: section 417 of the energy bill authorizes $85 million to test advanced technologies for the protection of transportation fuels manufactured from Illinois base coal. It also provides funding for the construction of testing facilities at the University of Kentucky's Center for Applied Energy Research, the Southern Illinois University Coal Research Center and the Energy Center at Perdue University. Could you provide an update on this initiative.

Dr. MILLER. That initiative has been addressed as one of the requirements of EPAct 5 and we have prepared a submission that is consistent with the associated date for that so I do know that there has been an analysis done, I do know that there has been some conversation with the Consortium of Universities and that report has been prepared. I will have to find out the status but I do know that we have addressed that, we have prepared a deliverable, and I'll just have to check where it is.

Senator BUNNING. Just so our energy committee staff gets a copy of that because it's essential that we know what's going on.

Dr. MILLER. Okay. I will certainly get back to you with that.

[The information follows:]

Section 417 authorizes $85 million for the period of fiscal years 2006 through 2010 to do R&D on transportation fuels from coal at specific universities using designated coals. This section further states that "not later than one year after the date of enactment of this Act, the Secretary shall offer to enter into agreements . . ." to do Fischer-Tropsch R&D and to modify/construct appropriate facilities at the referenced universities.

However, the Department has not identified funding available to do the authorized work. The Department's FY 2006 enacted appropriation and the FY 2007 budget request did not include funding for this effort. It should be noted that the Department has not asked for Coal-to-Liquid (CTL) R&D funding for several years. The earlier effort to develop CTL technology has been considered a success, as it lowered the cost of the coal derived product to a $35 per barrel range for large mature plants ($45 per barrel range for first-of-a-kind, commercial facilities). These costs are considered to be competitive with other forms of energy and an indicator of the commercial status of the technology. Further R&D to marginally reduce these costs would be costly.

Senator BUNNING. Senator Thomas, do you have any more?

Senator THOMAS. No.

Senator BUNNING. I want to thank you for coming today. We'll submit three other questions I have for the record and I appreciate you coming today.

Dr. MILLER. Again, I thank the committee for the opportunity to introduce you into coal-to-liquids and where the status of the technology is.

Thank you.

Senator BUNNING. Thank you. If the second panel would come up and staff would get ready for them. I hope I don't destroy your name in the pronunciation of it. Dr. Arie Geertsema.

Dr. GEERTSEMA. Pretty close, Mr. Chairman.

Senator BUNNING. Pretty close. Okay. Mr. David Hawkins, Mr. Hunt Ramsbottom, and Mr. James Roberts. Doctor, you are our initial man so you start us off.

**STATEMENT OF DR. ARIE GEERTSEMA, DIRECTOR, UNIVERSITY OF KENTUCKY CENTER FOR APPLIED ENERGY RESEARCH**

Dr. GEERTSEMA. Thank you, Mr. Chairman, ladies and gentlemen. Thank you very much for the opportunity to be here and the invitation to talk to you this afternoon. As background, I've been with the South African company SASOL for about 20 years of which 3 years as a works manager of the SASOL I plant and the last 10 years as the person in charge of corporate research and development. I was in Australia involved with gas to liquids for a number of years before I joined the University of Kentucky as director for the Center for Applied Energy Research about 5 years ago.

I wish to discuss how progress can be made to establish a viable, sustainable coal-to-liquids industry in the USA. And I'll focus on coal-to-liquids and gasification from a technology development and project execution perspective. In my written testimony I mentioned a number of factors which contributed to SASOL's success. In the interest of time, I will not dwell on those now but I'm pleased to note that provisions of the EPAct regarding loan guarantees and thick tax credits will similarly facilitate the early deployment of coal-to-liquids in collaboration with industry. Also subsequent ongoing legislation will strengthen this approach. I think one should note that this applies not only to coal-to-liquids in a generic sense but specifically to fuels, chemicals, and also to industrial gasification facility and also synthetic natural gas.

In support of implementing the intent of the Energy Policy Act, I suggest that serious consideration be given to reestablish official coal-to-liquids program in the DOE fossil energy budget. I say that with respect to the testimony that Dr. Miller has just submitted. In the DOE there are indeed components of CTL being addressed right now but CTL as such doesn't appear as a programmatic line any more. There are projects which proceed along the lines of the Clean Coal Power Initiative which involve Fischer-Tropsch technology in direct liquefaction but I believe we urgently need a broad-based research, development, and deployment program covering enabling, developmental, and piloting work. The benefits of such work are in my opinion clear. Human resources could be generated that way. They're urgently needed across the board at the moment in the coal field, coal technology field. It will provide a basis for process development and it will create facilities to provide test quantities of finished products of different grades. And the key thing here is that this will be open access research. At the moment, as Dr. Miller has indicated, companies can move forward but all that IP is so closely held that there is very little in the public domain and I think the sort of work that the DOE can fund and has funded in the past can open this up a bit.

There's just been reference to section 417 by the chairman and I don't want to elaborate on that except to say that we have formed an alliance called the Coal Fuel Alliance and have submitted a request to the House Appropriations Committee for year one's appropriation to establish and expand the facilities in order to produce about half a barrel a day liquid fuels with the specific intents of coupling the synthesis with the refining to final products. That's a facility which doesn't exist anywhere and we at CAER have had experience with the open access type of research for quite a number of years, but that has not been put into the appropriations process formally yet.

Going forward, I suggest that the emphasis should be first to establish larger scale facilities and, second, but in parallel to strengthen the R&D base by creating an aggressive Federal R&D program. I provided comments regarding cost estimates for project implementation. We all appreciate that large facilities generally provide an economy of scale whereas I also recognize that smaller facilities, and I'm talking of facilities in the range of maybe 5,000 or 10,000 barrels a day, might under specific circumstances also have a viable justification. That would have a sort of a penalty in terms of the capital cost outlay but circumstances are different from case to case.

Looking ahead, I suggest that an initial target for coal-to-liquids should be in the range of about a million barrels per day. I said initial and beyond that one can certainly take it further. A million barrels a day is only about 5 percent of the current consumption of liquid products in the United States. In going forward with this strategy, one should surely consider the construction capabilities, the coaling fact as was mentioned, and certainly also the human resource. All these things should be an integral part of that strategy.

In this context I want to also alert you to the American Energy Security Study which was initiated through the Southern States Energy Board. The report is due by the end of June and this report will cover strategy, macro-economic impacts, and costs of the CTL and other technologies. Furthermore, it will I believe help to shape the paths to greater fuel self-sufficiency.

In conclusion, Fischer-Tropsch fuels are environmentally superior and as shown at the Great Plains facility in North Dakota $CO_2$ capture and sequestration can be done successfully in a gasification facility. Second, the EPAct sets us on the right course. We need to pick up speed to facilitate together with industry the rapid building of facilities and simultaneously to broaden our R&D base. Third, I believe CTL economics support viable projects even at crude prices significantly below what we see today. And, lastly, commercial scale CTL has been done successfully and I believe it can be done again here in the United States.

Thank you, Chairman.

[The prepared statement of Dr. Geertsema follows:]

PREPARED STATEMENT OF DR. ARIE GEERTSEMA, DIRECTOR, UNIVERSITY OF KENTUCKY CENTER FOR APPLIED ENERGY RESEARCH (CAER)

Mr. Chairman and Members, thank you for the invitation to contribute to the discussion about gasification and coal to liquids (CTL) in the context of the Energy Policy Act of 2005.

By way of introduction, I present some of my background. I was with the South African company Sasol, the world's only commercial coal-to-liquids company, for 20 years. I was the Works Manager at the original Sasol One plant for three years and then led the corporate R&D of Sasol for a decade until the end of 1997. Then followed a period in Australia working on natural gas conversion to liquid fuels (GTL) before I joined the CAER in the beginning of 2001. I am therefore very familiar with both the theory and practice of CTL and gasification technologies.

In this testimony I wish to share with you some of my views regarding the greater deployment of CTL technology and, more importantly, suggestions on how progress can be made to establish a viable and sustainable CTL industry in the USA. I do this on behalf of the CAER and also wish to note that I am a member of the executive panel for the Southern States Energy Board's "The American Energy Security Study" where I am the representative of the Kentucky Office of Energy Policy, a co-sponsor of the study. I am also representing the University of Kentucky in the three-university "Coal Fuel Alliance". I'll later comment on both these activities.

I shall not dwell on the by now well-known compelling statistics regarding liquid fuels supply and projected demand coupled with strategic and security of supply considerations. I'd rather focus on CTL and gasification from a technology development and project execution perspective. I shall deal with CTL with emphasis on indirect (Fischer-Tropsch) rather than direct liquefaction.

In Attachment A,* I present a brief review of aspects of the Sasol developments from which some pointers can be taken which have contributed to their known commercial success. Some of these aspects from especially the Sasol Two and Three experiences include:

- A national will to reduce the import of crude oil for transportation fuels existed
- The projects showed financial viability when started
- Government loan guarantees were provided
- A floor price mechanism (fuel prices are regulated in South Africa) was established
- Timing, in retrospect, was ideal
- Rapid repayment of loans occurred and the company has long been functioning financially independently in the private sector and there are and were very significant macro-economic benefits to the establishment of this industry
- Subsequent internationalization of the business and diversification strengthened profitability
- Many further growth opportunities were implemented, and a 34,000 bbl/d Gas-to-Liquids plant in Qatar is due to be inaugurated early in June 2006
- Ongoing significant investments in R&D are made and technology developments improved profitability. ($60 million for additional FT pilot units was announced this year.)

Reflecting on the above considerations, one notices that the Energy Policy Act of 2005 provides a framework for establishing conditions which reflect spine of the mentioned Sasol success factors, such as loan guarantees and tax credits which will ease the financing of projects. The President clearly stated that the USA should move to a greater self-sufficiency regarding transportation fuels, with specific reference to coal derived fuels. Thus the strategic intent to promote CTL in the U.S. is developing and is set to gain further momentum as is reflected by legislation introduced by various senators since the enactment of the Energy Policy Bill of 2005.

The latest DOE Fossil Energy budget contains some components for funding CTL related activities, like gasification, gas clean-up and CO capture with sequestration. However, CTL as such does not currently feature as a separate program. Although there are now commercial FT units, it is, in my opinion, justifiable to put CTL RD&D back into the DOE portfolio. The geopolitical and commercial circumstances

*Attachments A and B have been retained in committee files.

now justify such a step. An increased level of funding at all levels of RD&D will greatly enhance future success, as will be discussed below. There has been support for projects of Syntroleum, Headwaters and WMPI (the latter two through the Clean Coal Power Initiative), some of which are still in negotiation. Demonstrations of this kind are appropriate but I believe a more broad-based program with a balance between enabling research, pilot units and demonstration facilities should be supported.

In the deployment of CTL there is often an urge to deal with a perceived lack of commercial progress by promoting more Research and Development. Any technology can be improved by doing more R&D, as has been proven. In this case, I believe the short term thrust should be to get facilities built and to establish an experience base for the production of products and to simultaneously embark on a more aggressive R&D program. There is much to be gained by establishing an active FT CTL program in the U.S. again. There will be several substantial benefits from doing this:

- Currently the local human resources in this area, as in coal technology in general, are scarce. By encouraging industrial and DOE sponsored research, new human resources will be cultivated at undergraduate and graduate level. Prototype pilot plants can serve as valuable training grounds for operators and technicians and can also be used for component level development.
- The results from such R&D could be closely coupled to operating facilities to ensure relevance to, optimize processes and products further.
- Studies to improve product performance can be done much more cheaply at a small pilot scale which needs to be a "proof of concept" type facility where products of different specifications could be produced for engine and turbine testing. Especially with the great interest from the DOD in "single battlefield" fuels, this could be an important asset.

The Energy Policy Act of 2005, Section 417, authorized $85 million for the universities of Purdue, Southern Illinois and Kentucky to pursue the development of FT CTL based on Illinois basin coal.

- These universities entered into a Memorandum of Understanding in October 2005 and have started collaborating with seed funds made available by the respective state governments. The name Coal Fuel Alliance (CFA) was chosen. A request for the appropriation of funds for the first year was submitted in March 2006 to the House Energy and Water Appropriations Subcommittee. Attachment B is a copy of this request. It outlines the rationale for the initiative with emphasis on the first year's activities. A request of $14.5 million, which will be leveraged by contributions from the universities and states to make $18.1 million available, was submitted. The first step will be to establish a ½ bbl/d FT facility at CAER with a "mini-refinery" to produce products for engine testing. This is on the critical path to generate samples of different grades and qualities so that later, larger facilities can be designed more specifically to meet targeted specifications. These products will be tested in the engine testing facilities at Purdue. Collaboration with the DOD to make products in the "mini refinery" for their applications is envisaged.
- The CFA wishes to carry on "open" research, such as the CAER has done over many years. This implies not being locked in to a single technology or having constraining IP limitations, but rather to be available as a test bed for various technologies and companies.
- The CFA has been in discussions with DOE NETL officers to keep them informed of its plans. The CFA accepts that within the current NETL programs and budget there is not provision for the CFA activities but a profitable collaboration is foreseen in the near future as appropriations might be made to the CFA.
- The plans for the next few years have started to take shape although the CFA has not yet decided on details for the "test facility" as foreshadowed in the Act.

There are existing commercial technologies which could produce transportation fuels by using CTL. (This argument has been used in the past to terminate the DOE funded FT catalysis work.) However, FT technologies and applicable commercial experience are not necessarily readily available to all industrialists who wish to practice CTL. There are commercial reasons for this situation, which I do not want to go into now. I suggest that there will be great value in supporting a range of technological options for the various processes involved in CTL. For instance, various gasifier developments have been and are being supported. The same approach can be applied to CTL. By creating more options at the enabling, pilot and demonstration level, the market place and commercial realities can take implementation forward.

Several factors are of importance and supported development of different approaches could help to address these matters:

- A CTL plant is comprised of a very complex integration of a number of major process blocks such as coal gasification, air separation (when an oxygen-blown gasifier is used), gas cleaning, FT synthesis and FT product refining to final products. There are also numerous infrastructural, environmental control, ash handling and steam/power system facilities which are essential. The full commercial integration of these process steps for CTL has so far only been done by Sasol. Building blocks at various levels of operational readiness are offered commercially but more experience with integrated facilities is needed to provide comfort to financiers. A so-called "wrap-around" package from a reputable company will greatly improve the bank-ability of CTL projects. In this phase of uncertainty, support and encouragement measures will be helpful.
- Recent estimates by the DOE, various consultants and Sasol indicate that the capital outlay for a CTL facility could be $60,000 per daily barrel or more provided it is of a meaningful size, preferably about 50,000 bbl/d or larger to get good economy of scale. These numbers are only indicative and the actual cost will vary with the location, site-specific conditions and other factors. This means that a 50,000 bbl/d facility will cost at least $3 billion. It should however, be noted that there are cases when smaller plants would suit the needs of project developers or site specific circumstances better. By accepting a certain "dis-economy" of scale, (a higher capital cost per instilled capacity), the overall project economics might still be attractive. There could for instance, be a justification for facilities of 5,000 to 10,000 bbl/d to produce products for certification by the military for special grades of fuel. There might also be developers who prefer modular decentralized facilities rather than large units.
- There are options for lowering the capital cost, such as using a brown field site or co-locating with facilities and sharing common infrastructure. Such cases are site specific and generic economic numbers can be misleading and should be avoided.
- The yield of liquid products in a CTL facility will depend on the quality of the coal and also how much coal will be used in a facility to co-produce the needed power for the plant, or to produce additional power for export. A typical figure is about 2 barrels per ton of coal. This implies that for a 100,000 bbl/d facility about 50,000 tons/day coal is required or about 18.3 million tons per year.
- It seems on paper that a combination of CTL with IGCC (co-production) can be more attractive than only CTL. A few considerations: Both CTL and IGCC plants should preferably be running at high stable production levels and are not easily and profitably suitable for short term "peaking" or load following adjustments. For IGCC the profitability is very dependent on the competitive price of power at the location of the plant. From an operational perspective, this adds one more level of complexity. However, for a CTL plant there is a substantial amount of power required within the plant and normally there will be on-site power generation using energy resources from the process. Therefore, expanding such power generation to a full-fledged IGCC facility should be considered on a case-by-case basis. Synergies could well make this more viable, albeit at a higher capital outlay.
- If one wishes to make a strategic impact, I consider about 1 million barrels/day as a meaningful initial target. (That is less than 5% of the current 21 million barrels of oil and fuel used in the U.S. daily). For this the coal supply would require about a 20% increase above current coal consumption. The impact of such a growth in coal production has to be considered together with the ongoing projected growth in coal demand for electric power generation.
- Reliable production cost figures are hard to come by since such numbers are usually not provided in detail by operating companies and are very specific to a chosen set of circumstances. However, numbers recently made available by Sasol indicate a direct operating cost of $10/barrel. If a coal cost of $30/ton is added, that adds another $15/barrel. To this amount the financing costs need to be added, which depends very much on the particular project structure and financial arrangements. It is clear that this provides a wide margin to establish a feasible project, and viability is likely even at crude oil prices as low as $45-$50/barrel.

Environmental considerations favor FT CTL. It can be stated that CTL can truly be a Clean Coal Technology when modern commercially available processes are implemented. Furthermore:

- FT diesel is a premium product; even better in environmental performance that CARB diesel and it can sustainably demand a substantially higher price (conservatively about $8/barrel) than crude oil. This differential between CTL diesel and regular diesel above crude oil prices should be calculated into viability analyses. The product qualities of FT diesel are well known. The FT process requires total sulfur removal from syngas (the sulfur is taken out of the process as elemental sulfur, as sulfuric acid or as fertilizer grade ammonium sulphate) and therefore the diesel is essentially sulfur free.
- The $CO_2$ produced in a CTL plant can be readily captured for sequestration (as is done in the Great Plains synthetic natural gas facility in North Dakota).
- FT CTL diesel is compatible with current diesels and can readily be blended into the existing infrastructure. For niche applications, like for special military fuels, certification would be required which could require hundreds of thousands of gallons of products.

A recent project has been initiated through the Southern States Energy Board (SSEB). It is called "The American Energy Security Study". This study has the support from the member states of the SSEB together with a number of other stakeholders. It will deal with strategic matters and present a plan to establish energy security and independence through the production of liquid fuels from various resources, including CTL. It will indicate measures for the rapid deployment of selected options to provide indigenous fuel supplies. Policy issues will be considered with macro-economic impact analyses. An analysis of the relative economics of CTL facilities as a function of the capacity of plants will be presented. The report is due to be available by the middle of the year. It is anticipated that this study will be a powerful tool to help shaping the path forward to greater fuel self-sufficiency.

Numerous design case studies have been performed over the years to evaluate the viability of CTL technologies. With no CTL facilities erected after the Sasol Three in the early 1980's, these estimates are often on the basis of expected performance rather than on proven performance. This can be overcome by involving reputable engineering companies with relevant experience in the field to do a detailed level design to form the basis for a definitive cost and economic evaluation. Such studies can cost tens of million of dollars, depending on the size and scope of the project. These costs will come down in due time as more plants will be built and initial support from governments would assist in expediting earlier deployment of CTL.

Establishing a major project requires getting appropriate partners together. This typically takes a long time for large projects. The team could typically include the owner of the coal resources, the company which has the ability to operate the facility (preferably an owner-operator), a reputable engineering contractor and certainly a strong input to deal with financial, legal and permitting aspects at all levels of government. In this regard the government can and does facilitate some of these steps, but in practice it does not (normally) erect or own such a commercial facility. Under the current circumstances I would expect that such teams will start forming soon to take CTL forward. Indications from the DOD that they might provide product off take agreements will assist in this process.

In conclusion I observe the following:

1. At current crude oil prices and even if prices drop by as much as $20/bbl, I believe that large CTL plants can be economically viable propositions in the U.S.
2. The basic diesel fuels from CTL are fungible and should be able to be introduced into the market without disruptions.
3. The initiatives created by the Energy Policy Act of 2005 set the stage for encouraging CTL and gasification deployment and the momentum to firm up the support mechanisms for potential such projects should be maintained.
4. Close collaboration between DOD and DOE to establish facilities for producing fuels of different grades for testing and certification should be encouraged and initial smaller plants could be supported to get the quantities needed for certifying, for instance, jet fuels.
5. The DOE budget should be strengthened to again support aspects of FT CTL technology development in parallel with the current gasification developments.
6. CTL has been done and can be done in the U.S.

Senator BUNNING. Thank you very much, Doctor.

Mr. Hawkins, go ahead.

**STATEMENT OF DAVID G. HAWKINS, DIRECTOR, CLIMATE CENTER, NATURAL RESOURCE DEFENSE COUNCIL**

Mr. HAWKINS. Thank you, Mr. Chairman, and thank you for the opportunity to testify today on the subject of coal liquefaction or coal-to-liquids technology.

My name is David Hawkins. I direct the climate center at the Natural Resources Defense Council. The idea of making liquid fuels out of coal is being promoted as a way of helping to solve the problem of U.S. dependence on oil. Let me say that NRDC agrees completely that we need aggressive action to reduce oil dependence. There are important questions that need to be asked about each proposal to reduce oil dependence, including a coal-to-liquids program. Is it technically feasible? How much oil consumption will it save? How soon? How much will it cost? What will be the impacts on the proposal of such proposals on health and the environment? And it's that last question that I've been asked to discuss today.

Depending on how coal is produced and used, it can cause very large damages to health and the environment, as we all know. In discussing the coal-to-liquids processes today, I want to focus just on three areas, global warming pollution, conventional air pollution, and the impacts of mining production and transportation of coal. Let me say again that NRDC agrees wholeheartedly that reducing oil dependence should be a national priority and that we need new policies and programs to avert the mounting problems associated with today's dependence and the much greater dependence that will occur if we do not act.

Now, if coal were to play a significant role in displacing oil, it's very clear that the enterprise will have to be very large. In fact, displacing 10 percent of U.S. oil demand would require nearly 500 million tons of additional coal production in the United States, over a 40 percent increase from today's 1.1 billion tons of production. So the question is can that kind of a scale be compatible with our environmental needs and objectives?

On the first question, can we implement a large scale coal-to-liquids program and still get on a path of reducing global warming emissions? The context is to stabilize concentrations of global warming emissions we'll need to reduce emissions significantly from today's levels. Today we haven't settled on how much those emissions will need to be reduced so we need to assess new programs like coal-to-liquids to ask, one, how do they compare to today's crude oil system and, two, how do they compare to where we may need to go in terms of total reductions in emissions to avoid dangerous disruption of the climate?

Now, processing coal to make liquid fuel produces large amounts of coal in the production plant, and then when the fuel is burned, it releases additional amounts of $CO_2$. Available information today on the existing technologies that are being proposed to be deployed indicates that the total emissions from those two components of a CTL program are about 80 percent higher than a crude oil based gasoline or diesel program, if the $CO_2$ from the CTL production plant is released to the atmosphere. Now, if the $CO_2$ emissions are captured from the production plant, the assessment is that emissions from coal-to-liquids would be about the same as today's crude oil system. Now, these facts mean that a large scale program for

CTL would not be compatible with achieving significant global warming emission reductions unless ways can be found to dramatically reduce emissions from the current technology. I'm not going to go into detail on the conventional air pollution and mining impacts in the interest of time. I have laid out in some detail in the prepared testimony the fact that we have very significant impacts associated with mining and transportation of today's 1.1 billion tons of coal and if we're going to be talking about substantial increases in coal production in the United States we simply have to find a better way to deal with those very large impacts and commit ourselves to a real program to reduce those impacts from today's levels.

Today's energy use patterns are responsible for two growing problems, oil dependence and global warming. It would be extremely unwise to try to solve one of these problems and ignore the other. Now, fortunately we don't have to. I lay out in my testimony a package of proposals that would cut oil consumption from today's levels in the next 10 years by three million barrels a day and by 2025 by over 10 million barrels a day. All of these measures will also achieve substantial cuts in global warming emissions and improve environmental quality.

Thank you for your attention.

[The prepared statement of Mr. Hawkins follows:]

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

Thank you for the opportunity to testify today on the subject of coal liquefaction, or coal-to-liquids technology. My name is David Hawkins. I am director of the Climate Center at the Natural Resources Defense Council (NRDC). NRDC is a national, nonprofit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 1.2 million members and online activists nationwide, served from offices in New York, Washington, Los Angeles and San Francisco.

Today's energy use patterns are responsible for two growing problems that require early action to keep them from spiraling out of control—oil dependence and global warming. Both are serious; both warrant much more proactive policy action than has occurred to date. But most important, both problems must be addressed together. Designing strategies that address only one of these problems and ignore the other is a recipe for huge and costly mistakes. Fortunately, we have in our tool box energy resource options that can dramatically reduce both oil dependence and global warming emissions.

Proposals to use coal to make liquid fuels for transportation need to be evaluated in the context of the compelling need to reduce global warming emissions steadily and significantly, starting now and proceeding constantly throughout this century. Because today's coal mining and use also continues to impose a heavy toll on America's land, water, and air, damaging human health and the environment, it is critical to examine the implications of a substantial coal-to-liquids program on these values as well.

REDUCING OIL DEPENDENCE

NRDC fully agrees that reducing oil dependence should be a national priority and that new policies and programs are needed to avert the mounting problems associated with today's dependence and the much greater dependence that lies ahead if we do not act. A critical issue is the path we pursue in reducing oil dependence: a "green" path that helps us address the urgent problem of global warming and our need to reduce the impacts of energy use on the environment and human health; or a "brown" path that would increase global warming emissions as well as other health and environmental damage. In deciding what role coal might play as a source of transportation fuel NRDC believes we must first assess whether it is possible to use coal to make liquid fuels without exacerbating the problems of global warming, conventional air pollution and impacts of coal production and transportation.

If coal were to play a significant role in displacing oil, it is clear that the enterprise would be huge, so the health and environmental stakes are correspondingly huge. The coal company Peabody Energy is promoting a vision that would call for production of 2.6 million barrels per day of synthetic transportation fuel from coal by 2025, about 10% of forecasted oil demand in that year. According to Peabody, using coal to achieve that amount of crude oil displacement would require construction of 33 very large coal-to-liquids plants, each plant consuming 14.4 million tons of coal per year to produce 80,000 barrels per day of liquid fuel. Each of these plants would cost $6.4 billion to build. Total additional coal production required for this program would be 475 million tons of coal annually—requiring an expansion of coal mining of 43% above today's level.[1]

In this testimony I will not attempt a thorough analysis of the impacts of a program of this scale. Rather, I will highlight the issues that should be addressed in a detailed assessment.

GLOBAL WARMING POLLUTION

To avoid catastrophic global warming the U.S. and other nations will need to deploy energy resources that result in much lower releases of $CO_2$ than today's use of oil, gas and coal. To keep global temperatures from rising to levels not seen since before the dawn of human civilization, the best expert opinion is that we need to get on a pathway now to allow us to cut global warming emissions by 60-80% from today's levels over the decades ahead. The technologies we choose to meet our energy needs in the transportation sector and in other areas must have the potential to perform at these improved emission levels.

To assess the global warming implications of a large coal-to-liquids program we need to examine the total life-cycle or "well-to-wheel" emissions of these new fuels. Coal is a carbon-intensive fuel, containing double the amount of carbon per unit of energy compared to natural gas and about 50% more than petroleum. When coal is converted to liquid fuels, two streams of $CO_2$ are produced: one at the coal-to-liquids production plant and the second from the exhausts of the vehicles that burn the fuel. As I describe below, with the technology in hand today and on the horizon it is difficult to see how a large coal-to-liquids program can be compatible with the low-$CO_2$-emitting transportation system we need to design to prevent global warming.

Today, our system of refining crude oil to produce gasoline, diesel, jet fuel and other transportation fuels, results in a total "well to wheels" emission rate of about 27.5 pounds of $CO_2$ per gallon of fuel. Based on available information about coal-to-liquids plants being proposed, the total well to wheels $CO_2$ emissions from such plants would be about 49.5-pounds of $CO_2$ per gallon, nearly twice as high as using crude oil, if the $CO_2$ from the coal-to-liquids plant is released to the atmosphere.[2] Obviously, introducing a new fuel system with double the $CO_2$ emissions of today's crude oil system would conflict with the need to reduce global warming emissions. If the $CO_2$ from coal-to-liquids plants is captured, then well-to-wheels $CO_2$ emissions would be reduced but would still be higher than emissions from today's crude oil system.[3]

This comparison indicates that using coal to produce a significant amount of liquids for transportation fuel would not be compatible with the need to develop a low-$CO_2$ emitting transportation sector unless technologies are developed to significantly reduce emissions from the overall process. But here one confronts the unavoidable fact that the liquid fuel from coal contains the same amount of carbon as is in gasoline or diesel made from crude. Thus, the potential for achieving significant $CO_2$ emission reductions compared to crude is inherently limited. This means that using a significant amount of coal to make liquid fuel for transportation needs would make the task of achieving any given level of global warming emission reduction much more difficult. Proceeding with coal-to-liquids plants now could leave those in-

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[1] Peabody's "Eight-Point Plan" calls for a total of 1.3 billion tons of additional coal production by 2025, proposing that coal be used to produce synthetic pipeline gas, additional coal-fired electricity, hydrogen, and fuel for ethanol plants. The entire program would more than double U.S. coal mining and consumption.

[2] Calculated well to wheel $CO_2$ emissions for coal-based "Fischer-Tropsch" are about 1.8 greater than producing and consuming gasoline or diesel fuel from crude oil. If the coal-to-liquids plant makes electricity as well, the relative emissions from the liquid fuels depends on the amount of electricity produced and what is assumed about the emissions of from an alternative source of electricity.

[3] Capturing 90 percent of the emissions from coal-to-liquid plants reduces the emissions from the plant to levels close to those from petroleum production and refining while emissions from the vehicle are equivalent to those from a gasoline vehicle. With such $CO_2$ capture, well to wheels emissions from coal-to-liquids fuels would be 8 percent higher than for petroleum.

vestments stranded or impose unnecessarily high abatement costs on the economy if the plants continue to operate.

CONVENTIONAL POLLUTION

Conventional air emissions from coal-to-liquids plants include sulfur oxides, nitrogen oxides, particulate matter, mercury and other hazardous metals and organics. While it appears that technologies exist to achieve high levels of control for all or most of these pollutants, the operating experience of coal-to-liquids plants in South Africa demonstrates that coal-to-liquids plants are not inherently "clean." If such plants are to operate with minimum emissions of conventional pollutants, performance standards will need to be written—standards that do not exist today in the U.S. as far as we are aware. In addition, the various federal emission cap programs now in force would apply to few, if any, coal-to-liquids plants.[4]

Thus, we cannot say today that coal-to-liquids plants will be required to meet stringent emission performance standards adequate to prevent either significant localized impacts or regional emissions impacts.

MINING, PROCESSING AND TRANSPORTING COAL

The impacts of mining, processing, and transporting 1.1 billion tons of coal today on health, landscapes, and water are large. Peabody's coal-to-liquids vision advocates another 475 billion tons of coal production. To understand the implications of such an enormous expansion of coal production, it is important to have a detailed understanding of the impacts from today's level of coal production. The summary that follows makes it clear that we must find more effective ways to reduce these impacts before we follow a path that would result in even larger amounts of coal production and transportation.

*Health and Safety*

Coal mining is one of the U.S.'s most dangerous professions. The yearly fatality rate in the industry is 0.23 per thousand workers, making the industry about five times as hazardous as the average private workplace.[5] The industry had 27 fatalities in 2002, an all-time low,[6] and there were 55 deaths in 2004 and 57 deaths in 2005.[7] The first month of 2006 was particularly deadly, however, with 18 fatalities through February 1st. Sixteen of these deaths occurred in West Virginia mines, leading the Governor to call for an unprecedented suspension of production while safety checks were conducted. Coal miners also suffer from many non-fatal injuries and diseases, most notably black lung disease (also known as pneumoconiosis) caused by inhaling coal dust. Although the 1969 Coal Mine Health and Safety Act seeks to eliminate black lung disease, the United Mine Workers estimate that 1500 former miners die of black lung each year.[8]

*Terrestrial Habitats*

Coal mining—and particularly surface or strip mining—poses one of the most significant threats to terrestrial habitats in the United States. The Appalachian region,[9] for example, which produces over 35% of our nation's coal,[10] is one of the most biologically diverse forested regions in the country. But during surface mining activities, trees are clearcut and habitat is fragmented, destroying natural areas that were home to hundreds of unique species of plants and animals. Even where forests are left standing, fragmentation is of significant concern because a decrease in patch size is correlated with a decrease in biodiversity as the ratio of interior habitat to edge habitat decreases. This is of particular concern to certain bird species that require large tracts of interior forest habitat, such as the black-and-white warbler and black-throated blue warbler.

After mining is complete, these once-forested regions in the Southeast are typically reclaimed as grasslands, although grasslands are not a naturally occurring

[4] The sulfur and nitrogen caps in EPA's "Clean Air Interstate Rule" ("CAIR") may cover emissions from coal-to-liquids plants built in the eastern states covered by the rule but would not apply to plants built in the western states. Neither the national "acid rain" caps nor EPA's mercury rule would apply to coal-to-liquids plants.

[5] Congressional Research Service, U.S. Coal: A Primer on the Major Issues, at 30 (Mar. 25, 2003).

[6] *Id.*

[7] Melissa Drosjack, FoxNews.com, Congress to Examine Mine Safety (Jan. 20, 2006), online at www.foxnews.com/story/0,2933,182276,00.html (visited Feb. 1, 2006).

[8] http://www.umwa.org/blacklung/blacklung.shtml

[9] Alabama, Georgia, Eastern Kentucky, Maryland, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

[10] Energy Information Administration. Annual Coal Report, 2004.

habitat type in this region. Grasslands that replace the original ecosystems in areas that were surface mined are generally categorized by less-developed soil structure [11] and lower species diversity [12] compared to natural forests in the region. Reclaimed grasslands are generally characterized by a high degree of soil compaction that tends to limit the ability of native tree and plant species to take root. Reclamation practices limit the overall ecological health of sites, and it has been estimated that the natural return of forests to reclaimed sites may take hundreds of years.[13] According to the USEPA, the loss of vegetation and alteration of topography associated with surface mining can lead to increased soil erosion and may lead to an increased probability of flooding after rainstorms.[14]

The destruction of forested habitat not only degrades the quality of the natural environment, it also destroys the aesthetic values of the Appalachian region that make it such a popular tourist destination. An estimated one million acres of West Virginia mountains were subject to strip mining and mountaintop removal mining between 1939 and 2005.[15] Many of these mines have yet to be reclaimed so that where there were once forested mountains, there now stand bare mounds of sand and gravel.

The terrestrial impacts of coal mining in the Appalachian region are considerable, but for sheer size they cannot compare to the impacts in the western United States.[16] As of September 30, 2004, 470,000 acres were under federal coal leases or other authorizations to mine.[17] Unlike the East, much of the West—including much of the region's principal coal areas—is arid and predominantly unforested. In the West, as in the East, surface mining activities cause severe environmental damage as huge machines strip, rip apart and scrape aside vegetation, soils, wildlife habitat and drastically reshape existing land forms and the affected area's ecology to reach the subsurface coal. Strip mining results in industrialization of once quiet open space along with displacement of wildlife, increased soil erosion, loss of recreational opportunities, degradation of wilderness values, and destruction of scenic beauty.[18] Reclamation can be problematic both because of climate and soil quality. As in the East, reclamation of surface mined areas does not necessarily restore pre-mining wildlife habitat and may require scarce water resources be used for irrigation.[19] Forty-six western national parks are located within ten miles of an identified coal basin, and these parks could be significantly affected by future surface mining in the region.[20]

*Water Pollution*

Coal production causes negative physical and chemical changes to nearby waters. In all surface mining, the overburden (earth layers above the coal seams) is removed and deposited on the surface as waste rock. The most significant physical effect on water occurs from valley fills, the waste rock associated with mountaintop removal (MTR) mining. Since MTR mining started in the United States in the early 70's, studies estimate that over 700 miles of streams have been buried from valley fills, and 1200 additional miles have been directly impacted from valley fills through sedimentation or chemistry alteration.[21] Together, the waterways harmed by valley fills are about 80 percent as long as the Mississippi River. Valley fills bury the headwaters of streams, which in the southeastern U.S. support diverse and unique habitats, and regulate nutrients, water quality, and flow quantity. The elimination of headwaters therefore has long-reaching impacts many miles downstream.[22]

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[11] Sencindiver, et al. "Soil Health of Mountaintop Removal Mines in Southern West Virginia". 2001.

[12] Handel, Steven. Mountaintop Removal Mining/Valley Fill Environmental Impact Statement Technical Study, Project Report for Terrestrial Studies. October, 2002.

[13] *Id.*

[14] EPA. Mountaintop Mining/Valley Fills in Appalachia: Draft Programmatic Environmental Impact Statement. 2003

[15] Julian Martin, West Virginia Highlands Conservancy, Personal Communication, February 2, 2006.

[16] Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming.

[17] Bureau of Land Management, Public Land Statistics 2004, Table 3-18.

[18] See, e.g., U.S. Department of the Interior, Bureau of Land Management, 1985 Federal Coal Management Program/Final Environmental Impact Statement, pp. 210-211, 230-231, 241-242, 282 (water quality and quantity), 241, 251, 257.

[19] Bureau of Land Management. 3809 Surface Management Regulations, Draft Environmental Impact Statement. 1999

[20] National Park Service, DOI. "Coal Development Overview". 2003.

[21] EPA. Mountaintop Mining/Valley Fills in Appalachia: Draft Programmatic Environmental Impact Statement.

[22] *Id.*

Coal mining can also lead to increased sedimentation, which affects both water chemistry and stream flow, and negatively impacts aquatic habitat. Valley fills in the eastern U.S., as well as waste rock from strip mines in the west add sediment to streams, as does the construction and use of roads in the mining complex. A final physical impact of mining on water is to the hydrology of aquifers. MTR and valley fills remove upper drainage basins, and often connect two previously separate aquifers, altering the surrounding groundwater recharge scheme.[23]

Acid mine drainage (AMD) is the most significant form of chemical pollution produced from coal mining operations. In both underground and surface mining, sulfur-bearing minerals common in coal mining areas are brought up to the surface in waste rock. When these minerals come in contact with precipitation and groundwater, an acidic leachate is formed. This leachate picks up heavy metals and carries these toxins into streams or groundwater. Waters affected by AMD often exhibit increased levels of sulfate, total dissolved solids, calcium, selenium, magnesium, manganese, conductivity, acidity, sodium, nitrate, and nitrite. This drastically changes stream and groundwater chemistry.[24] The degraded water becomes less habitable, non potable, and unfit for recreational purposes. The acidity and metals can also corrode structures such as culverts and bridges.[25] In the eastern U.S., estimates of the damage from AMD range from four to eleven thousand miles of streams.[26] In the west, estimates are between five and ten thousand miles of streams polluted. The effects of AMD can be diminished through addition of alkaline substances to counteract the acid, but recent studies have found that the addition of alkaline material can increase the mobilization of both selenium and arsenic.[27] AMD is costly to mitigate, requiring over $40 million annually in Kentucky, Tennessee, Virginia, and West Virginia alone.[28]

*Air Pollution*

There are two main sources of air pollution during the coal production process. The first is methane emissions from the mines. Methane is a powerful heat-trapping gas and is the second most important contributor to global warming after carbon dioxide. Methane emissions from coal mines make up between 10 and 15% of anthropogenic methane emissions in the U.S. According to the most recent official inventory of U.S. global warming emissions, coal mining results in the release of 3 million tons of methane per year, which is equivalent to 68 million tons of carbon dioxide.[29]

The second significant form of air pollution from coal mining is particulate matter (PM) emissions. While methane emissions are largely due to eastern underground mines, PM emissions are particularly serious at western surface mines. The arid, open and frequently windy region allows for the creation and transport of significant amounts of particulate matter in connection with mining operations. Fugitive dust emissions occur during nearly every phase of coal strip mining in the west. The most significant sources of these emissions are removal of the overburden through blasting and use of draglines, truck haulage of the overburden and mined coal, road grading, and wind erosion of reclaimed areas. PM emissions from diesel trucks and equipment used in mining are also significant. PM can cause serious respiratory damage as well as premature death.[30] In 2002, one of Wyoming's coal producing counties, Campbell County, exceeded its ambient air quality threshold several times, almost earning non-attainment status.[31] Coal dust problems in the West are likely to get worse if the administration finalizes its January 2006 proposal to exempt mining (and other activities) from controls aimed at meeting the coarse PM standard.[32]

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[23] Keating, Martha. "Cradle to Grave: The Environmental Impacts from Coal." Clean Air Task Force, Boston. June, 2001.

[24] EPA Office of Solid Waste: Acid Mine Drainage Prediction Technical Document. December, 1994.

[25] EPA. Mountaintop Mining/Valley Fills in Appalachia: Draft Programmatic Environmental Impact Statement. 2003

[26] EPA. Mid-Atlantic Integrated Assessment: Coal Mining. http://www.epa.gov/maia/html/coalmining.html

[27] EPA. Mountaintop Mining/Valley Fills in Appalachia: Final Programmatic Environmental Impact Statement. 2005

[28] *Id.*

[29] DOE/EIA, 2005. Emissions of Greenhouse Gases in the United States 2004. (December).

[30] EPA. Particle Pollution and Your Health. 2003

[31] Casper [WY] Star Tribune, January 24, 2005.

[32] National Ambient Air Quality Standards for Particulate Matter, Proposed Rule, 71 Fed. Reg. 2620 (January 17, 2006); Revisions to Ambient Air Monitoring Regulations, Proposed Rule, 71 Fed. Reg. 2710 (January 17, 2006).

*Coal Mine Wastes*

Coal mining leaves a legacy of wastes long after mining operations cease. One significant waste is the sludge that is produced from washing coal. There are currently over 700 sludge impoundments located throughout mining regions, and this number continues to grow. These impoundment ponds pose a potential threat to the environment and human life. If an impoundment fails, the result can be disastrous. In 1972 an impoundment break in West Virginia released a flood of coal sludge that killed 125 people. In the year 2000 an impoundment break in Kentucky involving more than 300 million gallons of slurry (30 times the size of the Exxon Valdez spill) killed all aquatic life in a 20 mile diameter, destroyed homes, and contaminated much of the drinking water in the eastern part of the state.[33]

Another waste from coal mining is the solid waste rock left behind from tunneling or blasting. This can result in a number of environmental impacts previously discussed, including acid mine drainage (AMD). A common problem with coal mine legacies is the fact that if a mine is abandoned or a mining company goes out of business, the former owner is under no legal obligation to cleanup and monitor the environmental wastes, leaving the responsibility in the hands of the state.[34]

*Effects on Communities*

Coal mining can also have serious impacts on nearby communities. In addition to noise and dust, residents have reported that dynamite blasts can crack the foundations of homes,[35] and many cases of subsidence due to the collapse of underground mines have been documented. Subsidence can cause serious damage to houses, roads, bridges, and any other structure in the area. Blasting can also cause damage to wells, and changes in the topography and structure of aquifers can cause these wells to run dry.

*Transportation of Coal*

Transporting coal from where it is mined to where it will be burned also produces significant quantities of air pollution and other environmental harms. Diesel-burning trucks, trains, and barges that transport coal release $NO_X$, $SO_X$, PM, VOCs (Volatile Organic Chemicals), CO, and $CO_2$ into the earth's atmosphere. Trucks and trains (barge pollution data are unavailable) transporting coal release over 600,000 tons of $NO_X$, and over 50,000 tons of PM 10 into the air annually.[36, 37] In addition to health risks, black carbon from diesel combustion is another contributor to global warming.[38] Land disturbance from trucks entering and leaving the mine complex and coal dust along the transport route also release particles into the air.[39] For example, in Sylvester, West Virginia, a Massey Energy coal processing plant and the trucks associated with it spread so much dust around the town that "Sylvester's residents had to clean their windows and porches and cars every day, and keep the windows shut."[40] Even after a lawsuit and a court victory, residents—who now call themselves "Dustbusters"—still "wipe down their windows and porches and cars."[41]

Almost 60 percent of coal in the U.S. is transported at least in part by train and coal transportation accounts for 44% of rail freight ton-miles.[42] Some coal trains reach more than two miles in length, causing railroad-crossing collisions and pedestrian accidents (there are approximately 3000 such collisions and 900 pedestrian accidents every year), and interruption in traffic flow (including emergency responders such as police, ambulance services, and fire departments). Local communities also have concerns about coal trucks, both because of their size and the dust they can leave behind. According to one report, in a Kentucky town, coal trucks weighing 120 tons with their loads were used, and "the Department of Transportation signs stating a thirty-ton carrying capacity of each bridge had disappeared."[43] Although the

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[33] Frazier, Ian. "Coal Country." On Earth. NRDC. Spring, 2003.

[34] Reece, Erik. "Death of a Mountain." Harper's Magazine. April, 2005.

[35] *Id.*

[36] DOT Federal Highway Administration. Assessing the Effects of Freight Movement on Air Quality, Final Report. April, 2005

[37] Energy Information Administration: Coal Transportation Statistics.

[38] Hill, Bruce. "An Analysis of Diesel Air Pollution and Public Health in America." Clean Air Task Force, Boston. February, 2005.

[39] EPA. Mountaintop Mining/Valley Fills in Appalachia: Draft Programmatic Environmental Impact Statement. 2003

[40] Michael Schnayerson, "The Rape of Appalachia," Vanity Fair, 157 (May 2006).

[41] *Id.*

[42] http://nationalatlas.gov/articles/transportation/a—freightrr.html

[43] Erik Reece, Lost Mountain: A Year in the Vanishing Wilderness 112 (2006).

coal company there has now adopted a different route for its trucks, community representatives in Appalachia believe that coal trucks should be limited to 40 tons.[44]

Coal is also sometimes transported in a coal slurry pipeline, such as the one used at the Black Mesa Mine in Arizona. In this process the coal is ground up and mixed with water in a roughly 50:50 ratio. The resulting slurry is transported to a power station through a pipeline. This requires large amounts of fresh groundwater. To transport coal from the Black Mesa Mine in Arizona to the Mohave Generating Station in Nevada, Peabody Coal pumped over one billion gallons of water from an aquifer near the mine each year. This water came from the same aquifer used for drinking water and irrigation by members of the Navajo and Hopi Nations in the area. Water used for coal transport has led to a major depletion of the aquifer, with more than a 100 foot drop in water level in some wells. In the West, coal transport through a slurry pipeline places additional stress on an already stressed water supply. Maintenance of the pipe requires washing, which uses still more fresh water. Not only does slurry-pipeline transport result in a loss of freshwater, it can also lead to water pollution when the pipe fails and coal slurry is discharged into ground or surface water.[45] The Peabody pipe failed 12 times between 1994 and 1999. The Black Mesa mine closed as of January 2006. Its sole customer, the Mohave Generating Station, was shut down because its emissions exceeded current air pollution standards.

## A RESPONSIBLE ACTION PLAN

The impacts that a large coal-to-liquids program could have on global warming pollution, conventional air pollution and damage from expanded coal production are substantial. Before deciding whether to invest scores, perhaps hundreds of billions of dollars in a new industry like coal-to-liquids, we need a much more serious assessment of whether this is an industry that should proceed at all.

Fortunately, the U.S. can have a robust and effective program to reduce oil dependence without rushing into an embrace of coal-to-liquids technologies. A combination of efficiency, renewable fuels and potentially, plug-in hybrid vehicles can reduce our oil consumption more quickly, more cleanly and in larger amounts than coal-to-liquids even on the massive scale advocated by Peabody Energy.

A combination of more efficient cars, trucks and planes, biofuels, and “smart growth” transportation options outlined in report “Securing America,” produced by NRDC and the Institute for the Analysis of Global Security, can cut oil dependence by more than 3 million barrels a day in 10 years, and achieve cuts of more than 11 million barrels a day by 2025, far outstripping the 2.6 million barrel a day program being promoted by Peabody.

The Securing America program is made up of these sensible steps that will cut oil dependence, cut global warming emissions, and reduce other harmful impacts of today’s energy production and consumption patterns:

Accelerate oil savings in passenger vehicles by:

- establishing tax credits for manufacturers to retool existing factories so they can build fuel-efficient vehicles and engineer advanced technologies, and
- establishing tax credits for consumers to purchase the next generation of fuel-efficient vehicles; and raising federal fuel economy standards for cars and light trucks in regular steps.

Accelerate oil savings in motor vehicles through the following:

- requiring replacement tires and motor oil to be at least as fuel efficient as original equipment tires and motor oil;
- requiring efficiency improvements in heavy-duty trucks; and
- supporting smart growth and better transportation choices.

Accelerate oil savings in industrial, aviation, and residential building sectors through the following:

- expanding industrial efficiency programs to focus on oil use reduction and adopting standards for petroleum heating;
- replacing chemical feedstocks with bioproducts through research and development and government procurement of bioproducts;
- upgrading air traffic management systems so aircraft follow the most-efficient routes; and
- promoting residential energy savings with a focus on oil-heat.

[44] Personal communication from Hillary Hosta and Julia Bonds, Coal River Mountain Watch (Apr. 7, 2006).

[45] NRDC. Drawdown: Groundwater Mining on Black Mesa.

Encourage growth of the biofuels industry through the following:

- requiring all new cars and trucks to be capable of operating on biofuels or other non-petroleum fuels by 2015; and
- allocating $2 billion in federal funding over the next 10 years to help the cellulosic biofuels industry expand production capacity to 1 billion gallons per year and become self-sufficient by 2015.

TECHNOLOGICALLY ACHIEVABLE OIL SAVINGS

[Million barrels per day]

| Oil savings measures | 2015 | 2025 |
|---|---|---|
| Raise fuel efficiency in new passenger vehicles through tax credits and standards | 1.6 | 4.9 |
| Accelerate oil savings in motor vehicles through | | |
| fuel efficient replacement tires and motor oil | 0.5 | 0.6 |
| efficiency improvements in heavy-duty trucks | 0.5 | 1.1 |
| Accelerate oil savings in industrial, aviation, and residential sectors | 0.3 | 0.7 |
| Encourage growth of biofuels industry through demonstration and standards | 0.3 | 3.9 |
| Total oil saved | 3.2 | 11.2 |

To cut our dependence on oil we should follow a simple rule: start with the measures that will produce the quickest, cleanest and least expensive reductions in oil use; measures that will put us on track to achieve the reductions in global warming emissions we need to protect the climate. If we are thoughtful about the actions we take, our country can pursue an energy path that enhances our security, our economy, and our environment.

Senator BUNNING. Thank you very much.

Mr. Ramsbottom.

**STATEMENT OF D. HUNT RAMSBOTTOM, PRESIDENT AND CEO, RENTECH, INC., LOS ANGELES, CA**

Mr. RAMSBOTTOM. Thank you, Mr. Chairman, distinguished Senators and guests.

I'm Hunt Ramsbottom, president and CEO of Rentech. We're a publicly held company listed on the American Stock Exchange. For 23 years Rentech has engaged in R&D on clean fuels from natural gas and coal. Right now we are creating a commercial coal-to-liquid industry in the United States.

I'd like to summarize my testimony.

The basic chemistry behind our fuel products has been known for over seven decades. The technology has been used extensively in other countries. We have tested our innovations in six pilot plants for over 20 years. We plan to have a fully commercial plant up and running by 2010. Our seventh plant, our process demonstration unit, will be operating by the first quarter of 2007. It will produce 10 barrels a day for demonstration, analysis, and further training.

This week Rentech will announce the purchase of the East Dubuque Fertilizer Plant. We will convert it in phases to produce three products, clean fuels, ammonia fertilizer, and electricity. The conversion will change the plant from expensive natural gas over to affordable Illinois coal. We will demonstrate that fertilizer production can still be a thriving domestic industry but the real innovation at East Dubuque will be the production of our ultra-clean fuels. I have a sample of Rentech's diesel with me. It is clear, refined to a high degree of purity and has almost no particulates or sulphur. Rentech's fuel can be used with no engine modifications in trucks, buses, and barges and processed into jet fuels. In 2010 East Dubuque will produce 2,000 barrels per day in phase one. Phase two will be close to 7,000 barrels per day.

As we manufacture our fuel we remove most harmful regulated pollutants seeing up to 33 percent reduction after conversion in East Dubuque. The sulphur and mercury, for example, drop out as elements in the gasification stage. Our fuels run cleaner than traditional diesel, is more stable, is biodegradable. I'd like to enter for the record analysis showing our environmental benefits.

Our commitment to the environment brings me to our second plant proposed in Natchez, Mississippi, which will produce 11,000 barrels per day, again, in phase one. There we're pursuing opportunities for 100 percent capture and storage of carbon. That would allow us to pump our carbon dioxide into local fields increasing production and trapping the carbon underground.

We've worked extremely hard to overcome the many hurdles to becoming the first commercial CTL plant in the United States. We're planning to make full use of the EPAct 2005 incentives, designed to jumpstart the clean fuels industry. Let me note that the States are also being very helpful in this process. Illinois helped us complete feasibility and engineering studies in assisting with the conversion to coal. Mississippi just passed a $50 million bond for the Natchez facility. What you've been doing at the Federal level is absolutely vital to our efforts. We intend to seek DOE self-pay loan guarantees in the first quarter of 2007. We commend the Secretary of Energy for quickly moving to implement the authorized programs. The self-pay guarantees are integral to financing the first CTL plants in the United States. We appreciate your efforts to fully fund and expedite the DOE loan programs. We would also apply for the industrial gasification investment tax credit provided by the energy bill. The recent initiative by Senators Grassley and Baucus to raise the current $350 million cap to $850 million is very helpful. Allow me to offer an observation. Even the larger cap only helps three to four more new plants and we spend currently $850 million on foreign oil every 2 days. To make a real difference, Congress should lift these caps entirely. Another way to help is make the 50 cent per gallon fuel excise tax credit available to coal-to-liquids fuels. To do that we should extend the expiration currently in 2009 when no CTL plants will be operating to at least 2014.

Senator Bunning, I recognize your unique position as a member of both energy and finance and support from the other members of the finance committee will certainly be appreciated.

Finally, long-term DOD contracts for military use could assist with the financing of these facilities. CTL fuel is economically competitive, we can produce finished fuels for $36 to $42 per barrel, the equivalent of buying raw crude at $30 to $35 per barrel. We're not asking the Government to subsidize an industry. We need your help to get the CTL clean fuel manufacturing industry launched with private sector funding.

Thank for what you've done so far with EPAct 2005 and thank you for your time today.

[The prepared statement of Mr. Ramsbottom follows:]

PREPARED STATEMENT OF D. HUNT RAMSBOTTOM, PRESIDENT AND CEO, RENTECH, INC., LOS ANGELES, CA

Thank you, Mr. Chairman. Distinguished Senators and guests, I'm Hunt Ramsbottom and I'm the President and CEO of Rentech, Inc. We are a publicly held, Denver-based firm and we are listed on the American Stock Exchange. For 23 years, Rentech has engaged in research and development, focusing on enhancing the production of ultra-clean fuels made from natural gas and coal, through a chemical process known as Fischer-Tropsch. We hold 20 U.S. patents and 4 foreign patents.

THE HISTORY OF RENTECH AND CTL

I'm here today to share how, right now, we are moving to establish a commercial coals-to-liquid—CTL—industry. The basic chemistry behind our fuel products has been known for 7 decades. The basic technology has been developed and used extensively in other countries. We have tested our Rentech innovations in the lab and in pilot programs, and deployed small-scale production.

We now have developed our technology around Coals-to-Liquids—or CTL—gasification, and for Rentech, the future of CTL in the United States is no longer a theoretical, what-if, conversation. We plan to have a fully commercial, fully operational CTL plant up and running by 2010.

Even before that, we will be operating our Process Demonstration Unit (PDU). By the first quarter of 2007, we will have that up and running in Colorado. It will produce 10 barrels per day of our fuel basis for demonstration and analysis by potential end users. And it will allow us to optimize our technology for variations in coal and other factors.

EAST DUBUQUE, ILLINOIS: THE FIRST CTL CLEAN-FUELS PLANT IN THE U.S.

Within the next month, Rentech will announce the purchase a fertilizer plant in East Dubuque, Illinois, and we plant to convert it in phases to CTL poly-generation over the next 3 to 4 years. By poly-generation, I mean that we will ultimately produce 3 products: ultra-clean transportation fuels, ammonia fertilizer and electricity.

The plant currently makes ammonia fertilizer from natural gas, and it already incorporates basic technologies that are critical to successfully implementing CTL. The conversion will include changing the feedstock from natural gas to Illinois coal. It will also entail adding a gasification unit to produce synthesis gas; adding a Rentech Reactor so that we can produce the basis of our ultra-clean fuels; and a finishing plant to produce the final fuel products. We chose our final planned product mix carefully.

Fertilizer will still be made in large quantities. As I'm sure all of you know from our friends in the farm states, domestic fertilizer plants are shutting down rapidly because of high natural gas prices—the current primary feedstock for fertilizer. Since 1999, the U.S. has switched from producing all its own fertilizer to becoming a net importer. We will demonstrate that fertilizer production can still be a thriving domestic industry using clean coal technologies.

Electricity will be produced in small quantities, primarily for the plant's own use. A small surplus, however, will be provided to the local grid.

RENTECH'S ULTRA-CLEAN FUELS

But the real innovation at East Dubuque will be the production of our ultra-clean fuels. I'm passing around a sample of Rentech's ultra-clean diesel. Please look at it closely—it is very different than the diesel made from petroleum. This is clear, refined to a high degree of purity, and has almost no particulates—which is what causes the belching cloud you see when a diesel truck or bus starts to accelerate. When the Air Force tested our fuels and similar fuels made by competitors, the tests showed reductions in particulates of up to and over 80%.

The Rentech fuel is also extremely low in sulfur—less than 1 part per million, far under the new EPA standard of 15 ppm. The finished fuel can be used with no engine modifications in any standard diesel engine—including trucks, buses and barges. It can even be processed into jet fuel. Under our timeline, the East Dubuque plant will be first commercial scale plant in the U.S. to produce quantities of this fuel—about 2000 barrels per day in 2010.

You should also smell the product. It has none of the typical odor of diesel. There are two other critical differences between this and typical diesel. Our fuel has a shelf life of at least 8 years, rather than 3-4 months for petroleum diesel—meaning that for the strategic reserve, for emergency first-responders, and the military, our fuel has incredible advantages. Next, our fuel is biodegradable. If it spills, it does not cause irreparable damage to waterways or wells.

ENVIRONMENTAL BENEFITS

Let me take a moment to highlight the environmental policies that we intend to pursue. Rentech is committed to being environmentally friendly—and both our production and fuels have environmental benefits.

As we manufacture our fuel, we remove most of the harmful regulated pollutants in the gasification stage. Sulfur and mercury come out as elements—they do not go up a smokestack to be scrubbed out, and do not leak into the environment. Once conversion is complete, regulated criteria pollutant emissions will be reduced about 33%. Some carbon dioxide emissions will be sequestered in products—in the fertilizer and in items like bottled sodas. Our fuel itself runs cleaner than traditional diesel, and as I mentioned earlier, it is much more stable and biodegradable. I would like to enter for the record an analysis that shows the environmental benefits of our CTL process.

NATCHEZ, MISSISSIPPI: A POSSIBLE SECOND PLANT

Our commitment to being environmentally-friendly brings me to our second proposed plant in Natchez, Mississippi, which would produce 11,000 barrels per day. There, we are pursuing opportunities for 100% capture and storage of carbon. Our carbon dioxide output would be pumped into nearby older oil well fields, both helping to produce additional oil by forcing out additional supplies and trapping the carbon underground.

As you can see, Rentech is aggressively pursuing commercial deployment. We have worked extremely hard to get over the significant financial hurdles that building—or as we are doing, converting—a plant takes. That is especially true of a first-of-its-kind-in-the-U.S. plant.

WHAT THE GOVERNMENT CAN DO

We are planning to make full use of the EPACT 2005 incentives designed to jump-start this critical clean-fuel industry. Let me note that the States are also lending their assistance. The State of Illinois has been extraordinarily helpful—they helped us to complete feasibility studies, engineering studies and provided grants to assist with conversion to coal. The State of Mississippi has also been exceptionally supportive of the possibility of our second plant being located in Natchez, and they just passed a $15 million bond bill for the proposal.

FEDERAL LOAN GUARANTEES

What you have been doing at the federal level, though, is absolutely vital to our efforts. We intend to seek the DOE self-pay loan guarantees for our conversion closing, planned for the first quarter of 2007. We understand that DOE's implementation has begun and we commend the Department and the Secretary of Energy for quickly moving to implement the authorized programs. The self-pay guarantees are integral to our financing of the East Dubuque conversion, so we appreciate and hope you will continue your efforts to ensure that the DOE loan programs are fully funded and implemented expeditiously.

INDUSTRIAL GASIFICATION INVESTMENT TAX CREDIT

To meet our aggressive timeline, we also will apply for the industrial gasification investment tax credit provided by the Energy Bill. The recent initiative by Senators Grassley and Baucus to raise the current $350M cap to $850 million is very helpful. If Congress is serious about trying to reduce our dependence on foreign oil import then allow me to offer an observation. Maintaining the current cap of $350M could slow the rollout of industrial gasification using coal to the point where the U.S. winds up losing more industry. Even an $850M cap will assist the development and deployment of only 6-7 plants—hardly the creation of a full-fledged industry. At $75 per barrel, the price of oil last Friday, the U.S. is paying $850 million to foreign countries for oil every two days. To create a real incentive, it might be better to lift the caps altogether.

FUEL EXCISE TAX CREDIT

There is another way for the federal government to help, by making the 50 cent-per-gallon fuel excise tax credit provided in the Highway Bill available to CTL fuels. To do that, you could extend the expiration of the current credit from 2009, when no CTL plants will yet be operational in the U.S., to at least 2014. Senator Bunning, I recognize your unique position a member of both the Senate Energy and Natural Resources Committee and the Senate Finance Committee, so any supportive words that you can pass on to other members of the Finance Committee would certainly be appreciated.

DEPARTMENT OF DEFENSE FUEL USE

There are other ways that the government could catalyze commercial deployment of the CTL industry. Use by the military as diesel and jet fuel under long-term contracts could assist with financing the first plants—but it is going to take a realistic assessment based on the actual costs of production. Historically, the cost of generating fuel from CTL in the U.S. has been the major stumbling block to commercialization. Until recently the costs were not competitive with petroleum. Now they are. Today, fuels from CTL technology can be produced—finished—for $36 to $42 per barrel. That's the equivalent to purchasing raw crude at prices of $30 to $35 per barrel. EIA's AEO 2006 projected long-term oil costs at $50 and above. The same forecast shows CTL production growing to 700,000 barrels per day by 2030. But the first plants must be financed and built, paving the way for the industry to flourish and add to the nation's energy security.

CONCLUSION

I think the great potential of CTL is using American resources, American know-how, and American innovation to create both energy independence and American jobs. It's a big vision, but it starts with small steps. As I close, I'd like to let you know how Rentech is moving to commercial deployment.

We intend to operate the first U.S. commercial-scale plant through the conversion I have outlined of the fertilizer plant in East Dubuque. We are pursuing a second larger scale plant in Natchez, Mississippi—the Natchez Adams Strategic Fuels Center. We were invited by the local community to consider the possibility after Hurricane Katrina when Mississippi ran disastrously low on diesel. At Natchez, we can use two feedstocks—both coal and petroleum coke, a byproduct of the local petroleum industry. And as I have mentioned, there is the very real possibility of capturing and storing 100% of the carbon dioxide emissions through enhanced oil recovery in nearby oil fields. To our knowledge, this would be the first large-scale U.S. commercial capture and storage of man-made carbon emissions. Carbon dioxide injection is already being used in this oil-producing basin, but additional supplies are need.

We are also exploring with several coal companies to create a replicable, iterative plant model that could be located at the mouths of mines. There, we would size a basic plant model that could be expanded. For twenty years, Rentech has researched and optimized our technology. We have refined our process to make it more effective and more environmentally-friendly. Now we are commercializing it.

We aren't asking the government to subsidize the industry. We urgently need your help, though, to get a CTL clean-fuel manufacturing industry launched with private-sector funding. A robust clean-fuels sector is important so that we can meet our national energy needs, foster greater energy independence, and preserve a full measure of our energy security. At Rentech, we are ready. We are using American innovation to produce environmentally-friendly, energy-rich fuels to build America's future. And we are doing it using America's greatest natural energy resource, coal.

Thank you for all that you have done to allow a jump-start of CTL in the Energy Policy Act of 2005, including the tax incentive. We intend to make use of your help to do just that—jump-start full scale utilization of CTL, and jump-start a new clean fuel manufacturing industry. Thank you as well for your time today.

Senator BUNNING. Thank you for your testimony.

Mr. Roberts, you are our cleanup hitter.

**STATEMENT OF JAMES F. ROBERTS, PRESIDENT AND CEO, FOUNDATION COAL CORPORATION, LINTHICUM HEIGHTS, MD, ON BEHALF OF THE NATIONAL MINING ASSOCIATION**

Mr. ROBERTS. Thank you, Mr. Chairman. I am James Roberts, president and CEO of Foundation Coal Corporation, one of the leading coal producers in the United States. I'm appearing this afternoon on behalf of the National Mining Association which I presently serve as vice-chairman. NMA and it's members applaud you and your colleagues for hosting this very timely and constructive hearing.

Coal is meeting America's immediate energy needs and is poised to play a major role in the development of long-term technologies in a hydrogen based economy such as fuel cells. In short, coal is the energy of America's past, present, and future. It is about our Nation's energy future that I am most concerned. Increasingly today energy security has come to be viewed not just as one among many national goals but as a vital national imperative. Across the world energy has become the lynchpin of economic competitiveness, forcing the United States and its industrial competitors to strategically reassess their energy supplies and resources. We have so far avoided the dire consequences of our dependence on imported energy largely because the relative low price of oil sheltered us from them. However, at today's prices let alone projected prices, it is unlikely our economy will remain unscathed for much longer. America's coal reserves can provide us with an invaluable hedge against our growing addiction to imported energy and provide a significant source of fuel for a growing economy. Congress acknowledged this fact in the Energy Policy Act of 2005, but while Congress was farsighted last year in appreciating the need for more sustained and determined action to decrease our reliance on foreign energy, the response it proposed, while necessary, is not nearly sufficient to the challenge we now face.

Consider the following circumstances that argue strongly for greater reliance on domestic fuels such as coal. First, even as after the Energy Act of 2005, the United States is projected to import a greater share of its growing oil needs. The result, according to the Energy Information Administration, is that net imports will make up 62 percent of our total oil supply by 2030. Bear in mind this is a very conservative estimate as EIA assumes a percentage of U.S. projected oil imports will be satisfied by liquid coal fuel. Absent large scale development of this fuel source, net imports will be significantly higher. Second, the oil we import will continue to come from unfriendly or unstable regimes. Third, oil imports from the region also force the United States to shoulder the burden of an enormous trade deficit as well. Fourth, energy has clearly become a central objective in the geopolitical struggle to secure global raw material supplies. China's energy demands alone are having and will continue to have a significant impact on global oil prices. In other words, no matter the perspective from which we examine our dependence on foreign oil, the unavoidable truth is that it makes our Nation less secure.

In it's most recent energy outlook, EIA projects that coal derived fuels will constitute 8 percent of our expected oil import requirements by 2030, but NMA believes this projection, much like the Energy Act of 2005, is too timid a response given the more urgent circumstances the Nation now faces. A more appropriate target we believe comes from the Southern States Energy Board which expect alternative fuels such as liquified coal to replace approximately 5 percent of imported oil each year for 20 years beginning no later than 2010. This target stems not only from the rising prices of oil but also from the abundant supply of secure coal within our own borders. Illinois Basin coal reserves, including Kentucky's, boasts a greater Btu content than all the oil in Iran, Iraq, Kuwait, and Saudi Arabia, and this does not include the Btu content from the coal contained in the great State of Wyoming. This is a resource that no foreign government can nationalize, that requires no costly armed forces to protect and no exploration budget to locate. Nor does coal-to-liquids technology require R&D funding. The requisite gasification and liquefaction technology has been used for decades in oil deprived countries with coal reserves. In South Africa, for example, liquified coal has furnished as much as 60 percent of that nation's transportation fuels.

Finally, and particularly appropriate for Earth Day this past weekend, the high grade diesel fuel produced from coal gasification is very clean. The low particulate, low mercury, and almost zero sulphur emissions profile of coal based fuel will mean reduced tailpipe emissions, cleaner running mass transit systems, and no measurable toxic pollutants.

The argument for government support for coal liquefaction is a strong one. The strategic justification, the supply of coal required, and the technology for using it clearly are all in place to put the United States on the path to greater energy independence. We lack only the will, the determination to use it in response to the gathering risk we face from our growing dependence on imported energy. For despite higher global prices for oil and gas today, there is no guarantee that tomorrow the oil cartel will not manipulate the price of their resources long enough to discourage private sector investment in alternative fuels. The Government's participation will therefore be critical for offsetting the risk of marketplace manipulation by jump-starting domestic production on the scale we need.

Certainly China appreciates the need for public sector participation. Like the United States, China boasts enormous coal reserves and also faces a growing oil import bill in the years ahead. But unlike the United States, China issues incremental solutions in favor of bold ones. China has evidently concluded that a different world calls for different approaches. I urge this committee to think not about the similarities between the oil issues today and those of the past years but about the differences that mark today's energy situation from that of the past and from these differences I hope you will draw the conclusion that we, too, must act more boldly than we have in the past.

Thank you again for this opportunity and I'm happy to answer any of your questions.

[The prepared statement of Mr. Roberts follows:]

PREPARED STATEMENT OF JAMES F. ROBERTS, PRESIDENT AND CEO, FOUNDATION COAL CORPORATION, LINTHICUM HEIGHTS, MD, ON BEHALF OF THE NATIONAL MINING COMPANY

Thank you, Mr. Chairman. I'm James F. Roberts, President and CEO of Foundation Coal Corporation, one of the leading coal producers in the United States. I'm appearing this afternoon on behalf of the National Mining Association, which I presently serve as Vice Chairman.

NMA and its members applaud you and your colleagues for hosting this very timely and constructive hearing. We are confident that coal gasification can make America stronger through cleaner and more efficient use of its unrivalled coal reserves—leading to clean, high quality transportation fuel, an abundant feedstock to produce ethanol and affordable energy to power our industrial facilities.

Coal is meeting America's immediate energy needs and is poised to play a major role in the development of long-term technologies in a hydrogen-based economy, such as fuel cells. In short, coal is the energy of America's past, present and future.

It is about our nation's energy future that I am most concerned.

Increasingly today, energy security has come to be viewed not just as one among many national goals but as a vital national imperative. Across the world, energy has become the linchpin of economic competitiveness, forcing the U.S. and its industrial competitors to strategically reassess their energy supplies and resources.

In a way, we have all been here before. The call for greater energy security through lessening our dependence on foreign energy has resounded several times in recent decades. The call was first heard during the Arab oil embargo in 1973, when President Nixon launched Project Independence. It was echoed subsequently during the Ford, Carter and Reagan presidencies and during both Bush presidencies

Unfortunately our repeated failure to break what President Bush so correctly called our addiction to foreign oil raises doubt amongst many of us that we will succeed this time. And yet never before has the price of failure been as great as it is today.

We have so far avoided the dire consequences of our dependence on imported energy largely because the relatively low price of oil shielded us from them. However, at today's prices—let alone at projected prices—it is unlikely our economy will remain unscathed for much longer. We literally can no longer afford the complacency of past decades. The argument for concerted, bipartisan action to strengthen energy security is greater now than ever before.

Increasingly, a secure America in the 21st century will mean energy security. This brings us to the nation's abundant and affordable coal reserves—and the purpose of this hearing.

America's coal reserves can provide us with an invaluable hedge against our growing addiction to imported energy, and provide a significant source of fuel for a growing economy. Congress acknowledged this fact in the Energy Policy Act of 2005, which encourages the development of alternative fuels such as coal-to-liquid transportation fuels and coal-derived natural gas substitutes.

But while Congress was far-sighted last year in appreciating the need for more sustained and determined action to decrease our reliance on foreign energy, the response it proposed—while necessary—is not nearly sufficient to the challenge we now face. Consider the following circumstances that argue strongly for greater reliance on domestic fuels such as coal.

First, the U.S. is projected to import a greater share of its growing oil needs. While our daily oil requirements are projected to increase from 20 million barrels a day currently to 28 million by 2030, our domestic oil supply is projected to flatten after a modest rise to a mere 10 million barrels per day. The result, according to The Energy Information Administration (EIA), is that net imports will make up 62% of our total oil supply.

Bear in mind this is a very conservative estimate, as EIA assumes a percentage of U.S. projected oil imports will be satisfied by liquefied coal fuel. Absent large scale development of this fuel source, net imports will be significantly higher. And as I believe others here will testify, this development is unlikely to materialize without additional incentives.

Second, the oil we import will continue to come from unfriendly or unstable regimes—simply because these regimes have the oil we use. Our reliance on the Middle East alone obligates the U.S. to maintain and deploy armed forces at enormous cost. Oil imports from the region also force the U.S. to shoulder the burden of an enormous trade deficit as well.

Third, energy has clearly become a central objective in the geopolitical struggle to secure global raw material supplies. China's energy demands alone are having—and will continue to have—a significant impact on global oil prices. The Congressional Budget Office recently estimated if China continues its current rate of growth, its unquenchable thirst for oil will force U.S. consumers to pay another 38 cents per gallon of gas in five years.

In other words, no matter the perspective from which we examine our dependence on foreign oil, the unavoidable truth is that it makes our nation less secure.

There is one consolation from the high oil and natural gas prices we are continuing to pay. It is the compelling incentives we now have to act decisively by developing energy alternatives from coal gasification—and from coal liquefaction. At even the most conservative levels projected, oil prices are expected to be high enough to make this technology economic to implement and the fuel it yields economic to produce.

Certainly EIA believes so. In its most recent energy outlook, EIA projects that coal-derived fuels will constitute 8% of our expected oil import requirements by

2030. But NMA believes this projection, much like the Energy Act of 2005, is too timid a response given the more urgent circumstances the nation now faces. A more appropriate target, we believe, comes from the Southern States Energy Board, which expects alternative fuels such as liquefied coal to replace approximately 5% of imported oil each year for 20 years beginning no later than 2010.

This estimate stems not only from the rising prices of oil, but also from the abundant supply of secure coal within our own borders. U.S. recoverable coal reserves of 275 billion tons is the energy equivalent of 550 billion barrels of oil. To put this enormous strategic resource into perspective, Illinois's coal reserves alone boast a greater BTU content than all the oil in Iran, Iraq, Kuwait and Saudi Arabia.

This is a resource that no foreign government can nationalize—that requires no costly armed forces to protect—and no exploration budget to locate.

Nor does coal-to-liquids technology require R&D funding. The requisite gasification and liquefaction technology has been in use for decades in oil-deprived countries with coal reserves. In South Africa, for example, liquefied coal has furnished as much as 60% of that country's transportation fuels.

Finally—and particularly appropriate for Earth Day this weekend—the high-grade diesel fuel produced from coal gasification is very clean. The low particulate, low mercury and almost zero sulfur emission profile of gasified coal will mean reduced tailpipe emissions, cleaner-running mass transit systems and no measurable toxic pollutants. Moreover, the coal-to-liquid (CTL) process can capture carbon dioxide for use in enhanced oil and coal bed methane recovery, or for sequestration deep underground. The fuel will be produced domestically under the most comprehensive environmental laws in the world.

The strategic justification, the supply of coal required and the technology for using it cleanly are all in place to put the U.S. on the path toward greater energy independence. We lack only the will—the determination to make this objective a strategic imperative commensurate to the gathering risk we face from our growing dependence on imported energy.

One sign of this determination would be a commitment from Congress to provide the financial assistance required to cover the front-end engineering and design costs of building coal liquefaction plants. For despite higher global prices for oil and gas today, there is no guarantee that tomorrow the relatively small number of producing countries will not manipulate the price of their resources long enough to discourage private sector investment in alternative fuels. The government's participation will therefore be critical for offsetting this risk of marketplace manipulation by jump-starting domestic production on the scale we will need.

This is simply an acknowledgement that private sector financing in the face of such risks is unavailable for costly, unconventional technologies that have not been widely used in the U.S.

Certainly China appreciates the need for public sector participation. Like the U.S., China boasts enormous coal reserves—second only to our own. Like the U.S., it too satisfies most of its energy needs with imported oil, again second only to the U.S.—and consequently it also faces a growing oil import bill in the years ahead.

But unlike the U.S., China eschews incremental solutions in favor of bold ones. It plans to secure its future prosperity by investing some $30 billion in coal gasification and liquefaction technology. It understands that government participation is the only way to insulate its fledgling liquefaction industry against a concerted effort by OPEC to destroy it.

China has evidently concluded that a different world calls for different approaches.

I urge this committee to think not about the similarities between the oil issues today and those of past years, but about the differences that mark today's energy situation from that of the past. And from these differences, I hope you will draw the conclusion that we too must act differently than we have in the past.

Thank you, again, for this opportunity. I'm happy to answer any questions you may have.

Senator BUNNING. Thank you, Mr. Roberts.

There's a long history of CTL research in Kentucky, and for that matter, for the rest of the United States of America. Most if it's dating back to the 1970's when we got the first red flags. I mean, they couldn't have sent a bigger message in the early 1970's when we had our first boycott. America's recoverable coal reserves of 275 billion tons are the energy equivalent of 550 billion barrels of oil, unless I'm mistaken. That is more than all of the oil estimated in Saudi Arabia, Iraq, and Iran.

Could you discuss the reasons why this vast supply has not been previously used and why CTL plants were never planned in Kentucky in the 1970's that were planned but were never completed? It's a jump ball. Go.

Dr. GEERTSEMA. Could I as somebody who was not here at that time.

Senator BUNNING. Oh, thanks. Call me on it.

[Laughter]

Dr. GEERTSEMA. But I was involved in direct liquefaction at SASOL. My first job at SASOL was as a group leader of the direct liquefaction facilities there and since that time I've been at DOE meetings very often. I'm rather familiar with the developments going on here. My main focus in those years, as Dr. Miller indicated, was on direct coal liquefaction and in short the direct liquefaction technology which is much more complex, much harsher process conditions than indirect liquefaction. So economically it was a risky one. The pilot plants which were built here in United States, as you know the one in Kentucky, others at Wilsonville. In Europe there was the Bottropp plant. There was a Japanese plant actually built in Australia. All those plants could eventually, technically produce products but the economics were just not there to support it. On the indirect route, after SASOL two and three have been built in the early 1980's one should keep in mind that SASOL didn't build SASOL four either, even though they had a lot of reasons perhaps to do so, and again it was a matter of economics. Now that the price is sustained for quite a while above the $40, $45 a barrel, I think things have changed quite a bit but I think it's a matter of revisiting what was done in those years and learn from it and to move forward.

Senator BUNNING. Anybody else want to take a shot?

Mr. RAMSBOTTOM. Yes, I would concur. I've spent a lot of time recently on Wall Street in the capital markets and I think it comes down to the economics and instability of the commodity pricing. I think there is a wave of change going on out there but I think clearly from the financing community, that's been the issue.

Senator BUNNING. Also the price domestically or internationally of domestic crude—international crude——

Mr. RAMSBOTTOM. Absolutely right.

Senator BUNNING [continuing]. Obviously when you can buy it at $8 a barrel or $12 a barrel, I don't think we're going to see that anywhere in the near future.

Kentucky sits at a unique position in America. We are home to state-of-the-art coal-to-liquids research as well as the coal mine production needed to fuel these new plants. I see significant investment in Kentucky but could you describe what kind of facilities would be interested in adopting CTL technology? Where in the countries would these plants be built, do you think? Well, obviously, one in Illinois and one in Mississippi.

Mr. RAMSBOTTOM. Yes, and being on the technology side of the equation, we're seeing where most plants are being proposed around the country so in our view, Kentucky and all the States that are mentioned. We're involved in the Wyoming project and thank you for your support, Mr. Thomas. So we're seeing the projects going on in most States that have coal supply today and I think from my perspective we're seeing a big ramping up of those States getting energized about it and the coal companies also getting energized about it. So I think from my perspective, you know, the States that have the coal, we won't see any barriers.

Senator BUNNING. Presently though those States that have coal are having a tremendous time just producing enough coal for the coal market. Now, give me an idea of how we're going to produce enough to take coal to liquified and be able to produce that much more coal.

Mr. RAMSBOTTOM. The gentleman to my left could probably address that better than I can.

Senator BUNNING. Okay.

Mr. ROBERTS. Well, let me just fall a little bit back on your previous question as to where the CTL plants might be located, and I would add that along with the technical side of that, I would suggest that a better place to locate the plants would be obviously near the coal so that the coal doesn't have to be transported to the CTL plant. As we all know, the problems that we're currently having in transporting the coal from our operations today just to meet the demands for our electricity base.

On the second part of that question, I'm fully confident that given the directive from the Federal Government on what the requirements will—a serious commitment from the Federal Government on the coal-to-liquids process, Senator, is that the coal industry is very capable of increasing the production of coal over the next 10 to 20 years to meet the demand. It can't do it, we can't do it without some certainty that the demand for our product will be there and that also issues such as transportation and permitting aren't streamlined. And I would just give a small example of that. Today, for us in the industry to develop a new coal mine, let's talk about the Eastern part of the United States in Northern App. or Central App., for us to develop a mine that would produce about seven to eight million tons a year will take us anywhere from 7 to 10 years to develop that mine most of which of that time is obtaining the necessary permits to develop the—before we even get to the development of the mines. So we can meet the demand for production for coal in the future but we have to look at other aspects that relate not only to the coal-to-liquids but also on how we can accelerate the process of developing the mines that are necessary.

Senator BUNNING. This is off the subject but it is very similar and I want to bring it up because in the energy bill we changed the rules for siting nuclear plants. Now we have 19 applications for siting of nuclear plants because of that change in the law. Maybe we need to take a look at the siting of mines and the development of mines and modernize the regulations so that it doesn't take 8 years because by the time you get it done maybe it won't be as good as it was, or at least the company thought it would be, 8 years prior. And that is a major problem commercially.

Mr. ROBERTS. No, and I agree, and I want to point out also that the mines that I was talking about were green field projects that we would be starting from scratch on them. To add additional production or capacity does not quite take that long but we still are measuring the time in years and not months. But I think a comprehensive view on the entire subject would be very helpful for our industry.

Senator BUNNING. Thank you.

Senator Thomas.

Senator THOMAS. Thank you. I appreciate the testimony. I think clearly some of it is kind of interesting. We all recognize the problem that we have and yet I think most of us recognize that there are some solutions available but we seem to be having a little trouble making the move. Clearly, I hope we don't end up in the politics of siting these plants. I think they ought to be sited where they are the most efficient, where the source of the fuel is, and, of course, we're looking at ways to be able to transmit that fuel more economically than you do in the case of coal. I might say that we're in a position in Wyoming, where we can't market all that we can produce largely because of the restraints on the shipping of railroads. So that's an opportunity.

Doctor, do you think the policies and incentives that are available now are sufficient to get the private sector moving in these projects?

Dr. GEERTSEMA. Senator Thomas, I think the framework is there but as was sort of discussed a bit earlier I think the rules for how this should be done need to be fleshed out and made very clear to potential investors. I think what is also very important is that this is an exercise, and I mentioned that in my written testimony, that calls for an integrated team of players. Obviously, the coal suppliers would be key. You need the technology suppliers, but you also need to have what I call an owner-operator partner in this whole exercise. At the moment utilities are not the sort of people who would easily step into running a CTL facility. It's more like a chemical plant than a power station. The chemical industry, by name, Eastman of course has done this sort of processing for their facilities in Kingsport so they have that framework for running a coal-to-liquids facility but besides that and of course the North Dakota people have done it in a different way but I think one needs to be pushing, facilitating's perhaps a better word, to get the owner-operators that can really take care of doing these things and have substantial resources at their disposal to take this forward. So it's a combined team effort to do it.

Senator THOMAS. It is, no question. And a lot of financial investment involved.

Mr. Roberts, you indicated the private sector needs more incentives. We provide $500 million in the form of 20 percent tax credits, authorized a billion dollars worth of tax credits to finance clean coal facilities, title XVII issues a loan guarantee up to 80 percent, what additional incentives are there to get the private sector ready to move?

Mr. ROBERTS. Well, I think they were a good step, Senator, and I think they addressed issues that maybe were not as imperative as the issues we have today. The Energy Policy Act that was passed in 2005 I think was developed and addressed matters that didn't really, I think, materialize from the national security side or the energy independence side until post-2005 and, for example, I think that Katrina showed us the vulnerability of our domestic sources of production and refining oil. I think that we have finally recognized as a country the increased demands that countries like China and India are placing on the same sources of oil that we use. So my point is that we need more—we need a much bolder approach. The EIA's forecast for coal-to-liquids is 8 percent. I don't think that's enough. Our energy demand for the next 20 years is going to increase by 27 percent. I think we need more than just the incentives that are in the current policy act. I think we need a much broader, much bigger. If you look at some of the numbers in the National Coal Council's report to the Department of Energy, in that report they have a proposal that spends about $500 billion over a period of time to increase coal production by 1.3 billion tons over the next 20 years which would not only be for coal-to-liquids but it would be also for coal to be used as a feedstock for ethanol, for coal bed methane, for the $CO_2$ capture and sequestration to be used for increase extraction of oil, so it's a much larger issue today that we need to address and I think the incremental approaches that we have taken in the past are not going to be enough to meet the energy demands that we're going to see this country will require over the next 20 years.

Senator THOMAS. I expect that's right, however, if you see yourself in the position that oil companies are in now, the profits look pretty good, don't they?

Mr. ROBERTS. I wish we were an oil company, Senator.

[Laughter]

Senator THOMAS. Mr. Ramsbottom, you mentioned you're removing sulphur and mercury as you convert to fuels. What do you do with the sulphur and mercury that's removed?

Mr. RAMSBOTTOM. The sulphur comes out in a pure stream and that is sold commercially into the marketplace to make feedstock for seeds, for ammonia fertilizer, again, back into the marketplace. And the mercury, again, same thing. The vapor is removed from the gasification, captured in beds, and that is sold back out commercially.

Senator THOMAS. I see. Just very quickly then, Mr. Hawkins, you in your testimony provided examples of the well to wheels carbon dioxide emissions from the current transportation fuels and so on. What are the well to wheels numbers for hydrogen produced by electronics?

Mr. HAWKINS. Senator, the well to wheel emissions from hydrogen would depend on what source of energy is used to produce that hydrogen. If one used electrolysis made from wind, then the well to wheels would be close to zero. If one used electrolysis made from coal, then the numbers would be similar to what it is for coal-to-liquids, that is similar to crude oil.

Senator THOMAS. Similar. Okay. All right. Well, I just hope that we can move forward. Obviously, we, I think, have some potential solutions there, long-term solutions, and we need to be able to move it as quickly as possible.

So, thank you for being here.

Senator BUNNING. A couple more questions and I'm going to then submit to you some questions in writing and I would like for you to respond for the record.

I understand the CTL fuel needs no alternations to be blended into current diesel stock. How compatible is CTL fuels with existing American infrastructure? Could CTL fuels be readily transformed into jet fuel or a DOD single battlefield fuel? Anyone.

Dr. GEERTSEMA. Gentlemen, I'll start by responding with the South African experience. Already when the SASOL one plants were commissioned in the mid-50's, exactly this happened, both gasoline and diesel were blended into products from conventional refineries. The composition is different. They were small adjustments in terms of additives and the motorist in South Africa at the moment would not know whether he or she is driving on synthetic fuels or crude oil refinery based fuels. So there's this full compatibility in that sense.

On the jet fuel side, it's not as straightforward as that because the requirements for jet fuel are more stringent than for normal automotive fuels. For quite a while already at the Johannesburg International Airport a number of the airlines there would be using 50/50 blend of SASOL derived fuels blended with crude oil based fuels.

So, again, full blending as a neat fuel or just a pure syn fuel, the requirements are a bit more tricky to reach, especially in terms of lubricity and those sort of things, but I think with further development it can certainly be achieved. What is at the moment a challenge, and the DOD has been also speaking to us on this topic, the single battlefield fuel is a fuel which doesn't exist yet. It's——

Senator BUNNING. It's different than this.

Dr. GEERTSEMA. It's different from that, sir. We do need to work on that and that's why I stressed in my testimony the issue of getting a Fischer-Tropsch technology with what I call a mini refinery to follow products for testing. Most current Fischer-Tropsch facilities of a larger scale have a fixed refinery to meet say diesel specifications. It's hard to play around at that level to tailor-make fuels for the military, whereas if we go for what I propose—the half a barrel a day facility—one can really optimize those processes to start with test quantities of say half a barrel a day and then from there eventually go to the next scale. But that will take time.

Senator BUNNING. Okay. Mr. Hawkins suggests in his testimony that a coal-to-liquids plant with an annual output of 80,000 barrels will cost about $6.4 billion to build. Do any of the other witnesses agree or disagree with that? Do you think that's a high price or do you think that's in line with about what it will cost?

Mr. RAMSBOTTOM. I can speak to 10,000 barrels up to 50,000 barrels.

Senator BUNNING. Okay.

Mr. RAMSBOTTOM. Ten thousand barrel a day facility is around a billion dollars and a 50,000 barrel a day plant is around $3 to $3.5 billion.

Senator BUNNING. Okay.

Dr. GEERTSEMA. I'd concur with him.

Senator BUNNING. That's just slightly less. And what about you?

Dr. GEERTSEMA. I concur with those numbers.

Senator BUNNING. You concur with those numbers? Okay.

Mr. HAWKINS. Just to clarify, Mr. Chairman, those numbers are not NRDC's estimates. They come from a National Coal Council report.

Senator BUNNING. Well, I just was trying to get a better opinion, if there was one, and there are similar and dissimilar opinions.

Mr. Ramsbottom, would you please explain how your process manages carbon emissions? Oh, you already have.

Mr. RAMSBOTTOM. Right.

Senator BUNNING. Excuse me.

Mr. RAMSBOTTOM. Sir, if I may go back on the blending.

Senator BUNNING. Go ahead.

Mr. RAMSBOTTOM. These fuels require no new infrastructure. And I think we talked about that earlier and since we have announced two plants, we have gotten tremendous interest from local refiners for blending our products into their products, to answer your question.

Senator BUNNING. Whether it be regular gasoline, whether it be jet fuel——

Mr. RAMSBOTTOM. Diesel products.

Senator BUNNING. Diesel products. Okay. In other words, we can blend similar diesel products whether they were made out of soy or——

Mr. RAMSBOTTOM. Current diesel products on the market today we can blend.

Senator BUNNING. Thank you. Okay. Mr. Hawkins, I want to ask another question. The loan guaranteed program envisioned by the 2005 Energy Act specifies, specifically suggests that projects funded by the program seek to address the carbon emissions that would be produced by products such as coal-to-liquids plants. While this would not necessarily address the carbon that would be emitted by vehicles, it does seek to substantially reduce the carbon emissions from the liquids produced through carbon sequestration. Do you agree that this effort has substantial merit from a national security standpoint and that it seeks to reduce our dependency on foreign sources of petroleum?

Mr. HAWKINS. Mr. Chairman, as I indicated in my statement, we support the priority of reducing our dependence on foreign sources of petroleum. And the question that we think is the right question to ask from a policy standpoint is which are the best options? Which options will deliver us the most oil savings the fastest in the most secure way and that will leave us with an environment that we all treasure. And we think certainly that when coal is used, it will be critical that coal have its carbon dioxide captured and so we support provisions in the law that encourage, and indeed, we would support provisions that require that capture and we hope the Congress will move in that direction very soon.

Senator BUNNING. I wish you'd been around in 1974 when we needed this technology to be advanced a lot quicker and we got into the problem of the cartel manipulating the price and stopping and boycotting and all those things that started and sent a red flag and nobody paid any attention for 25 to 30 years. We finally got an energy bill last year and now we're trying to refine that energy bill.

That's what this is all about. That's what this hearing's about, the first of many, and I appreciate your participation and I want to thank you for being here and we will submit some more questions to you for the record. Thank you. We're adjourned.

[Whereupon, at 3:45 p.m., the hearing was recessed, to be reconvened on May 1, 2006.]

# COAL GASIFICATION TECHNOLOGY

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**MONDAY, MAY 1, 2006**

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington, D.C.*

The committee met, pursuant to notice, at 2:31 p.m., in room SD–366, Dirksen Senate Office Building, Hon. Lamar Alexander presiding.

## OPENING STATEMENT OF HON. LAMAR ALEXANDER, U.S. SENATOR FROM TENNESSEE

Senator ALEXANDER. The hearing will come to order.

This is one in a series of hearings of the Committee on Energy and Natural Resources, authorized by our chairman, Pete Domenici, and Senator Bingaman, the ranking Democrat, to review the energy bill that the Congress passed last summer, and to make sure the provisions we adopted to try to provide a supply of clean energy for this country in large amounts at a reasonable cost are working.

We hear a lot today about the high price of gasoline. The hearing today is about gas, a different kind of gas, natural gas. I can recall that in 2005, when, along with Senator Johnson, I introduced the Natural Gas Price Reduction Act, we were startled by the increase in the price of natural gas. Many of the provisions that were included in our Natural Gas Price Reduction Act found their way into the Energy Act that the full Congress adopted nearly a year ago. Natural gas had a price of about $2.50 per unit in the year 2000. The economy of the United States was geared to operate at about that level. But the price of natural gas got as high as $15 per unit last December.

We had testimony at that time that if the price of gasoline were going up as fast as the price of natural gas, the price of gasoline at that time would be $7 a gallon. So, while we hear more about gasoline and the effect of it on the ordinary American is a major effect, the price of natural gas has as large an effect on farmers, on homeowners, and on keeping jobs in this country that might otherwise go overseas, as does the price of gasoline.

The price of natural gas, fortunately, has dropped back down to a level of about $7 per unit. But that's still too high, and it's higher than most of our economy is geared to work on. So, it's still hurting farmers, it's still hurting homeowners who are using natural gas, and it's still an incentive to drive American manufacturing jobs, especially, overseas. And I don't have the exact figure, but if the price of gasoline had gone up as much as the price of natural gas today, it would be higher than $3. It might be $4. And maybe someone on the panel can tell me what that comparative price would be.

One of the most interesting provisions in the Energy Act of last year dealt with the idea of turning coal, of which we have a lot in this country, into synthetic gas as a substitute for natural gas. Increasing the supply of synthetic gas would help stabilize, and maybe even bring down, the price of natural gas.

Coal can be turned into a synthetic gas, which is then used to make chemicals. That is exactly what, for example, Eastman Chemicals does. We're familiar with that in Tennessee, because Eastman has, for generations, provided a stable source of thousands of jobs. It's as much as a part of our landscape in Upper East Tennessee as the mountains are. And when the price of natural gas threatened jobs at Eastman, that got the attention of everybody in our State, just as it did in a similar way all across our country. But Eastman has been using coal since 1974 to make specialty plastic products. We'll hear more about that today.

But it's not just coal that can be gasified. Petroleum coke, heavy oils and waste, seemingly anything with carbon in it can be gasified. Gasification is very flexible. It can convert these into valuable products, including hydrogen, electricity, steam and chemicals. Gasification produces significantly fewer emissions, uses less water, generates less waste than other technologies. And gasification facilities can be designed to capture carbon dioxide for further industrial use or for sequestration.

Finally, gasification is a link to the hydrogen economy. Because of these many positive attributes, and because of the high price of natural gas in recent years, the Energy Policy Act of 2005 contains two provisions which we, in Congress, hope will speed the development and deployment of industrial gasification technologies.

The first is a tax credit for qualifying industrial gasification projects. We authorized these tax credits for a total of $350 million. The deadline for applying for these credits is June 30 of this year. Projects must be certified by Treasury, in consultation with the Department of Energy. A competitive bidding process will be used by the Government.

The second provision in the Energy Policy Act to speed development and deployment of industrial gasification technologies is the Federal loan guarantee provision. I just saw Senator Domenici on the Senate floor. He was the principal sponsor of that loan guarantee provision. He's very interested in its progress, how the Department is coming, looking forward to the results of this hearing.

So, this is an oversight hearing. We're here to hear from the Under Secretary of Energy—we're delighted that he has taken the time to be here—about the status of the administration's implementation of these two provisions of the Energy Policy Act. And we'll also hear from companies on the cutting edge of industrial gasification. And we'll hear from the Natural Resources Defense Council. It ought to be an interesting afternoon. We'll have two panels. We'll hear from Secretary Garman first, then from the companies and from the Natural Resources Defense Council.

But, first, I'd like to ask Senator Thomas if he has comments he'd like to make before we begin our hearing.

## STATEMENT OF HON. CRAIG THOMAS, U.S. SENATOR FROM WYOMING

Senator THOMAS. Thank you, much, Mr. Chairman. I appreciate having this hearing.

Of course, this is the second in a series of hearings to talk about implementing our policy. And that's really where we are. We hear a lot of people talking about the trouble with energy, Do we need some new laws? The fact is, probably more than anything, we need to implement the laws that are now in place. And we have an opportunity to do that.

There's lots of details, Mr. Chairman, and you've covered a lot of those. So, I'll submit my statement for the record.

But I just want to make a couple of points. One, of course, as we all know, is that our greatest source of future fossil fuels is coal. And what we need to do is find ways to use that coal in an environmentally sound way, sounder than we have in the past, if we can. Also, the cost to get it to the market. Much of the coal supply we have is in Wyoming and Montana and that part of the world; and much of the market, somewhere else. So, we have to work at getting those things there. And we can do that.

Half of our electricity is generated by coal. And, quite frankly, it ought to be more, because the other fuels are more flexible and can be used for other things.

We had a hearing in April. The Secretary was there. Thank you, Secretary Garman, for being there in Wyoming to talk about the conversion of coal to other sources. And, of course, this gasification is certainly one of those. And I appreciate that.

Relatively inexpensive for coal—and I was amazed at the kind of facts that came out of that, in terms of how you can really increase the efficiency and the cost of converting coal and getting it to the market in other forms. And we can do something about $CO_2$, we can do something about the corridors and the movement to them. And, really, that's a great thing to do.

I hope we can be realistic about developing some of these operations where the coal is. Now, I know there's always going to be debates about where the plants go, and particularly the early ones that have some incentives. But we ought to really put the facilities where the coal is. And we just recently had a memorandum of understanding between Wyoming and California for the purpose of using coal and getting it produced there in the West, having a corridor to get it to California, and also, as you know, they've been a little fussy about electricity made out of coal. But if this can be—this conversion, then they're more willing to do that.

I think it's a very important point. And, again, we need to just find a way to get on with it. People know how to do this. We just need to get the incentives on the ground and move.

Thank you, Mr. Chairman. I'm glad we're having this hearing.

[The prepared statement of Senator Thomas follows:]

### PREPARED STATEMENT OF HON. CRAIG THOMAS, U.S. SENATOR FROM WYOMING

Good afternoon and welcome. I'd like to thank all of the witnesses for appearing before the Committee today. This is the second in a series of hearings on implementation of the Energy Bill that was signed into law August of last year.

Last week we received testimony on the conversion of coal-to-liquid fuels. Today, we're talking about gasification, which is an important part of the coal-to-liquid fuels process.

Our conversation today has important implications not only for the United States, but for the international community as well. Coal is a significant potential feedstock for the gasification process. In the next ten years, global use of coal is projected to double. Coal accounts for 90 percent of the United States' total energy reserves.

The challenge is to meet our nation's environmental, economic, and security goals while developing this resource. Gasification is an incredible technology, and capable of helping us meet this challenge and overcome it.

As we heard last week, you can create liquid diesel and jet fuels from coal. You can even make plastics, epoxies, and other advanced materials from coal using gasification. Obviously, you can also generate electricity from coal. Over half of the electricity generated in the United States comes from coal.

Gasification will allow us to generate more energy from domestic fuels including coal, refinery by-products, and biomass.

One of the most significant benefits of gasification though, is our ability to produce the energy our consumers and businesses need in an environmentally sound manner.

On April 12th of this year, we had a chance to discuss coal issues at a Field Hearing that this Committee held in Casper, Wyoming. On April 13th, I also convened a forum on a broader set of energy issues in Casper. Undersecretary Garman joined us at that forum and his remarks were greatly appreciated by myself and the audience. I would like to thank you for making the trip to Casper Dave, and I would like to thank Chairman Domenici for scheduling the Field Hearing as well.

I am glad to be re-visiting these issues today.

Coal is a relatively inexpensive fuel and is abundant here in the United States. Wyoming is our nation's largest supplier of coal. Last year, 36 percent of domestic coal production came from Wyoming.

I've said before that Wyoming's ability to not only mine coal, but to use it in innovative projects is limited only by our capacity to get those value-added products to market. For this reason, we need to increase pipeline, rail, and electrical infrastructure.

We will do these things, and provide the necessary conditions for IGCC technologies to move forward in states like Wyoming where the coal reserves are located.

Of course, we must pursue these new technologies in conjunction with greater efficiency and conservation.

These Monday afternoon hearings are about implementing the Energy Bill, which contains provisions to address all of these things.

The private sector and state governments are ready to move forward with these projects. There is increasing evidence of this desire to get underway. A Memorandum of Understanding was recently signed by the Governors of Wyoming and California to use electricity produced in Wyoming from clean coal and renewable resources.

This is not a partisan issue, it cuts across party lines, and I look forward to working with Senators from the four states involved in the Frontier Line to move these IGCC projects, and the transmission necessary to deliver their electricity, forward.

In achieving these goals, we'll improve the nation's security and environment, while creating jobs and strengthening our economy.

I'll be interested to hear our witnesses' perspective on the issue of gasification technology and the opportunities that exist for us to move forward.

Thank you Mr. Chairman, that concludes my opening statement.

Senator ALEXANDER. Thank you, Senator Thomas. And your statement will be made a part of the record.

Senator Bingaman, would you like to make a statement before we begin the hearing?

## STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Senator BINGAMAN. Mr. Chairman, I appreciate Secretary Garman being here, and the other witnesses.

As I understand, this hearing is designed to look at issues related to syngas production; and, particularly, there's testimony talking about the section 48(b) tax credits that are found in section 1307. I guess the IRS comment period's about to close those tax credits, that section, and the DOE Loan Guarantee Programs that we authorized in title XVII of the bill. So, I'm anxious to learn more about the concerns that people have on both of those issues.

Thank you.

Senator ALEXANDER. Thank you, Senator Bingaman.

And we'll now proceed to the testimony of the Under Secretary of the Department of Energy, David Garman.

Secretary Garman, thank you for coming. If you could take 5 minutes or so, or if you need a little more, to present what you would like to say, and that'll leave us time to ask you questions. Then we'll go to the second panel.

**STATEMENT OF DAVID K. GARMAN, UNDER SECRETARY, DEPARTMENT OF ENERGY, ACCOMPANIED BY GEORGE RUDINS, DEPUTY ASSISTANT SECRETARY FOR COAL AND POWER SYSTEMS**

Mr. GARMAN. Thank you, Mr. Chairman.

And you said it very well, we really believe that gasification technology is poised to make a revolutionary impact in the United States and the global marketplace. It's appropriate that we transition toward large industrial and utility-scale gasification in the quest for greater efficiency and the cleaner use of combustible energy resources, particularly in light of the abundant supplies of coal and renewable biomass that we have available in this country.

Gasification-based power systems have the potential to almost double the efficiency of the current combustion-based fleet. Moreover, near-zero emission, gasification-based power systems are within our technical reach. Gasification-based systems can also produce clean hydrogen or liquid fuels or a variety of petrochemicals, synthetic natural gas, or any combination of these products and electricity. Thus, they could provide us with supply options we do not have today.

The diagram to my right, your left, describes gasification-based system concepts. A variety of feedstocks, including coal, biomass, petroleum coke, petroleum residuals, or even waste, can be gasified into a synthesis gas, or syngas, comprised mainly of carbon monoxide and hydrogen. From there, a variety of pathways leading to a variety of different products are possible. But whether you are generating liquid fuels, electricity using combustion turbines, electricity using steam turbines, electricity using fuel cells, or hydrocarbon-based chemicals and products, gasification is the common technology at the heart of all of those processes.

Of course, the prototype for the ultimate gasification-based power system, FutureGen, is now underway, led by a government/industry consortium that is dedicated and committed to its success. We're working to have FutureGen operating by 2012.

We're confident in the underlying technology behind gasification plants. Indeed, some gasification plants in certain applications have worked for many years, and worked well. But gasification powerplants, in particular, face early-mover issues, such as permitting delays, longer shakedown periods, and higher costs, since the learning curves in fabrication, construction, and operation have not yet taken hold. Therefore, the business risks of the first plants remain greater than conventional plants. Comparative costs are somewhat higher, as well, although we expect they will decline with time and experience. Since gasification systems, like most energy projects, have substantial upfront capital costs, financing remains a challenge, in light of the business risks and the higher costs just mentioned.

We're encouraged, however, by the fact that manufacturers of gasification-based powerplants are beginning to offer performance warranties, management and operating contracts, fixed-price construction contracts, and other instruments to diminish risk.

Consistent with the new authorities provided to the Department of Energy in the Energy Policy Act of 2005, we are also establishing a Loan Guarantee Program within the Department that we expect to be available for gasification-based technologies. Thus far, we have established a Loan Guarantee Office under the Department's chief financial officer, and we're currently recruiting a permanent director. We have detailed staff from other programs, and expect to be detailing staff from other agencies that have some of the necessary experience in Federal loan guarantee programs. We're drafting program policies and procedures. We're establishing a Credit Review Board. We're going to employ top outside experts for financial evaluation, construction engineering evaluation, and credit market analysis to assist us in our evaluations of applicants.

We're proceeding, but we're doing so with no small measure of caution and prudence. While the provisions of the Energy Policy Act provide a self-pay mechanism that, in theory, reduces the need for appropriations, it does not eliminate the taxpayers' exposure to the possible default of the total loan amount. It is also our view that the Federal Credit Reform Act of 1990 contains a requirement that prevents us from issuing a loan guarantee until we have an authorization to do so in an appropriations bill. We do not believe we have the authority to proceed with an award, absent having explicit necessary authorizations in an appropriations bill, and we'll look forward to working with Congress to address this issue.

I will end there, Mr. Chairman. I appreciate this opportunity to appear today. This is a very relevant and timely subject for the committee to cover, and we commend you for that.

Thank you very much.

[The prepared statement of Mr. Garman follows:]

PREPARED STATEMENT OF DAVID K. GARMAN, UNDER SECRETARY, DEPARTMENT OF ENERGY

Thank you for this opportunity to testify before the Committee on the subject of industrial scale gasification in the context of implementation of the Energy Policy Act of 2005.

Gasification technology is poised to make a revolutionary impact in the U.S. and global marketplace, so this is an extremely timely topic for the Committee's consideration. Simple combustion technologies have served us well since early humans first employed fire for warmth, light, and cooking. But it is appropriate that we in the 21st century transition toward large industrial and utility-scale gasification in the quest for greater efficiency and the cleaner use of combustible energy resources, particularly in light of the abundant supplies of coal and renewable biomass we have available.

The Department of Energy and industry have been investing in gasification systems research for decades. Very early in our work, we realized that commercially mature gasification-based power systems could nearly double the efficiency of the current combustion-based fleet. The average efficiency of today's combustion-based coal power plant fleet is 32 percent and state-of-the-art coal-fired power plants operate at about 38 percent efficiency. We believe commercially mature gasification-based power plants can achieve efficiencies in the 55 to 60 percent range. To the extent that any of the remaining waste heat can be channeled into process steam or heat, perhaps for nearby factories or district heating plants, the overall fuel use efficiency of future gasification plants could reach as high as 70 to 80 percent.

However, the potential efficiency gains only tell part of the story. Today, new gasification applications have emerged that were not even imagined at the start of our research efforts.

For example, near-zero atmospheric emission systems, emitting minimal pollutants and carbon dioxide, are within our technical reach. In addition, gasification-based systems can be configured to produce clean hydrogen or liquid fuels, or a variety of petrochemicals, synthetic natural gas, or any combination of these products and electricity. Gasification-based systems are also projected as having the potential to produce these products at reasonable cost while using some of our most abundant domestic fuel resources—coal and biomass.

This simple diagram describes gasification-based system concepts. A variety of feedstocks, including coal, biomass, petroleum coke and residuals, or even waste can be gasified into a synthesis gas (or syngas) comprised mainly of carbon monoxide and hydrogen. From there a variety of pathways leading to a number of products are possible. But whether you are generating liquid fuels, electricity via combustion turbines, electricity via steam turbines, electricity via fuel cells, or hydrocarbon based products, gasification is the common technology at the heart of the process.

Of course, the prototype for the ultimate gasification based system, FutureGen, is now under way led by a Government/Industry Consortium that is dedicated and committed to its success. Other governments and international companies have expressed strong interest in joining the FutureGen effort (and some have already joined), which will pave the way for the global deployment of gasification based zero emission systems.

In the State of the Union address, President Bush announced the Advanced Energy Initiative. The initiative's technology focus includes both power and transportation technologies, and it is important to stress that gasification has important contributions to make in each of these areas. For example, just as gasification can dramatically increase the efficiency and lower the environmental impact of power production as mentioned earlier, it can also be a pathway to the production of clean diesel, ethanol, synthetic crude, and other fuels and help reduce our dependence on foreign sources of energy—one of the key goals of the Advanced Energy Initiative.

The challenge that confronts the broader introduction of gasification-based systems is the same challenge that confronts many energy systems the up-front capital costs are substantial. Lenders lack experience with these projects, so they are less willing to assume the extra risks involved in early generation commercial deployments of gasification technologies. In addition, combustion-based systems have been the beneficiary of centuries of incremental improvement and cost reduction, so they understandably enjoy some "first cost" advantages. We have every reason to expect that the costs of gasification-based technologies will decline as experience with the technology increases—the 10th plant will be more affordable and reliable than the first. We are also encouraged by the fact that manufacturers are beginning to offer performance warranties, management and operating contracts, fixed-price construction contracts, and other instruments to diminish risk.

Gasification technologies offer benefits such as lower emissions and greater efficiencies. The widespread deployment of utility and industrial gasifiers may provide an economic alternative to natural gas for consumers who are able to switch to syngas, thereby increasing availability of natural gas for other residential, industrial, and commercial consumers who find it more challenging to change fuel or feedstock.

The industrial sector is the largest consumer of natural gas in the United States, accounting for a third of U.S. consumption. Bulk chemicals and petrochemical refining are the largest consumers of natural gas by volume, and natural gas is also a significant cost component of many other industrial sectors. Natural gas is used in the industrial sector as a feedstock in the production of chemicals, fertilizers, and refined petroleum products, and in the production of process heat. Among the industries that rely heavily on natural gas for process heat are paper and other forest products; food and beverage; primary metals, including steel, aluminum, and metal castings; and glass and other non-metallic production industries. All of these commodity industries are characterized by globally competitive markets with low margins. Thus for some plants, rising natural gas prices have increased the cost of domestic operations.

Much of industry is looking to gasification as an important element in reducing the impact of rising natural gas prices on their production costs. They believe that gasification of the Nation's abundant domestic energy feedstocks can play a significant role in creating a more affordable substitute for natural gas. Gasification of coal, petroleum coke, black liquor, and biomass can be used to create a synthetic gas suitable for providing either process heat or as a feedstock source for chemicals and fertilizers.

As mentioned earlier, gasification can be linked with other processes to produce liquid fuels. Liquid fuels used in transportation comprise about 27 percent of total U.S. energy use. Some industrial interests are looking at liquid fuels based on gasification as a source of energy. Co-production of some mix of power, chemicals, fertilizer, synthetic gas, process heat and steam, and liquid fuels may yield resilient business opportunities and greater energy security.

The ongoing gasification RD&D program and complementary programs now underway across the Department of Energy have the potential to accelerate commercial use of gasification technologies in the industrial marketplace, providing a substitute syngas suitable for relieving pressure on both fuel and feedstock availability and cost. These programs are actively pursuing advancements in membranes for more efficient separation of gas mixtures, catalysts for conversion of syngas into substitute natural gas, and fuel gases for combined cycle power production. At the same time, we support R&D underway in the hydrogen fuel initiative, which is looking at technologies for the production of hydrogen. The gasification program also is coordinated with major efforts now underway to address the issues of carbon management. It is the goal of the long term program to develop essentially emission free processes for the production of power, industrial feedstocks, and substitute fuels.

We are fulfilling our responsibilities with respect to EPAct 2005 tax credits that provide incentives to help bring these technologies into early commercial use and, eventually, widespread adoption across the American economy if they prove economic. In this regard, working with industry, the Department of Defense, and the Environmental Protection Agency, we are studying the business risks associated with industrial gasification and are performing financial modeling to understand the impact of EPAct 2005 incentives on early commercial plants.

Let me turn now to the topic of loan guarantees. Loan guarantees are only one part of a toolkit—one best used after the technology development cycle is complete. The toolkit established in EPAct 2005 contains several tools, including authorization of R&D for developing technologies, tax credits to reduce the cost of plants that utilize them or improve cash flows, and loan guarantees.

We are confident in the underlying technology behind gasification plants. Indeed, some gasification plants in certain applications have worked well for years. But early gasification plants face "first mover" issues such as permitting delays, longer shakedown periods, and higher costs since learning curves in fabrication, construction, and operations have not yet taken hold. Therefore, the business risks of the first plants remain greater than combustion plants.

Therefore, consistent with the new authorities provided us in the Energy Policy Act of 2005, we are establishing a loan guarantee program within DOE. We are mindful that the Department does not have an enviable record of accomplishment with loan guarantees issued in the past, but we will follow the Federal Credit Reform Act of 1990 (FCRA) and Office of Management and Budget (OMB) guidelines issued since our last experience with loan guarantees, and we will emulate the best practices of other federal agencies. We will move prudently to ensure that program objectives are achieved while meeting our responsibilities to the taxpayer. Toward that end:

- We have established a small loan guarantee office under the Department's Chief Financial Officer.
- We have detailed staff from other programs and may soon be detailing staff from other agencies with some of the necessary experience in Federal loan guarantee programs.
- We are drafting program policies and procedures.
- We are establishing a credit review board.
- We will employ top outside experts for financial evaluation, construction engineering evaluation, and credit market analysis to assist us in our evaluations of applicants.

We are proceeding, but we are doing so with no small measure of caution and prudence. While the provisions of the Energy Policy Act provide a "self pay" mechanism that, in theory, reduces the need for appropriations, it does not eliminate the taxpayer's exposure to the possible default of the total loan amount.

It is possible that the ultimate cost to the taxpayer could be significantly higher than the cost of the subsidy cost estimate. Therefore, DOE's evaluations of loan guarantee applications will entail rigorous analysis and careful negotiation of terms and conditions.

It is also our view that the Federal Credit Reform Act of 1990 contains a requirement that prevents us from issuing a loan guarantee until we have an authorization, such as a loan volume limitation, to do so in an appropriations bill. We do not believe we have the authority to proceed with an award absent having explicit necessary authorizations in an appropriations bill.

Again, I thank you for this opportunity to appear today, and I welcome your questions either today or in the future.

Senator ALEXANDER. Thank you very much, Mr. Secretary.

I'll take 5 minutes, and then we'll go to Senator Thomas and then to Senator Bingaman, if that's all right.

What you just said about the appropriations bill, is that new, or is that—"Does Senator Domenici know about that?" I guess is my question.

Mr. GARMAN. Yes. We have communicated.

Senator ALEXANDER. Are we making provisions so that we can have an appropriate provision in the appropriations bill this year to do what needs to be done, in your opinion?

Mr. GARMAN. We have provided the staff with our view of the kind of language that would be necessary. The relevant provision in the Federal—in FCRA, as we call it, basically states that notwithstanding any other provision of law, no new direct loan obligations can be made unless there is new budget authority to cover the costs provided in advance in an appropriations act or a limitation on the use of funds, or some other authority otherwise provided in an appropriations act.

Senator ALEXANDER. Thank you. I may come back to loan guarantees if I have time. But let me switch to the tax credit provision. Will the guidance be in place by June 30 so that applicants for the tax credits will be able to make a proper application?

Mr. GARMAN. Well, actually, yes. June 30 is the date that the applications are due. On the Internal Revenue Service Web site, there is information continuously being updated and made available to would-be applicants, to make sure that they have the latest information. And the guidelines, I understand, have been established.

The Department plays a supporting role to the Department of the Treasury in this regard. Treasury has the lead on the tax credits. We support them. We will assist them with evaluating projects, but they will have the final say.

Senator ALEXANDER. So, as far as you know, is the guidance that an applicant would need in order to comply with the June 30 deadline available from the Department of Treasury or——

Mr. GARMAN. That is my understanding.

Mr. RUDINS. Yes.

Mr. GARMAN. Yes.

Mr. RUDINS. They, in fact, have published the guidelines.

Senator ALEXANDER. Thank you. And there is another date, November 2006, which was in the Energy Policy Act, which I believe is the final decision date. Is that still a date that you intend to honor?

Mr. GARMAN. For the tax credits?

Senator ALEXANDER. For the tax credits.

Mr. GARMAN. For the tax credits, that is my understanding, and we see nothing that would prevent us from meeting that obligation.

Senator ALEXANDER. So, applicants should be able to apply properly by June 30, and the Department should be able to make decisions by November of this year.

Mr. GARMAN. The Department of Energy is making its recommendation, and the Department of the Treasury will be making their decision in November, yes, that's correct.

Senator ALEXANDER. Okay. In the original legislation for tax credits, I believe that our number was $850 million. It was eventually $350 million. I would suppose there could be many applications here. What will you do to try to resist the temptation to spread what is a relatively small amount of money by—for these kinds or projects—out among a great many projects and concentrate them on those that show the greatest merit?

Mr. GARMAN. That's a very real concern, because there is some language in the act urging us to almost do just that, considering different types of coal, bituminous, subbituminous, and lignite, as well as geographical considerations. And I understand the balancing act that we have to weigh there. We want—it seems to me, that we would want to be able to provide a tax incentive that is meaningful enough to help a project go forward. Our interest, in the Department, is that we have been working on these technologies, from an R&D point of view, for decades. And we would very much like to see them out in the marketplace. And they need a little help to get through the so-called "valley of death." So, we want to make it work, and we want to work with Treasury and use all of the authorities to help us get those technologies out the door.

Senator ALEXANDER. I understand that it's not unprecedented that Congress would sometimes give conflicting signals, or signals that might fit a larger tax-credit number. But, as one Senator, I would hope that the attitude of the Department would be what you concluded your statement with, which is to take into account the broad range of suggestions that were made, but make sure that we fund—that we have enough money for a handful of projects that have a chance to succeed and demonstrate the technology.

Mr. GARMAN. That's correct.

Senator ALEXANDER. My time is up. Let me go to Senator Thomas.

Senator THOMAS. Thank you.

Obviously, there are a number of different kinds of conversions of coal that could be made. Are there any priorities in the Department with respect to whether it's gas or electricity or diesel fuel or whatever? What's the status on that?

Mr. GARMAN. We have merely had some conversions. Title XVII is extremely broad. Almost any technology that one could conceive of that results in an advanced energy technology that reduces overall greenhouse gas outputs or meets any number of other criteria, could be considered under title XVII loan guarantee authority. And the question arises, should we, in the early going, constrain applications for loan guarantees to self-payers, and constrain it some other way, to meet the most pressing needs—for instance, coal to liquids, or biomass to liquids—to try to offset petroleum? Those kinds of discussions are underway at the Department, as we ask ourselves, what's the policy priority for us right now? I could argue, and have argued internally, that technologies that displace foreign petroleum should be weighing heavy on our minds right now. And that would include coal-to-liquids and cellulosic biomass to ethanol as top priorities.

But the Secretary has stated that he wants us to get this right. We view this as a long-term authority for the Department, and a tool we would like to keep in our toolkit to help us engage in technology transfer in the future. And, as you know, the track record of the Department of Energy on loan guarantees is not superb. And we want to get off to a very good, solid start with this program. It may mean that we're going a little more slowly than some would wish us to go, but we think it's very important to lay a very solid foundation for a solid program that's going to last for years and be very successful.

Senator THOMAS. Well, I'm sure most people would agree with that. On the other hand, we see a need to be moving on some of these things.

Mr. GARMAN. That's right.

Senator THOMAS. I mean, after all, it's going to take a while to actually develop these facilities once the decisions are made. And so, it seems to me we're going to have to move along fairly quickly. And some of the ones that are—we hear, sometimes, that the eligibility for the incentives in the—are more based on R&D and not on commercial sales operations. Can you clarify for me what the Department is hoping to achieve through these programs?

Mr. GARMAN. Well, through both the Loan Guarantee Program and the tax incentive authorities, the economic viability of the technology is extremely important, because we want these technologies to be replicated many times over. And an ideal project, from my point of view, would be one where we think the technology is very sound, yet the business risks or the fact that it is just new, and, therefore, financiers on Wall Street are a little skittish about it. This is the ideal project for us to be able to incentivize through one of these methods. But the fundamentals of the project, in terms of being able to demonstrate that it has a cash flow, that it is a sound business approach, and that it's something that can be replicated once——

Senator THOMAS. But that judgment generally come from the investor? They're the ones that are more concerned about the return. You're putting in a relatively small amount of money compared to what's involved there. I hope the agency isn't holding up what could be done, when you're putting in 5 percent of it and they're putting in 95, where they're going to be pretty careful about what they're doing.

Mr. GARMAN. If we're talking about loan guarantees, it's—a typical project, say a billion-dollar project, it may come in with 40-percent equity, 60-percent debt, and we may be guaranteeing $600 million worth of——

Senator THOMAS. Not all the incentives are loan guarantees. There's other kinds of things, as well.

Mr. GARMAN. That's correct.

Senator THOMAS. Finally, some witnesses have said that there has not been much dialogue with the private sector between the Department on how to implement. Is that a fair reaction?

Mr. GARMAN. I think that's a fair—there's been a lot of informal discussion. In fact, among the witnesses on the second panel, I've met with at least two of the groups, myself, and there's been a great deal of informal dialogue that's taken place. Right now, we have not yet been appropriated any money to implement this program. We have a reprogramming request that has been developed and that is awaiting concurrence at OMB that I think's going to happen any day. And once we actually have—I mean, I—we are operating this program with no money, through the kindness of others and other program activities. And we're hoping that we will be able to have the kind of formal interfaces, workshops, symposia with the private sector to help them understand what we're thinking and help give us the benefit of their experience and thought once we have this reprogramming and we actually have money to do these things.

Senator THOMAS. That's interesting. I think we need to discuss that issue a little more. I mean, we've got our policy out there. There's a great press on doing something on energy. Clearly, we need to be using more coal, so these other fuels are available for other things. And if you're—haven't gotten any money, that's a kind of a surprise, so we'll need to work at that.

Mr. GARMAN. Well, actually, the energy and water appropriations from fiscal year 2006 explicitly said that no incremental additional dollars were provided for Energy Policy Act implementation. And frankly, it's a matter of pride for me and the Department that, with no incremental dollars, of the 363 deliverables in this act that I am tracking for the Department, we've been able to deliver 74 of them today, with no incremental dollars. Now, some of these are relatively easy things to do, reports, and some of them are more difficult things to do.

Senator THOMAS. Yes, I understand.

Mr. GARMAN. But we take this act very seriously, and we're doing our very best to implement it, even though we haven't been given explicit resources to do it.

Senator THOMAS. Good. Thank you.

Senator ALEXANDER. Senator Bingaman.

Senator BINGAMAN. Thank you very much.

It occurs to me that if you needed resources to do it, this supplemental appropriation bill we're considering on the floor is a very likely opportunity to get those resources. I don't know of any requests from the administration for any funds to implement EPAct as part of this supplemental. Are you aware of any?

Mr. GARMAN. I'm not aware, in the supplemental.

Senator BINGAMAN. Yes. That would be a good place to do it. I'm sure that many of us on this committee would support funding in this supplemental, if you could tell us what you need.

Mr. GARMAN. But you will very shortly see a reprogramming request using fiscal year 2006 dollars, reshifting dollars already appropriated and—you know, a request that allows us to spend funds for, for instance, the Loan Guarantee Office.

Senator BINGAMAN. Okay. Well, let me ask about the loan guarantee proposals. As I understand it, you contemplate issuing draft regulations for comment on the Loan Guarantee Program that's in title XVII. When would that happen? Do we have a timeframe?

Mr. GARMAN. Actually, because it would be a very long process, we are attempting to go with guidelines rather than regulations. We are trying to expedite the process to go with some guidelines, which we have drafted and which are under an interagency review right now.

Senator BINGAMAN. Okay.

Mr. GARMAN. And it is our hope that we get these out shortly, and folks will be able to take a look at those and see what we're thinking.

Senator BINGAMAN. So, once the guidelines have been issued or released, there's not a comment period. I mean, there's no comment period required, or no formal procedure, since you would be using guidelines rather than regulations. Is that right?

Mr. GARMAN. That is my understanding. I think there are some after-the-fact steps where we would have to do some regulations, but they're deferrable. We chose a path that would enable us to be able to accept applications, perhaps during this fiscal year, in the next 6 months.

Senator BINGAMAN. Okay. So, that would mean you would have your guidelines finalized and usable, and people could actually make application between now and on October 1.

Mr. GARMAN. Yes, sir.

Senator BINGAMAN. And that's what you're expecting and working toward at this point. All right.

Mr. GARMAN. Yes, sir.

Senator BINGAMAN. I was struck by your comment that you've been able to implement 74 of the 380——

Mr. GARMAN. Three hundred and sixty-three.

Senator BINGAMAN [continuing]. 363 requirements that we laid on you, or obligations that we imposed on you, as part of EPAct. How are the others coming? There are a lot that aren't in that list, it would seem to me.

Mr. GARMAN. Well, keep in mind that some of those deliverables aren't due yet, so—I'm trying to remember my math here—but—yes, a large tranche of those are due in August, 1 year post the date of enactment.

Senator BINGAMAN. Okay.

Mr. GARMAN. So, 74 is a pretty good track record. There's a combination of deliverables that include rulemakings, miscellaneous mandatory items, and reports. We're doing pretty well on the reports. We're doing pretty well on the rulemakings. There are a number of provisions that we won't do as well on. As you know, this bill authorized a number of new programs, that, if I were to add up the authorizations in the bill, it comes out to about $16 billion. And, clearly, there are some provisions in that bill that are going to await funds before we're going to be in a position to implement them. But we've taken the position of trying to implement the maximum amount that's available to us. And we'll continue that path, that approach.

Senator BINGAMAN. I think it would be useful. And you're in direct communication, I'm sure, with our chairman and others on the Appropriations Subcommittee on Energy and Water Appropriations, but it would be very useful, I think, for all of us to have an idea of what items are awaiting funding before you can actually go ahead and implement them. I mean, I realize we put an enormous burden on the Department when we passed this legislation. And I've not been critical about failure to get it all done in a hurry. I do think, though, that once a funding cycle comes and goes, there's going to be a lot less sympathy around here for pleas that we haven't adequately funded this thing. I mean—because I think we'll have a chance to correct that here pretty soon. I hope that you'll communicate any needs along those lines to the rest of us, as well.

Thank you, Mr. Chairman.

Senator ALEXANDER. Secretary Garman, you alluded to this, but one of the interesting provisions of the loan guarantees is the idea of a risk premium that the applicants are the—those who are the beneficiaries of the loan guarantee would pay a risk premium that would be judged to be sufficient, so that the taxpayer doesn't lose any money. It's an interesting concept, but an important one to the passage of this provision. You said, I believe, in response to Senator Bingaman, that you hope that things would continue along so that you might be able to accept applications for the loan guarantees by October. How are you coming on the risk premium analysis? And what can you tell us about how you're approaching that?

Mr. GARMAN. Let me clarify this. The self-payer loan applications, or ones who are offering to put up that risk premium, are the applications that we would be in a position to accept, hopefully this fiscal year, because that is—as you say, no explicit appropriations are needed, although there is some appropriation authorization needed, as we talked about earlier.

I'll give you an example, and it's just a hypothetical example. If there is—let's say a project cost of a billion dollars, and the applicant is coming in with 40-percent equity funding, or $400 million, leaving debt of $600 million to cover, and, through the evaluation process that we developed, we decided that there was a 10-percent risk of default, meaning that the applicant would have to come up with a cash payment of $60 million, or 10 percent of $600 million, to go into a Treasury fund, and that fund would grow over time with other applicants and other self-payers, to be used to pay for loan guarantees that didn't pan out. And that's——

Senator ALEXANDER. Would that $60 million be an expense, an amount of money that was put in the Treasury, or would it simply be a credit?

Mr. GARMAN. It would remain in the Treasury in a special dedicated fund, is my understanding, because the Federal Government would have a contingent—or the taxpayer would have a continent liability of $540 million on that project. If that project went belly up, and there was no means to save it, then the taxpayers would have to come——

Senator ALEXANDER. But if it doesn't go belly up, does the applicant—or the operator get the $60 million back?

Mr. GARMAN. No. The $60 million remains in the fund. Inevitably, we anticipate that eventually one of these will fail, and this fund would be growing in the Treasury to pay the default costs for failed projects.

Senator ALEXANDER. So, to get that $600 million, the applicant would have to—would borrow it from the Federal Government for—I mean, I know this is an example, but—and then, in addition, pay $60 million fee, in effect?

Mr. GARMAN. Well, instead of——

Senator ALEXANDER. An insurance fee?

Mr. GARMAN. In other words—another way of thinking about it is, instead of bringing $400 million of equity to the table, the applicant would have to bring, in this example, $460 million of equity to the table.

Senator ALEXANDER. Well, where does the $600 million come from? That's borrowed, right?

Mr. GARMAN. That's borrowed. And that is the——

Senator ALEXANDER. So, the applicant would have to pay an interest cost on the $600 million, and then it would have to pay, in effect, an insurance fee that would amount to 10 percent to the Government.

Mr. GARMAN. In this example.

Senator ALEXANDER. In that example.

Mr. GARMAN. But, of course, the interest costs would probably be lower, because the lender would—realizing that this was a federally guaranteed loan, would offer more favorable interest to the applicant. So, that is a tradeoff that an applicant would have to consider if they were using the self-payer pathway. Is the benefit to them resulting from the Federal loan guarantee worth the price? In this hypothetical example of 10 percent, the risk premium may be lower. We don't know.

Senator ALEXANDER. I can see a lot of financial minds whirring in the audiences to think about those numbers.

Mr. GARMAN. Those are big numbers.

Senator ALEXANDER. That will be an important decision to make, both from the taxpayers' point of view and from the point of view of creating an insurance premium fee that is reasonable enough so that it makes a loan guarantee worth anything to the applicant.

Mr. GARMAN. Correct.

Senator ALEXANDER. Otherwise—I mean, it might be such an expensive cost of money that the applicant might say, "Well, that's not—I mean, that's interesting, but it's not even in the marketplace, in terms of what I'm willing to pay for the cost of money in order to go forward with a project of this kind."

Mr. GARMAN. That's right. Our measure of success would be, how many projects are going to closing? I mean, that is a measure of success. That shows that the negotiation between the Government and the applicant has been successful, and we've gone to closing, and that is the first stepping stone of success.

Senator ALEXANDER. I see the red light on, but another thing to be careful about, I can think of, is that someone who might be willing to pay too high a fee might be a less worthy applicant, or have a less worthy—a less worthy project which would be something to consider in the evaluation.

Senator Thomas, do you have additional questions?

Senator THOMAS. No, let's go ahead and continue.

Senator ALEXANDER. Senator Dorgan and Senator Murkowski have arrived. Why don't we let you ask questions, if you'd like, of Secretary Garman, and then—we have five witnesses following him in the next panel, and then we'll go to those witnesses.

Senator Dorgan.

Senator DORGAN. Mr. Chairman, thank you very much.

Mr. Secretary, thank you for being here. Just a couple of observations and a question. As you know, we have, I believe, the only coal gasification plant in operation north of Beulah, North Dakota. It's been in operation for a long, long while. It produces synthetic gas from lignite coal. It is really a technological marvel in many ways. It produces well above anything that was originally projected to produce. It produces valuable byproducts. And we are using the $CO_2$ pipe to Canada to inject into oil wells to increase the productivity of marginal wells in Canada. It's pretty unbelievable. We sequester that $CO_2$, we produce synthetic gas out of coal.

I guess the point of my comment is, there's no question about whether this can be done. It is being done. And that plant, at the moment, is producing an enormous amount of profit, a substantial portion of which will be shared, because of the profit-sharing, with the Department of Energy. And I don't remember the exact amount. I think it's $60 or $80 million that will be turned over soon. So, the question isn't whether this can be done. It is being done.

Is the technology—and I think you have visited that plant—is the technology in that plant old technology or is there technology that is more modern than that technology in gasification?

Mr. GARMAN. There are more modern technologies. I believe the $CO_2$ scrubber at that plant is amine-based.

Mr. RUDINS. I believe it's Rectisol.

Mr. GARMAN. Right, okay.

But there are better and newer technologies. This Great Plains gasification plant was from an older synfuels loan guarantee program that we had.

Senator DORGAN. It was?

Mr. GARMAN. It was an example of an actual loan guarantee that defaulted. But efforts were made to recoup the investment. And I think both the Government and the project sponsors, the "white knights," if you will, came in and made a pretty good showing of it. They, although they had an opportunity—they decided not to avail themselves of some tax incentives that were available. And, thus, made it almost a wash for the Government—not quite, but it was a very, very good technology step for us, and it shows that this can be done. And we've learned a lot from it, and we continue to learn from it today.

Senator DORGAN. I don't know the numbers of that plant, but I think that plant is producing synthetic gas from lignite coal at somewhere between $2 to $3 per Mcf. And if that's right, you know, at the market price by which they're now marketing the synthetic fuel from that plant, that plant is spinning off a great deal of money, and, again, with the profit-sharing with the Federal Government, is—has become a good bargain. And I applaud the Department of Energy. There was a time when the Department of Energy simply could have said, “No, no, we’re going to close that thing down. This is a default.” But, because it didn’t, and it stuck with trying to have the only research plant of this type of—commercially sized research plant of this type up and operating, we now know that we have the world’s largest reserve of lignite coal, called Fort Union, that that large reserve of coal is available. We now know that we can gasify it, produce synthetic gas from it. We can sequester $CO_2$. There a whole series of things that make a lot of sense for us here. The reason I wanted to come today was simply to describe the experience we’ve had, a pretty substantive experience.

I was actually there the first day that Art Seder, from Michigan-Wisconsin Pipeline, came to North Dakota to describe his goal of building 21 coal—21 synthetic fuel plants. They eventually built one, and had financial difficulty doing that. But now—and having gone through two different visions of financial trouble, now that plant has—is quite a remarkable marvel with—hugely profitable. And the Federal Government is participating in that profit, which makes a lot of sense.

So, I think what Congress did last year in this area, providing loan guarantees and moving in this direction, can be very helpful, and the experience we’ve had in the past with the Great Plains plant can be very instructive.

So, Secretary Garman, thank you for being here, and thanks for your testimony. I had a chance to read it prior to coming here, but I’m sorry I wasn’t here for all of your testimony.

Mr. GARMAN. Thank you.

Senator ALEXANDER. Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman. Appreciate you chairing this hearing today. And, Secretary Garman, thank you for being here. And thank you and the Department for your efforts over the past many years, for all that you’ve done in the clean coal effort, in the coal gasification technology. You’ve taken an important role there, and we appreciate it.

We specifically thank you for what has recently come out of the Arctic Energy Office. This is the review of the Alaska Cook Inlet coal resources for us to move forward with what we consider to be some pretty exciting initiatives, the information that you will get from that review will be vitally important, and we, again, appreciate your leadership on that.

The first question that I’ve got—this is as it relates to the tax incentive and the loan guarantees, and I kind of came in on the tail end of the conversation, so if I’m asking something that you’ve already answered, I apologize—but in addition to the loan guarantees, the tax incentives, is there anything else out there, in terms of funding assistance, that could be made available either for research or for project grants to help advance this technology, to advance the commercialization of the coal gasification technology? Is there anything else beyond these two areas?

Mr. GARMAN. Yes. There is of course, the Clean Coal Power Initiative, which is a demonstration program that can provide up to 50-percent cost share for demonstration plants of gasification technologies or other advanced coal technologies. For example, there is a plant under design in Orlando, Florida, with the Southern Company, to design, demonstrate, and operate an IGCC coal plant with the Government having a 50-percent, or thereabout, share in the demonstration of this technology.

In addition to that, there is our general R&D activity in our coal budget, which is, oh, probably—the R&D portion of that, roughly $50 million a year, that's available for a much higher cost-share, with the Government—the Federal Government paying more along the lines of 80 percent of the costs of working R&D issues related to the use of coal in advanced gasifiers or in other means.

So, they're out there. They're generally awarded on the basis of competitive solicitations, and there is often a solicitation on the street.

Senator MURKOWSKI. Let me ask you—in the second panel, we've got some representatives from Agrium who will be speaking to that project, and how the loan guarantee, and how the tax incentives, can help them if we understand a little bit better what the parameters are. The date that is set out there for the tax credits—and I understand that it's June 30, the applications need to be submitted—are these applications for projects that have been completed in the sense that they're all defined, or would it work if they have gone to prefeasibility of the project? I need to know how hard and fast this June 30 application date on this——

Mr. GARMAN. The June 30 date is hard and fast. This was set by Treasury. We're playing a supporting role on the tax incentives, and helping Treasury review the applications and see which we think have both technical and economic viability. We're looking at technical feasibility, suitability of the proposed site, economic feasibility. And we need to have a pretty good understanding of those factors, so that we can make the decision and meet Treasury's deadlines. I'm familiar with the Agrium project. I've sat down with them, and I understand what they have planned, and it is an exciting project, and I don't know that we're perfectly synced up in terms of what their prefeasibility information is providing and what we'll be requiring on the June 30 deadline. But we encourage them to provide us as much as they can. And we'll try to show whatever kind of flexibility we're allowed to. But we want you to know, we're under the gun from Treasury to stick to these dates.

Senator MURKOWSKI. Well, what's the December 31, 2007, deadline, then? Because it was my understanding that, up until that point in time, you were able to accept projects, or to qualify projects, perhaps.

Mr. GARMAN. I think the December deadline relates to another provision having to do with nuclear powerplants, but we will check with you and get back to your staff on that.

Senator MURKOWSKI. Okay. If you could check on that, I'd appreciate it.

Mr. GARMAN. Yes, Senator.

[The information follows:]

Applications for certification are due to the Department of Energy by June 30, 2006. DOE will determine feasibility and if the project qualifies, certify it by October 1, 2006. The IRS will accept or reject an application for certification by November 30, 2006. Applicants have two years from the date the application is accepted to provide evidence that they satisfy the criteria for certification. If the aggregate credit pool is not fully allocated in 2006, there will be similar allocation rounds in 2007 and 2008, following the same date guidelines in the future years. An applicant that receives a certification for an Advanced Coal Project has five years from the date of the certification to place the project in service. For Gasification Projects, the applicant has seven years. In both instances if the project is not in service at the end of the specified period, the certification is void.

Another provision of EPAct 2005 provides for the Credit for Production from Advanced Nuclear Power Facilities. The deadline requirements for this provision differ substantially from those for Credit for Investment in Clean Coal Facilities.

Senator MURKOWSKI. Last question, then. This relates to the insurance premium fees. In terms of how this 10-percent figure was arrived at, is—what's the basis to that——

Mr. GARMAN. Please understand that that was merely a hypothetical figure. The risk premium is somewhat analogous to the notion of, what do we think the risk of default of this project is? It may be 2 percent, it may be 20 percent. And, thus, the premium that we would require, based upon this risk of default, is really the driving factor. And that would be dependent on the individual project—the technical and the economic feasibility and other factors. If a project has, for instance, a power purchase agreement in place, or if the project has a guaranteed take of—you know, guaranteed off-take agreement with someone, that obviously lowers risk, and would lower the risk of default. So, it would pretty——

Senator MURKOWSKI. So, it really is judging it on a project-by-project type of an approach.

Mr. GARMAN. That's correct.

Senator MURKOWSKI. Thank you, Mr. Chairman.

And I do have an opening statement that I'll submit for the record, but I appreciate the opportunity to ask these few questions of Secretary Garman.

Mr. GARMAN. Thank you, Senator.

Senator ALEXANDER. Thank you, Senator Murkowski, and it'll be made a part of the record.

[The prepared statement of Senator Murkowski follows:]

PREPARED STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

Thank you Senator Alexander for chairing this hearing, the second into how agencies are progressing in their efforts to implement the Energy Policy Act of 2005 that we passed last summer.

This hearing focuses on, in my view, one of the important provisions of the Energy bill, its ability to promote the use of coal gasification technology to produce products, electricity and new fuels from America's abundant coal resources, and especially the ability of the process to allow us to produce energy without necessarily emitting any carbon into the atmosphere—instead sequestering it underground.

We all know America is the Saudi Arabia of coal. Our half trillion tons of demonstrated reserves is the highest in the world. My state of Alaska has demonstrated reserves of 160 billion short tons, that would place it second in the world in coal reserves, only behind all of the former Soviet Union—if Alaska seceded from the Union. (And if we did then we could develop ANWR far more easily),

The problem with coal in the past has been its pollutants and in the future the issue likely will be the amount of carbon dioxide produced when it is burned. Both are solved through gasification of the coal, which readily allows you to separate out carbon dioxide for use or capture and which also allows the removal of pollutants from sulfur and nitrogen to mercury. This could be our biggest environmental boon.

And given our growing shortage of natural gas, and the skyrocketing prices for natural gas, coal gasification and the products it will generate, could be the savior for an American petrochemical and manufacturing sector. The prepared testimony today includes an eyepopping statistic: that the U.S. has lost $484 billion in domestic industrial production in the past six years because plants have moved overseas or lost business because of high natural gas prices here.

For coal gasification to help our industrial sector to survive these price shocks, we have to immediately implement the provisions that we included in the Energy

Bill to improve the economics of gasification by increasing the economies of scale in construction of such plants and by helping to perfect commercial-scale gasification technology.

An example of why this help is needed comes from Alaska.

In panel 2 Bill Boycott will be testifying. Welcome Bill thanks for coming a long distance to appear at this hearing. He is general manager of the Agrium fertilizer plant on the Kenai Peninsula in Alaska—the only year-round value-added manufacturing plant currently operating in all of Alaska, if you don't count a neighboring LNG plant.

The huge price increases in natural gas, the company's current feedstock for fertilizer/urea production, is threatening to force the plant's closing—the 20th fertilizer plant in America to close in the past four years.

Coal gasification would allow Agrium to make its nitrogen fertilizer from the 1.4 billion tons of coal located just across Cook Inlet from the plant. It would allow it to make badly needed excess electricity to power the Railbelt. It would also produce the tons of $CO_2$ that could be readily piped underground into the neighboring Swanson River and Cook Inlet oil fields that could in turn help produce another 300 million barrels of oil from the aging Cook Inlet fields.

That would not only allow Agrium's employees to keep receiving paychecks, it would produce domestic fertilizer for American farmers and produce another 25,000 barrels a day of oil from Cook Inlet. And given the prices at the pump this morning, we need every barrel of oil we can get to increase supplies and drive down prices in this nation.

And Alaska clearly needs a coal product in Cook Inlet to proceed to propel the state's economy in the future.

I truly look forward to the testimony and the suggestions we are going to receive today on how we can fully implement last year's bill NOW, and if there are ways to improve the bill and speed the gasification process along, I would welcome them too.

Seemingly almost daily we hear concerns about global climate change stemming from greenhouse gas emissions. Since this is a process that would allows carbon sequestration. That alone should be grounds to really push economic development of commercial coal gasification technology to the front burner.

Thank you.

Senator ALEXANDER. Secretary Garman, thank you for being here. And as—to summarize, as I understand it, what you have told us is that so far as you know, that the information to permit an application on the tax credits will be sufficient, so that applications can be made by June 30, 2006, as the legislation said; and, so far as you know today, that, by November of this year, the Department of Energy will be able to make its recommendations to the Department of the Treasury, so that it can make its decisions; and that, if things continue as they are, applications for at least some of the loan guarantee projects might be made by 6 months from now. Is that correct?

Mr. GARMAN. Yes. We would hope to be able to be in a position to accept applications for self-pay loan guarantees by October 1.

Senator ALEXANDER. Self-pay loan guarantees. And that we should expect, very shortly, to learn more about a reprogramming request that will provide additional already appropriated funds, which will help you in implementing the provisions of the Energy Policy Act that were passed last year.

Mr. GARMAN. Correct. And I would also hope that we should have guidelines out and available for public perusal very shortly, as well.

Senator ALEXANDER. And that you're using the procedure of guidelines so as to speed things along——

Mr. GARMAN. Speed things up.

Senator ALEXANDER [continuing]. Rather than to go through regulations, which might take a year or two.

Mr. GARMAN. Yes, sir. And I will monitor this hearing and the witnesses, and if we hear things that come up as a consequence of the second panel, you have my assurance that we'll work with you and with them to try to allay any concerns or fears they might have, as well.

Senator ALEXANDER. Thank you very much for your time.

We have five interesting witnesses we'd like to hear from now, and I'll invite them to come to the table. I'll introduce all five of them, and ask them to present their testimony.

[Pause.]

Senator ALEXANDER. Let me welcome all five of the witnesses to the hearing.

What I would like to suggest—we have four Senators here. We've had Senator Bingaman here, as well, for part of the hearing. And I know all of those who are here would like to have a chance to ask you questions. So, we have your statements. We thank you for being here. And may I suggest that you try to summarize your statements within 5 minutes. There's a little machine here that'll report the 5 minutes with a yellow, and then red, light. And then, that will give us more time to ask you questions or to make comments on the things that you've said.

Our witnesses today are Brian Ferguson, who's the chief executive officer of Eastman Chemicals, in Kingsport, Tennessee—welcome, Mr. Ferguson; Mr. William Bruce, president, BRI Energy, in New Smyrna Beach, Florida; Mr. Bill Douglas, vice president, Econo-Power International Corporation, in Houston, Texas, would be the third witness; Mr. Bill Boycott, general manager of Agrium U.S.A., Incorporated, would be the fourth witness; and then Dr. Antonia Herzog, who is the Climate Center staff scientist for the Natural Resources Defense Council, in Washington, D.C. Thank you for coming, Dr. Herzog. And we'll ask you to comment after the other four have, if that's all right with you.

So, Mr. Ferguson, let's start with you, and we'll move right along through all five witnesses.

**STATEMENT OF BRIAN FERGUSON, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, EASTMAN CHEMICAL CO., KINGSPORT, TN**

Mr. FERGUSON. Good afternoon. Thank you so much, Senator. It's a pleasure to be here. I want to thank the members for this opportunity to comment on my perspective on the Energy Policy Act. I appreciate the opportunity to discuss with you our concerns about certain provisions of the act, particularly those around the Federal industrial gasification tax credits and the self-pay Federal loan guarantees for industrial gasification, some of which were just discussed by Secretary Garman.

And, as you said, I've submitted written comments. I'll be short and sweet in my personal comments, and I look forward to your questions.

The corporation I represent, Eastman Chemical Company, has been operating an industrial gasification facility since 1983, and we've been competing with the largest chemical companies in the world successfully since that time with that facility. But, like many of my chemical brethren today, we are all under extreme pressure from rising costs of energy and raw materials. My industry has experienced a cumulative $60 billion—that's "billion," with a "b"—a $60 billion increase in our natural gas bill since the beginning of this decade. And, as a result to that—let me give some quick examples. In a recent *Business Week* magazine, it was noted that there were 120 global chemical sites valued at more than $1 billion currently under construction in the world. Only one of those is located in the United States. The remaining plants, offering high wages and stable employment, are being constructed in places where energy costs are lower and less volatile. My friends over at Dow Chemical Company, for example, are currently building a $4 billion plant in Oman. The Dow Chemical chairman and CEO, Andrew Liveris, went on record recently saying that he was originally going to build that plant in Freeport, Texas, but the high cost of natural gas in this country, which, at that time, was 12 times higher than it was on the Arabian Peninsula, forced him to choose Oman instead. It's important for all of us to remember that Dow's new plant will employ about 1,000 people in high-paying R&D, engineering, operations, and—those are 1,000 employees that could have been U.S. employees if we had an energy policy that worked to help us and not punish us. And the "us" I'm talking about are industrial manufacturers, like Dow and Eastman.

Now, the point is that Dow isn't alone. Every industrial company is facing the same dilemma, build in the United States or build overseas, invest where the energy policy is a liability or where it's an asset. And, frankly, Senators, I'm facing that same choice around the end of this year on a very large investment.

That's why I was so pleased when I saw that Congress finally created, within the Energy Policy Act of 2005, the incentives that would help correct 20 years of problematic energy regulations, finally move us away from a costly and wasteful dependence on natural gas.

As you know, Congress helped create the situation we're in now. Congress drafted regulations promoting the burning of natural gas to produce power at the expense of pretty much everything else. So, I'm pleased to see that Congress has now begun to correct that and put a renewed emphasis into the American industrial areas, examples such as chemicals, agriculture, glass, steel, and forest products.

For both the industrial tax credits and the Federal loan guarantees to be effective if they're going to change the course of investment in energy and feedstock technology investments in this country, they need to address global market risks and support commercial-scale projects. While there is a separate need for demonstration projects to validate key technologies, the real need for America now is to assure that these incentives support investment in commercial-scale industrial gasification projects that are calculated to meet global competitors and are ready to deploy.

The Federal industrial gasification tax incentives and the self-pay Federal loan guarantees in the Energy Policy Act are huge steps in the right direction, and I thank you for creating those. However, we have some serious concerns about the investment tax credit and the self-pay Federal loan guarantee implementation. And I'd like to just comment on those, very briefly.

First, it is imperative that the process for implementing section 48(b) is more transparent and meritorious than we have seen so far. The primary objective should be to assure that these early projects be technically, financially, and commercially solid projects with experienced and capable owner-operators. Recently issued industrial tax credit application guidance did not outline measurable selection criteria that would allow applicants to have confidence that this crucial objective would be met.

Industry raised many important questions that were either politely dismissed or have gone wholly unanswered. And under the June 30 application deadline set forth in the guidance, time is running out for a serious applicant to submit a responsible project application in the face of the untimely answers or unanswered questions. I request that the Senate Energy and Natural Resources Committee, along with the Senate Finance Committee, ask IRS and DOE to seriously address the questions submitted by a wide cross-section of industrials.

Second—and this is a concern I think you talked about with Secretary Garman—we're concerned that the Federal loan guarantee process itself is not moving quickly enough. We understand that there is some agreement to take applications by the end of the year, as was discussed, but the dialogue has really not happened between DOE and any intended beneficiaries to foster that at a formal level, maybe some at an informal level. It's imperative that the dialogue begin immediately if these projects are going to move forward in the timetable that you were discussing. And I'm confident that there are projects that will be ready to go as soon as this process is clarified, but we need to start with some active dialogue.

Third, the focus for the incentives needs to be squarely aimed at domestic industries that are suffering under the burden of high natural gas prices. We anticipate that the availability of these incentives will attract a number of project developers who will try to claim qualification even though they are not in the intended group of recipients. It's extremely important that the focus of the incentives remain on the group of eligible entities that were defined in section 48(b) of the Energy Policy Act.

Senator ALEXANDER. Please finish up. You're past 5 minutes.

Mr. FERGUSON. I'm sorry, I'm over? Let me close——

Senator ALEXANDER. Go ahead and finish your thought.

Mr. FERGUSON. Well, a fourth concern would be the budget issue that was raised by Secretary Garman. We support his initiative to have some money to work with. And we believe that by implementing these initiatives and these incentives properly, it can make a big difference to the country. And we hope you can support the implementation process.

[The prepared statement of Mr. Ferguson follows:]

PREPARED STATEMENT OF BRIAN FERGUSON, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, EASTMAN CHEMICAL CO., KINGSPORT, TN

Mr. Chairman, members of the Committee, I am Brian Ferguson, CEO and Chairman of Eastman Chemical Company, headquartered in Kingsport, Tennessee. I want to thank you for the invitation to come before you today and give you my perspective on the Energy Policy Act of 2005. And I appreciate the opportunity to discuss with you our concerns with certain provisions of the Act, particularly those around the Section 48B Federal Industrial Gasification Investment Tax Credits in

Title 13 and the self pay Federal Loan Guarantees for industrial gasification projects under Title 17.

INTRODUCTION TO EASTMAN

The corporation I represent is Eastman Chemical Company. Eastman manufactures and markets chemicals, fibers and plastics worldwide. It provides key differentiated coatings, adhesives and specialty plastics products; is the world's largest producer of PET polymers for packaging; and is a major supplier of cellulose acetate fibers. Founded in 1920 and headquartered in Kingsport, Tenn., Eastman is a FORTUNE 500 company with 2005 sales of $7 billion and approximately 12,000 employees. For more information about Eastman and its products, visit www.eastman.com.

Eastman is not unlike many chemical companies in the United States today. That is to say that we are all under extreme pressure from rising costs of energy and raw materials. My industry has experienced a cumulative $60 billion—that's billion with a 'B'—a $60 billion increase in our natural gas bill since the beginning of the decade.

What's the result? Let me give you a quick example.

One report in *Business Week* noted that there were 120 global chemical sites valued at more than $1 billion currently under construction in the world. Of those, only one was located in the United States. The remaining plants—offering high wages and stable employment—are being constructed in places where energy and raw materials not only cost less, but their availability and prices are more stable, too.

Dow Chemical Company, for example, is currently building a $4 billion plant in Oman. This plant was originally going to be built in Freeport, Texas. But the high cost of natural gas in this country—which was 12 times higher in Texas than on the Arabian Peninsula—forced Dow to site it in the Middle East instead.

With that decision, America has lost a new plant that will employ 1,000 people in high-paying science, engineering and operations jobs—and we have taken on more step toward creating for our chemicals industry the same kind of dependence that we face with imported oil. One thousand employees who could have been U.S. employees and billions of dollars that could be flowing into—rather than from the U.S. economy—if we had an energy policy that worked to help—not punish—industrial manufacturers like Dow.

Dow isn't alone, of course. Every industrial company is facing the same dilemma. Build in the U.S. or build overseas. Invest where the energy prices are a liability—or go where they are an asset.

That's why I was so pleased when I saw that Congress finally created within the Energy Policy Act of 2005 the incentives that would help correct 20 years of shortsighted energy regulations and finally begin to move us away from a costly and wasteful dependence on natural gas for electricity generation.

IMPORTANCE OF GASIFICATION

Wide spread deployment of sound, proven gasification technology is an important tool that can help keep currently-natural-gas-dependent globally competitive American industries in America. Gasification provides the opportunity for American industry to use a wide array of feedstocks such as coal, petcoke, biomass and even many industrial waste materials in lieu of expensive natural gas. On the market side, creation of synthesis gas permits a very broad suite of products and uses. So, gasification technologies offer important flexibility to industry.

Other benefits:

- Feedstock Diversity—Reduced cost and greater flexibility of feedstock input. Industrial manufacturers operate in a globally competitive market where their price of natural gas makes a huge difference in final product prices. Unlike the electric utility industry, for example, production costs largely determine where our goods are manufactured.
- Jobs—Preservation of U.S. jobs, especially high-paying ones in the chemical industry which has already lost more than 100 plants and 100,000 jobs between 1999 and 2005. But notably, other natural gas dependent sectors have also suffered dramatically, i.e., agriculture, paper, metals, iron and steel. See Attachment 3*
- Avoids Mid-East Energy Dependency—Maintains U.S. economic strength and avoids "oil style" dependence on Middle East—truly a slippery slope.

*Attachments 1-3 have been retained in committee files.

- Environment—Even using fossil fuels, emissions of $SO_2$ and $NO_X$ from gasification processes are similar to sources using natural gas. Also, gasification can capture mercury and $CO_2$ for safe disposal-sequestration, etc.
- Trade balance—The U.S. has lost $484 billion in domestic industrial production between 1999 and 2005, further exacerbating our Nation's huge trade deficit in manufactured goods. As capital costs decline with broad deployment of gasification technology, new plants will produce synthesis gas that permits domestic production to be competitive with foreign plants.
- All Natural Gas Consumers—With industrial gasification, natural gas prices for all domestic consumers (48A program also contributes to this benefit) will fall. Facilities operational under 48B tax credits will reduce costs to all American natural gas consumers over the long term and pay for themselves in about six months. This is a conservative estimate which assumes only the output of the plants receiving the credit and does not reflect the subsequent stimulation of additional, cheaper gasification plants which will reduce natural gas demand and prices further.

### NEED FOR TIMELY ACTION

There is suddenly a lot of hype regarding gasification technologies. Not a week goes by that I don't read or hear some story in the news about a new gasification technology that will be the panacea for the Nation's energy ills. Development of new technology is important—important in the next decade or the one after that. For gasification to make a difference to American industry now, when industry needs it most, we must deploy sound, proven, currently available technology.

For both the Section 48B Investment Tax Credits and Federal Loan Guarantees to be effective in my industry—if they're to change the course of investment in energy and feedstock technology investments in this country—they need to support commercial scale projects that address global market risks, now. I want to emphasize that point. Industry needs deployment of proven, commercial scale gasification technology now, not just more research and more demonstration projects that may, or may not be adopted by industry ten or fifteen years from now. While there is a need for future demonstration projects to validate key technologies, the real difference for America now is to assure that these incentives support investment in commercial scale industrial gasification projects that are calculated to meet global competition so that these industries will still be contributing mightily to the American economy when those new technologies become available.

America will need technology improvements in the future if we are to remain competitive in the global industrial marketplace, but only if we take the necessary steps now to ensure that the U.S. still has an industrial base in the next decade. That may sound like hyperbole until one considers the more than 2 million American manufacturing job losses overall since 1999, and particularly in the natural gas dependent industries—in chemicals, forest products, glass, steel, and even agriculture.

### NEED TO MAINTAIN THE ORIGINAL FOCUS

The Section 48B tax credits were added to HR 6 specifically for the gasification of coal, biomass, petcoke and waste materials to serve the fuel and/or feedstock requirements of certain globally competitive industries that were facing economic distress due to rapidly rising natural gas prices in the U.S. The focus for these incentives needs to continue to be squarely aimed at domestic industries that are suffering under the burden of high natural gas prices, as identified in the new law. We anticipate that the availability of these incentives will attract a number of project developers who will try to claim qualification even though they are not in the intended group of recipients.

It is important that the focus of the incentives remain on the group of eligible entities that were listed in Section 48B of the Energy Policy Act. Now is not the time to dilute the impact of the incentives by spreading the relatively moderate amount of incentives across too many projects or to unintended projects. The selected projects should be adequately funded, should be focused on directly helping the intended industries, and should be ones deemed most likely to succeed in the near term.

### HARD WORK AHEAD

The subject of today's hearing: the passage of legislation (PL 109-58) was only the first of many steps needed to realize the potential of gasification technologies.

The hard work has just begun for both industry and government.

The second step—the step that is in play right now—is the drafting of regulations to implement the authorities conveyed to the Administration by the energy bill.

I have serious concerns about the implementation of the Investment Tax Credit and the self pay Federal Loan Guarantee programs.

Congress passed Public Law 109-58 more than nine months ago (July 29, 2005); yet, to date, there has been no formal dialogue between the private sector and the Department of Energy (or other federal agencies) regarding implementation of the loan guarantee provisions of Title 17. Of greater and more immediate concern is that the regulations published this February regarding the 48B industrial gasification tax credits need major revision if the credits are to be awarded effectively, fairly and for sound projects, as I believe Congress intended.

The Section 48B tax credits were originally added to HR 6 as a Senate Finance Committee amendment totaling $850 million. As mentioned above, these funds were provided specifically for the gasification of coal, biomass, petcoke and waste materials to serve the fuel and/or feedstock requirements of certain globally-competitive industries that were facing economic distress due to rapidly rising natural gas prices in the U.S.

Even at the $850 million amount, it was generally assumed that there would be many more applicants for the tax credit than available funds. Given the cost premium for the first generation of gasification projects to be built, parceling out the limited funding to all qualified applicants on a *pro rata* basis was recognized as potentially spreading the money too thinly to advance any projects. Consequently, industry proposed that DOE and Treasury jointly solicit tax credit applications on a single date after which DOE would evaluate and rank the projects according to technical and economic merits for Treasury's subsequent award of the credits on a "competitive" basis.

When funding for Section 48B was cut to $350 million in Conference, the need for a strong DOE role to assess and rank applicants by merit became even more apparent to industry.

The competitive award of the 48B tax credits is a novel way for Congress to target limited financial resources to the most meritorious applicants within a class. Such an approach might not be appropriate for many types of tax credits; but I believe it clearly is when the intent of Congress is to stimulate investment in technology to achieve broad public benefits with limited funds.

Fortunately, even though there was no direct legislative requirement to do so, Treasury and the DOE did agree to establish a "competitive process" for accepting, evaluating and awarding certificates of eligibility for the limited pool of 48B industrial tax credits.

Both departments should be commended for the novel mechanism that has been crafted to promote the most effective use of taxpayer resources to spur the early introduction of gasification technology leading to the many benefits identified at the beginning of this testimony. But more can and must be done by both departments to ensure that fairness, process transparency, merit and technical readiness for deployment are the final determinants in the awards that are made later this fall.

Government sources anticipate perhaps six or seven times [Note: if recent estimates of 48 projects are correct, that would be sixteen times] the number of project applications that can be supported by the $350 million available. And, each industrial applicant will spend, on average, more than $1 million developing their application. In such a competitive and expensive situation where industry is preparing to commit very large financial resources to build these gasification projects (greater than $1 billion in many cases), fairness, transparency and judgment on project merits seem like a small request. And, it is just "good government."

## DETAILED CONCERNS AND RECOMMENDATIONS

Eastman Chemical Company joined with numerous other companies and trade associations (also known as the Industrial Gasification Initiative) to present unified recommendations to both departments related to the process for awarding the 48B investment tax credits. Subsequently, the Department of the Treasury published guidelines in the Federal Register on February 21st for the joint conduct of the 48B Industrial Gasification Program with DOE. Certainly the intent of IRS and DOE to work together to award the tax credits on a competitive basis is a good first step. However, the process described in the February announcement ignored many constructive suggestions proposed by the Industrial Gasification Initiative.

Specifically, the 48B process designed by Treasury will not utilize DOE's capability to evaluate, compare and rank multiple large projects applications, such as it does in the Clean Coal program. Instead, Treasury has asked DOE to simply determine whether a project meets a "pass-fail" standard in several categories. Obviously, an evaluation process of this nature does not separate the simply good projects from the superior ones.

Did Congress intend that the industrial gasification investment tax credits potentially be awarded to "B" grade projects over "A+" projects? I hope not.

There is still time to fix this problem if key Members of Congress move quickly to do so. The Committee has jurisdiction over DOE; but of course Treasury, and specifically IRS, has the lead in determining the process for awarding the 48B industrial gasification tax credits. I urge the Senate Energy and Natural Resources Committee to collaborate with the Senate Finance Committee to ensure that the Industrial Gasification Initiative's recommendation for a transparent and competitive process for industrial gasification tax credit awards based on merit is achieved.

Members of the Industrial Gasification Initiative would be pleased to work with the Congress and the agencies on these improvements.

The Initiative members have many additional concerns about the criteria that may, or may not, be used by the DOE and IRS to evaluate projects. Mr. Chairman, you were one of the first Senators to recognize the need for legislation addressing the adverse impacts of rising natural gas prices on domestic manufacturing industries' ability to compete in world markets, in fact on their very ability to continue operations in the U.S.

The Section 48B Industrial Gasification Investment Tax Credits were born of that very concern. Congress intended for the credits to stimulate investment in gasification plants that can use a wide variety of fuels to displace natural gas as a fuel and/or feedstock. The credits are intended to assist early adopters of gasification technologies to "buy down" the high price of these first plants to be deployed.

This approach is quite different than DOE's usual mission of developing and demonstrating new technologies. Yet, there appear to be suggestions in the February IRS guidelines that novel technologies, not proven technologies, will be favored in the selection of projects. This "research" bias is reflected in two of the three Program Policy Factors listed in Appendix B, section "F" of the February Notice: 1) "Diversity of technology approaches and methods, and 2) Geographic distribution of potential markets. These factors would be suitable for a technology demonstration program such as Clean Coal, but they are wholly inappropriate for the purposes of Section 48B—to deploy technically sound synthesis gas plants that can begin to reduce natural gas demand in globally competitive domestic industries, to reduce the cost penalty associated with those plants, to offer hope for saving U.S. industrial jobs, and to do so in an environmentally sound manner.

So, the Industrial Gasification Initiative members ask the Committee to ensure that the 48B program is not hijacked to become just another extension of existing federal RD&D programs.

Beyond these points, the Industrial Gasification Initiative is concerned by the process for obtaining clarification on many technical issues raised by the February Federal Register notice (IRS Notice 25-2006). The Initiative submitted ten questions to the DOE more than one month ago. The DOE responses are underlined. Additionally, questions that appear in italics were also submitted to the IRS at that time. To date, no response has been received from the Service.

The Initiative's questions and answers received to date follow as Attachment 1 at the end of my testimony.

I call your attention to submitted question #4b and the "non-answer" as an illustration of the confusion that still exists less than 60 days before applications are due. Although obviously a technical question, DOE deferred it to the IRS, which has provided no timetable of their response—nor is IRS likely to possess the technical background to appreciate the basis for this question. If this language were to remain, and depending on its interpretation, potentially, no project would qualify. All projects need start-up fuels, chiefly natural gas, in the testing and ramp-up period. These start-up fuels will be used in far less quantities during normal operations. As soon as a project uses the first molecule of natural gas for start-up, it fails this criterion based on current language. While this outcome might seem like a ridiculous scenario, unanswered, the question raises considerable doubts about how the notice will be applied. There needs to be an allowable and adequate start-up period before which such language is applied, or else there needs to be a more distinct boundary regarding its application to only the production of syngas from the gasification block (which is the primary boundary of the eligible property definition for application of the tax credit). Companies that are spending considerable time and money to develop applications and, more importantly, to develop projects that are essential to our nation's energy objectives, deserve a straight answer, especially to questions as purely technical as #4b.

Another basis for concern is the non-response to question #5c and the second part of question #5b. This process-type question was again deferred to the IRS. Eastman and most of the companies that may apply for the ITC are public companies with extremely sensitive disclosure requirements. We need to know the process of public announcements in enough time so that we can be prepared with our concurrent public disclosure. This is a process question, not a policy question, so again it should be fairly straightforward to address.

Both of these questions were raised according to the DOE procedure on March 25th. DOE indicated a response time of about five business days. It is now May 1, the closing date for questions. Any applicant that has follow up questions regarding any response, or non-response, to previous questions will not be allowed to seek further clarification after today.

CLOSING REMARKS

Let me close by encouraging you to maintain the integrity of this process. It is crucial, not only for those beneficiaries who have projects in the pipeline, but crucial for the country as well.

If the desire of this Congress continues to be one of providing help to the job-producing portion of the American economy—to keep jobs here in the U.S.—it is critical that you protect the funding for those sectors where it can do the most good: commercial, industrial projects.

That's where American jobs are on the line and that's where the real power of the country's economic engine lies.

For convenience, I have included a summary of the Industrial Gasification Initiative's recommendations under Attachment 2 of my testimony.

Again, I thank you for the opportunity to share our concerns. And I thank you for the leadership you've already demonstrated on this important topic.

Senator ALEXANDER. Thank you very much.

Mr. Bruce.

## STATEMENT OF WILLIAM F. BRUCE, PRESIDENT, BRI ENERGY, LLC, NEW SMYRNA BEACH, FL

Mr. BRUCE. Thank you, Senator. Senators, good afternoon. It's a pleasure to be here. My name is William Bruce, and I am appearing on behalf of my company, BRI Energy. I appreciate the invitation to appear before this committee today and have the opportunity to share with you an exciting new technology my company intends to utilize to produce ethanol from coal syngas.

This technology has been developed over the past 15 years by many dedicated scientists and engineers and aided financially by the Department of Energy. As one of your esteemed colleagues told me recently, "Bill, you're really sitting on top of the right technology. You just need to get it to the appropriate people."

This technology, which I will refer to as "syngas fermentation," is now ready to be commercialized. It has been validated in a pilot plant and can cost-effectively produce ethanol from any carbon material. This technology can use synthesis gas from any coal gasifier. It can also convert syngas from the gasification of petroleum coke, agriculture waste, and even municipal solid waste into ethanol.

In the simplest of terms, the process uses heat in modern gasification equipment to break apart carbon compounds, creating carbon monoxide, hydrogen, and carbon dioxide, which is then converted biologically into a single product, ethanol, in approximately 1 minute. It is projected that the process will produce approximately 150 gallons of ethanol per dry, ash-free ton of coal. Five-hundred million tons of coal per year, about 50 percent of our Nation's current coal consumption, would produce 75 billion gallons of ethanol, roughly half of our Nation's gasoline consumption. If we want to solve the fuel problem in this country, the gasification of coal and converting that into ethanol, I think, is a viable alternative.

Utilizing this clean coal technology can help to make our Nation energy-independent. An important byproduct of the process is the ability to create large amounts of steam. For example, a plant processing 2,500 tons of coal per day could produce steam capable of powering steam turbines totaling approximately 100 megawatts of electric power, while at the same time producing 135 million gallons of ethanol.

In short, the syngas fermentation technology is a breakthrough, for three reasons: the process is environmentally friendly, the process is economically viable, and the process uses homegrown feedstock resources.

First, our commitment to the environment and reduction of greenhouse gases is to produce ethanol with little or no air emissions. Emission testing from the pilot plant demonstration has been successful in meeting that commitment.

Second, the passage of last year's national Energy Policy Act has laid some very important foundation blocks for commercializing this process. The next step is to gain the approval of the financial community by building a commercial-scale plant and demonstrating that this technology is a cost-effective means to produce ethanol. It is hoped that grant and loan guarantee provisions in the current energy legislation will help us to achieve this goal. With the assistance of a Federal loan guarantee, a 7-million-gallon-per-year coal-to-ethanol facility can be constructed and fully operational within 15 to 18 months. In light of the many challenges in today's fuel and energy economy, we are able to offer a viable, economic solution.

Third, this process uses domestic sources of feedstock to produce ethanol. As I stated, any carbon-based material can be used, and the United States has 23 percent of the world's coal reserves. With the abundance of coal located throughout most of the Nation, along with other readily available carbon feedstock, our technology could allow each State to domicile ethanol production facilities.

This technology has been technically studied and accepted by private engineering firms, and uses commercially available equipment. I can sit before you today and clearly state that a technological solution now exists to make a significant contribution towards solving our Nation's energy challenges.

In closing, I would like to reiterate that our technology is a plausible energy solution, because it is environmentally friendly, economically viable, and uses homegrown feedstock resources. This technology is capable of removing our dependence on foreign oil.

Again, I truly appreciate this opportunity, and would be happy to address any questions that you may have.

[The prepared statement of Mr. Bruce follows:]

PREPARED STATEMENT OF WILLIAM F. BRUCE, PRESIDENT, BRI ENERGY, LLC, NEW SMYRNA BEACH, FL

Mr. Chairman and Members of the Committee, good afternoon. It is a pleasure to be here. My name is William Bruce and I am appearing on behalf of my company, BRI Energy. I appreciate the invitation to appear before this Committee today and have the opportunity to share with you an exciting new technology my company intends to utilize to produce ethanol from coal syngas. This technology has been developed over the past 15 years by many dedicated scientists and engineers and aided financially by the Department of Energy. As one of your esteemed colleagues told me recently, "You are really sitting on top of the right technology, you just need to get it to the appropriate people."

This technology, which I will refer to as Syngas Fermentation, is now ready to be commercialized. It has been validated in a pilot plant and can cost effectively produce ethanol from any carbon material. This technology can use synthesis gas from any coal gasifier. It can also convert syngas from the gasification of petroleum coke, agriculture wastes, and even municipal solid waste into ethanol. In the simplest of terms, the process uses heat in modern gasification equipment to break apart carbon compounds, creating carbon monoxide, hydrogen and carbon dioxide, which is then converted, biologically into a single product—ethanol, in approximately one minute. It is projected that the process will produce approximately 150 gallons of ethanol per dry, ash free, ton of coal. 500 million tons of coal per year, about 50% of our nation's current coal consumption, would produce 75 billion gallons of ethanol, roughly half of our nation's gasoline consumption. Utilizing this "clean coal technology" can help to make our nation energy independent. An important byproduct of the process is the ability to create large amounts of steam. For example, a plant processing 2500 tons of coal per day could produce steam capable of powering steam turbines totaling approximately 100MW of electric power, in addition to producing 135 million gallons of ethanol.

In short, this Syngas Fermentation technology is a breakthrough for three reasons:

1. The process is Environmentally Friendly
2. The process is Economically Viable
3. The process uses "Home Grown" Feedstock Resources

First, our commitment to the environment and reduction of greenhouse gases is to produce ethanol with little or no air emissions. Emission testing from the pilot plant demonstration has been successful in meeting that commitment.

Second, the passage of last year's National Energy Policy Act has laid some very important foundation blocks for commercializing this process. The next step is to gain the approval of the financial community, by building a commercial scale plant and demonstrating that this technology is a cost effective means to produce ethanol. It is hoped that grant and loan guarantee provisions in the current energy legislation will help us to achieve this goal. With the assistance of a federal loan guarantee, a 7 million gallon per year coal to ethanol facility can be constructed and fully operational within 15 to 18 months. In light of the many challenges in today's fuel and energy economy, we are able to offer a viable economic solution.

Third, this process uses domestic sources of feedstock to produce ethanol. As I stated, any carbon-based material can be used and the United States has 23% of the world's coal reserves. With the abundance of coal located throughout most of the nation, along with other readily available carbon feedstocks, our technology could allow each state to domicile ethanol production facilities.

This technology has been technically studied and accepted by private engineering firms and uses commercially available equipment. I can sit before you today and clearly state that a technological solution now exists to make a significant contribution toward solving our nation's energy challenges.

In closing, I would like to reiterate that our technology is a plausible energy solution because it is environmentally friendly, economically viable, and uses homegrown feedstock resources. This technology is capable of removing our dependence on foreign oil.

Again, I truly appreciate this opportunity and would be happy to address any questions that you may have.

Senator ALEXANDER. Thank you, Mr. Bruce.

Mr. Douglas.

**STATEMENT OF WILLIAM C. DOUGLAS, SENIOR VICE PRESIDENT, BUSINESS DEVELOPMENT, ECONO-POWER INTERNATIONAL CORPORATION, HOUSTON, TX**

Mr. DOUGLAS. Thank you, Mr. Chairman, members of the committee.

I'm pleased to be here today to share with you our views about the benefits which coal gasification systems technology can deliver, and, in specifics, the technology that we have developed. It's our belief that if coal gasification can achieve widespread adoption in the industrial sector, it's going to help the country displace the usage of scarce natural gas and put Americans to work mining, transporting, and converting coal.

Use of synthetic fuel gas will also assist industry in meeting the environmental goals of reducing $NO_X$, $SO_X$, mercury, and other pollutants, while also advancing sound energy policy. Our company, EPIC, builds, owns, and operates industrial coal gasification systems to convert coal to a clean alternative to natural gas. We believe that the use of domestic coal offers a stable-priced, clean alternative to the volatile pricing inherent in domestic and imported natural gas and LNG.

EPAct 2005 represents a major step forward in providing incentives to bring clean coal initiatives to the very large industrials and to utility companies. However, we believe it has a very select impact on the small-to-medium-sized industrial that is evaluating alternative energy, such as coal gasification. Major credit available to us, of course, is the investment tax credit. However, those credits are restricted to certain industries and require that the fuel be used for a specific purpose, such as the production of electricity. This restriction eliminates a large proportion of the U.S. industrial base as potential users of synthetic fuel gas. The small- and medium-sized industrials are the companies having the greatest difficulty in dealing with the high price of natural gas and electricity used in their facilities. These companies are rapidly—as the large companies have already—becoming noncompetitive with other nations, because of high energy costs. These same companies are also reluctant to change their energy source from the tried and true natural gas and electricity. For them, a commitment to change to a coal-based syngas will likely require some type of financial incentive.

Coal gasification provides a significant environmental advantage. When used to replace direct coal combustion in boilers or kilns, the following benefits are available: the elimination of particulate emission, the reduction of $SO_X$ emissions by at least 100 times over unscrubbed coal, reduction of $NO_X$ emissions by 90 percent or more, and the removal of mercury at greater than 90 percent.

In the ICGS process, harmful pollutants are removed from the syngas stream before combustion, rather than in post-combustion flue-gas treatment. The pressurizing gas stream represents less than 1/100th of the volume of the flue gas from direct coal combustion, and the contaminants in syngas are concentrated. Therefore, precombustion cleanup is far more effective, and at a much lower cost, than the post-combustion cleanup employed in direct-combustion coal steam-boiler plants.

The nature of coal gasification requires a significant capital commitment to build the system. Past and present incentives have only been available to the gas supplier or coal converter, which is us. Coal gasification is nominally quite competitive with natural gas, as we've already heard; however, the requirement to commit to a long-term contract for the coal gasification system complicates the customer's decision. If tax incentives for ICGS were available to the user in the form of credits for Btus of syngas used, the economic benefits would be more obvious and promote more rapid ICGS implementation. For users that are currently combusting coal, tax incentives for coal gasification would expedite the fuel switch and offer more rapid environmental cleanup of these polluting systems, while minimizing the economic impact of the additional conversion cost of the coal to fuel gas.

The current investment tax credit for the producer do help to minimize the conversion cost of the fuel-gas user, and, therefore, facilitate the acceptance by the financial communities for the conventional project financing. And we applaud that.

Thank you very much.

[The prepared statement of Mr. Douglas follows:]

PREPARED STATEMENT OF WILLIAM C. DOUGLAS, SENIOR VICE PRESIDENT, BUSINESS DEVELOPMENT, ECONO-POWER INTERNATIONAL CORPORATION, HOUSTON, TX

Good morning, Mr. Chairman and members of the Committee. My name is Bill Douglas. I am the Senior Vice President for Business Development for Econo-Power International Corporation or EPIC. We also have Mr. John Keller, Vice-President and Chief Financial Officer. We appreciate the opportunity to testify this morning.

We are pleased to be here today to share with you our views about the benefits that Industrial Coal Gasification Systems technology can deliver. ICGS can produce a synthetic fuel gas at prices below that of Natural Gas by converting solid fuels, such as coal, which are abundant and economically available in the U.S. If ICGS can achieve wide spread adoption in the industrial sector, it will help the country displace usage of scarce natural gas, put additional U.S. workers to work mining, transporting and converting coal. Use of economical synthetic fuel gas will assist industry in meeting environmental goals of reducing $NO_X$, mercury and other air pollutants, while also advancing sound energy policy goals of retaining a secure and diverse mix of fuels for industrial process and electric power generation.

EPIC, *The Clean Coal Gasification Company*™, builds, owns and operates industrial coal gasification systems to convert coal to a clean alternative to natural gas. The use of domestic coal offers a stable-priced, clean alternative to volatile-pricing for domestic and imported natural gas and LNG.

## EFFECT OF EPACT 2005 ON INDUSTRIALS IN THE U.S.

EPACT 2005 is a major step in providing incentives to bring clean coal initiatives to the very large industrials and Utility companies. It has a very select impact on the small to medium size industrial that is evaluating alternative energy such as Coal Gasification. The major credit available is the ITC. However, these credits are restricted to certain industries and/or require that the fuel be used for a specific purpose such as the production of electricity. This eliminates a large proportion of the U.S. industrial base as potential users of synthetic fuel gas. The small and medium sized industrials are the companies having the greatest difficulty in dealing with the high price of natural gas and electricity used in their facilities. They are rapidly becoming non-competitive with other nations because of high energy costs. These same companies are also reluctant to change energy sources from the tried and true natural gas and electricity infrastructure. For them, a commitment to change to a coal-based syngas will require some financial incentive. The most effective way to induce a company to change to Coal Gasification is through economic incentives. The way to provide these incentives is to modify EPACT to include the smaller industrials with incentives to use alternative energy sources such as Coal Gasification.

## OVERVIEW OF ICGS TECHNOLOGY

ICGS is a process that converts low value fuels such as coal, biomass, and municipal wastes into a high value, low Btu, environmentally friendly natural gas-type fuel, also called "synthesis gas" or simply "syngas". ICGS uses air-blown, modular gasifiers to accomplish the conversion.

Coal gasification has undergone many evolutions and improvements. The EPIC system of gasification and sulfur removal is an updated version of a time tested method to convert coal to a low Btu fuel gas. The EPIC system is covered by U.S. patents (pending) and is manufactured in the U.S. There are dozens of similar systems in operation for many years in other parts of the word that provide fuel gas for varied industrial processes. The potential U.S. industrial users need some incentive to allow them to accept the system in the U.S.

Industrial uses include virtually any natural gas fueled industrial process such as boilers, kilns, process furnaces, etc. The ICGS can also refuel older coal fired plants for environmental compliance without adding pollution control systems.

EPIC has also worked with major gas turbine suppliers to gain acceptance of the fuel gas produced in EPIC's system. This acceptance opens the Integrated Gasification Combined Cycle (IGCC) area for even small and medium sized industrial plants.

ENVIRONMENTAL ADVANTAGES OF ICGS

ICGS provides some significant environmental advantages. When ICGS is used to replace direct coal combustion in boilers or kilns, the following benefits are obtained;

- Elimination of particulate emissions.
- Reduction of $SO_X$ emissions by at least 100 times over unscrubbed coal.
- Reduction of $NO_X$emissions by 90% or more.
- Removal of mercury at greater than 90%.

When ICGS is used to replace natural gas, $NO_X$ reductions of at least 50% are obtained.

It is important to note that only minimal modifications are required to boilers, kilns or process furnaces to use ICGS. For most industrial boiler, kiln or furnace systems, major capital expenditures would be required to achieve compliance with even current environmental regulations. ICGS allows U.S. industrial companies to employ capital to improve process efficiency without having to dilute it for investing non-productive pollution control systems.

In the ICGS process, harmful pollutants are removed from the syngas stream before combustion, rather than in post combustion flue gas treatment. The pressurized syngas stream represents less than 1/100 of the volume of the flue gas from direct coal combustion and the contaminants in syngas are concentrated. Therefore, IFGS pre-combustion clean-up is far more effective and much lower cost than the post-combustion clean-up employed in direct combustion coal steam-boiler plants.

In ICGS, coal ash is converted in the gasifier into a solid, which is similar to conventional coal fired ash which can be employed in the construction industry as road fill or as strengthening aggregate for building concrete. ICGS does not require secure landfill sites for ash storage.

The sulfur is removed from the gas before combustion and is recovered in elemental, non-hazardous form. This sulfur may have economic in certain industrial processes and agriculture. Even if sulfur disposal is required, non-hazardous disposal is easily accomplished.

ICGS SHOULD BE VIEWED AS A FUEL SWITCH AND NOT A NEW SOURCE

In the case of retrofit for industrial boilers, kilns, furnaces, etc, the facility is normally permitted to operate on its present fuel. In general, the facility will continue to operate at the same production level (at a minimum) as with the existing fuel.

ICGS should be viewed as merely a fuel change and not a major modification triggering NSPS standards. Expedited permitting would also help the industrial user to keep competitive advantages while maintaining domestic fuel sources.

Consideration of ICGS's environmental benefits should lead to placing ICGS as PACT (Preferred Available Control Technology) for industrial energy users.

PACT designation would allow industrial customers to more rapidly achieve energy cost stability and remove this aspect of the perceived permitting risk when using ICGS.

ICGS USES

The EPIC ICGS is inherently "modular" and is easily applicable to most industrial processes. The number of gasification modules is determined to closely match the fuel gas needs for each individual user. There is no "one size must fit all" requirement, as is the case with larger oxygen-blown systems being offered for large IGCC plants.

Gasification is a steady state chemical process and steady state industrial processes are the best candidates for its use. With modular ICGS, should the user's fuel gas needs expand, the ICGS is normally easily expandable to match the expanded needs.

Another industrial strategy could be to co-fire ICGS gas with natural gas to obtain partial benefits. The ICGS system can be expanded in the future for increased coal gas use. This strategy could allow the user to more rapidly obtain some ICGS benefits while a larger system is being constructed.

EPIC is working to improve the process and overall efficiency, thereby offering the user increased benefits from ICGS use.

ECONOMIC ISSUES

The nature of ICGS requires a significant capital commitment to build the system. Past and present incentives have only been available to the gas supplier/coal converter. ICGS is nominally quite competitive to natural gas. However, the requirement to commit to a long-term contract for the ICGS system complicates the decision. If tax incentives for ICGS were available to the user in the form of credits for Btu's of syngas used, the economic benefits would be more obvious and promote more rapid ICGS implementation.

For users that are able to directly combust coal, tax incentives for ICGS use would expedite the "fuel switch" and offer more rapid environmental clean-up of these polluting systems while minimizing the economic impact of the additional "conversion" cost of the coal to ICGS fuel gas.

For the system provider of the ICGS, capital cost is a major issue. Investment tax credits would help to minimize the "conversion cost", to the fuel gas user and therefore, facilitate the acceptance by the financial communities for conventional project finance.

VALUE TO INDUSTRY AND THE COUNTRY

- Reduce industrial dependence on natural gas or foreign LNG.
- Use the 225 year supply of U.S. coal resources for a broad base of industrial plants.
- Help U.S. industrial producers keep competitive with foreign competitors with cheaper synthetic fuel gas.
- Reduce industrial emissions.
- Allow industrial producers to stabilize energy prices over the long term without the high volatility of natural gas prices.
- Keep and create new U.S. jobs.

NEEDED TO ACCOMPLISH BROAD ICGS IMPLEMENTATION

- Broaden the base of industries and applications in which EPACT 2005 and other legislation encourage the use of gasification technologies by removing restrictions as to the types of industry and ends use of the syngas produced
- Incent the ultimate gas user by providing incentives based on the amount of energy in Btu's obtained from coal gasification
- Adopt ICGS as Preferred Allowable Control Technology (PACT) to allow environmental regulators to more easily issue permits for fuel switching rather than the full new source reviews that could be required without PACT designation.

CONCLUSIONS

- ICGS can benefit a broad spectrum of U.S. industries.
- ICGS can significantly reduce industrial pollution.
- Additional broad based tax incentives available to the fuel user would expedite implementation of ICGS.
- ICGS can be a viable means of reducing U.S. dependence on imported energy (oil and natural gas/LNG).

Thank you for the opportunity to testify before your committee and we would be happy to provide additional information if required.

Senator ALEXANDER. Thank you, Mr. Douglas.

Mr. Boycott.

**STATEMENT OF WILLIAM A. BOYCOTT, GENERAL MANAGER, KENAI NITROGEN OPERATIONS, AGRIUM U.S. INC., KENAI, AK**

Mr. BOYCOTT. Good afternoon, Mr. Chairman and members of the committee. Thank you for the opportunity to appear today to discuss the Energy Policy Act of 2005 and its applications to industrial coal gasification.

As you mentioned, I'm responsible for Agrium's operations in Alaska. Those operations are a gas-based fertilizer-production facility with the capability to produce 2 million tons a year of fertilizer.

We are the second largest nitrogen complex in North America and one of the largest manufacturers in the State of Alaska. At capacity, we employ 230 people directly.

As I mentioned, we're based on natural gas, and, specifically, natural gas produced in the Cook Inlet of Alaska. After 35 years of industrial usage, we're seeing this gas in significant decline. The natural-gas reserves that we are dependent on are no longer able to support contracts for the long-term supply into our facility. As a result, in November of last year we shut down half of our complex and laid off 85 of our employees. If we're not successful in contracting for additional supplies, we'll be forced to shut down entirely in November of this year.

Closing the plant will have a devastating effect in the Kenai Peninsula area of Alaska. As I mentioned 230 direct jobs, 420 indirect jobs, will be lost, along with more than $100 million annually that we inject into the local economy through our activities.

As we continue to pursue a short-term solution in natural gas contracts, we're also evaluating coal gasification. We've initiated a feasibility study to look at the potential for the utilization of large reserves located about 25 miles from our plant to support our ongoing operations. If this project proves to be commercially viable, it not only will protect and—the jobs and the economic impact of our business, but it also has the potential to supply low-cost power into the Alaskan grid, utilize sequestered carbon dioxide in the production of oil—crude oil and enhanced oil recovery operations, and provide the anchor demand required to develop a world-scale coal resource that to date has not had an economic opportunity for development.

As we've gone through the economic evaluation of this project, we're looking at a large project. Current estimates, $1.5 to $2 billion. As we look through the evaluation on the decisionmaking as to whether to move forward with this, just the decisionmaking is a daunting process. Our two-phase feasibility study of the economics of the project will cost in excess of $32 million. These expenditures are at-risk dollars, in that they're not recoverable if the project doesn't move forward.

A key component of these plans in any decisions we make to put dollars at risk is the certainty of Federal Government assistance, if it is offered. Suffice to say that, at this point, if we determine that it is needed, then it will be imperative that the assistance be there when the time comes.

After comprehensive analysis of the Energy Policy Act, we've concluded that the industrial gasification tax credits and the innovative technologies loan guarantee program have the potential to provide significant benefits to the project. The degree to which either of these programs is beneficial, however, will be determined by the manner in which the executive branch implements them.

The Blue Sky project could be eligible for a maximum of $130 million in tax credits. Our preliminary analysis shows that these could be material in our decisionmaking process. As stated earlier by Secretary Garman, we have concerns that we're somewhat out of link, and—with trying to supply the level of definition required by June of this year. And so, that causes us some concern, and that concern has—you know, although we continue to move forward with this evaluation, at this point we aren't able to ascribe much benefit to the tax credits program in our project evaluation.

Similarly, the loan guarantee program holds great potential to reduce the cost and risk of financing capital-intensive projects such as the Blue Sky project. That potential could be significantly limited, however, by its implementation—in particular, the evaluation and implementation of the risk premium, as previously discussed. I had an example here I was going to discuss, but I think it's been very adequately covered already. Suffice to say that if the risk premium is calculated in a way that the project implementor bears all the risk, then the value to the implementor of the project is greatly reduced or eliminated.

In conclusion, I believe that the development of industrial gasification projects is crucial as we look to address our national energy issues. And I applaud you for the work that you have done in the development of the national energy program.

I believe strongly that the opportunity we are evaluating in Alaska is a very sound opportunity supported by a very interesting cross-section of commercial opportunities through $CO_2$, the fertilizer complex, and the coal resource that is there in place in Alaska.

The national energy policy is on the right track. However, definition and certainty are required in order to support the decisionmaking that private industry is facing. What we're looking for is certainty and simplicity. And, currently, where we're at with the loan guarantee program and the tax credits, we don't see that, to this date, and we are afraid that they are not supporting the decisionmaking that is going on.

Thank you.

[The prepared statement of Mr. Boycott follows:]

PREPARED STATEMENT OF WILLIAM A. BOYCOTT, GENERAL MANAGER, KENAI NITROGEN OPERATIONS, AGRIUM U.S. INC., KENAI, AK

INTRODUCTION

Good afternoon Mr. Chairman, Members of the Committee. Thank you for the opportunity to appear before the committee to discuss the Energy Policy Act of 2005 and its applications to industrial coal gasification. My name is Bill Boycott. I am the General Manager of the Agrium U.S., Inc. Kenai Nitrogen Operations (KNO). I am here to address how provisions of the Energy Policy Act of 2005 (EPAct 05) could potentially benefit Agrium's Blue Sky coal gasification project.

KNO is a manufacturing facility located in Kenai, Alaska, that relies upon natural gas as a feedstock to produce ammonia and urea fertilizers. Like many U.S. fertilizer manufacturers, we are unable to assure ourselves of a reliable, long term, reasonably priced supply of natural gas the primary feedstock required for fertilizer production. As a result, KNO actively is evaluating the feasibility of constructing a coal gasification facility to produce the necessary hydrogen and carbon dioxide feedstocks for fertilizer production. As part of our feasibility evaluation, we have analyzed all of the provisions of the Energy Policy Act of 2005 that potentially could facilitate investment in and development of the Blue Sky coal gasification project. We have determined that two particular provisions—the Internal Revenue Code § 48B industrial gasification tax credit and the Title XVII loan guarantee authority—could be of significant value to the project, depending on how they are implemented.

AGRIUM

Agrium is a leading global producer and marketer of agricultural nutrients. Our wholesale division manufactures, markets and distributes over 8 million tons of nitrogen, potash and phosphate fertilizers each year from 12 production facilities in the United States, Canada and Argentina. Agrium is also one of the largest agricultural retailers with more than 500 retail centers in 31 States and more than 30 stores in South America. These facilities are staffed by more than 8,000 employees worldwide.

KENAI NITROGEN OPERATIONS

Agrium acquired the Kenai facility from Unocal Agricultural Division in 2000. The facility was constructed in 1968 and expanded in 1977. It is the second largest nitrogen complex in North America with the capacity to produce in excess of 2.0 million tons of fertilizer per year when operating at full capacity. KNO is one of the largest manufacturers in Alaska, employing 230 employees when operating at full capacity. It is one of Alaska's few value added industries—for every one thousand cubic feet of natural gas used, more than $9 in total economic output is generated.

COOK INLET NATURAL GAS SUPPLY & DEMAND

The Cook Inlet region of Alaska has a variety of established industries that were built around an abundance of low cost natural gas. The local natural gas supply is finite. The once large reservoirs of natural gas have been depleted, the historic pricing structure has not promoted exploration for new reserves, and demand, principally for electric power generation and commercial and residential uses, has grown significantly. Gas dependent industries have ceased operations and the cost of natural gas to electric utilities and their customers, as well as end-users of the fuel, has risen dramatically. This combination of factors has created a situation in which we are unable to contract for a long-term reliable supply of natural gas.

KNO has been confronted with ever deepening supply shortages since 2002 and acquiring and maintaining a steady supply of natural gas has been a challenge. Because of these shortages, long-term natural gas contracts are not possible and we now operate on year-to-year gas contracts. Under these short-term arrangements we have been unable to acquire sufficient natural gas to meet our needs and, as a result, reduced our operations to 50% in 2005. This resulted in a reduction of 85 of our 230 full-time employees. This January, during a cold spell that significantly increased residential and commercial demand for heating, we were forced to shut down the entire operations for almost two weeks. See Appendix A* for a depiction of the reduction in gas use at KNO over the last four years as a result of lack of available supply.

We only have an assured supply of natural gas for another six months, until October 31, 2006. If we are not successful in arranging additional supplies beyond that date we will be forced to shut down the plant on November 1, 2006. Closing the KNO facilities will have a devastating effect on the Kenai Peninsula area of Alaska—230 high paying skilled jobs will be eliminated and another 420 indirect jobs will be lost along with the more than $100 million KNO injects into the Alaska economy each year. It will also add to the long list of domestic fertilizer production facilities that permanently have shut down due to feedstock pricing and supply issues.

Mr. Chairman, I should explain here why the Alaska natural gas pipeline, which has been the subject of much discussion in this Committee over the last several years, is not a solution to KNO's dilemma. As you know, that pipeline will access the 35 trillion cubic feet of known natural gas reserves on Alaska's North Slope. To achieve the economies of scale necessary to finance the extraordinary capital costs of such a project, the pipeline needs to transport a very large volume of gas (4.5 billion cubic feet per day) to a market that can absorb such a large volume. The residential, commercial, utility and industrial consumers of the lower-48 states comprise the market for North Slope gas. As a result, none of the vast North Slope gas reserves will be available for consumption in the State of Alaska until a project to deliver that gas to lower-48 consumers is constructed. Even then, a small "spur" pipeline of approximately 340 miles would have to be constructed at an approximate cost of $750 million to deliver North Slope gas from the main trunk line to the Kenai Peninsula. Under the best-case scenario, KNO would not have access to Alaska North Slope natural gas before 2016. We can not last that long on current Cook Inlet supplies and need to find another solution if we are to keep the KNO facility operational.

* Appendixes A-C have been retained in committee files.

THE BLUE SKY PROJECT

To maintain operations at the KNO facility, Agrium must find a long-term supply of feedstock to substitute for natural gas. Fortunately, multi-year supplies of undeveloped Alaskan coal can be found some 25 miles from the KNO facility. Given the proximity of these coal reserves, coal gasification may be the answer to providing the long-term feedstock that is essential to keep KNO operational.

In 2005, KNO initiated a two-year feasibility study to examine the use of gasification technology utilizing Alaskan coal and other appropriate indigenous fuel resources to produce the hydrogen, nitrogen and $CO_2$ we need to manufacture fertilizer. We are calling the gasification project the Blue Sky Project. This project would utilize commercially offered gasification technology and capitalize on unique market conditions and strategic partnerships to provide a long-term commercial alternative to natural gas reliance in the Cook Inlet region of Alaska. Our engineering work to date has led us to the conclusion that our project will not be designed as an IGCC facility. Rather, we plan to construct a state of the art gasification facility as well as a traditional pulverized coal-fired power plant, using the latest in emissions control technology. The power plant will provide needed electricity to the Kenai fertilizer facility as well as coal-fired power to Alaska residences and other Kenai industries. If we move forward, the plan is for the facility to be commissioned in 2011. To date, Agrium has committed $3.3 million to this study.

The benefits of the Blue Sky project are substantial: we could retain the annual production of 0.8 million tons of ammonia and 1.3 million tons of urea, along with associated jobs, community support and business opportunities for Alaska companies. In addition, the project could provide low cost power for use in the population centers of Alaska, which currently rely heavily on natural gas fired generation. Blue Sky also could capture and supply excess $CO_2$ to recover up to 300 million barrels of Cook Inlet oil through enhanced oil recovery. The project also provides the anchor demand necessary to develop a world-class coal mine. This will in turn assist in the economic development of other Alaskan communities and companies by supplying an alternative for by-products and demand for services.

Given the cost and magnitude of Blue Sky, the current view is that the ultimate business structure will include several strategic partners with an interest in the overall structure or perhaps individual components with strong contractual ties. Agrium could bring nitrogen production experience and use its existing marketing capacity and network to market the product. Usibelli Coal Mine Inc. (UCM) brings to the project over 60 years of experience as the only operating Alaskan coal mining company. The proven experience of Agrium and UCM, combined with the excellent operating performance of the Kenai Nitrogen Operations, is a strong foundation on which to build Blue Sky. Ultimately this project will need additional equity participants to be successful. These participants could include power producers, gasification technology providers, and oil and gas companies interested in enhanced oil recovery.

COMPONENTS OF THE BLUE SKY PROJECT

See Appendix B.

*Gasifier Block*

The Blue Sky Project envisions constructing two Shell coal gasification trains to produce the hydrogen, nitrogen, steam and carbon dioxide required by KNO. The process dries and pulverizes delivered coal conveying it to the gasifier where the coal reacts with substoichiometric amounts of pure oxygen to form a gas stream rich in carbon monoxide and hydrogen (syngas). This gas is reacted with water in shift converters where the carbon monoxide (CO) is shifted into carbon dioxide ($CO_2$) and hydrogen ($H_2$). The $CO_2$ is then removed from the syngas along with sulfur and other impurities. Finally a pure hydrogen stream is supplied to the KNO nitrogen plant where it will be combined with pure nitrogen from the air separation unit and then converted into ammonia ($NH_3$).

*Air Separation Unit*

The air separation unit (ASU) processes air directly from the atmosphere to generate the nearly pure oxygen required by the gasification block. The air separation unit is the largest power consumer in the envisioned complex due to the large compressors required to liquefy and separate pure oxygen and nitrogen from the air. The gasifier block requires pure oxygen to process the coal, all of which is supplied by the air separation unit.

*Nitrogen Plant*

The nitrogen plant takes pure hydrogen from the gasifier and pure nitrogen from the air separation unit and combines them in a high-pressure converter to form ammonia ($NH_3$). Some of the ammonia is then refrigerated and sold into the global market. The remaining ammonia is combined with carbon dioxide ($CO_2$) in a high-pressure reactor to form urea ($NH_2CONH_2$). The urea is sold as the highest grade of solid nitrogen fertilizer produced for agricultural and industrial markets.

*Power Block*

The Blue Sky Project will require approximately 100 MW of electricity to power the gasifier block, the ASU and the nitrogen plant. Since there is not sufficient power generating capacity in the Kenai area to supply this amount of electricity, the Blue Sky Project envisions building a pulverized coal-fired facility to supply power to the Project. These units also have the potential to generate additional power for sale into the electrical grid that serves the population centers of the Kenai Peninsula, Anchorage and the Matanuska Valley. The project will use best available control technology (BACT) for emissions control. We are also considering the application of additional technology that could further reduce emissions.

*Enhanced Oil Recovery*

$CO_2$ not used in the fertilizer manufacturing process may be captured and sold to Kenai area oil producers who will inject it into the aging Cook Inlet oil fields to produce an estimated 300 million barrels of additional crude oil from these fields. The potential daily oil production increase is estimated to be as much as 25,000 barrels per day. The use of $CO_2$ to enhance the recovery of oil from existing fields has been proven in many fields across North America. The unique properties of $CO_2$ allow this gas to dissolve into the remaining heavy oil in the reservoir and change the oil's flow characteristics. The result is that more oil is able to flow from the reservoir, be recovered and $CO_2$ emissions to the environment are reduced. The Department of Energy has sponsored two studies that have identified the high potential for oil recovery in the Cook Inlet fields.

*Coal Supply*

The Blue Sky Project could utilize up to five million tons of coal per year. The long-term nature, volume and location of this demand can support the development of new coal mining opportunities in Alaska. UCM is evaluating options associated with utilization of coal from the Beluga coal fields on the west side of Cook Inlet as well as from the existing coal mine at Healy, Alaska. UCM is also evaluating the transportation of coal to the Blue Sky facility. A draft report is expected by early summer 2006. Phase 2 of the project will continue to expand on this and will narrow the scope to identify the most viable strategic option. See Appendix C.

## EVALUATING THE ECONOMICS OF THE BLUE SKY PROJECT

Our preliminary estimates are that the total cost of the Blue Sky Project will be between \$1.5 and \$2 billion. Determining whether Agrium and its partners should invest this amount of capital in the project is a challenging and expensive undertaking.

Keep in mind that KNO is in a substantially different position than most other U.S. industrial firms that are reliant on natural gas and that are evaluating a gasification project. These other firms basically have three options from which to choose—continue current operations using high priced natural gas for energy and feedstock; convert to coal or another alternative source of energy and feedstock by installing gasification technology; or cease U.S. operations and move overseas. Because KNO does not have an assured supply of natural gas at any price, we in effect have only two options—develop a coal gasification capability or permanently close the facility.

Our limited options do not mean, however, that we can construct the Blue Sky Project regardless of the economics. We still must market our ammonia and urea competitively. And, as production of fertilizer shifts from traditional industrialized nations to the areas of the world with low cost stranded natural gas, these areas are setting the world price. Thus, we are using very sharp pencils to determine if the Blue Sky Project makes sense.

KNO is evaluating the economics of the Blue Sky Project through a two-phase feasibility study. Phase 1 began in October of 2004 and consists of preliminary engineering, commercial and environmental feasibility assessments. We anticipate having the results of Phase 1 within the next four to six weeks. If the results of Phase 1 are positive, we will advance to Phase 2, in which we will develop a Front End

Engineering and Design (FEED) package. We hope to complete Phase 2 by late 2007 at which time we will be in a position to make the "go/no go" decision on the Project.

We expect the total cost of Phase 1 to approach $4.0 million and that Phase 2 will cost at least another $28 million. Mr. Chairman, for the Committee to fully understand the difficulty in advancing one of these projects to the construction stage and the role EPAct 05 plays in that regard, it is important for the Members to appreciate that these Phase 1 and Phase 2 expenditures are "at risk" dollars. In other words, if we determine at the end of Phase 2 that the Blue Sky Project is not commercially viable, Agrium and its partners will have spent nearly $32 million and all we will have to show for those dollars are a number of studies and analyses. A key component of these plans and any decisions to put more dollars at risk is the certainty of the federal government's assistance if it is offered. Suffice to say at this point, if we determine that federal assistance is crucial once the studies are completed, then it is imperative that the federal assistance be there.

ENERGY POLICY ACT OF 2005

A significant component of our Phase 1 work has been a comprehensive analysis of the EPAct 05 to determine whether any of the programs authorized by the Act could improve the commercial viability of the Blue Sky Project. We have concluded that there are two programs that could be beneficial—the industrial gasification tax credits authorized by § 48B of the Internal Revenue Code and the innovative technologies loan guarantee program authorized in Title XVII of EPAct 05. These programs have the potential to provide significant benefits to the Project. However, the potential value of these programs will be determined by the manner in that they are implemented by the Executive branch.

That only two of the multiple programs authorized by EPAct 05 are relevant to our Blue Sky Project may be surprising to some. It was somewhat of a surprise to us. One of the basic reasons for this is that a significant majority of the EPAct 05 programs are applicable only to research and development projects, and are not available for commercial scale projects. While we believe it is appropriate for the federal government to support long-term research and development, we would suggest that, if development of capital intensive commercial scale projects utilizing innovative energy technologies is a priority, the Congress may want to consider focusing additional resources on assisting such projects to get over the financial risk hurdles that confront them.

Before discussing the two specific programs, we would like to note that we have found EPAct 05 to be beneficial in an intangible way. It has been our experience that the enactment of EPAct 05 has sent a strong signal to government agencies, particularly the Department of Energy (DOE), and the commercial market place that supporting and promoting the development of these projects is a high priority of the Congress. This signal, in turn, has resulted in a more favorable environment for projects such as Blue Sky. It does not mean that we can ignore commercial realities, but it does mean that we have a greater opportunity to present the case for such projects.

Under IRC § 48B, the Blue Sky Project could be eligible for a maximum of $130 million in tax credits. Our preliminary analysis shows that these tax credits could improve the rate of return on investment in the project by up to one half of one (0.5) percent, which could be the difference between going forward and not. However, the manner in which the Internal Revenue Service (IRS) proposes to implement the tax credit authority creates some fundamental uncertainties, not only the Blue Sky Project, but also for other industrial gasification projects. The guidance issued by the IRS calls for DOE to determine which projects should receive the tax credits through a competitive process. Since the total amount of credits is currently limited to $350 million, it is highly likely that only two or three projects will be chosen to receive the credits. Applications for the credits must be submitted by June 30, 2006 with the final decisions regarding which Projects qualify for the credits to be made by November 2006. Given that our Phase 2 detailed study will be just underway on June 30, we will, by necessity, have to submit an application for the tax credits that is somewhat contingent on the outcome of that analysis. We already have amassed a great deal of reliable information but the timing for tax credit applications may be a factor that works against the Blue Sky Project. While we understand the IRS's desire to expeditiously implement the § 48B program, the proposed schedule does not match well with the timing of the Blue Sky Project and other projects being evaluated in the United States.

Mr. Chairman, I understand that you played a significant role in the development of the Title XVII loan guarantee program. Thank you for your foresight. The policy behind Title XVII—that the federal government should share some of the risk of commercializing capital intensive projects such as Blue Sky—has the potential to be the most beneficial and far-reaching contribution of EPAct 05 to the development of innovative energy technologies. However, this potential may not be realized if the Administration takes an overly restrictive approach to implementation of the program.

First, there does not seem to be a uniform commitment within the Executive branch agencies to this program. While DOE appears to be anxious to move forward and lay the groundwork for implementation, it is our understanding that the Office of Management and Budget (OMB) has not yet approved the funding necessary to staff and operate the program. Second, once the program is up and running, every project that hopes to take advantage of a loan guarantee must address the issue of the "risk premium" for the guarantee. Unlike other federal loan guarantee programs, Title XVII permits the DOE to collect funds for the project seeking a loan guarantee to "cover" the probability that the project will default on the guaranteed loan (so-called "risk premium"). Other guarantee programs require that federal appropriations be provided to cover the risk premium in order to support the issuance of a guarantee. While the self funding device is a creative means to initiate the Title XVII program without impacting the federal budget, everything depends upon how the premium amount is determined.

DOE, in consultation with OMB, will determine the amount of the required risk premium by estimating the probability of default on the guaranteed loan. This default probability determination will be the most important factor in whether the Blue Sky Project (or any other gasification project) will benefit from a Title XVII loan guarantee. If DOE and 0MB employ a very conservative approach designed to protect the federal government from virtually all risk, then the premiums for the loan guarantees are likely to be so large that either a federal appropriation will be infeasible or payment of the premium by the applicant will more than offset whatever financing cost benefits are gained by the loan guarantee. As an example, if the total cost of the Blue Sky project were $1.5 billion and we sought a loan guarantee for the maximum 80% of the cost allowed by Title XVII, the guaranteed amount of debt would be $1.2 billion. If the default probability were determined to be 10%, the risk premium would be $120 million. In light of the current federal budget situation, it is doubtful that Congress would appropriate this amount for one project. In the alternative, KNO and it partners would have to provide the $120 million thus increasing the overall cost of the project by 8 percent. This added cost is likely to make the project uneconomic.

In addition to the risk premium issue, we understand that DOE is considering requiring "risk sharing" from lenders. It also appears that DOE has an expectation that the federal loan guarantee will only cover certain negotiated risks during project execution as opposed to providing 100% guarantee coverage on 80% of total project cost as authorized by Title XVII. Likewise, it appears that DOE may limit the applicability of the guarantee to certain identified periods of time rather than the life of the construction loan and/or the term of the permanent financing for a project.

As noted earlier, the policy behind Title XVII is that the federal government will share some of the risk in order to move these new technologies into the marketplace. If DOE and OMB administer the program to eliminate virtually all of the government's risk exposure then the objective of the Title XVII program will be lost. We would encourage the Congress to provide special oversight to this portion of Title XVII implementation.

Finally, I would note that we have not yet determined whether using the Title XVII loan guarantee program would force Agrium to comply with other federal requirements, specifically the Davis Bacon prevailing wage provisions or some type of domestic content requirements. Having to comply with one or more of these types of requirements will simply add to the overall cost of the project and diminish whatever benefit is gained from the loan guarantee.

## CONCLUSION

Thank you again, Mr. Chairman and Members of the Committee for this opportunity to present our Blue Sky Project. As you see, these projects are massive undertakings that involve a great deal of risk. Enactment of EPAct 05 has created an environment that is more favorable toward industrial gasification projects than in the past and certain programs authorized by the Act have the potential to improve the commercial viability of some projects. However, unless these programs are implemented in the manner that you intended they will not provide sufficient support to stimulate or sustain value added industrial manufacturing in the United States.

Senator ALEXANDER. Thank you, Mr. Boycott.

Dr. Herzog, thank you for coming.

**STATEMENT OF ANTONIA HERZOG, STAFF SCIENTIST AND CLIMATE ADVOCATE, CLIMATE CENTER, NATURAL RESOURCES DEFENSE COUNCIL**

Dr. HERZOG. Thank you very much. Thank you for the opportunity to testify here today and discuss coal gasification and environmental impacts of this technology.

My name is Antonia Herzog, and I work at NRDC in the Climate Center. NRDC is a nonprofit organization of scientists, lawyers, and environmental experts dedicated to protecting public health and the environment. We were founded in 1970, and have more than 1.2 million members and activists online.

One of the primary reasons that people are interested in coal gasification that has been clear in the discussions here today is that it can be used as a substitute for natural gas. Coal certainly has advantages. It's affordable, and it's a domestic resource. However, we believe that affordable energy is certainly very important for the quality of life of all Americans, but I'm sure Senators on this committee equally well believe that clean air, clean water, clean lands, and a stable climate are also extremely important for our quality of life.

Thus, unfortunately, the disadvantages of coal also need to be taken into account. It has underground accidents and mountaintop removal mining issues, air emissions of acidic, toxic, and heat-trapping pollution from coal combustion, water pollution from coal mining and combustion wastes, and the conventional coal fuel cycle is probably among the most environmentally destructive activities on our Earth today. But we can do better with both production and use of coal. And that's what I'd like to talk to you about today, especially because it seems unlikely that the world will continue to be using large quantities of coal in the near and longer terms.

In particular, coal use and climate protection do not need to be at odds with each other. Our interest in coal gasification, in particular, is the fact that you can capture the carbon cost effectively and sequester it underground in geologic formations, thus reducing the global warming emissions from coal substantially.

However, because of the long lifetime of carbon in our atmosphere, we need to get this technology, this carbon capture and disposal technology, out there as soon as possible, and we need incentives to do so. In addition, we strongly advocate for binding measures on global warming pollution.

Reducing natural gas demand. As I said, this is an important issue to consider. However, we feel that, first and foremost, we need to consider energy efficiency. That's the cheapest, cleanest, most effective way to reduce our natural gas demand. Second, renewable energy is the best way to help supplement. Then we should turn to the issue of coal gasification, after we have addressed energy efficiency and renewable energy.

Some can call coal "clean." However, it is not likely ever to be a—the most clean option for energy production that we have. However, as I said, it appears inevitable that we will be using coal for some time to come. The good news is that with the right standards and incentives, it is possible to chart a future for coal that is compatible with protecting public health, preserving special places, and avoiding dangerous global warming.

To address global warming, we have to get on a path quickly to start reducing our emissions for the long term. Any technologies that we start deploying today has to take this into account.

Let's look specifically at coal gasification in the electricity sector. In this case, you can capture the carbon, and you can dispose of it in geological formations, and significantly reduce the global warming emissions, such that we could stay on a path to prevent dangerous impacts in the future. The other issue that has been brought up is using coal gasification to produce synthetic gas. We did a calculation. Remember, coal has about twice the amount of carbon content as natural gas. If you produce synthetic gas using coal, you are going to produce 2½ times the amount of carbon than you would if you just used synthetic gas. Now, if you capture the coal at the plant, you could reduce that substantially, yet you'd still be producing about 12 percent more carbon than just using natural gas. So, the issue here is: what is that natural gas going to be used for? And a second is: what are its lifecycle emissions, and is that compatible with stabilizing our climate and our atmospheric concentrations? That must be taken into account. We can't invest money in technologies that have lifetimes of 50-plus years and then say, 20 years down the line, "We have to deal with our carbon emissions," and then have these sunk costs in these extremely expensive capital investments.

Chemical products, for the most part, is the same issue. I believe that using coal gasification at a chemical plant, it would probably be mostly a wash, as far as the carbon emissions go, as long as you capture those carbon emissions. That is the critical point here. And, unfortunately, though, some mention of the fellow—my fellow witnesses made mention of the carbon capture. I would say perhaps not enough attention was put to that issue.

Liquid fuels were discussed at last Monday's hearing, so I won't go into that. I will just say that creating a liquid fuel from coal, you produce twice as much carbon emissions as using gasoline. The transportation sector—we have to start reducing our emissions from the transportation sector significantly. Even capturing the carbon when you produce liquid fuel from coal, you'd still be—just about break even. And that's not a long-term solution.

Finally, let me just turn quickly to the Energy Policy Act. There is the issue—and I'm glad to say, in it, they dealt with the issue of carbon-capture ready. Our concern, though, with the carbon-capture ready is, this is an extremely ill-defined term. What does it mean to have a plant that is carbon-capture ready? It means you have to put in equipment that separates the carbon out, that captures the carbon, and disposes of it. Does that mean you simply build an IGCC plant? Does that mean you build an IGCC plant with space for the capture equipment, or do you build it near a place to dispose the carbon? These are all questions that are not addressed by this term, and need to be addressed.

I see my time is up, so I will stop here, and would be happy to answer any questions.

Thank you.

[The prepared statement of Dr. Herzog follows:]

PREPARED STATEMENT OF ANTONIA HERZOG, STAFF SCIENTIST AND CLIMATE ADVOCATE, CLIMATE CENTER, NATURAL RESOURCES DEFENSE COUNCIL

Thank you for the opportunity to testify today on the subject of coal gasification technology. My name is Antonia Herzog. I am a staff scientist and climate advocate of the Climate Center at the Natural Resources Defense Council (NRDC). NRDC is a national, nonprofit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 1.2 million members and online activists nationwide, served from offices in New York, Washington, Los Angeles and San Francisco.

One of the primary reasons that the electric power, chemical, and liquid fuels industries have become increasingly interested in coal gasification technology in the last several years is the volatility and high cost of both natural gas and oil. Coal has the advantages of being a cheap, abundant, and a domestic resource compared with oil and natural gas. However, the disadvantages of conventional coal use cannot be ignored. From underground accidents and mountain top removal mining, to collisions at coal train crossings, to air emissions of acidic, toxic, and heat-trapping pollution from coal combustion, to water pollution from coal mining and combustion wastes, the conventional coal fuel cycle is among the most environmentally destructive activities on earth.

But we can do better with both production and use of coal. And because the world is likely to.continue to use significant amounts of coal for some time to come, we must do better. Energy efficiency remains the cheapest, cleanest, and fastest way to meet our energy and environmental challenges, while renewable energy is the fastest growing supply option. Increasing energy efficiency and expanding renewable energy supplies must continue to be the top priority, but we have the tools to make coal more compatible with protecting public health and the environment. With the right standards and incentives we can fundamentally transform the way coal is produced and used in the United States and around the world.

In particular, coal use and climate protection do not need to be irreconcilable activities. While energy efficiency and greater use of renewable resources must remain core components of a comprehensive strategy to address global warming, development and use of technologies such as coal gasification in combination with carbon dioxide ($CO_2$) capture and permanent disposal in geologic repositories could enhance our ability to avoid a dangerous build-up of this heat-trapping gas in the atmosphere while creating a future for continued coal use.

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 to start deploying these technologies. Current government policies are inadequate to drive the private sector to invest in 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.

Congress is now considering proposals to gasify coal as a replacement for natural gas and oil (as discussed in testimony NRDC provided before this committee in the April 24th, 2006 hearing on "Coal Liquefaction and Gasification").[1] These proposals need to be evaluated in the context of the compelling need to reduce global warming emissions steadily and significantly, starting now and proceeding constantly throughout this century. Because today's coal mining and use also continues to impose a heavy toll on America's land, water, and air, damaging human health and the environment, it is also critical to examine the implications of a substantial coal gasification program on these values as well.

REDUCING NATURAL GAS DEMAND

The nation's economy, our health and our quality of life depend on a reliable supply of affordable energy services. The most significant way in which we can achieve these national goals is to exploit the enormous scope to wring more services out of each unit of energy used and by aggressively promoting renewable resources. While coal gasification technology has been touted as the technology solution to supplement our natural gas supply and reduce our dependence on natural gas imports, the most effective way to lower natural gas demand, and prices, is to waste less. America needs to first invest in energy efficiency and conservation to reduce demand, and

[1] David Hawkins, Testimony before the Senate Energy and Natural Resources Committee, "Coal Liquefaction and Gasification", April 24th, 2006. http://docs.nrdc.org/globalwarming/glo—06042401a.pdf

to second promote renewable energy alternatives to supplement supply. Gasified coal may have a role to play but in both the short-term and over the next two decades, efficiency and renewables are the lead actors in an effective strategy to moderate natural gas prices and balance our demand for natural gas with reasonable expectations of supply.

We know that today's natural gas prices have had a particularly significant impact on the agricultural sector by raising the cost of making fertilizer among other products. We agree that effective steps should be taken to fix this problem. In our view a package of measures to increase the efficiency of current gas uses, substitution of renewable energy for other gas uses, and judicious use of coal gasification with $CO_2$ capture and disposal would be the most effective program. With respect to the coal gasification component of this policy package, it is important to address and prevent the additional harmful impacts to land and water that would result if incremental coal production were carried out with current mining and production practices. As pointed out later in Appendix A, current practices are causing unacceptable and avoidable levels of damage to land, water and mining communities.

Increasing energy efficiency is far-and-away the most cost-effective way to reduce natural gas consumption, avoid emitting carbon dioxide and other damaging environmental impacts. Technologies range from efficient lighting, including emerging L.E.D. lamps, to advanced selective membranes which reduce industrial process energy needs. Critical national and state policies include appliance efficiency standards, performance-based tax incentives, utility-administered deployment programs, and innovative market transformation strategies that make more efficient designs standard industry practice.

Conservation and efficiency measures such as these can have dramatic impacts in terms of price and savings.[2] Moreover, all of these untapped gas efficiency "resources" will expand steadily, as a growing economy adds more opportunities to secure long-lived savings. California has a quarter century record of using comparable strategies to reduce both natural gas consumption and the accompanying utility bills. Recent studies commissioned by the Pacific Gas & Electric Company indicate that, by 2001, longstanding incentives and standards targeting natural gas equipment and use had cut statewide consumption for residential, commercial, and industrial purposes (excluding electric generation) by more than 20 percent.

Renewables can also play a key role in reducing natural gas prices. Adoption of a national renewable energy standard (RES) can significantly reduce the demand for natural gas, alleviating potential shortages. The Energy Information Administration (EIA) has found that a national 10 percent renewable energy standard could reduce gas consumption by 1.4 trillion cubic feet per year in 2020 compared to business as usual, or roughly 5 percent of annual demand.[3]

Studies have consistently shown that reducing demand for natural gas by increasing renewable energy use will reduce natural gas prices. According to a report released by the U.S. Department of Energy's Lawrence Berkeley National Laboratory, "studies generally show that each 1% reduction in national gas demand is likely to lead to a long-term (effectively permanent) average reduction in wellhead gas prices of 0.8% to 2%. Reductions in wellhead prices will reduce wholesale and retail electricity rates and will also reduce residential, commercial, and industrial gas bills."[4] EIA found that increasing renewable energy to 10 percent by 2020 would result in $4.9 billion cumulative present value savings for industrial gas consumers, $1.8 billion to commercial customers, and $2.4 billion to residential customers.[5] EIA also found that renewable energy can also reduce electricity bills.[6] Lower natural gas

[2] American Council for an Energy-Efficient Economy (ACEEE), Fall 2004 Update on Natural Gas Markets, November 3, 2004. *See also* Consumer Federation of America, "Responding to Turmoil in Natural Gas Markets: The Consumer Case for Aggressive Policies to Balance Supply and Demand," December 2004, pp. 28, 11 ("[V]igorous efforts to improve efficiency" should be the first policy option pursued, because even small reductions in natural gas consumption can have a significant downward impact on prices.)

[3] EIA, Impacts of a 10-Percent Renewable Portfolio Standard, SR/OIAF/2002-03, February 2002. EIA, Analysis of a 10-Percent Renewable Portfolio Standard, SR/OIAF/2003-01, May 2003. *Union of Concerned Scientists, Clean Energy Blueprint: A Smarter National Energy Policy for Today and the Future,* October 2001.

[4] U.S. Department of Energy, Lawrence Berkeley National Laboratory, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices Through Increased Deployment of Renewable Energy and Energy Efficiency,* January, 2005, p. 13.

[5] EIA, Impacts of a 10-Percent Renewable Portfolio Standard, SR/OIAF/2002-03, February 2002.

[6] *Id.* at Figure 3.

prices for electricity generators and other consumers offset the slightly higher cost of renewable electricity technology.[7]

Implementing effective energy efficiency measures is the fastest and most cost effective approach to balancing natural gas demand and supply. Renewable energy provides a critical mid-term to long-term supplement. Analysis by the Union of Concerned Scientists found that a combined efficiency and renewable energy scenario could reduce gas use by 31 percent and natural gas prices by 27 percent compared to I business as usual in 2020.[8]

In contrast to these strategies, pursuing coal gasification implementation strategies that address only natural gas supply concerns, while ignoring impacts of coal, is a recipe for huge and costly mistakes. Fortunately, we have in our tool box energy resource options that can reduce natural gas demand and global warming emissions as well as protecting America's land, water, and air.

ENVIRONMENTAL IMPACTS OF COAL

Some call coal "clean." It is not and likely never will be compared to other energy options. Nonetheless, it appears inevitable that the U.S. and other countries will continue to rely heavily on coal for many years. The good news is that with the right standards and incentives it is possible to chart a future for coal that is compatible with protecting public health, preserving special places, and avoiding dangerous global warming. It may not be possible to make coal clean, but by transforming the way coal is produced and used, it is possible to make coal dramatically cleaner—and safer—than it is today.

*Global Warming Pollution*

To avoid catastrophic global warming the U.S. and other nations will need to deploy energy resources that result in much lower releases of $CO_2$ than today's use of oil, gas and coal. To keep global temperatures from rising to levels not seen since before the dawn of human civilization, the best expert opinion is that we need to get on a pathway now to allow us to cut global warming emissions by 60-80% from today's levels over the decades ahead. The technologies we choose to meet our future energy needs must have the potential to perform at these improved emission levels.

Most serious climate scientists now warn that there is a very short window of time for beginning serious emission reductions if we are to avoid truly dangerous greenhouse gas reductions without severe economic impact. Delay makes the job harder. The National Academy of Sciences recently stated: "Failure to implement significant reductions in net greenhouse gases will make the job much harder in the future—both in terms of stabilizing their atmospheric abundances and in terms of experiencing more significant impacts."[9]

In short, a slow start means a crash finish—the longer emissions growth continues, the steeper and more disruptive the cuts required later. To prevent dangerous global warming we need to stabilize atmospheric concentration at or below 450 ppm, which would keep total warming below 2 degrees Celsius (3.6 degrees Fahrenheit). If we start soon, we can stay on the 450 ppm path with an annual emission reduction rate that gradually ramps up to about 2.4% per year. But if we delay a serious start by 10 years and continue emission growth at the business-as-usual trajectory, the annual emission reduction rate required to stay on the 450 ppm pathway jumps almost 3-fold, to 6.9% per year. (See Figure 1.)[9a] Even if you do not accept today that the 450 ppm path will be needed please consider this point. If we do not act to preserve our ability to get on this path we will foreclose the path not just for ourselves but for our children and their children. We are now going down a much riskier path and if we do not start reducing emissions soon neither we nor our children can turn back no matter how dangerous the path becomes.

In the past, some analysts have argued that the delay/crash action scenario is actually the cheaper course, because in the future (somehow) we will have developed breakthrough technologies. But it should be apparent that the crash reductions scenario is implausible for two reasons. First, reducing emissions by 6.9 percent per year would require deploying advanced low-emission technologies at least several times faster than *conventional* technologies have been deployed over recent decades. Second, the effort would require prematurely retiring billions of dollars in capital

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[7] UCS, *Renewable Energy Can Help Alleviate Natural Gas Crisis,* June 2003, at 2.

[8] UCS, *Clean Energy Blueprint: A Smarter National Energy Policy for Today and the Future,* October 2001.

[9] National Academy of Sciences, *Understanding and Responding to Climate Change: Highlights of National Academies Reports,* p.16 (October 2005), http://dels.nas.edu/dels/rpt__briefs/climate-changefinal.pdf.

[9a] Retained in committee files.

stock—high-emitting power plants, vehicles, etc.—that will be built or bought during the next 10-20 years under in the absence of appropriate $CO_2$ emission limits.

It also goes without saying that U.S. leadership is critical. Preserving the 450 ppm pathway requires other developed countries to reduce emissions at similar rates, and requires the key developing countries to dramatically reduce and ultimately reverse their emissions growth. U.S. leadership can make that happen faster.

To assess the global warming implications of a large coal gasification program we need to carefully examine the total life-cycle emissions associated with the end product, whether electricity, synthetic gas, liquid fuels or chemicals, and to assess if the relevant industry sector will meet the emission reductions required to be consistent with the "green" pathway presented in Figure 1.

*Electricity Sector*

More than 90 percent of the U.S. coal supply is used to generate electricity in some 600 coal-fired power plants scattered around the country, with most of the remainder used for process heat in heavy industrial and in steel production. Coal is used for power production in all regions of the country, with the Southeast, Midwest, and Mountain states most reliant on coal-fired power. Texas uses more coal than any other state, followed by Indiana, Illinois, Ohio, and Pennsylvania.[10]

About half of the U.S. electricity supply is generated using coal-fired power plants. This share varies considerably from state to state, but even California, which uses very little coal to generate electricity within its borders, consumes a significant amount of electricity generated by coal in neighboring Arizona and Nevada, bringing coal's share of total electricity consumed in California to 20 percent.[11] National coal-fired capacity totals 330 billion watts (GW), with individual plants ranging in size from a few million watts (MW) to over 3000 MW. More than one-third of this capacity was built before 1970, and over 400 units built in the 1950s—with capacity equivalent to roughly 100 large modern plants (48 GW)—are still operating today.

The future of coal in the U.S. electric power sector is an uncertain one. The major cause of this uncertainty is the government's failure to define future requirements for limiting greenhouse gas emissions, especially carbon dioxide ($CO_2$). Coal is the fossil fuel with the highest uncontrolled $CO_2$ emission rate of any fuel and is responsible for 36. percent U.S. carbon dioxide emissions. Furthermore, coal power plants are expensive, long-lived investments. Key decision makers understand that the problem of global warming will need to be addressed within the time needed to recoup investments in power projects now in the planning stage. Since the status quo is unstable and future requirements for coal plants and other emission sources are inevitable but unclear, there will be increasing hesitation to commit the large amounts of capital required for new coal projects.

Electricity production is the largest source of global warming pollution in the U.S. today. In contrast to nitrogen and sulfur oxide emissions, which have declined significantly in recent years as a result of Clean Air Act standards, $CO_2$ emissions from power plants have increased by 27 percent since 1990. Any solution to global warming must include large reductions from the electric sector. Energy efficiency and renewable energy are well-known low-carbon methods that are essential to any climate protection strategy. But technology exists to create a more sustainable path for continued coal use in the electricity sector as well. Coal gasification can be compatible with significantly reducing global warming emissions in the electric sector if it replaces conventional coal combustion technologies, directly produces electricity in an integrated manner, and most importantly captures and disposes of the carbon in geologic formations. IGCC technology without $CO_2$ capture and disposal achieves only modest reductions in $CO_2$ emissions compared to conventional coal plants.

A coal integrated gasification combined cycle (IGCC) power plant with carbon capture and disposal can capture up to 90 percent of its emissions, thereby being part of the global warming solution. In addition to enabling lower-cost $CO_2$ capture, gasification technology has very low emissions of most conventional pollutants and can achieve high levels of mercury control with low-cost carbon-bed systems. However, it still does not address the other environmental impacts from coal production and transportation discussed in more detail in Appendix A.[11a]

The electric power industry has been slow to take up gasification technology but two commercial-scale units are operating in the U.S.—in Indiana and Florida. The

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[10] http://www.eia.doe.gov/cneaf/coal/page/acr/table26.html

[11] California Energy Commission, 2005. 2004 Net System Power Calculation (April.) Table 3: Gross System Power. http://www.energy.ca.gov/2005publications/CEC-300-2005-004/CEC-300-2005-004.PDF

[11a] Appendix A has been retained in committee files.

Florida unit, owned by TECO, is reported by the company to be the most reliable and economic unit on its system. Two coal-based power companies, AEP and Cinergy, have announced their intention to build coal gasification units. BP also has announced plans to build a petroleum coke gasification plant that will capture and sequester $CO_2$.

*Synthetic Gas*

Another area that has received interest is coal gasification to produce synthetic natural gas as a direct method of supplementing our natural gas supply from domestic resources. However, without $CO_2$ capture and disposal this process results in more than twice as much $CO_2$ per 1000 cubic feet of natural gas consumed compared to conventional resources.[12] From a global warming perspective this is unacceptable. With capture and disposal the $CO_2$ emissions can be substantially reduced, but still remain 12 percent higher than natural gas.

In Beulah, North Dakota the Basin Electric owned Dakota Gasification Company's Great Plains Synfuels Plant is a 900MW facility which gasifies coal to produce synthetic "natural" gas. It can produce a 150 million cubic feet of synthetic gas per day and 11,000 tons of $CO_2$ per day. However, it no longer releases all of its $CO_2$ to the atmosphere, but captures most of it and pipes it 200 miles to an oil field near Weyburn, Saskatchewan. There the $CO_2$ is pumped underground into an aging oil field to recover more oil. EnCana, operator of this oil field, pays $2.5 million per month for the $CO_2$. They expect to sequester 20 million tons of $CO_2$ over the lifetime of this injection project.

A potential use for coal-produced synthetic gas would be to burn it in a gas turbine at another site for electricity generation. This approach would result in substantially higher $CO_2$ emissions than producing electricity in an integrated system at the coal gasification plant with $CO_2$ capture at the site (i.e., in an IGCC plant with carbon capture and disposal). Coal produced synthetic natural gas could also be used directly for home heating. As a distributed source of emissions the $CO_2$ would be prohibitive to capture with known technology.

Before producing synthetic pipeline gas from coal a careful assessment of the full fuel cycle emission implications and the emission reductions that are required from that sector must be carried out before decisions are made to invest in these systems.

*Chemical Products*

The chemical industry has also been looking carefully at coal gasification technology as a way to replace the natural gas feedstock used in chemical production. The motivator has been the escalating and volatile costs of natural gas in the last few years. A notable example in the U.S. of such a use is the Tennessee Eastman plant, which has been operating for more than 20 years using coal instead of natural gas to make chemicals and industrial feedstocks. If natural gas is replaced by coal gasification as a feedstock for the chemical industry, first and foremost $CO_2$ capture and disposal must be an integral part of such plants. In this case, the net global warming emissions will change relatively little from this sector. However, before such a transformation occurs a careful analysis of the life cycle emissions needs to be carried out along with an assessment of how future emissions reductions from this sector can be most effectively accomplished.

*Liquid Fuels*

The issue of converting coal into a liquid fuel was explored in detail in testimony NRDC provided before this committee in the April 24th, 2006 hearing on "Coal Liquefaction and Gasification".[13] To briefly reiterate, to assess the global warming implications of a large coal-to-liquids program we need to examine the total life-cycle or "well-to-wheel" emissions of these new fuels. Coal contains about 20 percent more carbon per unit of energy compared to petroleum. When coal is converted to liquid fuels, two streams of $CO_2$ are produced: one at the coal-to-liquids production plant and the second from the exhausts of the vehicles that burn the fuel. With the technology in hand today and on the horizon it is difficult to see how a large coal-to-liquids program can be compatible with the low-002-emitting transportation system we need to design to prevent global warming.

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[12] The National Coal Council, "Coal: America's Energy Future," March 22, 2006. This report actually assumes a less efficient coal to synthetic gas conversion process of 50% leading to three times as much $CO_2$ per 1000 cubic feet of natural gas consumed compared to conventional resources.

[13] David Hawkins, Testimony before the Senate Energy and Natural Resources Committee, "Coal Liquefaction and Gasification", April 24th, 2006. http://docs.nrdc.org/globalwarming/glo__06042401a.pdf

Based on available information about coal-to-liquids plants being proposed, the total well to wheels $CO_2$ emissions from such plants would be nearly twice as high as using crude oil, if the $CO_2$ from the coal-to-liquids plant is released to the atmosphere.[14] Obviously, introducing a new fuel system with double the $CO_2$ emissions of today's crude oil system would conflict with the need to reduce global warming emissions. If the $CO_2$ from coal-to-liquids plants is captured, then well-to-wheels $CO_2$ emissions would be reduced but would still be higher than emissions from today's crude oil system.

This comparison indicates that using coal to produce a significant amount of liquids for transportation fuel would not be compatible with the need to develop a low-$CO_2$ emitting transportation sector unless technologies are developed to significantly reduce emissions from the overall process. But here one confronts the unavoidable fact that the liquid fuel from coal contains the same amount of carbon as is in gasoline or diesel made from crude. Thus, the potential for achieving significant $CO_2$ emission reductions compared to crude is inherently limited. This means that using a significant amount of coal to make liquid fuel for transportation needs would make the task of achieving any given level of global warming emission reduction much more difficult. Proceeding with coal-to-liquids plants now could leave those investments stranded or impose unnecessarily high abatement costs on the economy if the plants continue to operate.

*$CO_2$ Capture and Disposal*

Methods to capture $CO_2$ from industrial gas streams have been in use for decades. In the U.S., for example, they are used to separate $CO_2$ from "sour gas" at natural gas processing plants and are even in use at a few coal-fired power plants to produce $CO_2$ for sale to the food and beverage industries. As previously mentioned, in North Dakota a large coal gasification plant captures $CO_2$ and ships it by pipeline to an oil field in Saskatchewan, where it is injected to produce additional oil. In Wyoming, a large gas processing plant captures $CO_2$ for sale to oil field operators in that state and in Colorado. Smaller plants in Texas do the same thing to serve oil fields in the Permian Basin.

Once captured, the $CO_2$ must be disposed of and the currently viable approach is to inject the $CO_2$ into deep geologic formations that are capable of permanently retaining it. Geologic injection of $CO_2$ has been underway in the U.S. for a couple of decades as a method for producing additional oil from declining fields. Today, oil companies inject about 30 million tons annually into fields in the Permian Basin, Wyoming, Colorado and other states.

Because industrial sources can emit $CO_2$ for free under current U.S. policy, most of the injected $CO_2$ is supplied from natural $CO_2$ reservoirs, rather than being captured from emission sources. Ironically, due to the lack of emission limits and the limited number of natural $CO_2$ fields, a $CO_2$ supply shortage is currently constraining enhanced oil recovery from existing fields. There is, of course, a huge supply of $CO_2$ from power plants and other sources that would become available to supply this market, but that will not happen as long as $CO_2$ can be emitted at no cost.

Such enhanced oil recovery (EOR) operations are regulated to prevent releases that might endanger public health or safety but they are not monitored with any techniques that would be capable of detecting smaller leak rates. Small leak rates might pose no risk to the local surroundings but over time could undercut the effectiveness of geologic storage as a $CO_2$ control technique. Especially in EOR operations, the most likely pathways for leakage would be through existing wells penetrating the injection zone.

Much of the injected $CO_2$ is also brought back to the surface with the oil produced by this technique. That $CO_2$ is typically reinjected to recover additional oil, but when oil operations are completed it may be necessary to inject the $CO_2$ into a deeper geologic formation to ensure permanent storage.

In addition to these EOR operations, $CO_2$ is being injected in large amounts in several other projects around the world. The oldest of these involves injection of about 1 million tons per year of $CO_2$ from a natural gas platform into a geologic formation beneath the sea bed off the coast of Norway. The company decided to inject the $CO_2$ rather than vent it to avoid paying an emission charge adopted by the Norwegian government—a clear example of the ability of emission policies to produce the deployment of this technology. The Norwegian operation is intensively

[14] Calculated well to wheel CO, emissions for coal-based "Fischer-Tropsch" are about 1.8 greater than producing and consuming gasoline or diesel fuel from crude oil. If the coal-to-liquids plant makes electricity as well, the relative emissions from the liquid fuels depends on the amount of electricity produced and what is assumed about the emissions of from an alternative source of electricity.

monitored and the results from over seven years of operation indicate the $CO_2$ is not migrating in a manner that would create a risk of leakage. Other large-scale carefully monitored operations are underway at the Weyburn oil field in Saskatchewan and the In Salah natural gas field in Algeria.

While additional experience with large-scale injection in various geologic formations is needed, we believe enough is known to expand these activities substantially under careful procedures for site selection, operating requirements and monitoring programs. The imperative of avoiding further carbon lock-in due to construction of conventional coal-fired power plants and the capabilities of $CO_2$ capture and storage technologies today warrant policies to deploy these methods at coal gasification plants without further delay.

*Conventional Air Pollution*

Dramatic reductions in power plant emissions of criteria pollutants, toxic compounds, and global warming emissions are essential if coal is to remain a viable energy resource for the 21st Century. Such reductions are achievable in coal gasification plants. In particular, integrated gasification combined cycle (IGCC) systems enable cost-effective advanced pollution controls that can yield extremely low criteria pollutant and mercury emission rates and facilitates carbon dioxide capture and geologic disposal. Gasifying coal at high pressure facilitates removal of pollutants that would otherwise be released into the air such that these pollutant emissions are well below those from conventional pulverized coal power plants with post combustion cleanup. These technologies will not be widely employed, however, without a sustained market driver, which requires vigorous enforcement of clean air standards, new limits on global warming emissions, and market oriented incentives to deploy carbon capture and disposal.

*Mining, Processing and Transporting Coal*

The impacts of mining, processing, and transporting 1.1 billion tons of coal today on health, landscapes, and water are large. To understand the implications of continuing our current level of as well as expanding coal production, it is important to have a detailed understanding of the impacts from today's level of coal production. A summary is included in Appendix A and was also given in testimony NRDC submitted on April 24th, 2006 to the Senate Energy and Natural Resources full committee hearing on "Coal Liquefaction and Gasification." [15] It is clear that we must find more effective ways to reduce the impacts of mining, processing and transporting coal before we follow a path that would result in even larger amounts of coal production and transportation.

## "CARBON CAPTURE READY" AND THE "ENERGY POLICY ACT OF 2005"

Among the various environmental concerns associated with coal use, the global warming emissions are particularly critical as coal fired power generation emits more carbon dioxide per unit of energy than any other power generating process. It is clear that for coal to remain a major source of electricity generation within a carbon constrained world, carbon capture and disposal technologies will have to be deployed in conjunction coal fired power plants.

The three required elements of a coal-based $CO_2$ capture and disposal (CCD) system have all been demonstrated at commercial scale in numerous projects around the world. But there is large potential for optimization of each element to bring down costs and improve efficiency. In addition, the experience with large scale injection of $CO_2$ into geologic formations is still limited.

For coal, the first element of a CCD system is a method to convert coal into useful energy that produces a waste stream that makes $CO_2$ capture relatively inexpensive. The method for doing this that is commercially demonstrated is through gasification of coal. In contrast to the conventional coal combustion methods used in electric power generation, gasification converts the coal under pressure and temperature to produce a smaller gas stream with higher $CO_2$ concentrations. This approach significantly reduces the cost and energy required to capture $CO_2$.

In the "Energy Policy Act of 2005" (EPACT05), while there are myriad incentives for deploying coal gasification technology, there are no requirements to include $CO_2$ capture and disposal. Scattered throughout the Act is language referring to the capability of coal gasification technology to capture its carbon emissions or to be "carbon capture ready". However, nothing requires the facilities to actually capture and dispose of their $CO_2$ emissions. Several examples are the following:

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[15] David Hawkins, Testimony before the Senate Energy and Natural Resources Committee, "Coal Liquefaction and Gasification", April 24th, 2006. http://docs.nrdc.org/globalwarming/glo__06042401a.pdf

- Title IV—Coal—section 413(b)(3) Western Integrated Coal Gasification Demonstration Project: "Shall be capable of removing and sequestering carbon dioxide emissions."
- Title VIII—Hydrogen—section 805(e)(1)(A) "Fossil fuel, which may include carbon capture and sequestration;"
- Title XIII—Energy Policy Tax Incentives—section 1307(b) "Sec. 48A. (c) Definitions (5) GREENHOUSE GAS CAPTURE CAPABILITY—The term 'greenhouse gas capture capability' means an integrated gasification combined cycle technology facility capable of adding components which can capture, separate on a long-term basis, isolate, remove, and sequester greenhouse gases which result from the generation of electricity."

  "Sec. 48B. (c) Definitions (5) CARBON CAPTURE CAPABILITY—The term 'carbon capture capability' means a gasification plant design which is determined by the Secretary to reflect reasonable consideration for, and be capable of, accommodating the equipment likely to be necessary to capture carbon dioxide from the gaseous stream, for later use or sequestration, which would otherwise be emitted in the flue gas from a project which uses a nonrenewable fuel."
- Title XVII—Incentives for Innovative.Technologies—Section 1703(c)(1)(A)(ii) "that have a design that is determined by the Secretary to be capable of accommodating the equipment likely to be necessary to capture the carbon dioxide that would otherwise be emitted in flue gas from the plant;"

The issue I would like to address here is the definition of "carbon capture ready." Adding carbon capture capabilities to a coal gasification power plant is not a simple modification.[16] Without any current regulatory or economic incentives for these facilities to capture and dispose of their carbon emissions the extent of the capture modifications that will be incorporated into the gasification facilities remains extremely unclear. I would, in fact, argue that due to the vagueness of this term the result will be a "race to the bottom", a minimal effort to incorporate the necessary design elements and equipment that would allow coal gasification plants to qualify for EPACT05 incentives.

What are the required technical details associated with coupling coal gasification plants with carbon capture and disposal? Carbon capture in a coal gasification plant occurs after the coal gasification process. I will focus on the case for electricity generation (an IGCC plant) where the syngas produced then enters a gas turbine. It is at this stage that the chemical process can be inserted to separate and capture the $CO_2$ and other pollutants from the syngas. Once the $CO_2$ is separated it can be transported to a disposal location.

In addition to adding the $CO_2$ separation and capture equipment, changes in other components are also necessary for electricity generation case. The removal of $CO_2$ prior to combustion in the turbine alters the composition of the gas to be burned, increasing the hydrogen content, which may affect the design or operational requirements of the turbine. In addition, the $CO_2$ capture process may alter the optimal design of the desulphurization and other gas clean-up processes. For these reasons, an IGCC plant built without consideration for $CO_2$ capture technology designed to produce power at a minimum cost and maximum efficiency will be significantly different than an IGCC plant designed to incorporate $CO_2$ capture technology.

"Three major technological components need to be added to a basic IGCC plant to allow for separation and capture of the $CO_2$: (1) the shift reactor to convert the CO in the syngas to $CO_2$, (2) the process to separate the $CO_2$ from the rest of the gas stream, and (3) a compressor to reduce the volume of separated $CO_2$ before it can be transported."[17] Furthermore, other components will require modification, as previously mentioned, including the gas turbine that will have to be capable of operating with a hydrogen enriched gas stream, the timing of the sulphur removal process, plus some scaling up to accommodate the larger quantities of coal needed to generate the same amount of power.

A further consideration is the $CO_2$ transportation and disposal. Once the $CO_2$ is captured and compressed at the plant it must be transported and injected into an underground geologic formation. Therefore, the location of the plant can also become a significant factor in the ease of transformation.

What should be clear from this listing of requirements for integrating capture and disposal of $CO_2$ into an existing IGCC plant is that the term "carbon capture ready"

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[16] Jennie Stephens, "Coupling $CO_2$ capture and Storage with Coal Gasification: Defining "Sequestration-Ready" IGCC", BCSIA Discussion Paper 2005-09, Energy technology Innovation Project, Kennedy School of Government, Harvard University, 2005.

[17] Ibid.

could encompass a whole host of definitions. Does it simply mean that one builds an IGCC plant? Does it mean that you leave space in the design for separation, capture and compression equipment? Does it mean you include the appropriate turbine to burn a high H2 gas stream? Does it mean you locate the plant within proximity to a geologic reservoir where the $CO_2$ can be disposed of? The list and variations of the possibilities could go on and on, calling into question whether the term "carbon capture ready " has any real meaning.

The likely result is that companies when taking advantage of the coal gasification incentives provided in the "Energy Policy Act of 2005" will follow the least cost option, i.e., build an IGCC plant with little or no design elements necessary for the future integration of $CO_2$ capture and disposal—unless there is a clear policy to reduce $CO_2$ emissions or if it is required that they include all the necessary equipment to capture their $CO_2$.

NRDC strongly advocates that all government funds that leverage the building of coal gasification plants should only go to those facilities that actually capture their $CO_2$. Subsidizing gasification by itself wastes taxpayers' money by subsidizing the wrong thing. Gasification is commercial and needs no subsidy but capture and storage is the primary policy objective and is likely to require subsidies pending adoption of $CO_2$ emission control requirements.

The first proposed coal gasification plant that will capture and dispose of its $CO_2$ was recently announced on February 10, 2006 by BP and Edison Mission Group. The plant will be built in Southern California and its $CO_2$ emissions will be pipelined to an oil field nearby and injected into the ground to recover domestic oil. BP's proposal shows the technologies are available now to cut global warming pollution and that integrated IGCC with $CO_2$ capture and disposal are commercially feasible.

## THE PATH FORWARD

The impacts that a large coal gasification program could have on global warming pollution, conventional air pollution and environmental damage resulting from the mining, processing and transportation of the coal are substantial. Before deciding whether to invest scores, perhaps hundreds of billions of dollars in deploying this technology, we must have a program to manage our global warming pollution and other coal related impacts. Otherwise we will not be developing and deploying an optimal energy system.

One of the primary motivators for moving toward coal gasification technologies has been to reduce natural gas prices. Fortunately, the U.S. can have a robust and effective program to reduce natural gas demand, and therefore prices, without rushing to embrace coal gasification technologies. A combination of efficiency and renewables can reduce our natural gas demand more quickly and more cleanly.

Implementing effective energy efficiency measures is the fastest and most cost effective approach to reducing natural gas demand. Efficiency standards, performance-based tax incentives, utility-administered deployment programs, and innovative market transformation strategies will bring energy efficient technologies to market and make efficient designs standard industry practice.

Renewable energy provides a critical mid-term to long-term supplement to natural gas use. Potential renewable resources in the U.S. are significant and renewable electricity generation is expanding rapidly, with wind and biomass currently offering the most cost-effective power in both countries. Some 20 U.S. states have adopted renewable portfolio standards requiring electricity providers to obtain a minimum portion of their portfolio from renewable resources. Federal tax incentives have also played an important role, particularly for wind.

With current coal (and oil) consumption trends, we are headed for a doubling of $CO_2$ concentrations by mid-century if we don't redirect energy investments away from carbon based fuels and toward new climate friendly energy technologies.

We have to accelerate the progress underway and adopt policies in the next few years to turn the corner on our global warming emissions, if we are to avoid locking ourselves and future generations into a dangerously disrupted climate. Scientists are very concerned that we are very near this threshold now. Most say we must keep atmosphere concentrations of $CO_2$ below 450 parts per million, which would keep total warming below 2 degrees Celsius (3.6 degrees Fahrenheit). Beyond this point we risk severe impacts, including the irreversible collapse of the Greenland Ice Sheet and dramatic sea level rise. With $CO_2$ concentrations now rising at a rate of 1.5 to 2 parts per million per year, we will pass the 450ppm threshold within two or three decades unless we change course soon.

In the United States, a national program to limit carbon dioxide emissions must be enacted soon to create the market incentives necessary to shift investment into the least-polluting energy technologies on the scale and timetable that is needed. There is growing agreement between business and policy experts that quantifiable and enforceable limits on global warming emissions are needed and inevitable. To ensure the most cost-effective reductions are made, these limits can then be allocated to major pollution sources and traded between companies, as is currently the practice with sulfur emissions that cause acid rain. Targeted energy efficiency and renewable energy policies are critical to achieving $CO_2$ limits at the lowest possible cost, but they are no substitute for explicit caps on emissions.

A coal integrated gasification combined cycle (IGCC) power plant with carbon capture and disposal can also be part of a sustainable path that reduces both natural gas demand as well as global warming emissions in the electricity sector. Methods to capture $CO_2$ from coal gasification plants are commercially demonstrated, as is the injection of $CO_2$ into geologic formations for disposal. On the other hand, coal gasification to produce a significant amount of liquids for transportation fuel would not be compatible with the need to develop a low-$CO_2$ emitting transportation sector. Finally, gasifying coal to produce synthetic pipeline gas or chemical products needs a careful assessment of the full life cycle emission implications and the emission reductions that are required from those sectors before decisions are made to invest in these systems.

In the absence of a program that requires limits on $CO_2$ emissions IGCC systems with carbon capture and disposal will not be brought to market in time. We need to combine $CO_2$ limits with financial incentives to start building these integrated plants now, because industry is already building and designing the power plants that we will rely on for the next 40-80 years.

To reduce our natural gas demand we should follow a simple rule: start with the measures that will produce the quickest, cleanest and least expensive reductions in natural gas use; measures that will put us on track to achieve the reductions in global warming emissions we need to protect the climate. If we are thoughtful about the actions we take, our country can pursue an energy path that enhances our security, our economy, and our environment.

Senator ALEXANDER. Thank you, Dr. Herzog.

And thanks to each of you for your comments. We know you have a lot to say, and you've said it in your statements, which we appreciate. And I thank you for summarizing it.

Mr. Ferguson, you said that projects eligible for the tax credit—and I guess also for the loan guarantees—you suggested ought to be of a commercial scale. How do you define "commercial scale"?

Mr. FERGUSON. "Commercial scale" would be something that would be competitive in whichever sector—if—in the case of the chemical sector, a global-scale facility that is going to be globally competitive. These are typically, in the case of a powerplant, at least 500 megawatts in size; in the case of a chemical plant, we're talking about hundreds of millions of pounds. Typically, demonstration facilities are in the tens of millions of pounds, in, you know, very small quantities. So, I guess that's the kind of distinction I was talking about.

Senator ALEXANDER. Well, we're talking about an industrial gasification plant. Can you put a range of a dollar figure on it, to give us some idea of——

Mr. FERGUSON. We believe that a scale facility is on the order of half a billion dollars, $500 million, probably upwards of $750 million would be the kinds of things that we'd be looking at.

Senator ALEXANDER. You mentioned, and Mr. Boycott also mentioned, that the guidance you'd received so far from Treasury and Energy isn't sufficient to permit applicants to make the best possible application by June 30. Mr. Garman seemed to think that that was moving pretty well. What specific—there's a little polarity—advice would you have for the departments?

Mr. FERGUSON. The questions that have been referred to IRS and Treasury seem to be the ones that are the most troublesome. The dialogue with DOE has been pretty good, but there have been a number of questions that have been referred to the IRS, on the Treasury side of the house, and we have not heard answers, and we can't respond fully until we hear those answers.

Senator ALEXANDER. How many employees does Eastman Chemicals have today?

Mr. FERGUSON. Twelve thousand worldwide, 7,500 in the Tennessee facility, where we gasify coal.

Senator ALEXANDER. And how many employees did you have in the Tennessee facility 5-10 years ago?

Mr. FERGUSON. Probably on the order of 20,000.

Senator ALEXANDER. And what difference has the price of natural gas made in the smaller number of employees in the Tennessee facility?

Mr. FERGUSON. Like other companies of our kind, we've had to diversity our populations and our production around the world so that we can be competitive. And it certainly has helped to increase the numbers there.

Senator ALEXANDER. You're talking about a major decision coming up which might have to do with a number of jobs. Is it possible to produce enough synthetic gas from coal to substitute for natural gas, and to do it economically enough so that chemical jobs can stay in Tennessee or in the United States and not go to India and China?

Mr. FERGUSON. Absolutely, or I wouldn't be here, Senator. That's the choice that we make.

Senator ALEXANDER. Are you convinced that synthetically produced gas for, in your case, feedstocks is competitive? And, if it is, how would you describe what the price levels are to make it competitive?

Mr. FERGUSON. We have been doing this, as I said, since 1983, going head to head with the biggest chemical companies in the world, like Dow and DuPont, Rohn and Haas, and BASF, and all of them. We judge that the typical price arbitrage between coal and gas during more normal times is about $1-a-million Btu for coal, and more like $3-a-million Btu for gas. And we're competing successfully at that level. When the arbitrage is wider between those two, of course, it favors coal.

Senator ALEXANDER. We make a lot of speeches around here about outsourcing jobs, jobs going overseas, and I'm constantly reminded that, if I'm not mistaken, we have, or had, about 1 million chemical jobs, jobs in the chemical industry in the United States. They're mostly high-paying jobs, blue-collar/white-collar jobs, the kinds that support families. And it is sobering to hear repeated the facts which we've often heard, that there are 120 new chemical plants scheduled to be built around the world, one of them in the United States. Consequences of that are significant, not just in upper east Tennessee, where Eastman has been there as long as the mountains, it seems, but to our entire country. And it seems to me that making gas from coal and other products is one very promising method for that.

My time is up. Let me go to Senator Thomas.

Senator THOMAS. Thank you.

Mr. Douglas, you produce what in your business? What do you produce?

Mr. DOUGLAS. We produce synthetic gas.

Senator THOMAS. From——

Mr. DOUGLAS. From coal.

Senator THOMAS. Okay.

Mr. DOUGLAS. We can also use a portion of petcoke. We can use MSW. But it is primarily from coal.

Senator THOMAS. If you're doing that, what is it that you need to do differently? What's going to change the world here?

Mr. DOUGLAS. What's going to change the world is widespread acceptance of the concept of coal gasification. To move industrial customers from a comfort zone of natural gas is a very, very large step for customers. It's not something that they take lightly when they look at a technology that, from—maybe not from my viewpoint, but from theirs, is a new technology. It's a change. It's a paradigm shift for them.

Senator THOMAS. No question. What does the product that you sell cost, compared to natural gas produced otherwise?

Mr. DOUGLAS. In today's market—and I think the Senator was talking, earlier, about $7 gas—in today's market, we're going to be about a $1.50 under that.

Senator THOMAS. Really?

Mr. DOUGLAS. Yes. Understand that our technology, our process, is—if I were to make an analogy, when Senator Dorgan was speaking earlier, he was talking about the project in North Dakota—it would be analogous to say that our process is a newer version of that process, a more modern version of that process. But it is a proven process. I mean, we're not trying to introduce things that don't already exist in other parts of the world. So, in that sense, it's quite tried and true.

Senator THOMAS. Mr. Boycott, you mentioned running short of gas in Alaska. Is that right?

Mr. BOYCOTT. That's correct.

Senator THOMAS. Why are we building a pipeline from Alaska to the United States?

Mr. BOYCOTT. Well, the gas that we are dependent on is the Cook Inlet gas, and we're—the pipeline we're discussing is regarding North Slope gas. And we don't have access to that gas. There's on infrastructure to bring that gas to market. It's also, if you consider the timing of that pipeline, really not a solution for our production facility, because I believe the earliest we would consider a spur line into the Anchorage Bowl would be about 2016——

Senator THOMAS. I see.

Mr. BOYCOTT [continuing]. Somewhere in that neighborhood. And it's not realistic for us to expect that we could get gas contracts to support our business.

Senator THOMAS. What's the production area in Alaska on coal? Are you doing a good deal of that?

Mr. BOYCOTT. Yeah, we have one coal mine in Alaska that's currently operating, that's operated by Usibelli Coal mine in Healy, Alaska. Usibelli has been our partner in the development of this project. And we are looking to open a new mine in Beluga, which is just——

Senator THOMAS. Are there adequate resources of coal?

Mr. BOYCOTT. There is. Estimates are as much as 100 years of coal supply for a project of this magnitude.

Senator THOMAS. Open-pit mines or underground?

Mr. BOYCOTT. Open-pit.

Senator THOMAS. Open-pit? Hmm.

Mr. Bruce, you're producing ethanol, is that right?

Mr. BRUCE. Correct.

Senator THOMAS. How does what you're doing compete with the other sources of ethanol, in terms of price and capacity?

Mr. BRUCE. In terms of pricing?

Senator THOMAS. Yes.

Mr. BRUCE. I think that we would be very competitive. I think we would be under the current costs of the farmers, for example, or any chemical catalytic process.

The ingredient in our process which makes it unique is the fact that we biologically, through a natural bacteria, convert the synthesis gas into ethanol. That's a very important point. It's not that—there's no chemical catalytic reaction going on. It's a biological one.

Senator THOMAS. What do you do with the sulfur and mercury that's removed?

Mr. BRUCE. Well, we scrub them out. We have to clean the gas after it's gasified, we scrub it, and we clean out those impurities at that time. In our process, by the way, we also cool that gas. And when we cool it, we create steam. That steam can be used to create a byproduct of electric power. But we scrub it and then introduce it to the microorganism that converts it into ethanol.

Senator THOMAS. Dr. Herzog, the Under Secretary said IGCC technologies would double the efficiency of our current fleet of coal plants. What would the corresponding reduction in carbon, sulfur, and mercury, if the current supply were generated by ICC technologies that are now available?

Dr. HERZOG. If the conventional coal plants were replaced with IGC coal gasification technology, IGCC is slightly more efficient than conventional coal, the current conventional coal. The older plants, it's much more efficient. Exactly what the overall efficiency improvement is, I don't know off the top of my head, though I could certainly figure that out. The issue, though, is that it wouldn't substantially reduce our carbon emissions, and the only way to do that would be to capture the carbon, but you can do that much more easily and cost effectively from the coal gasification plants.

Senator THOMAS. Okay, thank you.

Senator ALEXANDER. Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

Mr. Boycott, I want to personally welcome you. I know you've made the long trek out a couple of different times to speak to the Agrium project, and I appreciate you coming and providing the testimony today. I think it is an opportunity for us in the State of Alaska, you know, to develop some very substantial coal resources in the State, to provide for an energy source for south central that needs it in a very pressing way, and to provide for the continuing employment of those in our only manufacturing industry there in the area. So, I appreciate the energy and commitment that you and others have made to this project.

Now, I know that you heard Secretary Garman, just before he concluded his remarks. He said he was going to be listening attentively to this next panel to see what it was that you cite specifically that you may need, so that, if it's necessary, they're able to change things, or tweak things. And you specifically said that when it comes to the implementation of the loan guarantees, when it comes to implementation of the tax credits, you needed clarity in implementation—you need definition, clarity, and, I think, simplicity was the word that you used. What, specifically, does Agrium need to be able to take advantage of the tax credits, the loan guarantees? You've mentioned both of them will be key to the success of moving this project forward. What do you need from Secretary Garman right now?

Mr. BOYCOTT. I'll speak to the two, individually. And, thank you.

Respecting the tax credits—we are concerned that the timing of our project is slightly out of step, that the June deadline—and Secretary Garman, I think, covered it very effectively—that the June deadline may put us somewhat at a disadvantage in having the sufficient project definition to compete for those opportunities. And so, specifically to that, we're looking through the flexibility to work with the Department and ensure that our opportunity is cast in a fair light.

Relative to the loan guarantees, our concern there is a high level of complexity and basically a risk-elimination or risk-minimization strategy, as opposed to a risk-sharing strategy. And so, we would encourage, as we look to the loan guarantees, that we look to that on a risk-sharing basis to make it an attractive opportunity for industrial commercialization and that it doesn't simply become a 10-percent adder on the financing of the project, but it actually encourages the investment, as I believe it's intended to do.

Senator MURKOWSKI. Do you think that you need an extension or perhaps an expansion of these tax credits?

Mr. BOYCOTT. I think that the tax credits is definitely a step in the right direction. As I think about the role of the Federal Government, I applaud that effort. And I think there are numerous opportunities in this arena that are coming to light. And so, I would encourage, irrespective of the Agrium opportunity, that we consider an expansion and an extension of that program to ensure that we encourage the development of these technologies and the use of this energy source.

Senator MURKOWSKI. Mr. Ferguson you also mentioned the need for some certainty in implementation. Would your answer be any different than Mr. Boycott's, in terms of what you are looking for?

Mr. FERGUSON. I share his concerns. We're trying to get a definition from both DOE and Treasury about what "good" looks like in the nature of an application, so we know what the criteria are they're judging us on, what we need to be responsive to. And I think in their defense, this is new for them, as well. And they're trying to decide who's got the ball, between Treasury and IRS, in determining some of these answers. So, I sympathize with their issue, but it leaves us in a bit of a quandary about: what does "good" look like in the form of an application? Once we know that, we can all respond properly. And I think Mr. Boycott shares some of those concerns.

Senator MURKOWSKI. Well, and June 1 is not too very far away.

Mr. FERGUSON. Only 2 months.

Senator MURKOWSKI. Okay.

Thank you, Mr. Chairman.

Senator ALEXANDER. Thank you, Senator Murkowski.

Mr. Bruce, this technology that you propose to use is to turn gas into ethanol—has been around awhile, except your biologic process. Is that the new part of your proposal?

Mr. BRUCE. Yes, Senator.

Senator ALEXANDER. As I understand it, you're proposing to build a new plant in Oak Ridge, is that correct? And how big would that be?

Mr. BRUCE. Yes, sir. We want to scale up to a commercial size. And our plants would be modular. What we are proposing to do is to build just two lines, two modules. So, initially we would only build a plant that would produce 7 million gallons. A full-scale commercial plant for us in the future would probably handle as much as 2500 tons of coal per day, producing maybe 135 million gallons of ethanol. But we want to prove the technology at a commercial level, and then modularize our way up from there.

Senator ALEXANDER. Would you say, in your opinion, that the technology is proven at a test level, but not yet proven at a commercial level?

Mr. BRUCE. Yes, I would, exactly. We've been—the Great Plains project, we ran syngas off that project for 3 weeks, and tested the project there. We've tested it in our own facility. We've built our own gas-fire a couple of years ago. It's a small one, ton and a half a day. But we can make synthesis gas out of municipal solid waste, auto shredder residue, cornstalks, any biomass, and convert that into ethanol.

And I want to comment on something that was said earlier. I think that the perfect utilization of our technology would be a blend of coal with energy crops. If we're going to get a real handle on the $CO_2$ problem, we're going to have to do it with biomass. And I think that blending, for example, one-third coal and two-thirds energy crops—and I say "energy crops," because I think we have a vast amount of idle land, arable land, also in this country that could be utilized to grow energy crops, such as energy cane that was developed at the University of Florida, many others, where you get a large amount of tonnage per acre—that would balance out the negative effect of the increased carbon from coal. However, because of our biological process, I think we're minimizing that carbon effect anyway.

Senator ALEXANDER. Well, I'm glad you said that. I want to have a chance to ask Dr. Herzog some more about $CO_2$, but I was wondering, first, what you, or any of the other industrial witnesses, would say about what she said about carbon and coal gasification. The NRDC has—what interests me about their position as a leading environmental group in the country is, they're actually, for large-scale baseline production of electricity, after conservation and efficiency—and she mentioned renewable, which is limited, in terms of what it can do for electricity—is a coal strategy, if it's—

if the carbon's recaptured. So, what's your view of the technological—of the feasibility of carbon recapture?

Mr. FERGUSON. If I could comment?

Senator ALEXANDER. Mr. Ferguson.

Mr. FERGUSON. Sir, we're evaluating a process that would be relatively neutral to burning natural gas. It does require some sequestration.

Senator ALEXANDER. Now, explain, what do you mean by "relatively neutral"?

Mr. FERGUSON. The carbon emissions from the gasification process to make power—electric power—would be equivalent to making electric power from natural gas.

Senator ALEXANDER. Okay.

Mr. FERGUSON. There is some sequestrations required for doing that, and the—and how you sequester that, and what it's used for, is the next step of our journey here. We think we might be able to find a win-win solution to do that.

Senator ALEXANDER. Anyone else have a comment?

Mr. Boycott.

Mr. BOYCOTT. Yes, Mr. Chairman. I'd just like to comment. I think the ammonia/urea process is somewhat unique in the integration with gasification, because urea is the combination of ammonia and carbon dioxide. So, as we're evaluating our project, the gasifier in this opportunity is estimated to produce 12,000 tons a day of carbon dioxide. We actually are forced to sequester that carbon dioxide and utilize 5,000 tons a day of it in the production of urea. And so, that type of complex lends itself directly to $CO_2$ sequestration. And then, we're evaluating the utilization of the balance. We have oilfields immediately adjacent to our facility which are in significant decline. So, we're in the midst of evaluating the utilization of the balance of that carbon dioxide for enhanced oil recover.

Senator ALEXANDER. Mr. Douglas, anything to add?

Mr. DOUGLAS. Nothing to add, Senator.

Senator ALEXANDER. Okay.

Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman. I just had a very quick question for you, Mr. Douglas. You were mentioning the best way to get the small industrials utilizing the coal gasification process.

Mr. DOUGLAS. Sure.

Senator MURKOWSKI. And you indicated that you felt that some financial incentives would be necessary. Can you expand, just a little bit more, in terms of what you think might be reasonable, in terms of incentives?

Mr. DOUGLAS. What might be reasonable, and what we've thought about quite a bit, is some type of Btu credit, a small Btu credit for the user for the replacement on a one-to-one basis from natural gas to syngas. We believe that it's going to take an incentive of that type, not unlike former credits that we have had in other legislation—that it would take that sort of a push to try and ensure that coal gasification is more widespread than just large IGCC, because it's our view that right now what we're seeing in the United States—and it's not a particularly bad thing—is that there's a very strong move toward large IGCC. I think the number that was quoted earlier was, what, four to five hundred megawatts. IGCC is just as valuable to America at 260 megawatts as it as at 500 megawatts. It's just a smaller scale. It's a downscale.

And there are an awful lot of industrials that would like—that could benefit from syngas, not only for their process—that is, for their boilers, for their kilns—but also to do onsite generation. And there are going to be larger industrials, obviously, that are going to do this, that are going to produce, for example, 100 megawatts of their own, on their own site. We have that capability today. Okay?

And all I'm trying to advocate for is that the limitation of credits at the very largest level is also going to serve as a limitation in America to the full introduction of the benefits of coal gasification. And that's my point.

Senator MURKOWSKI. Appreciate that.

Dr. Herzog, you mentioned that as we move forward with any of the processes as they relate to coal, the importance of dealing with the carbon. So, I think it is important to hear what some of the proposals out there are that are out there.

And, Mr. Boycott, I guess I look at what we are currently envisioning with the Agrium proposal, and, yes, we realize that there are a lot of dollars involved with this project, but when you look at something that can really provide a win for the consumer, a win for the environment, in the sense of figuring a way to take all—utilize all that carbon, whether it's sequestration into the oil fields—and I realize that there's still a lot of searching to determine if that's viable, but these are the things that we need to be looking to, to make sure that the process works every way that we can. And, unfortunately, these are expensive processes, expensive projects, and that's why the tax credits, and that's why the loan guarantees are going to be helpful.

Mr. Chairman, I appreciate the testimony of the witnesses, and appreciate, again, you calling this hearing.

Senator ALEXANDER. Thank you, Senator Murkowski.

I would just like to ask Dr. Herzog a question or two, and then we'll conclude the hearing.

I was in India a couple of weeks ago. The people told me India needs 200,000 megawatts of electricity in the next 10 years. And I asked several people in India if that could be possible, and no one really—you know, I suppose you could say it could be more, could be less, but it's a huge amount.

I'm a supporter of the President's proposal on Indian civilian nuclear power, but even that, plus whatever else they do in India in civilian nuclear power, won't come close to producing 200,000 megawatts of electricity over the next 10 years.

I agree, as I think most members of this committee agree, that the first thing we ought to try to do is conservation and efficiency. And we did a good bit of that last year in the energy bill, and we probably should do twice as much, or three times as much. And on the renewables side, especially in the fuel area, the Congress is moving in that direction.

But it looks to me like, in India, in China, other places in Southeast Asia, and in the United States, which are the big growing places, that the demand for electricity is going to require large amounts of baseline production of electricity, and that the only two places to get that are nuclear power—after you do conservation, after you do some renewable, are nuclear and coal.

I've been intrigued by the Natural Resources Defense Council's coal strategy and its willingness to recognize that fact. And, as you hear this testimony today, and as you look toward the future, thinking not just of the United States, but of India and China, what comments or suggestions do you have for these industries that would make it more likely that they could succeed in—and I don't want—and I want to ask you to also consider sulfur and nitrogen and mercury, because those are dangerous pollutants, as well, and we do want to sequester the carbon, recapture the carbon. That affects global warming. But I don't want to minimize the importance of India and China and in the United States over the next 20 or 25 years, having coal plants that produce no sulfur, nitrogen, and mercury, and begin to get carbon under control. So, what's a realistic way for us to look at this? What's your advice for them? What's your advice for us as we make additional policy on this question?

Dr. HERZOG. Right. All excellent questions, all excellent points, and certainly ones that we've been thinking about, struggling with, as well. As you said, the other pollutants are very important. I happen to be an expert on global warming, and I didn't have the time to discuss those other pollutants as—in addition to the global warming issue. Coal gasification, as you said, significantly reduces those other pollutants, and that's one of its advantages that we see and advocate for.

As far as the India question—and China, as well, for that matter, even more so, much more so, actually—they both have large coal resources. And even though we'd love for efficiency or renewables to be the only efforts that move forward, we realize, as you've stated, that coal is here, and it's going to be here, and we need to deal with it. And that coal gasification is one of those technologies for the electricity sector that can deal with the criteria pollutants you mentioned—mercury—and also the global warming. So, I mean, in the United States, we feel that the plants that Government money is going towards right now, the gasification plants, those plants should be capturing their carbon. We need to get that technology out there now. We have about 10 years to really get started. We don't have time to wait. I'd love to see the United States lead the way. And so, then India and China can follow suit and use the technologies that we develop.

So, we can capture our carbon. That technology is out there. Various projects are going on in this country and elsewhere around the world to dispose of the carbon, both for enhanced oil recovery and in deep saline aquifers. Do we know everything we need to know? No. But if we get started now, and we learn, and use government subsidies, leveraged by industry money, as well, we can get that knowledge we need in the timeframe we need it.

Senator ALEXANDER. Doesn't NRDC have some estimate of the pollution in the air in Los Angeles that comes from China and India? And do you know what it is, it does?

Dr. HERZOG. Off the top of my head, I don't. We do have a China program. They may——

Senator ALEXANDER. But it is true, is it not, that what happens in India and China affects the air in the United States, and what we do here affects the world, and what they do there affects us as well?

Dr. HERZOG. Absolutely.

Senator ALEXANDER. Well, this has been a very interesting hearing for the Senators who came. We appreciate your succinctness and your preparation and your questions. We had good attendance here.

As we said at the beginning, the whole purpose of this hearing is oversight, to see whether what we enacted in July and August of last year is getting where we're going.

One of the things we heard today was that some of the deadlines for tax credits and loan guarantees are moving right along. The other thing we heard that—is, those of you who might be applying for tax credits and loans, are still somewhat in the dark about how to make those applications. Hopefully, this hearing today will suggest to the Department of the Treasury and to the Department of Energy that they have some work to do. Our staff will follow up with them and convey these thoughts. Secretary Garman said he'd be monitoring what you said, and listening. And I'm sure he'll pay attention to that, as well.

I want you to know that this entire committee is interested in industrial gasification, coal gasification, the idea of using coal in a cleaner way to produce homemade electricity that'll make us less dependent on dirtier and more foreign sources of energy. And so, we'll continue—this is not the last, by far, hearing that we'll be having on this subject.

Other Senators may—or some of the Senators who were here—may have additional questions. If they do, we'll get them to you by the close of business tomorrow, and I hope you'll answer those questions, as well.

What was said here today may provoke you to want to say more to us, and we'd like to have your additional comments in the next 10 days to 2 weeks so that we can consider them specifically. If you want to be more specific about the kind of questions you'd like to have answered that would be helpful to you, in terms of applications that you might be making for tax credits or loan guarantees, let us know that. And part of our job is to pass that along to the Department for them to consider.

So, unless Senator Murkowski has something else to add, thank you for coming. The hearing is adjourned.

[Whereupon, at 4:28 p.m., the hearing was recessed, to be reconvened on May 8, 2006.]

# LICENSING OF HYDROELECTRIC FACILITIES

**MONDAY, MAY 8, 2006**

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington, DC.*

The committee met, pursuant to notice, at 3:01 p.m., in room SD–366, Dirksen Senate Office Building, Hon. Larry E. Craig presiding.

## OPENING STATEMENT OF HON. LARRY E. CRAIG, U.S. SENATOR FROM IDAHO

Senator CRAIG. Good afternoon, ladies and gentlemen. The Committee on Energy and Natural Resources will convene, and thank you for your interest today in the oversight hearing on the implementation of the energy bill's hydropower licensing procedure.

As most of you know, it is an extremely important issue to me personally. In this time of increased oil and gas prices, hydropower is a clean, renewable, and low-cost source of energy. My State of Idaho benefits greatly from the renewable resource, receiving almost 80 percent of its electricity from hydropower.

Over the last several years I have worked to reform the hydropower relicensing procedure. The Federal resource agencies, with their authority to issue mandatory environmental conditions or fishway prescriptions, play a major role in FERC's licensing process. However, such conditions must be supported by facts and that, in my opinion, has not always been the case.

Last year, with the enactment of the Energy Policy Act of 2005, Congress finally brought much-needed reform to this area and we did it in a way that I was very proud of, a bipartisan way. If you had told me a couple of years ago that we would have had myself, Senator Domenici, Senator Cantwell, Senator Bingaman, Senator Feinstein, Representative Barton and Representative Dingell involved in a compromise on this issue, I think there are many in the audience, and myself among them, who would simply not have believed it. But that is exactly what we did. It does not get more bipartisan than that listing.

The agreement provides full participation for all parties involved in a licensing procedure. Any party may request a trial-type hearing on disputed issues of material fact, to examine whether an agency's conditions are factually supported. Any party may propose alternatives. This is a sound policy which will provide much-needed accountability to the process.

The resource agencies have established the new implementing procedure and, with a full 20 percent of the Nation's non-Federal dams up for relicensing in the next decade, we will see it in action. It just so happens to turn out that the first trial-type hearing will take place this June in my State of Idaho to examine issues relating to the Hells Canyon complex. I hope to attend those hearings personally. I am fascinated to see how this process will work out.

Now, before I ask our colleagues to make any statements, let me introduce the witnesses here today. I am pleased to welcome Mark Robinson from FERC, Larry Finfer from the Department of the Interior, Dan Adamson on behalf of the National Hydropower Association, and Andrew Fahlund on behalf of American Rivers. I look forward, gentlemen, to your testimony. Again, let me thank you for being here today.

Now let me turn to the ranking member of the committee, Senator Bingaman of New Mexico, for any comments that he might have.

Senator Bingaman.

**STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO**

Senator BINGAMAN. Thank you very much, Mr. Chairman, for having this hearing. I think it is very useful too, as we were discussing before the hearing started, to have oversight about some of the provisions that we included in last year's energy bill. I am anxious to hear about the agency's efforts to administer these new provisions.

During the course of considering that bill last year, I was glad to see that the hydroelectric relicensing provisions were revised and improved. Changes were made to ensure that all parties to a licensing proceeding, including States and tribes and third parties, are able to participate equally, and I think that was a good change.

I do continue to have concerns that the new process for alternative mandatory conditions and fishway prescriptions and the new trial-type hearings that you were referring to may add complexity and delay to an already complex and slow process. So I hope that is not the case. I think this hearing may shed some light on that. I hope it does. I hope the new provisions are being implemented in a manner that maintains protections for Federal and Indian lands and fishery resources.

I understand the goal of these provisions is to improve the cost effectiveness and efficiency of conditions and fishways and not— this is not seen as an opportunity to undermine the conditions and fishways that resource agencies determine are necessary.

So once again, thank you for having the hearing. I look forward to learning something from each of these witnesses and then I may have a question or two. Thank you.

Senator CRAIG. Jeff, thank you very much.

Let me turn to Senator Craig Thomas of Wyoming for any comments you have.

**STATEMENT OF HON. CRAIG THOMAS, U.S. SENATOR FROM WYOMING**

Senator THOMAS. Thank you, Mr. Chairman.

I am pleased to have this meeting and I welcome the witnesses here. This is the third meeting of this kind we have had, one each week, and we are going to continue to do that, to seek to implement our energy policy that we put into place last year. Hydroelectric power, hydropower, of course is very important and produces about 7 percent of electricity generated in the United States, much higher than that, of course, in the Pacific Northwest. In Wyoming, about 5 percent of our electricity comes from hydro. About 10 percent of electricity in Wyoming comes from renewable sources, and that is good.

As was mentioned, I think our bill last year did a good job of establishing a bipartisan process for relicensing hydro and that is a good thing. So I strongly feel we need to continue to implement the provisions of the policies as quickly as possible and as effectively as we can. So I look forward to the witnesses this afternoon, Mr. Chairman. Thank you.

Senator CRAIG. Craig, thank you for being here.

Now we will turn to our witnesses and I am proud to introduce Mark Robinson, Director of the Office of Energy Projects, the Federal Energy Regulatory Commission. Mark, thank you for being here and your full statement will become a part of the record. Please proceed.

**STATEMENT OF J. MARK ROBINSON, DIRECTOR, OFFICE OF ENERGY PROJECTS, FEDERAL ENERGY REGULATORY COMMISSION**

Mr. ROBINSON. Thank you, Senator Craig. First I would like to make sure and pass along the sentiments of my boss, Joe Kelleher, and his desire to compliment you on the work that you did in getting the hydro provisions into EPAct 2005. They have made a difference, as I think my testimony states and hopefully I will confirm here today. But he wanted me to make sure and pass that on to you, and I join him in that.

My name is Mark Robinson. I'm Director of the Office of Energy Projects. Our office authorizes the construction of LNG terminals, natural gas pipelines, and natural gas storage facilities. After EPAct 2005 we will be involved in electric transmission lines. But more significantly today, we are involved in the licensing, the administration, the safety and security of about 1600 hydroelectric projects across the country, constituting about half of the Nation's hydroelectric power.

You hear statistics like you have already mentioned today about the hydropower and what it means to electric generation in this country, 7 percent, 6 percent. I hear different numbers. But that does not really reflect the significance of hydropower to the Nation's energy security. All you have to do is look back a few years when we had low water years in the Northwest, to how that can play out to ensuring the economy of this country. Or even more recently, look at the low water year in Spain and how that plays out with our getting LNG delivery into the United States. Hydropower in many instances is the base that everything else works from, regardless almost of the percent that hydropower represents in the Nation's energy portfolio.

We have about 218 hydroelectric projects coming up for relicensing this decade, constituting 22 gigawatts of power. So it is a very important time frame for us to be looking at how we are licensing these projects and ensuring that that electricity is available to the public.

About a year or so ago now, I guess a little longer than that, the Commission tried to prepare itself for these licenses that were coming in by the development and issuance of the integrated licensing process for handling the relicense principally of projects in this country. We spent a lot of time on that with all the agencies, people represented at this table, to make sure that we had it as right as we could at that time and to add discipline to a process that had gotten very long and very expensive.

One of the challenges of EPAct 2005 in terms of taking the provisions that were provided, principally on the mandatory conditioning authority of the agencies, was making sure that that was integrated into our new integrated licensing process and would not add delay. Yes, there was going to be some more steps, principally with the agencies, but to make sure that it fit within our process. I think, with the work done by the Department of the Interior, the Department of Commerce, and the Department of Agriculture, and our own staff at FERC, we have accomplished that. We have a process that allows for those mandatory conditions to be developed, reviewed, and brought into the FERC licensing process without delay.

Two things about those conditions, those provisions of EPAct 2005, I would like to mention: the trial-type hearing and the alternative conditions. I think both are important and they work in tandem to improve the conditions that the Commission gets. The trial-type hearing makes sure that the information base that everybody relies on to determine whether or not a fish ladder is needed, whether or not the minimum flow is correct, actually has a sound foundation, and I think that is a critical aspect of what EPAct 2005 did for hydro.

EPAct also allowed alternative conditions to come that would be less costly and maybe allow for the project to operate better, but would also either adequately protect in terms of section 4(e) or give equal—I am sorry—no less protective of for section 18 for prescriptions, but allow for other ideas to come in and be tested in the FERC marketplace as well as with the agencies, to ensure that we have the right conditions in those licenses.

I think the net result of those provisions is that, along with the responsibility that the agencies have to provide those conditions, they now have an accountability aspect to it. They have to take a hard look at what it is they are proposing to make sure that it does in fact serve the public interest. In many ways it aligns itself with the requirements that the Commission has always been under to ensure that the public interest is met, that the developmental and non-developmental values are both looked at and given equal consideration in providing for those conditions and imposing them in a license.

The agencies now have that similar criteria in developing their conditions. I think the net result of that ultimately will be less conflict, fewer ALJ hearings after we get over this initial round, I think, and a greater conformance between what the agencies would provide through their mandatory conditioning authority and what the commission would require in any case, given the requirements that they have under the Federal Power Act. I think that is nothing but good in bringing all the Federal agencies into harmony in developing these licenses and will ultimately result in better stewardship both for the hydropower resources that we are all required to do, to take a look at, as well as the natural resources.

[The prepared statement of Mr. Robinson follows:]

PREPARED STATEMENT OF J. MARK ROBINSON, DIRECTOR, OFFICE OF ENERGY PROJECTS, FEDERAL ENERGY REGULATORY COMMISSION

Mr. Chairman and Members of the committee, I appreciate the opportunity to appear before you to discuss the provisions of the Energy Policy Act of 2005 (EPAct 2005) relating to the Federal Energy Regulatory Commission's hydropower licensing program. My name is J. Mark Robinson, and I am the Director of the Commission's Office of Energy Projects. Our office is responsible for the regulation of non-federal hydropower projects; the certification of between 500 and 2,000 miles of interstate natural gas pipelines annually; the certification of natural gas storage facilities; and the authorization, safety and security of liquefied natural gas (LNG) terminals. I appear today as a Commission staff witness speaking with the approval of the Chairman of the Commission. The views I express are my own and not necessarily those of the Commission or of any individual Commissioner.

The Commission currently regulates over 1,600 hydroelectric projects at over 2,000 dams pursuant to Part I of the Federal Power Act (FPA). Together, these projects represent 57 gigawatts of hydroelectric capacity, more than half of all hydropower in the U.S. and over five percent of all electric generating capacity in the United States. Hydropower is an essential part of the Nation's energy mix and offers the benefits of an emission-free, renewable energy source.

The Commission is in the midst of processing the 218 relicense applications being filed this decade. These projects include many large capacity and complex projects and have a combined capacity of about 22 gigawatts, or 20 percent of the Nation's installed hydroelectric capacity. The Commission is faced with the challenge of licensing these projects in a reasonable time frame, while complying with statutory requirements under the jurisdiction of a host of federal and state agencies.

Dependable and affordable hydroelectric energy requires a licensing process that is efficient and fair. As the Commission begins 2006, its hydropower staff is focused on pursuing various initiatives to meet current challenges, including implementation of the Commission's Integrated Licensing Process (ILP) to increase the efficiency and timeliness of licensing hydroelectric projects under its jurisdiction, while balancing stakeholder interests and improving the quality of decision-making.

The Commission's hydropower activities generally fall into three categories. First, the Commission licenses and relicenses hydroelectric projects. Relicensing involves projects that originally were licensed 30 to 50 years ago. The Commission's second role is to manage hydropower projects during their license term. This post-licensing workload has grown in significance as new licenses are issued and as environmental standards become more demanding. Finally, the Commission oversees the safety and security of licensed hydropower dams.

My testimony today will address implementation of the hydropower provisions of section 241 of Subtitle C of Title II and section 1301 of Subtitle A of Title XIII of EPAct 2005 and provide examples of how these sections have already begun to positively affect the hydropower program.

While the Commission's responsibility under the FPA is to strike an appropriate balance among the many competing developmental and environmental interests, as required by the public interest standards of sections 4(e) and 10(a) of the FPA, various statutory requirements give other agencies a significant role in licensing cases. Several entities have mandatory authorities that limit the Commission's control of licensing requirements and of the cost and timing of licensing. For example, section 4(e) of the FPA authorizes federal land-administering agencies to provide mandatory conditions for projects located on federal reservations under their jurisdiction. Further, section 18 of the FPA gives authority to the Secretaries of the Departments of the Interior and Commerce to "prescribe" fish ways.

Prior to the passage of EPAct 2005, the other federal agencies were not required to consider or strike a balance among the many competing developmental and environmental interests, nor were they required to consider alternatives proposed to their mandatory conditions, even if those alternative conditions were less costly and achieved the same level of environmental protection.

Section 241 of EPAct 2005 amends sections 4(e) and 18 of the FPA to provide that any party to a license proceeding is entitled to a determination on the record, after opportunity for an agency trial-type hearing of no more than 90 days, of any disputed issues of material fact with respect to any agency's mandatory conditions or prescriptions. Section 241 further mandates that, within 90 days of the date of enactment of EPAct 2005, the Departments of the Interior, Agriculture, and Commerce establish jointly, by rule and in consultation with FERC, procedures for the expedited trial-type hearing, including the opportunity to undertake discovery and cross-examine witnesses.

Section 241 of EPAct 2005 also adds a new section 33 to the FPA that allows the license applicant or any other party to the license proceeding to propose an alternative condition or prescription. The Secretary of the agency involved must accept the proposed alternative if the Secretary determines, based on substantial evidence provided by a party to the license proceeding or otherwise available to the Secretary, (a) that the alternative condition provides for the adequate protection and utilization of the reservation, or that the alternative prescription will be no less protective than the condition or fishway initially proposed by the Secretary, and (b) that the alternative will either cost significantly less to implement or result in improved operation of the project works for electricity production.

New FPA section 33 further provides that, following the consideration of alternatives, the Secretary must file with FERC a statement explaining the reasons for accepting or rejecting any alternatives and the basis for any modified conditions or prescriptions to be included in the license. If FERC finds that the modified conditions or prescriptions would be inconsistent with the purposes of the FPA or other applicable law, it may refer the matter to its Dispute Resolution Service (DRS). The DRS is to consult with the Secretary and FERC and issue a non-binding advisory within 90 days, following which the Secretary is to make a final written determination on the conditions or prescriptions.

Since enactment of EPAct 2005, Commission staff has worked with the U.S. Departments of Agriculture, Interior, and Commerce (Departments) to integrate the provisions of section 241 into the Commission's licensing process. We have reviewed the Departments' draft and interim final rules; met with the Departments several times to ensure that the timeframes for the trial-type hearings and alternate conditions and prescriptions fit within the licensing process and to consider how the rules affect pending (transition) and future projects; and commented on schedules for individual transition projects. We continue to coordinate on procedures for notices, for conducting the environmental review process, and priorities for holding hearings and/or considering alternative conditions.

We wish to compliment the Departments for issuing a joint Interim Final Rule in a short timeffame. We are satisfied that the opportunity for a trial-type hearing and the filing of alternate conditions and prescriptions are appropriately integrated into the Commission's licensing time frames. The attached flow chart* shows the integration of section 241 of EPAct into our licensing process. Provided that the timelines established in the Interim Final Rule are met, section 241 will not extend the Commission's licensing schedule.

The Hells Canyon Project No. 1971 is the first case to follow these timelines. Almost 500 terms and conditions and recommendations were received on the relicense application, including land management conditions under section 4(e) of the FPA and fishway prescriptions for federally listed bull trout under section 18 of the FPA. The National Marine Fisheries Service did not require fishways for anadromous fish at this time because of poor upstream water quality, but rather reserved authority to prescribe fishways at a later date. In February 2006, Idaho power filed a request for trial-type hearings with the Departments of Agriculture and Interior and provided alternative license conditions under the Energy Policy Act of 2005 in response to the land management conditions and fishway prescriptions. The administrative law judges' decisions on the trial-type hearings are due July 2006, Our draft environmental impact statement (EIS) is scheduled to be issued in July 2006. Decisions on alternative license conditions are due 60 days after issuance of the draft EIS.

Currently, there are 15 "transition" projects with hearing requests and/or alternative conditions (these are projects for which license applications had been filed when EPAct 2005 was enacted, but with respect to which the Commission had not yet issued a license). The Departments have issued schedules for each of these projects. The attached table shows these transition projects and the Departments' schedules for initiating hearings and filing modified terms and conditions.

Due to a scarcity of Departmental administrative law judges available to hear these cases, the Departments of Interior and Agriculture have stated that they are able to schedule only one hearing per month. We are concerned about the impact these schedules may have upon the Commission's ability to take final action on

*The attachment has been retained in committee files.

these transition cases. For example, for the Priest Rapids Project No. 2114 in Oregon, Interior does not expect to file modified terms and conditions until June 11, 2007. The Commission staff issued its Draft EIS Statement in February 2006 and has scheduled the Final EIS for August 2006. The application is expected to be ready for final Commission action by October 2006. As a result of Interior's bearing schedules and delayed filing of modified terms and conditions, final action on the application could be delayed by eight months or longer. Similarly, for eight of the remaining 14 transition projects, potential delays for taking final Commission action range from six to 14 months. We would hope that the Departments are able to obtain additional staff resources to expedite hearings and the filing of modified terms and conditions for these cases.

Notwithstanding the potential for delays on the transition projects, there have been a number of positive outcomes that we surmise may have resulted from section 241 of EPAct 2005:

For the Priest Rapids Project No. 2114 in Washington State, the licensee challenged the Bureau of Reclamation's (BOR) section 4(e) conditions under EPAct. Subsequently, BOR withdrew its mandatory conditions and refiled them as recommendations pursuant to section 10(a) of the FPA.

For the Upper North Fork Feather River Project No. 2105 and the Poe Project No. 2107, both located in California, the National Oceanic and Atmospheric Administration of the Department of Commerce (NOAA Fisheries) substituted a reservation of authority to prescribe fishways in the future for its previously filed specific section 1 prescriptions.

For the Rocky Reach Project No. 2145 in Washington, the licensee submitted alternatives to Interior's section 18 fishway prescriptions. Subsequently, the licensee and Interior's Fish and Wildlife Service (and others) entered into a comprehensive settlement agreement addressing, among other things, the licensee's fish passage concerns.

As discussed previously, the FPA requires that the Commission authorize projects that are best adapted to a comprehensive plan for improving or developing a waterway for beneficial public purposes, including power generation, irrigation, flood control, navigation, fish and wildlife, municipal water supply, and recreation, giving equal consideration to developmental and non-developmental values. Based upon the above examples, it appears that section 241 of EPAct 2005, which more closely aligns the criteria that the agencies must use in formulating mandatory conditions with the Commission's "equal consideration" criteria for licensing projects under the FPA, is already reducing conflict between mandatory conditions and the conditions the Commission finds reflect the public interest.

In addition, the above examples seem to indicate that EPAct 2005 has provided an increased incentive for agencies to provide cost-effective and factually supported mandatory conditions and has encouraged greater interaction between the resource agencies and the licensees in the development of environmental measures. EPAct 2005 has added a degree of accountability that previously did not exist, and the federal resource agencies are making a laudable effort to comply with Congress' mandate. I believe this will result in mandatory license conditions that are fairer and more balanced.

A second important aspect of EPAct 2005 is section 1301 of Title XIII Subtitle A, which provides for renewable energy tax credits for incremental energy gains from efficiency improvements or capacity additions to existing hydroelectric facilities placed into service after August 8, 2005 and before January 1, 2008.

Under that section, the Commission certifies the "historic average annual hydropower production" and the "percentage of average annual hydropower production at the facility attributable to the efficiency improvements or additions of capacity" placed in service after August 8, 2005 and before January 1, 2008.

We have issued a guidance document to help our licensees seeking tax credit certification. The document, which is posted on our web site, explains what information our licensees need to provide for our review and evaluation to certify incremental energy gain. We have also disseminated information about the tax credit at national conferences throughout the country, to encourage efficiency upgrades.

These efforts have resulted in licensees initiating evaluation of possible upgrades at their projects. At this early stage, the Commission has already received 4 applications for a total capacity increase of about 17 megawatts that may qualify for the credit.

Thank you. will be pleased to answer any questions you may have.

Senator CRAIG. Mark, thank you very much.

Now let me introduce Larry Finfer, Acting Director, Office of Policy Analysis, Department of the Interior. Welcome before the committee.

**STATEMENT OF LAWRENCE FINFER, ACTING DIRECTOR, OFFICE OF POLICY ANALYSIS, DEPARTMENT OF THE INTERIOR**

Mr. FINFER. Thank you, Mr. Chairman. Mr. Chairman and members of the committee, thank you for the opportunity to testify on the implementation of section 241 of EPAct. I would like to make brief remarks and request my full statement be included in the record.

In issuing new licenses, it is important to ensure the significant natural resource and Indian tribal asset safeguards are in place. These are addressed in mandatory conditions and prescriptions that are developed by the Departments of Agriculture, Commerce, and the Interior and submitted to FERC for inclusion in a license.

Historically, agencies have found it necessary to develop such conditions or prescriptions in a distinct minority of licenses. While intended to protect fish, wildlife, and other resources, we recognize they often entail additional costs for utilities and consumers. Licenses may be granted for 30 to 50 years, so it is important to consider all relevant facts and issues and potential alternatives by which to achieve the intended goals.

Section 241's implementation presented our three Departments with significant challenges. I am pleased to report we are meeting them and we believe we have a process that meets your expectations.

Our first challenge was to promulgate rules for the trial-type hearing process. EPAct required the Departments to establish rules jointly within 90 days in consultation with FERC and to include provisions for the opportunity to undertake discovery and cross-examine witnesses. It limited the length of hearings to 90 days and their scope to disputed issues of material fact.

We formed an inter-agency team to draft the rules and consulted with FERC, whose staff was accessible and helpful and approved the final product. The main task was to create a process with a notably more rigorous time frame than usual for administrative appeals in order to comport with the time frame under which FERC must complete licensings.

The Departments published the rules on November 17, 2005, as interim final rules with a request for comments. In publishing the rules, we indicated we would review the comments received and our initial experience in implementing the new process and consider issuing final rules in about 18 months. The rules set forth an efficient process for hearings and procedures for considering alternatives. Under the rules any party to a proceeding may request a hearing or submit alternatives. Hearings will be conducted by administrative law judges. Agencies have the option to consolidate hearing requests into a single proceeding. Once a hearing request is received, parties may file responses and/or notices of intervention, after which agencies file answers to the requests. In the answer, an agency may stipulate to some or all of the facts, which may preclude the need for a hearing on some or all issues. It may also consider whether an alternative should be accepted and of doing so might preclude the need for a hearing. If more than one agency receives a hearing request, they jointly determine whether to consolidate and who should hear the case.

This pre-docketing phase takes 90 days, after which the 90-day hearing clock begins. The 90-day hearing phase provides for discovery and other essential steps, followed by the hearing, post-hearing briefs, and the ALJ's decision, which is binding with respect to the facts. The hearing is timed to occur prior to FERC's issuance of a joint NEPA document in order to assure the results are considered in a manner that reduces licensing delays. We will strive to ensure deadlines are met.

After the rules were published, parties to proceedings with proposed conditions and prescriptions had until December 17 to request hearings or propose alternatives. We received 19 requests covering 17 projects, all of which were submitted by license applicants, and we consulted among ourselves and with FERC to develop schedules. Since then, new requests were received for the Hell's Canyon and Klamath projects. Klamath is the first for which requests for hearings and alternatives were received from parties in addition to license applicants.

The first hearings will address the Hell's Canyon and Klamath projects. The current schedule calls for hearings on Hell's Canyon to be conducted in June and decisions by the respective ALJ's in July. The Klamath schedule is expected to result in hearings by Commerce and Interior, unless a decision is made to consolidate, in August, with a decision in September. Other proceedings have been scheduled for later this year and in 2007. In some cases, the Departments and involved parties are considering settlements and in two cases settlements have already been achieved and the hearing requests have been withdrawn.

Each agency has identified ALJ's to conduct hearings. Ag and Interior have done so through their respective ALJ offices. Commerce has augmented an existing MOU with the Coast Guard to cover these requests, and training has been conducted.

These initial steps in implementing section 241 are encouraging. We have a process in place to meet Congress's expectations. Cooperation continues to address hearing requests and alternatives. While inter-agency coordination and the consideration of alternatives are not new features, they act to enhance this level of cooperation and resulted in a heightened and more rigorous consideration of alternatives.

Mr. Chairman, I am pleased to answer any questions you may have.

[The prepared statement of Mr. Finfer follows:]

PREPARED STATEMENT OF LAWRENCE FINFER, ACTING DIRECTOR, OFFICE OF POLICY ANALYSIS, DEPARTMENT OF THE INTERIOR

Mr. Chairman and Members of the Committee, thank you for the opportunity to testify on the implementation of Section 241 of the Energy Policy Act, which addresses the process by which Federal agencies develop conditions and prescriptions for hydroelectric licenses issued by the Federal Energy Regulatory Commission (FERC) pursuant to sections 4(e) and 18 of the Federal Power Act.

Hydropower is an important part of our nation's energy infrastructure, providing about 7% of our electricity. By 2018, projects that include almost half of our non-Federal hydropower capacity and cover every region must receive new operating licenses. In issuing new licenses, it is important to ensure that significant natural resource and Indian tribal asset safeguards are put in place. These concerns are addressed in conditions and prescriptions that are developed by resource agencies, namely the Departments of Agriculture, Commerce and the Interior and submitted to FERC for inclusion in the license.

Historically, agencies have determined it necessary to develop mandatory conditions or prescriptions only in a distinct minority of license proceedings. While mandatory conditions or prescriptions are intended to protect fish, wildlife, and other important resources, we recognize these protections often entail additional costs for utilities and consumers, and that it is important to consider all relevant facts and issues in the decision making process. Since licenses may be granted for periods covering 30 to 50 years, it is important to assure that the full range of issues associated with conditions and prescriptions, and potential alternatives by which to achieve their intended goals, are appropriately assessed.

At the outset, it should be noted that several Congresses examined the conditioning process prior to the enactment of section 241. The new statute reflects Congress's desire to ensure that resource agency conditions and prescriptions which are included in hydroelectric licenses are carefully formulated. Further, key provisions of section 241 provide stakeholders with the opportunity to raise concerns about the basis of proposed conditions and prescriptions and to propose alternative approaches.

The implementation of Section 241 presented the three departments that have authority to file conditions and prescriptions, the Departments of Agriculture, Commerce, and the Interior, with significant challenges. I am pleased to report that we are meeting them, in large measure through the enhanced interagency coordination that Congress intended. Although we are still in the early stages of implementation and pre-hearing processes have just begun in the first two cases, the agencies have developed a process that meets Congress's expectations. We further believe that the Act highlights the importance of enhanced interagency cooperation and a high level of integrity in the agencies' conditions and prescriptions.

The first major challenge we faced was the promulgation of rules to set forth the trial-type hearing process outlined in sections 241 (a) and (b). The Act required the three Departments to establish rules jointly within 90 days, in consultation with the Federal Energy Regulatory Commission (FERC) and to include specific provisions for the opportunity to undertake discovery and cross-examine witnesses. It further limited the length of hearings to 90 days and limited their scope to disputed issues of material fact.

The Departments formed an interagency rulemaking team immediately upon the Act's approval by the President on August 8, 2005, in order to develop an adjudicatory process that met the Act's requirements. In so doing, the agencies consulted with FERC, whose staff was accessible and helpful, and approved the final product. The most substantive challenge was the need to create an adjudicatory process that assumed a notably more rigorous time frame than normally occurs for administrative appeals. This is essential to ensure that hearings comport with the time frame under which FERC must complete the licensing process. FERC sets forth licensing schedules under its rules to meet Congress's expectations for prompt completion of licensing actions.

The three Departments published their rules in the Federal Register on November 17, 2005, as interim final rules with a request for comments. The rules, which are substantively identical, set forth an efficient process for the hearings. In addition, the rules also establish procedures for considering alternative conditions and prescriptions submitted by any party to the licensing proceeding. Under the rules, any party to a license proceeding may request a hearing on contested material facts and/or submit alternative conditions and prescriptions for assessment by the agencies. Hearings will be conducted by Administrative Law Judges (ALJs). The rules provide the respective Departments with the option to consolidate hearing requests for a particular license into a single proceeding that is conducted by one agency. Further, the rules allow hearing requests and alternatives to be filed for ongoing license proceedings where FERC had not issued a license as of November 17, 2005, as well as for those initiated after its publication. In publishing the rules, the agencies indicated that they would consider the comments received and their initial experience in implementing the new processes, and consider issuing revised final rules within approximately 18 months.

The rules outline a rigorous process, beginning with the submission requirements for hearing requests and proposed alternatives. Once a hearing request is received, license parties may file responses and/or notices of intervention within 15 days, and agencies may file answers to the hearing request within the next 30 days. In formulating its answer, an agency may stipulate to some or all of the facts at issue, which may preclude the need for a hearing on some or all issues. In addition, it may consider whether an alternative condition or prescription should be accepted, and whether doing so might preclude the need for a hearing. If more than one agency receives a hearing request in a given case, the agencies will jointly determine whether to consolidate any hearings and, if so, determine whose ALJ will hear the case. This pre-docketing phase takes about 80 days to complete, after which the case is formally referred to an agency's hearings office for docketing, at which point the 90 day hearing "clock" begins.

The 90 day hearing phase provides for discovery, pre-hearing conferences, pre-hearing motions, confirming witness lists, preparing exhibits and testimony, and the actual hearing, which is followed by the filing of post-hearing briefs and ultimately the decision by the ALJ. The ALJ's decision is binding with respect to the facts at issue. The hearing is timed to occur prior to FERC's issuance of a draft NEPA document, in order to assure that the results are considered in a manner that reduces the probability of delay in the overall license proceeding. The Departments will strive to ensure the deadlines are met.

After the agencies promulgated the rules, parties to proceedings that already had proposed or modified conditions or prescriptions had until December 17, 2005, to request hearings and/or propose alternatives. The agencies received 19 requests (covering 17 projects), and all of these were submitted by license applicants:

Agriculture (Forest Service)—11;
Commerce (NMFS)—2;
Interior—6

Agencies have consulted among themselves and with FERC to develop schedules for addressing these requests. In addition, new requests have been received within the past few months for the Hells Canyon and Klamath projects. The latter project is the first for which requests for hearings and the consideration of alternative conditions or prescriptions have been received from parties in addition to license applicants. Based on the schedules that have been established, the first hearings will address the Hells Canyon and Klamath projects. The current schedule calls for individual hearings on the Hells Canyon Project to be conducted by Agriculture and Interior in June and decisions by the respective ALJs in July. The Klamath Project schedule is expected to result in hearings by Commerce and Interior (unless a determination is made to consolidate the proceedings) in August with a decision in September. Several other proceedings have been scheduled for later this year and in 2007. It is important to note that in several cases the Departments and involved parties are considering settlements that may preclude the need to pursue the requested proceedings. In two cases, settlements have already been achieved, resulting in the withdrawal of the hearing requests by the project applicants.

As noted above, the three agencies made completion of the joint rules a high priority. This high level of attention continues as we implement section 241. Each agency has identified ALJs for potential availability to conduct hearings. In Interior's case, the Office of Hearings and Appeals has four ALJs, and in the Fiscal Year 2007 President's Budget requested an additional $400,000 to support an additional ALJ and a staff attorney. Agriculture's Office of Administrative Law Judges has designated three ALJs who may be available. Commerce does not have an ALJ office, but the agency has augmented an existing Memorandum of Understanding with the Coast Guard, whose ALJs now conduct hearings for NMFS in other types of cases, to cover section 241 requests. In addition, a number of training sessions have been conducted for agency program specialists, attorneys and ALJs, and additional training is anticipated.

These initial steps in implementing section 241 are encouraging. The agencies have put in place an expedited process to meet Congress's expectations. The cooperation among the agencies that occurred to complete the rulemaking has continued as we address hearing requests and proposed alternative conditions and prescriptions. It is important to note that interagency coordination and the consideration of alternatives are not new features. The Departments of Agriculture, Commerce, and the Interior have always coordinated among themselves and with other parties in exercising their authorities under the Federal Power Act, and in so doing considered alternatives by which to meet their objectives. Nevertheless, the Act has enhanced the level of cooperation among the agencies, as well as a resulted in a heightened and more rigorous consideration of alternatives. Further, it underscored the need for careful deliberation, justification, and documentation with respect to the formulation of conditions and prescriptions.

In summary, the agencies believe we have an expedited process in place, and have developed strategies to comply with the Act's requirements. Since we are still in the early phase of implementation, and have yet to conduct a hearing or undertake an assessment of proposed alternatives, it is obviously too early to claim success. Indeed, our experience will indicate whether changes to the rules or to our management of the new process are required. Rest assured, however, that the agencies, having already demonstrated the commitment to implement section 241, will persevere to achieve positive results. Thank you for your consideration. I will be pleased to answer your questions.

Senator CRAIG. Larry, thank you very much for that testimony.

Now let us turn to Dan Adamson, vice chair, Legislative Committee, National Hydropower Association here in Washington. Dan, welcome.

**STATEMENT OF DAN ADAMSON, VICE CHAIR, LEGISLATIVE AFFAIRS COMMITTEE, NATIONAL HYDROPOWER ASSOCIATION**

Mr. ADAMSON. Good afternoon, Senator Craig, Senator Bingaman, and Senator Thomas. I am Dan Adamson. I am an attorney with the law firm Davis, Wright, Tremaine. I am here today to testify on behalf of the National Hydropower Association, NHA. Our statement has also been endorsed by the Edison Electric Institute, American Public Power Association, and NRECA.

Before I get into my statement, Senator, just on behalf of NHA and the other trade associations, we want to thank you for the efforts you have made. It took almost 10 years to get this enacted and I think you did an extraordinary job and it is a textbook example of how to get legislation passed on a very politically and technically complex subject. So we really appreciate what you have done, as well as that of all the other Senators and House members that made this possible.

Licensing reform was needed because there were serious problems, as you have referred to, with the exercise of mandatory conditioning authority. The gist of the problem was this. If an agency issued a mandatory condition that either was not supported by the facts or ignored another more cost-effective alternative, the licensee or any other party essentially had no recourse. That would just go into the license.

I will give you one example. There is a project in Washington State called Box Canyon. In that case, which was pretty recent, the Fish and Wildlife Service prescribed fish passage for bull trout. That sounds good. The only problem is the field surveys all indicated there were no bull trout there. So the licensee had no recourse. Just as an example, establishing fish passage for fish that do not exist does not do anything for the environment. All it does is impose costs on ratepayers.

NHA and its partners strongly support the interim rule that Larry Finfer and his colleagues and Mark Robinson and others put together to implement the new law. We think for the most part it really does a good job of being consistent with congressional intent. There are three provisions I want to highlight.

First, they decided that the new reforms would apply to pending licensing proceedings. That was critical. If they had not done that, this law would essentially have no impact for about 5 years, and I do not think that is what Senator Craig or any of the other people that worked on this intended.

They also clarified that the reforms apply to the exercise of reserve conditioning authority, which happens a lot. They also put independent ALJ's in charge of deciding whether or not a party has a right to a hearing. That is turning out to be very important.

We do have a few concerns about the rule, however. The first is the rule provides for hearings on preliminary conditions, which are not the conditions that will actually be imposed on you as a licensee. So our preference would be that those hearings be on the final conditions because those are the ones that are actually going to apply if they go through.

Another concern is we think it is very important to clarify that the new equal consideration requirement applies to all mandatory conditions.

Finally, as far as the trial-type hearing, we are concerned that the timetable for the hearing is so tight and inflexible that when you hit a very complex proceeding with literally hundreds of factual issues it may be difficult to make the process work well.

So although we are generally very happy with what the Departments have done and we think, considering the amount of time they had, it was really an extraordinary accomplishment, we would like to see a revised rule issued later this year to fix these problems and some others. Now that the rule has been issued, we are into early implementation and, as has been mentioned, a number of licensees have filed requests for alternative conditions and requests for a hearing. But we are still in an early stage. None of the alternative conditions have been acted on and only one hearing, the Hell's Canyon hearing that you referred to, has just started.

Nevertheless, the early indications from our standpoint are positive. It looks to us like the Departments are trying to be more thorough and careful in their preparation of their conditions and make sure they are supported by the facts. That is very good news and that is consistent, I think, with the congressional intent.

Just to mention one company, Avista Corporation, which has a project in Idaho and Washington State called Post Falls, Spokane River. They are trying to settle, as they always have. They settled in other hydro proceedings. But if they are not able to settle, these hydro reforms offer kind of an alternative path forward for them and many other licensees that is very positive.

I just want to give a quick plug for extending the production tax credit for incremental hydro. This is very important to a lot of NHA's members and it is key to developing new hydro, and unfortunately the time frames in the current law are not well suited to hydro, which is a long lead time development.

In conclusion, the hydro reforms are really making a difference. It is very positive. They are going to result in more economic energy production, they are going to preserve the environment, in some cases improve environmental protection. We really commend you, Senator Craig, and all the other folks that have worked on this legislation. Thank you very much.

[The prepared statement of Mr. Adamson follows:]

PREPARED STATEMENT OF DAN ADAMSON, VICE CHAIR, LEGISLATIVE AFFAIRS COMMITTEE, NATIONAL HYDROPOWER ASSOCIATION

INTRODUCTION

Good afternoon, I am Dan Adamson, Partner with the law firm of Davis Wright Tremaine LLP and a Vice Chair of the Legislative Affairs Committee of the National Hydropower Association (NHA).[1] Though I appear before this Committee today on behalf of NHA, our statement has been endorsed by the hydroelectric industry coalition, including the Edison Electric Institute (EEI), the American Public Power Association (APPA), and the National Rural Electric Cooperative Association (NRECA).

NHA and its coalition partners strongly support the hydroelectric provisions included within the Energy Policy Act of 2005 (EPAct 05)—both the hydropower licensing reforms and the inclusion of certain hydropower development in the tax incentive provisions.

NHA appreciates this opportunity to testify on behalf of the hydroelectric industry regarding the hydroelectric provisions within EPAct 05. Our message this afternoon is simple—while we are still in the early stages of implementation, there is no question that the hydroelectric provisions included within EPAct 05 are having a positive impact. To date, 10 companies have availed themselves of the new licensing tools in 18 different hydropower project relicensings. We anticipate others will take advantage of these opportunities in the coming months. Agencies appear to be rethinking their approach to conditioning projects, and incremental hydroelectric generation is being built. The EPAct 05 licensing reforms and the tax provisions are making a difference.

We commend Congress for passage of these provisions and believe they will result in increased energy production and energy savings, all while preserving important environmental values. These are important goals, particularly now as our nation struggles to find near and long-term solutions to the problem of the high price of natural gas and oil.

We deeply appreciate Senator Craig's longstanding and effective leadership on the hydroelectric licensing reform issue. For nearly a decade, Senator Craig has worked with colleagues on both sides of the aisle to address serious problems inherent in the licensing process. We also thank Chairman Domenici for his leadership, as well as Senators Ben Nelson, Smith, Cantwell and Feinstein who worked with Senator Craig, and their House counterparts, to find a bipartisan solution that was included in EPAct 05. The compromise guarantees equal access to the new reforms for all of those involved in the hydroelectric licensing process. In addition, we are appreciative of Senator Smith's leadership on the Finance Committee in securing the inclusion of certain new hydropower development in the renewable energy production tax incentive provisions of the Internal Revenue Code.

While it was a long road to enactment, the effort was well worth it because the provisions adopted by Congress in 2005 are a major improvement in the hydroelectric licensing process. The provisions will help to preserve the viability of our nation's domestic hydropower resource. Hydropower is an emissions-free technology that provides significant environmental, economic and energy security benefits to the nation, supplying the country with seven percent of our electric generation and 85 percent of our clean renewable energy.

## NEED FOR LICENSING REFORM

Legislative reform of the hydroelectric licensing process was needed because of problems that existed with respect to the exercise of mandatory conditioning authorities under Sections 4(e) and 18 of the Federal Power Act (FPA) by the Departments of Interior, Commerce and Agriculture (Departments). Although the Federal Energy Regulatory Commission (FERC) issues hydroelectric licenses and is in charge of the overall process, FERC generally has no authority to modify or reject the conditions imposed by the Departments, and licensees had no avenue to challenge the scientific bases of mandatory conditions other than seeking judicial review of a FERC license order in the federal Court of Appeals.

The broad authority of the Departments to impose conditions without necessarily considering either their impacts on energy production and other project benefits or cost-effectiveness has led to serious problems. For example, the National Marine Fisheries Service insisted on proposing a mandatory fish passage requirement on the Enloe Dam Project, rendering it uneconomic even though such passage was opposed by a fish and wildlife agency, an Indian Tribe and the Canadian government. Salmon had not historically accessed the stream above the existing dam and introducing this species could also transmit diseases that would harm resident fish. Simi-

[1] NHA is a non-profit national association dedicated exclusively to advancing the interests of the U.S. hydropower industry. The association represents 61 percent of domestic, non-federal hydroelectric capacity and nearly 80,000 megawatts overall in North America. Its membership consists of more than 140 organizations including public utilities, investor-owned utilities, independent power producers, equipment manufacturers, environmental and engineering consultants, and attorneys.

larly, in the recent relicensing of the Box Canyon Dam, the U.S. Fish and Wildlife Service insisted on a mandatory condition requiring fish passage for bull trout even though extensive field research indicated that there were no bull trout attempting to pass the Box Canyon Dam.

FERC has made significant strides to improve the hydroelectric licensing process, including the newly implemented "Integrated Licensing Process" (ILP). However, FERC is generally without the authority to address problems associated with mandatory conditions issued by the Departments under Sections 4(e) and 18 of the FPA. Several years ago, the Departments undertook initial steps to improve the mandatory conditioning process. A federal advisory committee was formed and a series of meetings was held. In addition, the Department of Interior initiated a rulemaking in September 2004 to establish an agency administrative appeal process. However, neither of these actions addressed the essence of the problem—the imposition of mandatory conditions that were not cost effective and/or not supported by the facts. The appeals rulemaking was a positive step and our industry supported it. However, a final rule was never issued. This further confirmed that legislative reform was needed to improve the mandatory conditioning process.

COMMENTS ON THE DEPARTMENTS' INTERIM FINAL RULES IMPLEMENTING THE EPACT 2005

When Congress enacted EPAct 05 last year, it directed the Departments of Interior, Commerce, and Agriculture to issue a joint rule within 90-days to establish "procedures for such expedited trial-type hearings . . ." In response, the Departments issued interim final rules on November 17, 2005. The agencies requested public comment on the rules and indicated that revised rules may be issued in 2007 based on the comments received as well as the experience gained from real world application of the provisions.

NHA submitted joint comments with the Edison Electric Institute on the interim rule on January 17, 2006. Our comments are attached to our statement as Appendix A [1a] and we ask that they be made part of this hearing record. NHA strongly supported the agencies' rules. In particular, we endorsed provisions making the trial-type hearing and alternative conditions processes applicable to pending licensing proceedings where no license had been issued as of November 17, 2005. Further, NHA supported the Departments' clarification that the rights to propose alternative conditions and to a trial-type hearing apply to the exercise of reserved conditioning authority. We believe that any other approach would undermine the intent of Congress because it would establish a mechanism by which the Departments could avoid their Section 241 obligations by simply deferring the exercise of their authority until after final issuance of the license. We believe these provisions were necessary to implement the new law as Congress intended.

In addition, we applaud provisions in the rules that mandate that the administrative law judge ("ALJ") determines whether there are disputed issues of material fact, and that the ALJ's factual findings are final. We believe that these provisions will help prevent agency staff, who may be proponents of a mandatory condition, from unduly limiting access to the trial-type hearing process. Treating the All's findings of fact as conclusive should assure that the relevant conditions/prescriptions issued by the Departments are supported by the facts.

Despite our strong support for some of the provisions of the interim final rules, NHA does have serious concerns about certain other provisions contained within the interim rules. Primary among these concerns is the rules' lack of clarity regarding the "equal consideration" standard. Section 231 of EPAct 05 requires that agencies demonstrate in writing that they gave equal consideration to the effects of a mandatory condition on energy supply, distribution, cost and use, flood control, navigation, water supply and air quality, for every condition submitted to FERC. NHA views the equal consideration provision as one of the most important licensing improvements within EPAct 05. We strongly believe that the equal consideration requirement applies to the development of all mandatory conditions. However, the Department of Commerce, in a licensing proceeding concerning a project in Augusta, Georgia, has taken the position that "equal consideration" only applies to their mandatory conditions if an alternative condition is submitted. We believe that Commerce's interpretation is in conflict with the plain language of Section 241 and must be reversed. NHA also believes that the Departments need to clarify the interim final rules to make clear that the equal consideration requirement applies to all mandatory conditions, preliminary and final, regardless of whether alternatives are offered.

[1a] The appendix has been retained in committee files.

In addition, NHA is concerned that the interim rules do not provide for a trial-type hearing of up to 90-days as required by Section 241. We believe that the hearing schedule simply will not provide the opportunity to develop an adequate factual record as well as provide due process in many proceedings where there are a multiplicity of highly complex issues. Moreover, we are troubled that the interim final rules provide for a trial-type hearing on preliminary conditions, rather than final conditions.[2] NHA believes this clearly conflicts with the intent of Section 241. We believe conducting hearings on preliminary conditions, which are not necessarily the conditions that the Departments will ultimately seek to impose on a license applicant, is an inefficient use of the resources of the Departments, license applicants, and other parties. Instead, providing the right to a trial-type hearing on final conditions would be much more efficient and would ensure that the license applicants only utilize a trial-type hearing after all other avenues are exhausted.

In light of these concerns as well as other issues raised in our comments on the interim rules, NHA recommends that the Departments issue revised final hydropower rules no later than November 1, 2006, in order to better ensure that the full benefits of the hydroelectric licensing reforms enacted by Congress are obtained.

EARLY EXPERIENCE WITH THE LICENSING PROVISIONS

Since the passage of EPAct 05, the hydropower industry has embraced the use of the trial-type hearing and alternative condition provisions. Ten companies have filed to either offer alternatives and/or request a trial-type hearing involving the licensing of 18 projects. The Departments have yet to act on any requests for alternative conditions and only one trial-type hearing process has begun to date. The general sense of the industry is that Section 241 appears to be causing the agencies to exercise more care in the preparation of license conditions and to perhaps refrain, in some instances, from proposing conditions that are not supported by the facts. This, of course, is a very positive development.

The posture of one of our member companies, Avista Corporation, is typical. Because of EPAct 05, the company has the option of filing a request for a trial-type hearing and/or alternative conditions in the Spokane River/Post Falls Projects relicensing proceeding. Avista has expended a great deal of effort working to achieve a settlement in this proceeding and it continues to pursue every settlement opportunity that presents itself. However, if these efforts do not bear fruit, EPAct 05 provides Avista and all of the other participants in the Spokane River/Post Falls relicensing process an alternative means of resolving differences through either alternative conditions and/or a trial-type hearing. Avista believe this adds valuable flexibility and scientific rigor to the relicensing process that significantly increases the likelihood of positive relicensing outcomes.

Since the interim hydropower licensing rule went into effect on November 17, 2005 license applicants have filed 17 requests for trial-type hearings, in 13 project relicensings. Hearing requests have been filed before all three agencies—Interior, Agriculture and Commerce. The majority of the trial type hearing requests have been filed before the U.S. Forest Service within the Department of Agriculture (eight of 17), six have been filed at the Department of the Interior, and three before the National Marine Fisheries Service.

License applicants have also offered alternative conditions in 18 project relicensings. In twelve projects alternatives were offered in response to mandatory conditions proposed by the U.S. Forest Service within the Department of Agriculture. In seven projects alternatives have been offered in response to conditions proposed by the Department of the Interior, and in three projects alternatives have been proposed to the National Marine Fisheries Service in the Department of Commerce.

As these numbers clearly demonstrate, the licensing reform provisions addressed a significant need. These new tools are important and the industry is making full use of them. However, we are still in the very early stages of implementation of these provisions. NHA encourages this Committee to continue its oversight and recommends that another hearing next spring may be appropriate to review the experience of licensees, the agencies and stakeholders.

[2] The American Public Power Association, in its comments on the rules, approached the trial-type hearing procedure differently. Though not objecting to a hearing on preliminary conditions, APPA asked the Departments to clarify that a hearing on a final condition is allowed if the final condition submitted differs substantially from the preliminary condition and/or relies on different material facts.

INCLUSION AND EXTENSION OF HYDROPOWER PRODUCTION INCENTIVES

While not the main focus of this hearing, it is critical to note the importance of the tax provisions included in the Act. We are particularly appreciative that EPAct 05 expanded the definition under the Section 45 production tax credit (PTC) to recognize certain new hydropower projects as eligible renewable resources. The credit for hydropower is 0.9 cents per kilowatt hour. In addition, for tax-exempt entities, EPAct 05 created a new category of clean renewable energy bonds (CREBs) that provide a financial incentive for public power, electric co-ops and others to issue modified, interest-free bonds to build qualified renewable energy projects.

The PTC needs further revision to fully achieve its intent to bring new, clean electric energy online. Because of the time constraints placed on this program, its usefulness to industry is unnecessarily limited. The PTC limits application only to those projects that are placed in service by January 1, 2008. In many instances, this tight window of time does not give the hydropower industry the opportunity to license, site, and construct a qualified hydropower energy resource. Under good circumstances securing license amendments can take six months or more, designing and fabricating one-of-a-kind hydroelectric generators can take two to three years, and installation can take another year or more. Realistically, for licensees to take advantage of the PTC, the placed in service date needs to be extended this year through at least 2010, or longer, in order for anything close to the full potential to be realized.

In addition, the amount of the Section 45 PTC for qualifying hydropower energy resources is at a level that is only one-half the level of most other renewable energy resources. NHA believes that new qualifying hydropower resources should receive the same tax benefit as other renewable resources, such as wind power.

The clean renewable energy bond program functions somewhat differently from the PTC. The Energy Policy Act of 2005 provided $800 million of authorization for CREBs from January 1, 2006 through January 1, 2008. Although authorized for two years, the $800 million authorization is already oversubscribed by well over a billion dollars. Congress should extend the program immediately and ensure that it is funded at levels sufficient to unlock pent up demand among not-for-profit utilities to finance new hydropower projects.

Despite the limitations, some projects have been able to utilize these provisions. To date, FERC has received two requests from licensees to certify incremental hydropower for eligibility for the PTC, which will result in a 2.6 percent and 6.4 percent increase in generation for those projects. In addition FERC has recently received four license amendment applications for additional capacity totaling 17 megawatts, which may qualify for the credit. A number of companies have also applied for clean renewable energy bonds for hydropower.

For the most part, these companies were able to use the provisions for these projects because they ordered equipment and began the license amendment process well in advance of the enactment of EPAct 05. These companies took a financial risk that few companies are capable of undertaking. We know of many utilities and developers that are forgoing the development of clean, incremental hydropower either because of insufficient funding for the CREBs program or because they cannot meet the deadlines of the PTC or CREBs programs. As a result, our nation loses the opportunity to develop more emissions-free, domestic energy at a time when we need it the most. This simply does not make sense and we urge this Committee to work with the Senate Finance Committee to revisit, extend and revise these tax provisions.

CONCLUSION

While it remains early in the implementation phase, the hydroelectric provisions contained within EPAct 05 have begun to make a difference. Hydropower owners are using these provisions in a responsible way to improve licensing outcomes that will result in more economic energy production while preserving environmental values. The National Hydropower Association commends Congress for its enactment of these provisions, and we look forward to working with you to ensure their effective implementation.

Finally, we again thank you, Mr. Chairman, and many of the members of this Committee, for your leadership, perseverance, and steadfast support to make significant improvements in hydropower policy that will preserve our nation's hydroelectric resource while protecting our nation's rivers.

Thank you.

Senator CRAIG. Dan, thank you for that testimony.

Now let us turn to Andrew Fahlund, vice president of protection and restoration, American Rivers. Andrew, welcome to the committee.

**STATEMENT OF ANDREW FAHLUND, VICE PRESIDENT FOR CONSERVATION, AMERICAN RIVERS, STEERING COMMITTEE MEMBER, HYDROPOWER REFORM COALITION**

Mr. FAHLUND. Thank you very much. Mr. Chairman, distinguished members: Good afternoon and thank you for inviting me to testimony at this important oversight hearing. My name is Andrew Fahlund and I am vice president for conservation programs with American Rivers, the leading national voice for rivers and river communities. I am also a member of the Steering Committee of the Hydropower Reform Coalition, a consortium of 130 groups from around the Nation whose common goal is ecological and recreational enhancement at hydropower dams.

American Rivers staff have logged hundreds of hours collaborating with utilities, agencies, American Indian tribes, and others to improve the efficiency and effectiveness of the hydropower licensing process. These actions speak to the fact that we are not obstructionists, opposed to change. We are advocates for efficiency, fairness, and of course strong protections for public trust resources.

Over the course of the debate surrounding the energy bill, American Rivers stated its consistent opposition to the hydropower title, cautioning that the proposed hydropower provisions would bias the process in favor of licensees who have vastly more resources than other parties. We also cautioned that it would lead to a steady erosion in the implementation of many vital and important environmental conditions.

Although proponents claimed that the energy bill did not eliminate so-called mandatory conditions, fish passage, and protections for public lands, we warned that the imposition of overwhelming red tape on resource agencies and a hideously litigious process would provide enough incentive to curtail their use. While it is still early to be certain what the outcomes will be on many of these proceedings, it appears that our fears were not unreasonable. The mere request for a trial-type hearing, no matter how trivial, imposes a significant burden on all stakeholders, including the agencies. Each party must gather evidence, line up witnesses, file interventions, meet onerous and complex service requirements, hire costly lawyers, and begin pretrial discussions, all within a few short weeks.

Most licenses used to be decided through negotiation and settlement. These new rules mark the beginning of a war of attrition, one that will divert time and attention from negotiation and settlement toward litigation. The new process is extremely burdensome for agencies, which have been granted no additional time to participate in trial-type hearings. The alternatives process requires Federal resource agencies to consider 11 new factors in developing their environmental conditions. Congress needs to appropriate additional funding to the agencies to ensure that they can carry out these new mandates.

Thus far there has been a proverbial gold rush of requests for this sort of administrative litigation, with high-priced lawyers appearing to be the only ones guaranteed to benefit. There have been 13 requests for hearings, addressing roughly 100 separate disputes, and dozens of requests for alternative conditions. The rules invite hearing requests, trial-type hearing requests, that are not disputes over material facts, but are instead disputes over policy and law. Industry seems to consider almost anything these days a material fact.

FERC, which has a process of requesting trial-type hearings on disputed issues of material fact, has the ability to screen whether a request is worthy of a trial or could be resolved through a paper process. We strongly urge the agencies to adopt similar discretion, that they strictly limit hearings to true disputes over facts, and that Congress support those changes.

The FERC process was already complex, but with the passage of the Energy Policy Act 47 more pages were added to the rules. These rules establish a set of steps, timelines, and requirements so complex that license applicants, agencies, and non-governmental organizations alike are struggling to understand and comply with them, and it is no wonder. The agencies moved forward with implementing the new rules without any consideration of any public comment from any party. The so-called interim final rules are not even complete. The rules fail to answer who has the burden of proof in a trial-type hearing, the hearing requester or the agency that proposed the conditions. This is fundamental. The rules seek comments on this question, ignoring the fact that perhaps dozens of trial-type hearings will take place before the rules are re-issued. Hearing examiners will have to determine the burden of proof on an ad hoc basis during that period. In FERC's trial-type hearings, as in all administrative law, it is the hearing requester that has that burden of proof. We continue to urge the agencies to follow FERC's lead and for Congress to support them.

I would like to commend the Senate Energy and Natural Resources Committee and you, Mr. Chairman, for exercising your oversight role and urge you to maintain this oversight to prevent the loss of reasonable and important environmental conditions to red tape, litigation, and political pressure. The committee also must ensure that the new process for hydropower licensing is adequately funded. Dams whose licenses expire today have never been subject to modern environmental laws. Hydropower licensing is a once in a lifetime opportunity to bring a 19th century technology up to 21st century standards. We hope that these rules and this law will not stand in the way of that.

Thank you.

[The prepared statement of Mr. Fahlund follows:]

PREPARED STATEMENT OF ANDREW FAHLUND, VICE PRESIDENT FOR CONSERVATION, AMERICAN RIVERS, STEERING COMMITTEE MEMBER, HYDROPOWER REFORM COALITION

## I. INTRODUCTION

Good afternoon, Mr. Chairman, and members of the Senate Energy and Natural Resources Committee. I appreciate the opportunity to appear before you today and am grateful that the Committee is exercising its oversight role in ensuring the effective implementation of the hydroelectric provisions of Energy Policy Act of 2005 (EPAct, P.L. 109-58). My name is Andrew Fahlund and I am the Vice President for Conservation at American Rivers, the leader of a national river movement, dedicated to protecting and restoring the nation's rivers some of our greatest community assets. American Rivers has more than 45,000 members, from every state across the country and has more than fifty staff members in ten different offices. As a steering committee member of the Hydropower Reform Coalition, I also speak for 130 national and local organizations dedicated to improving rivers through the licensing of hydropower projects by the Federal Energy Regulatory Commission (FERC). Coalition members are active in more than 75 percent of the relicensing cases currently pending before FERC and have constructively contributed to numerous policy discussions concerning FERC regulated hydropower.

More specifically, I am before you today to share the opinions of American Rivers and the Hydropower Reform Coalition on the implementation of the EPAct. My testimony addresses three basic points:

1. Hydropower relicensing significantly improves environmental quality at a negligible cost to power supply.
2. The EPAct rules tilt the scales of justice in the favor of industry and disadvantages states, tribes, local landowners, irrigators, conservation groups, and other interested members of the public who all have interests in how dams are operated.
3. The outcome of the hydroelectric EPAct rules is regulatory complexity, decreased certainty, a lengthened timeline for licensing, increased costs for all parties, and diminished environmental standards.

I would like to stress that hydropower relicensing is a natural resources issue and not simply an energy issue, due to the enormous impacts dam operations have on hundreds of species, thousands of river miles, and millions of dollars in recreational opportunities for decades to come. Changes to dam operations that better conserve natural resources have a negligible impact on energy generation, electric rates, and industry viability.

While hydropower has provided significant benefits to society over the past 100 years, this has not come without a cost to our rivers and the communities they flow through. Dams harm the physical, chemical, and biological function of rivers by disrupting flows, degrading water quality, and blocking passage of fish and other species. Simple changes in the operating procedures for these projects can significantly reduce these impacts without significantly reducing generation.

When the scores of hydroelectric licenses scheduled to expire over the next decade were originally licensed decades ago, meeting environmental standards was not required and our understanding of complex ecological systems was in its infancy. For decades, these projects have operated with minimal environmental controls leading to significant and sometimes irreversible damage. Current relicensing represents our first opportunity to review these dams, reservoirs, and turbines, and to place environmental safeguards on them for the next 30 to 50 years that will improve our rivers and protect fish and wildlife for our children and grandchildren.

American Rivers and members of the Hydropower Reform Coalition wish to ensure that dams are operated to protect and restore river resources using best available technologies and best management practices. Coalition members including American Rivers have been involved in the relicensing of more than 300 dams over the past ten years, supporting the continued operation of more than 9,000 megawatts of electricity capacity. According to FERC, the relicensing of more than 140 hydropower projects resulted in an average per project generation loss of only 1.6%.

The Federal Power Act (FPA), although commonly considered an energy statute, also occupies an important role in environmental protection. The statute was amended in 1986 to require FERC to give "equal consideration" to power (electricity generation) and non-power (fish and wildlife protection, recreation, etc.) benefits of the river. However, Congress did reserve specific authorities to expert federal and state resource managers to establish basic conditions that form a floor above which FERC then establishes license conditions in the public interest. Sometimes referred to as mandatory conditions, the statutory requirements assure that:

1. Fish can be passed upstream and downstream of a dam (FPA Section 18); [1]

[1] Section 18 of the Federal Power Act grants authority to the Secretaries of Commerce and the Interior to mandate the construction and operation of fish passage. Section 4(e) grants authority to land management agencies to ensure that projects on their lands meet current management goals and objectives. These authorities have been upheld by the courts on a regular basis. *Escondido Mutual Water Company et al. v. La Jolla Band of Mission Indians, et al.,* 466 U.S. 765, 777 (9th Cir. 1984) (citations omitted); *Bangor Hydro v. FERC,* 78 F.3d 659 (1st Cir. 1996); *American Rivers v. Federal Energy Regulatory Commission,* 187 F.3d 1007, 1030 (9th Cir. 1999).

2. If a nonfederal dam is located on federally owned land, the purposes of the federal land are protected (FPA Section 4(e));[2] and

3. The dam complies with state-developed water quality standards (Clean Water Act, Section 401).[3]

These laws establish the simple rule that hydroelectric projects must meet basic environmental standards before operating on our rivers. Just as we should not allow coal-fired plants to operate without modern emissions control devices, hydro plants should not operate without use of best available technologies and practices.

### III. SOME IMPROVEMENTS TO THE RELICENSING PROCESS ARE WORKING

For the last ten years, American Rivers and members of the Hydropower Reform Coalition have been working with industry, federal and state agencies, and FERC to make administrative improvements to the hydropower licensing process. We have made steady progress in a number of areas, including federal agency actions and procedures to ensure consistency, timeliness, and coordination. We are concerned that EPAct and its implementing rules threaten and undermine that progress and we ask that the Committee utilize its oversight role to prevent this from happening.

Since 1997, FERC has undertaken two rulemaking efforts to streamline hydropower licensing. The first effort was the Alternative Licensing Process (ALP), established on October 29, 1997, designed to promote collaboration and settlement in hydropower licensing. From 2001 through 2004, of the total 135 licenses issued by FERC, 51 licenses or 38% were settlement agreements. Interestingly, settlements accounted for 71% of the total electrical capacity of licenses issued during that time, or 3,208 megawatts.

Effective October 23, 2003, FERC established a positive new licensing process called the Integrated Licensing Process (ILP), designed to establish a single "integrated" environmental analysis. The proposal was the culmination of work by FERC staff and federal agencies as well as a parallel process initiated by hydropower licensees, conservation groups, state agencies, and Indian tribes. FERC estimates that the ILP will reduce the average time it takes to complete the licensing process by 60%. Further, it estimates that the proposed process will reduce the cost of licensing for a project below 5 megawatts by $150,000 and for a project greater than 5 megawatts by $690,000.[4] American Rivers supports the Integrated Licensing Process.

### IV. THE AGENCIES' EPACT RULES BIAS THE LICENSING PROCESS AND HARM THE ENVIRONMENT

American Rivers and the Hydropower Reform Coalition opposed EPAct because we feared that it would increase regulatory complexity, decrease certainty, lengthen the timeline of license issuance, provide unjust advantages to hydropower dam owners, establish hurdles to the full participation of states, tribes, homeowners, businesses, and other members of the interested public, and diminish environmental quality. Moreover, we expressed repeated concerns that the new provisions of EPAct would undermine the increasingly common practice of local solutions developed through settlement. Rather than spending their time trying to reach resolution, we warned that parties would be forced to take sides, and spend scarce resources and time on drafting legal documents and participating in adversarial hearings. The publication of the new rules, as well as their initial implementation, suggests that our earlier fears were justified.

#### *A. EPAct rules skew the processes to favor licensees*

The EPAct rules are skewed to favor those parties with substantial financial resources. To request a trial-type hearing and propose alternative conditions, one

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[2] More than 400 FERC regulated projects are located on Forest Service, Bureau of Land Management, and tribal lands. These projects have impacts on water resources, recreation, fish and wildlife, and cultural resources and also receive the benefit of below market rent. U.S. General Accounting Office, *Federal Energy Regulatory Commission: Charges for Hydropower Projects' Use of Federal Lands Need to Be Reassessed,* Washington, D.C., May 2003, GAO-03-383, p. 5.

[3] The protection of water quality is a responsibility that has been delegated to the states since the Clean Water Act was adopted 30 years ago. Section 401 ensures that private hydro projects will not conflict with state standards and requires each federally licensed project to obtain a state certification. The Supreme Court confirmed in *PUD No. 1 of Jefferson County v. Washington Dep't of Ecology,* 511 U.S. 700 (1994), that these standards include chemical, physical, and biological parameters.

[4] Commissioner Nora Brownell, Federal Energy Regulatory Commission, Testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, House of Representatives, Washington, D.C., March 5, 12, and 13, 2003.

must act on deadlines as short as 15 days to hire expensive legal counsel and technically skilled witnesses, and gather new data. Only licensees have the financial resources to undertake that process over and over again and at the level of sophistication required for success. Because the agencies must conduct these trials upon request, any party with an interest in the conditions and prescriptions appealed must expend its limited resources to intervene and participate in the trial-type hearing, because the decision of the Administrative Law Judge is final with respect to the disputed issues of material fact (7 C.F.R. § 1.660).

Likewise, the process for requesting alternative conditions favors the license applicant. The entity most likely to file for an alternative condition is the license applicant because the law grants preferential status to alternative conditions that cost significantly less and generate more electricity. The rules however, magnify that inequity by failing to give other interested parties any clear venue in which to comment on the proposed alternatives. For proceedings in which the preliminary conditions or prescriptions were filed after November 17, 2005, the rules imply that comments on alternatives should be filed through comments on FERC's National Environmental Policy Act (NEPA) document. The appropriate venue for comment should be the resource agency, not FERC, since it's the resource agency's alternative conditions.[5] In retroactive cases, those with conditions filed before November 17, 2005 and for which the NEPA documents have already been published, the rules unfairly do not offer a clear avenue for public comment at all. Likewise, in cases in which the resource agency accepts the alternative condition or prescription as its own, the rules provide no clear opportunity for comments or appeals.

In addition to imposing severe hardships on nongovernmental, tribal, and state and local agency license parties, the rules are extremely burdensome for the federal agencies, which have been granted no additional funding authorization to participate in or administer trial-type hearings or to conduct the complex analyses envisioned in the alternative conditions process. According to the rules, the "Departments expect 47 requests for hearings per year under the rules, each requiring about 800 hours of additional work by the requesters and 600 hours for other parties in the hearing process. The Departments expect about 351 alternative conditions and prescriptions to be proposed per year under the rules, each requiring 200 hours of additional work by the proponent and 120 hours for other parties to the alternatives process. Staff costs for 47 hearing requests and 351 alternatives per year are estimated at $5 million." (70 Fed. Reg. at 69815). A worst case scenario is double those amounts. It is clear that the hearings and alternatives processes could easily overrun the licensing process. This Committee should aggressively push for ample funding for agencies to engage in trial-type hearings and conduct the evaluations required in the alternative conditions process.

*B. The EPAct rules invite frivolous filings*

During the debate over EPAct, we warned that the proposed trial-type hearings would invite abuse and a new culture of litigation not seen in the relicensing process for the past decade. Again, the new rules and their initial implementation appear to confirm our concerns. The law requires hearings only on issues of material fact (Section 241(a) of the Federal Power Act), yet the rules require agencies to move forward with initial preparations without even a threshold determination of whether a request for a trial-type hearing raises any such issues (7 C.F.R. § 1.625). Further, the rules fail to grant the resource agencies the authority to determine which issues were appropriate for a trial-type hearing, which could be resolved through paper filings, and which fail to qualify at all as issues of material fact. It is the epitome of government waste to reflexively provide for trial-type hearings without determining whether one is warranted. The costs associated with convening an Administrative Law Judge hearing every time a party files a request will add up and will either result in needless taxpayer expense or surrender by agencies that don't have the resources to respond.

This approach is also unreasonably burdensome for other parties who are forced to respond or live with the results. The mere request for a trial-type hearing, no matter how trivial, will impose a significant financial burden on all stakeholders with an interest in the condition or prescription to gather evidence, obtain witnesses, file interventions, meet onerous and complex service requirements, secure costly representation, and begin pre-trial discussions, all within short deadlines to prepare for a formal adjudicatory hearing that is not allowed and may not be necessary at all.

[5] FERC has a different mandate, balancing interests, schedule, and requirements. (70 Fed.Reg. 69,807, cols. 1 and 2. Also, see: 7 C.F.R. § 1.673)

FERC has the authority to hold hearings on disputed issues, but has largely abandoned the process in lieu of paper filings, except in rare cases, at significant savings of time and resources for all parties. Agencies should exercise similar authority in the rules.

Several requests for trial-type hearings under EPAct already demonstrate the flaws in this automatic-hearing provision. One utility filed a petition for a hearing challenging assertions that were never even made by the agency.[6] In response to another petition for a hearing, the U.S. Forest Service found that 24 of 26 alleged disputed issues of material fact do not qualify as such factual, disputed, and material.[7] Worst of all, some companies have requested trial-type hearings for matters that could be resolved by a simple phone call or meeting. Instead, the implementation of the rules has fostered a culture of litigation.[8]

*C. The EPAct rules make a complex process more so*

At a time when everyone is working to streamline hydropower licensing, the EPAct rules add complexity and confusion to the process. The 47 pages of rules establish a set of steps, timelines, and requirements so complex that license applicants, agencies, and non-governmental organizations alike are struggling to understand and comply with them. For example, the service requirements, which differ among the three relevant agencies establish different rules for serving documents to one group of stakeholders versus another. (7 C.F.R. § 1.612 and 1.613) Agency staff can only be served with paper copies, ignoring the fact that we live in an electronic age. There is no central database or website to track filings or decisions made in the various trial-type hearings.

The regulations are curiously silent on which side has the burden of proof in trial-type hearings or how such hearings will even be run. Although the rules are deemed "final" by the agencies, they still seek public comments on this question, ignoring the fact that perhaps dozens of trial-type hearings will take place before the rules may be re-issued in a year and a half and any clarifications or changes may be made. (70 Fed.Reg. at 69813, col. 3) Common sense and now experience show that this and many other provisions in the rules need such clarification. The agencies could have avoided this ambiguity if they had simply taken the time for a meaningful notice and comment process prior to issuance and implementation of an interim final rule.

The alternatives process mandated by EPAct in Section 241 adds complexity through the mandate that federal resource agencies consider eleven new factors in developing their environmental conditions. Consideration of these factors places an enormous burden on the resource agencies. At present, the relevant state and federal agencies do not have sufficient staff or funding to meet these proposed requirements for new, complex analyses which are beyond historic scope of their resource protection responsibilities. Again, it is critical that Congress provide these agencies with the resources necessary to carry out these new unfunded mandates.

*D. The EPAct rules lengthen the licensing timeline*

EPAct requires that the regulations must ensure compliance for the trial-type hearing "within the timeframe established by the Commission for each license proceeding." (Section 241 of the FPA) However, the EPAct rules allow a waiver for all proceedings with preliminary conditions filed as of November 17, 2005, enabling them to apply the new rules and substantially altering the licensing schedule for these projects. (7 C.F.R. § 1.601 and 1.604 and 70 Fed.Reg. at 69815, col. 2) The rules unfairly allow the Departments to modify the sequence and timing of the new processes to accommodate these requests. The Departments, in clear violation of

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[6] Examples include "factual issues" as to whether sandbars are below the ordinary high water mark (this determination would not affect the agency condition) and whether Hells Canyon Complex is the sole cause of erosion (an assertion never made by the Forest Service). U.S. Forest Service, USDA Forest Service Answer to Idaho Power Company, Hells Canyon Complex (FERC Project No. 1971) Request for Hearing, April 13, 2006.

[7] U.S. Forest Service, USDA Forest Service Answer to Idaho Power Company, Hells Canyon Complex (FERC Project No. 1971) Request for Hearing, April 13, 2006.

[8] PG&E requested a trial-type hearing on the "reasonableness" of the eradication of noxious weeds. In its request for alternative conditions, the company recommends that noxious weeds be "controlled" rather then "eradicated." Pacific Gas and Electric Company, Pacific Gas and Electric Company's Request for Administrative Hearing on Material Issues of Disputed Fact on Certain Final Section 4(e) Conditions Submitted by the United States Forest Service for the Poe Hydroelectric Project, FERC Project No. 2107, December 16, 2005, p. 19; and Pacific Gas and Electric Company, Pacific Gas and Electric Company's Submittal to the USFS of Alternative Conditions for Certain preliminary Section 4(e) Conditions Submitted by the USFS for the Poe Hydroelectric Project, FERC Project No. 2107, December 16, 2005, p. 54.

their own rules which precluded any further extensions, also granted an even longer extension of EPAct timelines for one project.[9]

*E. The EPAct provisions decreases environmental protection*

Our fundamental fear concerning EPAct was that the net result of the new provisions would result in less protection for environment. The addition of numerous procedural hurdles opens an array of new avenues for challenge and litigation of protections for fisheries and federal lands. The threat of a costly trial-type hearing, which agencies have not been given additional resources to hold, is a powerful incentive for agencies to not propose conditions to protect natural resources in the first place. It remains to be seen whether these fears will come to fruition but it is important Congress to monitor whether there is a decline in environmental conditions.

VI. CONCLUSION

American Rivers, along with our colleagues in the conservation community, dozens of States and American Indian Tribes, and other stakeholders warned that the hydropower licensing provisions in EPAct would make the relicensing process more complex, litigious and threaten public trust resources that already bear the brunt of relicensing delays. The complexity of the implementing rules and our initial experience with implementation appear to confirm these fears. We strongly urge the Committee to continue to exercise its oversight role to evaluate whether the objectives of EPAct—a timely check and balance on resource agencies—are being met, or whether the complexity of the new provisions is effectively eliminating these critical resource protections. In particular, this Committee should pay close attention to whether the agencies are swamped by frivolous requests for hearings that do not raise disputes of material fact or matters that don't require the expense and formality of a "trial-type" hearing. Congress should also ensure that EPAct is not an unfunded mandate for the resource agencies and that they are able to meet their responsibility to participate in the licensing process, timely issue conditions and prescriptions, participate in trial-type hearings, evaluate alternative conditions, and undertake newly required analyses.

Senator CRAIG. Andrew, thank you for your testimony. We appreciate it.

We will follow a 5-minute rule here for our questioning today. Let me start that off, and let me ask this question of all of the witnesses. Regarding the new equal consideration provision that requires the respective Secretaries to demonstrate in writing that they give equal consideration to the effects of a mandatory condition on power and non-power issues, it is my understanding that the Department of Commerce has taken the position that equal consideration applies only if an alternative condition is submitted. Is that your understanding of the act or do you believe that the equal consideration requirement applies to all mandatory conditions regardless of whether alternatives are offered?

Mr. ROBINSON. No, that is not my understanding. Equal consideration should be applied to both preliminary conditions and final conditions. It would make little sense to have two sets of criteria within the same agency to design different outcomes. In fact, it would be very helpful if under the preliminary conditions the agencies provided that equal consideration record with the preliminary conditions to demonstrate why it is in the public interest.

Senator CRAIG. Anyone else? Yes.

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[9] Letter to Magalie R. Salas, Federal Energy Regulatory Commission from Andrew L. Raddant, Regional Environmental Officer, U.S. Department of the Interior, re: Modified Fishway Prescription, Bar Mills Hydroelectric Project, P-2194, December 12, 2005; and letter to Magalie Salas, Secretary, Federal Energy Regulatory Commission from Patricia A. Kurkul, Regional Administrator, National Marine Fisheries Service, Northeast Region, National Oceanic and Atmospheric Administration, United States Department of Commerce, re: Bar Mills Hydroelectric Project (FERC No. 2194), December 12, 2005.

Mr. FINFER. Mr. Chairman, I cannot answer for the Department of Commerce, but I can say that in the Interior Department this issue has been raised to a policy level and is being considered now. What we hope is that we can have a position soon and discuss it with the other Departments and arrive at a consistent outcome.

Mr. ADAMSON. I would say when in doubt read the statute, and the statute is very clear. It provides that equal consideration has to be documented, quote, "with any condition" under section 4(e) or, quote, "any prescription" under section 18. So I think it is pretty clear that equal consideration was intended across the board.

Senator CRAIG. Andrew, any comment on this provision?

Mr. FAHLUND. Well, I guess my only comment is perhaps a little less responsive to your question and more just a general restatement of what I said in my testimony, which is that I think, however you slice it, these agencies are in dire need of support and additional funding for their participation. If you look across the board, agencies throughout the country are struggling to just keep up with the workload under the past rules and statute. To keep up with this additional burden I think is going to require some additional support.

Senator CRAIG. Well, you make an excellent point. As I think we get into this, we will see the burden of the agencies, and it is their job to be forthcoming with the necessary requests for resources. This being the authorizing agency, we should be due diligent in that area. I appreciate that comment.

Another question of all of you. In your opinion, what constitutes a disputed issue of material fact for purposes of invoking the right to a trial-type hearing? Is it not important that an independent administrative law judge make this determination?

Mr. ROBINSON. I think a material issue of dispute of fact is one that is pertinent to the issue or to the condition, whatever stage it is in, preliminary or final. And it does seem appropriate to have an ALJ have the opportunity to decide whether or not in fact it is an issue of fact.

Mr. FINFER. Mr. Chairman, that is exactly what the rules do. They do provide for the ALJ to make that determination. "Material fact" is defined as a an issue which, if proved, would affect the Department's decision to affirm, modify, or even withdraw a condition. In so doing, the rule also states that it does not cover legal or policy issues.

Senator CRAIG. Dan.

Mr. ADAMSON. I think it is really important and, if you look at the early results in the hearing process, what the agency counsel have done is essentially state that every single issue raised, every single one, by industry is not a material fact. The judge just dealt with this issue in the Hell's Canyon proceeding and he said, no, you are wrong, to the agency counsel, you are pretending as if this statute has not passed. So he did not agree that every issue the company had raised was a material fact, but I would say about three-fourths of them.

So if you let Interior staff that have actually worked on the condition, or Commerce—I do not mean to pick on Interior—decide whether or not a license applicant or an environmental group or what have you has the right to a hearing, they have a lot of stake in that hearing not taking place. So you have to have the judge decide, and he or she will be the determinant as to whether or not you get a hearing.

Senator CRAIG. Any additional comment, Andrew?

Mr. FAHLUND. I would urge that if the ALJ's are to decide whether an issue is a material fact, I think that reaching some form of summary judgment very immediately, before everybody pours enormous investment and time into a trial-type hearing, is really critical, because if you do not actually cut out the frivolous lawsuits, if you will, from the ones that are actually meaningful and probative, then you are simply just creating this war of attrition that I was talking about before. You are just going to overwhelm the agencies and the ALJ's.

It is our understanding that, at least with the Department of Commerce and Interior, that it is the district offices that are going to pay for each one of these things. You can just imagine a district manager confronted with the threat of all of these potential trials is going to quickly back off and run away, despite the merits of their case. This is just the realities of doing business out in the field.

Senator CRAIG. Thank you all.

Let me turn to Senator Bingaman.

Senator BINGAMAN. Thank you.

Mr. Robinson, one of the points that is made in Mr. Fahlund's testimony—I believe this is made in his testimony—is American Rivers has brought suit challenging what they call retroactive application of the rules, that is that the rules allow license applicants to challenge conditions and prescriptions that were final before the date that the rules were enacted, or before the date of the enactment of the statute.

Is that an accurate statement as to what the rules provide and, if so, how is that justified?

Mr. ROBINSON. I think—and Mr. Finfer can correct me if I am wrong here. I believe the rules apply to those projects that are still pending as of November 17, 2005, the projects that are pending at the Commission still, have not been licensed as of November 17, 2005.

Senator BINGAMAN. That date was the date that the rules became——

Mr. ROBINSON. Published.

Senator BINGAMAN. Were published?

Mr. ROBINSON. Correct.

Senator BINGAMAN. Okay. But they are not—a person is not able to challenge retroactively with regard to license applications where they have already been finalized, is that right? I mean, where the rules have been finalized.

Mr. ROBINSON. As long as the license had not been issued prior to November 17, 2005, anything that was in that licensing proceeding is still pending, was available for going for alternative conditions or ALJ hearing.

Senator BINGAMAN. So even if the condition was final, if the license had not been issued you could go back and challenge?

Mr. ROBINSON. We had final 4(e) conditions and section 18 prescriptions that were within the proceeding which was not completed, that were then available to go back to the Interior, Commerce, and Agriculture for review.

Senator BINGAMAN. Do you think that is an acceptable arrangement?

Mr. ROBINSON. Absolutely.

Senator BINGAMAN. To go ahead and challenge those, even though they were finalized?

Mr. ROBINSON. Absolutely. The proceeding is still pending, and it is not unusual for us to have reservations of authority for section 18 or 4(e), to do those conditions after the license has been issued.

Mr. ADAMSON. Can I respond, Senator?

Senator BINGAMAN. Sure, go ahead.

Mr. ADAMSON. Thank you, Senator. A mandatory condition has no force and effect until FERC issues a license, and it often happens in these proceedings that it is years after the condition has been submitted that it is in a license, and the Departments always reserve their right to change the condition. So there is nothing retroactive. They have no force and effect until a license is issued. They do not apply to you.

Senator BINGAMAN. Let me ask another question. And again, I guess Mr. Fahlund has raised this argument about war of attrition and just the amazing burden that is being put on the various agencies here. As I understand it, in your testimony, Mr. Adamson, you say that the resource agencies appear to be, quote, "rethinking their approach to conditioning projects." I believe that is what you said.

Is that in fact happening? Are the agencies rethinking their approach to conditioning projects and, because of the fear that they have got this amazing legal challenge now available to them, essentially backing off on the issuance of conditions? Is that a real danger?

Mr. FINFER. Senator, if I may, the act certainly underscored the fact that we need to provide for a foundation for the fact that there may be a trial-type hearing. Therefore, we have got to outline our facts in a very meticulous way, provide detailed documentation and a very clear pathway of how they led to a condition, that is to anticipate that indeed a hearing may happen.

But it does not follow from that that we would necessarily pull our punches on protecting resources. In fact, I would say quite the contrary has occurred, at least so far. The best example I can point to is the Klamath project conditions that were proposed by Commerce and Interior. Those were developed with full knowledge of the new section 241 and the understanding that hearing and alternative requests might be received, in fact were likely to be received. Yet these conditions are very comprehensive across the range of resource issues and we are very confident in them and we believe they are sufficiently protective.

We are not the only ones who feel that way. In fact, Earth Justice, an organization that has strongly criticized the resource agencies and which in fact is representing the plaintiffs in the lawsuit against the rules, commented very favorably to the *Washington Post* after those conditions were submitted to FERC on Klamath. Just to quote, their representative said: "It feels hopeful and it feels different. Credit is due the Government scientists who are finally saying the right thing and the politicians who are allowing them to say it."

I do not believe Earth Justice would have said that if they felt we were skimping on protection.

Senator BINGAMAN. Mr. Fahlund, did you have a comment on this same issue?

Mr. FAHLUND. Just a brief response, and that is that, while I very much appreciate, like Earth Justice, the example set in the Klamath, I think that what we are going to find is that the highest profile cases are going to receive those resources necessary to do their job and the ones that are not, that do not have those resources, are not. That is where that war of attrition is going to take place.

So projects where groups like American Rivers and others are really pushing aggressively on one side and the industry is pressing on the other, those are certainly going to merit the attentions and the resources of the agencies, while others I think are going to fall by the wayside.

Senator BINGAMAN. Thank you very much, Mr. Chairman.

Senator CRAIG. Senator Thomas.

Senator THOMAS. Thank you.

You know, it is kind of interesting, gentlemen. I understand your principal responsibility apparently is regulation and licensing, but do any of you have any discussion or any thought or is there anything going on in your industry about efficiency or more production or increasing? That is kind of what we are talking about on energy these days. Do you have any feeling about that, any of you?

Mr. ROBINSON. I think there are some aspects of EPAct 2005 which you have also seen the early evidence of, for efficiency upgrades and additional capacity of hydroelectric projects and incentives associated with those. We have had two applications so far for projects, and I am hopeful we will see more, for those efficiency upgrades that were based solely on those incentives that you have provided. We also have four applications for increases in capacity of projects that may qualify for those incentives as well.

Along with that, we have seen an uptick in the number of applications for new projects. I have been involved with licensing projects now for 29 years and probably over the last 15 years it has been rare that we would get an application. I think we have something on the order of 16 pending license applications now.

Mr. ADAMSON. Senator Thomas, I think, on behalf of the industry, this legislation will make hydro more cost effective and it will probably preserve in certain cases hydro that might otherwise go away because of the licensing process. I mentioned briefly the production tax credit on incremental hydro. A number of our members are building projects, are upgrading projects in response to that. So we think it is very important to have more hydro resources at existing plants, to increase their capacity, and hopefully new projects, as Mark Robinson has mentioned.

Senator THOMAS. Thank you.

Mr. Finfer, have the new rules impacted the agencies' method of setting conditions? How many alternatives have you granted or denied?

Mr. FINFER. Senator, in answering Senator Bingaman's question I indicated that the early notice was that we were still proceeding as we had before in meeting our responsibilities. In terms of actual actions to date, we have not acted in a complete way on any of the conditions or alternatives that have been proposed to us. That process is just under way. We are just having the first two hearings in June and in August respectively, after which we will have the results of the hearings and the alternatives will be assessed. There will be more proceedings this fall and this winter.

So as of now, no actual findings have occurred.

Senator THOMAS. So there have not been any settlements reached?

Mr. FINFER. In terms of settlements, yes. Settlement processes are continuing even when these requests have been filed, and in fact in two cases for which hearings have been requested settlements have been arrived at and the hearing requests have been withdrawn. There are more settlements among this group that are under way which could potentially occur.

Senator THOMAS. How do the agencies intend to implement the equal consideration provision of 33(b)?

Mr. FINFER. We mentioned some of that in our rule, and specifically that equal consideration does not mean equal treatment, but literally what it says in plain language, that we will weigh the various impacts and concerns and try and consider them faithfully and equitably. The new process puts in place a very structured requirement whereby the Secretary involved has to produce a finding and determine whether to accept the condition. In fact, the process of course requires us to accept the condition unless we can demonstrate why it should not be accepted.

As I have mentioned, we have not gone through that process yet for any condition.

Senator THOMAS. Sounds pretty complicated.

Mr. Robinson, has FERC invoked the dispute resolution process yet?

Mr. ROBINSON. No, we have not. We have not gotten that far down the process.

But if I could just make one comment about this war of attrition very quickly. I actually see this quite differently than the way it has been represented. I think over time what we will see is a coming together of these license conditions, mandatory or otherwise, because we are all now working under the same standards that Congress has set for us.

We are going through a period here where people are feeling their way through, but, as Mr. Finfer said, we are seeing movement already towards settlement discussions, where previously it was just: here is your condition; take it. I think that is a really positive step, to try to work these things out, and will result in less conflict, not a war of attrition but less conflict, and more public interest licensing being done at the commission as a result of EPAct.

Senator THOMAS. It sounds like a pretty complicated process.

Thank you, Mr. Chairman.

Senator CRAIG. Thank you very much, Craig.

Let me go right back to that question. Then under what circumstances will FERC invoke the new dispute resolution process?

Mr. ROBINSON. Well, if the Secretary, after having a trial-type hearing and alternative condition, comes to the Commission and says, here is our final conditions, and the Commission looks at those and believes that they are not consistent with the equal consideration standard, the Commission has the opportunity to refer that—it is not a must, but can—refer that to the dispute resolution process at the Commission.

I think that is a 90-day period that we are allowed for that. Then that finding would be provided back to the Secretary for a final statement from the Secretary on whether or not those are in fact the final terms and conditions.

Senator CRAIG. Mark, could FERC report back to this committee in about 6 months to see what additional progress is being made in implementing the hydro provisions of EPAct?

Mr. ROBINSON. I think it is important that we do that. We are just at the early stages. There is very much promising. There is a lot promising going on that is not even in the ALJ or the alternative condition process, but the roll-out from this and the way the agencies are dealing with licensees, I think that is one of the real plusses here. But I think in 6 months we will have a much better picture on how the actual process of the ALJ process and the alternative conditions process is actually working. So we would be happy to.

Senator CRAIG. Well, I think it is important that we monitor it closely, because several expressions have been made as to what is believed might happen, but until it happens or we see clear evidence that there is difficulty I do believe we are at a bit of a rush to the line at the moment. Once this thing levels off and we get through this process several times, will we have a clear vision of what is or is not happening there.

Senator Bingaman had asked you, Mr. Finfer, in relation to concern that American Rivers expressed as to would you do your job well. I think I heard Mr. Fahlund suggest that, depending on the profile of a project, it would be kind of pick and choose. I cannot let that one lie. Are you suggesting, Mr. Fahlund, there will be a double standard within the agencies as to how they would handle one licensing process versus another?

Mr. FAHLUND. I would posit that in any situation where you are managing scarce resources you have to allocate those resources in the best way that you see fit. I think that if you have a project that has higher profile I think that you are more likely to allocate those resources to that project if those resources are limited.

So I do in fact stand by my statement and I think that—and again, this is just speculation at this point because we have not seen the results of too many of these things yet. But I fully expect to see agencies either never issuing conditions in the first place or backing off from them very, very quickly, simply because they cannot handle the cost of actually even trying to fight a frivolous petition for a trial-type hearing.

Senator CRAIG. Then I have to come back again: Do you think American Rivers would allow that kind of action to stand without public exposure to it or bringing the attention of the Congress if this were to happen?

Mr. FAHLUND. Well, I think actually bringing it to the attention of the Congress is precisely why I was encouraging these continued oversight hearings. But American Rivers will try to bring it to the attention of the public. But of course, we cannot see what is going on in the minds and in the back rooms of the agency when they are making those kinds of decisions. All we can do is point to the fact that—we can point to the absence of conditions that we think should clearly be there. But unfortunately, EPAct did not set up a situation where an absence of a condition is very easily challenged. It certainly makes challenging existing conditions very easy, too easy in my view.

Senator CRAIG. Well, we will monitor closely, as I am confident you will, as we go through this so that we get the necessary and appropriate effect.

Mr. FAHLUND. We would certainly appreciate that.

Senator CRAIG. Mr. Finfer, as we were developing the hydro legislative piece some critics warned that the opportunity for the trial-like hearing would discourage settlements. Has that happened or are settlements, I think you have already said, are still under way? That has not happened?

Mr. FINFER. Mr. Chairman, it is early, but we are not seeing that settlements are being discouraged. In fact, some settlements have already occurred among projects for which hearings have been scheduled, and more discussions are under way among a number of the ones that are still active. I would also add that since the Klamath conditions were submitted the stakeholder-driven settlement process that is taking place there for Klamath does not appear to have been deterred by the fact that the hearings were requested on Klamath.

So the early indication is that settlements are not being deterred.

Mr. FAHLUND. Mr. Chairman, may I respond to that?

Senator CRAIG. Yes.

Mr. FAHLUND. Because I think this brings up a really important point. That is, while I do not think that settlement, at least in the Klamath, has been derailed altogether, it has been postponed. It has essentially been frozen in place until the trial-type hearing process is completed, because we simply just cannot work on both tracks at the same time. No one can. It is just too resource-intensive for that period of time.

And Mr. Adamson—and I might shock him right now, but he made a recommendation about the timeline or a suggestion that the timeline is tight. I think that we would encourage the agencies to have a provision, an ability to impose a stay on a trial-type hearing proceeding, just hold it in abeyance for a period of time to facilitate settlement agreement, particularly where folks have very limited resources and can only kind of work in one venue at a time.

We have done that with the commission. I think it has been by and large effective. I do not think people have abused that stay process too much. But I think it would be helpful to consider as an addendum.

Mr. ADAMSON. Senator, I agree that some type of limited stay, maybe 30 to 60 days just to figure out if you can sit down, work things out, so that you are not just thrust right into the hearing immediately.

Senator CRAIG. Mr. Robinson.

Mr. ROBINSON. Congress, I think quite rightly, when they passed this act put a 90-day provision in there to complete these hearings. We have worked hard with the agency to make this work within the ILP time frame. Keep in mind this is a 5-year process we are talking about, and people have been talking for years and years and years by the time they get to the point that they would have a trial-type hearing and alternative conditions. To think that we need another 30 days at that point, it is just going to build in the expectation that we will get a stay or get another delay.

I would encourage the agencies to stay with the time frames that are in the rule and in the law.

Senator CRAIG. Well, gentlemen, one of the reasons you are before us today looking at a new law and how to implement it is because of the way the old law was handled—12 and 14-year processes that cost millions and millions of dollars. It was what drove this Congress to make change, hopefully the change to be transparent and open, but predictable, procedural, in a way that there is some relationship as we work through these kinds of processes.

So I certainly do not believe people ought not have access or that there not be appropriate time. But time here has been so badly abused in the past, at least this Senator is very sensitive to it. Now, I understand startup. I understand getting into a new law and process and procedure and making it work well. I think all of us understand a little flexibility in that process. But that is why the Congress was specific as it relates to time.

Mr. Finfer, why did not the resource agencies proceed with a notice of comment period before issuing the hydro rule?

Mr. FINFER. Senator, we took a look at the issue and decided that these rules were actually procedural and interpretive, rather than substantive, and hence did qualify for the exemption from notice and comment under the Administrative Procedures Act. Further, the act included a mandate to put the rule in place in 90 days. It was a very emphatic mandate.

So we decided that those two factors together gave us reason to publish as interim final, but with a request for comment. We are hoping that that offered the best, in that it allowed the parties to get into the process sooner, but still provided the opportunity for comment, which they ought to have the right to and which in fact we need because it is a new process.

Senator CRAIG. Why is it appropriate that the rule apply to pending procedures? That was discussed earlier. For the record, how did Interior see that?

Mr. FINFER. In the act, the phrase, the operative phrase that is used throughout, is "license applicant." It does not say an applicant for a license who applies after the date of enactment. It said "license applicant." Just reading the plain language, we believe that this was the appropriate reading of the statute and hence applied it accordingly.

I should add, the opportunity for people with existing conditions and prescriptions to use the process was limited. They had to file in the first 30 days after the rule was published, that is by December 17. So that was a one-time opportunity. The window was not left open forever.

Senator CRAIG. So how many are we talking about?

Mr. FINFER. We received for these, 19 requests of various types, covering 17 projects. Those are the requests, along with the few new ones like Hell's Canyon and Klamath, that we are processing right now.

Senator CRAIG. Mr. Adamson, from your perspective how is the ability to request a trial-type hearing and offering alternatives an improvement over the previous process, and how do you respond to the criticism that the new process will add additional time to an already lengthy process?

Mr. ADAMSON. Well, as it is structured now it adds no time at all. Under any circumstance, the alternative conditions adds no time. Equal consideration adds no time. The problem you had before is that you could literally—and I have worked on proceedings where you get a condition and there are no facts identified at all, but you have no recourse except appealing the license order years later in the court of appeals.

In fact, what this will do is give you or an environmentalist—I know Andrew is not happy with this law and not happy with this proceeding. But I predict that within 5 years, I predict that American Rivers or some other environmental group will use this condition because they think that a decision is not supported by the facts.

So it is going to go both ways over time. But right now you have an opportunity to solve this problem at the get-go instead of waiting for years and then having a Cushman-like situation, where a relicensing is sitting around in the court of appeals for 10 years, which is I think what we are trying to avoid.

Senator CRAIG. In his testimony, Andrew asserts that environmental conditions present negligible costs to power supply. Would you agree and how will electricity ratepayers benefit from the hydro relicensing reform?

Mr. ADAMSON. Well, I think that it definitely has an impact. I just think of a couple of proceedings. One is Box Canyon, where the price of power from that project has doubled, according to FERC, because of relicensing. So that is certainly a ratepayer impact.

Another recent project, just to pick one out of the hat, is Baker River project. There has been a settlement there. It is another project in Washington State. So the licensee supports that, but that settlement did more than double the cost. So I think if you look, for example in the Northwest, over time at all the projects as they go through relicensing and add together cumulatively the increase in costs from every project, you get a pretty substantial impact.

But sure, one proceeding, if it is a really large company, it is going to be spread out amongst a lot of people. But cumulatively it all adds up.

Senator CRAIG. Andrew, when Congress first began to look at hydro licensing reform we developed language that American Rivers criticized as licensee applicant only. Your organization advocated that all parties to the proceedings be given the same opportunity to request a trial-type hearing and offer alternatives. In our bipartisan agreement, we did just that.

Do you agree that any party, including an organization such as American Rivers, can trigger a hearing?

Mr. FAHLUND. Absolutely, Senator. And I guess what you are hearing from me today is that American Rivers may be able to participate as a practical matter in some of these proceedings. Again getting back to the prioritization issue, we will have to prioritize, as anyone does. My concern—and I am representing 130 groups from around the country, most of whom have very limited resources. I think the ability of those organizations to keep up and participate as a practical matter, even though they have a legal possibility of participating, I think is going to be increasingly difficult.

Senator CRAIG. Do you agree that any party can offer alternatives?

Mr. FAHLUND. Yes, sir. The problem there is that the alternatives that are offered—the way the alternative conditions language is written, only conditions that must be included by an agency—they have to be cheaper or no less, I guess better for power production, and no less protective. But what about if the agency low-balls the condition? I think that that was always a concern of ours and something that we always believed we should have the right to an equitable appeal on.

Senator CRAIG. So now that American Rivers is beginning to see where the law is taking us with the agencies involved, and I gather by your testimony your continued opposition, is the opposition what you envision the process to become and be or is it, as you have said, a process that could become more costly to the least among us?

Mr. FAHLUND. I think that the way we view the—it is very hard to judge from sitting where we are right now. These things are just getting started and so we really have not launched into it. So it is, in all fairness, it is very hard to judge.

But I do think that every indication is that our concerns have been realized and that this is going to be a lot messier than I thought it needed to be. I would have preferred an opportunity to get at what Dan has been describing his interest, at least, but doing it in a much more streamlined, efficient, and equitable way.

Now, given that that is not an option before us and that we have to do the best with what Congress passed, I certainly hope that we can work with everyone here to make this work well and work effectively without any compromise to environmental protections. I would love to come back here in a year and eat crow, but——

Senator CRAIG. I might give you that opportunity.

Mr. FAHLUND. You might. But I do not know that I will be. I might be crowing.

Senator CRAIG. Well, I think Mr. Finfer and others in their testimony have stated it well. We are talking about a process that is valid for a period from 30 to 50 years and we ought to try to get it right.

Mr. FAHLUND. Yes.

Senator CRAIG. At the same time, we ought not, in dealing with the Federal Government, make it such a phenomenally difficult process that it drives costs beyond where—unless you simply believe hydro ought to be extracted from the rivers and streams of America, then it ought not be so costly as to drive it through to the consumer, who is finally beginning to awaken to the new realities of energy costs in our country.

So I think all of us are extremely concerned about that. I think you agree with me, as all of you do, that it is tremendously important that we get the facts and the conditions right. That is why a reasonable dialogue, trial-like proceedings where there is dispute, that there are alternatives that can be argued effectively—I became quite frustrated that agencies had in the name of the environment an absolute authority or dictatorial ability, when in fact they may not be the experts or their expertise may not be where it ought to be to arrive at the right environmental conditions to continue to maintain an effective, efficient, hydro operating facility.

So we will stay tuned as all of you proceed. We will watch it very, very closely.

Andrew, I would love to have you eat crow. But more importantly, I would also love to have you come back and say: No, they are getting it wrong and here is what we can do to improve it. That is going to be certainly our part of the job here also.

But I must tell you, to date, gentlemen, I am pleased with what I see and I hope we can continue to move down this road toward an effective open process that brings this thing into a predictable timeline. And time is money, there is no question about it. And if time frames are shortened once this procedure is in place, maybe the cost concerns that you have will be lessened to some degree. But certainly there will be an obligation on the part of all parties involved.

So I want to thank you all very much for being with us today, taking time. We will have you back before us. As I asked you, Mark, to report within 6 months as to where this procedure is taking us, by then we will have actually had a chance to see how it is working in a trial-like proceeding and whether in fact we are getting what we have asked for here.

Gentlemen, thank you all very much for coming. We appreciate your time and your testimony.

The committee will stand adjourned.

[Whereupon, at 4:08 p.m., the hearing was recessed, to be reconvened on May 15, 2006.]

[The following statement was received for the record:]

STATEMENT OF THE EDISON ELECTRIC INSTITUTE

The Edison Electric Institute (EEI) is submitting this written statement to the Committee for consideration during its May 8 hearing on implementation of the hydropower licensing provisions of the Energy Policy Act of 2005 (EPAct 2005). Under Section 241 of the new law, Congress amended the Federal Power Act (FPA) to require federal land and fish and wildlife agencies, when prescribing mandatory hydropower license conditions, to consider the impacts of those conditions on other hydropower project benefits. Section 241 also requires the agencies to consider alternative conditions suggested by license applicants and others that can achieve the same resource goals at lower energy or dollar costs. Finally, Section 241 requires the resource agencies to provide a trial-type hearing to resolve disputed issues of material fact relating to any mandatory condition and allows the Federal Energy Regulatory Commission (FERC) to refer any condition for a non-binding opinion by FERC's Dispute Resolution Service.

EEI vigorously supported enactment of these EPAct 2005 hydropower licensing improvements, and we are strongly interested in their effective implementation. We deeply appreciate Senator Craig's longstanding and steadfast leadership on hydroelectric licensing issues, starting with the legislation he introduced in 1999 and extending through the comprehensive energy bills considered in the 107th, 108th and 109th Congresses. We also thank Chairman Domenici for his leadership and Senators Smith, Nelson, Cantwell, and Feinstein for their roles in working with Senator Craig to develop the bipartisan compromise that was the basis for the provision ultimately enacted by Congress. The compromise assured that everyone involved in the hydroelectric licensing process has the same opportunity to obtain the benefits of the licensing improvements, which introduced greater accountability and transparency into the licensing process without compromising protection of the environment.

The Section 241 provisions ultimately adopted by Congress are a significant improvement to the hydroelectric licensing process. They will help preserve the viability of our valuable domestic hydropower resource, which provides substantial economic, environmental, and energy security benefits to the nation.

EEI is the trade association of United States shareholder-owned electric utility companies, international affiliates, and industry associates worldwide. Our U.S. members serve 71 percent of all electric utility customers in the nation and generate almost 60 percent of the electricity produced by U.S. generators. In providing these services, many EEI members rely on hydropower, and many own and operate hydropower projects licensed by FERC. In fact, EEI members comprise the largest group of FERC hydropower project license holders.

Hydropower has played and will continue to play an important role in meeting the nation's need for electricity. Approximately 10% of the nation's generating capacity is hydropower, and it is by far the nation's largest domestic source of clean, affordable, renewable energy, providing more than 85% of our renewable energy. Also, hydropower projects are particularly valuable for maintaining the reliability of our nation's electricity system. If allowed by their licenses to do so, hydropower projects can provide quick start and stop capabilities that help electric system operators maintain the integrity of the nation's transmission grid and restore the system in cases where it may experience disturbances or even outages. Finally, hydropower generation provides communities across the country with other benefits besides electricity, including flood control, drinking water, irrigation, fish and wildlife, and recreation benefits.

## MANDATORY CONDITIONS

Legislative improvements to the hydropower licensing process were needed because of problems that arose in the exercise of mandatory conditioning authorities under FPA Sections 4(e) and 18 by the Departments of the Interior, Commerce, and Agriculture (Departments). Although FERC issues hydropower licenses and is in charge of the overall licensing process, under the FPA, as interpreted by a series of federal court decisions, the Departments write key parts of the licenses that relate to the "adequate protection" of certain federal lands under Section 4(e) and fish passage under Section 18. FERC generally has no authority to reject or modify these conditions, and prior to EPAct 2005 licensees had no avenue to challenge the scientific bases of the Departments' mandatory conditions other than requesting judicial review of a license order in the federal Court of Appeals. This interpretation of the FPA resulted in an extraordinarily broad exercise of conditioning authority by the Departments, which led to serious problems when exercised without consideration of the likely impacts on energy production and without regard to their cost-effectiveness. In many cases, the Departments made clear that they could and would impose a broad array of license conditions, too often without regard to the cost or the impact on other project benefits including electricity production, without considering more efficient alternatives, and even without adequately demonstrating the need for the conditions in the license proceeding record.

Although prior to EPAct 2005 FERC undertook several significant efforts to improve the hydroelectric licensing process, including the establishment of a new "Integrated Licensing Process" in 2003, it did not attempt to solve the generally recognized problems with the mandatory conditioning process. FERC believed it generally lacked authority to address the issue. Furthermore, though the Interior Department took a step in the direction of reforming the mandatory condition process when it issued a proposed rule to create an appeal process in 2004, it never issued a final rule. These developments confirmed the need for Congressional action to address mandatory conditioning if hydropower was to remain a viable element in the nation's generating portfolio.

## SECTION 241 OF THE ENERGY POLICY ACT OF 2005

The licensing improvements adopted by Congress in Section 241 are designed to ensure that the mandatory license conditions and prescriptions issued by the Departments under FPA Sections 4(e) and 18 are cost-effective, are supported by the facts, and take into account impacts on the wide range of benefits provided by hydropower projects. They were also designed to introduce accountability and transparency to the licensing process. As mentioned briefly above, the key provisions of Section 241 are:

*1. Right to a Trial-Type Hearing*

The license applicant or any other party to a licensing proceeding has the right to an expedited "trial type hearing" on "disputed issues of material fact" regarding mandatory conditions. This provision of the legislation is critical to assuring that mandatory conditions are supported by sound science, not speculation. Prior to enactment of EPAct 2005, the only recourse a license applicant or other party had if they believed a mandatory condition was not supported by the facts was to seek review in the Court of Appeals of the offending condition, following the issuance of a license by FERC in a licensing process that took five to ten years. This remedy was too little too late, following as it did the investment of substantial effort and resources by all parties just to produce a license with conditions that raised serious concerns, for review by a court after-the-fact with deference to the agencies issuing the troubling conditions.

Section 241 corrects this problem by giving license applicants and others the ability to contest the fundamental factual assertions that underlie an agency's mandatory conditions before a license containing those conditions is issued. This will have significant environmental and economic benefits. For example, it will advance environmental interests by helping to assure that fishways achieve their intended purpose of providing passage' for fish with a biological need for such passage. There is no environmental benefit to installing costly fish passage facilities that either do not work or are not used by targeted fish species, and such a result harms electricity consumers who must pay higher rates to cover the cost of the flawed condition.

*2. Equal Consideration*

Under Section 241, when issuing any mandatory condition, the Departments must "demonstrate that the Secretary gave equal consideration to the effects of the condition adopted and alternatives not accepted on energy supply, distribution, cost, and use; flood control; navigation; water supply; and air quality . . ." If appropriately implemented by the Departments, this equal consideration requirement should lead to the issuance of more reasonable mandatory conditions that reflect consideration of all of the impacts of the conditions, both economic and environmental. It also corrects a longstanding problem with the licensing process where FERC was charged with assuring that a license reflected "equal consideration" of all relevant values, but the mandatory conditions submitted by the Departments were not based on the same "equal consideration." This change in law will assure that all federal agency conditions included in a FERC license reflect "equal consideration," regardless of whether they are imposed by FERC or by the Departments. This should result in the issuance of more balanced licenses that are in the public interest.

*3. Alternative Conditions*

The license applicant or any other party to the license proceeding may submit an alternative mandatory condition, which must be adopted by the Department if the alternative meets the environmental goals of the mandatory condition proposed by the Department and will either "cost significantly less to implement" or result in improved power production. In the case of Section 4(e) conditions, the alternative must meet the existing "adequate protection and utilization of the reservation" standard. For Section 18 alternative fishway conditions, the alternative must be "no less protective than the fishway" prescribed by the Department.

This change in law will give license applicants and others the opportunity to convince a Department that there is a more cost-effective or energy-efficient way to address the environmental problem the Departments want to remedy by their mandatory conditions. Again, it should increase the likelihood that hydro licenses will be balanced and reasonable.

INTERIM SECTION 241 RULE

Section 241 required the Departments to issue a joint rule within 90-days of enactment of the EPAct 2005 to establish "procedures for the expedited trial-type hearings . . ." In response, the Departments issued an "interim" final rule on November 17, 2005, coming quite close to complying with the statutory deadline. The Departments requested public comment on the interim rule, however, and indicated that they might issue a revised rule in 2007 based on the comments received as well as the experience gained with the trial-type hearing process.

EEI together with the National Hydropower Association (NHA) submitted extensive comments on the interim rule to the Departments on January 17, 2006. In those comments, EEI strongly supported the rule. In particular, we endorsed provisions contained in the rule that make the trial-type hearing and alternative condition processes applicable to pending licensing proceedings where no license had issued as of November 17, 2005. We believe that such an approach is required by law and prevents a long delay in obtaining the many economic and environmental benefits provided by EPAct 2005.

Further, EEI supported the Departments' clarification that the rights to propose alternative conditions and to a trial-type hearing apply to the exercise of reserved conditioning authority in addition to conditions set during the licensing process. Any other approach would completely subvert the intent of the statute because it would permit the Departments to avoid their Section 241 obligations by simply deferring the exercise of any such authority until after a license is issued, through use of reserved authority or "reopener" conditions.

In addition, we applauded provisions in the rule that mandate that the administrative law judge (ALJ) determine whether there are material disputes of fact, and that the ALJ's factual findings are final. This will prevent Department staff, who may be proponents of a mandatory condition, from unduly limiting access to the trial-type hearing process. The final nature of the All's findings of fact will assure that the relevant conditions/prescriptions issued by the Department are consistent with the facts.

Notwithstanding EEI's strong support for the interim final rule, we do have concerns about certain provisions of the rule, and we expressed those concerns to the Departments in our comments. Primary among those concerns is that the interim rule does not provide for a trial-type hearing of up to 90-days as required by Section 241 because the hearing schedule set out in the interim final rule is unreasonably compressed. Instead of providing up to 90-days for the conduct of the hearing itself, the interim final rule requires that multiple other steps also occur during the 90 day period, including various preliminary procedural steps and the ALJ's ultimate decision. We are concerned that this approach to the hearing schedule simply will not provide the opportunity to develop an adequate factual record in many proceedings where there are one or more highly complex issues.

Moreover, we are troubled that the interim final rule provides for a trial-type hearing on preliminary conditions, rather than final (modified) conditions, in conflict with Section 241. We are concerned that conducting hearings on preliminary conditions—which are not necessarily the conditions that the Departments will ultimately seek to impose on a license applicant—is an inefficient use of the resources of the Departments, license applicants, and other parties. Instead, providing the right to a trial-type hearing on final conditions would be much more efficient and would assure that the license applicants and others only use a trial-type hearing after other avenues for resolving issues are exhausted.

EEI also believes that it is very important that the Departments clarify that the "equal consideration" standard applies to all mandatory conditions—both preliminary and final. This is necessary because the Department of Commerce has taken the position that "equal consideration" applies only to its mandatory conditions if an alternative condition is submitted. We strongly believe that Commerce's interpretation conflicts with the plain language of Section 241 and must be reversed.

In light of these concerns, EEI recommends that the Departments issue a revised final hydropower rule no later than November 1, 2006 in order to better assure that the full benefits of the hydroelectric licensing improvements enacted by Congress are obtained. We hope that the Departments will respond positively to the concerns we have raised in commenting on the interim final rule, in particular the equal consideration, final condition, and 90 day concerns.[1]

We are still at a very early stage of implementation of the Section 241 reforms, so it is difficult at this time to gauge the ultimate impacts of the legislation as well as additional implementation issues that may arise. The Departments have yet to act on any requests for alternative conditions, and only one trial-type hearing process has begun to date. The preliminary general sense of the industry is that Section 241 is causing the agencies to exercise somewhat more care in the preparation of

[1] American Rivers along with other environmental groups have filed a complaint in the U.S. District Court for the Western District of Washington seeking "to overturn the entire rule. Additional complaints have been filed by both Pend Oreille PUD and Ponderay Newsprint in the U.S. District Court for the District of Columbia seeking a determination that the rule incorrectly excludes the relicensing of the Box Canyon Project from being subject to the provisions of EPAct.

preliminary license conditions, including ensuring that conditions are supported by the facts. If true, this is a very positive development.

For projects where preliminary or final license conditions were issued prior to November 17, 2005, the Departments required requests for trial-type hearings and/or alternative conditions to be filed no later than December 19, 2005 (December 19th filings). Under the interim rule, the Departments have discretion regarding when they trigger the beginning of the trial-type hearing process for the December 19th filings. In March 2006, the Departments issued a series of notices regarding the December 19th filings that delay the first step in the trial-type hearing process, namely the Department's answer to the request for trial-type hearing, until at least June 2006 and in some cases until January 2007 or later.

By contrast, the interim rule does not provide the Departments with discretion as to when a hearing process should begin for requests for trial-type hearings in proceedings where preliminary conditions were issued subsequent to November 17, 2005. For these hearing requests, the Department's answer must be made within 45 days after the deadline for filing the request. Then 5 days after the answer is issued, the case must be referred to the respective Department's ALJ office for hearing. This is why the trial-type hearings regarding the relicensing of the Hells Canyon Project are the first hearings to be conducted under the new law even though the preliminary conditions in this proceeding were issued in January, 2006 and Idaho Power's requests for trial-type hearing and alternative conditions were filed on February 27, 2006, months after the group of requests filed on or about December 19, 2005.

EEI and many others are monitoring the Hells Canyon trial-type hearings, one of which is being conducted by the Department of the Interior on Bureau of Land Management Section 4(e) conditions and the other by the Department of Agriculture on U.S. Forest Service Section 4(e) conditions. We expect that there will be many "lessons learned" from these pioneer trial-type hearings that can be applied in the future to maximize the broad benefits that we expect will result from the hydroelectric licensing improvements adopted by Congress in EPAct 2005.

## CONCLUSION

In conclusion, EEI strongly supports the provisions of Section 241 of EPAct 2005, and we appreciate the steps that Congress took to improve the FPA hydropower licensing process by including these provisions in the energy bill last year. We are optimistic that the provisions—if properly implemented—will improve the federal mandatory condition part of the licensing process. We support the Senate Energy Committee's continued oversight to ensure that the objectives sought by Congress in Section 241 are fulfilled.

# APPENDIX

## RESPONSES TO ADDITIONAL QUESTIONS

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DEPARTMENT OF ENERGY,
CONGRESSIONAL AND INTERGOVERNMENTAL AFFAIRS,
*Washington, DC, June 15, 2006.*

Hon. PETE V. DOMENICI,
*Chairman, Committee on Energy and Natural Resources, U.S. Senate, Washington, DC.*

DEAR MR. CHAIRMAN: On April 24, 2006, Clarence L. Miller, Director, Office of Sequestration, Hydrogen, and Clean Coal Fuels, Office of Fossil Energy, testified regarding the economic and environmental issues associated with coal liquefaction technology and on implementation of the provisions of the Energy Policy Act of 2005 addressing coal liquefaction.

Enclosed are the answers to 11 questions that were submitted by Senators Bunning, Bingaman, and Wyden for the hearing record. The one remaining answer is being prepared and will be forwarded to you as soon as possible.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Lillian Owen, at (202) 586-2031.

Sincerely,

JILL L. SIGAL,
*Assistant Secretary.*

[Enclosures.]

### RESPONSES TO QUESTIONS FROM SENATOR BUNNING

*Question 1.* It has been over a year since we passed the energy bill and I have not seen any movement on the part of D.O.E. to implement the loan guarantee program. What is the status of this program and loan guarantees for "C.T.L." projects?

Answer. The Department has established a small loan guarantee office in the Department's Office of the Chief Financial Officer. In implementing the program we will follow the Federal Credit Reform Act of 1990 (FCRA) and Office of Management and Budget (OMB) guidelines. Toward that end, we are drafting program policies and procedures, establishing a credit review board, and planning to employ outside experts.

Title XVII of EPAct 2005 authorizes DOE to issue loan guarantees for projects that avoid, reduce, or sequester air pollutants and/or anthropogenic emissions of greenhouse gases, and "employ new or significantly improved technologies as compared to commercial technologies in service in the U.S. at the time the guarantee is issued." Projects that employ coal-to-liquids technology may be eligible under the Act to apply for loan guarantees.

Under Secretary Garman provided the Committee with an update on our progress in implementing the loan guarantee program at the May 1, 2006, SENR hearing on industrial gasification. In his testimony he stated,

> We will move prudently to ensure that program objectives are achieved while meeting our responsibilities to the taxpayer. . . . We are proceeding, but we are doing so with no small measure of caution and prudence. . . . It is possible that the ultimate cost to the taxpayer could be significantly higher than the cost of the subsidy cost estimate. DOE's evaluations of loan guarantee applications will entail rigorous analysis and careful negotiation of terms and conditions.

Title XVII allows for project developers to pay the subsidy cost of a loan guarantee issued by DOE. While this "self pay" mechanism may reduce the need for appropriations, it does not eliminate the taxpayer's exposure to possible default of the entire amount of the loan.

FCRA contains a requirement that prevents us from issuing a loan guarantee until we have authorization to do so in an appropriations bill. We do not believe we have authority to proceed with an award absent having explicit authorization in an appropriations bill.

*Question 2.* When will DOE's guidance be issued and when will D.O.E. be accepting applications for the loan guarantee program? What do you foresee as a timeline for this program?

Answer. The Department has established a small loan guarantee office under the Department's Chief Financial Officer. In implementing this program we will follow the Federal Credit Reform Act of 1990 (FCRA) and Office of Management and Budget (OMB) guidelines, and we will emulate "best practices" of other federal agencies. Toward that end we are drafting program policies and procedures, establishing a credit review board, and will employ outside experts.

COAL TO LIQUIDS (CTL)

*Question 3.* As you know, the Department of Defense has expressed great interest in "C.T.L." technology as a way to produce a secure, domestic fuel source for our military. Section 369 of the Energy Bill provided that D.O.E. participate in D.O.D.'s Assured Fuels program to evaluate the potential of "C.T.L." for use by the military. What is the status of that program?'

Answer. Section 369 of the Energy Policy Act of 2005 (PL 109-58) directs the Secretary of Energy, in coordination with the Secretary of the Interior and the Secretary of Defense, to establish a task force to develop a program to coordinate and accelerate the commercial development of strategic unconventional fuels, including, but not limited to oil shale and tar sands. This task force has been convened and coal-to-liquids technologies are being evaluated. Also, as Under Secretary Garman indicated in his testimony before the Committee on May 1, 2006, "working with industry, the Department of Defense, and the Environmental Protection Agency, we are studying the business risks associated with industrial gasification and are performing financial modeling to understand the impact of EPAct 2005 incentives on early commercial plants."

PRODUCTION OF TRANSPORTATION FUELS

*Question 4.* Section 414 of the Energy Bill authorizes $85 million to test advanced technologies for the production of transportation fuels manufactured from Illinois Basin coal. It also provides funding for the construction of testing facilities at the University of Kentucky's Center for Applied Energy Research, the Southern Illinois University Coal Research Center, and the Energy Center at Purdue University. Could you provide an update on this initiative and a timeline for funding?

Answer. The Department has not identified funding to perform the work authorized in Section 417 of the Energy Policy Act of FY 2005. The Department's enacted budget for FY 2006 and the Department's budget request for FY 2007 did not include funding for this work. The Department has not requested Coal-To-Liquid (CTL) R&D funding for several years because the CTL technology is mature.

ENVIRONMENTAL IMPACT OF CTL FUELS

*Question 5.* From your research experience, could you describe the environmental impact of "C.T.L." fuels compared to petroleum-based fuels?

Answer. The environmental impact of coal to liquids (CTL) fuels depends significantly on the technologies employed for pollution abatement, but pollution abatement technologies have been too expensive to implement to date. Commercially operating CTL facilities currently do not employ these technologies and consequently have much larger environmental impact than petroleum-based fuels. For example, one of South Africa's existing CTL plants switched to natural gas as its feedstock to reduce the environmental impact, rather than install pollutant control technologies for a coal feedstock process. A CTL facility using clean coal technology, maximum air cooling, and carbon capture and storage is technically capable of plant emissions comparable to those associated with the production of petroleum-based fuels, but may not be economic.

RESPONSES TO QUESTIONS FROM SENATOR BINGAMAN

CTL RAIL TRANSPORT

*Question 1.* Have you looked specifically at what the implications for our rail system will be in a scenario such as the EIA forecast of more than 2 million barrels per day equivalent of CTL fuel? I know that there are issues with regard to the transport of coal by rail right now. This was a topic of one of the panels at our Coal Conference last year. Will this problem (a shortage of rail capacity) be exacerbated by the further development of CTL? Do you know of any analysis on this subject specific to the development of CTL?

Answer. It is possible that the implementation of a Coal-To-Liquids (CTL) industry of the size forecast by the Energy Information Administration (EIA) (i.e., 11% of total coal consumption in 2030) will have an impact on the associated infrastructure including the rail system. Currently, there is at least one study of the potential impact being performed by an industrial consortium.

LOAN GUARANTEES

*Question 2.* Title XVII of the Energy Policy Act of 2005 instructs the Secretary to create a loan guarantee program for innovative technologies, which includes CTL. What is its current status?

Answer. The Department has established a small loan guarantee office in the Department's Office of the Chief Financial Officer. In implementing the program we will follow the Federal Credit Reform Act of 1990 (FCRA) and Office of Management and Budget (OMB) guidelines. Toward that end, we are drafting program policies and procedures, establishing a credit review board, and planning to employ outside experts.

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> We will move prudently to ensure that program objectives are achieved while meeting our responsibilities to the taxpayer. . . . We are proceeding, but we are doing so with no small measure of caution and prudence. . . . It is possible that the ultimate cost to the taxpayer could be significantly higher than the cost of the subsidy cost estimate. DOE's evaluations of loan guarantee applications will entail rigorous analysis and careful negotiation of terms and conditions.

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FCRA contains a requirement that prevents us from issuing a loan guarantee until we have authorization to do so in an appropriations bill. We do not believe we have authority to proceed with an award absent having explicit authorization in an appropriations bill.

CTL AS WATER RESOURCE

*Question 3.* Water is a very important resource. CTL fuel production requires significant quantities of water. Given that fact (or perhaps constraint), how far do you think that we can take this on a national scale? What work has DOE done on looking at the potential impact of large-scale deployment of CTL for our national water supply?

Answer. We agree that water is a very important resource, particularly in the West where some of the largest deposits of coal are located. Coal-To-Liquid (CTL) facilities will have to compete with other uses of water resources. Given a potentially tight water market, the private sector has the incentive to consider designs for CTL facilities in which water use has been minimized through the maximum use of air cooling equipment in the design and operation of the plant.

RESPONSES TO QUESTIONS FROM SENATOR WYDEN

COAL-TO-LIQUIDS (CTL)

*Question 1.* If price volatility and crude oil prices are the two major impediments to bringing coal-to-liquids (CTL) fuels to U.S. markets, the "tipping point" to make CTL economically viable is at $40/barrel and the price of oil is now at $70 per barrel, why does the government need to continue subsidizing more CTL research? Why can't the private sector start building commercially viable production plants?

Answer. The Department has not requested for Coal-to-Liquids (CTL) R&D funding for several years because CTL is a mature technology.

If the private sector believed that investment in CTL production facilities were economic, they would make them. However, the private sector (and the private capital market) appear to have judged CTL facilities as too risky to invest in. The private sector is best able to determine the most efficient allocation of their financial resources. As a result of this efficiency, the U.S. economy prospers. Considering the past history of the price of oil (e.g., in 1986 and 1998), investors must consider the likelihood that the price of oil could drop into a range that would make it impossible for investors to recover its capital. In addition, underscoring the risk of the projects, private lenders want CTL production projects to have off take agreements which match the term of the project debt. Such agreements are not commercially available because customers would have to book the value of a long-term purchase agreement on their balance sheet.

*Question 2.* As a Westerner, I am concerned about the water resources that are needed to produce fuels from coal. I am also concerned about the increased air pollution and greenhouse gases that are emitted. Much of the water that would go into CTL production could be used to grow biomass and produce biofuels instead. Has anyone done a comparison of which types of energy production cause the least harm to the environment while delivering the biggest benefits to customers? Do you know of any analyses that have looked at the "opportunity costs" involved in producing water-intensive energy like CTL?

Answer. We fully recognize the issues associated with water use in the production of liquid fuels from coal, particularly in the West. These issues have given the private sector an incentive to consider Coal-To-Liquid (CTL) facilities that incorporate the maximum amount of air cooling to reduce to a minimum the use of water. We are not aware of any specific analyses that have looked at the opportunity costs in producing products similar to those obtained from CTL facilities.

*Question 3.* If the German and South African experience in producing coal fuels is any indicator, wouldn't you say that the only policy reason that justifies producing CTL fuels in the U.S. would be at a time when the U.S. no longer had access to world oil markets?

Answer. Generally, the private sector will make those investments (and private capital markets will provide financing for those investments) that they believe will be economic and return a profit. The private sector is best able to determine the most efficient allocation of their financial resources. As a result of this efficiency, the U.S. economy prospers. If oil becomes scarce, market prices will incent additional, diversified oil production as well as alternative and unconventional energy production. The market is the most efficient mechanism for "choosing" those resources that would be developed. However, there may be reasons why the nation would be willing to incur economic losses which could result in reduced or negative economic growth, in order to support uneconomic synthetic fuel production.

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RESPONSES OF DAVID HAWKINS TO QUESTIONS FROM SENATOR BUNNING

*Question 1.* The finished "C.T.L." product is low particulate, low mercury and almost zero sulfur. Could you elaborate on the emissions characteristics of "C.T.L." transportation fuels compared to current fuels?

Answer. We have no reason to question the claims that the finished coal-to-liquids (CTL) fuel will have low particulate, low mercury, and very low sulfur characteristics. As I point out in my testimony, our concerns with CTL fall into three areas: the global warming emissions resulting from the production and use of CTL products; the need for performance standards for conventional air pollution from CTL production plants; and the impacts on land and water from expanded coal production.

*Question 2.* As the Energy Information Administration forecast indicates, we have two choices: we can import "C.T.L." fuels from foreign countries or we can produce it ourselves. I believe, and I think the witnesses here today have shown, that America can produce these fuels cleaner than anywhere else. Given the environmental and safety records of other coal countries, wouldn't you agree that the production of coal and "C.T.L." in other nations would cause more environmental damage than if they are produced in America?

Answer. We most certainly need to build new industries here in America to meet our transportation fuel needs. But it would be ineffective and very shortsighted to build industries that cannot meet the performance requirements that will be required to reduce global warming emissions in the near future. Today some may hold the opinion that limits on global warming emissions will not be put in place for some time but there is a growing consensus among industry leaders and others that such limits are inevitable. The new fuels industries that are being considered today need to be viable for decades if they are to provide us with real solutions.

As my testimony stated, with the processes that we know of today, making liquid fuels from coal results in much greater global warming emissions than from the crude oil cycle if CTL production plant emissions are not captured. Even if production plant emissions are captured the system emissions are still as high as from crude oil. We conclude from those facts that deploying a CTL industry would make it more difficult and costly to achieve any given level of global warming emissions reduction in the future.

Fortunately, as my testimony noted, the United States has many other options available to reduce oil dependence that are economically attractive and will assist us in achieving reductions in global warming emissions at lower costs. I outline these alternatives in my answer to your next question. Thus, our choices are not limited to producing CTL fuels here or importing them from other countries.

*Question 3.* On page 17 of your written remarks, you make a number of recommendations regarding oil savings that relate to improvements in vehicle use and in industrial, aviation and residential building energy consumption. Would you please expand on your brief referral to these ideas?

Answer. My testimony provided a very brief summary of the findings of the report "Securing America,"* produced by NRDC and the Institute for the Analysis of Global Security. The report identified technically feasible, cost-effective methods for reducing our dependence on oil in two broad program areas: improving the efficiency of our transportation system and of industrial processes and buildings that consume oil today; and replacement of oil in the transportation sector with fuels made from biomass.

As my testimony notes, these measures can achieve oil savings of more than 3 million barrels a day within ten years and 11 million barrels a day by 2025:

Accelerate oil savings in passenger vehicles by:

- establishing tax credits for manufacturers to retool existing factories so they can build fuel-efficient vehicles and engineer advanced technologies, and
- establishing tax credits for consumers to purchase the next generation of fuel-efficient vehicles; and raising federal fuel economy standards for cars and light trucks in regular steps.

Accelerate oil savings in motor vehicles through the following:

- requiring replacement tires and motor oil to be at least as fuel efficient as original equipment tires and motor oil;
- requiring efficiency improvements in heavy-duty trucks; and
- supporting smart growth and better transportation choices.

Accelerate oil savings in industrial, aviation, and residential building sectors through the following:

- expanding industrial efficiency programs to focus on oil use reduction and adopting standards for petroleum heating;
- replacing chemical feedstocks with bioproducts through research and development and government procurement of bioproducts;
- upgrading air traffic management systems so aircraft follow the most-efficient routes; and
- promoting residential energy savings with a focus on oil-heat.

Encourage growth of the biofuels industry through the following:

- requiring all new cars and trucks to be capable of operating on biofuels or other non-petroleum fuels by 2015; and
- allocating $2 billion in federal funding over the next 10 years to help the cellulosic biofuels industry expand production capacity to 1 billion gallons per year and become self-sufficient by 2015.

As you requested, I provide additional detail from that report below. I am also attaching the entire report. The report is available online at http://www.nrdc.org/air/transportation/oilsecurity/plan.pdf.

EXCERPTS FROM "SECURING AMERICA"

We recommend the following actions:

* The report has been retained in committee files.

Establish a minimal national commitment to save 2.5 million barrels per day by 2015 and 10 million barrels per day by 2025.

Saving oil requires mobilizing American ingenuity, factories, and farms around a clear goal. The first, most critical, step is for Congress to establish a national commitment to cut oil expenses and reinvest the resources-otherwise sent to oil producing countries-in American factories and farms. If the past is an indicator of success for such a commitment, this savings goal is achievable. During World War II, American factories converted in just months from building cars to building tankers and bombers that became the arsenal of democracy. And after the first oil crisis in the early 1970s, America cut its oil demand to keep our economy strong. Although some may doubt the ability to turn this ship around, history shows us that American efficiency and ingenuity can meet the challenge. Saving 2.5 mbd by 2015 and 10 mbd by 2025 is well within our technical potential.

We recommend the following policy measures to achieve the oil savings:

Accelerate oil savings in passenger vehicles by:

- establishing tax credits for manufacturers to retool existing factories so they can build fuel-efficient vehicles and engineer advanced technologies, and for consumers to purchase the next generation of fuel-efficient vehicles; and
- raising federal fuel economy standards for cars and light trucks in regular steps.

As oil prices have risen, so has the demand for fuel-efficient cars and trucks, especially hybrids. Unfortunately, the "Big 3" automakers, General Motors, Ford Motor Company, and DaimlerChrysler, have been slow to get into the hybrid market. As a result, they are losing the race for clean and efficient vehicles, automakers move faster to build hybrids, thousands of jobs could be lost. And with business as usual, the Big 3 will face a significant competitive disadvantage in the global auto market over the next few decades. Putting American innovation to work can reverse this course, saving jobs while saving oil.

Tax credits for factories, consumers. Producing fuel-efficient, advanced technology vehicles will require automakers and their suppliers to retool their factories. Hybrid vehicles rely on advanced equipment such as battery packs, electric motors and generators, and electronic power controllers. Advanced diesel drivetrains require sophisticated fuel injection systems, turbochargers and advanced pollution control devices (to meet emission standards). Factories in Japan and Europe currently supply these components to the United States. Tax credits help expand market demand for these vehicles, aid manufacturers in making capital investments necessary to retool their factories, make advanced technologies more cost-effective, and stimulate job growth in the production of cleaner, more efficient vehicles.

We endorse the proposals offered by a bipartisan group, the National Commission on Energy Policy (NCEP), which recommended a total of $3 billion over the next five to ten years in consumer and manufacturer tax credits. These tax credits will not only help reduce oil dependence but also will pay for themselves through increased tax revenue from new economic activity, including new jobs in the production of high-efficiency vehicles.

Fuel economy standards. The NCEP also recommended that to ensure public benefits from these tax credits, federal fuel economy standards should be raised to ensure that the increased production of the most fuel-efficient vehicles translates into national oil savings. Fuel economy standards were highly effective in cutting oil use in the late 1970s and the 1980s. According to a 2002 report from the National Academy of Sciences, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards, the CAFE standards enacted in 1975 were a key factor in the dramatic rise of car and light-truck fuel economy between 1975 and 1988. Fuel economy for new passenger cars nearly doubled, rising from 15.8 mpg in 1975 to a peak of 28.6 in 1988. Fuel economy for new light trucks increased 50 percent, rising from 13.7 mpg in 1975 to 21.6 mpg in 1987.

Although total fuel use by passenger vehicles has risen by 30 percent since the federal fuel economy standards were enacted, the majority of this increase took place after the fuel economy standards leveled in the mid- and late 1980s. Adding to the growth in fuel use was the rise in sales of light trucks (such as SUVs, minivans, and pickups) for general passenger use. The increase in fuel consumption would have been even greater if fuel economy standards had not been in place.

Accelerate oil savings in motor vehicles through the following:

- requiring replacement tires and motor oil to be at least as fuel efficient as original equipment tires and motor oil;
- requiring efficiency improvements in heavy-duty trucks; and
- supporting smart growth and better transportation choices.

Replacement tires and motor oil. We should adopt a program that ensures replacement tires are as fuel-efficient as original equipment tires. The program should follow the approach already being implemented in California, by developing tire efficiency and labeling standards (based on rolling resistance) that will enable consumers to purchase the most efficient models. This measure would achieve an overall decrease in gasoline consumption by all U.S. vehicles of approximately 3 percent.

Automakers already equip new cars with low rolling resistance, fuel-efficient tires in order to comply with federal fuel-economy standards. Rolling resistance is the measure of the amount of energy needed to move a tire, so the higher the rolling resistance, the more gas the car consumes. There are no efficiency standards or efficiency labels for replacement tires, so most consumers unknowingly buy high rolling resistance tires to replace originals. A set of four low rolling resistance tires would cost consumers just $5 to $12 more than conventional replacement tires, but the average driver would recoup the additional expense of tires in fuel savings in less than one year. The efficient tires would save the typical driver $50 to $150 over the 50,000-mile life of the tires.

A program similar to the tire replacement program should be implemented to encourage the use of fuel efficient motor oils. Like replacement tires, more efficient motor oil can provide fuel savings from on road passenger cars and light trucks. According to the U.S. Department of Energy, the use of specifically formulated low-friction motor oil can increase a vehicle's fuel economy by 1 to 2 percent. A producer of synthetic motor oil has projected that fuel economy benefits could be as much as 5 percent.

Heavy-duty trucks. We should establish standards for the smallest and largest heavy trucks. The smallest of the heavy trucks, those from 8,500 to 10,000 pounds can be improved with the same technology systems applied to other light-duty trucks. Improvements could be achieved by expanding the upper weight limit of the light-duty fuel economy standard from 8,500 to 10,000 pounds, which would bring the smallest heavy trucks into federal fuel economy program.

Improving the fuel economy of heavy-duty trucks offers a major opportunity for oil savings. Today, vehicles ranging from 8,500 pounds to more than 33,000 pounds consume the equivalent of more than 2.8 million barrels of oil each day. More than two-thirds of this energy is consumed by the heaviest trucks, such as tractor-trailers weighing more than 33,000 pounds. Lighter, shorter range trucks use the remaining third of trucking fuel energy. All truck classes can benefit from fuel-efficiency gains from current and emerging technology. Technology assessments by the American Council for an Energy-Efficient Economy (ACEEE) found that truck fuel-efficiency advances up to 70 percent are cost-effective. The heaviest long range trucks can increase fuel economy through conventional technology improvements, including enhancements to aerodynamics, reduction of rolling resistance using tires, improved engine fuel injection and thermal management, and reductions in vehicle weight.

Although medium, short-haul trucks can also benefit from conventional technology improvements, large fuel economy advances can best be achieved through hybrid gasoline-electric or diesel-electric drivetrains. Approximately 47 percent of the mileage covered by medium trucks is in urban stop-and-go traffic where hybrid designs offer significant fuel savings by shutting down combustion engines and driving short distances on electric motors.

A wide range of technologies also exists to reduce the tremendous amount of fuel used during idling. Long-haul truckers travel the highways for days. During their rest stops, drivers commonly idle their diesel engines to warm or air condition their sleeping cab, to run electrical appliances and to keep their truck's engine block warm during cold weather. Large diesel engines are designed to move heavy loads, not run auxiliary systems. More efficient technologies are available to perform the needed idling functions. Auxiliary power units sip diesel fuel compared with engine idling and, in many cases, the idling services can be performed by electrical hookups and other non-petroleum-fueled systems.

Smart growth and better transportation choices. Saving oil is one more reason to pursue smart growth as an alternative to suburban sprawl and to expand Americans' transportation options. Federal strategies to support smart growth and better transportation choices save oil by reducing the total amount we are required to drive when we commute or run errands. The potential for smart growth oil savings is immense. If all new construction were built in a similar fashion to existing smart growth developments, the nation would save over half a million barrels of oil per day after 10 years of construction.

Congress can overcome barriers to smart growth in several ways. First, it should direct federal agencies to revise their planning models so that they account for smart growth. Currently, when new highway projects or new transit projects are evaluated economically, they rely on models that all but ignore the influence of smart growth development. Upgraded models will save money in directing investment toward more cost-effective transit and highway projects and away from ones that do not justify their cost. Enhanced models can also be used in clean air planning and in the evaluation of transit service levels.

One barrier to smart growth is that many homes located in efficient neighborhoods cost more, and the lending system treats such additional costs as barriers to affordability. The Location Efficient Mortgage solves these problems by allowing potential borrowers with low transportation costs to apply the savings to qualification for a mortgage. Congress could require agencies like Freddie Mac and Fannie Mae to offer Location Efficient Mortgages throughout the country in a way that allows dollar-for-dollar tradeoffs between lower transportation costs and higher housing costs.

We should promote commuter choice with a tax-free benefit for employees who car-pool, use transit, bike to work, or telecommute (currently limited to $100 per month) equal to that provided in the form of free parking (which is at about $200 and is pegged to inflation). This can have a big effect: One recent study in Minneapolis-St. Paul found that more than one in 10 employees shifted from driving to some other way of commuting when offered tax-free commuter benefits equal to those provided in the form of free parking. We should also support cutting the red tape and streamlining financing for public transportation projects that significantly increase mobility of public-transportation-dependent populations and promote economic development in urban "transit-oriented development zones." Projects to evaluate road user charges, which would make the portion that a driver pays for highway maintenance costs depend on how much a person uses the roads, are also worthy of support. This system of recovering costs, currently being researched by several experts, would ensure continued revenue to the highway trust fund.

Accelerate oil savings in industrial, aviation, and residential building sectors through the following:

- expanding industrial efficiency programs to focus on oil use reduction and adopting standards for petroleum heating;
- replacing chemical feedstocks with bioproducts through research and development and government procurement of bioproducts;
- upgrading air traffic management systems so aircraft follow the most-efficient routes; and
- promoting residential energy savings with a focus on oil-heat.

Approximately one-third of U.S. oil demand is consumed in industrial manufacturing plants, airplanes, and residential homes. Efficiency gains in these sectors can save America more than 300,000 barrels per day in 2015 or 12 percent of the 2.5 millions barrels per day national target.

Industrial process heating efficiency. The industrial sector includes manufacturers of diverse products including steel, cement, food, plastics, glass, paper, and chemicals. Heating fuel oil, diesel fuel, and liquefied petroleum gas are used by manufacturing companies for firing boilers and heating and reheating materials during the manufacturing process. Improving the efficiency of boilers and process heating can reduce oil consumption by 15 percent by 2020. We should expand industrial efficiency programs to focus on oil use reduction and adopt standards for petroleum heating efficiency and incentives to accelerate old, inefficient equipment.

Bioproducts. Also in the industrial sector, using petroleum as a feedstock for chemicals and manufactured materials consumes four times the amount of oil used for heating. Oil savings can be achieved by substituting petroleum-based feedstocks with materials derived from crops, or biomass. Today, biomass is used in the production of solvents, pharmaceuticals, adhesives, resins, detergents, inks, paints, lubricants and plastics. According the U.S. Department of Energy (DOE), biofeedstocks could displace 13 percent of petroleum-based feedstocks by 2020. Continued funding of biomass research and development efforts and on-going requirements for government procurement of environmentally sustainable bioproducts will spur the production of substitutes to petrochemical feedstocks. In 2015, oil saving in the production of industrial chemicals could add up to 120,000 barrels per day.

Air traffic management. Airlines use less jet fuel when they use the most direct traffic patterns and minimize idling time before and after landing. Advanced air traffic management technologies available today for aviation communications, navigation, and surveillance (CNS) systems improve airline fuel efficiency by enabling planes to take more direct routes (such as more great circle routes) between destinations, use more airspace at currently prohibited lower elevations, and minimize time waiting for landing and take-off strips. Improvements to CNS systems allow aviation control to migrate from groundbased, limited-range systems to less-constrained satellite-based systems.

According to the U.S. DOE, CNS improvements can reduce commercial jet fuel consumption by 5 percent by 2020. CNS upgrades minimize aircraft rerouting (when conditions unexpectedly change in the air or at airports), control take-off and landing spacing and enable after-flight aircraft and routing performance analysis. We should fund advancements to the air traffic management system that increase routing efficiency and therefore reduce per-passenger fuel consumption.

Oil-heated homes. Petroleum products remain an important source of heating energy in homes. According to the EIA, approximately 8 million residences continue to burn fuel oil, liquefied petroleum gases (LPG), propane, and kerosene for space and water heating. 60 cost-effective home improvements to space and water heating systems such as insulating walls, ceilings and pipes, sealing drafts and especially sealing ducts, installing new windows, upgrading thermostats; updating furnaces; replacing old clothes washers and dishwashers with new efficient models; and replacing water heaters can reduce heating oil use by 30 percent or more.

We should promote residential energy savings with a focus on oil heat to help reduce the nation's oil dependence by adopting stringent efficiency standards for house and apartment building boilers and furnaces; by adopting performance-based tax incentives for home retrofits and for efficient water heaters; and by updating codes for new buildings. Together these measures can save 100,000 barrel of oil per day in 2015. We should promote residential weatherization and other energy saving programs to help achieve the national oil savings commitment.

Encourage growth of the biofuels industry through the following:

- requiring all new cars and trucks to be capable of operating on biofuels or other non-petroleum fuels by 2015;
- converting the federal oxygenate requirement, which is not necessary to meet clean air goals, to a renewable fuel standard; and
- allocating $2 billion in federal funding over the next 10 years to help the cellulosic biofuels industry expand production capacity to 1 billion gallons per year and become self-sufficient by 2015.

Although fuel efficiency is critical to immediately reducing our oil dependence, we must also develop alternative, non-petroleum fuels that can be grown by American farmers. The biofuel feedstock with the potential to displace the largest amount of oil is cellulosic biomass, which includes agricultural residue (the leaves, stems, and stalks of plants), dedicated energy crops, and the biomass portion of the municipal waste stream. Ethanol and methanol, both alcohol fuels, can be made from cellulosic biomass.

A market for biofuels already exists. In 2004, the United States produced more than 3.4 billion gallons of ethanol, almost all from corn, for use as an additive to gasoline. Because the gasoline oxygen additive methyl tertiary butyl ether (MTBE) has been found to contaminate water supplies, the chemical is being replaced by ethanol. Gasoline blended with 10 percent by volume ethanol can be used in unmodified vehicles, but it creates air pollution problems in today's on-road cars. Higher blends of these alcohol fuels, however, can be used only in vehicles specifically designed to burn high-oxygen fuel. So-called flexible fuel vehicles (FFV) can run on gasoline blended with almost any amount of alcohol fuel. The most common high-blend fuel is 85 percent ethanol, E-85. Because high blend ethanol fuel is typically more expensive than gasoline, less than 1 percent of the FFVs on the road today burn gasoline with high ethanol content such as E-85 high blend ethanol from corn. Fortunately, ethanol made from other sources, called cellulosic ethanol, promises to substantially reduce this cost.

Biofuels in new cars and trucks. We should require the use of higher-biofuel blends in gasoline. Higher ethanol blends not only displace more oil but also decrease harmful particulate air pollution associated with lower-ethanol blends in gasoline. To accomplish this, we should require all new cars and trucks to be capable of operating on biofuels or other non-petroleum fuels by 2012. To operate on E-85, and other high-ethanol and methanol blends, FFVs require low-cost technology improvements that generally make the FFV only slightly more costly to buy than its conventional, gasoline-only counterpart.

Ethanol made from cellulosic biomass offers numerous advantages, as detailed in a recent report lead by NRDC for the National Centers for Environmental Prediction (NCEP). The technology for converting cellulose to biofuels is expected to be cost-competitive with petroleum-based fuels. Cellulosic biomass crops, such as switchgrass, have the potential to produce more biomass per acre than almost any other crop and as a perennial they require lower inputs of energy, fertilizer, pesticide, and herbicide, and is accompanied by less erosion and improved soil fertility. Cellulosic biomass also contains substantial amounts of non-fermentable, energy-rich components that can be used to provide energy for the conversion process as well as to produce electricity and other fuels using non-biological conversion processes. With the right policies in place, there is tremendous potential for biofuels to displace petroleum in our cars and trucks. By 2050, biofuels could contribute the equivalent of 7.9 million barrels of oil per day, or 53 percent of our current demand.

Federal oxygenate requirement. To facilitate the transition to cellulosic biofuels, the federal oxygenate requirement, which is not necessary to meet clean air goals, should be converted to a renewable fuel standard. Such a system would provide much needed flexibility to areas that are suffering from the nation's worst air quality to blend effective, low cost, cleaner burning gasoline formulations. To encourage cellulosic production, credits for biofuel production should be awarded based on the environmental performance of its lifecycle including its feedstock production, processing, refining and combustion. In addition to displacing oil consumption, the EPA should be required to ensure that biofuels are used in a way that maintains or improves air quality, water quality and water supply. As the capacity for biofuels production with cost-effective and sustainable practice grows, we should increase production targets of the renewable fuels standard only if it can be demonstrated that there will be no increase in air pollution.

Biofuels funding. Two billion dollars in federal funding for biofuels over the next 10 years would spur innovation, development, and demonstration projects aimed at making biofuels cost-effective for consumers. The funding should supply incentives that will stimulate the growth of the cellulosic biofuel industry toward a production target of 1 billion gallons per year and make the industry self-sufficient by 2015. These funds should be used to achieve two major goals:

- Investing in a package of research, development, and demonstration policies that create the innovations and advances needed for a large-scale, competitive biofuels industry; and
- Funding deployment policies that drive the development of the first billion gallons of cellulosic biofuels capacity at a price approaching that of gasoline and diesel.

RESPONSES OF DAVID HAWKINS TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Your testimony highlights the emissions implications of dramatically increasing our use of coal-to-liquids technology for transportation fuels. Doctor Miller's statement however talks about coal to liquids as a clean technology with near-zero atmospheric emissions of criteria pollutants and carbon capture sequestration. Are your assumptions different? How do you reconcile these two views?

Answer. In fact, my testimony and Dr. Miller's are consistent. With respect to emissions, my testimony focused on emissions of conventional air emissions and of global warming emissions from CTL production plants. Regarding conventional emissions I stated, "While it appears that technologies exist to achieve high levels of control for all or most of these pollutants, the operating experience of coal-to-liquids plants in South Africa demonstrates that coal-to-liquids plants are not inherently 'clean.' Noting the absence of performance standard requirements today, I said "we cannot say today that coal-to-liquids plants will be required to meet stringent emission performance standards adequate to prevent either significant localized impacts or regional emissions impacts."

Dr. Miller stated, "The technology that underlies CTL fuel production offers the potential for low emissions of criteria and toxic air pollutants, water quality, and solid wastes. Nonetheless, this promise of high performance needs to be verified during the design and initial operations of first-of-a-kind CTL plants and costs may be prohibitively expensive." I believe these two statements are completely consistent: for conventional pollutants CTL plants have the potential to be low-emitting but that is not yet assured in practice.

Regarding global warming emissions, I stated "the total well to wheels $CO_2$ emissions from such plants would be about 49.5 pounds of $CO_2$ per gallon, nearly twice as high as using crude oil, if the $CO_2$ from the coal-to-liquids plant is released to the atmosphere." And further that, with "$CO_2$ capture, well to wheels emissions from coal-to-liquids fuels would be 8 percent higher than for petroleum." Dr. Miller did not provide a value for $CO_2$ emissions from plants without capture but he cited a report "Mitretek Technical Report 2005-08, "A Technoeconomic Analysis of a Wyoming Located Coal-To-Liquids Plant" whose estimates of $CO_2$ emissions are similar to ours. Regarding $CO_2$ from plants that capture emissions Dr. Miller stated, "It is possible that CTL plant emissions and the emissions from utilization of CTL products would be comparable to those associated with the production and consumption of petroleum-based fuels."

To summarize, our testimony agrees that CTL plants have the potential to achieve low emission rates for conventional emissions but achieving this performance in practice remains to be demonstrated; that $CO_2$ emissions from the CTL system will be much higher than from the crude-oil system if CTL production plant emissions are not captured; and that $CO_2$ emissions from the two systems would be about the same if CTL production plant emissions were captured.

*Question 2.* Everyone is focused on the need for a demonstrated commercial scale and market for CTL in addition to an adequate coal supply in order to insure that CTL goes forward. Isn't the development of CTL somewhat tied to the development of the carbon market also? Please comment.

Answer. The development of policies to limit $CO_2$ emissions, such as through the establishment of a market-based cap and trade program, will be a key factor in the comparative value of CTL-based fuels compared to alternatives. Some advocates of CTL assert that the industry would need to be provided with government assurances about the future price of oil before the private sector is willing to make large investments in this technology. There is a strong argument that uncertainty about the future costs of managing $CO_2$ emissions will be an impediment to private sector interest in this and other technologies as well.

Some investors may be willing to guess about the pace and level of future $CO_2$ requirements. The only certain thing one can say about that prospect is that some of those guesses will be wrong, resulting in economic waste and potentially large sunk costs in high-$CO_2$-emitting alternatives to conventional oil.

The fact that the U.S. appears to awakening to the need to develop real alternatives to oil provides us with an enormous opportunity—to create the market signals and incentives that will stimulate oil alternatives that are selected because they improve energy security, create jobs at home and put us on a path to protect the climate. If we leave $CO_2$ performance out of the picture in crafting policies to reduce oil dependence we would almost certainly produce a distorted set of responses by the private sector—mistakes that would cost us dearly to correct.

RESPONSES OF DAVID HAWKINS TO QUESTIONS FROM SENATOR WYDEN

*Question 1.* If price volatility and crude oil prices are the two major impediments to bringing coal-to-liquids (CTL) fuels to U.S. markets, the "tipping point" to make CTL economically viable is at $40/barrel and the price of oil is now at $70 per barrel, why does the government need to continue subsidizing more CTL research? Why can't the private sector start building commercially viable production plants?

Answer. As Dr. Miller's testimony noted, the current administration agrees with this view. He stated, "The primary barrier to commercial introduction of the technology has been the volatility and uncertainty of world oil prices. The private sector financial markets are best positioned to evaluate whether, when, and how to build coal to liquids plants given this market uncertainty." A case can be made for providing government support for key technologies that are well-suited to meet future needs but are currently discounted by the private sector. As my testimony argues, coal-to-liquids processes are not well-suited to meet our needs for lower greenhouse gas emitting fuels. Accordingly, it is not a technology that we believe should be a candidate for these types of public subsidies. In general, public support for petroleum fuel replacements should be limited to fuels which, among other criteria, achieve substantial reductions in global warming pollution relative to the fuels they replace.

*Question 2.* As a Westerner, I am concerned about the water resources that are needed to produce fuels from coal. I am also concerned about the increased air pollution and greenhouse gases that are emitted. Much of the water that would go into CTL production, could be used to grow biomass and produce biofuels instead. Has anyone done a comparison of which types of energy production cause the least harm to the environment while delivering the biggest benefits to consumers? Do you know of any analyses that have looked at the "opportunity costs" involved in producing water-intensive energy like CTL?

Answer. Thank you for your question regarding comparative water use by coal to liquids (CTL) technologies. We do not believe that a comprehensive analysis of this issue has been completed. We urge the Committee to support a comprehensive analysis of the water supply implications of not only CTL technologies, but of all the leading alternative fuel sources and petroleum-based fuels. To be authoritative, such a "Well to Wheel" analysis must consider water use in all stages of fuel production. For CTL, biofuels and petroleum based fuels, this analysis must include:

- The amount of water required per unit of product to turn coal into Fischer-Tropsch (FT) fuel, by technology type (cooling process, etc)
- The water usage of turning raw material into usable feedstocks (e.g. mining, refining)
- The efficiency with which the energy in feedstocks is converted into usable fuel.

- The availability of existing waste material as feedstock for ethanol production.
- The geographic distribution of ethanol feedstock production (e.g. irrigation needs)
- The use of water to assist in the extraction of petroleum from well fields with declining production.

This analysis should also include a study of water quality impacts. Water quality impacts can, in turn, lead to significant water supply impacts. For example, the severe water quality impacts caused by coal mining and petroleum production and refining have had a significant impact on the ability of many downstream communities to use their water supplies.

Some existing agricultural practices also result in significant water quality impacts. In the case of the emerging technology of biofuels, it is not yet clear what crops (e.g. switchgrass or corn) would provide the bulk of feedstock for cellulosic ethanol production, nor is it yet clear how those crops would be grown.

As previously stated, there is not yet a substantive body of research on water use in CTL facilities. The only existing analysis that we are aware of—by Mitretek Systems of a possible Wyoming facility—states that "complex conversion facilities like CTL plants usually require large quantities of water for process steam and for cooling and steam condensation."[1] The same report notes that the equivalent of "less than one barrel of water per barrel of FT product" would be needed if dry-cooling technology was employed.

However, dry-cooled power systems are still a relatively immature technology and are significantly more expensive to build and operate than water cooled ones. According to a recent study using EPA calculations which analyzes the water used in the production of power, *The Last Straw, Water Use by Power plants in the Arid West,*[2] operating and maintenance costs of a 700MW dry-cooled plant would be four times higher than for a similar water-cooled plant. The same study notes that total annualized costs for the dry-cooled plant would be more than four times higher ($13.1 million versus $3.1 million) than a water-cooled counterpart.

Additional water use by the power sector in the West would come at a time when water resources in the region are already strained by drought and competing demands. According to the Energy Information Administration, coal and gas-fired electric power plants in the eight state Interior West withdraw over 650 million gallons of water per day.[3] In a one year period, that's the same amount of water used by almost four million people, or six or seven cities the size of Denver, Tucson and Albuquerque.[4]

Western streams and rivers are also an important part of regional and local economies. Yet in many areas, years of drought and altered precipitation patterns have put heavy strains on these water bodies and their ecosystems, adversely affecting the economies they help support. According to recent data, almost 80 percent of the water used by power plants comes from fresh surface waters—mostly rivers.[5] Substantial development of new power generating facilities would exacerbate strains on river and streamflow.

In contrast to energy efficiency projects and renewable energy facilities, water availability is proving to be a growing hurdle for new coal-based generating projects. Increased competition for water from other sectors of the economy and a growing understanding of the importance suitable water levels play in maintaining complex biotic systems have combined to lead permitting authorities to deny permits or condition them on addressing potential impacts to water resources.[6] This is true even in non drought-ridden regions of the country.[7]

Substantial development of CTL plants also will likely result in significant increases in upstream coal mining impacts, which in turn affect water resources. History is instructive. In the western U.S., estimates of the damage from acid mine drainage (AMD) range between five and ten thousand miles of streams polluted.[8] AMD is the most significant form of chemical pollution produced from coal mining

[1] Mitretek Systems, *A Techno-Economic Analysis of a Wyoming Located Coal-to-Liquids (CTL) Plant,* (April 2005).
[2] Clean Air Task Force, The Land and Water Fund of the Rockies, *The Last Straw: Water Use by Power Plants in the Arid West,* (April 2003), http://www.westernresourceadvocates.org/media/pdf/WaterBklet-Final.pdf.
[3] ibid, p. 1.
[4] ibid.
[5] Clean Air Task Force, *Wounded Waters: The Hidden Side of Power Plant Pollution,* (February 2004), p. 2.
[6] ibid., p. 10.
[7] ibid., p. 10.
[8] EPA. *Mid-Atlantic Integrated Assessment: Coal Mining.*

operations. In both underground and surface mining, sulfur-bearing minerals common in coal mining areas are brought up to the surface in waste rock. When these minerals come in contact with precipitation and groundwater, an acidic leachate is formed. This leachate picks up heavy metals and carries these toxins into streams or groundwater. Waters affected by AMD often exhibit increased levels of sulfate, total dissolved solids, calcium, selenium, magnesium, manganese, conductivity, acidity, sodium, nitrate, and nitrite. This drastically changes stream and groundwater chemistry. The degraded water becomes less habitable, non potable, and unfit for recreational purposes. The acidity and metals can also corrode structures such as culverts and bridges.[9]

As previously stated, NRDC agrees that it is essential to consider the water-related implications of energy policy decisions, particularly in arid regions, such as the American West. In 2004, NRDC issued a report entitled Energy Down the Drain, which explores this relationship from a different perspective—the energy implications of water management decisions.[10]

NRDC has also studied water implications of renewable sources, most recently in our report Growing Energy. One promising potential fuel source highlighted in the report (and also by President Bush in his State of the Union address), switchgrass, could result in fewer water quality impacts than other potential feedstocks, because switchgrass requires less fertilizer, herbicide, insecticide and fungicide per ton of biomass than corn, wheat or soybeans. In addition, because switchgrass is a perennial plant, it could also reduce erosion-related water quality impacts compared with other crops.[11] Federal incentive programs for the biofuels industry could encourage more sustainable agricultural practices with reduced water quality and water supply impacts.

NRDC has also determined that, nationally, assuming a value of $30 per dry ton, existing mill waste, forest residues and agricultural residues could produce up to 68 million dry tons of feedstocks for biofuels.[12] This feedstock could be provided with little additional water consumption prior to refining. Our modeling of the potential for switchgrass production also focused production in Appalachia, the Corn Belt and the Southeast, rather than the West, where a greater percentage agricultural water needs are met by irrigation, rather than rainfall. This approach would reduce potential water use implications.[13]

In our *Growing Energy* report,[14] NRDC also determined that "The high level of water recycling also allows us to minimize the total amount of fresh water used. Approximately 2 kg water per kg dry biomass feedstock—about 1,700 gallons per minute—are required as make-up water to account for the treated discharge as well as water consumed during hydrolysis or lost to evaporation. Petroleum refineries, by comparison, typically use 1.8 to 2.5 kg process water per kg crude feedstock—4,400 to 6,200 gallons per minute for a 100,000 barrel per day refinery—and discharge between 1.7 and 3.1 times as much water." Thus, biomass refining may have the potential to reduce water usage in comparison with petroleum-based refineries.

A comprehensive analysis of water use by electricity and fuel supply production is required for another reason. Climate change has the potential to cause significant water supply impacts. Last September, NRDC, the Desert Research Institute and the Southern Nevada Water Authority co-sponsored a conference of water managers and climate scientists to explore the potential water management impacts of climate change. The consensus among scientists is that climate change could reduce available water supplies in the West and in other parts of the nation. The implications in this context are significant. Finding solutions that work in the future will require finding synergies that solve multiple problems. The wrong approach to meeting long-term fuel needs could worsen climate change, increase water use and increase conflicts over water. On the other hand, the development of appropriate technology could result in reduced climate change, lower water use and reduced water conflicts.

*Question 3.* If the German and South African experience in producing coal fuels is any indicator, wouldn't you say that the only policy reason that justifies producing CTL fuels in the U.S. would be at a time when the U.S. no longer had access to world oil markets?

[9] EPA Office of Solid Waste. *Acid Mine Drainage Prediction Technical Document,* (December 1994).

[10] NRDC, *Energy Down the Drain,* (August 2004), http://www.nrdc.org/water/conservation/edrain/edrain.pdf.

[11] NRDC, *Growing Energy,* (December 2004), p. 28, http://www.nrdc.org/air/energy/biofuels/biofuels.pdf

[12] ibid., p. 20.

[13] ibid., p. 27.

[14] ibid., p. 43.

Answer. As your question implies, the historical precedents for countries embracing coal-to-liquids (CTL) fuels involve countries which found themselves (more accurately put themselves) in circumstances where no other alternatives for transportation fuels were available. Obviously, pursuit of a technology by an evil regime does not make the technology evil. The relevant questions are whether CTL fuels are well-suited for our country's needs and whether we have superior alternatives. In my testimony and my responses to your earlier questions and those from other Senators, I have pointed out why we believe CTL fuels are not well-suited to America's needs, especially with regard to the need to protect the climate from global warming emissions but also from the harms that expanded coal production would cause, given today's practices.

Fortunately, our situation is in no way as desperate as that which confronted Nazi Germany or Apartheid South Africa. We have the capacity to meet our transportation needs and reduce oil dependence by producing homegrown fuels from biomass and by using American ingenuity to get more work out of every barrel of fuel we use, through application of known technologies to make more efficient cars, trucks and aircraft and to deploy more efficient industrial processes. In my response to Senator Bunning's question I describe these abundant opportunities in more detail. Coal has an important role in today's economy and will continue for years to come but we do not need to use it to address our addiction to oil.

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RESPONSES OF ARIE GEERTSEMA TO QUESTIONS FROM SENATOR BUNNING

*Question 1.* Some people have argued that "C.T.L" technology exists and that the government should focus on deployment of those existing technologies. You seem to take a different approach, suggesting that more Research is required. Could you explain what research is needed?

Answer. By urging for more R&D, I indicated this should be done in parallel to promoting the deployment of CTL. Deployment does not need to wait for R&D, but R&D will be a meaningful contributor to bringing costs down.

CTL as an integrated combination of gasification of coal with the conversion of the syngas to liquid fuels is currently only practiced commercially by Sasol as indicated in my testimony. Several other companies have gasification facilities while some have Gas to Liquids (GTL) or Fischer-Tropsch technology. Shell is the only one besides Sasol with commercial FT technology. In all cases the technology, at whichever level of maturity, is very closely protected. An important consideration in funding FT R&D is to broaden the technological base and to provide alternatives and expertise which is outside of the closely protected IP areas of the commercial entities. "Commercial technologies" do not mean that these technologies are available to anyone wishing to apply it.

It is not unusual for the Government through DOE to fund research in areas where there are commercial technologies available. To name but a few: Gasification, Fuel Cells and Turbines. These projects were supported to improve on existing commercial technologies or to get them to operate under more demanding circumstances. In the same way I believe that further R&D regarding CTL will provide opportunities to improve viability and to facilitate deployment. CTL is an issue of strategic dimensions, not merely one where small companies will put up small plants: we need to think big.

Furthermore, I indicated that by funding research in CTL, a wider basis will be provided from which we can again grow a coal technology human resource capability which has nearly disappeared since the interest in coal technology waned in the 1980's. Industries currently do little in this regard and the few people who have expertise are very much in demand. We need to increase the size of the pool.

An example of the ongoing need for R&D is that Sasol, even after more than 50 years of R&D, is still investing continuously in process improvements. This year it announced that additional FT R&D reactors will be erected at a cost of about $33 million. This will invariably be closely IP protected. The point is that we need to also do open research to promote the technology and even in commercial environments R&D is continuing.

Specifically, the type of research which can be funded as "open" is similar to the catalysis research funded in the 1990's and which led CAER to now being the most significant open access R&D facility for FT catalysis. This can be witnessed by the fact that CAER does testing for national and international FT companies. This addresses the catalysis, but it takes much more than a good catalyst to make a good technology. Research can be done to firm up the understanding of the separation of catalysts from wax in slurry FT systems, understanding the complex physical properties of multiphase systems in slurry reactors at high temperatures and pressures, improving syngas cleaning processes specifically for FT and matching those processes with novel, more resistant catalysts, producing test quantities of refined FT fuels under different refining conditions for optimal product properties, etc. It will be of great benefit if such R&D could be done in small scale units which are fully integrated from the syngas to refined products to ensure that the system as a whole is optimized and not operated as sub-systems in isolation.

*Question 2.* The finished "C.T.L." product is low particulate, low mercury and almost zero sulfur. Could you elaborate on the emissions characteristics of "C.T.L." transportation fuels compared to current fuels?

Answer. The superior qualities of FT fuels have been widely investigated and reported. Institutions like the Southwest Research Institute (SWRI) did independent comparative tests on FT diesels from different sources and all showed similar excellent performance regarding emissions, cetane number, minimal sulfur with reduced hydrocarbon and particulate emissions. Mercury does not appear in the FT fuels as mercury is captured in the syngas cleaning process following gasification. As an example, results from SWRI tests were published in 1997 ("*Diesel Exhaust Emissions Using Sasol Slurry Phase Distillate Process Fuels*" by Schaberg, P.W. et al. and co-authored by Starr, M.E. of SWRI, published as a SAE Technical paper 972898). This publication reports results from testing seven diesel fuels. There were different FT diesels, CARB and US 2-D fuels as well as three blends of FT fuels and 2-D fuels. The report shows improvements in all characteristics for the blends in proportion to the amount of FT fuel in the blend with the best results for pure FT fuels. This indicates the compatibility as a blending component or as a pure fuel. Similar results have been published by companies like Shell, Rentech and Syntroleum and can be accessed on their web sites.

*Question 3.* As the Energy Information Administration forecast indicates, we have two choices: we can import "C.T.L." fuels from foreign countries or we can produce it ourselves. I believe, and I think the witnesses here today have shown, that America can produce these fuels cleaner than anywhere else. Given the environmental and safety records of other coal countries, wouldn't you agree that the production of coal and "C.T.L." in other nations would cause more environmental damage than if they are produced in America?

Answer. The question raises the matter whether CTL should be practiced in the US (with tight environmental requirements) or whether developing countries could do it (with potential negative environmental consequences) and export the FT products to the USA. The need for the fuels is in the USA and it is economically advantageous to have local production. If we would promote the production in coal rich developing countries, this will not reduce our dependence on foreign fuel imports and secondly, there might indeed be a greater negative environmental impact than if we put up well regulated CTL facilities in the US.

My preference is clearly to erect the CTL facilities in the USA.

RESPONSES OF ARIE GEERTSEMA TO QUESTIONS FROM SENATOR WYDEN

*Question 1.* If price volatility and crude oil prices are the two major impediments to bringing coal-to-liquids (CTL) fuels to U.S. markets, the "tipping point" to make CTL economically viable is at $40/barrel and the price of oil is now at $70 per barrel, why does the government need to continue subsidizing more CTL research? Why can't the private sector start building commercially viable production plants?

Answer. The price of crude and its price volatility are certainly risk factors which impact the investment decisions. Several other risk factors enter into the investment decision, such as the maturity of technology under local conditions, environmental permitting, plant siting and the need for very large capital investments for plants which are large enough to have strategic impact. Which companies will step up to enter into CTL ventures as "owner-operators" is not yet clear. "Private sector" is an amorphous concept in this case seeing that there is not yet a CTL industry in the US and there is uncertainty as to who will take the lead. Once a plant or two of meaningful capacity have been built, I believe more will follow.

Regarding "Why fund more R&D?", I believe that this is to promote the capabilities and creative new concepts in this area while the commercialization should continue in any case. Please also refer to my answer to Senator Bunning's question number 1. above.

*Question 2.* As a Westerner, I am concerned about the water resources that are needed to produce fuels from coal. I am also concerned about the increased air pollution and greenhouse gases that are emitted. Much of the water that would go into CTL production could be used to grow biomass and produce biofuels instead. Has anyone done a comparison of which types of energy production cause the least harm to the environment while delivering the biggest benefits to consumers? Do you know of any analyses that have looked at the "opportunity costs" involved in producing water-intensive energy like CTL?

Answer. I am not personally informed about environmental or "opportunity cost" studies which have been done to do the comparisons referred to and I cannot comment on the results of such studies. I do believe that the energy issue is so wide in its impact, that we should pursue multiple options for farther development across the spectrum of modernized traditional methods as well as the range of "alternative" and novel energy sources. Different technologies will have applications in different circumstances and diversity in the approaches will enable us to make responsible choices for the benefit of the environment and the consumer

CTL facilities do in fact, like coal based power stations, require substantial amounts of water. Exactly how much depends on the design and complexity of the facility. Generic numbers can be misleading. For instance, the choice between water cooling versus air cooling greatly impacts water consumption.

Regarding air pollution/green house gases: I indicated that the technologies are now available to make these facilities true "Clean Coal" facilities. Whether the $CO_2$ will be captured and sequestered is a matter of permit requirements, mandated carbon trading and similar factors. These eventually boil down to whether a particular entrepreneur considers a project viable for a particular site.

*Question 3.* If the German and South African experience in producing coal fuels is any indicator, wouldn't you say that the only policy reason that justifies producing CTL fuels in the U.S. would be at a time when the U.S. no longer had access to world oil markets?

Answer. I believe that CTL is competitive at oil prices around $45 to $50 per barrel. In my testimony I indicated that the decision to build Sasol Two was based on economic considerations. The Sasol Three decision had an additional consideration of security of supply but Sasol has for many decades been commercially competitive and very profitable as a private sector company.

The German plants by all accounts had limited capacities (statistics differ and many of them were operating very sporadically during the war). That was clearly a war effort and economics did not come into the picture. However, already before the war there were commercial units operating in Germany and the South African case is a commercial success story from its early (pre-sanctions) years. Thinking of Germany and South Africa as cases where FT went ahead merely because of supply concerns is not doing justice to history.

The main reasons for encouraging CTL in the US are that such ventures are likely to be profitable; it makes sense from a security of supply perspective; it reduces our import dependency and it will have a significant favorable economic multiplier effect. The sooner we start with CTL, the sooner we shall start reaping the benefits of this opportunity.

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RESPONSES OF JAMES ROBERTS TO QUESTIONS FROM SENATOR BUNNING

*Question 1.* You suggest that our efforts need to focus on the deployment of coal-to-liquids facilities rather than on research and development. You argue that the technology is proven and ready for deployment. How best can the Department of Energy fashion the load guarantee program established by the Energy Policy Act to foster deployment of such technology?

Answer. NMA supports the use of federal loan guarantees, both self-pay and traditional, for 10 CTL plants through 2015. This type of commitment (authorized by Title XVII of the Energy Policy Act of 2005) specifically focused on the financing of gasification projects dedicated to the producing synthetic gas from coal will serve as the basis for the production of liquid transportation fuels.

*Question 2.* The finished "CTL" product is low particulate, low mercury and almost zero could you elaborate on the emissions characteristics of "CTL" transportation fuels compared to current fuels?

Answer. Once the coal is gasified, virtually all sulfur must be removed from the gas prior to its entry into the Fischer-Tropsch (FT) reactor. The result is a near-zero sulfur fuel. Sulfur-based emissions are a primary drawback of conventional diesel fuels because sulfur decreases the effectiveness of control devices (like catalytic converters) that could otherwise further reduce harmful emissions. FT diesel therefore directly eliminates sulfur emissions and allows even greater control of other emissions.

Largely because FT diesel contains very low aromatics, combustion results in very low PM. Recent tests conducted by the Department of Defense (DOD) showed particulate matter exhaust reductions using FT diesel as high as 90 percent.

FT diesel results in fewer $NO_X$ emissions because the fuel itself makes no contribution to the formation of $NO_X$ in the engine cylinders. With FT diesel, thermal $NO_X$ emission levels have been found to be reduced by anywhere from 9 percent to 28 percent when compared to low sulfur diesel or CARB (California grade) diesel.

Tests have shown the use of FT diesel reduces hydrocarbon emissions by as much as 72 percent.

FT diesel, because of its higher cetane and lower aromatics, significantly reduces the emission of harmful carbon monoxide as compared even to low sulfur diesel because it burns more cleanly and completely.

While actual $CO_2$ emissions of a given diesel fuel depend on a number of factors, including the quality of the fossil fuel feedstock (coal or oil), FT diesel should produce no more tailpipe $CO_2$ than petroleum diesel.

*Question 3.* As the Energy Information Administration forecast indicates, we have two choices: we can import "C.T.L." fuels from foreign countries or we can produce it ourselves. I believe, and I think the witnesses here today have shown, that America can produce these fuels cleaner than anywhere else. Given the environmental and safety records of other coal countries, wouldn't you agree that the production of coal and "C.T.L." in other nations would cause more environmental damage than if they are produced in America?

Answer. Yes, I do. In the U.S. coal is mined under the most comprehensive environmental laws found anywhere in the coal producing regions of the world. At both the state and federal levels producers are obliged to follow specific laws that regulate and control the environmental impacts of coal mining. Extensive permit approvals must first be obtained before mining operations begin. The impact of coal mining on water quality, air quality and wildlife habitat are just some of the major considerations that ensure against harm to the surrounding ecosystem. Land reclamation following mining is also required by law. Since 1978 more than 2 million acres have been reclaimed based on detailed plans that must be approved before mining activity begins. All coal mines are required to report their toxic releases to the air and water. Finally, federal environmental agencies in the U.S. tend to operate more independently of political or economic influence than is typically the case in many other countries.

RESPONSES OF JAMES ROBERTS TO QUESTIONS FROM SENATOR WYDEN

*Question 1.* If price volatility and crude oil prices are the two major impediments to bringing coal-to-liquids (CTL) fuels to U.S. markets, the "tipping point" to make CTL economically viable is at $40/barrel and the price of oil is now at $70 per barrel, why does the government need to continue subsidizing more CTL research? Why can't the private sector start building commercially viable production plants?

Answer. The need for government involvement is not in the research arena but in the initial financing stages of developing large-scale CTL production. By helping to "jump start" investment at the front-end engineering and design work required for billion-dollar CTL plants, the federal government would help to overcome the reluctance of U.S. investors to back what they consider to be unfamiliar technology. U.S. financial participation will also reassure private investors by discouraging the foreign oil cartel from once again manipulating oil prices to kill investment in competing domestic energy production, as the cartel did in past decades.

*Question 2.* As a Westerner, I am concerned about the water resources that are needed to produce fuels from coal. I am also concerned about the increased air pollution and greenhouse gases that are emitted. Much of the water that would go into CTL production could be used-to grow biomass and produce biofuels instead. Has anyone done a comparison of which types of energy production cause the least harm to the environment while delivering the biggest benefits to consumers? Do you know of any analyses that have looked at the "opportunity costs" involved in producing water-intensive energy like CTL?

Answer. I know of no formal comparison of the environmental impacts of various types of energy production vis-a-vis consumer benefits or any analyses which have looked at the water related "opportunity costs" involved in the production of CTL. However, all forms of energy production have associated lifecycle costs, such as water, fertilizer and transportation.

*Question 3.* If the German and South African experience in producing coal fuels is any indicator, wouldn't you say that the only policy reason that justifies producing CTL fuels in the U.S. would be a time when the U.S. no longer had access to world oil markets?

Answer. What is instructive about the examples of Germany and South Africa is that, like the U.S., they both had substantial coal reserves and also faced a dire need to reduce their reliance on costly imported energy to service their economies.

Their successful experience suggests that the U.S. should not wait any longer to see its reliance on offshore energy increase before developing—as these countries did—an alternative domestic source of fuels that is affordable, abundant and not subject to foreign control.

Across the world, energy has now become the linchpin of economic competitiveness, forcing the U.S. and its industrial competitors to strategically reassess their energy supplies and sources. The perception of energy scarcity has become acute as political instability menaces existing supplies, unfriendly governments threaten to nationalize energy assets, and nation states revive great power alliances to find and secure reliable supplies of oil and gas for their growing economies.

The 2005 hurricane season and the resulting disruption of petroleum production and refining capacity in the gulf, coupled with our nation's increasing dependence on imported energy and the intensified competition for this energy from rapidly expanding economies such as China and India, are compelling reasons for the U.S. to secure and diversify domestic sources of energy.

Clearly, a secure America in the 21st century will mean energy security. Our security is jeopardized, however, by our increasing reliance on foreign energy. The United States currently depends on foreign sources for 60 percent of its domestic oil requirements, including crude oil and refined products. According to the Energy Information Administration (EIA), that dependence will grow to 70 percent by 2025.

Already, imported energy—including crude oil and natural gas—accounts for a third of the record U.S. trade deficit and caused Americans to pay 17 percent more for energy in 2005 than the year before.

The Energy Policy Act of 2005 encouraged the development of alternative fuels such as coal-to-liquid (CTL) fuels and coal-derived natural gas substitutes, but its modest incentives are far too timid a response to today's stark realities.

For a forceful response to the energy challenge, the U.S. must make greater use of its unrivalled coal reserves—to provide significant new supplies of clean CTL fuels, to enhance oil and coal bed methane recovery and to produce ethanol.

The U.S. has 27 percent of world coal supply—the largest of any country—but less than 2 percent of the world's oil and less than 3 percent of its natural gas. By contrast, Iran and Russia possess almost half of the world's supply of natural gas between them.

Production of coal-derived liquid fuels would expand potential uses of America's nearly 250 billion tons of recoverable coal reserves beyond electricity generation to help reduce our reliance on foreign sources of oil, while promoting national security and providing for sustained economic growth.

With coal reserves and production dispersed widely among more than two dozen states, the U.S. boasts a geographic diversity of domestic fuel supply that is less susceptible to natural disasters and terrorist threat.

Producing CTL fuel does not depend on unproven technology nor require extensive R&D. China is already building a $2 billion CTL plant that will begin using its enormous coal reserves in the fall of 2007, and plans to build many more.

Moreover, U.S. coal reserves cannot be nationalized by a foreign government, require no costly armed forces to protect, nor costly exploration efforts to discover.

[Responses to the following questions were not received at the time this hearing went to press:]

QUESTIONS FOR HUNT RAMSBOTTOM FROM SENATOR BUNNING

*Question 1.* Would you please explain how your process manages carbon emissions as well as sulfur, nitrogen and mercury? How your emissions profile compare with other coal-to-liquids processes?

*Question 2.* The finished "C.T.L." product is low particulate, low mercury and almost zero sulfur. Could you elaborate on the emissions characteristics of "C.T.L." transportation fuels compared to current fuels?

*Question 3.* Your plant in Illinois will convert a natural gas-powered facility into a coal-powered facility that will produce surplus electricity as well as "C.T.L." fuel. Your second plant in Mississippi will achieve an impressive rate of 100% Carbon sequestration. Do you believe that "C.T.L." can reasonably be implemented with these levels of sequestration, electricity generation and "C.T.L." fuel production? Wouldn't such a plant be a very efficient and clean energy source?

*Question 4.* As the Energy Information Administration forecast indicates, we have two choices: we can import "C.T.L." fuels from foreign countries or we can produce it ourselves. I believe, and I think the witnesses here today have shown, that America can produce these fuels cleaner than anywhere else. Given the environmental and safety records of other coal countries, wouldn't you agree that the production of coal and "C.T.L." in other nations would cause more environmental damage than if they are produced in America?

QUESTIONS FOR HUNT RAMSBOTTOM FROM SENATOR BINGAMAN

*Question 1.* In testimony before the EPW Committee in November 2005, one coal-to-liquids company stated that if the United States converted five percent of its recoverable coal reserves to oil, it would be equivalent to the existing 29 billion barrels of proven oil reserves in the United States.

I have heard that most processes for converting coal into liquids turn a ton of coal into a little more than a barrel's worth of oil or refined product such as gasoline or diesel.

In your experience, is there a process that is that efficient in the way it converts coal to oil?

*Question 2.* Several companies have indicated support for the loan guarantees for coal to liquids plants that are contained in the new energy law Congress passed last summer.

As a company, is this loan guarantee helpful to you as it is presently structured? Does it need to be adjusted in any way to assist coal to liquids producers?

*Question 3.* Several companies have expressed interest in the construction of FT plants.

Is it correct that the development and planning for these plants is occurring in compliance with existing environmental law and with the acceptance of the local communities in which the plants are proposed to be located?

*Question 4.* I'm told that the Fischer-Tropsch process has the advantage of forming products that are highly paraffinic and these products are desirable because they exhibit excellent combustion and lubricating properties. Unfortunately, I'm also told a disadvantage of the Fischer-Tropsch process is that the process emits relatively large amounts of $CO_2$ during the conversion of solid hydrocarbons into liquid.

Would you review the greenhouse gas emissions associated with your technology?

QUESTIONS FOR HUNT RAMSBOTTOM FROM SENATOR WYDEN

*Question 1.* If price volatility and crude oil prices are the two major impediments to bringing coal-to-liquids (CTL) fuels to U.S. markets, the "tipping point" to make CTL economically viable is at $40/barrel and the price of oil is now at $70 per barrel, why does the government need to continue subsidizing more CTL research? Why can't the private sector start building commercially viable production plants?

*Question 2.* As a Westerner, I am concerned about the water resources that are needed to produce fuels from coal. I am also concerned about the increased air pollution and greenhouse gases that are emitted. Much of the water that would go into CTL production, could be used to grow biomass and produce biofuels instead. Has anyone done a comparison of which types of energy production cause the least harm to the environment while delivering the biggest benefits to consumers? Do you know of any analyses that have looked at the "opportunity costs" involved in producing water-intensive energy like CTL?

*Question 3.* If the German and South African experience in producing coal fuels is any indicator, wouldn't you say that the only policy reason that justifies producing CTL fuels in the U.S. would be at a time when the U.S. no longer had access to world oil markets?

MONDAY, MAY 1, 2006

DEPARTMENT OF ENERGY,
CONGRESSIONAL AND INTERGOVERNMENTAL AFFAIRS,
*Washington, DC, July 5, 2006.*

Hon. PETE V. DOMENICI,
*Chairman, Committee on Energy and Natural Resources, U.S. Senate, Washington, DC.*

DEAR MR. CHAIRMAN: On May 1, 2006, David Garman, Under Secretary, testified regarding the economic and environmental issues associated with coal gasification technology and on implementation of the provisions of the Energy Policy Act of 2005 addressing coal gasification.

Enclosed are the answers to five questions that were submitted by Senators Talent, Bunning and Bingaman for the hearing record. The remaining seven answers are being prepared and will be forwarded to you as soon as possible.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Lillian Owen, at (202) 586-2031.

Sincerely,

JILL L. SIGAL,
*Assistant Secretary.*

[Enclosures.]

RESPONSE TO QUESTION FROM SENATOR TALENT

QUALIFYING GASIFICATION PROGRAM

*Question.* We have a significant domestic supply of coal in the U.S. and I am strongly supportive of technologies that will increase its use in the environmentally sensitive manner, specifically coal gasification. In last year's energy bill, we included many incentives for coal and petroleum residue gasification. I want to see those incentives work. Will you, working with the IRS, please clarify the definition of "gasification technology" and "eligible property" as it relates to FRS NOTICE 2006-25, Qualifying Gasification Program?

Answer. Gasification technology and eligible property are defined in IRC Sec. 48B(c)(2) and IRC Sec. 48B(c)(3) as added by EPAct 1307(b). These definitions are sufficient to prepare applications for the Department of Energy (DOE) certification and the Internal Revenue Service (IRS) allocation. However, DOE has discussed with the Internal Revenue Service (IRS) the possible need to further clarify these definitions. The IRS informs us that it is developing supplemental guidance on the coal gasification credit and will consult with DOE regarding appropriate clarifications to the definitions as part of that process.

RESPONSES TO QUESTIONS FROM SENATOR BUNNING

COAL TO LIQUIDS

*Question 5.* As you know, Section 369 of the Energy Bill provided that D.O.E. participate in Department of Defense's Assured Fuels Program to evaluate the potential of coal-to-liquids for use by the military. What is the status of that program?

Answer. Section 369 of the Energy Policy Act of 2005 (PL 109-58) directs the Secretary of Energy, in coordination with the Secretary of the Interior and the Secretary of Defense, to establish a task force to develop a program to coordinate and accelerate the commercial development of strategic unconventional fuels, including but not limited to oil shale and tar sands. This task force has been convened and coal-to-liquids technologies are being evaluated.

TRANSPORTATION FUELS

*Question 6.* Section 417 of the Energy Bill authorizes $85 million to test advanced technologies for the production of transportation fuels manufactured from Illinois Basin coal. It also provides funding for the construction of testing facilities at the University of Kentucky's Center for Applied Energy Research among other locations. Could you provide an update on this initiative?

Answer. The Department has not identified funding to do the work authorized in Section 417 of the Energy Policy Act of FY 2005. The Department's enacted budget for FY 2006 and the Department's budget request for FY 2007 did not include funding for this work. The Department has not asked for Coal-To-Liquid (CTL) R&D

funding for several years because the CTL technology is mature, from a research perspective.

RESPONSES TO QUESTIONS FROM SENATOR BINGAMAN

TAX CREDIT PROPOSAL

*Question 3.* Section 48B tax credit—Undersecretary Garman, it is my understanding that the IRS is using the DOE to help select tax credit proposal. How will the DOE assess merit to these proposals, has this been communicated effectively or will you simply certify to the IRS a proposal has met the criteria outlined by the IRS?

Answer. The Department of Energy has been asked by IRS to certify that tax credit applications are feasible and consistent with energy policy goals. DOE will assess applications based on the criteria published in the IRS Notice and will internally rank the projects based on those criteria. In the event that there are more qualified (certifiable) applications than there are available tax credits, DOE will certify projects to the IRS in descending order of rank, but only until the available tax credits are exhausted. The ranking of qualified applications for the Section 48B tax credit will be determined by DOE based on Program Policy Factors in accordance with Appendix B of IRS Notice 2006-25 "Guidelines for Program Policy Factors to be used by DOE in the evaluation of the applications". Evaluation of Program Policy Factors may include consideration of a variety of project characteristics, as appropriate, such as the ratio of plant capacity to requested tax credit, plant efficiency, process design compatibility with carbon capture (gasifier sizing and pressure, air separation unit sizing, quench system, etc.), and location of the facility relative to potential carbon sequestration locations and $CO_2$ pipelines or pipeline easements.

SYNGAS OPERATION

*Question 4.* Section 48 tax credit—Undersecretary Garman, it is my understanding that there seems to be a concern with section 48B(d)(3)(D) regarding 90 percent of the facility operating using syngas apparently the IRS and the DOE have put forth in a rule for comment that it be at "all times". Can you please explain why this phase was added—it seems virtually impossible to achieve during the start up phase of many of these facilities.

Answer. The Department of Energy has discussed with the Internal Revenue Service (IRS) the difficulty of operating with 90 percent syngas during startup. The IRS will issue a notice to clarify.

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AGRIUM U.S. INC.,
KEANI NITROGEN OPERATONS,
*Kenai, AK, May 11, 2006.*

Hon. PETE V. DOMENICI,
*Chairman, Senate Committee on Energy and Natural Resources, Washington, DC.*

DEAR SENATOR DOMENICI: Thank you for the opportunity to testify before the Senate Committee on Energy and natural. Resources on May 1, 2006 regarding the industrial gasification provisions of the Energy Policy Act of 2005.

As requested, enclosed please find responses to the questions provided to me on May 4, 2006.

Should yoy require anything further please do not hesitate to contact me.

Sincerely,

WILLIAM A. BOYCOTT,
*General Manager.*

RESPONSES TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Section 4 tax credits—Mr. Boycott, how tight are your margins and will the tax credits make a difference in deciding to produce your plant?

Answer. The section 48B tax credits could make a difference. If the Kenai Blue Sky Project qualified for the maximum $130 million in tax credits, we estimate that this amount would improve the overall return on investment in the project by approximately 0.5 percent. We are still too early in our feasibility analysis to say whether this improvement to project economies would make a difference in the ultimate decision to proceed.

*Question 2.* Section 48 tax credits—Mr. Boycott, approximately how big a credit would you apply for and how many projects do you realistically think the Energy Policy Act could fund?

Answer. Under section 48B a total of $650 million in qualifying property is eligible for the 20% credit, resulting in a maximum $130 million credit per project. Since our project will cost significantly more than $650 million, we anticipate applying for the maximum amount of credit available. We also believe that any industrial scale gasification project will cost more than $650 Million, thus every project will be applying for the maximum amount of credit. If this is the ease, then the total of $350 million available under section 48B will fund between 2 and 3 projects.

*Question 3.* Loan Guarantees—Mr. Boycott, do you believe it is important that the DOE cover 100 percent of the 80 percent project cost guarantee?

Answer. Yes. For the loan guarantee program to be effective, it must provide a degree of certainty to the private sector investors (project proponent, equity partners and banks and other lenders) that the federal government is going to share some of the risk of the project. To the extent the federal government implements the loan guarantee in a selective approach, agreeing to guarantee less than 100 percent of covered debt financing becomes significantly more complicated and expensive and the certainty provided by the loan guarantee will be eroded and its effectiveness will he diminished.

*Question 4.* Loan Guarantees—Mr. Boycott, do you believe that it is important for the loan guarantee to cover the life of the financing for the project or smaller increments of time?

Answer. The principle is the same as expressed in #3 above. These capital-intensive projects are very complex and, as a result, arranging financing for them is a difficult undertaking. If the federal government embarks on a path of trying to determine that certain phases of the project are eligible for a loan guarantee and others are not, the value of the loan guarantee as a risk sharing mechanism is significantly diminished and the difficulty of acquiring and cost of debt is significantly increased.

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## RESPONSES TO QUESTIONS FROM SENATOR BUNNING

*Question 1.* Across the world, energy has become the lynchpin of economic competitiveness. America's coal reserves can provide us with an invaluable hedge against our growing addiction to imported energy, and provide a significant source of fuel for our growing economy. Could you describe the benefits coal gasification could offer to the American economy in terms of prices, environmental effects and national security?

Answer. Use of coal gasification technology could provide an important alternative source of feedstock for the U.S. fertilizer industry. The biggest challenge coal gasification faces today is the initial capital investment to construct a commercial-scale facility. Once the initial capital hurdle is overcome, it is projected that coal derived synthetic gas can provide a very economic feedstock on a dollar per BTU basis for the manufacture of fertilizer. In the U.S. fertilizer industry, the high price of natural gas has forced the closure of some 8 million t/y of U.S. ammonia capacity since 1999, leaving approximately 11 million t/y of capacity currently operational.[1] Domestic ammonia production in 2006 is expected to account for only 47% of total U.S. ammonia requirements compared to 77% in 2000.[2] Imported fertilizer has replaced domestic production, greatly increasing our nation's reliance on foreign imports to sustain our agricultural industry. The Kenai Blue Sky coal to ammonia project not only provides art opportunity to use an alternative energy source to replace scarce and expensive natural gas but this project, and others like it, can be configured to emit minimal emissions thus allowing an important U.S. industry to be sustained in this country. Furthermore, the Kenai Blue Sky project is being planned to capture and use the carbon dioxide generated for enhanced oil recovery that will in turn enable additional production of domestic oil.

*Question 2.* It seems to me that industry is only asking the government for help with the front-end financing of coat gasification plant construction. How does the loan guarantee program fit this goal? What additional programs may be needed?

Answer. In order to commercialize coal gasification technology for use in the fertilizer industry public support to reduce financing risks appears to be required. Theoretically, a properly constructed loan guarantee program could assist project costs by reducing the costs of borrowing and providing lenders with an additional degree of comfort that project debt will be repaid. Because the Title XVII loan guarantee program has yet to be implemented (regulations or guidelines for administering the program have not been issued) it is not certain how a loan guarantee

[1] Ammonia Outlook, March 2006, FERTECON Limited, p. 99.
[2] Ibid.

might actually assist our project. A federally backed loan guarantee has the potential to greatly enhance the success of a gasification project. Until the Department of Energy actually implements the loan guarantee program we are not able to comment upon the utility of such a program to support the Kenai Blue Sky project. An additional program that should be considered is extension and enhancement (additional amounts) of the Section 48B tax credits. Chairman Chuck Grassley and Ranking Member Max Baucus of the Senate Finance Committee have introduced legislation (S. 2401) that, if enacted, could be of great benefit to projects, like the Kenai Blue Sky project, that may not be ready in time to apply for the limited and existing industrial gasification tax credits but would be so in future years.

*Question 3.* Would you please explain how the coal gasification process could be used to manage emissions?

Answer. Coal gasification technology has improved and been refined over the several decades that technology has been in use. In traditional combustion processes, emissions can only be controlled at the stack (i.e. once combustion has occurred in coal gasification, the gas is purified throughout the process. This allows for the capture of potential pollutants, such as sulfur before the pollutant reaches the stack. The gasification process also allows for the capture of carbon dioxide so that it can be utilized in the production of fertilizer (urea) or utilized to increase production from existing oil fields through Enhanced Oil Recovery (EOR). Using modern gasification processes, the overall emissions of pollutants can be less than what is achieved with traditional natural gas processes.

*Question 4.* As the Energy Information Administration forecast indicates, we have two choices: we can import energy from foreign countries or we can produce it ourselves. I believe, and think the witnesses here today have shown, that America can produce these fuels from our coal reserves clearer than anywhere else. Given the environmental and safety records of other coal countries, wouldn't you agree that the production of coal in other nations would cause more environmental damage than if they are produced in America?

Answer. I believe that we can and will develop projects in North America that will mitigate damage to our air, land, and water. The Kenai Blue Sky project is a good example of how America's resources can be developed responsibly to invigorate our domestic fertilizer industry by using coal, our nation's most abundant, domestically controlled fossil fuel resource, while also protecting the environment.

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RESPONSES OF BRIAN FERGUSON TO QUESTIONS FROM SENATOR BUNNING

*Question 1.* Across the world, energy has become the lynchpin of economic competitiveness. America's coal reserves can provide us with an invaluable hedge against our growing addiction to imported energy, and provide a significant source of fuel for our growing economy. Could you describe the benefits coal gasification could offer to the American economy in terms of prices, environmental effects and national security?

Answer. Coal-gasification offers high potential to remove price volatility from fuels and feedstocks that are essential as major inputs to U.S. manufacturing. Those distressed industries that are natural gas dependent, and globally competitive, can economically use gasification to produce synthesis gas as substitution for natural gas. Today, faced with volatility, they must choose to switch technology and feedstocks, or shift production to cheap feedstock regions of the world. Gasification technology is a key to preserving hundreds of thousands of American jobs that remain at risk, as well as future investments in industrial research and innovation that are essential for a growing and competitive U.S. economy. Environmental benefits are well known—greatly reduced emissions as compared to other solid fossil fuels technologies, emissions approaching those of natural gas fueled facilities, with the lowest cost option for carbon capture and sequestration of any coal-based technology. National security benefits will include greater diversity of fuels and feedstocks domestically based, rather than deepening dependencies upon fossil fuels from politically unstable regions of the world. Almost any use of oil and natural gas can be replaced with technologies utilizing syngas produced from coal gasification if national security is a primary concern.

*Question 2.* It seems to me that industry is only asking the government for help with the front-end financing of coal gasification plant construction. How does the loan guarantee program fit this goal? What additional programs may be needed?

Answer. The federal loan guarantee program will address acute "capital market imperfections" that pose barriers to the capital intensive investments in gasification by early adopter industrials. These include: higher first-of-a-kind costs including higher financial risk premiums; free-rider problems with competitors who adopt later when capital costs and risk premiums have been reduced; and Federal policies that restrain natural gas supply and increase natural gas demand for power generation, while restraining market entry for energy and power sales from industrial gasification polygeneration units. In short, early adopters of industrial gasification will have perceived risks that are greater than later adopters, thus their financing costs will be higher and financing may even be difficult to obtain without some form of loan guarantee backstop. The federal loan guarantee program would allow industrials to overcome capital market imperfections in the early development and use of commercial gasification technology and would minimize the risk premium for financing of early adopter projects. Together with investment tax credits, these incentives will work to jump-start industrial investments. Beyond commercial deployment, other programs should include expanded cost-shared RD&D between industry and the federal government. Particularly important research topics include reduction of air separation costs and its parasitic power losses, development of advanced gasifier designs that improve performance at lower costs, development of advanced syngas cleanup technologies, and development of advanced technologies for conversion of syngas into desired chemicals, fertilizers, and fuels.

*Question 3.* Would you please explain how the coal gasification process can be used to manage emissions?

Answer. Typically, oxygen-blown gasification produces a concentrated high-pressure syngas stream that enables cost efficient and highly effective removal of contaminants such as sulfur and metals prior to any downstream combustion or use of the syngas. The process can take almost any carbonaceous material, laden with impurities, and produce a very clean synthesis gas composed primarily of carbon monoxide and hydrogen. Any carbon monoxide in the syngas can be further reacted with water and converted to carbon dioxide and hydrogen. Carbon dioxide is concentrated in the gas stream and can be relatively easily separated from the ultraclean hydrogen and made ready for sequestration or enhanced oil recovery.

*Question 4.* As the Energy Information Administration forecast indicates, we have two choices: we can import energy from foreign countries or we can produce it ourselves. I believe, and I think the witnesses here today have shown, that America can produce these fuels from our coal reserves cleaner than anywhere else. Given the environmental and safety records of other coal countries, wouldn't you agree that the production of coal in other nations would cause more environmental damage than if they are produced in America?

Answer. Generally, yes, but only if American markets get moving with coal-gasification investments now. This technology is rapidly moving to other regions of the world for industrial production beyond power, and where capital market imperfections are addressed (e.g., China). The attitude of the regulated utility sector in the U.S. is that coal gasification at commercial scale is technology for a more distant future, and EPACT 2005 provided incentives to accommodate that view. Thus environmental benefits are distant. The attitude of distressed, globally competitive, natural-gas-dependent industrials is different. Industrials can simply shift production to low cost, natural gas regions of the world; or with appropriate incentives to overcome capital market imperfections, industrials can stay and America can realize superior economic and environmental performance from coal, sooner, rather than later.

RESPONSES OF BRIAN FERGUSON TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Section 48 tax credit—Mr. Ferguson, I understand there is concern with the addition of the phrase "at all times" to the 90 percent syngas rule for a facility to receive a tax credit. Can you please explain this problem and whether the DOE or IRS has answered your concerns?

Answer. The problem is that, during periods of start up and testing, other fuels may be needed that would make the 90% rule impossible to follow. DOE recently indicated that it has asked IRS to allow non-conforming fuels during plant startup and shutdown periods. Unfortunately, with less than 45 days before the DOE application deadline, IRS has provided no response to this or any other question.

*Question 2.* Section 48 tax credit—Mr. Ferguson, how important are the confidentiality provisions of the applications that are to be submitted?

Answer. Application confidentiality is key to Eastman's global business competitiveness. Plant process efficiencies and specific designs and operational methodologies revealed in any Eastman application would be the result of more than 20 years of unique operating experience and innovation. This is competitive advantage. Also, the sheer magnitude of these projects could result in any public disclosure being considered a material disclosure.

*Question 3.* General Competitiveness of the Chemical Industry—Mr. Ferguson, your testimony comments on how most if not all chemical plants are now being built overseas, is the price of natural gas the predominant reason? Can the tax credits and loan guarantees be enough to retain the facilities here in the U.S.?

Answer. The industry belief is that natural gas feedstock volatility in the U.S. is the single largest reason for the shift in chemical production to other regions of the world. Natural gas represents fully one quarter of the U.S. chemical industry's product costs. Of course, higher rates of economic growth in Asia for example, suggest that there would be more plant investment in that region. But the global picture is wholly unbalanced, with a full retreat, or route, out of the U.S. to cheaper natural gas regions of the world.

Domestic chemical manufacturers intent on staying in this country have limited choices aside from deploying gasification technology to produce competitively priced substitutes for natural gas. While the cost of synthesis gas is higher in the U.S. than natural gas prices are in Oman, for example, domestic producers will enjoy some transportation cost advantage in North American markets. Also, gasification of coal and other plentiful fuels will afford resource price stability in contrast to volatile natural gas prices.

The 48B tax credits represent the estimated "cost premium" for earlier adopter of commercial gasification technology in the U.S. These investment tax credits make it rational for the first developers to invest money now with reasonable expectation that their investment will be competitive with that of subsequent developers who will be able to build these same plants for considerably less money in the future. The loan guarantees should lower the cost of money for early adopters of these highly capital intensive projects, who would otherwise pay a risk premium for being early adopters, and are a necessary tool to impede the exodus of U.S. chemical companies. I cannot say with certainty that these two incentives alone will reverse the exodus, but I can assure you that our industry has little hope for staying home without them.

[Responses to the following questions were not received at the time this hearing went to press:]

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington, DC, May 4, 2006.*

Mr. WILLIAM F. BRUCE,
*President, BRI Energy, LLC, 114 Canal Street, Suite F, New Smyrna Beach, FL.*

DEAR MR. BRUCE: I would like to take this opportunity to thank you for appearing before the Senate Committee on Energy and Natural Resources on Monday, May 1, 2006, to give testimony regarding the economic and environmental issues associated with coal gasification technology and on implementation of the provisions of the Energy Policy Act of 2005 addressing coal gasification.

Enclosed herewith please find a list of questions which have been submitted for the record. If possible, I would like to have your response to these questions by Thursday, May 18, 2006.

Thank you in advance for your prompt consideration.

Sincerely,

PETE V. DOMENICI,
*Chairman.*

QUESTIONS FROM SENATOR BUNNING

*Question 1.* Across the world, energy has become the lynchpin of economic competitiveness. America's coal reserves can provide us with an invaluable hedge against our growing addiction to imported energy, and provide a significant source of fuel for our growing economy. Could you describe the benefits coal gasification could offer to the American economy in terms of prices, environmental effects and national security?

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QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Ethanol production from gasification syngas—Mr. Bruce how economically competitive will your facility be to produce ethanol as compared to current methods? Can you give what the cost of a gallon would be from the method you are employing?

*Question 2.* Various gasification feedstocks—Mr. Bruce, how will the efficiency of your process vary depending on your feedtocks, be it coal, corn stover or other biosolids?

*Question 3.* Production capacity—Mr. Bruce, what is the size of the production system you hope to achieve and can you build fermenters to these scales?

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U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington, DC, May 4, 2006.*

Mr. BILL DOUGLAS,
*Vice President, Econo-Power International Corp., 1502 Augusta, Suite 100, Houston, TX.*

DEAR MR. DOUGLAS: I would like to take this opportunity to thank you for appearing before the Senate Committee on Energy and Natural Resources on Monday, May 1, 2006, to give testimony regarding the economic and environmental issues associated with coal gasification technology and on implementation of the provisions of the Energy Policy Act of 2005 addressing coal gasification.

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QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Filtering of syngas waste gases—Mr. Douglas how effective are the current technologies for filtering $SO_X$, $NO_X$ and mercury?

*Question 2.* Types of Coal—Mr. Douglas, are your smaller units tuned to specifics types of coal, like Powder River Basin or other geographic regions?

*Question 3.* Coal Shipment—Mr. Douglas, since these are comparatively small units do you have a hard time trying to ship coal on rail systems which usually supply large electric power plants?

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington, DC, May 4, 2006.*

Dr. ANTONIA HERZOG,
*NRDC, Climate Center Staff Scientist, 1200 New York Ave., NW, Suite 400, Washington, DC.*

DEAR DR. HERZOG: I would like to take this opportunity to thank you for appearing before the Senate Committee on Energy and Natural Resources on Monday, May 1, 2006, to give testimony regarding the economic and environmental issues associated with coal gasification technology and on implementation of the provisions of the Energy Policy Act of 2005 addressing coal gasification.

Enclosed herewith please find a list of questions which have been submitted for the record. If possible, I would like to have your response to these questions by Thursday, May 18, 2006.

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QUESTIONS FROM SENATOR BUNNING

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QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Addition of Carbon Capture Technologies—Ms. Herzog, how hard will it be to retrofit a gasification plant with carbon capture technologies and what percentage would it increase the facility cost after it has been built as compared to adding $CO_2$ capture during construction?

*Question 2.* Cost for Industrial Gasification Plants—Ms. Herzog, given that the chemical feedstock gasifiers are about 1/10 the size of the larger electric power production gasifiers—how much cost do you expect carbon sequestration to add to the process?

MONDAY, MAY 8, 2006

RESPONSES OF THE DEPARTMENT OF THE INTERIOR TO QUESTIONS FROM SENATOR CRAIG

*Question 1.* What are the agencies' plans to revise and finalize the Interim Final Rule?

Answer. When the rules were published on November 17, 2005, the agencies indicated they would consider the public comments that were received and their initial experience in implementing the rules and consider issuing Final Rules within approximately 18 months. That remains our intent. The agencies have received comments through the Interim Final Rule and are currently reviewing them.

*Question 2.* In your opinion, once the 15 "transition projects" are addressed, will we settle into a process that works within FERC's timelines?

Answer. We believe that our major workload challenge is occurring in this initial period of implementation, which will carry forward through most of Calendar Year 2007. This is because we are not only implementing a new process, but also: (a) addressing the transition projects; (b) managing two high profile, complicated cases, namely Hells Canyon and Klamath; and (c) considering (next year) possible changes to the rule. After this initial period, workloads may be at more manageable levels. Historically, approximately 1/4 to 1/3 of all relicensings have included conditions or prescriptions from any of the three resource agencies and a far lesser number have conditions from more than one agency. It is expected that parties will request EPAct processes in the majority of those re-licensing proceedings, but we will not be dealing with pending proceedings and considering whether to revise the rules. At any given time, the need to address one or more difficult cases may create workload issues, but that should not be typical after the initial implementation period.

*Question 3.* At the hearing, I asked FERC to report back to the Committee in about six months regarding the progress that is being made in implementing the new hydropower licensing procedures. Will DOI work with FERC on this progress report?

Answer. DOI, DOC, and USDA will be pleased to provide FERC with any assistance it requests.

RESPONSES OF THE DEPARTMENT OF THE INTERIOR TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Mr. Robinson's testimony lists several instances where the resource agencies have withdrawn or modified conditions and prescriptions, and he attributes this at least in part to the new law. Can you explain why conditions and prescriptions have been withdrawn or modified in the examples given by Mr. Robinson?

Answer. Interior has three cases where section 4(e) conditions or section 18 prescriptions were modified after the deadline for requesting Energy Policy Act processes.

First, in the Rocky Reach Project (Washington) relicensing, the Chelan Public Utility District (PUD) filed alternative section 18 prescriptions on December 19, 2005. At that time, however, the Chelan PUD, Interior, through the FWS, and other parties to the FERC proceeding were close to executing a comprehensive settlement to resolve outstanding issues in the relicensing. On March 20, 2006, the Chelan PUD filed the fully executed settlement agreement with FERC, and on March 27, 2006, the Chelan PUD withdrew its alternatives. This reflects Interior's continuing policy to seek to resolve resource issues in FERC license proceedings through settlement. The Energy Policy Act had no bearing on Interior's decision to enter into the settlement.

Second, in the Priest Rapids Project (Washington) relicensing, the Grant PUD requested a trial-type hearing regarding section 4(e) conditions filed by Interior on behalf of the Bureau of Reclamation (BOR), and section 18 prescriptions filed on behalf on the FWS on December 19, 2005. After several discussions with Grant PUD, the BOR decided to withdraw its section 4(e) conditions and, in their place, file section 10(a) conditions. The BOR's section 10(a) recommendations are very similar to its section 4(e) conditions, and the BOR believes its recommendations are in the public interest and will be supported by FERC. For those reasons, the BOR did not see the need to go through a trial-type hearing.

Third, in the Hells Canyon Project (Idaho), the Idaho Power Company requested a trial-type hearing regarding preliminary section 4(e) conditions filed by Interior on behalf of the BLM on March 29, 2006. During the pre-hearing phase of the trial-type hearing, IPC and the BLM agreed on terms to resolve IPC's concerns with the

BLM's preliminary conditions, pursuant to which, on May 15, 2006, the BLM filed with FERC revised preliminary section 4(e) conditions. On May 16, 2006, IPC withdrew its hearing request.

The USDA Forest Service has agreed to revise or modify section 4(e) conditions in two license proceedings since the deadline for requesting EPAct processes. First, in the Boulder Creek Hydroelectric Project license proceeding, FERC No. 2219, the USDA received a hearing request on December 19, 2005, from Garkane Energy Cooperative (Utah), the licensee/applicant. The request pertained to one of the Section 4(e) conditions that the Forest Service had submitted to FERC in the Boulder Creek Project licensing proceeding. In April 2006, Garkane and the Forest Service reached a settlement that provided for a modification by the Forest Service of the disputed condition and new protection, mitigation, and enhancement measures to be added to Garkane's license proposal.

Second, in the Hells Canyon Project (Idaho), the Idaho Power Company (IPC) requested a trial-type hearing regarding preliminary section 4(e) conditions filed by the USDA Forest Service. During the pre-hearing phase of the trial-type hearing, IPC and the Forest Service agreed on terms to resolve issues regarding nine of ten conditions at issue in OPC's hearing request. On May 9, 2006, the Forest Service filed with FERC revised preliminary section 4(e) conditions covering the nine conditions resolved.

Regarding the National Oceanic and Atmospheric Administration (NOAA) prescriptions referred to in Mr. Robinson's testimony (Upper North Fork Feather River, project no. 2105, and Poe, project no. 2107, both in California), the agency amended previously filed section 18 prescriptions on December 12, 2005, because it was reasonably certain that a watershed-scale settlement agreement would be reached that would provide greater protections for Central Valley spring-run Chinook salmon and Central Valley steelhead. The settlement was signed earlier this year.

*Question 1a.* Are you in fact "rethinking your approach" to conditioning projects, as the NHA testimony suggests? If so, in what manner?

Answer. The new statute underscored the need to carefully formulate and justify conditions and prescriptions. Given that conditions and prescriptions may generate hearings on contested material facts, agencies are taking care to make certain that the factual basis of their determinations is especially clear. However, this does not mean that agencies are or will be reluctant to propose conditions and prescriptions where warranted. The agencies continue to participate in FERC license proceedings in accordance with their statutory and trust responsibilities. This includes, as applicable, determining conditions necessary to adequately protect and utilize reservations, and to prescribe fishways at projects where the Secretary deems them to be necessary and appropriate. As in the past, agencies must support those decisions with substantial evidence, and must provide a clear rationale for their conditions and prescriptions. We realize that we must marshal the facts and documents supporting conditions and prescriptions in a manner that anticipates factual challenges before an Administrative Law Judge.

*Question 1b.* How can we be assured that the hydroelectric relicensing provisions are being implemented in a manner that does not undermine resource protection?

Answer. As noted in the answer to the previous question, the new statutory requirements have not made agencies reluctant to propose conditions or prescriptions where warranted. As Mr. Finfer noted at the hearing, the Departments of Commerce and the Interior formulated prescriptions and conditions for the Klamath Project under the new requirements, yet their proposed prescriptions and conditions address the full range of resource protection issues.

*Question 2.* The Administration estimates that the new law will result in the request of at least 47 hearings and the proposal of 351 alternative conditions and prescriptions per year, with a cost to the Federal Government of $5 million. Do the resource agencies have necessary funding and staff to undertake the hearings and evaluate the alternative conditions and prescriptions as required by the new provisions?

Answer. The cited workload estimate was provided when the rule was published on November 17, 2005, in order to comply with the requirements of the Paperwork Reduction Act. However, it was an initial estimate that applied only to the first year of implementation, and a new estimate was required. Further, the initial estimate had to be provided before the submittal of hearings and alternative requests for the "transition" projects. We recently completed a draft revision of the initial estimate that reflects the submittals for transition projects. It projects a reduction in workload of approximately 2/3 from the initial estimate provided with the rule. Notice of the proposed revision to the workload estimate was published in the Federal Register on May 3, 2006.

We believe that our major workload challenge is occurring in this initial period of implementation, which will carry forward through most of Calendar Year 2007. This is because we are not only implementing a new process, but also: (a) addressing the transition projects; (b) managing two high profile, complicated cases, namely Hells Canyon and Klamath; and (c) considering (next year) possible changes to the rule.

After this initial period, however, workloads may be at more manageable levels. Historically, approximately 1/4 to 1/3 of all relicensings have included conditions or prescriptions from any of the three resource agencies and a far lesser number have conditions from more than one agency. It is expected that parties will request EPAct processes in the majority of those re-licensing proceedings, but we will not be dealing with pending proceedings and considering whether to revise the rule. At any given time, of course, the need to address one or more difficult cases may create workload issues, but that should not be a normal occurrence after the initial implementation period. We believe that agency budgets, when both base funding and the increases requested in the FY 2007 President's Budget (as noted in the answer to Question 2a below) are taken into account, will prove adequate to address this workload.

It should be noted that the $5 million figure cited in the question was not cited as a measure of Federal costs but instead costs to the public participants in the process.

*Question 2a.* Can we expect to see this level of funding requested in the President's Budget for future fiscal years? Was this amount requested for FY 2007? If not, why not?

Answer. The Department of the Interior has requested an increase of $400,000 for Fiscal Year 2007 to address the anticipated hearings workload. The Department of Commerce has requested $2.8 million to augment technical and legal capabilities and to pay the U.S. Coast Guard, which is providing Administrative Law Judges to conduct hearings. The Forest Service did not request additional funding.

We believe that the above agency budgets will prove adequate to implement the new requirements. As noted in the answer to the previous question, we have provided revised workload estimates that are reduced from those that were provided when the rules were published, and believe that workloads are likely to prove more manageable after the initial implementation period.

*Question 3.* What has been the average time that it takes the Department of the Interior's Office of Hearings and Appeals to complete an on-the-record hearing? How many cases are currently on the docket? With respect to these pending cases, what is the average length of time between filing of a notice of appeal and the commencement of an evidentiary hearing?

Answer. For on-the-record hearing cases concluded during FY 2005 and the first 7 months of FY 2006, the average length of time from receipt of the case by the Office of Hearings and Appeals (OHA) to case completion was 17 months. At the end of April 2006, OHA had 306 on-the-record hearing cases on its docket, of which 33 had had a hearing. The average length of time from receipt of the case to the commencement of the evidentiary hearing in those cases was 22 months. This data is not for cases filed after enactment of the EPAct.

*Question 3a.* Will the hydro hearings impact the hearing dockets at the resource agencies in a manner that will delay hearings on other matters? For example, will hearings on oil and gas, mining and grazing matters at the Department of the Interior be delayed because of the hydro provisions? Will the hydro appeals take precedence over other matters?

Answer. Because of the tight statutory time frame for the resource agencies to complete hydropower licensing hearings, these cases may take precedence over other matters. In FY 2006, Interior may have to delay hearings on certain matters (e.g., mining and grazing issues) to conduct hydropower licensing hearings. As noted in the answer to Question 2a, Interior has requested funding in FY 2007 for an additional Administrative Law Judge (AU) and staff attorney to assist with these cases, in order to minimize any impact on other cases. NOAA's hydropower hearings are not expected to have impacts on the U.S. Coast Guard's ability to conduct hearings for other programs within the Department of Commerce or other Departments. The U.S. Coast Guard's ALJ Office is adequately staffed to handle the workloads and to meet the timeframes specified in the regulation. The Department of Agriculture (Forest Service) also believes it is adequately staffed to address the anticipated workload.

*Question 3b.* You mention that USDA has made ALJ's available to conduct these hearings. What types of cases have these ALJ's been handling? Do these ALJ's have expertise in this subject matter?

Answer. The USDA Office of Administrative Law Judges has wide ranging expertise in areas that include making findings of fact on natural resource issues such as those that may be raised in these proceedings.

*Question 3c.* I understand from your testimony that Coast Guard ALJ's will be handling the NOAA fishway appeals. Do these ALJ's have expertise in this subject matter?

Answer. The U.S. Coast Guard ALJ Office has authority under the U.S. Code to hear adjudicatory matters on behalf of NOAA when one of its marine resource statutes or regulations is implicated. The Coast Guard ALJ's have many years of experience dealing with procedural regulations such as the regulations the Departments promulgated (e.g., the NOAA fisheries enforcement procedural regulations at 15 USC 904). NOAA has been working closely with the Coast Guard to alert them to the rules, participate in training for their ALJs and inform them about new developments.

*Question 3d.* What is the legal basis for allowing an ALJ from one Department to make determinations for the Secretary of another Department (for example, for a Coast Guard or USDA ALJ to make determinations that bind the Secretary of the Interior)?

Answer. Section 241 of the Energy Policy Act of 2005 (EPAct) gives parties to a hydropower license proceeding the right to "a determination on the record, after opportunity for an agency trial-type hearing. . . ." The agencies have interpreted this language as making applicable to hydropower licensing hearings the adjudication provisions of the Administrative Procedure Act (APA), 5 U.S.C. § 554 et seq. Under 5 U.S.C. §§ 556(b)(3), 557(b), an agency is authorized by the APA to use any duly appointed ALJ to take evidence and render an initial decision, which can become the decision of the agency without further proceedings if the agency so provides by rule. In the interim final rules on hydropower licensing hearings, each resource agency authorized ALJs employed or used by another resource agency to render final decisions on disputed issues of material fact for both agencies in consolidated cases. In addition, the Economy Act, 31 U.S.C. § 1535, authorizes an agency to procure services from another agency pursuant to a reimbursable agreement. Since the APA allows an agency to use any duly appointed ALJ to preside at a trial-type hearing, the agencies can use Economy Act agreements to procure adjudication services from each other's ALJs where doing so will conserve resources for both the agencies and the parties and will avoid the risk of inconsistent results on common issues of material fact.

*Question 4.* Section 241 of the Energy Policy Act requires the resource agencies to submit into the record of the FERC proceeding a written statement demonstrating that in accepting conditions and prescriptions and rejecting others the Secretary gave equal consideration to the effects of the condition on energy supply, distribution, cost, and use; flood control; navigation; water supply; air quality; and preservation of other aspects of environmental quality. Does the Department have expertise in these areas? What information do you plan to rely on in considering these factors? Please describe how you plan to carry out this procedural requirement. Will this requirement cause new delays?

Answer. The agencies will rely on the record of the entire licensing proceeding to prepare the statement. In doing so, it is expected that they will draw on interdisciplinary expertise including, as applicable, attorneys, biologists, economists and other professionals. They will also have the option to acquire this expertise from other departments or, if appropriate and feasible, to seek assistance from consultants. The process has been designed to fit within the time frames of FERC's rules, so we do not expect it to result in delays although, as noted in the answer to Question 2, the initial period of implementation will be especially challenging.

*Question 5.* Why were the rules implementing the hydroelectric relicensing provisions of EPAct issued as interim final rules without opportunity for public comment? Please provide the legal justification. Were persons outside of the Administration consulted regarding these rules? If so, who?

Answer. As noted when the rule was published, we believe that the fact that the rules are procedural and interpretative, coupled with Congress's express direction to put them in place within 90 days of enactment, necessitated their publication as interim final rules, a determination that is consistent with the Administrative Procedure Act (sections 553(b)(A) and (B)). However, the rules were published with a request for comments, and we have indicated that we will consider these comments and our initial experience in implementing the rules in order to make a determination on issuing a final rule next year. During the period in which the rules were under preparation, various agency staff held a small number of meetings with outside parties, most notably the National Hydropower Association and the Hydropower Reform Coalition. The purpose of these meetings was to hear the general views of these parties, but the agencies did not share drafts of the rules.

*Question 6.* Will implementation of the hydroelectric relicensing provisions cause new delays?

Answer. As noted in the answer to Question 2a, we believe that our major workload challenge is occurring in this initial period of implementation, which will carry forward through most of Calendar Year 2007. This is because we are not only implementing a new process, but also: (a) addressing the transition projects; (b) managing two high profile, complicated cases, namely Hells Canyon and Klamath; and (c) considering (next year) possible changes to the rule.

After this initial period, workloads may be at more manageable levels. Historically, approximately 1/4 to 1/3 of all relicensings have included conditions or prescriptions from any of the three resource agencies and a far lesser number have conditions from more than one agency. It is expected that parties will request EPAct processes in the majority of those re-licensing proceedings, but we will not be dealing with pending proceedings and considering whether to revise the rule. At any given time, the need to address one or more difficult cases may create workload issues, but that should not be typical after the initial implementation period.

*Question 7.* Who has the burden of proof in the trial-type hearings required by section 241 of EPAct? Has this issue been raised in any appeals proceedings to date? Do you expect that the ALJ's will be consistent in their interpretation of who has the burden of proof?

Answer. The trial-type hearings required by section 241 of EPAct are conducted in accordance with the adjudication provisions of the APA. These provisions include 5 U.S.C. § 556(d), which states, "Except as otherwise provided by statute, the proponent of a rule or order has the burden of proof." Since the EPAct itself does not provide a burden of proof, the APA default burden of proof applies. The issue of which party in a hydropower licensing hearing is the "proponent" of an order has been raised in *Idaho Power Co. v. Bureau of Land Management,* No. DCHD-2006-01 (OHA). On May 3, 2006, the ALJ in that case issued an order determining that Idaho Power Company, as the party that requested the hearing, was the proponent and therefore had the burden of proof. On May 31, the USDA ALJ issued a similar ruling in the Hells Canyon proceeding involving Idaho Power and the Forest Service. While the agencies cannot predict whether other ALJs will rule the same way if the issue is presented to them, the agencies requested comments on this issue when they issued interim final rules, and expect to address it in their revised final rules, which will thereafter ensure consistency among all the ALJs handling these cases.

*Question 8.* Please provide for the record for each proceeding in which an appeal has been requested: (1) the conditions and prescriptions that are the subject of appeal; (2) the material facts that are alleged to be in dispute; (3) resolution, if any, of whether the fact is material; and (4) resolution, if any, of the appeal. What definition of "material fact" is to be used by the ALJ's?

Answer. Since publishing the Interim Final Rules, Interior has received hearing requests in seven FERC license proceedings: Hells Canyon, Klamath, Box Canyon, Condit, Priest Rapids, Merrimack, and Bar Mills. The Forest Service (USDA) has received hearing requests in eight proceedings: Hells Canyon, Boulder Creek, Kern Canyon, Pitt River 3-4&5, Upper North Fork Feather River, Poe, Stanislaus-Spring Gap, and Portal. The Department of Commerce (National Marine Fisheries Service) has received hearing requests in three proceedings: Bar Mills, Condit, and Klamath.

In response to questions 8(1) and 8(2), we have provided CDs that include, for each case above, the agency's filing (or FERC license in Box Canyon) that includes the pertinent conditions or prescriptions, as well as the hearing requests, which include the alleged issues of material fact. In addition, we have (on separate pages for each project) provided narratives that identify the hearing requests in response to questions 8(2) and narratives that respond to questions 8(3) and 8(4). In the case of the Hells Canyon Complex, we have also provided a supplemental CD with the revised agency filings by Interior and USDA (Forest Service) which are referenced in their respective narratives.

The interim final rule defines material fact as "a fact that, if proved, may affect a Department's decision whether to affirm, modify or withdraw any preliminary condition or prescription."

*Department of the Interior—Hells Canyon Complex*

(2) On January 26, 2006, Interior filed preliminary section 4(e) conditions on behalf of the BLM and preliminary section 18 prescriptions on behalf of the FWS. On February 27, 2006, the Idaho Power Company (IPC) filed a hearing request regarding the BLM's section 4(e) conditions.

(3) On May 4, 2006, the ALJ in this proceeding dismissed three issues (11.1, 12.2, and 19.2) for lack of jurisdiction without ruling specifically on materiality. These were issues that the BLM had previously stipulated to in its answer. In that same order, the AU replaced IPC's six remaining issues with 60 new issues drafted by the ALJ. It appears that IPC's original issues have been dismissed, but the ALJ did not make specific rulings as to whether they were in fact material, factual, or disputed. The ALJ reserved the right to narrow or reduce his list of 60 issues following discovery. The ALJ apparently relied on the regulation's definition of "material fact," 43 C.F.R. § 45.2, and did not further define that term.

(4) During the pre-hearing phase of the trial-type hearing, IPC and the BLM agreed on terms to resolve IPC's issues regarding the BLM's preliminary conditions, pursuant to which, on May 15, 2006, the BLM filed revised preliminary conditions with FERC. On May 16, 2006, the IPC withdrew its hearing request.

*Department of the Interior—Klamath Project*

(2) On March 29, 2006, Interior filed preliminary section 4(e) conditions on behalf of the BOR and BLM, as well as preliminary section 18 prescriptions on behalf of the FWS. On April 28, 2006, Interior received a hearing request from PacifiCorp asserting several issues of material fact pertaining to the BOR's section 4(e) conditions, the BLM's section 4(e) conditions, and the FWS' section 18 prescriptions. On April 27, 2006, the Pacific Coast Federation of Fisherman Association and the Institute for Fisheries Resources filed a joint hearing request alleging issues of material fact regarding the BOR's section 4(e) conditions.

(3) There have been no rulings on materiality in this case. It is presumed that the ALJ will use the regulatory definition of "material fact," which is set forth at 43 C.F.R. § 45.2 and clarified in the preamble of the Interim Final Rules.

(4) These hearing requests remain pending.

*Department of the Interior—Box Canyon Project*

(2) On July 11, 2005, FERC issued a license to the Public Utility District No. 1 of Pend Oreille County (PUD). In that license, FERC included section 4(e) conditions filed by Interior on behalf of the BIA, as well as section 18 prescriptions filed by Interior on behalf of the FWS. We have included the BIA's section 4(e) conditions and the FWS's section 18 prescriptions as they appear in Appendices A and C of the July 11, 2005 license. On December 19, 2005, the PUD and Ponderay Newsprint Company (PNC) each filed a request for a trial-type hearing regarding the BIA's section 4(e) conditions and FWS's section 18 prescriptions.

(3) The hearing requests were rejected on jurisdictional grounds (see below), so materiality was not addressed.

(4) On July 11, 2005, FERC issued a license to the PUD for the Box Canyon Project, nearly a month prior to enactment of the EPAct and over four months prior to publication of the Interim Final Rules. Hence, both the PUD's and PNC's hearing requests fell outside the scope of the EPAct and the Interim Final Rules, and, consequently, Interior rejected their hearing requests. The PUD and, more recently, the PNC filed separate lawsuits in the D.C. District Court. Those matters are still pending.

*Department of the Interior—Condit Project*

(2) In 1994, Interior filed section 18 fishway prescriptions on behalf of the FWS. On December 19, 2005, PacifiCorp filed a request for a trial-type hearing regarding the FWS's section 18 fishway prescriptions.

(3) There have been no rulings on materiality in this case. It is presumed that, if the case is ever referred to an ALJ, the ALJ will use the regulatory definition of "material fact" in effect at the time of referral.

(4) In 1999, PacifiCorp, Interior, and several other parties executed a settlement agreement to resolve disputes in the relicensing of the project through surrender of the project license and decommissioning of project works. That settlement remains pending before FERC, which has deferred evaluation of PacifiCorp's 1991 license application. As a result, on March 15, 2006, Interior notified PacifiCorp and all hearing interveners that Interior would not schedule any hearing for the Condit Project unless and until FERC issues a notice or order reinitiating the proceeding to evaluate PacifiCorp's 1991 license application. In the event FERC issues such a notice or order, Interior will, within 45 days, issue a notice establishing a time frame for the FWS' answer and hearing.

*Department of the Interior—Priest Rapids Project*

(2) On May 26, 2005, Interior filed preliminary section 4(e) conditions on behalf of the BOR and section 18 prescriptions on behalf of the FWS. On December 19, 2005, the Public Utility District No. 1 for Grant County (Grant) filed a hearing re-

quest regarding the FWS's section 18 prescriptions and the BOR's section 4(e) conditions.

(3) There have been no rulings on materiality in this case. It is presumed that the ALJ will use the regulatory definition of "material fact" in effect at the time the case is referred to an ALJ.

(4) In March 2006, the BOR withdrew the challenged section 4(e) conditions, and shortly thereafter Grant amended its hearing request and withdrew the issue pertaining to BOR's section 4(e) conditions. At this time, Grant's issues pertaining to the FWS's section 18 prescriptions remain pending.

*Department of the Interior—Merrimack Project*

(2) On May 16, 2005, Interior filed preliminary section 18 prescriptions on behalf of the FWS. On December 19, 2005, the Public Service Company of New Hampshire filed a hearing request regarding the FWS's section 18 fishway prescriptions.

(3) There have been no rulings on materiality in this case. It is presumed that the ALJ will use the regulatory definition of "material fact" in effect at the time the case is referred to an ALJ.

(4) This hearing request remains pending.

*Department of the Interior—Bar Mills Project*

(2) On December 12, 2005, Interior filed modified section 18 fishway prescriptions on behalf of the FWS. On January 11, 2006, FLP Energy Maine Hydro filed a hearing request regarding the FWS's section 18 prescriptions.

(3) There have been no rulings on materiality in this case. It is presumed that the ALJ will use the regulatory definition of "material fact" in effect at the time the case is referred to an ALJ.

(4) In March 2006, DOI notified FPL Energy Maine Hydro and all hearing interveners that the FWS will file its answer by January 19, 2007. The hearing will be consolidated with NMFS and the case will be referred to the U.S. Coast Guard. The hearing will occur in mid/late March 2007. This hearing request remains pending.

*Department of Agriculture—Forest Service—Hells Canyon Complex*

(2) On January 26, 2006, the Forest Service filed preliminary section 4(e) conditions covering a range of issues. On February 27, 2006, the Idaho Power Company (IPC) filed a hearing request regarding the Forest Service's section 4(e) conditions.

(3) IPC and the Forest Service are currently in negotiations regarding the disputed conditions.

(4) On May 10, 2006, the Forest Service filed revised preliminary conditions with FERC for the Hells Canyon Project. The revisions cover 9 of the 10 challenged conditions. However, IPC's hearing request remains pending before a USDA ALJ with respect to the remaining condition.

*Department of Agriculture—Forest Service—Boulder Creek Hydroelectric Project*

(2) Garkane Energy Cooperative (Garkane), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding one of the Section 4(e) conditions that the Forest Service had submitted to FERC in the Boulder Creek Hydroelectric Project (Project, FERC No. P-2219) licensing proceeding.

(3) Garkane and the Forest Service reached settlement regarding the disputed condition; therefore, there was no need to resolve whether the disputed facts were material. Per the settlement, Garkane withdrew its hearing request and the Forest Service submitted a modified condition to FERC. The settlement reflects the Forest Service's consideration and balancing of resource protection and project economics. The settlement agreement also includes additional protection, mitigation, and enhancement measures that were not included in the Forest Service final condition nor could they be required under FPA 4(e) authority.

(4) The request for hearing was withdrawn, and the Forest Service filed a modified condition.

*Department of Agriculture—Forest Service—Portal Project*

(2) Southern California Edison (SCE), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding two of the FPA Section 4(e) conditions that the Forest Service had submitted to FERC in the Portal Hydroelectric Project (FERC No. P-2174) licensing proceeding.

(3) SCE and the Forest Service are currently in negotiations regarding the disputed conditions, but no resolution has been reached at this time.

(4) The hearing request remains pending.

*Department of Agriculture—Forest Service—Kern Canyon Project*

(2) Pacific Gas and Electric (PG&E), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding two of the FPA Section 4(e) conditions that the Forest Service had submitted to FERC in the Kern Canyon Hydroelectric Project (FERC No. P-178) licensing proceeding.

(3) PG&E and the Forest Service are currently in negotiations regarding the disputed conditions, but no resolution has been reached at this time.

(4) The hearing request remains pending.

*Department of Agriculture—Forest Service—Pit 3/4/5 Project*

(2) Pacific Gas and Electric (PG&E), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding one of the FPA Section 4(e) conditions that the Forest Service had submitted to FERC in the Pit 3/4/5 Hydroelectric Project (FERC No. P-233) licensing proceeding.

(3) PG&E and the Forest Service are currently in negotiations regarding the disputed condition, but no resolution has been reached at this time.

(4) The hearing request remains pending.

*Department of Agriculture—Forest Service—Upper North Fork Feather Project*

(2) Pacific Gas and Electric (PG&E), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding one of the FPA Section 4(e) conditions that the Forest Service had submitted to FERC in the Upper North Fork Feather Hydroelectric Project (FERC No. P-2105) licensing proceeding.

(3) PG&E and the Forest Service are currently in negotiations regarding the disputed condition, but no resolution has been reached at this time.

(4) The hearing request remains pending.

*Department of Agriculture—Forest Service—Stanislaus-Spring Gap Hydroelectric Project*

(2) Pacific Gas and Electric (PG&E), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding one of the FPA Section 4(e) conditions that the Forest Service had submitted to FERC in the Stanislaus-Spring Gap Hydroelectric Project (FERC No. P-2130) licensing proceeding.

(3) PG&E and the Forest Service are currently in negotiations regarding the disputed condition, but no resolution has been reached at this time.

(4) The hearing request remains pending.

*Department of Agriculture—Forest Service—Poe Hydroelectric Project*

(2) Pacific Gas and Electric (PG&E), the licensee/applicant, submitted a request with the USDA Forest Service on December 19, 2005, for a trial-type hearing regarding two of the FPA Section 4(e) conditions that the Forest Service had submitted to FERC in the Poe Hydroelectric Project (FERC No. P-2107) licensing proceeding.

(3) PG&E and the Forest Service are currently in negotiations regarding the disputed conditions, but no resolution has been achieved.

(4) The hearing request remains pending.

*Department of Commerce—National Marine Fisheries Service—Condit Project*

(2) On June 1, 1994, the National Marine Fisheries Service (NMFS) filed preliminary section 18 prescriptions. On December 19, 2005, PacifiCorp filed a hearing request regarding NMFS's preliminary section 18 prescriptions.

(3) There have been no rulings on materiality in this case. It is presumed that, if the case is referred to an ALJ, the ALJ will use the regulatory definition of "material fact" in effect at the time of referral.

(4) In 1999, PacifiCorp, NMFS, and several other parties executed a settlement agreement to resolve disputes in the relicensing of the project through surrender of the project license and decommissioning of project works. That settlement is pending before FERC, which has deferred evaluation of PacifiCorp's 1991 license application. As a result, on March 16, 2006, NMFS notified PacifiCorp and all hearing interveners that NMFS would not schedule any hearing for the Condit Project unless and until FERC issues a notice or order reinitiating the proceeding to evaluate PacifiCorp's 1991 license application. In the event FERC issues such a notice or order, NMFS will, within 45 days, issue a notice establishing a time frame for its answer and the hearing.

*Department of Commerce—National Marine Fisheries Service—Bar Mills Project*

(2) On December 12, 2005, the National Marine Fisheries Service (NMFS) filed modified section 18 prescriptions. On January 11, 2006, FPL Energy Maine Hydro filed a hearing request regarding NMFS's modified section 18 prescriptions.

(3) There have been no rulings on materiality in this case. It is presumed that the ALJ will use the regulatory definition of "material fact" in effect if and when the case is referred to an ALJ.

(4) On March 16, 2006, NMFS notified FPL Energy Maine Hydro and all hearing interveners that NMFS will file its answer by January 19, 2007. The hearing will be consolidated with DOI and the case will be referred to the U.S. Coast Guard. The hearing will occur in mid/late March 2007. This hearing request remains pending.

*Department of Commerce—National Marine Fisheries Service—Klamath Project*

(2) On March 29, 2006, the National Marine Fisheries Service (NMFS) filed preliminary section 18 prescriptions. On April 28, 2006, PacifiCorp and the Hoopa Valley Tribe filed hearing requests regarding NMFS' preliminary section 18 prescriptions. Those documents include alleged issues of material fact.

(3) There have been no rulings on materiality in this case. It is presumed that the ALJ will use the regulatory definition of "material fact," which is set forth at 50 C.F.R. § 221.2 and clarified in the preamble of the Interim Final Rules.

(4) These hearing requests are pending.

*Question 9.* Do the rules afford an opportunity for public comment on alternative conditions and fishway prescriptions (both those that are proposed by the parties and those that are adopted by the resource agencies)? If not, should there be an opportunity for comment?

Answer. The rules do not provide a distinct public comment period on alternatives. However, they do require parties to file alternatives early in the FERC process, so that FERC can evaluate any alternative conditions and prescriptions in its draft NEPA document, which does have a public comment period. All parties are allowed to comment on FERC's NEPA document, including the agencies' preliminary conditions and/or prescriptions and any alternatives. Further, each agency must consider FERC's NEPA document and any comments filed on such document when deciding whether to modify its preliminary conditions and prescriptions or to accept an alternative.

*Question 10.* Do you expect to issue revised rules implementing section 241? If so, when will they be published? What issues do you expect to address?

Answer. When the rules were published on November 17, 2005, the agencies indicated they would consider the public comments that were received and their initial experience in implementing the rules and consider issuing Final Rules within approximately 18 months. That remains our intent. It is important to note that the rules outline in detail the requirements associated with requests for hearings and how they will be processed. As this is a new requirement, we will examine closely any technical or managerial issues that arise as we address the initial set of cases.

*Question 11.* How do you plan to fulfill the Secretary's tribal trust responsibility in implementing section 241 of EPAct? Has the Department undertaken Government-to-Government consultation with the Tribes on implementation of these provisions? If so, please indicate when this occurred and what Tribes participated.

Answer. In accordance with the President's memorandum of April 29, 1994, "Government-to-Government Relations with Native American Tribal Governments," 59 FR 22951 (May 4, 1994), supplemented by Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, 65 FR 67249 (Nov. 6, 2000), the Departments assessed the impact of the new regulations on Tribal trust resources and determined that they do not directly affect Tribal resources. The rules are procedural and administrative in nature. However, conditions and actions associated with an actual hydropower licensing proposal may directly affect Tribal resources. The Departments will continue to consult with Tribal governments in specific cases when developing section 4(e) conditions and section 18 prescriptions needed to address the management of Tribal trust resources. Consultation on individual projects typically occurs over a multi-year period and requires numerous contacts with the affected tribes.

A good example of such government-to-government consultation can be seen with the Klamath Project, in which Interior and Commerce each consulted with several tribes on their joint section 18 prescription, which was ultimately filed with FERC on March 29, 2006.

RESPONSE OF MARK ROBINSON TO QUESTION FROM SENATOR CRAIG

*Question 1.* Under the new procedures, will FERC wait until a trial-type hearing is completed before issuing a Draft Environmental Statement?

Answer. No. The trial-type hearing is scheduled for completion 10 days prior to issuance of the DEIS. The DEIS will contain an analysis of any alternative conditions or prescriptions that have been filed. The new procedures anticipate trial-type hearing results being incorporated into the final EIS after opportunity for comment on both the hearing results and the DEIS findings. We believe the parallel processing of the DEIS and the trial-type hearing will allow for efficient license application processing and allow the Commission to appropriately consider conditions and prescriptions and the factual basis upon which they're founded.

RESPONSES OF MARK ROBINSON TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Will implementation of the provisions of EPAct 2005 result in improved conditions and prescription? If so, in what way? If not, why not?

Answer. Yes, I believe that implementation of the provisions of EPAct 2005 will result in mandatory conditions that are fairer and more balanced. The legislation provides an increased incentive for agencies to provide cost-effective and factually-supported mandatory conditions. In addition, it appears to have begun to foster greater interaction between resource agencies and the licensees in the development of environmental measures, and provide a degree of accountability that previously did not exist.

*Question 2.* The testimony of the National Hydropower Association states that the resource agencies "appear to be rethinking their approach to conditioning projects." Do you agree? Please explain.

Answer. Yes, I agree. Although the new provisions have been in effect for only a short period and as explained in my testimony, there have been a number of positive outcomes that we surmise may have resulted from section 241 of EPAct 2005:

For the Priest Rapids Project No. 2114 in Washington State, the licensee challenged the Bureau of Reclamation's (BOR) section 4(e) conditions under EPAct. Subsequently, BOR withdrew its mandatory conditions and refiled them as recommendations pursuant to section 10(a) of the FPA.

For the Upper North Fork Feather River Project No. 2105 and the Poe Project No. 2107, both located in California, the National Oceanic and Atmospheric Administration of the Department of Commerce (NOAA Fisheries) substituted a reservation of authority to prescribe fishways in the future for its previously filed specific section 18 prescriptions.

For the Rocky Reach Project No. 2145 in Washington, the licensee submitted alternatives to Interior's section 18 fishway prescriptions. Subsequently, the licensee and Interior's Fish and Wildlife Service (and others) entered into a comprehensive settlement agreement addressing, among other things, the licensee's fish passage concerns.

The FPA requires that the Commission authorize projects that are best adapted to a comprehensive plan for improving or developing a waterway for beneficial public purposes, including power generation, irrigation, flood control, navigation, fish and wildlife, municipal water supply, and recreation, giving equal consideration to developmental and non-developmental values. Based upon the above examples, it appears that section 241 of EPAct 2005, which more closely aligns the criteria that the agencies must use in formulating mandatory conditions with the Commission's "equal consideration" criteria for licensing projects under the FPA, may already be resulting in the agencies taking a broader look at the impacts of their conditions and fishway prescriptions.

*Question 3.* Your testimony states concern about whether the resource agency appeals process will cause new delay. You note that the agencies indicate they can only handle one appeal per month, and you are concerned that some licenses may be delayed 6 to 14 months. Do you have recommendations on how to prevent these delays?

Answer. My concern is only for the near term, during which the agencies must process hearings and alternatives for 15 transition projects (those projects where the Departments of the Interior, Commerce, or Agriculture had filed preliminary conditions or prescriptions, but no license had been issued, as of November 17, 2005) as well as hearings and alternatives for large, complex projects being processed under the Interim Final Rule timelines. Because the Departments of the Interior and Agriculture have indicated to us that they are able to schedule only one hearing per month, we are concerned the schedules for addressing hearings and alternatives for transition projects will extend some licensing proceedings. We would hope that the agencies are able to obtain additional staff resources to expedite hearings and the filing of modified terms and conditions for these cases.

*Question 4.* Do resource agencies have necessary funding and staff to undertake the hearings and evaluate the alternative conditions and prescriptions as required by the new provisions?

Answer. I have no information about the agencies' funding and staffing.

*Question 5.* With respect to pending license applications, if as a result of implementation of EPAct 2005 final conditions or prescriptions are modified by the resource agencies, what opportunities will the public have to provide input? Will additional analysis of the modified conditions and prescriptions be required under the National Environmental Policy Act, the Endangered Species Act, and other environmental statutes? If so, please describe. Will this require extra time?

Answer. The hearing and alternative condition and prescription process is well integrated into FERC's hydropower licensing process. Modified conditions and prescriptions would be analyzed in the final environmental document. Parties who wish to comment on the final environment document may do so. Also, after the Commission issues an initial licensing order, any party to the proceeding will have the opportunity to seek rehearing from the Commission, in the event that they disagree with conclusions in the environmental document or the order. As to whether additional analysis of modified conditions and prescriptions will be necessary, by the time the modified conditions are filed, there will already have been three years of prefiling discussion about project issues, studies, and environmental measures. It is therefore likely that any proposed alternatives or modifications will have previously been raised and accordingly considered in the Commission's environmental analysis. However, in the unlikely event that an agency does develop a condition or prescription that has not already been analyzed, the Commission would have to take the time to do so.

*Question 6.* How do you plan to fulfill the FERC's tribal trust responsibility in implementing EPAct 2005? Has the FERC undertaken Government-to-Government consultation with the Tribes on implementation of these provisions? If so, please indicate when this occurred and what Tribes participated.

Answer. I am not aware of any additional tribal trust responsibilities set forth in EPAct 2005. The Commission has already fully integrated tribes and their interests into its hydropower licensing processes. The Commission staff identifies and contacts directly tribes likely to be interested in any hydropower case to determine whether and to what degree a tribe may desire to participate.

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NATIONAL HYDROPOWER ASSOCIATION,
*Washington, DC, May 18, 2006.*

Hon. PETE V. DOMENICI,
*Chairman, Committee on Energy and Natural Resources, U.S. Senate, Dirksen Senate Office Building, Washington, DC.*

DEAR SENATOR DOMENICI: The National Hydropower Association is most appreciative of the opportunity to present industry's views at the May 8th oversight hearing on the implementation of the hydropower licensing provisions of the Energy Policy Act of 2005 (EPAct 2005). These provisions are extremely important to the hydropower industry as they bring more transparency to the licensing process, while protecting important environmental standards.

Attached are NHA's responses to the questions submitted for the record by Senator Craig and Senator Bingaman.

As we requested in our statement, we hope that the Committee will hold additional oversight hearings on this matter in the future as it is far too early to gain a full understanding of the impact of these provisions and additional experience is warranted.

NHA commends your leadership and your willingness to hold this important oversight hearing.

Sincerely,

LINDA CHURCH CIOCCI,
*Executive Director.*

RESPONSE TO QUESTION FROM SENATOR CRAIG

*Question 1.* Do hydroelectric licensing reforms make any changes to applicable environmental requirements? Is the State's Clean Water Act certification process in any way impacted?

Answer. No, the hydroelectric licensing reforms do not make changes to the underlying environmental standards in the Federal Power Act (FPA). The FPA standards remain exactly the same as they were prior to the adoption of EPAct 2005 and the federal agencies retain their authority to impose Section 4(e) and 18 conditions and prescriptions on hydropower projects as part of the Federal Energy Regulatory Commission (FERC) licensing process. In fact, it is NHA's hope that the provisions will reduce process and litigation delays so that environmental improvements associated with relicensing are implemented quicker to the benefit of the natural resources.

Additionally, the reforms have no impact or effect on the application of the Clean Water Act's state certification process to hydropower projects. None of the EPAct 2005 provisions apply to Section 401 of the Clean Water Act. The reforms also have no impact on the application of other federal environmental statutes, such as the Endangered Species Act, to hydropower relicensing.

RESPONSES TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Your testimony states that the resource agencies "appear to be rethinking their approach to conditioning projects." Please explain and provide examples.

Answer. While it is still very early in the implementation of the relicensing provisions, NHA believes that the agencies are devoting more thought and attention in the preparation and formulation of license conditions and are taking a closer look to ensure that conditions are supported by the facts.

Conditions are only as good as the facts that underlie them. NHA supported the relicensing reform provisions to bring transparency and accountability to the conditioning process. As the Department of Interior's Mr. Finfer stated in his testimony, EPAct 2005 ". . . underscored the need for careful deliberation, justification, and documentation with respect to the formulation of conditions and prescriptions." Now that licensees and other parties can challenge disputed facts underlying a condition, it follows that the agencies are working to better demonstrate and record them in order to support their conditioning decisions.

*Question 2.* Will implementation of the provisions of EPAct 2005 result in improved conditions and prescriptions? Is so, in what way? If not, why not?

Answer. Yes, NHA anticipates that the new provisions will result in improved conditions and prescriptions. The trial-type hearing provision will help ensure that all conditions are based on a full consideration of the relevant facts, as determined by an independent neutral party—the departmental administrative law judge. NHA believes that better facts will produce better conditions.

In addition, the equal consideration provision will ensure that the agencies evaluate the effects of conditions on energy supply, distribution, cost, flood control, navigation, water supply, air quality and other aspects of environmental quality, resulting in licenses that are best suited to the public interest.

Most important, before a cost or power-saving alternative condition is adopted, the agency must determine it meets the statutory FPA requirements for environmental and resource protection.

Better licensing conditions that meet environmental needs and improve energy production are possible with these new provisions. This is a positive development at a time when the country needs the clean, domestic, renewable energy that hydropower provides.

*Question 3.* Will implementation of the hydroelectric relicensing provisions cause new delays?

Answer. No, NHA does not anticipate that the relicensing provisions, if properly implemented and used, will cause any significant delays in the process. In fact, the provisions should reduce overall delays by providing licensees and other parties additional tools to resolve disputes before a license is issued. By resolving disputes early, it should dispense with the need to review licenses in the Court of Appeals, which past experience has shown can delay license implementation for years. Reducing delays serves all parties and allows environmental improvements associated with relicensing to be implemented more quickly to the benefit of the natural resources.

*Question 4.* Please describe the key issues raised in the litigation that has been filed by industry with respect to the interim final rules?

Answer. The National Hydropower Association has not filed any litigation on behalf of the hydropower industry challenging the interim final rules. However, American Rivers and other non-governmental organizations have filed suit to enjoin the regulations. NHA also understands that one individual hydropower licensee in Washington State, Pend Oreille Public Utility District, has also filed a suit challenging application of the relicensing reforms to the relicensing of the Box Canyon project.

As NHA is not participating in any legal challenge to the interim final rules, we cannot address the specifics of those proceedings. Additional details can be obtained directly from those organizations.

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AMERCIAN RIVERS,
*Washington, DC, May 22, 2006.*

Hon. PETE V. DOMENICI,
*Chairman, Senate Committee on Energy and Natural Resources, U.S. Senate, Washington, DC.*

DEAR SENATOR DOMENICI: Thank you very much for providing me with the opportunity to testify before the Senate Committee on Energy and Natural Resources on Monday, May 9, 2006, regarding issues associated with the implementation of the provisions of the Energy Policy Act of 2005 addressing licensing of hydroelectric facilities.

Enclosed are responses to the questions submitted to us by you and Senator Jeff Bingaman. If you have any follow-up questions to the answers provided, please feel free to contact me.

Sincerely,

ANDREW FAHLUND,
*Vice President for Conservation.*

[Enclosures.]

RESPONSES TO QUESTIONS FROM SENATOR CRAIG

*Question 1.* In your testimony you claim that license applicants are using the hearing process to raise frivolous issues that are not disputed material facts and that the agencies—not ALJs—should determine whether a hearing is warranted.

a. Wouldn't that give the same agency staff that have developed a preliminary condition the right to prevent a hearing on the facts that underlie such a condition? For example, I understand that in the ongoing hearing regarding preliminary BLM conditions for the Hells Canyon Project, agency counsel filed a Motion to Dismiss virtually every issue raised on the grounds that it was not material. The ALJ denied this motion and instead found that most of the issues raised were material facts.

b. Isn't an independent judge better equipped to decide whether a party has raised material facts and is entitled to a hearing than agency staff?

Answer. Agencies should not be forced to expend resources on trial-type hearings that are not authorized under the Act. In filings before the Administrative Law Judge (ALJ), federal agencies have rightly attempted to limit the scope of the hearings, not because they have a vested interest in dismissing claims against their conditions but because the issues fail to qualify as material. In the case of the trial-type hearing in the Department of the Interior concerning material facts underlying BLM's conditions on the Hells Canyon Complex, the ALJ did not find that the facts raised were material, but rather that his interpretation of Congressional intent required him to hold a trial-type hearing to make a determination of materiality (even so, he ruled that 3 facts did not qualify as material). Agencies can readily create systems to ensure impartiality, such as designating hearing officer staff (who are not involved in agency conditions) to make determinations on whether disputed issues should be dismissed as immaterial. We think this approach is preferable to that of deferring immaterial issues to ALJs, because of the cost to license parties. However, even if all issues are sent to the ALJs, it would still be possible to avoid trial-type hearings if ALJs were empowered to make summary judgment determinations on materiality before conducting hearings.

*Question 2.* In American Rivers' comments on the Interim Final Rule and in its lawsuit filed in U.S. District Court to vacate that rule, your organization argues that the rule's applicability to pending licensing proceedings is somehow "retroactive" and improper. Can you explain how the rule is "retroactive" when it applies to proceedings where no license has been issued? Since these licenses are valid for 30-50 years, shouldn't we make sure the facts are right for the 15 projects that are at issue?

Answer. Please see our attached motion.*

*Question 3.* Why does American Rivers continue to claim that states are somehow disadvantaged with this new process when Congress did not alter state authority in any way?

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*The attached motion and comments on the rules have been retained in committee files.

Answer. States are an integral part of the licensing process and have interests to protect including their mandatory authority to impose water quality certifications and their recommendations under sections 10(a) and 10(j) for the protection of fisheries, wildlife, and recreation. Conditions and prescriptions now subject to EPAct are often the result of a collaboration between state and federal interests in protecting resources. When those conditions and prescriptions are challenged, states have a direct interest in ensuring that their interests are protected. For example, the states of Idaho and Oregon filed interventions in the request for a trial-type hearing by Idaho Power Company to the Forest Service for the Hells Canyon Complex hydroelectric proceeding. Thus, scarce taxpayer dollars must be expended to file interventions, line up witnesses, and assemble data, all within a short-timeline. While profitable license applicants will have the financial resources to challenge conditions, we are concerned that states, especially those running deficits, may not have the luxury to protect their interests due to finite taxpayer dollars. In addition, the states' concerns will not necessarily be addressed by the criteria given for evaluation of alternative license conditions.

RESPONSES TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* Will implementation of the provisions of EPAct 2005 result in improved conditions and prescriptions? If so, in what way? If not, why not?

Answer. The sheer burden of the process is likely to harm some conditions and cause some agencies to weaken them or narrow their scope not based on the merits of doing so, but rather due to the financial hardship of imposing them. It is also possible that in some cases, agencies will forgo proposing needed resource protection measures altogether.

*Question 2.* Will implementation of the hydroelectric relicensing provisions cause new delays?

Answer. Already the rules and their provision allowing settled cases to be reopened have and will delay the hydroelectric licensing process. In their testimony to your committee, FERC staff estimated that for 9 of the 14 retroactive cases, there will be 6 to 14 month delays in final Commission action despite the requirement in the law that the trial-type hearing "be conducted . . . within the time frame established by the Commission for each license proceeding." (Section 241) For example, in the Priest Rapids proceeding, a January 2006 FERC schedule states that the application will "be ready for Commission action" in 2006, but the trial-type hearing is scheduled for January 2007. The rules openly acknowledge the fact that the decision to allow retroactive proceedings to access the EPAct processes will lead to disruption in the licensing process. "In many cases, this sequence and timing will need to be adjusted with respect to any license application that is currently pending before FERC, if the license applicant or another party wants a trial-type hearing or wants to submit an alternative condition or prescription." (Fed. Reg. at 69807, col.2).

*Question 3.* Are the hydroelectric relicensing provisions being implemented in a manner that maintains natural resource protection?

Answer. Absolutely not. We have already seen agencies back down from conditions they prescribed, not necessarily because their conditions lacked merit, but likely because they cannot afford the costs of going through the EPAct processes. For example, in the case of Garkane Energy Cooperative proceeding, the Forest Service revised its 4(e) conditions to reduce the minimum flow releases from 3 to 6 cfs to 2 cfs. This accommodation allowed the Forest Service to avoid the trial-type hearing and the alternative conditions processes. In the Hells Canyon Complex licensing, the Forest Service narrowed the scope of the trial-type hearing and alternatives process by reducing the requirement in its 4(e) conditions that Idaho Power Company acquire riparian habitat to offset project impacts from 1,522 acres to 56.3 acres.

*Question 3a.* Can you suggest any modifications to the implementation or the regulations that would help achieve natural resource protection?

Answer. Rule changes that could counter the disincentive for agencies to propose conditions and prescriptions would include: explicitly allowing license parties to propose alternative conditions when an agency fails to propose conditions; requiring that all communications with agencies concerning alternative conditions and trial-type hearings be open to all license parties; and providing for an explicit comment period on all alternative condition requests. It will be imperative that agencies strictly adhere to the requirement that alternatives be no less protective than the original prescription or provide for the adequate protection and utilization of the reservation. Other recommendations discussed below regarding measures to enhance citizen participation will also ensure resource protection, since citizens play a vital role in protecting resources. Finally, adequate agency funding to ensure effective implementation is critical.

*Question 4.* Do you believe that all parties to the FERC relicensing proceeding will be able to participate fully in the process under the new provisions?

Answer. Over time there will be a war of attrition, as license parties, with the exception of license applicants, find it difficult to muster the resources to continue to engage in costly adjudicatory proceedings. This will be particularly true if every request for a trial-type hearing results in such a hearing, even for immaterial issues.

*Question 4a.* Can you suggest steps that could be taken by the resource agencies and FERC that would help to facilitate participation?

Answer.

- The agencies should change the rules to ensure that they have the express authority to reject trial-type hearings in which the issues raised are not factual or not material and can be resolved otherwise through the licensing process. Agencies can designate impartial staff, such a hearing officers, to accomplish this task. Granting agencies this authority ensures that citizens are not compelled to expend time and limited resources on trial-type hearings that fail to qualify as material or that can be resolved without a trial-type hearing. Moreover, ALJs should be empowered to make summary judgment determinations prior to commencing trial-type hearings.
- The agencies should establish ex parse rules for decisions regarding alternative conditions and trial-type hearings and also ensure that all parties have equal access to decision-making. The intent of the law and rights granted under the Administrative Procedures Act prohibit unilateral discussions with license applicants that leave out citizen groups, but that limitation should be made explicit in the rules.
- The rules should confirm that the burden of proof in a trial-type hearing falls upon the hearing requester. In filings before ALJs, the agencies have noted that a recent decision by the U.S. Supreme Court concerning the application of the Administrative Procedures Act, as well as common law, holds that an entity seeking to overturn an agency decision bears the burden of persuading the ALJ and the ALJs have agreed.
- The rules should be altered to eliminate the provision that the decision of the ALJ is final with respect to the disputed issues of material fact. A decision of the ALJ should not be binding and should be subject to appeal by all parties.
- The rules should establish a public comment period on all proposed alternative conditions. Comments on the NEPA document are insufficient to address alternatives proposed after FERC has completed its NEPA analysis on the agencies' proposed conditions. The omission of public comments in favor of NEPA comments also fails to account for cases in which the agency adopts the alternative as its own prior to the trial-type hearing. Finally, the allowance for NEPA comments in lieu of a discreet comment period on alternatives does not recognize that comments are directed to FERC, an agency with a different mandate and requirements than those of the resource agencies.
- The rules should allow for delaying the trial-type hearing to facilitate settlement talks. The agencies have deliberately postponed the hearings in some of the retroactive cases to see if agreement can be reached on issues that are the subject of challenges, but the rules fail to allow this flexibility in the prospective cases.
- The agencies should encourage and allow e-filing to the Departments and others of all documents. The service requirements and their heavy reliance on multiple paper copies, overnight mail, hand-delivery of documents imposes a heavy administrative and financial burden on citizen groups.

*Question 5.* Please describe the key issues raised in the litigation that has been filed by American Rivers and other conservation organizations with respect to the interim final rules.

Answer. Please see attached motion.

*Question 6.* Please provide for the record a copy of any comments filed by American Rivers on the November 17, 2005 interim final rule of the resource agencies implementing EPAct 2005.

Answer. Please see attached comments on the rules.

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