S. HRG. 111–276

# NATURAL GAS

# HEARING

BEFORE THE

# COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED ELEVENTH CONGRESS

FIRST SESSION

TO

RECEIVE TESTIMONY ON THE ROLE OF NATURAL GAS IN MITIGATING CLIMATE CHANGE

OCTOBER 28, 2009

Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE

54–945 PDF WASHINGTON : 2010

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512–1800; DC area (202) 512–1800
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# NATURAL GAS

**Wednesday, October 28, 2009**

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

The committee met, pursuant to notice, at 10:05 a.m. in room SD–366, Dirksen Senate Office Building, Hon. Jeff Bingaman, chairman, presiding.

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

The CHAIRMAN. Why don't we go ahead and get started.

Today's hearing regards the significant increase in estimates of technically recoverable natural gas resources as reported by the Energy Information Administration and other experts, such as the Potential Gas Committee.

The witnesses will discuss factors leading to increased supply, the impact on future natural gas usage that is expected as a result of that supply—increased supply. The witnesses will also discuss how natural gas resources may be used to mitigate climate change and also provide their perspectives on pending climate change legislation.

Some of the key questions that I hope we can find answers to are—let me mention five:

No. 1, what are the latest domestic reserve estimates and the economics of delivering natural gas from those newly found reserves?

No. 2, how will this updated supply picture impact the fuel mix used for power generation, and how will this affect electricity prices?

No. 3, will an expanded supply reduce the volatility and the price spikes that have characterized the natural gas market in the past decade?

No. 4, what are the most appropriate roles for natural gas to play in the mitigation of climate change? Would a simple price on carbon cause natural gas to be used in those roles or should some other policy option be considered?

No. 5, if natural gas usage increases, how will industries using natural gas as a feedstock respond to potential price increases?

We have a distinguished group of witnesses.

Before I introduce the witnesses, let me call on Senator Murkowski for any statement she has.

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

Senator MURKOWSKI. Thank you, Mr. Chairman.

Good morning to all the witnesses. I am impressed with the very distinguished panel. I have had an opportunity to meet with many of you before, but it's nice to have you here today.

I know that several of you are engineers by training —petroleum and materials, chemical, and mechanical. I think that this technical expertise will help us focus on the facts and realities of natural gas in the context of climate policy.

I have made it very clear that any climate policy that decreases the use of natural gas would be a step backward, because natural gas is a natural ally of our low-carbon goals.

Previously described by some as "too precious to burn," it's now clear that natural gas can play as valuable a role in America's energy future as any other resources out there. The Alaska gas line continues to make important progress, and shale deposits from the Rockies, all the way to New York, are becoming economical to produce.

While we have a greater supply of natural gas than ever before, both the House and Senate climate bills fail to acknowledge and embrace its potential. I'm hopeful that today we can draw attention to these deficiencies and remedy them in any bill that draws enough support to move forward.

I also want to address concerns that have been raised by the coal industry. First, I guess I'd like to point out that Alaska's has more coal than any other State, about half of the country's total endowment. I want to make sure that coal is not sterilized as a valuable energy resource. I think clean coal is particularly critical to our future, not least because millions of Americans rely on its development for their livelihoods and the viability of their regions.

This hearing is not intended to take anything away from coal's status as a large component of our energy supply or its viability, going forward. I think the purpose here is to simply examine how natural gas can serve as a complement to clean coal, to nuclear, to renewables, in an all-of-the-above energy policy.

Now, some would have it that certain domestic resources simply get pushed out entirely from our energy—future energy mix. I think that is unacceptable. For starters, the world will use an estimated 45 percent more energy in 2030 than it does today. EIA tells us that U.S. energy consumption won't decrease, but rather increase by half a percent per year over that period. Senator Inhofe and I, on Friday, released a memo from CRS demonstrating that America has more recoverable fossil fuel resources than any other nation.

Given the projected growth in demand and our own abundant supplies, I think it's pretty clear that Congress does not need to pick between energy resources. Rather, we need to pick all of them, and proceed accordingly. It's difficult to imagine an energy future that doesn't involve using all of our fossil resources in as clean and efficient a manner as possible.

Climate legislation that fails to promote, or that is designed to prevent, the most cost-effective emissions reductions will threaten Americans with unaffordable energy prices. We have a duty to protect our constituents against that risk. We can start by keeping all of our options on the table.

I'm looking forward to a thoughtful discussion this morning about how we strike that balance between getting the greatest amount of our emissions reduced for the lowest cost to the consumer.

With that, Mr. Chairman, I thank you for yet another very informative hearing on these very important issues.

The CHAIRMAN. Thank you very much.

Let me introduce our witnesses. We have a very distinguished group here. First, Richard Newell, who is the administrator with the Energy Information Administration.

Welcome back to our committee.

Mr. Lamar McKay, who is the chairman and president of BP America.

Thank you very much, for being here.

Mr. David Wilks, president of Energy Supply with Xcel Energy.

Thank you, for being here.

Mr. Edward Stones, the director of Risk—Energy Risk with Dow Chemical Company.

Thank you for being here.

Mr. Dennis McConaghy, who is senior vice president of business development with TransCanada Pipelines, in Calgary; and Mr. Jack Fusco, who is the president and chief executive officer of Calpine Corporation.

Thank you all very much, for being here.

We'll take your full statements and put them in the record as if read. If you could take 6 or 7 minutes each and give us the main points that you think we need to understand about this set of issues, that would be very helpful to us.

Let's start with you, Mr. Newell, and hear the perspective of the Energy Information Administration.

**STATEMENT OF RICHARD NEWELL, PH.D., ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY**

Mr. NEWELL. Thank you, Mr. Chairman and members of the committee. I appreciate the opportunity to appear before you today to discuss natural gas and its role in mitigating climate change.

The Energy Information Administration is the statistical and analytical agency within the Department of Energy. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government, so our views should not be construed as representing those of the Department of Energy or the administration.

The main factors to be considered in addressing today's topic are the supply of natural gas, the outlook for natural gas demand, absent new policies, and the possible impact of new policies on natural gas use.

In terms of domestic supply, EIA focuses on three key measures: production, proved reserves, and estimates of technically recoverable resources. The major and very positive story in all three measures is the growing role of unconventional natural gas sources, particularly gas in shale formations. Over the past few years, total natural gas production has significantly increased through the application of new technologies to these unconventional natural gas resources. As a result, in 2008, domestic production met 90 percent of dry gas consumption in the United States, with imports from Canada and imports of liquefied natural gas making up the balance.

Despite higher production, proved reserves of natural gas have also been increasing. EIA reported a 13-percent increase in proved reserves during 2007 and will report a further 3-percent increase when we release reserves data for 2008 later this week. EIA and other experts have also been raising their estimates of technically recoverable resources, and EIA expects to incorporate a further increase in gas resources in the 2010 edition of its Annual Energy Outlook, which will be due out at the turn of the year.

Turning to demand, natural gas currently supplies 23 percent of total U.S. primary energy. Total natural gas use has moved within a narrow range over the past 15 years. Use of natural gas in residential and commercial buildings has been fairly stable, while a significant decline in industrial use of natural gas has been roughly offset significant growth in the use of natural gas to generate electricity.

Looking forward, the demand for natural gas in the electricity and industrial sectors is a key area of uncertainty in the overall use of natural gas. The price of natural gas and the rate of growth of the economy in general, and energy—intensive industries in particular, are critical drivers of industrial natural gas demand.

In the absence of changes in policy, there are two key factors that affect the growth of natural gas use for electric power generation. One is the rate of growth in electricity demand, which EIA projects will average under 1 percent annually through 2030. The other is the growth in generation from renewable energy sources, spurred by incentives in the recent economic stimulus bill and State-level mandates for increased use of renewable energy. Given these factors, EIA expects total natural gas use to be roughly flat in our current reference case scenario.

Developments in energy and environmental policy can also influence the prospects for using natural gas, whether focused on greenhouse gas mitigation or other objectives, such as diversifying the transportation fuel mix. Actions to reduce greenhouse gas emissions would tend to increase the attractiveness of electricity generation using natural gas relative to conventional coal generation. However, although generation using natural gas produces less greenhouse gas emissions than generation using conventional coal, it produces more emissions than generation using renewable energy or nuclear power, which are emissions-free.

EIA's analysis of House-passed climate legislation, the American Clean Energy and Security Act of 2009, considered its impacts over the next two decades under different scenarios regarding the cost and availability of international offsets and low- and no-carbon electricity generation technologies. Our results suggest that this legislation would likely result in increased use of natural gas for generation over the next decade, but the effect over the 2020 to 2030 period and thereafter can be either an increase or reduction in natural gas use relative to our reference case, depending on the assumptions of the cases used.

Another type of policy proposal that has received recent attention would provide tax credits or other incentives to encourage the use of natural gas in the transportation sector in place of petroleum-based fuels. While natural gas could be used in many different types of vehicles, the need for the simultaneous introduction of vehicles and fueling infrastructure has led many analysts to view centrally-fueled fleets as being one of the relatively more suitable market segments for deployment of natural gas vehicles. Local air pollution concerns and tighter emissions standards for new, heavy-duty diesel trucks that are now taking effect also tend to increase the relative attractiveness of natural-gas-fueled vehicles. However, EIA's reference case projections, which do not assume new policy-based incentives, do not show significant market penetration of natural-gas-fueled vehicles.

Mr. Chairman and members of the committee, this concludes my testimony. I look forward to answering any questions you might have.

[The prepared statement of Mr. Newell follows:]

PREPARED STATEMENT OF RICHARD NEWELL, PH.D., ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

Mr. Chairman, and members of the Committee, I appreciate the opportunity to appear before you today to discuss natural gas and its role in mitigating climate change.

The Energy Information Administration (EIA) is the statistical and analytical agency within the Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. EIA is the Nation's premier source of energy information and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. Therefore, our views should not be construed as representing those of the Department or the Administration.

To briefly summarize, the main factors to be considered in addressing today's topic are the supply of natural gas, the outlook for natural gas demand absent new policies, and the possible impact of new policies on natural gas use and greenhouse gas emissions.

In terms of domestic supply, EIA focuses on three key measures—production, proved reserves, and estimates of technically recoverable resources. The major, and very positive story, in all three measures is the growing role of unconventional natural gas sources, particularly gas in shale formations. Over the past few years, total U.S. natural gas production has significantly increased (Figure 1)* through the application of new technologies to these unconventional natural gas resources. Despite higher production, proved reserves of natural gas have also been increasing. EIA reported a 13-percent increase in proved reserves during 2007 and will report a further increase when we release reserves data for 2008 later this week. EIA and other experts have also been raising their estimates of technically recoverable resources, and EIA expects to incorporate a further increase of natural gas resources in the 2010 edition of its *Annual Energy Outlook*.

Turning to demand, natural gas currently supplies about 23 percent of total U.S. primary energy. Total natural gas use has moved within a narrow range over the past 15 years. Use of natural gas in residential and commercial buildings has been fairly stable, while a significant decline in industrial use of natural gas has roughly offset growth in the use of natural gas to generate electricity. Looking forward, the demand for natural gas in the industrial and electricity sectors is a key area of uncertainty in the overall use of natural gas. The price of natural gas, the rate of growth of the economy in general and energy intensive industries in particular, and

* Figures 1–7 have been retained in committee files.

the rate of growth in electricity demand are likely to be key drivers of natural gas demand.

Developments in energy and environmental policy can also influence the prospects for using natural gas, whether focused on greenhouse gas mitigation or other objectives such as diversifying our transportation fuel mix. Action to reduce emissions of greenhouse gases, for example, would increase the attractiveness of electricity generation using natural gas relative to coal-fired generation. However, although generation using natural gas produces less greenhouse emissions than generation using coal, it produces more emissions than generation using renewable energy or nuclear power, which are emissions-free generation sources. EIA's analysis of the House-passed climate legislation, H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), considered its impacts over the next two decades under different scenarios regarding the cost and availability of international offsets and low-and no-carbon electricity generation technologies. Our results suggest that this legislation would likely increase the use of natural gas for generation over the next decade in all of the scenarios we analyzed, but the longer-run effect can be either an increase or reduction in natural gas use relative to our Reference Case.

## SUPPLY OF NATURAL GAS IN THE UNITED STATES

Natural gas is both produced within the United States and imported. In 2008, domestic production of dry natural gas equaled about 90 percent of dry gas consumption, with imports from Canada (7 percent of consumption) and imports of liquefied natural gas (LNG) (about 3 percent of consumption) making up the balance. Though I will discuss both domestic production and imports, the most important recent developments are in domestic production.

Natural gas production is often classified as either "conventional" or "unconventional," although the definition of the boundary between these categories varies across analysts and over time. Traditionally, unconventional resources include historically harder-to-produce supplies embedded in tight sands and shale and in coalbeds. Two technological advances have made some unconventional resources easier to produce. Horizontal drilling gives producers access to large, relatively thin layers of rock without having to drill many traditional vertical wells. Horizontal drilling for natural gas and oil in the United States even outpaced traditional vertical drilling this year (Figure 2). Hydraulic fracturing, or "fracking," shatters rocks that are not very permeable, allowing embedded natural gas to flow more rapidly into the well bore. Hydraulic fracturing is a common procedure in both horizontal and vertical wells in the United States.

These technological changes have led to large increases in available reserves by expanding the types of resource rock that can be drilled economically. Most recently, natural-gas-bearing shale that is located across the entire United States (Figure 3) has been the focus of attention. So far, the Barnett shale in Texas has been the most developed, but others, such as Haynesville, may prove more productive and the Marcellus in the Northeast is much larger.

EIA has traditionally taken a relatively optimistic view of the unconventional natural gas resource, even at a time earlier this decade when many other analysts were suggesting that the lack of natural gas resources in North America would lead to a rapid and inexorable increase in our reliance on imports of LNG. Recent shale gas developments suggest that even our perspective was not optimistic enough. In recent years, EIA and other experts, such as the Potential Gas Committee (PGC), have raised their estimates of technically recoverable resources, and EIA expects to incorporate a further increase in the 2010 edition of its *Annual Energy Outlook*. Most of these increases arise from reevaluation of shale-gas plays in the Appalachian basin and in the Mid-Continent, Gulf Coast, and Rocky Mountain areas. I should note, however, that appraisals of the "technically recoverable" natural gas resource potential of the United States do not take into account the costs of finding and recovery.

Later this week, EIA will release its year-end 2008 report *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves*. Proved natural gas reserves, a small subset of the technically recoverable resources, are those volumes that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In the report, we will show that proved reserves of natural gas rose from 2007 to 2008, not only replacing production of 20.5 trillion cubic feet (Tcf), but also growing by almost 3 percent over 2007 (Figure 4). The year-end 2008 increase follows an increase of 13 percent the year before, reflecting in part stronger price conditions, which was a record for the 32 years EIA has collected these data. For both years, growth was largely due to continued development of unconventional natural gas from shales.

More recently, some have raised concerns about whether shale can continue to deliver relatively low-cost supply to domestic customers. Concerns expressed relate to the relative newness of the large-scale application of horizontal drilling and hydraulic fracturing technologies to shales. Shales in different parts of the country are not the same, and differences in techniques and technology are actively being developed by the industry. This creates uncertainty in assessing the overall resource base. Horizontal wells with fracturing to stimulate the flow of natural gas in shale also tend to deliver their greatest volumes in the first few years. This raises questions as to the ability of the industry to continue to drill productively over the long term, which is necessary to sustain higher, or even constant, levels of production.

Delivery of most of a well's volume relatively quickly has attractive financial implications as well, providing producers with a quicker and more certain return on their investment. In the long term, the question will be cost. At this point in the development of new technologies, where possible, producers are likely working with the easiest, lowest-cost resources they can identify. Continued technology improvements will tend to reduce costs, while the exploitation of more difficult resources over time will tend to increase them. How these costs evolve over time is an important question, though we are seeing some immediate effects today as, at prevailing prices, development has slowed significantly in the Barnett shale in Texas, although production continues to increase rapidly in the Haynesville in Louisiana and the Marcellus in the Northeast. The direction of prices is also important to future drilling activity, because it is the difference between price and cost that determines the profitability of drilling activity. Both EIA's short-and long-term projections and the futures price curve for natural gas contracts traded on the New York Mercantile Exchange support the view that U.S. natural gas prices will rise relative to their level in the current economic downturn.

The other major concern about long-term development of shale gas relates to environmental issues. Any new technology is likely to raise environmental issues, and drilling, particularly in areas that have not seen much in recent years, raises a set of important local environmental issues. Drilling requires heavy truck traffic, makes noise, and changes the landscape. Fracturing to stimulate the flow of natural gas, though it involves mainly highly-pressurized water and sand, also involves a relatively small amount of chemical additives. Some of these environmental issues have been explored over the past few years in Texas. Much of the Barnett shale lies beneath suburban, and even urban, Fort Worth. In the case of the Marcellus, the shale lies below areas predominantly in Pennsylvania, West Virginia, and New York that have not seen large-scale drilling efforts in a century.

Because of the local nature of the potential environmental effects of drilling and hydraulic fracturing, and the authority that resides largely in the States for regulating these environmental issues, development is likely to be highly dependent on State and local development policies. Those policies relate not only to access, but also to regulation of certain development activities that may be associated with air and water pollution. Formations holding shale gas resources have very low permeability and typically lie far below sources of ground water. Therefore, water-related concerns have largely centered on the amount of water used in the fracturing process and the need to handle, recycle, and treat fracking fluids, including used fluids that are returned to the surface as part of the process, in a manner that addresses the risk of spills that can potentially affect water quality. These locally-managed environmental issues make assessing the longer-term role of shale natural gas more difficult.

Depending on overall market conditions, LNG may also continue to serve as a source of additional natural gas supply. The United States currently has more than 4 Tcf of annual receipt capacity for imported LNG. The United States, given its extensive natural gas storage system, has in effect become the marginal customer in the international LNG trade, attracting uncommitted supplies when spot prices available in the United States are higher than international alternatives. In this sense, LNG can act as a safety valve in the event that spot prices rise due to unanticipated demand growth or supply shortfalls. Under present market conditions, where domestic supply has been robust, imports have averaged much lower than capacity, totaling a little over 0.3 Tcf last year and up about 20 percent year-to-date in 2009.

## DEMAND FOR NATURAL GAS IN THE UNITED STATES

Natural gas has long played an important role in meeting U.S. energy needs, providing about 23 percent of the primary energy used in the United States, heating more than half of U.S. homes, generating more than one-fifth of U.S. electricity, and providing an important fuel and feedstock for industry. About one-third of the natural gas consumed in 2007 was used for electric power generation, one-third for industrial purposes, and the remaining one-third in residential and commercial buildings. Only a small portion is used in the transportation sector, predominately at pipeline compressor stations, although some is used for vehicles.

The EIA projects and analyzes U.S. energy supply, demand, and prices through 2030 using the National Energy Modeling System and presenting results in our *Annual Energy Outlook*. Earlier this year, EIA updated its *Annual Energy Outlook 2009 (AEO2009)* Reference Case to include estimates of the implementation of the American Recovery and Reinvestment Act (ARRA), which includes significant programs to promote both energy efficiency and smart-grid technologies. The updated Reference Case shows a continuing slow growth in natural gas use in residential and commercial buildings, averaging less than one-third of a percent annually through 2030. Our estimates reflect both the increase in the amount of residential and commercial space that uses natural gas as a primary fuel for space and water heating, which tends to increase natural gas use, and projected increases in the efficiency of natural-gas-using equipment and better performance of buildings subject to tougher codes and standards, which tend to reduce natural gas use.

Projections of industrial natural gas demand are highly sensitive to the price of natural gas as well as the level and composition of economic activity. As noted previously, natural gas use by industry has declined over the past 15 years. In our Reference Case projections, industrial-sector natural gas consumption is projected to rebound slightly after the recession, and then level off as energy-intensive industries continue to grow at a much lower rate than the overall economy.

The electric power sector has been the growth market for natural gas over the last decade. In 2009, notwithstanding a projected 4.6-percent decline in overall electricity demand, generation with natural gas is actually expected to grow by 4.1 percent, reflecting a situation where generation using efficient natural-gas-fired units is less costly than generation from some coal units in parts of the country.

Looking forward, however, given the projected rise in natural gas prices relative to coal prices, displacement of existing coal-fired generation does not persist in our Reference Case, where there is no implicit or explicit value placed on carbon dioxide emissions emitted from the combustion of coal in existing plants. In this setting, the growth in electricity demand and the competition of natural gas with other electricity sources to serve that growth will determine the amount of natural gas used for generation.

While the recent decline in demand for electricity is largely attributable to the current economic downturn, slowing growth in the demand for electricity has been a long-term trend for more than 50 years. After averaging nearly 10 percent per year in the 1950s, the annual growth in the demand for electricity slowed to just over 7 percent in the 1960s, less than 5 percent in 1970s, less than 3 percent in the 1980s, less than 2.5 percent in 1990s, and just over 1 percent in the first 7 years of the 21st century (Figure 5). The slowing growth in electricity demand is projected to continue over next two decades, averaging only 0.9 percent per year in our updated recent projections through 2030.

With this outlook for electricity demand growth, natural gas generation in our Reference Case is projected to fall over the next few years. This occurs because growing renewable generation, stimulated in part by the extension of production tax credits and the provision of grants and loans in the recent American Recovery and Reinvestment Act, together with increased coal generation from new plants already under construction, crowd out the increased use of natural gas that might have otherwise occurred. Over the longer term, however, natural gas generation is projected to grow because few new coal plants beyond those currently under construction are projected to be added and the production tax credit for eligible renewable sources currently sunsets in 2012 or 2013, depending on the technology.

Of course there are uncertainties. Chief among these is whether new electricity-intensive technologies might enter the market to reverse this trend. The one most discussed today is plug-in hybrid electric vehicles. While we do see plug-in hybrids entering the market over the next two decades, we do not expect their penetration to be large enough by 2030 to reverse the slowing electricity demand growth trend. A simple calculation illustrates the point. One million plug-in hybrid electric vehicles with an all-electric range of 40 miles (PHEV-40) taking a 14-kilowatthour charge 365 days a year would add about 5 terawatthours of electricity load on an annual basis. This would represent slightly more than one-tenth of 1 percent of projected U.S. electricity demand in 2030. Tens of millions of PHEV-40s could, of course, make a significant difference to electricity demand, but EIA's Reference Case does not envision PHEV penetration on this scale over the next two decades given that the technology has yet to be introduced commercially, and there are significant challenges in reducing the cost and improving the performance of batteries to make this technology competitive in the marketplace without continuing subsidies.

THE EFFECT OF GREENHOUSE GAS MITIGATION POLICIES ON NATURAL GAS USE

Just two weeks ago, I had the opportunity to appear before you to discuss the recent EIA analysis of the energy and economic impacts of ACESA. EIA's analysis of ACESA focuses on those provisions that can be readily analyzed using our National Energy Modeling System, including the cap-and-trade program for greenhouse gases and its provisions for the allocation of allowances, Federal building code updates for both residential and commercial buildings, and Federal efficiency standards for lighting and other appliances.

As I noted at the earlier hearing, EIA's analysis shows that the estimated impacts of ACESA on energy prices, energy use, and the economy are highly sensitive to assumptions about the availability and cost of international offsets as well as no- and low-carbon technologies for power generation. The six main analysis cases considered in EIA's report reflect a variety of different assumptions regarding these factors.

EIA's analysis suggests that the vast majority of reductions in energy-related emissions are expected to occur in the electric power sector. Across the ACESA main cases, the electricity sector accounts for between 80 percent and 88 percent of the total reduction in energy-related carbon dioxide ($CO_2$) emissions relative to the Reference Case in 2030, even though electricity comprises only 41 percent of such emissions. Emission reductions in the electricity sector come primarily from reducing conventional coal-fired generation, which in 2007 provided 50 percent of total U.S. generation. A portion of the electricity-related $CO_2$ emissions reductions results from reduced electricity demand stimulated both by consumer responses to higher electricity prices and by incentives in ACESA to stimulate greater energy efficiency.

There are several reasons for the concentration of emissions reductions in the electric power sector. First, more than 90 percent of coal, the fuel with the highest carbon content, is used in the electricity sector. Second, while coal-fired generation is a major source of current and projected Reference Case emissions, there are several alternative generation sources already demonstrated (e.g., natural gas, renewables, and nuclear), and others are being developed (e.g., fossil with carbon capture and storage (CCS)). Third, changes in electricity generation fuels do not require fundamental changes in distribution infrastructure or electricity-using equipment.

What does this mean for natural gas use in electricity generation? In addition to the Reference Case, Figure 6 also shows natural gas generation from several cases we prepared in our analysis of ACESA. As shown, the impact on the level of natural gas generation depends on assumptions about the cost and availability of international offsets and low-emitting electricity generating technologies like nuclear, fossil with CCS, and biomass.

In the Basic Case where international offsets are assumed to be available and the cost assumptions for low-emitting electricity generating technologies are the same as those in the Reference Case, natural gas generation rises above the Reference Case through about 2020, but then falls below it as new renewable and nuclear plants are brought on line. In the High Cost Case, where new nuclear and CCS plants are assumed to cost 50 percent more than in the Reference Case, natural gas generation rises above the Reference Case throughout the projections. Finally, in the No International/Limited Case where the availability of international offsets and low-emitting electricity generating technologies is very limited through 2030, natural gas generation is well above the Reference Case level throughout most of the projections, exceeding the 2030 Reference Case level by 68 percent.

One question of interest is why companies don't switch from using existing coal plants to increased use of existing natural gas plants to reduce their greenhouse gas emissions. The reason is that the dispatch decision is quite sensitive to the price of natural gas, and it generally takes a fairly significant greenhouse gas allowance price to make this switching attractive at projected natural gas prices. Figure 7 provides an illustrative example of this trade-off with three difference assumptions about natural gas prices. As shown, if delivered natural gas prices were approximately $5 per million Btu it would make sense to dispatch a natural-gas-fired combined-cycle plant before a coal plant when the greenhouse gas allowance price reached a little over $30 per metric ton of $CO_2$. However, this crossover point rises to around $60 per ton of $CO_2$ with $7 natural gas prices and around $100 per ton of $CO_2$ with $10 natural gas prices. In the Reference Case of our analysis of H.R. 2454, natural gas prices to electricity generators are just over $7 per million Btu in 2020 and just over $8.30 per million Btu in 2030. If natural gas prices turn out to be significantly lower than we project, there could be considerably greater use of gas than indicated in these scenarios.

CONCLUSION

Given strong technologically-driven U.S. supply development, natural gas is likely to play an important role in domestic energy use for the foreseeable future, regardless of policy. Clearly, adequacy of resources and local environmental implications will be important considerations, but if those concerns prove manageable, it should be possible for domestic natural gas production to increase well beyond its current level, which already reflects significant growth over the last several years. While growth in the domestic use of natural gas may be constrained by increases in efficiency and relatively slow growth in electricity demand, its environmental advantages relative to some other energy options suggest that it could be considered for a policy-driven role as well.

Mr. Chairman and members of the Committee, this concludes my testimony. I would be happy to answer any questions you may have.

The CHAIRMAN. Thank you very much.

Mr. McKay.

**STATEMENT OF LAMAR MCKAY, CHAIRMAN AND PRESIDENT, BP AMERICA, INC., HOUSTON, TX**

Mr. MCKAY. Chairman Bingaman, Ranking Member Murkowski, members of the committee, my name is Lamar McKay, and I am chairman and president of BP America.

I represent the more than 29,000 Americans who work for BP, the leading producer of oil and natural gas in the United States and the largest investor in U.S. energy development.

BP is committed to working with the Congress and with a broad cross-section of energy producers, energy consumers, and others stakeholders to address the challenges of climate change in the context of increasing U.S. energy demand.

We appreciate the opportunity to share our views on energy and climate policy, as well the chance to discuss the major role natural gas can play in speeding emissions reductions in the power sector, delivering the greatest reductions at the lowest cost, using technology that is available today.

BP advocates an all-of-the-above approach, as Senator Murkowski mentioned. We believe this approach is the best to tackle climate change, enhance U.S. energy security, and meet the Nation's growing need for energy. We support policies that encourage conservation, energy efficiency, and greater production of domestic energy, including alternatives, fossil fuels, and nuclear.

Our views on climate policy flow from the fact that a ton of carbon is a ton of carbon, whether that comes out of a tailpipe or a smokestack, and the belief that every ton should be treated fairly and equally. A climate policy that results in disparate treatment of energy producers and consumers will result in massive misallocation of capital and insulated consumption. That will impede, and make more costly, the carbon reductions that we are all working to achieve.

Now, we support a national climate policy that creates a level playing field for all forms of energy that produce carbon emissions. In pending legislation, the playing field is not level. In spite of its economic and environmental benefits, gas is being squeezed out of the power sector by mandates for increased use of alternatives and protection of high-carbon coal generation. We have long supported transitional incentives for alternatives. If we can't achieve a level playing field within the power sector, then we would support transitional incentives to kick-start the phased retirement of the Nation's least efficient and most carbon intense coal-fired plants.

Now, we very strongly believe that coal is an absolutely essential part—essential part—of the Nation's energy future. We are working on technology to reduce carbon emissions from stationary sources which could be ready for commercial use by 2020. Now, because of their—some of these coal plants' locations and the likelihood of more stringent air quality standards, many of the very least efficient, most carbon intense coal plants may not be candidates for carbon capture and storage. Our analysis shows that the phased replacement of about 80 of these bottom-tier plants would deliver 10 percent of the cumulative 2010 to 2020 emission reduction targets now being considered by the Congress.

Now, we're not advocating an overnight change. Instead, we see a steady, smooth transition involving the retirement of perhaps eight to ten coal plants per year. Over the next decade, this could create annual incremental gas consumption of about one Tcf—one trillion cubic feet. We believe the domestic gas industry can very easily meet that demand. In fact, thanks to a gas supply picture that has been utterly transformed by using technology to unlock vast reserves of shale gas, domestic production increased, here in the U.S., 1.5 trillion cubic feet just last year. Estimates vary, but the U.S. probably has between 50 and 100 years worth of recoverable natural gas.

Now, some have expressed concern about the volatility of natural gas prices. Going forward, we believe natural gas prices will be less volatile, thanks to a greatly expanded resource base, ranging from shales to Alaska gas, better connectivity via significant new pipelines, increased U.S. storage volumes, and the capacity of U.S. LNG receiving terminals.

Now, in closing, I want to emphasize again that BP stands ready to work with this committee and others to reduce the carbon we put into the atmosphere, meet the Nation's growing need for energy, and do it at an affordable price for American families.

Natural gas is clean, abundant, affordable, and American. We encourage policymakers to provide a level playing field in which all sources of carbon are treated fairly. If you do, we believe natural gas will deliver the greatest emissions reductions at the lowest possible cost using technology available today.

So, I thank you, and I look forward to your questions.

[The prepared statement of Mr. McKay follows:]

PREPARED STATEMENT OF LAMAR MCKAY, CHAIRMAN AND PRESIDENT, BP AMERICA, INC., HOUSTON, TX

Chairman Bingaman, Ranking Member Murkowski, members of the committee, my name is Lamar McKay, and I am the Chairman and President of BP America.

I appreciate the opportunity to appear before this panel to present BP's views on the role natural gas can play in mitigating climate change.

BP has long been a proponent of comprehensive energy policies that promote energy security at an affordable cost through the development of both traditional and non-traditional sources of energy, as well as conservation and efficiency. We have also been a long-time advocate of taking a precautionary approach to $CO_2$ emissions, and are committed to reducing the environmental impacts of both energy production and consumption.

Throughout the 20th century, an abundant supply of low-cost energy was the driving force behind America's prosperity and development. EIA projects that US energy demand will grow by 11 percent from 2007 to 2030. Satisfying such demand in a sustainable way is one of our nation's most significant challenges.

Accomplishing these objectives in the 21st century will require a more diverse energy mix—increased efficiency, nuclear power, renewable energy, cleaner coal, oil, and natural gas.

This will require the right combination of policies and market-based systems to incentivize the transformation of energy use. Getting there will require all energy participants—consumers, governments, energy companies and other stakeholders—to work together to build a sustainable energy future.

If we do that, the result will create new jobs, enhance our nation's energy security, and mitigate the impacts of climate change.

At BP, we believe that natural gas, which is in abundant supply, is key to making the vision of a lower-carbon energy future a reality.

As a member of US Climate Action Partnership (CAP), we helped draft a blueprint for climate change legislation that recommended, among other things, how cap and trade could work—with equitable treatment between all sources of carbon as a basis.

Current legislative proposals do not create a level playing field and, as a result, natural gas is in danger of being squeezed. In spite of its economic, energy security and environmental benefits, gas is caught between support for emerging low carbon technologies on the one hand, and relief for coal generation on the other.

If all sources of carbon are not treated equitably, massive misallocation of capital and insulated consumption will occur. Our bottom-line is a ton of carbon is a ton of carbon—whether it comes out of a tailpipe or a smokestack, it should be treated the same.

## BP AMERICA

BP has a long history in the US energy market. I represent the 29,000 US employees of BP America. We are not only the largest oil and gas producer in the United States, but also the company that invests in the most diverse energy portfolio in the industry. In the last five years, we have invested approximately $35 billion in the US to increase existing energy sources, extend energy supplies and develop new, low-carbon technologies.

### *Oil & Gas*

Offshore and onshore, BP is one of the largest producers of oil and gas in the United States. From the Alaskan North Slope to the deep waters of the Gulf of Mexico, we are a leader in providing America's traditional energy needs. Our recent discovery of the Tiber oil field in the Gulf is only the latest in a long list of BP investments in America's energy security.

### *Wind*

We are major investors in wind generation and have amassed a land portfolio capable of potentially supporting 20,000 megawatts (MW) of wind generation, one of the largest positions in the country. As of year-end 2008, we had 1,000 MW of wind generation on-line and expect to have an installed capacity of 2,000 MW of wind power by the end of 2010.

### *Biofuels*

We are one of the largest blenders and marketers of biofuels in the nation. BP has committed more than $1.5 billion to biofuels research, development and production in response to increasing energy demand and the need to reduce overall greenhouse gas emissions from transport fuels. Our cutting-edge research looks to use dedicated energy crops that will contain more energy and have less impact on the environment than past generations of biofuels. They will also be more compatible with existing engines and transport infrastructure, making them less costly to deploy at scale.

### *Carbon Management/Carbon Capture and Storage (CCS)*

BP is involved in three major CCS projects: active operations in Algeria; a potential hydrogen energy project in California, and a planned project in Abu Dhabi.

### *Solar*

BP's solar business has been in operation for over 30 years and last year had sales of 162 MW globally. This represents an increase of 29% over 2007 and further growth is expected.

By investing heavily in the most diverse portfolio of energy sources in the industry, BP is helping meet America's energy needs while ensuring a more sustainable and secure energy future.

## TRANSITION TO A LOWER-CARBON ECONOMY

The transition to a lower-carbon economy will take substantial time, investment and technology—spanning decades. While we look to the future, we can make choices today based on what we know.

In reviewing current climate legislative proposals, we have found aspects we endorse—such as transitional support for renewables. There are other areas, however, that cause us concern.

First is the way in which mature energy sources (coal, oil, natural gas) are treated. Because the utility sector is insulated, the transportation/refining sectors foot the vast majority of near-and medium-term costs for the entire energy economy. This results in an under-allocation of allowances to the refining sector, which puts further pressure on an industry already facing significant challenges.

Our second concern is the lack of a level playing field within the utility sector for natural gas—especially over the next decade or so.

To some extent, this may be an oversight, as America's growth in domestic natural gas reserves is a relatively new story. However, we have not seen any analysis of legislative proposals which forecast natural gas growth to 2020.

Indeed, our own forecasts indicate the potential for lower demand, as natural gas is squeezed over the next decade between growing renewable mandates and coal. Our analysis indicates legislative insulation for even the oldest and least efficient coal-fired power plants.

Having said that, we are pleased that the Senate climate proposal creates a "place holder" to discuss natural gas. We welcome the opportunity to elaborate on the role natural gas can play in mitigating climate change.

## THE POTENTIAL OF NATURAL GAS

Natural gas has played a supporting role in America's energy story. However, we believe it is time for its role to change.

If the necessary technology is applied, within a stable fiscal and regulatory framework, natural gas can help fundamentally transform America's energy outlook and emissions profile in the decades going forward.

Its advantages are many:

- Natural gas is far and away the cleanest burning fossil fuel in the energy portfolio. It generates less than 50 percent of the $CO_2$ as coal per kilowatt hour and emits significantly less sulfur dioxide, nitrogen oxide, and particulate matter. Unlike coal, natural gas does not emit mercury and generates no waste ash.
- It is also the most versatile fuel, because it can be employed in the transportation sector, for home heating as well as the electricity/industrial sectors.
- Natural gas infrastructure is already in place—with gas pipelines already crisscrossing the country with more being built. There is also significant underutilized gas-fired power generating capacity.
- Natural gas generators are also more easily switched on and off, providing a synergistic compliment to intermittent sources such as solar and wind.
- Finally, natural gas-fired plants can be more easily expanded and permitted than other sources.

Policies promoting the use of natural gas in power generation hold the potential to create new American jobs throughout the natural gas value chain (exploration, production, pipelines and gas plants). We believe such policies can also help to address concerns around natural gas supply and volatility.

## SUPPLY

Over the last few years, a revolution has taken place in America's natural gas fields. Deposits of shale gas once thought out of reach are now accessible, thanks to new uses of proven technologies, such as hydraulic fracturing and horizontal drilling.

These technologies have enabled production in three of BP's key fields in Texas to more than double between 2006 and 2008. Successes such as these have led to major new discoveries, not only in traditional oil and gas states, but also in such non-traditional ones as Pennsylvania, Ohio and New York.

As a result, the US natural gas picture has been transformed. US gas production increased last year by 1.5 tcf—the largest increase in the world and the largest in US history. And we can do more of this, if the right policy framework is put in place to encourage and enable the use of natural gas.

Estimates vary, but the US probably now has between 50 and 100 years worth of recoverable natural gas which is accessible with technology available today.

## PRICE VOLATILITY

Natural gas prices are driven by a combination of short-term and structural factors. Short-term events, such as cold weather and hurricanes, will always impact energy markets, and financial tools exist to help consumers and producers alike manage such risks. Earlier in this decade, structural factors included availability of domestic supply and limited LNG import availability.

That picture has changed dramatically. In addition to the increased domestic supplies of natural gas referenced above, there has also been significant expansion of LNG import capacity in recent years. These two factors, we believe, can help contain structural pressures on natural gas prices in the future. Also, stronger base-load demand will encourage development of a stronger, more flexible supply base.

Given this positive new supply picture, the question then becomes: What should we do with it?

## OPTIONS FOR LOWERING US CARBON EMISSIONS

The US has already taken some significant steps toward lowering carbon emissions. In the arena of transportation, which generated about 2 billion tons of carbon dioxide in 2007, according to the EIA, the federal government has mandated more fuel efficient vehicles and increasing use of biofuels.

According to the EPA, electricity generation is the largest single source of $CO_2$ emissions, accounting for 41 percent of all such emissions. Therefore, this is an area where we should dedicate some real focus.

The numbers are well known. Coal provides around half of America's electricity, but contributes over 80 percent of the $CO_2$ produced via electricity generation.

Virtually all projections show coal playing an indispensable role in the US energy picture for decades to come—and we agree. Coal, as well as natural gas plants, can be fitted with carbon capture and storage (CCS) technology. This involves capturing $CO_2$ and reverse-engineering and building a gas injection field so that we can put $CO_2$ back into the ground.

CCS faces challenges of implementation at scale, substantial costs and specific locational issues. It will take time, perhaps a decade or more, for the technology to mature.

Nuclear power is carbon-free and should be part of the solution. However, it is also capital intensive and has long lead times.

Wind and solar are the sources most often mentioned as alternatives to existing fuels, and BP is an industry leader in both. Wind can be economically competitive with more conventional sources, which is one reason it is growing so rapidly—but it still requires subsidies in today's environment. Solar is higher cost than wind and requires a greater government subsidy, though costs are coming down.

Both sources, however, face challenges and have limitations of intermittence and affordability. The development of smart-grid technology might alleviate some of these challenges, but we're not there yet.

So where does this lead us?

## THE ROLE OF NATURAL GAS IN MITIGATING CLIMATE CHANGE

We support greater efforts toward energy efficiency and transitional incentives to encourage the rapid growth of alternatives.

We also think it is important to establish an economy-wide carbon price, with all hydrocarbon sources treated the same. In that framework, increased reserves of natural gas mean we can rely on it more fully to support demand growth in electric power generation.

As we have indicated, current legislative proposals distort that framework in favor of coal. Either those distortions should be removed, or alternatively, incremental transitional incentives are needed to accelerate the retirement of the leastefficient coal-fired generating capacity.

For example, our analysis indicates that if the least efficient coal-fired plants are provided with transitional incentives to retire, the power sector could deliver a significant amount of near-to-medium term emission reductions at low costs. Approximately 80 plants (30 GW of generating capacity) fall into the "least efficient" category, having an average efficiency of 27.1 percent versus 32.7 percent for the average plant. In reality, this means that the least efficient plants must burn 20 percent more coal to achieve the same amount of output.

Most of these facilities are not located in areas where CCS is an apparent option and are not suitable to be retrofitted with CCS. This is because of their vintage and emission profiles, factors which will also require significant investment to reduce $NO_X$, $SO_X$ and particulate matter in order to meet new clean air requirements.

The retirement of these 80 facilities over the next decade (8-10 plants per year) could deliver 10 percent (700 million tons) of the Waxman-Markey, Boxer-Kerry targets of 7 billion tons of cumulative reductions from 2012-2020. If replaced by gas alone, demand would increase by about 1 TCF per year of natural gas by 2020, or roughly five percent of the current US market. Given the transformed gas market conditions, we believe that such an increase in demand can easily be met by existing reserves—recall that US natural gas production grew last year by more than this amount.

We are not suggesting that gas be mandated as a replacement for the retired capacity. It could also be replaced by cleaner, more efficient energy sources. However, with a level playing field for carbon, we believe the market will choose gas, because it offers the lowest-cost option to replace retired coal capacity.

BP believes these important actions will result in a significant down payment on carbon emission reductions, with minimal costs to generators and consumers while CCS and alternative energy technologies mature.

CONCLUSION

In summary, BP is committed to providing the United States with the energy it needs to grow in coming decades, and doing so in a responsible and sustainable manner.

We support policies which:

- encourage energy efficiency;
- provide transitional support to renewable technologies; and
- apply a consistent, economy-wide carbon price to all hydrocarbons.

Failing that we support policies which promote early retirement of the least efficient sources of electric power generation as a means of achieving and sustaining significant $CO_2$ emission reductions. We believe legislation should aim to deliver the greatest carbon reductions at the lowest cost, with technology that is available today.

Expanded use of domestic natural gas can help not only the environment, but also the economy by providing sufficient supplies to meet agricultural and industrial demand.

BP is eager to join with policy makers, members of the energy sector, and other stakeholders in order to develop responsible policies that reduce carbon emissions and promote the use of clean, domestic sources of energy. Such efforts must not exclude or sideline any stakeholder.

America is at a critical juncture. If we begin to move now, we can enable a cleaner energy future for the nation. I don't believe we can afford to wait.

And with that, I would be happy to take your questions.

The CHAIRMAN. Thank you very much.

Mr. WILKS. Go right ahead.

**STATEMENT OF DAVID WILKS, PRESIDENT, ENERGY SUPPLY BUSINESS UNIT, XCEL ENERGY, INC., MINNEAPOLIS, MN**

Mr. WILKS. Thank you, Chairman Bingaman and members of the committee.

My name is David Wilks, and I am president of the Energy Supply Business Unit of Xcel Energy. I am pleased to be here today to discuss the potential role of natural gas in reducing emissions of greenhouse gases by the utility industry.

Xcel energy is an investor-owned electricity and natural gas company headquartered in Minneapolis, Minnesota. We are one of the Nation's largest combined electric and gas companies. We serve approximately 3.3 million electric customers and 1.8 million gas customers. We serve Minneapolis-St. Paul, Denver, Amarillo, and other communities in southeast New Mexico, Minnesota, Wisconsin, Michigan, North and South Dakota, Colorado, and Texas.

In my capacity as president of Energy Supply, I'm responsible for the construction, operation, and maintenance of Xcel Energy's power plants, as well as our company's environment, energy, trading, fuel, and markets functions. There's more detail in attachment A on Xcel Energy.

Xcel Energy has adopted environmental leadership as a cornerstone of its corporate strategy. As a result of our environmental leadership strategy, our company is utilizing a growing diverse portfolio of clean technologies in its operations. In particular, the American Wind Energy Association has ranked Xcel Energy as the number-one wind utility provider in the Nation. Similarly, the Solar Electric Power Association ranked us No. 5 amongst U.S. utilities for the amount of solar power we have in our system. Xcel Energy is America's leading renewable energy utility, and by 2020 we expect our increase of our renewable energy resources to be 25 percent of our energy mix.

As a result of this commitment to environmental leadership, our company is one of the first utilities in the Nation with a voluntary plan to reduce greenhouse gases and have reduced our actual carbon emissions by 8 percent since 2003. Our emission reduction strategy relies on the clean energy initiatives that I discussed with you above, and the company is also reducing its emissions by retiring coal-fired plants and replacing them with natural-gas-fired generation.

We recently completed a voluntary project in Minnesota called the Metro Emissions Reduction Project, or MERP. This is a $1 billion effort, which includes the conversion of two of our older pulverized coal generating units to natural gas. Now, through this project we reduced our $SO_2$ and $NO_X$ emissions by over 95 percent, and we've also reduced and accomplished a carbon dioxide reduction of 40 percent. Now, details regarding the MERP are included in Appendix B to my testimony. We're following a similar strategy in Colorado.

Although we believe that, in a carbon-constrained future, utilities must rely on a variety of resources, including coal, nuclear, and renewable energy, our experience with the MERP demonstrates that natural gas conversion is an excellent method of reducing emissions. As a rough rule, natural gas combined-cycle plants emit about one half has much carbon dioxide as coal-fired electricity. Natural gas generation is a proven technology, has a lower capital cost, and is far easier to permit that some of the other technology options, such as nuclear energy; unlike renewable energy, a dispatchable and controllable resource that's easily integrated into a utility system.

The historic problem with natural gas, of course, has been the volatility of the price, and the industry's increasing reliance on natural gas for generation of electricity could increase customers' exposure to volatile natural gas prices. For this reason, we join in welcoming the recent technological developments in the production of new natural gas in the United States. The development of gas from shale formations has the potential to provide a long-term stable supply for the generation of electricity. These new technologies will enable utilities to make significant short-term emission reductions while awaiting the development of innovative clean energy technologies necessary to make significant long-term reductions in greenhouse gases, and—such as required by the bill of Kerry-Boxer, Energy Jobs and American Power Act.

To take full advantage of the opportunity created by these large new natural gas supplies, industry and government together should consider the following issues:

First, abundant natural gas bodes well for renewable energy integration.

Second, it's important to continue policies that promote the development of new clean technologies, regardless of what happens to natural gas prices. The Nation should continue to invest in R&D for the next generation of nuclear, clean coal, energy efficiency, and renewables, and should continue to promote incentives designed to assure robust markets for these technologies.

In this regard, Xcel Energy is an advocate of the Renewable Energy Tax Credit, a tax credit that would encourage utilities to integrate intermittent renewable energy on their systems. Such a tax credit would reduce the cost of renewable energy and promote its wise use, and happens to be—and basically improve the natural gas prices.

Third, Xcel Energy supports the creation of other incentives under the Climate Clean Energy Program to promote the retirement or replacement of aging coal plants with natural gas. For example, we support the creation of a bonus allowance pool to provide support for utilities retiring existing coal plants and replacing them with natural gas. A similar incentive might make sense under national renewable energy standard or a clean energy portfolio standard. In any such incentive, however, it is important that Congress recognize the efforts of utilities, like Xcel Energy, that have already reduced their emissions.

Finally, while we're optimistic, we have to remember that there are other options that have to be created for us. We have to have all of the—all the choices available, and not just one. At Xcel Energy, we're excited by the new supply opportunities created by the natural gas market. With a balanced use of natural gas and other clean energy sources, we believe we can continue our progress toward a clean energy future.

Thanks again for the opportunity to speak with you today.

[The prepared statement of Mr. Wilks follows:]

PREPARED STATEMENT OF DAVID WILKS, PRESIDENT, ENERGY SUPPLY BUSINESS UNIT, XCEL ENERGY, INC., MINNEAPOLIS, MN

Chairman Bingaman, Members of the Committee, my name is David Wilks, and I am President of the Energy Supply business unit at Xcel Energy Inc. I am pleased to be here today to discuss the potential role of natural gas in reducing emissions of greenhouse gases from the utility industry.

Xcel Energy is an investor-owned electricity and natural gas company headquartered in Minneapolis, Minnesota. We are one of the nation's largest combined electricity and gas companies. We serve approximately 3.3 million electric customers and 1.8 million gas customers. We serve the Twin Cities of Minneapolis-St. Paul, Denver, Amarillo and numerous other communities in Southeast New Mexico, Minnesota, Wisconsin, Michigan, North and South Dakota, Colorado, and Texas. In my capacity as President of Energy Supply, I am responsible for the construction, operation and maintenance of Xcel Energy's power plants, as well as our company's environmental, energy trading, fuel and markets functions. More detail regarding Xcel Energy is found in Attachment A* to my testimony.

Xcel Energy's Environmental Leadership Strategy. Xcel Energy has adopted environmental leadership as the cornerstone of our corporate strategy. We are building a clean energy future for our customers and the communities we serve by investing

*Document has been retained in committee files.

in advanced technology, innovating our business and engaging our customers in energy efficiency.

As a result of our environmental leadership strategy, our company is utilizing a growing, diverse portfolio of clean energy technologies in its operations. Xcel Energy is America's leading renewable energy utility. By 2020 we will increase our use of renewable energy resources to 25 percent of our energy mix. We rely on a broad range of renewables:

- For the past five years, the American Wind Energy Association has ranked Xcel Energy as the number one utility wind energy provider in the nation. At the end of the year, we will have about 3,235 megawatts of wind energy on our system, and, by 2020, we plan to have 7,000 megawatts.
- The Solar Electric Power Association ranks us No. 5 among U.S. utilities for the amount of solar power on our system. In Colorado, we already purchase over eight megawatts of utility scale solar power and are close to completing a process that will add almost 300 megawatts of additional solar power to our system by 2015. We also have helped our customers install nearly 35 megawatts of on-site solar energy with incentives provided through our Solar*Rewards program.
- We are developing new biomass projects and recently proposed converting an aging coal plant in Wisconsin to one of the largest biomass plants in the Midwest.

Xcel Energy is also a leader in energy efficiency. Xcel Energy runs some of the largest demand-side management and energy efficiency programs in the nation. Since 1992 our customers have saved more than enough electricity to enable us to avoid building more than eleven 250-MW power plants. Our goal is to double these savings by 2020.

In addition, we are investing in a variety of innovative, clean technology programs, including developing the nation's first SmartGridCity™ in Boulder, Colorado. Also, for many years, we have partnered with the National Renewable Energy Lab ("NREL") to research, demonstrate and deploy various clean energy technologies, including plug-in-hybrid electric vehicles and cutting-edge renewable energy storage. Last week, as a founding member, we helped break ground on the Solar Technology Acceleration Center in Aurora, Colorado. SolarTAC is a world-class facility for the solar industry and research institutions designed to test and demonstrate advanced technologies for the emerging solar market.

Natural Gas and Greenhouse Gas Emission Reductions. As a result of this commitment to environmental leadership, our company is one of the first utilities in the nation with a voluntary plan to reduce greenhouse gases. We have already reduced our carbon dioxide emissions by about 8 percent since 2003. Our emission reduction strategy relies on the clean energy initiatives I discussed earlier, but the company has also reduced its emissions by retiring coal-fired plants and replacing them with natural gas fired generation.

We recently completed a voluntary project in Minnesota called the Metro Emissions Reduction Project, or "MERP." This one billion dollar effort included the conversion of two of our older pulverized coal generating plants to natural-gas combined cycle technology. Through this project, we reduced our SO2 and NOx emissions from these facilities by over 95%, and we have also accomplished carbon dioxide emissions reductions of roughly 40%. Details regarding the MERP are included as Appendix B to my testimony. In Colorado, Xcel Energy is pursuing a similar strategy: In the next three years, we will retire some of our older, less efficient coal plants, and a significant portion of their energy will be replaced by efficient natural gas-fired electricity.

Although we believe that, in a carbon constrained future, utilities must rely on a variety of resources, including coal, nuclear and renewable energy, our experience with the MERP demonstrates that natural gas conversion is an excellent method of reducing emissions. As a rough rule, natural gas combined cycle plants emit about half as much carbon dioxide as coal-fired electricity. Natural gas generation is proven technology; unlike carbon capture and sequestration or other clean technologies that will become important in the future, utilities can rely on natural gas without reservation today. It has lower capital cost and is far easier to permit than some of the other technological options, such as nuclear energy. And, unlike renewable energy, it is a dispatchable, controllable resource easily integrated into a utility system.

The historic problem with natural gas, of course, has been the volatility of the price of natural gas fuel. And, the industry's increasing reliance on natural gas for generation of electricity could increase customers' exposure to volatile natural gas prices.

For this reason, we join in welcoming recent technological developments in the production of new natural gas resources in the United States. The development of gas from shale formations has the potential to provide a long-term, stable supply of natural gas for the generation of electricity. These new technologies will enable utilities to make significant short-term emission reductions while awaiting the development of the innovative clean energy technologies necessary to make the significant long term greenhouse gas reductions that would be required by bills like the Kerry-Boxer Clean Energy Jobs and American Power Act.

Considerations for the New Natural Gas Market. In other words, natural gas can serve as a bridge fuel as we await the development of the next generation of technology. To take full advantage of the opportunity created by these large new natural gas supplies, industry and government together should keep consider the following issues:

- First, natural gas found in shale formations must be transported from the well to power plants for use as fuel. In other words, the nation will need the right combination of gas pipelines (to serve gas-fired power plants) and electric transmission lines (to transmit the electricity generated to the customer).
- Second, abundant natural gas bodes well for renewable energy integration. Renewable energy resources can vary quite a bit during a given hour, day or season. Unlike coal and nuclear plants, utilities can start and stop gas plants quickly when a wind or solar plant suddenly drops off line or starts back up as wind or sun conditions change. However, the use of gas for renewable energy integration comes at a cost—a cost closely related to the price of natural gas. In particular, utilities often have additional gas fired units kept below normal loading levels to provide back up capability should renewable energy production decline in a particular hour. If the price of natural gas is lower because of the new production technology, the cost of renewable energy integration will be correspondingly lower as well.
- Third, although low-priced natural gas assists in renewable energy integration, ironically it also competes with renewable energy and other clean energy technologies. Essentially, because the nation has a limited supply of clean energy dollars, utilities, customers and policy-makers are more likely to direct those dollars to natural gas-fired generation if natural gas is projected to be cheaper and more abundant in the future. For this reason, it is important to continue policies that promote the development of new, clean technologies regardless of what happens to natural gas prices. The nation should continue to invest in research and development of the next generation of nuclear, clean coal, energy efficiency and renewables. It should also continue to promote incentives designed to assure robust markets for these technologies. In this regard, Xcel Energy is an advocate of a "renewable integration tax credit," a tax credit that would encourage utilities to integrate intermittent renewable energy (wind and solar) on their systems. Such a tax credit would reduce the cost of renewable energy and promote its use regardless of what happens to natural gas prices.
- Fourth, Xcel Energy supports the creation of other incentives under a climate or clean energy program to promote the retirement and replacement of aging coal plants with natural gas. Such incentives could help reduce emissions in the short term, especially emissions from marginal facilities that would otherwise continue to operate. For example, we support the creation of a bonus allowance pool to provide support to utilities retiring existing coal plants and replacing them with natural gas. A similar incentive might make sense under a national renewable energy or clean energy portfolio standard. In any such incentive, however, it is important that the Congress recognize the efforts of utilities like Xcel Energy that have already employed natural gas to reduce their emissions. Xcel Energy and its customers should not be penalized for their foresight in undertaking projects like our Metro Emissions Reduction Project or our early adoption of wind, solar and biomass generation in advance of any climate mandate.
- Finally, while we are optimistic that new gas production technologies may indeed prove to be "game changers," it is important to keep in mind that gas remains a historically volatile commodity. The increased use of natural gas for electric generation could by itself lead to higher natural gas prices than anticipated. We should not put all of our eggs in one basket, even one as promising as natural gas. A continued reliance on a diverse portfolio of resources remains the nation's best electricity and energy policy.

At Xcel Energy, we are excited by the new supply opportunities created in the natural gas market. With a balanced use of natural gas and other clean energy resources, we believe we can continue our progress toward a clean energy future.

Thanks again for the opportunity to testify today. I look forward to your questions.

The CHAIRMAN. Thank you very much.
Mr. Stones, go right ahead.

**STATEMENT OF EDWARD STONES, DIRECTOR OF ENERGY RISK, THE DOW CHEMICAL COMPANY**

Mr. STONES. Thank you, Chairman Bingaman and members of the committee. My name is Edward Stones. I'm the director of energy risk for Dow Chemical.

I follow natural gas so closely that my blood pressure goes up and down with the price.

[Laughter.]

Mr. STONES. So, Dow uses the energy equivalent of more than 3500 million cubic feet of natural gas every day in our global operations. Of this total, about half is in the United States. To put this in a dollars-and-cents perspective, in 2008 we spent $27 billion on energy, and that's up from 2002, when we spent 8 billion.

The energy Dow uses is primarily naphtha, natural gas and natural gas liquids, Both as an energy source for our operations and as a feedstock to make products essential to our economy and our citizens' quality of life. These products serve as building blocks for everything from pharmaceuticals to building insulation, electronic materials, fertilizers, and much more. In fact, the U.S. chemical industry takes every dollar of energy we buy and turns it into $8 of high-value products.

We understand the importance of natural gas as a clean fuel, and that it has a role in climate mitigation; however, climate policies that legislate an increase in natural gas demand can negatively impact certain sectors of our economy as prices rise. For example, from 1997 to 2008, U.S. industrial gas demand fell 22 percent as average annual prices rose 160 percent. The economic term for this is "demand destruction." But, in human terms, it's "job destruction."

Over the last 12 years, there have been five significant natural gas spikes. During this time, these spikes have contributed to the loss of nearly 4 million manufacturing jobs, 135,000 chemical industry jobs, the permanent loss of nearly half of the U.S. fertilizer production capacity, and a $1-billion trade surplus in the chemical industry in 1997, turning into a deficit over 2001 to 2007.

We hope the predictions about increased natural gas supply are right. But, we think it's too early to declare natural gas a silver bullet or a bridge fuel solution.

Driving natural gas preferentially into power generation could further erode our manufacturing economy and increase the volatility of natural gas, especially for those that remain, including residential energy users.

If the predictions of increased supply of natural gas turn out to be true, it would be a greater value to our economy as a fuel to spur increased manufacturing investment. More industrial users of natural gas will also help dampen volatility, as we'll have more price-conscious consumers, not fewer.

Let me be clear. Dow supports prompt congressional action on climate and energy bills that achieve environmental results while maintaining the competitiveness of American manufacturing. Congress should adopt policies that ensure the diversity of our energy sources while, at the same time, reducing demand through robust efficiency efforts. A price on carbon, in our opinion, will be a sufficient market incentive for natural gas to aid in the transition to a low-carbon economy over a reasonable period of time.

In summary, Congress is debating legislation that would make dramatic changes to the Nation's energy markets. We urge you to act now and to make policy choices that increase and do not limit our energy options. We must be careful to avoid a dash to natural gas. Congress created such a dash in the 1990 Clean Air Act amendments. It then followed with restrictions on access that disconnected the supply from demand. We cannot afford to replay that scenario.

Some call natural gas a "bridge fuel." But, if the wrong policy causes a "dash to gas," it's going to be "a bridge too far."

Thank you, for your time today, and I'd be happy to answer any questions you may have.

[The prepared statement of Mr. Stones follows:]

## PREPARED STATEMENT OF EDWARD STONES, DIRECTOR OF ENERGY RISK, THE DOW CHEMICAL COMPANY

### INTRODUCTION

The Dow Chemical Company appreciates the opportunity to submit these written comments to the Committee on Energy and Natural Resources.

Dow was founded in Michigan in 1897 and is one of the world's leading manufacturers of chemicals and plastics. We supply more than 3,300 products to customers in approximately 160 countries, connecting chemistry and innovation with the principles of sustainability to help provide everything from fresh water, food, and pharmaceuticals to insulation, paints, packaging, and personal care products. About 21,000 of Dow's 46,000 employees are in the US, and Dow helps provide health benefits to more than 34,000 retirees in the US.

Dow is committed to sustainability. We have improved our performance on greenhouse gas (GHG) emissions, and we are committed to do even better in the future. Our ambitious 2015 sustainability goals underscore this commitment.

Dow is an energy-intensive company. Dow uses energy, primarily naphtha, natural gas and natural gas liquids, as feedstock materials to make a wide array of products essential to our economy and quality of life. We also use energy to drive the chemical reactions necessary to turn our feedstocks into useful products, many of which lead to net energy savings.

This testimony describes the current US energy situation and recommends specific policies to ensure a sustainable energy policy for the United States. Particular attention is focused on natural gas prices, which have and continue to affect the US manufacturing sector.

Dow believes that natural gas will play a critical role in US policy to control greenhouse gases. Because US manufacturing jobs are dependent on the US natural gas market, policies that impact natural gas will have a direct impact on jobs in the US manufacturing sector. We recommend that Congress consider policies that utilize natural gas in ways that preserve the competitiveness of US manufacturers.

### NATURAL GAS IN ENERGY AND CLIMATE POLICY

Natural gas is a relatively "clean" (in terms of GHG emissions per unit of energy) fossil fuel. Current estimates of the domestic supply of natural gas are greater than those of just a few years ago. Therefore, increased use of natural gas could help the United States reduce GHG emissions and reduce its reliance on foreign sources of energy. Climate change and energy security are two of the biggest challenges facing the United States, so policies that affect natural gas markets impact our collective well being.

## NATURAL GAS POLICY IS CRITICAL TO US MANUFACTURERS

Major sectors that use natural gas include the power, industrial, residential, commercial, and transportation sectors. Those sectors in which demand is most sensitive to natural gas prices are termed price elastic. The more elastic the demand, the more quickly a sector will change its demand for natural gas after a change in price. Inelastic demand occurs when a change in price results in little change in demand. Of the sectors previously identified, the industrial sector has the most elastic demand for natural gas. From 1997 to 2008, US industrial gas demand fell 22% as average annual prices rose 167%. Over the same time, demand for power rose 64% (EIA data). Clearly, a change in natural gas price will impact industrial sector demand before that in other sectors.

Both price volatility and the "average" price over time have an impact on the industrial sector and should be addressed by a comprehensive energy policy.

## PRICE VOLATILITY IN THE US NATURAL GAS MARKET

Since 1997, there have been five natural gas price spikes, each caused by lags between price signals and production response. The lag between changes in drilling and changes in production has been remarkably consistent, at about six months. This is the time required to fund drilling programs, site wells, schedule crews, drill and tie new wells into the grid. When the gas market is over supplied, producers respond by reducing drilling, leading to a reduction in supply.

In 2009, as in 2002, 2004 and 2006, drilling has declined dramatically as price has fallen. After each trough, natural gas demand and price rise once the economy turns, signaling the production community to increase drilling. During the lag between the pricing signals and new production, only one mechanism exists to rebalance supply and demand: demand destruction brought about by price spikes. Demand destruction is an antiseptic economic term for job destruction.

These price spikes have significantly contributed to the US manufacturing sector losing over 3.7 million jobs, the chemical industry losing nearly 120,000 jobs, and the permanent loss of nearly half of US fertilizer production capacity. The manufacturing sector, which has limited fuel switching ability, has become the shock absorber for high natural gas costs.

Although increased supply from shale gas appears to have changed the production profile, we have seen similar scenarios occur after past spikes. In 1998, significant new imports from Canada came on line; in 2002-2003, there were new supplies from the Gulf of Mexico and in 2005, new discoveries in the Rockies were brought into play. In each case, the initial hopes were too high and production increases were not as large as initially expected. Some claim that the lag expected for shale gas will be shorter due to the reduced drilling scope of shale type wells. However the latest available data show natural gas production peaked with the same delay from the start of drilling reductions as in other cycles. The inherent lags between changes in drilling and production created natural gas spikes over the last ten years, and will continue to do so after this and every trough.

The next table shows the EIA-estimated levelized cost for new power plants by fuel type in 2030. This table shows that the levelized cost of a new power plant is equal across the four fuel types. However, the variable component of cost for natural gas fired generation is much greater than for other fuel choices. This means that electricity consumers served by natural gas will experience the biggest price shocks. Along with manufacturers who rely on natural gas, consumers of electricity generated by natural gas are among those who will be most negatively affected by price spikes in the natural gas market.

**Table. Power Generated from Natural Gas Is Much More Susceptible to Price Shocks than that from Coal, Nuclear or Wind**

| | Natural Gas | Coal | Nuclear | Wind |
|---|---|---|---|---|
| Levelized Power Generation Cost from EIA | 2007 Mills/ KWH | | | |
| 2030 Base Line | 82 | 83 | 82 | 82 |
| % of Total Cost Which is Variable | 74% | 23% | 12% | 0% |
| Cost with fuel at Highest Quarter in 2000's | 113 | 92 | 83 | 82 |
| Cost with fuel at Lowest Quarter in 2000's | 39 | 73 | 81 | 82 |
| **Price variability (High vs. Low)** | **74** | **19** | **2** | **0** |

Note: Power projections for 2030 from 2009 Annual Energy Outlook Figure 57. Gas prices are for NYMEX HH, Coal for Illinois Basin, Nuclear based on % change in 2000's - all from Bloomberg. High and Low Quarter costs estimate the 2030 Levelized cost assuming fuel at the highest and lowest quarterly costs seen in the years 2000-9

We believe that the increased supply of natural gas from shale plays will be an important resource for the United States over the next decades. However, as has been demonstrated in previous cycles, this new production will not end the cyclicality of natural gas markets. Placing a price on GHG emissions will also not overcome the most important factors affecting volatility of natural gas prices (e.g., weather).

When it comes to natural gas and climate policy, Congress should consider policies that minimize the demand destruction that occurs in natural gas price spikes. This means supporting price elastic consumers of natural gas and avoiding the disproportionate addition of inelastic demand.

AVERAGE PRICE LEVEL IN THE US NATURAL GAS MARKET

It is not just price spikes in natural gas that hurt US manufacturers. It is also the average level of natural gas prices. Much of the US chemical industry was built when natural gas prices were below $2/MMBtu. Since 2001, this historic price level has been exceeded, maybe forever. We do not expect US natural gas prices to return consistently to this low level in the future.

Because manufacturers that depend on competitive natural gas prices must make capital investment decisions that span decades, the US faces stiff competition from abroad. In fact, in our 2005 testimony before this Committee, Dow stated that of the 120 world scale petrochemical plants proposed to be built, only one was planned for the US.

Should the US enact a price on GHG emissions, the net impact on supply and demand balances must be considered in cases of both average and extreme demand. The country's energy supply must be resilient enough to overcome natural phenomena such as hurricanes, harsh winters, and arid summers. It must continue to support economic growth, allowing for high-value job creation in the industrial sector. Without this resiliency, natural gas price volatility will increase, affecting both employment in the industrial sector and all electricity users.

EIA modeling of the House-passed energy and climate bill indicate how to avoid a "dash to gas" in the power sector under a cap and trade program. If new power plants using nuclear, renewable, and coal with associated carbon capture and sequestration (CCS) are not developed and deployed in a timeframe consistent with emission reduction requirements, covered entities will respond by increasing their use of offsets, if available, and by turning to increased use of natural gas in lieu of coal-fired generation. Therefore, it is critical to advance all low carbon emitting energy sources and ensure the availability of offsets under any cap and trade program.

RELATIONSHIP BETWEEN THE PRICE OF CARBON AND FUEL SWITCHING

A price on GHG emissions will increase demand for natural gas relative to other fuels that emit more GHGs per unit of energy. Demand is also influenced by the relative price of natural gas compared to other fuels in the absence of a price on GHG emissions. Both these factors—the relative price differential and the price of GHG emissions—work together to influence fuel switching. For example, if the price of natural gas is only slightly higher than the price of coal, then fuel switching from coal to natural gas will occur at a relatively low price on carbon. Conversely, if the price of natural gas is much higher than the price of coal, then it would take a higher price on carbon to impact fuel switching from coal to natural gas.

In practice, major investment decisions—such as in power generation—can impact fuel choices for decades. Therefore, investors project the relative price of natural gas and coal and the expected carbon price over the entire time period of the investment. Due to the much higher capital cost of coal-fired power generation plants, greater uncertainty in price outcomes for power or green house gas emissions raises the cost of capital for new power projects, and favors natural gas generation. A well-considered, comprehensive, and timely energy policy will both lower the cost of power for American consumers and reduce the impact of implementing policies to address GHG's.

For policy makers, the lesson to be learned is straightforward: The higher the expected carbon price, the greater the degree of fuel switching from coal to natural gas in the power sector. Therefore, cost containment is key to minimizing fuel switching under any climate policy that places a price on carbon. Under a cap and trade system, cost containment depends on the reduction schedule over time and on the availability of offsets (and international offsets in particular).

RECOMMENDED POLICIES

When it comes to natural gas and climate policy, Dow favors policies that will avoid the demand destruction that occurs in natural gas price spikes, along with policies that will allow the US to use all of its low-carbon resources. Such policies will maintain industrial competitiveness.

Dow also believes that the US needs a sustainable energy policy. Climate change is an important component of a sustainable energy policy, but it is not the only part. We have developed a list of specific recommendations that, if implemented, would form the basis of a sustainable energy policy.

First, aggressively promote the cleanest, most reliable, and most affordable "fuel"—energy efficiency. Energy efficiency is the consensus solution to advance energy security, reduce GHGs, and keep energy prices low. It is often underappreciated for its value. Of particular importance is improving the energy efficiency of buildings. Buildings are responsible for 38% of $CO_2$ emissions, 40% of energy use, and 70% of electricity use. A combination of federal incentives and local energy efficiency building codes is needed.

Second, increase and diversify domestic energy supplies, including natural gas. Nuclear energy and clean coal with carbon capture and sequestration (CCS) should be part of the solution, as should solar, wind, biomass, and other renewable energy sources. We believe a price on carbon will advantage natural gas, and further incentives would only dangerously increase inelastic demand. Therefore, Congress should not provide free allowances or other incentive payments for the purpose of promoting fuel switching from coal to natural gas in the power sector.

An estimated 86 billion barrels of oil and 420 trillion cubic feet of natural gas are not being tapped. History suggests that the more we explore, the more we know, and the more our estimates of resources grow. EIA has said that "the estimate of ultimate recovery increases over time for most reservoirs, the vast majority of fields, all regions, all countries, and the world." And we have the technology that allows us to produce both oil and natural gas in an entirely safe and environmentally sound manner. Any new fossil energy resources must be used as efficiently as possible.

One way to maximize the transformational value of increased oil and gas production is to share the royalty revenue with coastal states and use the federal share to help fund research, development and deployment in such areas as energy efficiency and renewable energy. Production of oil and gas on federal lands has brought billions of dollars of revenue into state and federal treasuries. Expanding access could put billions of additional dollars into state and federal budgets.

Third, act boldly on technology policy through long-term tax credits, and increased investment in R&D and deployment. These are costly but necessary to provide the certainty that the business community needs to spur investment. We didn't respond to Sputnik with half-measures. We can't afford to respond to our energy challenges with halfmeasures, either.

Fourth, employ market mechanisms to address climate change in the most cost-effective way. There is a need for direct action now to slow, stop, and then reverse the growth of greenhouse gas levels in the atmosphere. We concur with the principles and recommendations of the US Climate Action Partnership (USCAP), of which Dow is a proud member. And we recognize that concerted action is needed by the rest of the world to adequately address this global problem. Particular attention must be paid to cost containment and the availability of offsets (and international offsets). Also, climate policy should not penalize the use of fossil energy as a feedstock material to make products that are not intended to be used as a fuel.

To minimize the downsides of natural gas price volatility, Congress should adopt policies to increase the number of elastic users of natural gas, and consider policies to increase US supply of natural gas. A resilient natural gas market would empower US manufacturers to create high value jobs as they did from 1983-1996, during which period US industrial gas use grew at an average rate of 2.7%/yr. In the event weather increases natural gas demand, price sensitive exports would be temporarily reduced, rebalancing the natural gas market with less disruption.

Under this scenario, price spikes won't be as severe, and won't cause as much harm when they occur, which is ultimately good for both industry and all consumers. Under this scenario we can envision a circumstance in which the chemical industry is once again able to preferentially invest in the US.

CONCLUSION

Natural gas will play a critical role in US climate policy. US manufacturing jobs are closely linked to natural gas price and price volatility. The policy choices Congress will make on natural gas are therefore critical to US manufacturers. Without industrial gas users, any disruption in supply or demand must be met by dramatic price changes.

Energy efficiency should become a national priority. Congress should enact legislation to create a sustainable energy supply based on all sources of domestic energy, including nuclear energy. Technology policy should create powerful incentives for clean energy technologies, such as CCS. A price on carbon, coupled with appropriate cost containment measures, would be a large and sufficient incentive to promote US natural gas demand, which is already growing even in the absence of a price on carbon.

There is no one silver bullet solution to our energy and climate problems. All Americans paid a high price for over-reliance on natural gas in the last ten years. Our country cannot afford to repeat that mistake. This time we must fashion a comprehensive energy policy which addresses supply and demand realities, and environmental, security and economic goals to ensure energy costs in the US remain globally competitive and avoid economically devastating volatility.

The CHAIRMAN. Thank you very much.

Mr. McConaghy.

**STATEMENT OF DENNIS MCCONAGHY, EXECUTIVE VICE PRESIDENT, PIPELINE STRATEGY AND DEVELOPMENT, TRANSCANADA PIPELINES, LTD., CALGARY, CANADA**

Mr. MCCONAGHY. Thank you, Senator Bingaman. I welcome the opportunity this morning to discuss TransCanada's perspective on the opportunity of natural gas in climate change legislation. It's good to see Senator Murkowski again, and the other members of the committee.

Just to put into context what TransCanada is, in terms of the energy infrastructure of the United States, we have more than 36,000 miles of pipelines that deliver 20 percent of the natural gas consumed daily in North America. We also own approximately 370 billion cubic feet of natural gas storage, enough to meet the needs of nearly 4 million homes each year. We operate almost 11,000 megawatts of nuclear, coal, hydro, and wind generation in Canada and the United States, enough capacity to power 11 million homes.

TransCanada is also a leader in the development of the Alaska and Mackenzie gas projects, both designed to connect Arctic reserves of natural gas into the North American Market.

TransCanada's message today can be distilled into three basic points:

No.1, North America is blessed with an enormous long-term supply of natural gas. The ability to produce natural gas supplies efficiently and economically from shale formations has become a game-changer in terms of how we think about natural gas availability, supply, and how it can integrate into not only energy security, also in terms of how consumers can rely on that supply, but also, and perhaps just as importantly, climate change legislation.

No. 2, natural gas pipeline industry has constructed, and will continue to construct, the necessary infrastructure to deliver these supplies and that goes directly to one of the concerns related to volatility.

No. 3, greater use of North America's abundant natural gas resource can make a substantial contribution to tangibly reducing greenhouse gas emissions in the short and medium term.

Let me elaborate very briefly on these three points:

Robust supply. Contrary to the view of a few years ago, no one now sees natural gas as a declining resource. DOE and EIA estimates would suggest that we have enough natural gas to last for the next 100 years. Shale formations in the Lower 48 alone are estimated to hold over 650 Tcf of technically recoverable gas. On the North Slope of Alaska, there are 35 Tcf of proven reserves and another 200 Tcf of estimated recoverable reserves. Not only will these supplies—these reserves supply U.S. demand for years to come, but they will also dampen gas price volatility and lead to an overall general lower level of prices than would otherwise have pertained.

In respect to infrastructure, in 2008 the natural gas pipeline industry completed 84 projects, which added nearly 45 Bcf of capacity to the pipeline grid. That—this industry has demonstrated that we have the capability, in terms of financial capability, engineering know-how, to deliver this gas as customers and producers require them.

Presently, TransCanada and its partner, ExxonMobil, are leading the development of the Alaska gas pipeline project, which is probably the biggest single delivery opportunity that is available in the United States. I'm pleased to note to the committee that we are on schedule to conduct an open season for that capacity next year and that will be a significant milestone in advancing that project.

Last, the contribution to mitigating climate change. As has been noted by others on this panel already, natural gas emits the lowest of amount of carbon dioxide per unit of generated electricity of any fossil fuel. We have the ability to substantially increase the amount of electricity generated from natural gas. As an example, the current annual average capacity utilization factor of the installed fleet of natural gas combined-cycled generation units is 42 percent. If we could increase that utilization factor to up to 55, we would achieve a reduction in greenhouse gas emissions of approximately 135 million metric tons and to put this into perspective, the first-year reduction of greenhouse gas emissions, required under Waxman-Markey, is 143; so, 135 out of 143. An increase in the utilization factor of this magnitude will require an additional 5 Bcf per day of natural gas, an increase well within the capability of the continental supply available to us.

Greater use of natural gas offers the U.S. a readily available economic means of achieving early and genuine greenhouse gas emissions. I would only point out that, under the current versions of climate change legislation—and this has been modeled by the EIA—that the current architecture of some of that legislation, as currently proposed, may actually constrain the U.S.'s ability to take full advantage of this natural gas opportunity and that's one, I think, important challenge that we can all make a contribution to finding the best means of increasing natural gas utilization, not just for energy security and the interests of consumers, but also to advance climate change. TransCanada is eager to participate in that process, going ahead.

Thank you very much.

[The prepared statement of Mr. McConaghy follows:]

PREPARED STATEMENT OF DENNIS MCCONAGHY, EXECUTIVE VICE PRESIDENT, PIPELINE STRATEGY AND DEVELOPMENT, TRANSCANADA PIPELINES, LTD., CALGARY, CANADA

Chairman Bingaman, Ranking Member Murkowski and members of the Committee, thank you for the opportunity to testify today.

INTRODUCTION

I am pleased to be here on behalf of TransCanada Corporation to present our views on the role of natural gas in mitigating climate change. Accompanying me today is Dr. Bill Langford, Vice President, Pipeline Strategy, TransCanada Pipelines, Limited. Bill is TransCanada's in-house expert on natural gas supply and demand.

With approximately $40 billion in assets, TransCanada, through its subsidiaries, is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

TransCanada delivers 20% of the natural gas consumed each day in North America. Our 36,661 mile wholly-owned natural gas pipeline network taps into virtually every major natural gas supply basin on the continent. Our vast pipeline network is well positioned to connect new sources of supply such as shale gas, coalbed methane and offshore liquefied natural gas as well as supply from the north.

TransCanada also is a leading participant in the Alaska Pipeline Project and the Mackenzie Gas Project, both designed to connect Arctic reserves of natural gas to the North American market.

TransCanada is also one of the continent's largest providers of natural gas storage and related services with approximately 370 billion cubic feet of capacity—enough to meet the needs of nearly four million homes each year.

TransCanada is also one of Canada's largest independent power producers. TransCanada owns, controls or is developing more than 10,900 megawatts of power generating capacity in Canada and the United States—enough capacity to power 11 million homes. Our diversified power portfolio includes natural gas, nuclear, coal, hydro and wind generation primarily located in Alberta, Ontario, Quebec and the northeastern United States.

This year, TransCanada is serving as the chair of the Interstate Natural Gas Association of America (INGAA), which represents interstate and interprovincial natural gas pipeline companies in North America. However, this testimony is being presented only on behalf of TransCanada and does not necessarily represent the views of INGAA or any of its other member companies.

ROLE OF NATURAL GAS IN MITIGATING CLIMATE CHANGE

TransCanada believes that increased natural gas utilization can make a significant contribution to meeting the energy security and climate change objectives of the U.S., for the following reasons:

- Natural gas is a largely domestic resource.
- Natural gas is abundant.
- Natural gas is the cleanest burning hydrocarbon.
- Natural gas has substantial infrastructure in place today to move and use the supplies.
- Natural gas can immediately increase its share of baseload power to deliver real emission reductions.
- Natural gas from international sources can be accessed, if necessary, through the nation's well-developed liquid natural gas (LNG) facilities.

TransCanada believes that effective U.S. climate policy should recognize the significant potential of natural gas in meeting greenhouse gas (GHG) emission reduction objectives in both the short and long term.

In the short term, meaningful GHG emission reductions can be achieved by more fully utilizing already installed natural gas electric generation capacity. Because of abundant and readily available supplies of natural gas, these emission reductions can be achieved without a substantial impact on natural gas prices. In the longer term, TransCanada believes that North America's abundant natural gas resource endowment can be one of the foundations upon which United States climate change policy is built.

SUPPLY OUTLOOK

Current Department of Energy (DOE) and Energy Information Administration (EIA) estimates, based in large part on improved drilling technologies, show that the U.S. has enough natural gas to last for the next 100 years .

In 2008, the U.S. and Canada together consumed 26.8 trillion cubic feet (Tcf) of natural gas, with the U.S. consuming 23.2 Tcf and Canada consuming 3.5 Tcf. Almost all of this gas was domestically produced. LNG imports accounted for 1% of total U.S. and Canadian supplies in 2008.

On the supply side, a recently released INGAA Foundation Report predicted that U.S. natural gas production will increase by 25% (more than 5 Tcf) in 2030 compared to 2008 levels. The EIA AEO Reference case also shows a significant growth in U.S. gas production from 2008-2030, albeit somewhat less than the INGAA Foundation's analysis.

While conventional natural gas production is expected to decline, unconventional[1] and frontier[2] natural gas will increase significantly. It is important to note that the term "unconventional" refers to the source of this gas, not its chemical makeup. Unconventional natural gas has the same combustion characteristics as gas from other sources, and is fully interchangeable with gas from other sources. INGAA's analysis forecasts that unconventional and frontier natural gas supplies will grow from 8 Tcf in 2008 to between 16.1 and 22.4 Tcf in 2030. According to the EIA, natural gas production from unconventional resources in the U.S. will increase 35%, or 3.2 Tcf, between 2007-2030.

This major increase in North American natural gas supplies marks a paradigm change for natural gas. Only a few years ago, many industry observers expected a long-term decline in domestic natural gas supply. This fundamental change in outlook has resulted from remarkable success in developing new exploration techniques, particularly extraction of gas from U.S. shale deposits.

According to the "Modern Shale Gas Primer" issued by the DOE in April 2009, the lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. These shales include over 300 Tcf of technically recoverable resources, including some of the following major formations:

- The Barnett Shale is located in the Fort Worth Basin of north-central Texas. With over 10,000 wells drilled to date, the Barnett Shale is the most prominent shale gas play in the U.S. Technically Recoverable Resources = 44 Tcf.
- The Fayetteville Shale is situated in the Arkoma Basin of northern Arkansas and eastern Oklahoma. With over 1,000 wells in production to date, the Fayetteville Shale is currently on its way to becoming one of the most active plays in the U.S. Technically Recoverable Resources = 41.6 Tcf.
- The Haynesville Shale (also known as the Haynesville/Bossier) is situated in the North Louisiana Salt Basin in northern Louisiana and eastern Texas. In 2007, after several years of drilling and testing, the Haynesville Shale made headlines as a potentially significant gas reserve, although the full extent of the play will only be known after several more years of development are completed. Technically Recoverable Resources = 251 Tcf.
- The Marcellus Shale is the most expansive shale gas play, spanning six states in the northeastern U.S. (NY, OH, PA, WV, KY, and VA). Technically Recoverable Resources = 262 Tcf.
- The Woodford Shale is located in south-central Oklahoma. Technically Recoverable Resources = 11.4 Tcf.
- The Antrim Shale is located in the upper portion of the lower peninsula of Michigan within the Michigan Basin. Aside from the Barnett, the Antrim Shale

[1] Unconventional natural gas is produced from geologic formations that may require well stimulation or other technologies to produce. For more information, see the report ICF International prepared for the INGAA Foundation in 2008 entitled *Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies*.

[2] Frontier supplies include Arctic natural gas production and production from remote or new offshore areas, such as the deeper waters of the Gulf of Mexico and the offshore moratorium areas off of the East and West Coasts and the coasts of Florida.

has been one of the most actively developed shale gas plays with its major expansion taking place in the late 1980s. Technically Recoverable Resources = 20 Tcf.

- The New Albany Shale is located in the Illinois Basin in portions of southeastern Illinois, southwestern Indiana, and northwestern Kentucky. Technically Recoverable Resources = 19.2 Tcf.
- Northeast British Columbia shales, although early in their development, exhibit potential reserves comparable to the larger U.S. shale plays.

The robust development of shale plays in the United States has been due to the improvement in, and successful application of, several technologies that allow the economic production of natural gas from shale formations.

The successful application of these improved technologies has opened up the possibility of accessing an extremely large natural gas resource. Furthermore, inevitable continued improvement in technology will, in all likelihood, result in a larger and larger proportion of existing gas resources—the 'gas in place'—being economically produced. This will allow for continued growth in North American natural gas production even farther into the future.

In addition to the five key shales in the U.S., shales have also been identified and drilled in Canada—the Horn River and Montney plays in Western Canada and the Utica in Quebec. These shales, particularly the Horn River and Montney plays, have the potential to further support U.S. demand growth.

Although Lower-48 and Canadian shale production will exhibit robust growth over the next decade, there will still be a requirement for substantial volumes of other, non-shale natural gas. Tight gas, coal-bed methane and conventional gas will remain prominent in the supply mix in the years to come. This will be true even with only modest demand growth. More rapid demand growth, perhaps due to the efforts aimed at reducing GHG emissions, suggest even larger amounts of non-shale gas will be in the supply mix.

Furthermore, the presence of plentiful and ready opportunities for natural gas development suggests that gas price volatility will be dampened, with any price spikes being smaller and of shorter duration.

With respect to natural gas prices, the cost of shale gas will not 'set' the price of natural gas in North America. But the added supplies will mean that gas is more plentiful and lower cost than it would have been without it.

## PIPELINE INFRASTRUCTURE

Today, there are over 300,000 miles of large-diameter, high pressure pipelines in the United States that have the capacity to deliver in excess of 70 Bcf per day. These pipelines constitute the interstate highway system of our nation's natural gas infrastructure. To accommodate the increases in natural gas supply described above, a continued expansion of the natural gas pipeline infrastructure is needed. To date, the North American natural gas pipeline industry successfully has met this challenge. The 84 projects completed in 2008—the greatest amount of pipeline construction activity in more than 10 years—added 44.6 Bcf per day of capacity to the pipeline grid. Those 2008 additions cost an estimated $11.4 billion. By comparison, pipeline expansion in 2007 was $4.3 billion for 50 projects that added 14.9 Bcf per day of capacity to the network

This expansion has (1) allowed market access for incremental gas supplies, notably from the Rockies and shale gas production areas; (2) moderated regional price differentials and contributed to reducing natural gas price volatility; and (3) provided greater supply access to domestic natural gas users, notably the power generation sector.

### *Infrastructure for Alaska Natural Gas*

TransCanada is continuing to invest in infrastructure that will accommodate growing domestic natural gas supplies. One prominent example is the Alaska Natural Gas Pipeline. Current proven natural gas reserves on the North Slope of Alaska are 35 trillion cubic feet. The US Geologic Survey has estimated yet to be proven reserves in excess of 200 Tcf. As currently contemplated, when the Alaska gas pipeline comes into service it will add 4.5 Bcf of natural gas per day to the supply available to consumers. This capacity can be easily expanded to over 6 Bcf per day. No other single source of natural gas has the ability to increase daily supply by this magnitude.

For more than 30 years, TransCanada has actively sought to bring the enormous proven and unproven reserves of natural gas from the North Slope of Alaska to consumers in the lower-48 states, and is leading the effort today. In December 2008 TransCanada Alaska Company, LLC, a subsidiary of TransCanada Corporation, was awarded a license by the State of Alaska pursuant to the Alaska Gasline Inducement Act (AGIA).

Under its AGIA license, TransCanada will conduct open seasons for capacity on the pipeline and prepare and file an application for a certificate of public convenience and necessity (CPCN) from the Federal Energy Regulatory Commission (FERC). Consistent with the requirements of AGIA, TransCanada began the field, engineering, design, commercial and regulatory work necessary to conduct an initial open season in 2010. In June, TransCanada reached an agreement with Exxon Mobil to pursue joint development of the pipeline. We are calling that joint effort the Alaska Pipeline Project (APP).

TransCanada is on schedule to make an open season filing with the FERC in late January 2010, and, assuming FERC's timely approval, conduct a 90 day open season beginning on or about May 1, 2010. This will be the first open season ever conducted for an Alaska gas pipeline. As with most open seasons for large pipeline projects, the bids from potential shippers in the initial open season are likely to have conditions that need to be satisfied before the shippers make a binding commitment. Nevertheless, TransCanada and the APP will continue the substantial work needed to prepare the CPCN application and will work with the State of Alaska and the potential shippers to resolve those conditions in a satisfactory and timely manner.

While there are many challenges confronting the Alaska Pipeline Project, more progress has been made on the project in the last 15 months than at any previous time. If all of the involved parties can successfully resolve their differences, the APP can deliver North Slope natural gas into the North American pipeline grid by late in the next decade.

*Pipeline and Supplies Match Power Demand*

Today, natural gas fired generation meets about 20% of U.S. electricity demand on an annual average basis. The U.S. electric power sector has approximately 400 gigawatts (GW) of installed natural gas capacity. However, the average capacity utilization factor for natural gas combined cycle units was only 42% in 2007. These facilities, which are already connected to the electric transmission grid and to natural gas supply, constitute a significant inventory of "ready to be dispatched" natural gas fired generation that can make a significant down payment on meeting GHG emission targets.

For example, if the average utilization factor of these installed combined cycle units was increased from the current 42% to 55% with a commensurate reduction in coal generation, the resulting net decrease in GHG emissions would be on the order of 134 million metric tons. And, such an increase in utilization would require roughly an additional 5 Bcf per day of natural gas—a volume that can be easily accommodated from a continental supply perspective considering the contributions from shale gas and /or Alaska. With electric generation accounting for a third of all greenhouse gas emissions, burning more natural gas for electric generation will produce immediate and verifiable GHG emission reductions.

When new generation capacity is required, natural gas has significant advantages as a low-carbon generating resource, in that it is dispatchable, easily scalable, and can be quickly deployed.

*Pipeline Capacity and Expanded Supply Moderate Prices*

There was a period of time where new gas-fired generation and drilling projects were outpacing the availability of pipelines. Recent major pipeline expansions have significantly improved the access of incremental supplies to markets, contributing to reduced price volatility and a lower overall price level for natural gas.

The availability of major new shale supplies in parts of the U.S. that are not as prone to weather-related incidents, like hurricanes in the Gulf of Mexico, helps reduce price volatility. And, if required, the current LNG infrastructure provides the option of accessing international supplies which would further assist in moderating price volatility.

NATURAL GAS AS PART OF THE CLIMATE CHANGE POLICY

Just as natural gas plays a key role in meeting U.S. energy demands, it can also play a key part in providing meaningful, immediate, and verifiable emission reductions. Natural gas emits the lowest amount of carbon dioxide per unit of generated electricity of any fossil fuel. Due to its reliability and ease of deployment, natural gas generation can also serve as a low-carbon backup resource for intermittent renewable energy sources.

The primary goal of climate change legislation is to reduce greenhouse gas emissions. Any GHG regulatory regime ultimately established by the Congress should move power generation choices in the direction of increased use of lower carbon resources, including natural gas, by establishing appropriate price signals and other structural provisions. Additionally, natural gas generation can ensure the integration of intermittent renewable energy sources into the electrical grid.

An increase in natural gas usage, as the lowest carbon content fossil fuel, in a stable investment environment that includes access to North America's large natural gas resources, both offshore and onshore, can be seen as the appropriate market response to properly designed carbon constraint policy.

However, EPA and EIA modeling of H.R. 2454, the Waxman-Markey climate bill, shows a potentially perverse result. For example, in EIA's July 2009 analysis of the Waxman-Markey bill, natural gas consumption in 2020 drops from a business-as-usual reference case projection of 22.1 quadrillion BTU to 21.5 quadrillion BTU in the basic Waxman-Markey scenario and drops even more in 2030 from 24.2 quadrillion BTU in the EIA reference case to 21.1 quadrillion BTU in the basic Waxman-Markey scenario. The only scenario where EIA shows an increase in the consumption of gas is the so-called "No International/Limited Case" where none of the other low carbon technologies, like expanded nuclear or carbon capture and sequestration, are sufficiently available in the relevant time frame and use of international offsets are constrained.

Consequently further policy adjustments to proposed climate change legislation are justified and necessary. As the Senate deliberates climate change and clean energy legislation, it should consider additional measures to take advantage of the unique potential of natural gas as a low-carbon power resource. Policy choices available to promote the use of natural gas would probably requireIn particular, the Senate should consider mechanisms that encourage the early retirement of less efficient, less clean power sources. A number of ideas, such as an auction of 100% of allowances, a climate allowance compliance option based on avoided coal/increase natural gas use (so-called "Bridge Fuel Credit"), cash for coal clunkers, and a broader resource-base clean energy mandate, have been suggested and should be considered as part of the climate debate. But, TransCanada also recognizes the need for some transitional support for the customers and shareholders of these less efficient, less clean power sources. TransCanada is committed to working with policymakers to find the best combination of these policy instruments.

*Specific Interstate Pipeline Concerns*

With respect to climate change legislative proposals that have a direct impact on interstate natural gas pipelines, TransCanada endorses recommendations made by INGAA to address two specific concerns—performance standards for fugitive emissions and the ability to ensure recovery of the costs of cap and trade allowances.

H.R 2454 proposes command-and-control performance standards on fugitive methane emissions from natural gas systems, landfills, and coal mines. Specifically, the proposed Clean Air Act Section 811 directs EPA to promulgate performance standards for new and existing uncapped sources that individually emit more than 10,000 metric tons of $CO_2e$ per year and collectively emit at least 20% of uncapped emissions. The Kerry-Boxer bill would delay the promulgation of performance standards for greenhouse gas emissions until 2020, but would still permit EPA to impose such standards after that date.

These proposed performance standards will impose heavy costs on the natural gas industry because of the vast number of small sources of fugitive emissions and the technological challenges inherent in capturing their emissions. In addition, these proposed standards would keep methane sources from qualifying as domestic offset projects—thereby restricting the supply of domestic offset credits and increasing the costs of compliance for all sources within the cap. TransCanada recommends that climate change legislation eliminate EPA's authority to impose performance standards on uncapped methane sources under the Clean Air Act, and instead treat methane sources as offset project opportunities. To provide offset project developers with greater certainty, the bill should include an explicit list of eligible offset project types that includes projects that reduce fugitive methane emissions from natural gas systems. In contrast to a command-and-control regulatory regime, this approach would give fugitive methane sources a market-based incentive to begin reducing emissions from the first day of the cap-and-trade program. Treating methane sources as offset projects would also give our industry the flexibility to identify and pursue cost-effective emission reduction opportunities; generate revenue to fund the installation of emission capture systems; and increase the supply of domestic offset credits to entities within the cap, making the entire cap-and-trade program more cost-effective.

PASS THROUGH COST RECOVERY

Under both the Waxman-Markey and Kerry-Boxer bills, natural gas pipelines are treated as industrial emitters and will incur significant costs to comply with the cap-and-trade regime and new Greenhouse (GHG) Performance Standards. Unlike most other industrial emitters, however, natural gas pipelines provide a regulated transportation service and therefore have difficulty passing these costs on to customers.

INGAA strongly urges the Senate to include a provision in its climate legislation that permits regulated entities to effectively and efficiently recover new costs imposed due to allowance compliance obligations as well as new GHG Performance Standards (if they are not eliminated as proposed above).

INGAA believes that the clear, automatic pass through of climate legislation-related costs is necessary to ensure timely recovery of highly volatile costs, which a traditional filed rate process. Such a pass through provision would also place pipelines on equal footing with other industrial emitters that have the flexibility to account for new costs in their pricing.

CONCLUSION

Natural gas plays an important role to U.S. energy and environmental security. Its benefits as a clean, abundant, available, and ready source must not be overlooked as part of a climate strategy. The new supply paradigm and robust infrastructure, both in terms of pipelines and gas-fired power plants, provide a solid foundation for a low-carbon energy future.

The CHAIRMAN. Thank you very much.

Mr. Fusco, why don't you go ahead. You're our cleanup witness here.

## STATEMENT OF JACK FUSCO, PRESIDENT AND CHIEF EXECUTIVE OFFICER, CALPINE CORPORATION, HOUSTON, TX

Mr. FUSCO. Thank you, Chairman Bingaman, Ranking Member Murkowski, and the members of the committee. Thank you for the opportunity to testify today on the role of natural gas in mitigating climate change.

I'm Jack Fusco, president/CEO of Calpine Corporation. Calpine is the Nation's largest independent power producer, one of the largest consumers of natural gas for electric generation.

Because environmental leadership has been a governing principle at Calpine for over 25 years, we've been able to achieve the lowest greenhouse gas footprint in the industry. Our fleet consists of 62 modern, clean, efficient natural-gas-fired power plants and 15 geothermal plants, located in 16 States, with the capacity to power over 20 million households. Additionally, we are the largest cogenerator in the country. We are a significant supplier to America's industry, producing steam for refineries, as well as chemical, paper, agricultural, and plastic manufacturers. We use approximately 3 percent of all the natural gas consumed in the country and almost 10 percent of that consumed by electric generators. Because we use existing modern technology and natural gas for fuel, our natural gas plants emit less than 40 percent less carbon dioxide than the electric generation industry average, virtually zero acid-rain-forming sulfur dioxides, less than one-tenth the industry average smog-producing nitrous oxides, and no mercury whatsoever.

I'm here today to tell you that the near- and medium-term solution to our climate change challenge is at hand. Natural-gas-fired electric generation is a compelling solution. First, it's far cleaner, with far less impact on our air, our land, our water resources, than any other form of fossil fuel generation. Second, the proven technology exists; it's far cheaper to construct than any other alternatives. Third, it's critical for the integration the intermittent renewable resources into the electric grid. Fourth, there is enough existing underutilized natural gas power plants located in the United States today to reduce the annual power sector $CO_2$ emissions by up to 20 percent. Then, last, as you heard from the others here today, there is an abundant, secure, and economical supply of domestic natural gas that should last for decades.

We could, today, simply through the increased use of existing modern natural-gas-fired power plants, meaningfully reduce the $CO_2$ emissions of the power sector. The power would be reliable, available all day and every day, and, with the right incentives, American businesses will continue to invest its own capital to build more natural-gas-fired plants and dramatically greenhouse gas emissions for the long term.

Calpine, I would modestly submit, is the model for a sustainable future. We use a mix of natural-gas-fired and renewable generation to achieve the results I just referred to. The majority of our gas-fired plants use state-of-the-art combined-cycle technology. A significant portion of the plants use combined heat and power, or cogeneration technology, to produce electricity and steam. Cogeneration opportunity—operations are significantly more efficient and result in less greenhouse gas emissions than having a standalone boiler at an industrial site. This is also a very efficient means of serving industrial production, and is recognized and encouraged by Federal policies.

We are also a significant contributor to the Nation's existing renewable generation capacity, with our 725 megawatts of geothermal power located in northern California. This is the only currently viable source of baseload renewable electricity, and our resource provides California with over 25 percent of its current renewable energy production.

We, at Calpine, continually challenge ourselves to further increase our corporate commitment to environmental leadership. For example, we have little impact on our Nation's water resources by not using once-through cooling at any of our plants; instead, we utilize treated municipal wastewater or air for cooling purposes.

Then, finally, we plan to build the Nation's first power plant with a voluntary limit on greenhouse gas emissions. The plant will emit less than half the carbon dioxide of even the most advanced coal-fired generating technologies.

Calpine has been, and continues to be, supportive of the House and Senate efforts to enact climate legislation. There are some key issues that I'd like to comment on.

First, we sell steam and power under long-term contracts, many of which may not be—may not allow us to recover our costs under a carbon-regulated program. Both the Waxman-Markey and the Kerry-Boxer proposals would allocate those free allowances to us and others, which is critical to the continued viability of those projects. We encourage you to leave those protections in place. Otherwise, early actors like Calpine will be unfairly punished.

Then, second, none of the proposals provide incentives to utilize existing, highly efficient, combined heat and power technology. We encourage you to add such incentives.

Third, none of the proposals provide incentives to encourage the full use of the existing modern natural-gas-fired power plants which could immediately reduce the electric sector's emissions by over 20 percent.

Then, fourth, both on the climate change proposal —both climate change proposals unduly favor dirtier generation to the point that incentives to switch to existing gas generation, or build new gas generation, are severely blunted. Under the proposed allowance methodologies, carbon prices would have to be extremely high for coal-to-gas switching to occur. The Kerry-Boxer proposal does include some incentives to replace high-emitting fossil fuel generation with a cleaner generation, but likely only for owners of high-emitting fossil fuel plants, and only if the new gas plants emit at levels not currently achievable by the industry.

In summary, while it's clear that we need a very varied energy source to meet the challenges of the future, we can meet our national goal of substantially reducing the electric power sector's carbon footprint with a policy designed to motivate greater use of existing, and to construct new, gas-fired power plants. It's also clear the natural gas supply is as secure and as abundant as the coal supply.

Thank you all, and I would be pleased to answer any of your questions.

[The prepared statement of Mr. Fusco follows:]

PREPARED STATEMENT OF JACK FUSCO, PRESIDENT AND CHIEF EXECUTIVE OFFICER, CALPINE CORPORATION, HOUSTON, TX

Chairman Bingaman, Ranking Member Murkowski and members of the Committee, thank you for the opportunity to testify today on the role of natural gas in mitigating climate change.

I am Jack Fusco, President and CEO of Calpine Corporation. Calpine is the nation's largest independent power producer with the lowest carbon footprint in the industry. In addition to the largest fleet of natural gas fired plants we have the largest baseload renewable energy resource in the country. We consume approximately 3% of all natural gas used in this country and almost 10% of that used to make electricity and thermal energy. In short we are uniquely positioned to address the role of natural gas in meeting the climate change challenge. Calpine has actively supported enactment of climate change legislation for many years and we have long put our money where our mouth is when it comes to minimizing our carbon footprint. (Please see appendix for more detailed background on Calpine.)*

I am here today to tell you that we could, today, simply through the increased use of existing natural-gas fired power plants, meaningfully reduce the $CO_2$ emissions of the power sector, immediately and for the foreseeable future. In other words, a near-and medium-term solution to our climate change challenge is at hand. No guesswork. No huge spending programs needed. That power would be reliable—available all day, every day. And if we embrace this solution with the right incentives, American business would continue to invest its own capital in existing proven technologies to build even more natural gas fired plants to dramatically further reduce emissions for the longer term.

We power American households, businesses and industry with plants that, compared with other fossil fuel plants, emit only half of the carbon, almost none of the other air pollutants and virtually no mercury. We are available now and can quickly build more capacity to help America grow tomorrow, responsibly and sustainably. Importantly, as you've heard from the other experts today, there is no security of fuel supply concern because natural gas supply is as secure as coal supply.

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*Appendix has been retained in committee files.

THE CALPINE MODEL IS THE MODEL FOR A SUSTAINABLE FUTURE

I would like to point out a real life example of how private business can be a leader in creating a sustainable future and reducing GHG emissions through the use of existing and developing technologies related to natural gas-fired electric power generation. The best way to do that is to tell you about what we have done at Calpine because I deeply believe it is the model for the future.

For better than two decades Calpine has put its money into clean, highly efficient natural gas plants and renewable energy production. The majority of our gas-fired plants use state-of-the-art combined-cycle natural gas-fired technology which capture and use the exhaust from gas turbines to generate additional energy in a steam turbine.

A significant portion of our generation uses combined heat and power (CHP or cogeneration) technology. At our cogeneration facilities, we use natural gas as a fuel to produce not only electricity but also thermal (steam) energy. The electricity produced is sold either into the wholesale power market or via a long-term contract to an end user (typically an electric utility or industrial consumer); the steam is sold, via contracts, to our industrial host. CHP operations are significantly more efficient and result in less GHG emissions than having a stand-alone power plant and a separate stand-alone boiler at an industrial site. For this reason there are federal policies and programs which actively support CHP. As the largest independent cogeneration company we help many of America's chemical, oil refining and other industrial facilities operate efficiently and cleanly.

While a small percentage of our generation mix is renewable, the resource we utilize makes it a significant contributor to the renewable generation capacity in the country. Calpine generates 725 MW of geothermal power at our Geysers facilities in Northern California. The geothermal resource is nearly emissions free and is available 24-7-365, making it the only currently viable source of baseload renewable electricity. Our geothermal operations provide California with its largest source of renewable energy.

Our investments in these technologies have made us a very clean generator, and as I said previously, with significantly fewer air emissions than the electric sector average. Compared with the electricity industry average, Calpine's natural gas plants emit 40% less $CO_2$, less than one-tenth of smog producing $NO_X$, virtually zero acid rain forming $SO_2$, and absolutely no mercury (see figure 1).*

Our sense of environmental responsibility extends beyond air emissions. For example, we invest to reduce or eliminate the impact on our nation's water resources. At our geothermal facility, we take treated waste water from nearby counties and re-inject it into our wells to supplement the steam resources. Further, Calpine has no once through cooling power plants. We strive to utilize treated municipal waste water for cooling purposes or air cooling. This is the sustainable approach.

We continually challenge ourselves to further increase our corporate commitment to environmental leadership and, to that end, we recently announced plans to build the nation's first power plant with a federal limit on emissions of $CO_2$ and other greenhouse gases, even though there currently is no regulation mandating that we do so. Our proposed Russell City Energy Center, a 600 MW plant using advanced combined-cycle technology, will be the cleanest natural gas-fired plant in the country. At baseload conditions, the plant is designed to operate at an efficiency rate that results in approximately 800 lbs of $CO_2$ /MWh of power delivered to the grid. This is less than half the 1,700 lbs of $CO_2$/MWh emitted by even the most advanced coal-fired generating technologies.

NATURAL GAS IS KEY

While the technologies we use are an important component of why we are so clean and efficient, the major source of our success is our chosen fuel—natural gas. Natural gas is considerably cleaner than other fossil fuels. Compared to coal, using natural gas as a fuel for electricity generation results in nearly 50% less $CO_2$ emissions, about 80-90% less NOx emissions, negligible SO2 emissions, and no mercury emissions. In addition, gas-fired plants produce a significantly smaller waste stream, if any, than coal (fly ash) and nuclear (spent fuel) plants.

There are a number of other advantages natural gas-fired generation has over other generation sources. Compared to many other generation sources, natural gas power plants can be permitted quickly and they have a much smaller footprint. In addition, they can be built more quickly and cost less to build on a per megawatt of capacity basis (see figure 2).

* Figures 1–3 have been retained in committee files.

Natural gas combined-cycle generation is also an ideal choice for backing up intermittent renewable electricity sources due to its ability to quickly ramp up and down. With the push for vastly expanding the nation's renewable generation capacity, much of the new capacity that will come on-line to fill this need is likely to be from intermittent sources. This could have an impact on the reliability of the electricity system. Americans demand and deserve reliable energy—when they flip on the light switch, the lights must go on. In the near term, this will only be achievable if gas-fired plants are there to provide that reliability.

Increased use of natural gas-fired generation can also have an immediate impact in reducing carbon emissions. Currently, there is a significant amount of existing natural gas-fired generation capacity that is not being utilized. The increased utilization of these existing facilities in place of older, dirtier power plants would result in near term GHG emissions reductions of up to 20% without the need for building new generating facilities (See figure 3).

Calpine continues to believe that natural gas is the right fuel choice for electricity generation. With the recent forecasts of substantial domestic supplies for the foreseeable future, natural gas is the key for providing the clean, efficient, reliable, and affordable electricity needed to help meet the nation's climate change goals.

## COMMENTS ON EXISTING CLIMATE CHANGE AND CLEAN ENERGY LEGISLATIVE PROPOSALS

Calpine has been very involved in the climate change and clean energy policy debate in Congress and applauds the legislative steps underway to address the climate change problem and to move the country towards the greater utilization of clean, efficient and renewable energy resources. We supported H.R. 2454, The American Clean Energy and Security Act of 2009, and we are encouraged to see that S. 1733, The Clean Energy Jobs and American Power Act, largely follows the same framework of H.R. 2454; we also supported components of S. 1462, the American Clean Energy Leadership Act of 2009, which passed out this committee. I would like to point out an issue of great importance to us contained in the climate change bills and some areas of concern in all of the bills.

## LONG-TERM CONTRACTS

Calpine sells some of our power and nearly all of our steam under long-term contracts. Many of our existing contracts were entered into before there was serious consideration of carbon regulations, thus these contracts do not include provisions to allow for compliance cost recovery. In general, merchant power generators will have an opportunity to recover compliance costs via the wholesale price of electricity and regulated utilities will have an opportunity to seek recovery of their compliance costs via their jurisdictional state or local regulatory commission. In our case we remain subject to the terms of our sales contracts, and it is unlikely we could successfully change these contracts to allow for cost recovery. Should we be unable to recover our costs associated with these long-term contracts, we could face financial harm and the contracts could be put into jeopardy. It is important to note that many of our contracts are associated with our CHP facilities.

Calpine believes it is imperative that climate change legislation provide protection for generators with such existing long-term contracts for delivery of both electricity and steam. We are very pleased that both H.R. 2454 and S. 1733 address this concern by providing free allowances to eligible generators with long-term electricity and steam contracts. As the legislation moves forward in Congress, we implore you to ensure that this provision remains intact.

## CHP INCENTIVES

We know there is established federal policy promoting CHP as an important form of energy efficiency. Per such policy, we would expect that there would be policies that promote the utilization of both existing and new CHP facilities. However, none of the existing legislative proposals provide real benefits for existing CHP units. There are many underutilized CHP facilities throughout the country that could help meet energy efficiency goals. Including credit for these facilities for the energy efficiency goals in the various bills would ensure that such existing CHP facilities are efficiently and effectively used.

## NATURAL GAS INCENTIVES

Real incentives to encourage the greater use of natural gas are also largely missing from all of the bills. We have heard arguments that just putting a price on carbon will naturally benefit natural gas, as this will likely automatically lead to fuel switching from coal to natural gas; therefore, there is no need to include incentives for natural gas in legislation. However, both H.R. 2454 and S. 1733 provide such broad benefits for dirtier sources of generation and for renewable energy resources, that the "natural benefit" for natural gas will be seriously blunted. Under the proposed allowances methodology, carbon prices would have to be extremely high for fuel switching to occur.

S. 1733 includes a provision promoted as encouraging the greater use of natural gas. The intent of the provision is to provide incentives to displace high GHG emitting electric generating units with lower emitting sources, which generally would benefit natural gas fired generation. However, the way the section is written could be interpreted and implemented in a way that ultimately does not benefit natural gas, particularly existing natural gas generation. First the funds would only go to new projects. Second, to be eligible for funds, the project must reduce emissions below a certain threshold that is lower than most natural gas fired plants can likely meet.

More work and thought needs to be put into providing true incentives for natural gas in these legislative proposals.

CONCLUSION

Calpine believes that natural gas is a key resource in helping to mitigate the effects of climate change. We remain committed to being an important player in working with you to resolve this problem. While it is clear that varied energy sources are needed to meet the challenge, it is equally clear that the greater use of natural gas with its compelling and distinct advantages has been overlooked. I urge you to seriously consider natural gas as a solution and to enact policy that promotes it.

Thank you again for this opportunity to testify.

The CHAIRMAN. Thank you. Thank all of you for your excellent testimony.

Let me start with a few questions and then Senator Murkowski, and I'm sure all members will have questions.

Mr. Newell, let me start with you. You know, when we started talking seriously, a couple years ago, about climate change legislation and putting a price on carbon, I can remember discussions where people said one of the effects of this would be to encourage more use of natural gas, since it's the least carbon-intensive of the various fossil fuels. I notice—and you commented on it—your analysis of the Waxman-Markey legislation, that's passed the House, predicts that natural gas usage would not be significantly higher as a result of putting a price on carbon, as that legislation proposes to do. In fact, in some of the modeling scenarios that you have, I guess you have natural gas usage even lower than in the reference case.

Could you just explain how—again, maybe you went over this in your comments, but, to the extent you could elaborate on why you do not see the enactment of climate change legislation, such as the House has passed, increasing the use of natural gas in power generation and other sectors of the economy?

Mr. NEWELL. Yes. Let me offer a little bit about the history. I think that one of the main factors that's changed, depending upon how far back you look, is that natural gas prices have come up significantly over the last several years, whereas, if you turn back the clock to a point when people were discussing, for example, the Kyoto Protocol and so on, at that point in time gas prices were significantly lower. So, as a cost-effective means of reducing greenhouse gas emissions, natural-gas-based generation for electricity looked relatively more competitive, compared to existing coal, than it does now. It's kind of a bit of——

The CHAIRMAN. The new finds of natural gas have not changed that perspective, as to what the price of natural gas will be, relative to other fuels?

Mr. NEWELL. I think they have, but, again, relative to historical prices that were down as low as $3, $4 per thousand cubic feet for many years. The expectation is, even given the new gas shale developments, that over the next several years we'll see a gradual increase in the price of natural gas that would be necessary to balance supply and demand.

So, we see that price increasing, over the next several years, to the $5 range, and, over time, to $6, $7, potentially $8 per thousand cubic feet as you go out a couple of decades.

If you think about comparing natural-gas-based generation versus existing coal, we find that the level of carbon price that would be necessary to make natural gas switch out for coal in existing plants depends what you assume about the natural gas price, again. So, at $5 per Mcf, we estimate, roughly, that it would take a \$30-per-ton-of-$CO_2$ price to encourage switching from a typical existing coal plant—conventional coal—to natural gas. If the price of natural gas is $7 per thousand cubic feet, it would take something like a $60-per-ton-of-carbon-dioxide allowance price to encourage switching among existing plants.

So, as one thinks about the results that come out of EIA's analysis of the Waxman-Markey bill, the key issue is that—in terms of the role that gas plays relative to other technologies—in the near term we find that gas tends to increase. The reason is that the competiting low-emission generation technologies, such as nuclear, renewables, and coal with carbon capture and storage, are on a longer-term development plan. But, in the longer term, as you get toward 2020, 2030, zero- to low-carbon technologies, like nuclear power, renewable energy, and coal with carbon capture and storage, start looking relatively more competitive compared to natural gas. So, that's why, over the long run, we actually see, in many of our cases, a reduction in natural gas use relative to the reference case.

Is that——

The CHAIRMAN. Yes, that helps. Let me ask one other question——

Mr. NEWELL. Yes.

The CHAIRMAN [continuing]. Before my time expires, here.

Mr. McKay, you talk about the importance of—or the idea that we might essentially provide incentives to shut down some of the least efficient nuclear plants—coal-fired plants—and have those replaced with natural gas.

Could you just elaborate on that proposal, or your suggestion there, as to how that could be accomplished? To what extent government should be telling companies what to replace coal-fired plants with, if we did that? Or, to what extent we should incentivize it?

Mr. MCKAY. Yes. Let me just expand on that a little bit. What we've looked at, and believe, is that some of the most inefficient coal plants—the oldest coal plants —are going to face increased environmental air standards, here, in the near future, and will have to do upgrades—sorry—will have to do upgrades of a fairly sizable proportion. So, we took about 80 plants that we think are in that category, and we said, "OK, those could be potentially upgraded and still working as they are. Or, would it be an opportunity to look at, if there's a way to retire those plants, what would be the climate benefit, in terms of $CO_2$ emitted, if other alternatives were used?" So, you could theoretically go to all wind, you know, if it would work. We looked at natural gas. We believe, you know, at a very low cost, natural gas could replace that capacity with very low effective carbon-mitigated price.

In other words, if you take a current coal plant, look at a new-build gas plant, we think it would add about 1 cent per kilowatt-hour to that coal plant. If you take that 1 cent per kilowatt-hour for those 80 coal plants, over the period of 2012 to 2020 that would be about a $5-billion dollar increment. OK? But, that's from current coal to brand new natural gas generation.

One of my colleagues here today has said there's a lot of excess capacity, so it would be lower cost if we use excess natural gas generating capacity. OK? So, this is about new build. If you did that, you would mitigate about 100 to 125 million tons a year, per year, as I indicated in my remarks, as you phase eight or ten of these out a year. So, over the period of 2012 to 2020, that would be about 700 million tons, we believe, of $CO_2$ mitigated, if you switched these to natural gas. The cost of that mitigation, if you take my $5 billion and that amount of $CO_2$, is about $13 a ton.

So, we think it's an efficient way to at least look at it as an option, if these coal plants need a lot of work, to start with. That's where we're coming from.

The CHAIRMAN. Thank you very much.

Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

Thank all of you for your testimony this morning.

I think, without exception, the comments have been that we have an available, secure supply of natural gas that can last for 100 or 150 years, but a considerable source. Mr. Stones, I appreciate the concerns that you have raised.

But, I want to ask you, Mr. McConaghy, you've actually used the term "game-changer," that the shale that we're finding, whether it's the Marcellus or the Barnett or wherever in the country, that this is a game-changer for us, in terms of identifying a vast resource, and the availability.

Can you explain to me and the other members of the committee a little bit more about Alaska's gas resources and its relevance as a long-term source of supply, given what we're seeing in the Lower 48 and the prospects that we're seeing with the gas shale? Does Alaska still play in the North America market for the long term?

Mr. MCCONAGHY. Thank you, Senator.

The short answer is, we very much do believe that Alaska, as a supply component to the North American fuel mix, is absolutely part of that future. One of the reasons that we have that view is that the price level that's going to have to pertain, over the back end of this decade, in order to ensure that the level of gas consumption that the United States will require for, not just carbon reasons, but for all the other applications that natural gas is used for, is going to be a price level —and our own view would be that

that price level is likely somewhere in the range of $6 to $8—would tell us that the cost structure that it's going to take to bring Alaska into the market can still make that a totally economic contribution to the supply mix. So, we very much are of the view that Alaska is a component of this, notwithstanding the significant, quote, "game-changing" advent of the shale gas resource, so that it's very much a case that we need both of these resources coming into the U.S. supply mix. Of course, in the case of Alaska, it is going to take us probably most of the rest of the next decade to realize that. But, we certainly do not ascribe to a view of crowding out. We don't take that view with respect to Mackenzie, either.

Thank you.

Senator MURKOWSKI. Mr. McKay, do you care to comment?

Mr. MCKAY. I think I generally agree with that. I mean, it's a world-scale resource. It's a long way from market, and it needs to compete into the U.S. market, but we—but I would agree, generally, with his comments, yes.

Senator MURKOWSKI. Good.

Let me ask a followup because you mentioned the price. You anticipate that natural gas prices are going to be holding somewhere between $6 to $8. That certainly helps TransCanada, as you look to build this out. It certainly helps BP and the other producers that are involved. You need that higher price for the natural gas. Given that right now the consumers are experiencing and enjoying a lower price, what does this do? How much of a pinch is this to the consumer? It helps to build out the project, but ultimately, what is the impact to the average household?

Mr. McConaghy, you can comment, or anyone else.

Mr. Stones, you can go ahead.

Mr. STONES. I mean, one of the things that we've seen over the last several years is, you know, we had a spike in 2001, in 2003, in 1997, in 2005, and 2008. We believe spikes will continue. We are enjoying low prices now. As a result, gas production is actually falling, per EIA data, in this country, at present. There will be a time lag between the resumption of it, and that's likely to lead to a spike.

These higher prices are going to continue, and they're going to be volatile, going forward. That's why we've ended up losing so many jobs in manufacturing. I disagree, respectfully, with Mr. McKay, that there's a need to drive demand to gas. Right now, over the last, say, 6 to 12 months, the United States has actually moved, by most accounts, 2 to 3 Bcf of electricity—2 to 3 Bcf of gas consumption's worth of electricity consumption from coal plants to gas plants, without any need for an incentive. We believe that there is enough incentive in the market, just left alone, to drive the replacement of these coal power plants, as was testified to by the members of the panel. They've already replaced them. Why do we need an additional incentive?

Senator MURKOWSKI. Mr. Chairman, my time is expired, but hopefully we'll have time for a second round.

The CHAIRMAN. Senator Menendez.

Senator MENENDEZ. Thank you, Mr. Chairman.

Mr. Newell, I'm concerned both about climate change, as well as our complete reliance on oil for virtually all of our transportation needs. When the economy fully rebounds, there are few, I think, who do not believe we'll see, again, a spike in oil prices. That's why, along with my colleague, Senator Hatch and the majority leader, Senator Reid, and Senator Murkowski, we introduced the Nat Gas Act, which is a bill that extends and increases important tax incentives to jump-start the national—natural gas vehicle industry and allow us to diversify our transportation fuel mix and also reduce carbon emissions.

Now, the Energy Information Administration seems to have some quite conservative estimates for oil price rises, and it did not predict the incredible volatility in oil prices we've experienced in recent years. So, my question is, Has the EIA done any work to explain this volatility or to examine how expanding the use of other fuels for transportation, such as natural gas or electricity, might help U.S. consumers from such volatility?

Mr. NEWELL. Yes, Senator, we have. In September, we launched what we're calling the Energy and Financial Markets Initiative, the purpose of which is to increase EIA's information base and our analytic capacity for understanding and explaining the wide variety of factors that influence oil and other energy prices. There are a number of different elements to the initiative, some of which are reflected in previous legislation that has actually passed out of this committee, so we're taking action on a number of those things already. It includes increasing information collection on various things, also increased cooperation with other Federal agencies that are, you know, involved in the issue of analyzing energy and financial markets. We're also undertaking analysis of various types.

One of the things that we have started doing in our short-term forecast, which is our Short-Term Energy Outlook, is that as of October, we now include uncertainty bands around our price forecasts, to better show that there is wide range of uncertainty on where oil prices and natural gas prices could go. If you look at that, based on the analysis we've done, there's a significant range around which oil and natural gas prices could be within the next couple of years.

Within our long-term projections, we have a central case for an oil price. We also have a high and a low price case. The high price case goes as high as $200 per barrel of crude oil.

So, we are trying to better articulate the broad range of possible future prices for oil and natural gas in our work. Also——

Senator MENENDEZ. Have you looked at expanding the use of, for example, natural gas or electricity for transportation costs as something——

Mr. NEWELL. We have not specifically analyzed that, and we haven't been asked to.

Senator MENENDEZ. OK. Let me ask you one other question. Many of my colleagues continue to promote the view that if we drill for more oil on the Outer Continental Shelf, we will soon drill our way into energy independence and low oil prices. The fact of the matter, the United States has 2 to 3 percent of the world's oil reserves. According to the EIA's report, even if we opened up all of our shores to drilling, quoting from your agency's report, quote, "the impact on average wellhead prices is expected to be insignificant." That's the end of the quote. Has there been any recent developments that would make you change that conclusion in your report? Is there any reason to believe that any change that would open up everything to U.S. oil production would have a different impact on wellhead prices, as the agency has previously said, that it would be insignificant?

Mr. NEWELL. No.

Senator MENENDEZ. No? That's a succinct answer. Rarely achieved here.

[Laughter.]

Senator MENENDEZ. Let me ask one last question.

Mr. McKay, with reference to that Nat Gas Act that I was referring to, transitioning our vehicles to natural gas would, of course, offer the dual accomplishment of mitigating emissions and reducing dependency on foreign oil.

What do you believe that companies like your own are willing to be, in terms of a partner, in bringing more natural gas vehicles to market, if the incentives are there?

Mr. MCKAY. Let me just first say that I do think there will be increased penetration of natural gas vehicles, because—for all the reasons you said, and primarily around centrally fueled fleet and commercial vehicles.

We actually, as Amoco—and I'm a former Amoco employee, before we merged with BP—we did this, and tried this, in the 1990s, and it works. We didn't have the customers at the time. The infrastructure is the issue. So, we will be continuing to watch this to see if it's an opportunity. But, there's experience with it. This has gone on for decades, and still going on in places we put it in, like Egypt, believe it or not. So, yes. We'll be watching this very——

Senator MENENDEZ. My time is up, but we'd appreciate hearing from you as to what it would take to have companies like your own be fully engaged, if we could incentivize it to do so.

Thank you, Mr. Chairman.

The CHAIRMAN. Senator Brownback.

Senator BROWNBACK. Thank you, Mr. Chairman. I appreciate that.

I appreciate the panel. It's been excellent information on a good topic.

Mr. Newell, I want to provide you with a little information, just on a local level. You were talking about some of the cost of the pending legislation on cap-and-trade. A couple of my utilities in my State have done some projections. Kansas City, Kansas, Board of Public Utilities says the first-year cost to their ratepayers would drive electric rates up 25 percent if the cap-and-trade legislation that's passed the House were to pass. Kansas City Power and Light is projecting a 4-percent increase—now, that's on their high-end projections—by 2012. So, to just to give you some real-world perspective. I'm sure you're familiar with how sensitive people are about electric rates going up. So, I hope you also track the projections on those—and I presume that you are—about what would happen—if you put these requirements in place, what happens to real people that are struggling in the economy presently, and driving up these sort of costs.

Mr. McKay, I want to ask you, if I could—Mr. Stones seems to have a legitimate question about—it's going up now, on natural gas demand through the electric power sector. I'm happy to see that. I toured, recently, in a new gas-fired power-generating unit in my State. Small footprint. Good unit. Seems to really go in well. Why the additional incentives for something that's growing presently?

Mr. MCKAY. Let me first acknowledge Mr. Stones' viewpoint, because one of their largest costs is feedstock cost, to do what they do.

Senator BROWNBACK. Right.

Mr. MCKAY. Natural gas is their feedstock. So, I totally understand the concern, and they're one of our customers.

However, natural gas is used for a lot of different things, not just the chemical industry. It's used for power. It's used for other industrial demand, natural gas vehicles, et cetera.

One fundamental thing that has changed recently, that I think we shouldn't underestimate, is the structural change in the gas resource base, and that has changed tremendously. Even over the last 3 years, that's gone up, by our estimates and, I think, EIA's estimates, 40 percent in the last 3 years. So, the resource base has enlarged and the pipeline infrastructure has enlarged. So, we're connecting a bigger resource base to the markets in a better way. I think this—things like this will help the volatility and help Mr. Stones.

I do also think that when you look at the power sector, as we're here today, natural gas does have the biggest role to play in the cheapest reduction of carbon dioxide emissions. I think what we're really balancing, then, is the usage of—I don't think we should reserve natural gas usage for one sector, and it has to play across the sectors. What we're trying to do is balance the right thing.

Let me just make one clarifying comment. What I said, to start with, is, we believe in a level playing field. We don't believe the playing field is level in the proposed legislation. If it's not level, then we would say, "Could we look at this as a way of a smooth transition?" That's our logic.

Senator BROWNBACK. That's a good thought.

I just—Mr. Chairman, I think these are interesting ideas, particularly Mr. McKay's, about, maybe that—the bottom-end coal-fired power plants and providing some support for transitioning. But, I don't want to create the situation that hurts the manufacturing sector, which we're desperately trying to bring back and to stimulate. This is my own pet peeve, or pet project, maybe, for my State, in Kansas, but if we could do things that combined the renewables, particularly wind, with natural gas as a way to maybe help in assisting those bottom-end coal-fired power plants—that may be too complicated by half, but might be fairly simple and——

We've got to do it in a cost-effective way. We can't drive utility rates up. Can't do that, because they just—people won't stand for that. We don't need to do it that way. I think, if we're wise enough, we could keep from doing that. So, I hope we can be balanced on this, without hurting people, and, at the same time, reduce our $CO_2$ emissions.

Thanks, Mr. Chairman.

The CHAIRMAN. Thank you very much.

Senator Stabenow.

Senator STABENOW. Thank you very much, Mr. Chairman, for an excellent hearing.

I first want to welcome Mr. Stones, from my native Michigan company, and also——

Mr. STONES. Glad to be here.

Senator STABENOW [continuing]. Mr. Wilks, for being a part of the Michigan economy, as well. So, it's great to see Michigan represented.

I guess I would go back to what Senator Brownback just asked, in terms—and what Mr. Stones asked—and that relates to, Why do we need additional incentives? If you look at natural gas and the incentives that come with it automatically, in terms of the environment, terms of what's happening now, the current cost incentives in moving—Mr. McKay, as you said—moving your plants, and so on—I think a basic question for us is, Is there enough incentive in the market place right now to be able to make things happen? That would be one question.

Then, second, it is of, obviously, great concern to me that we balance our natural gas policies. Clearly, natural gas is part of a low-carbon future for us. Critical. Important. We have large amounts of natural gas—very important for us—that that is a part of the mix, as I think we need to make sure everything is a part of the mix. But, we also have to balance that with our manufacturing policies. I'm deeply concerned, in the short run. Mr. Newell, you were talking about nuclear and CCS and other things becoming more viable by 2030. What happens in the meantime? I don't want to be losing jobs offshore until 2030 in manufacturing until those things happen. So, the key question really relates to cost, right now, and what this does for manufacturing, and, in fact, is there a necessity for additional incentives in an area of energy that already has, I think, a great deal of appeal and incentives to it.

Mr. Newell, I would ask you a question. You had indicated, in your testimony, that recent appraisals of technically recoverable natural gas does not take into account the costs of finding and recovery of supplies in previously unknown sources, such as shale. So, I wonder if you might talk a little about the cost of shale production. At what price do the supplies start to become viable?

Mr. NEWELL. Yes. I think that that part of the testimony was drawing the distinction between technically recoverable resources and proven reserves. The reserve concept takes into account the cost of drilling and extracting those reserves, as well as the price that one could get in the market, whereas resources is more about the physical resource base. So, we've seen significant expansion of the physical resource base, most of it associated with shale technology development.

In terms of the price levels for natural gas that would be necessary to continue expansion of shale production, there's a range. It depends on which shale play you're talking about, how mature it is. There's a range of estimates, some as low as $3 per thousand cubic feet for shale to be profitable. With other shale plays you need $7 per thousand cubic feet to make those profitable. So, there's a range.

In terms of looking forward, the price levels that we think are necessary to balance supply and demand are going to be moving up from the $5 to $6 to $7 range. But, you know, some plays will be relatively more profitable under those scenarios, and others will be just on the edge.

Senator STABENOW. OK. Thank you.

So, given that, I'm wondering, Mr. Stones, at what prices does your business model start to change when we look at this whole picture?

Mr. STONES. Let me say a couple of things. You know, one of the things we've talked a lot about is average price. You know, what we've seen over the last 5 years or more is that 80 percent of the time the price is lower than the average price. The issue is the other 20 percent of the time. How do we get through to the other side? These are the spikes. These are the—what actually causes us to shut down. So, when you have a 5 to 8—what—3 to 8, or whatever the number was, $6 to $8 dollar range, it can often be, for short periods of time, maybe, but out of that, for a period of time long enough to cause real significant job destruction and job losses.

The second thing, you know, I would talk about, that's important for us to think about, is, as we build more power demand and more natural gas vehicle demand, these are inelastic resources. These are people who will pay any price to get their fuel. We will not be cold, we will not be dark, we will drive our car to work. What manufacturing provides is a buffer and a way to minimize those spikes.

So, we're very excited. We hope that there is this new resource. But, it seems to us a very large risk to take, to pin everything on this and assume that the gas will follow.

Mr. MCCONAGHY. Senator, if I could make one—just one comment?

Senator STABENOW. Yes.

Mr. MCCONAGHY. Yes. Just in—respectfully, on the issue of volatility, which has been raised this morning, I would just emphasize there are, I think, two significant structural differences, and one is the fact that the shale gas resource is a different kind of gas resource. It is a resource that is more—almost akin to a manufacturing process of its own, because it's got less geological risk, its process is to just get the amount of necessary drilling done, to get it done. That's a significant difference than what was done previously, when geology was a much bigger issue, as to how you can ramp up.

Second, the pipeline infrastructure today, and most notably some of the infrastructure that's been created to bring Rockies gas to the midcontinent, the laterals that have been connected, some of the existing shales, whether it's Barnett, Fayetteville, et cetera—the infrastructure that will help reduce volatility is significantly better now than it has been before.

So, I'd respectfully make the point that the concern about volatility has changed and that, I would just register, is something that there can be, you know, honest debate about how extreme that is. But, I do think there have been, fundamentally, structural improvements that reduce that concern. I would just register that.

Senator STABENOW. I appreciate that. I guess the question—I know my time is up, Mr. Chairman—is, As we look at this new technology, are we at a point yet where it's cost effective even though there's great opportunities through that? I think that's probably something we'll have to further talk about.

So, thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Sessions.

Senator SESSIONS. Thank you.

To follow up on Senator Stabenow's question, Mr. McConaghy, perhaps, I've heard that one company is—drilled 4,000 wells in shale and not had a dry hole yet. Is that correct? Is——

Mr. MCCONAGHY. I could——

Senator SESSIONS [continuing]. Are those numbers realistic? Are——

Mr. MCCONAGHY. I could believe that. I can't, obviously, attest to what you've just referred to. But, it is a fundamentally different kind of production process than what was formerly known as conventional wildcat drilling.

Senator SESSIONS. The amounts of it indicate pretty clearly, Mr. Newell, that we have 100 years-plus of supplies of this shale oil, would you not agree—I mean, shale gas—or natural gas in America, maybe is better way, including the shale gas, discoveries that have added to the supply.

Mr. NEWELL. Exactly how many years, you know, depends—there is the resource base, and then you divide by something like current production, but certainly well above 50 years. I think there's a pretty broad consensus, whether it's 80 or 100 or a bit above 100. I think there's more there. The Gas Committee roughly doubled their estimate of the resource base, over the last 4 years.

Senator SESSIONS. Did they do it in terms of how many years of supply exist? Do you recall what those numbers were?

Mr. NEWELL. It basically went from roughly 50 years to roughly 100, yes.

Senator SESSIONS. That's proven reserves, right?

Mr. NEWELL. No, this is resources.

Senator SESSIONS. Resources?

Mr. NEWELL. Yes.

Senator SESSIONS. Now, with regard to the emissions, it's about—natural gas would get the same energy BTU production at about 40 percent less $CO_2$. Is that correct?

Mr. NEWELL. Yes, that's correct.

Senator SESSIONS. It seems to me that this is a dramatic development. The increase in supply of natural gas is just stunning, and a great development. It's cleaner. If it can be connected to the pipelines, it's very transportable.

I would think that one of the things we would like to see—and suspect it will happen naturally, but perhaps we could accelerate it—would be to utilize more natural gas for transportation in our fleets, which—mean buses here in Washington, DC, use natural gas, and other cities —and into larger vehicles. That's the—essentially what Mr. Boone Pickens has proposed, and I think, essentially, with the new discoveries, that makes sense to me, because—several things. It will pay for itself, will it not? Would anybody like to comment on that, in terms of at least vehicles?

Mr. Fusco.

Mr. FUSCO. Not so much on vehicles, Senator. But, if I could, just to clarify, you know, a conventional coal plant, which is what the U.S. has, has an efficiency of around 30 percent. That's the thermal efficiency. So, for the same BTU, in one of my modern gas plants you're going to get over 50-percent efficiency. You're actually get more megawatt hours, as well as lower emissions, than——

Senator SESSIONS. So, compared to coal, it's even better. Right.

Mr. FUSCO. Then, last, you know, on incentives, right? The reason we need incentives is—my company had the benefit of seeing coal-to-gas switching in our southern and southeastern fleet this past year. It's only when gas prices get around the low $3 in MMBTU, so extremely low, that incentivizes the coal guys to shut their units down. OK? With the current forecast of $6 to $8, it's going to be more of the same. There will be no switching. You will not get the—any environmental benefits. We need environmental regulations in this country.

Senator SESSIONS. We can make anything happen, Mr. Fusco, with enough subsidies. So, it's the question of how to do it. I'd like to not burden the American consumer any more than we possibly can.

With regard to current prices of natural gas, I have been informed that, even though a natural gas vehicle, like a bus or a truck, that travels many miles—Mr. McKay, I guess BP might know this—that it would pay for itself at current prices, the extra cost, if you used natural gas and had the infrastructure to utilize natural gas, as opposed to diesel fuel.

Mr. MCKAY. Yes. I think, at current natural gas prices, that would be true. We do believe there will be increased penetration or more natural gas vehicles. We do agree with that.

Senator SESSIONS. It would seem to me, as a matter of national policy, we should favor natural gas, because, in many ways, it's cleaner to produce, and secondly, it's almost all American. So, it eliminates the balance-of-trade deficits that we have when we import 60 percent of gasoline and diesel fuel. So, we import all of this, send American wealth abroad, when we could produce 40 percent less $CO_2$ and create a cost-effective substitute for at least fleets, I would think, if not every individual automobile. If we could figure a way to expand that, then we've not burdened the economy and we've reduced our balance-of-trade deficit and we've reduced, significantly, $CO_2$ emissions. Am I off base on that?

Mr. McKay. No.

Senator SESSIONS. I see most of you agree with that?

I would just say, Mr. Newell, we've got to watch the objections over the production. I mean you drill—my understanding is, most of the shale gas is about 2 miles deep, and your water level is 600 feet or less, where water exists. So, it's unlikely that anything injected to help get the gas out would impact our water supply, it seems to me. So, I really think that can be a problem that's—would cause some concern. You mentioned it, I think, in your written testimony. I hope we can work on it and make sure that we're not causing any pollution. But, I don't think, what we've seen so far, we're seeing a pollutant effect from natural gas production.

The CHAIRMAN. Senator Shaheen.

Senator SHAHEEN. Thank you, Mr. Chairman.

Thank you all for your testimony.

I would actually like to follow up a little bit on the Senator's question about the pollution and water, because there has been concern expressed about potential results of the new fracturing technology and what that might mean, in terms of polluting water supplies. So, I'd like to hear your thoughts about that, whether you've seen that to be a concern.

Senator Casey has introduced a bill, called the Fracturing Responsibility and Awareness of Chemicals Act, which would repeal the safe drinking water exemption, which was—is provided to hydraulic fracturing, and require a public disclosure of chemicals used in the process. So, I guess I'd like to also hear, those of you who are producers and users of natural gas, whether you think that's legislation that you could support.

Mr. MCKAY. Let me just address your original point, first. On FRAC, fracking is not a new technology. It's 50 years old, and there's been over 1 million fracks done in the U.S. So, that technology is not new. What's new in shale is that—you—we drill horizontal wells, maybe 5,000 feet, and do multiple fracks on those—on that lateral. That's the new part.

So, the fracking has been around—I mean, I worked on it when I first started. The fracking technology is —and the protection for groundwater—is very robust and very solid. Of those million frack jobs, there's very few that—I don't know of any that have had any surface water issues. So, I don't——

Senator SHAHEEN. I was thinking more of groundwater——

Mr. MCKAY. That's what I——

Senator SHAHEEN [continuing]. That would affect wells.

Mr. MCKAY. Sorry. That's what I mean by surface water—near surface water, groundwater. I didn't mean really on the surface. That's a——

Senator SHAHEEN. OK.

Mr. MCKAY [continuing]. Industry term. So, groundwater—there haven't been groundwater issues.

We have physics working on our side. When you frack underground at 10,000 feet or 5,000 feet, the horizontal stresses are what are relieved, and it propagates horizontally, it doesn't propagate up.

It's a solid technology. I do understand your fluids point about—the disclosure of what's in fluids, I think, was in your second point.

Senator SHAHEEN. Right. That's part of this proposed legislation.

Mr. McKay. We believe that fracking needs to be regulated at the State and local level. We believe that State and local regulation can include disclosure of what's in those fluids. We would support that. We have been working very hard to make sure the footprint of fracking, or any issues around fracking, is minimized and would be—Colorado's got a good plan that they've put in place and I think is a model that States could look at. So, State and local—because everything is different—geology, water, everything—at a local level. The technology is robust.

Senator SHAHEEN. So, you wouldn't support a repeal of the exemption to the Safe Water——

Mr. MCKAY. I would not.

Senator SHAHEEN [continuing]. Drinking Act?

Mr. MCKAY. I would not.

Senator SHAHEEN. Is there anybody here who would support that legislation?

[No response.]

Senator SHAHEEN. Mr. Fusco—I want to change the subject a little bit at this point—you testified about Calpine's use of combined heat and power and——

Mr. FUSCO. Yes.

Senator SHAHEEN [continuing]. The additional efficiencies that are created as the result of that. I know that a number of us on this committee believe that that's an important way to use power and improve the efficiency of our energy sources. So, as you think about what we might do to encourage that use of combined heat and power, are there incentives that you could suggest, or other ways that you would urge us, to better support combined heat and power?

Mr. FUSCO. Yes. Thank you, Senator.

I think, you know, currently there aren't any incentives for existing combined heat and power plants, in either of the bills. So, I think the first thing would be to try to incentivize those of us who have it to expand those facilities. Most of these gentlemen at the table are either a customer or a supplier, or both, in most instances. So, I believe in combined heat and power, mostly because when we talk about the efficiency of a combined heat and power plant, it exceeds 50 percent. It's in the mid-55-percent range, compared to the conventional plants that are 30 percent. But, I do think there—you know, and we're happy to work with you all to figure out the right mechanisms that need to be put in place for that.

Senator SHAHEEN. Thank you.

I'm almost out of time, so I'll try and ask this question very quickly.

Mr. Newell, I understood you to say that, despite incentives in the current legislation, that we wouldn't see our natural gas use increase in the future. Am I correct?

Mr. NEWELL. It depends on the scenario. In our reference case, which is absent the climate policy that's been discussed, we see a drop in natural gas consumption over the next several years, because new renewable energy for electricity and some coal installations are coming in. But, over the longer term, natural gas use comes up a bit and is roughly flat over the next 20 years, in our reference case. Once you layer on top of that a bill like the Waxman-Markey bill passed out of the House, depending upon the availability of other options for reducing greenhouse gas emissions—such as the availability of international offsets, and the cost and availability of nuclear power, and coal with carbon capture and storage, which are close to emission-free, or emission-free—if those are not available, natural gas could actually increase substantially, we find. If those are available, which is what our Basic Case and some of our other cases assume, natural gas does not compete with those technologies as a cost-effective greenhouse gas compliance option, given the other incentives that are in the system. There's also —and I think this gets back to one of the questions Senator Bingaman asked earlier—State renewable portfolio standards which are moving renewables into the mix. In the Waxman-Markey bill, we also have bonus allowances for carbon capture and storage, which are also part of what's driving that technology. So, it's not just the carbon price, per se. There are other policies and incentives that are in place. Is that——

Senator SHAHEEN. Thank you. My time is up.

Thank you, Mr. Chairman.

The CHAIRMAN. Senator Cantwell.

Senator CANTWELL. Thank you, Mr. Chairman. Thank you for holding this important hearing.

Gentlemen, thank you for being here and to talk about this larger issue of future energy supply.

I'm somebody who, even though we have a hydro system that is about 71 percent of our electricity grid, certainly want to see the U.S. electricity grid diversify and to have more natural gas. I mean, if we're at 23 percent today, I'm hoping that we can grow that significantly in the future. We have many farmers in our State that the supply of natural gas does really affect the price of product that we have. People think of Washington State as, you know, software and airplanes, but agriculture is still the number-one employer. So, diversifying is really important.

Mr. McKay, you talked about a level playing field and how important that was, not to pick winners and losers and to have the market continue to do that. I wondered if you could comment a little bit more on how you think the House bill treats that—I get a sense that you think it distorts the market—and what you think would happen as a result of that.

Mr. MCKAY. So, in the—if we use Waxman-Markey as a —as something as a—to talk about, there's two fundamental, we think, nonlevel playing fields. First is, the transportation sector is sort of a paying sector, and the utility sector—roughly, roughly—a nonpaying sector, in terms of the price of carbon, because free allowances are given. That's the first dislocation.

The second one within the utility sector is that we think alternatives are effectively mandated or encouraged, which—you know, we support transitional incentives, reasonable ones. Coal, we believe, is insulated. The consumers of coal are insulated, for sure. Some of the generation of coal is insulated through credits, allowances, funding for CCS with coal, not with natural gas, these type of things. Therefore, we think the price of carbon will not be—not flow easily to make changes in investment decisions about whether you should use coal or natural gas.

Senator CANTWELL. Basically, you're saying they're going to help pump up the price of—or support a lower price of coal and cause a——

Mr. MCKAY. I think it's insulation, primarily. So, what we're saying is, if you could strip all the insulation back and get to a really pure playing field, we're fine with that. Absolutely fine. If you can't strip the insulation back, how do we smooth the transition in the period of time when we're trying to get to lower carbon future?

I just want to say one thing about the demand or production. Industrial demand has dropped tremendously. The projections that we see, going forward, we don't even get back to last year's production until 2020, or later. So, this idea about, you know, natural gas production ramping up is not—every projection I've seen, after this drop, we barely get back to the level we were at last year. So, there's plenty of supply to do that, is all I'm saying.

Senator CANTWELL. So, definitely not a level playing field, as far as natural gas is concerned.

Then, on the sequestration issue, the same dilemma? The House-incented——

Mr. MCKAY. Yes.

Senator CANTWELL [continuing]. Carbon sequestration, but not any natural gas sequestration? Is that your read of it?

Mr. MCKAY. Yes, I think natural gas is a great clean utility player that's being not let on the field.

Senator CANTWELL. That what?

Mr. MCKAY. Not being let on the field fully.

Senator CANTWELL. OK.

Mr. MCCONAGHY. Senator, if I could just also add one comment to your question, I would—I understand that the bill that you have sponsored, in terms of a different approach than Waxman-Markey, to how one would design a cap-and-trade bill—I would—by my review of it, it comes the closest to establishing a level playing field, because it really starts with a full auction and that would clearly be responsive to the notion of a—setting a carbon price that would be without the distortion between the different alternatives and that should be, probably, all things being equal, advantageous to natural gas. So, I do make that observation.

But, given that we are reacting to what is currently in play, I endorse the comments that have just been made, quite eloquently, that, in fact, you have an insulation of coal, through the allocation of free allowances, you have the increasing phenomenon of renewable portfolio requirements growing, squeezing out the most benign, from a carbon perspective, of the hydrocarbons. Ultimately, the point of this exercise is to do something about carbon, despite the fact there are other collateral considerations, which others have talked about. So, I just wanted to make that acknowledgment of—you know, a different kind of carbon bill design could also level the playing field.

Senator CANTWELL. Thank you. No, I definitely agree. I think a level playing field and predictability is critical for moving forward.

So, I know I'm out of time, Mr. Chairman. I'll try to stay for a second round.

The CHAIRMAN. All right. Thank you.

Senator LANDRIEU.

Senator LANDRIEU. Thank you, Mr. Chairman.

I think this hearing has been exceptional and one of the best, and I really appreciate you putting panel together.

I want to associate myself with the remarks of Senators Sessions and Senator Cantwell as we move forward. But, I did want to comment—Senator Menendez, our colleague, has slipped out of the room, but I did want to comment on one of his points. Since I am, proudly, one of the leaders of more domestic oil and gas production in the Nation, I want to point out a couple of things and then get to two questions.

One, I've never heard anyone in the U.S. Senate say that they thought we could drill our way to national security. What I have said, and what I've heard others say, is, there's generally a lot more oil and gas, domestically, than we acknowledge. We fail, sometimes, to realize the dynamic and exciting changes in the industry that are providing more supply. I want, one more time —I've done this three times, but I'm going to do it again, for the record—this is what we thought was in the Gulf of Mexico, in 1987: 5 billion barrels of oil. Is this only oil, Tom?

Voice: That's right.

Senator LANDRIEU. Now, it's gone up, in 2006, to 30 billion. Meanwhile, we have been using and producing all of the oil between 5 billion and 30 billion barrels. We still have 30 billion. So, the fact of the matter is, if you look for it, you might find it.

No. 2—or you usually find it—and number two, we can extract it with a much smaller environmental footprint than ever before. I'm going to submit again, for the record, that the natural seepage of oil into the ocean is much greater than oil from spilled production.

No. 2, for gas—and I want to get this straight on the record. Drilling-related spills are less than 1 percent of spills in the ocean. Tankering of oil is a 4-percent. Run-offs from boats and jet skis is 20 percent. Natural seepage is 73 percent.

So, yes. I am an unabashed advocate for more domestic drilling of oil and gas, not because I think it solves any problem, but because I think the American people have a right to benefit from resources that they own. I think Americans are tired and feel like it is really embarrassing and downright shameful to ask OPEC to produce more, when we won't, ourselves. So, I'm going to continue to be a fierce advocate for more onshore and offshore natural drilling—I mean, production.

This is the gas resources, which is a good picture to show what these gentlemen have said, Mr. Chairman, that the gas resources—it really has been a game-changer, in terms of outlying projections. The great news is, is because we deregulated the natural gas pipelines, we've built 11,000 miles of pipelines pretty efficiently throughout this country, which is contrary to what we've been able to manage in electricity lines, which we're having a big fight over, now, and we can not only find gas in more places, but move it more quickly. So, there is not only a greater supply, a very clean supply, but it is almost in every corner of the country, which is not true of hydro. It's located—or it's not true of coal, or it—well, maybe coal is a different exception—not true of oil, maybe; not true of hydro; not true of other parts. But, natural gas has some really wonderful qualities.

So, my question is, I think, Mr. McKay, to you. Your comment about the distortions in Waxman-Markey are, I think, particularly telling. We don't have to go over that; it's fairly obvious. But, when you talked about the utilities being relatively insulated, or the electricity sector being insulated, what about the transportation sector and refineries? Could you talk a bit about that and see, maybe, is there an alternative that you might suggest, in the transportation sector?

Mr. MCKAY. So, in the transportation sector, that sector is about—let's just say 40 percent of the emissions—$CO_2$ emissions in the country, and needs to—for products and their own emissions—

and needs to buy the allowances, under Waxman-Markey, out of a—basically, a 15-percent government auction pool. So, it worries us, about how the transportation sector is going to cope with that.

Refineries within the transportation sector are very trade-exposed industries. Those refineries all around the country are exposed, in the sense they've got to scramble for their emission credits, under Waxman-Markey, and imported products don't, from refineries overseas. So, it's a trade-exposed industry that was left out of the trade-exposed industries in Waxman-Markey, is the fundamental point.

Senator LANDRIEU. I know my time is expired, but it's a real problem, Mr. Chairman, in the current framework of Waxman-Markey, because if we aren't careful, what little refining capacity we have left in this country, we will potentially eliminate if we don't do this correctly. Then, instead of importing unrefined products in and being reliant, as we are on unrefined products, we're now going to become reliant on refined products, which is worse, in some ways. So, I just really caution us. I know the chairman is sensitive to this.

My final point is, I do believe that natural gas, while we cannot be over-reliant on any one source of energy, and we want to be—have a multiple of clean-burning fuels, or clean-burning sources, I do believe that it is something that we potentially have overlooked. I hope, as we move forward, we can be more sensitive to it.

I'm pleased to be leading in that effort with Senator Chambliss on the new Natural Gas Caucus.

Thank you.

The CHAIRMAN. Thank you.

Senator Murkowski, you had some additional questions.

Senator MURKOWSKI. Thank you, Mr. Chairman.

I'll direct this to you, Mr. Fusco and Mr. Wilks. You both have spoken within Calpine and within Xcel, regarding business judgment decisions that have moved you from coal to natural gas. As Congress considers the various policies that are at play here, I'm very concerned about how we have this tendency to pick winners and losers within the industry. We have discussed level playing fields. As we discuss the policies that business really needs to provide for a level of certainty, and I assume you're making some business judgment decisions, based on the environmental considerations and the price considerations, but you never really know what we may do next. The next favored child within the energy sector may be algae, and you're out. What do you need from Congress to give you that level of certainty to make these long-term investments in your businesses?

Mr. Wilks, you can go first, and then we'll ask Mr. Fusco.

Mr. WILKS. Thank you, Senator Murkowski.

I'll just say that we do State-level resource planning in all of our States. All those States have different rules that apply in resource planning. From my standpoint, you know, the clarity on what we want to do, and the country needs to do, on carbon reduction, and how that's to be allocated—is allocated—that kind of clarity is what's going to support long-term investment in the infrastructure from power generation perspective.

Senator MURKOWSKI. So, let me just clarify. Do you want to see that specific 20-percent reduction by 2020? Is it definitely part of a cap-and-trade proposal? Does that give you business certainty?

Mr. WILKS. That's—what you described to me is a very good example of the clarity that we need. So, I think having that clarity will allow you to do, then, the long-term resource planning. Most of our assets are 30-year lived. So, when you make that kind of investment, you have to have certainty that the profile, the game plan, the economics that you're planning on, in fact, do unfold themselves for the future. So, that kind of certainty is very important.

Senator MURKOWSKI. Mr. Fusco.

Mr. FUSCO. Yes. I would just add to the "level the playing field," because I think that's extremely important, when you think through this legislation, as well as—I would also say, don't harm the good actors. We have been a leader. We never had coal generation at Calpine. We've stuck with natural gas and geothermal. We've been a good actor. We've designed plants that are ahead of their time, as far as environmental emissions, rules, regulations, and laws. We went from being excited about the potential of the bill, to being defensive, just trying to protect our current business. That's just not the way it should be here in America. I think the clarity would be helpful.

Then, last, when we look at the investment decision, what could be potentially harmful is, the people with the dirtier generation could potentially get favored to build the new units of the future. My investors, my shareholders, my board, expects growth. If that's not crafted right, you're going to favor those folks, or you're going to force me to have to buy old, dirty coal units so I can trade the credits in and build new units. Neither of those are the right answer.

Senator MURKOWSKI. Let me ask the rest of you——

Mr. STONES. Could I make a comment——

Senator MURKOWSKI. Mr. Stones? Yes.

Mr. STONES [continuing]. As well, too? I mean, we support——let's be clear—we support congressional action on a climate bill, and we—promptly—that supports a diversified portfolio, because what we need to be sure of is that we don't end up with another "dash to gas." So, our fear is that if it's not a comprehensive bill that keeps manufacturing competitive, that we don't know what the playing field is, just like these guys don't.

Senator MURKOWSKI. So, when you say "comprehensive," I'm assuming you would include nuclear——

Mr. STONES. Absolutely.

Senator MURKOWSKI [continuing]. As a robust component and all of the others?

Mr. STONES. Right. We need to make sure that the options for energy generation in America grow and become more flexible, not less flexible. That helps the consumers, because one of the concerns I have is, if flexibility in the natural gas market goes down, all of a sudden, when it gets cold, everybody has to buy at the same time and nobody can afford not to. So, gas prices will go higher and lower, and you'll get much more volatility. So, we need—you know, we agree, there's a potential to take a real step forward, here. But you need a balanced approach that covers supply, demand, energy policy, security, climate, manufacturing. All of those things need to be considered.

Senator MURKOWSKI. Thank you.

The CHAIRMAN. Senator Cantwell, did you have additional questions?

Senator CANTWELL. Yes. Thank you, Mr. Chairman.

I wanted to ask Dr. Newell—obviously, we were talking earlier about level playing fields. Let's assume a level playing field exists and that, because of that level playing field, renewables have the easier way to the marketplace by having a more accurate price on carbon. Is your assessment that—is EIA's analysis that there would be a likely use of natural gas as a backup to renewable power? So, the fact that renewables will be out there in the marketplace in a bigger way, that they have to—you know, there's this symbiotic relationship between natural gas and renewables for reasons of, obviously, consistency, and so, this will help pull more natural gas in the market? Is that what your analysis shows?

Mr. NEWELL. Depending upon the circumstances, there can be a symbiotic relationship, with natural gas backing up intermittents, like renewable power. On a net basis, though, in most of our climate analysis cases, except when various options are very limited, we see the net generation from natural gas going down after 2020. So, there's a certain amount of natural gas that's symbiotic, but, overall, after some initial period of increase, it's going down somewhat, except if nuclear power, international offsets, and other technological options that compete with gas are off the table, then natural gas expands significantly. But, it's not primarily due to the renewable, natural gas complementarity; it's due to other factors.

Senator CANTWELL. Mr. McKay, did you want to comment on that?

Mr. MCKAY. No. I think it's right. If alternatives come in at the speed we all would like and think they possibly could, then I think natural gas does get squeezed in that piece. If there's insulation, as I've said—and I know you don't want to go here—but, insulation, that I've said before, in the coal sector, then natural gas is getting squeezed in the middle. I just want to say that I think the supply side of this is fundamentally changed and can handle and lower volatility than it's been in the past.

Mr. MCCONAGHY. Senator, if I could——

Senator CANTWELL. Yes.

Mr. MCCONAGHY [continuing]. Just add this comment, because I think there are some practical considerations. Even if we hypothesize a level playing field that provides a transparent carbon price that's applicable to all the hydrocarbons, there are real constraints in how much incremental nuclear we could ever install, from today for the next—within the next 15 to 20 years, realistically.

Second, the cost of doing CCS is still, in some of our judgment, going to be much more expensive than is anticipated. As an actual, practical option, it's going to take longer to be available as a practical consideration.

So, when you look at the medium and short term—and by that, I'll say within the next 5 to 20 years—if we do have, quote, "a level playing field," I do believe that is going to require a greater utilization of gas, if the objective is to actually reduce carbon emissions and that's just going to be the case.

It is also the case that, regardless of what is done on carbon, natural gas prices are going to have to rise, simply because of the amount of loss of initial production from the conventional source, not withstanding the very welcomed addition of shale gas.

So, I'd just underscore, there are some practical constraints that—when we look at these other technologies. That's even accounting for a significant contribution from renewables. So, I do think it points, in the context of a level playing field, for a greater reliance on natural gas, if the objective is to achieve carbon goals.

Senator CANTWELL. I think the symbiotic relationship exists. We've already had to get very smart, in the Northwest, about hydro and wind and the balance with natural gas, because that, along with efficiency and Smart Grid technology—this is about how you make all those resources work together. I just think we need to work harder and—on this focus in research—of how to make all these resources work together. I think there's a sweet spot, here, as it relates to driving down cost and utilization, getting the best out of each of these energy sources, and putting that mix onto the grid. But, it's clear that natural gas is going to be a part of that.

Mr. FUSCO. Senator, if I may, you know, we have seen, in a massive increase in the utilization of our quick-starts and ramping capabilities at Calpine, for our customers here—Mr. Wilks would be a prime example of that at Xcel, in Colorado. I, a few weeks back, was in Colorado at our power plant called Rocky Mountain. The plant was sitting at a 20-percent loading. Immediately the pedal goes to the metal. These are very sophisticated pieces of equipment. Ramps up. Hits 80 percent output. We call the Xcel dispatcher, our customer, and say, "What happened?" He said, "The wind stopped blowing in Wyoming." That's the value we've added. We just negotiated five contracts with Pacific Gas and Electric because of that, because of the location of our plants and the ability to ramp quickly, start quickly, and manage that wind and solar intermittent loads.

Senator CANTWELL. Thank you.

Mr. FUSCO. It's been extremely valuable for us.

Senator CANTWELL. Thank you. You made my point for me. Thank you very much.

Mr. STONES. From our perspective, that's exactly right. Gas is going to grow dramatically. It did in—after the 1990 Clean Air Act. We don't know—you know, we've heard this story about, "There's lots of gas," before. You know, it was the Gulf of Mexico, it was Canada, it was the Rockies, and now it's shale gas. We are very hopeful that it's there. But, what we would urge is caution, moving forward, to ensure that we have a broad portfolio of ideas and ways to do it, like both of you said.

Senator CANTWELL. Thank you.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Sessions, did you have additional questions?

Senator SESSIONS. Just briefly.

Substituting natural gas for coal has environmental $CO_2$ benefits, but it's considerably more expensive. Coal is essentially an

American-produced, domestic-produced fuel, so we don't gain on our balance of trade. But, substituting natural gas for—in vehicles that utilize gasoline and diesel fuel, 60 percent of which is imported, also reduces the environmental impact substantially and helps us economically, and, as a matter of price, is no more expensive that diesel and gasoline.

So, I guess, Mr. McKay, I'll ask you, Are there things that we can do, at reasonable cost to the American citizenry, that will help us utilize more natural gas in vehicles—in particular, fleets and long-distance trucking? Anyone else who would like to comment on that, I'd like to hear.

Mr. MCKAY. I think the scale of the resource base opens up—effectively opens up confidence in what price is going to——the resource base expansion allows confidence, I think, in people to feel that natural gas prices are not going to get too far out of line. Therefore, we do believe natural gas vehicles are going to accelerate and it—there is infrastructure in place that can allow that. So, I don't think it needs a big infrastructure project, I just think that confidence needs to grow. We're seeing that growing. It already is.

Boone Pickens has recommended certain things. Those are big infrastructure things. That's an option that can be looked at. But, we think it's mostly about centrally fueled commercial fleets and that can grow naturally, I think.

Senator SESSIONS. You mean like fleets that operate within a given city?

Mr. McKay. Buses. Yes. Buses, heavy haulers, those kind of things, that centrally fuel and use a depot.

Senator SESSIONS. What about long-distance trucking?

Mr. MCKAY. Potentially. Potentially. But that's where you—

Senator SESSIONS. You'd have to have interstate supplies and—

Mr. MCKAY. That's where you've got to have infrastructure and filling stations and things like that. Which is possible, but that's another step of a process.

Senator SESSIONS. But, not exceedingly expensive, to achieve that.

Mr. MCKAY. I don't personally know the cost, but it probably wouldn't be exceedingly expensive, no.

Senator SESSIONS. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Landrieu.

Senator LANDRIEU. Yes, just two questions.

I think this has been gone over, but just to be clear, Mr. Newell. Our objective is to clean the environment and to do it in a very cost-effective manner. Would you believe that natural gas meets those two goals? Could you comment about that?

Mr. NEWELL. Yes, I think it does. Under the wide variety of different scenarios we've looked at, based on greenhouse gas legislation, natural gas continues to be a competitive part of the energy portfolio, looking forward as far as we can see.

Senator LANDRIEU. OK.

Let me ask Dow Chemical—and, of course, I'm in an interesting position, Mr. Chairman, as you know, because my State is a—one of the number of top producers of natural gas, but we also consume a great deal. Dow is in Louisiana——

Mr. STONES. We are.

Senator LANDRIEU [continuing]. In a big way. So, I'm extremely sensitive to this price issue, as well.

But, let me ask you—describe, just very briefly, how you use natural gas in your process and what Dow Chemical or other companies in your situation have done to diversify your own sources, so you're not over reliant, regardless of the price, of one source for your production.

Mr. STONES. Right. So, we use natural gas as a feedstock. We make power from it, and from that we create—you know, get the chlorine chain and plastics. The production of natural gas is how ethane comes out of the ground, and that becomes plastics—and all the other things we make. So, it's a big feedstock for us.

We've taken a number of different approaches. One of the things we haven't spoken much about in this room, but we've spend a lot of time on efficiency. We've saved 1400 trillion BTUs, since 1994, on efficiency. So, certainly when we consider climate change—and, you know, supporting energy efficiency is one of the things that we would, you know, think is appropriate.

We've also established an alternative feedstock group. So, for example, at present, we're looking at different ways to make plastics and chemicals from algae, coal, petroleum coke, sugarcane. We're trying to bring what we do best, which is bring technology to the party, as well. We've also looked at gasification in various stages.

So, we have a kind of an efficiency and also a—diversify the types of things we move. We have built a broad portfolio. As you know, our crackers in Louisiana can use multiple fuels, depending on what's most economic.

Senator LANDRIEU. But, Mr. Chairman, I don't want to underestimate the importance of our manufacturing base either being incentivized—not that they aren't already—but, for us to be mindful that—I guess, as Senator Cantwell said, the sweet spot is a wide variety of choices of clean fuels, with competition in the marketplace, so that it will eliminate, by the—if we can price carbon appropriately—eliminate these price spikes, create lots of jobs, more predictability in the market. We all have a responsibility to move in that direction.

So, I just wanted to say that I understand the "dash to gas." We've lived through—the people of Louisiana and Texas, and, to some degree Mississippi and Alabama, along the Gulf Coast,—these wild spikes in energy prices that—you know, when the price goes too high, we get criticized by everyone else; when it goes too low, we go bankrupt. So, you know, the people in the Gulf Coast, you know, have not had a very good comfort over the last 20, 25 years. We'd like to find a better place for all of us, both producers and our users.

So, I think that's important for manufacturers, like yourself, to be looking aggressively for other sources, so that if gas is in—more in demand to be the bridge to the future, that you can perhaps use sugarcane, which we have a lot of——

Voice: Understand.

Senator LANDRIEU [continuing]. As you know.

So, thank you, Mr. Chairman, you've been very generous.

The CHAIRMAN. Thank you.

I thank all the witnesses. It's been a useful hearing, useful testimony. Thank you very much.

That will conclude our hearing.

[Whereupon, at 12 p.m., the hearing was adjourned.]

# APPENDIXES

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## APPENDIX I

## Responses to Additional Questions

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### RESPONSES OF JACK FUSCO TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* I continue to hear concerns that placing a price on carbon through climate legislation will result in significant fuel-switching, or what has been referred to as a "dash to gas". The implication is that fuel-switching will result in sharp increases in electricity prices. Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation? What is the likelihood of a large-scale transition to natural gas, and what timeframe could that potentially occur on?

Answer. Under the current House and Senate climate change legislative proposals, the allowance allocation structure is such that large-scale switching to natural gas will not take place, particularly in the near to mid-term timeframe, based on EPA's $CO_2$ price forecast. Providing allowances to coal-fired generators based on an updating emissions basis for a long time period dampens the incentive to switch to cleaner burning resources. Under this structure, our analysis shows that it will take a carbon price of well over $100 to motivate switching from coal to natural gas.

Using current projected gas and coal prices, sub-bituminous coal becomes comparable to gas at a carbon price of $30 per metric ton and bituminous coal becomes comparable to gas at a carbon price of $25 per metric ton. This number would increase if a coal facility receives allowance allocations that are linked to output.

The EPA forecast 2015 $CO_2$ allowance prices of $13 in its June analysis of H.R. 2454. Thus, the EPA's analysis does not suggest that a "dash to gas" would occur (at least initially). Electricity price increases would be driven by $CO_2$ costs, not by switching to gas. Switching to gas would actually be electricity price neutral if $CO_2$ prices reach $25.

*Question 2.* Reducing the volatility in the price of natural gas is an important goal if we are to lean more heavily on this resource. For producers, independent generators, and utilities to enter into long-term contracts for gas supply would seem to be one way to reduce pricing volatility. Could you describe your willingness to enter into such long-term contracts, and what obstacles may stand in the way of them?

Answer. Calpine is willing to enter into long-term contracts for gas supply. One of the main obstacles standing in the way of long-term contracts is the regulatory uncertainty for carbon emissions.

*Question 3.* Is it your opinion that the advanced CCS bonus allocations in the Kerry/Boxer bill are enough to jumpstart broad deployment of CCS? I've noticed that only a maximum of 15% of the advance allocations can be given to projects that do not employ coal. Do you think that this will potentially restrict other industrial $CO_2$ emitters from being able to deploy CCS at their facility? Are the CCS allocations enough, in your opinion, to incentivize the gas industry to try and deploy this technology? If not, how would you improve the CCS bonus allowance to open up the field to all industrial stationary source emitters?

Answer. As currently structured, the advanced CCS bonus allocations are only available for coal-fired generation and qualifying industrial operations. Additionally, you point out that only a small percentage of the bonus allowances are available for industrial operations. The structure of this provision is unfair to natural gas-fired generation. Preferences should not be given to coal over natural gas or any other resources. While much cleaner than coal-fired generation (roughly 50% less $CO_2$), natural gas generation does have carbon emissions and should benefit from

CCS technologies. The provision should be available equally to coal fired generation, natural gas fired generation and other industrial operations.

*Question 4.* You mentioned that you use treated municipal wastewater at your natural gas fired power plants in the cooling towers. What are the economic differences between treated waste water and using the water available through the municipal water supply?

Answer. In general, water from municipal supplies requires less treatment to be suitable for use in our plants than wastewater sources. Thus, while cost savings can be obtained by using municipal wastewater, any savings are site specific. In addition to being economically viable, the use of recycled wastewater also has a positive environmental impact—the wastewater is not released into the local waterways, local freshwater resources are preserved for other beneficial uses, and there are no fisheries impacts from the use of recycled wastewater. Our proposed Russell City Energy Center will use 100% reclaimed water from the City of Hayward's Water Pollution Control Facility which will prevent four million gallons per day of treated water effluent from being discharged into San Francisco Bay.

*Question 5.* All of the natural gas discussed at the hearing will come from both conventional and unconventional extraction methods. A major stake of the gas future sits in extracting natural gas from tight gas sands/shales.

There has been some discussion here in Congress that the Safe Drinking Water Act exemption for hydraulic fracturing should be reconsidered. Do you think a repeal of this exemption would dramatically affect the future of natural gas extraction of these unconventional gas sources?

Answer. Calpine is in the wholesale electricity generation business, not the natural gas production business, so we are not in a position to give an informed opinion on this question.

*Question 6.* What is the marginal cost of Combined Cycle Gas Turbine (CCGT) electricity vs. that generated with pulverized coal? At what price for gas is it lower for CCGT?

How do these numbers compare for old, relatively inefficient coal plants vs. new gas plants?

Answer. Assuming a $5.00 per MMBtu gas price, a typical CCGT with a heat rate of 7.0 and a variable operations and maintenance expense ("VOM") of $1.05/MWh can generate electricity at approximately $37/MWh. Assuming a sub-bituminous coal (e.g. Powder River Basin coal) price of $1.81 per MMBtu and a bituminous coal (e.g. Appalachian coal) price of 2.71 per MMBtu, a modern sub-bituminous coal plant with a heat rate of 10.2 and VOM of $2.00/MWh can be used to generate electricity at approximately $21/MWh and a modern bituminous coal plant with a heat rate of 9.1 and VOM of $2.75 can be used to generate electricity at $28/MWh. A CCGT would be more competitive with an older, less efficient coal plant.

*Question 7.* How much does conversion from coal to CCGT cost per megawatt?

Answer. The Energy Information Association (the "EIA") does not provide any guidance on the costs associated with converting a coal-fired plant to a CCGT; and it is difficult to approximate a generic cost for switching from coal-fired to gas-fired due to numerous site-specific issues, including, but not limited to, variances in the amounts and types of equipment that can be salvaged, obtaining transportation of gas to the coal plants, and costs associated with cleaning up the coal plant.

We understand, however, that Xcel Energy recently converted its Riverside plant in Minnesota from coal-fired to gas-fired for approximately $536 per kilowatt. For reference, the EIA has calculated that a typical CCGT costs approximately $1000 per kilowatt.

In terms of converting the generation stack from coal-fired to gas-fired, which we have the existing capacity to do, and assuming a $6.00 per MMBtu gas price, gas-fired plants will begin to displace coal on the generation stack when carbon allowance prices reach $25/ton, and gas-fired plants will be more economical than almost all coal plants when carbon allowance prices reach $40/ton.

*Question 8.* What is the primary obstacle to CHP?

Answer. One of the primary obstacles to CHP is the lack of partners to contract with for the full power generated from the facilities. Without a PPA for the surplus electricity it is difficult to get financing for large-scale CHP projects. In addition, many industrial facilities already have on-site boilers to produce steam and although CHP would emit far less $CO_2$, contracting with a new CHP facility could be more expensive than using an existing boiler. Thus, incentives are needed to encourage the industrial facilities to make the switch.

RESPONSES OF JACK FUSCO TO QUESTIONS FROM SENATOR MURKOWSKI

*Question 1.* You may know that Senator Menendez and I are both on a bill to promote the development of natural gas vehicles. NGV advocates, myself included, have pointed out that natural gas as a transportation fuel reduces carbon emissions, offsets petroleum imports, and provides an economic boost here at home by using natural gas in place of imported petroleum. Given the recent findings concerning the increased availability of natural gas supplies in North America and here in the U.S. should we be doing more to advance the use of natural gas as a transportation fuel?

Answer. Because Calpine is in the wholesale electricity generation business, not the transportation business, we do not have an informed opinion on this issue.

*Question 2.* Currently there are serious regulatory obstacles positioning in front of domestic energy development. Particularly, surface coal mining rules are under serious assault and offshore oil and gas development is facing increasing scrutiny from at least three different federal agencies. Can the panel speak to how we ever get to a point of more natural gas power plants or, for that matter, clean coal if, despite policies encouraging the advancement of these new and exciting power sources, we simply can't access and produce the basic resource?

Answer. We refer to the testimony of the production experts who expressed the view that the resource is plentiful and production is far less difficult than current drilling methods.

*Question 3.* What would be your opinion about a Low Carbon Electricity Standard that would allow electric utilities to use a variety of alternatives to reduce greenhouse gas emissions, including renewables, natural gas, nuclear and hydroelectric?

Answer. Calpine would support a Low Carbon Electricity Standard that includes a variety of low and zero GHG emitting resources. As we move towards a low carbon future, the federal government should be encouraging the use of all low and zero emitting resources—we can meet our energy needs by focusing only on renewable resources. Including natural gas in a Low Carbon Electricity Standard is an excellent means to encourage the greater use of this resource.

*Question 4.* To the extent that deliverability of natural gas to markets has been an issue in the past, should recent improvements in pipeline infrastructure, as well as prospects for additional projects coming online, serve as any comfort to those with concerns about spikes in natural gas prices?

Answer. Yes, the discovery of vast reserves of shale gas as well as improved infrastructure for bringing gas to the market should dampen the volatility in natural gas prices.

*Question 5.* Please give me a sense of the relative challenges in choosing fuel investments from the perspective of a regulated versus a non-regulated utility—I understand Xcel is the regulated utility.

Answer. At Calpine we base our investment decisions on customer electric requirements and the contractual payments needed to provide an adequate return on investment. We expect to continue to focus our attention on developing power plants fueled by natural gas and geothermal energy given our view of environmental responsibility as well as our knowledge regarding their operation and maintenance. As noted in my testimony, natural gas fired generation is significantly cleaner than coal fired generation, In addition, compared to many other generation sources, natural gas power plants can be permitted and built more quickly and they have a much smaller footprint. Our expectation is bolstered by the likelihood that gas-fired capacity will continue to be the most cost effective form of new, reliable capacity for our customers.

*Question 6.* I was interested in Mr. Wilks' testimony about SmartGrid City in Boulder, Colorado, as well as the solar work that Xcel is doing in Colorado. Can you talk about why natural gas is so important as a backup, or baseload generator, for intermittent solar or wind power?

Answer. The increasing utilization of intermittent electricity generation resources could have a tremendous impact on the reliability of the electricity grid. As I noted in my written testimony, Americans demand and deserve reliable energy; they expect the lights to go on when they flip the light switch. In the near term, this will only be achievable if gas-fired plants are there to provide that reliability. Natural gas power plants are versatile and are designed such that they can be started quickly and placed into service instantly to meet demand when the wind stops blowing or the sun stops shining.

RESPONSES OF JACK FUSCO TO QUESTIONS FROM SENATOR SESSIONS

*Question 1.* If the transportation sector moves towards natural gas, how will this affect the price of natural gas, the United States' crude oil imports, greenhouse gas emissions, other energy sectors that currently use this energy source?

Answer. No comment.

*Question 2.* What incentives or regulatory changes are necessary to effectively enhance the use of natural gas over coal, diesel, or gasoline? And the cost associated with the switch?

Answer. One of the greatest incentives to enhance the use of natural gas is to put a price on carbon. Tighter regulations on other pollutants (e.g. $NO_X$, $SO_2$, mercury, coal ash, etc.) will also have an impact. Other regulatory changes that could be implemented to enhance natural gas usage are generation performance standards and low carbon energy standards. All of these incentives and regulatory changes will only be effective, however, if the playing field remains level in terms of incentives and allowance allocation structures for all fossil fuels.

We do not know what the exact costs associated with the switch would be, however, switching to gas would actually be electricity price neutral if $CO_2$ prices reach $25.

RESPONSES OF JACK FUSCO TO QUESTIONS FROM SENATOR CANTWELL

*Question 1a.* I think it is very important that we ensure that climate policy doesn't introduce unnecessary volatility into markets for oil and natural gas. We've seen gas prices fluctuate sharply over the past two years, from $5.90 up to $10.82 and then back down to around $3.40 where we are now. I think we all agree that this sort of uncertainty isn't good for energy producers or consumers.

What do modeling results and forecasts tell us about what would actually happen in the real world with regard to fuel mix, energy costs and investment under this kind of price volatility?

Answer. We believe that natural gas price volatility referenced in your question was driven in large part by concern of the long-term availability of domestic natural gas resources. The recent discovery of vast reserves of shale gas and the improved gas infrastructure should mute the volatility in natural gas prices.

*Question 1b.* Could a well-designed price collar mitigate this sort of volatility?

Answer. A well-designed price collar in a carbon cap-and-trade regulatory program could mitigate price volatility.

*Question 2a.* In thinking about alternative approaches to climate change policy, one important consideration is the point of regulation, especially with regard to an emissions cap. Both the House and Senate bills propose downstream caps by regulating thousands of emitting entities.

But an upstream cap for natural gas seems like it could achieve the same broad coverage much more simply, by regulating less than a thousand entities. What is the most efficient point of regulation to achieve broad coverage of fossil carbon for natural gas?

Answer. Calpine believes that an upstream cap on natural gas is the most efficient point of regulation. By regulating upstream, the cost of reducing emissions from natural gas combustion is borne by all users of this resource and the compliance costs are internalized within the price of natural gas. Upstream regulation also simplifies allowance allocation distribution as fewer entities are regulated under such a program. Further, because the number of regulated entities will be much smaller than regulating at the point of combustion, the cost of overseeing compliance will be far less.

*Question 2b.* Are there any problems with mixing upstream caps for some fossil fuels and downstream caps for others? Does an upstream cap on all fossil fuels help to promote a consistent, economy-wide carbon price signal necessary to transition to a low-carbon economy?

Answer. While Calpine believes that an upstream cap on all fossil fuels is the best and most efficient point for regulation, we do not think there would be problems with mixing upstream and downstream caps for different fossil fuels. Because natural gas is used in many diverse ways (electricity generation, direct home use, industrial processes, etc), regulating upstream ensures that emissions from all uses are captured and the compliance costs are lower and spread broadly. Oil is similar to natural gas with the added factor that it is difficult to regulate at the tailpipe for all mobile sources, so capping upstream definitely makes the most sense for oil. Coal, however, is primarily used for electricity generation so regulating downstream is just as practical as regulating upstream. Coal-fired power plants are already under regulation for a variety of air emissions and thus have experience with complying with emissions reduction programs.

*Question 3.* With the recent advances in drilling technology in the gas industry, domestic gas reserves shot up by more than 35 percent this year, which of course is terrific news for the gas industry and potentially for our efforts to address climate change by reducing greenhouse gas emissions.

But I'm wondering about the broader environmental implications of the use of technologies such as hydraulic fracturing to produce unconventional shale gas resources. What are the implications of shale gas production for ground water and drinking water quality? How do these environmental risks compare to those of other energy sources?

Also, from an economic perspective, at what price is shale gas production viable for the industry? Would the price certainty of a carbon price floor be necessary for shale gas to be economic? How do the two prices—the natural gas price and the carbon price—interrelate and affect shale gas production?

Answer. Calpine is in the wholesale electricity generation business, not the natural gas production business, so we are not in a position to give an informed opinion on this question.

*Question 4.* Since natural gas has the lowest carbon content among fossil fuels, I would expect that a carbon price would not lead to a decline in the natural gas industry. But over the longer term, as the economy decarbonizes, there will be pressure on gas-fired utilities, as with coal-fired ones, to adopt carbon capture and sequestration technologies.

What is your assessment of the feasibility of commercial scale carbon capture and sequestration with natural gas?

Are the economics of CCS likely to be comparable for gas and coal consumers?

Could reimbursements in the form of allowances in excess of the cap for the amount of carbon captured and sequestered make CCS economic? And would this framework treat both coal and natural gas fairly?

Answer. Calpine has not investigated the use of carbon capture and sequestration ("CCS") for natural gas generation. However, we are of the opinion that CCS for combined-cycle natural gas plants is feasible, in fact potentially more feasible and less expensive than for coal plants. It will likely be easier to reform natural gas on the front end into hydrogen (primarily for newer projects). On the back end, the lower flows and cleaner overall condition of exhaust gas will make it easier to remove carbon so the per megawatt cost will be less. Most coal applications will need entirely new facilities. If the playing field is level, natural gas CCS will be competitive with coal CSS.

As noted, Calpine has not given much consideration to CCS for natural gas generation so we have not thought through needed incentives or allowances. However, it is important that CCS incentives and allowances for coal and natural gas be fair and equal.

## Response of Jack Fusco to Question From Senator Lincoln

1. As you know, several recent studies have projected that our natural gas supply is much larger than previous estimates. For example, the Potential Gas Committee estimates that the U.S. now has a 35% increase in supply estimates from just two years ago, which is enough they say to supply the U.S. market for a century. The Energy Information Agency (EIA) has also predicted a 99-year natural gas supply. I am proud that the Fayetteville Shale in Arkansas is already producing over one billion cubic feet of natural gas per day, while only in its fifth year of development. What role do you believe the improvement in drilling technologies such as horizontal drilling and hydraulic fracturing played in the estimated increase in natural gas supply?

Answer. Calpine is in the electricity generation business, not the natural gas production business, so we do not have an informed opinion this question.

## Response of Jack Fusco to Question From Senator Udall

*Question 1.* It was mentioned that some coal utilities are already switching over to gas without incentive in place, could you elaborate on this dynamic? Does low gas price and region play any role in some of these changes?

Answer. Low gas prices and increasingly stringent environmental rules have contributed to fuel switching. Last Spring, for instance, our Southeast plants produced 60% more MWh than during the same period of 2008. This demonstrates that fuel switching (and corresponding emissions reductions) is feasible, even in the absence of $CO_2$ regulations. Although gas prices have been lower than we expect going forward, the introduction of $CO_2$ regulations would contribute to fuel switching even at higher gas prices if structured properly. However, the allowance allocation structure in the current House and Senate climate change legislative proposals dampens the incentive to switch to cleaner burning resources, particularly in the near to midterm timeframe. Our analysis shows that by providing allowances to coal-fired generators based on an updating emissions basis for a long time period, it will take a carbon price of well over $100 to motivate switching from coal to natural gas.

RESPONSES OF DENNIS MCCONAGHY TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1a.* I continue to hear concerns that placing a price on carbon through climate legislation will result in significant fuel-switching, or what has been referred to as a “dash to gas”. The implication is that fuel-switching will result in sharp increases in electricity prices. Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation? What is the likelihood of a large-scale transition to natural gas, and what timeframe could that potentially occur on?

Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation?

Answer. TransCanada has examined a wide range of gas prices and coal plant efficiencies to arrive at the following general conclusions.

For existing combined cycle and coal plants, with no consideration of the fixed costs of such plant, gas-fired generation will be lower or comparable in cost to coal generation when natural gas prices are in the $6—$8/mmBtu range and carbon prices are in the $20—$40/ton of $CO_2$ equivalent range. At the low end of the $CO_2$ price range, gas-fired generation becomes higher cost than the more efficient coal plants.

For new combined cycle and coal plants, with the full cycle costs of the investment factored in, gas-fired generation still is lower or comparable in cost to coal generation when natural gas prices are in the $6—$8/mmBtu range and carbon prices in the $20—$40/ton of $CO_2$ equivalent range, In the low end of the range of $CO_2$ prices, gas-fired generation becomes higher cost than coal when gas prices go beyond $8/mmBtu.

*Question 1b.* What is the likelihood of a large-scale transition to natural gas, and what timeframe could that potentially occur on?

Answer. The gas combined cycle fleet in most US markets is the swing electricity producer and currently operates at approximately 42% utilization of installed capacity. All other factors being equal, carbon prices in the $20—$40/ton of $CO_2$ equivalent range and gas prices in the $6-$8/mmBtu range would result in more of this capacity being used. For example, if the average utilization factor of these installed combined cycle units was increased from the current 42% to 55% with a commensurate reduction in coal generation, demand for natural gas would increase by an additional 5 Bcf per day—a volume that can be easily accommodated from a continental supply perspective while maintaining gas prices in the $6—$8/mmBtu range.

The likelihood of this transition and the timeframe in which it could occur largely depends upon what the Congress enacts by way of climate change and energy legislation. If that legislation establishes a transparent price on carbon that is applied equally to all emitters, then the transition is likely to occur in relative short order. On the other hand, if the legislation insulates coal-fired electric generation from the true costs of controlling greenhouse gas (GHG) emissions the transition will be much slower and may not occur at all.

*Question 2a.* One area of concern about depending on our natural gas resources is that gas has been prone to strong price spikes over the past decade. The most recent one was just in 2008, with prices soaring to about $13 per million BTU. In Dr. Newell’s testimony, he mentioned that the expanded reserves and greater ability to receive LNG shipments could mitigate future price spikes. Please comment on the factors that resulted in the 2008 price spike and other recent spikes. Is the supply situation now such that we will be insulated from such volatility in the future? Are there policy options we could pursue to reduce price volatility?

Please comment on the factors that resulted in the 2008 price spike and other recent spikes.

Answer. The Federal Energy Regulatory Commission (FERC) has prepared one of the most detailed analyses of that price spike in its 2008 State of the Markets Report, released in August 2009. See http://www.ferc.gov/market-oversight/st-mkt-ovr/2008-som-final.pdf. In general, FERC concluded that, while physical fundamentals of gas supply and demand can explain why natural gas prices rose during the first half of 2008, none of the physical fundamentals alone were extreme enough to explain the high level that natural gas prices reached.

From a study of this FERC report, TransCanada would make the following observations.

- Changes in the physical fundamentals of the market—supply and demand—are the main drivers of volatility, however, commodity market activity can, at times, increase the amplitude of price movements. .
- Increased levels of buying interest, easy access to capital, strongly rising commodity prices in general and trend trading by financial players all helped push prices higher during the first six months of 2008.

- During the last six months of 2008, reduced levels of buying interest, lowered liquidity, generally falling commodity prices and selling pressures all were financial factors that drove prices down.
- In the first half of 2008 market perceptions were very bullish and the market tended to ignore the emerging signs of unconventional gas supply growth, whereas in the second half, perceptions became very bearish and the market completely disregarded the serious impact of the two hurricanes on gas supply.
- With respect to the physical fundamentals in the first half of 2008, a mildly bullish stance was perhaps justified because of gas storage levels below recent years due to cold weather and moderate gas demand growth.
- A more bearish stance due to the impact of the spreading recession on gas demand and the clear evidence of a building over-supply of domestic gas was certainly appropriate for the second half of the year.

*Question 2b.* Is the supply situation now such that we will be insulated from such volatility in the future?

Answer. TransCanada believes that the robust supplies of natural gas from shale formations and the Arctic combined with expanded pipeline, storage, and LNG regasification infrastructure will moderate price volatility in the future.

Price volatility caused by the physical fundamentals of the market can be of two types. There is price volatility driven by temporary imbalances in continental supply and demand. This type of volatility affects the general level of gas prices across the continent and is reflected in higher prices at Henry Hub. A second type of volatility is regional, as opposed to continental. For example, prices in areas of the U.S. Northeast may spike for periods when storage facilities and/or transportation facilities are operating at full capacity and are unable to keep up with demand.

Increased transportation infrastructure out of the Rockies and out of the key shale plays (supply-connecting pipelines) help ameliorate continental price volatility by ensuring greater access to more gas supply.

Increased transportation infrastructure connecting supply pipelines to markets (market-connecting pipelines), on the other hand, help reduce regional market price volatility by ensuring that supply reaches the ultimate consumer.

The natural gas pipeline industry is increasing substantially the transportation infrastructure needed to help reduce volatility. In 2007 through the first 9 months of 2009 5808 miles of pipelines and 39.2 Bcf/day of capacity were added to the nation's pipeline grid.

In addition, substantial increases in gas storage over the past three years should reduce seasonal volatility in prices. Total U.S. gas storage capacity has increased by 187 Bcf or 55 per cent over this period.

It is equally true that the newly important shale gas resource and the increased investment in pipelines and storage will not eliminate price volatility. As with other commodities, natural gas will continue to exhibit price volatility characteristic of well-functioning markets reflecting supply and demand fundamentals. Natural gas prices will continue to respond to seasonal changes in demand, hurricane-related disruptions in supply, unanticipated changes in the demand for natural gas fired electricity as well as overall demand due to general economic conditions, and, to reactions of speculative commodity traders to these events.

TransCanada believes, however, that the size and nature of the shale resource together with the development of vast Alaskan and Canadian reserves over the next decade will assure sufficient supplies to assist in maintaining supply-demand balance for decades to come. These additional supplies together with sizeable new investments in pipelines and storage will continue to moderate price volatility in natural gas markets in the years to come.

Although substantial increases in gas demand over the next decade will mean somewhat higher prices (compared to a scenario without durable demand increases), TransCanada believes that the natural gas industry's continued development of conventional resources together with distant Alaskan and other Arctic supplies will, together with the "game-changing" shale gas resource, mean that prices remain at reasonable levels and volatility will be moderated.

*Question 3.* Is it your opinion that the advanced CCS bonus allocations in the Kerry/Boxer bill are enough to jumpstart broad deployment of CCS? I've noticed that only a maximum of 15% of the advance allocations can be given to projects that do not employ coal. Do you think that this will potentially restrict other industrial $CO_2$ emitters from being able to deploy CCS at their facility? Are the CCS allocations enough, in your opinion, to incentivize the gas industry to try and deploy this technology? If not, how would you improve the CCS bonus allowance to open up the field to all industrial stationary source emitters?

Answer. As a general proposition, TransCanada questions the efficacy of using free allowance allocations to provide incentives for CCS research and development. We recognize the considerable capital expense required for CCS research and development, but we believe that a mechanism that establishes a transparent price for carbon combined with direct subsidies for CCS research and development will be more effective and economically efficient. Such an approach will allow all emitters of GHG to determine the best means to control GHG emissions through CCS technologies and / or fuel-switching and will not mask or skew the true price of carbon.

If, however, the Congress decides to pursue a program of free allowances to promote CCS technology, TransCanada recommends that the current proposals should be modified to create a level playing field for all fossil fueled facilities that emit GHG.

The Kerry-Boxer and Waxman-Markey bills reserve 85% of the CCS bonus allowances for coal-fired power plants. This bias in favor of clearly will discourage other industrial $CO_2$ emitters from attempting to deploy CCS at their facilities.

In certain situations, facilities other than coal-fired power plants present more cost-effective and energy-efficient opportunities to capture and sequester $CO_2$ than coal-fired power plants. The exhaust streams from natural gas processors and hydrogen producers, for example, have a higher concentration of carbon dioxide than most coal-fired power plants—meaning that it is less expensive and less energy-intensive on a per unit of $CO_2$ to capture $CO_2$ from these facilities than from a coal-fired power plant. From an environmental perspective, a ton of sequestered $CO_2$ is just as beneficial whether it is emitted from a coal-fired facility or from a facility utilizing natural gas for an industrial process.

If the CCS bonus allowance program is artificially restricted to coal-fired facilities, it could end up needlessly spending more resources to achieve fewer emission reductions than it would absent the restriction.

*Question 4.* All of the natural gas we're discussing here today will come from both conventional and unconventional extraction methods. A major stake of the gas future sits in extracting natural gas from tight gas sands/shales. There has been some discussion here in Congress that the Safe Drinking Water Act exemption for hydraulic fracturing should be reconsidered. Do you think a repeal of this exemption would dramatically affect the future of natural gas extraction of these unconventional gas sources?

Answer. TransCanada transports natural gas through its pipelines and consumes natural gas in its electric generation facilities. We are not involved in the production of natural gas. As such, TransCanada has had no experience with the regulation of hydraulic fracturing and will defer to views of BP and other natural gas producers on this issue.

TransCanada does believe, however, that the environmental impacts of natural gas extraction from tight sands and shale formations can be managed effectively and efficiently without unduly limiting the production potential of these sources. To ensure this is the case, the regulatory process for managing environmental risks must be guided fundamentally by scientific and technical considerations and must yield expeditious and predictable results.

RESPONSES OF DENNIS MCCONAGHY TO QUESTIONS FROM SENATOR MURKOWSKI

*Question 1.* You may know that Senator Menendez and I are both on a bill to promote the development of natural gas vehicles. NGV advocates, myself included, have pointed out that natural gas as a transportation fuel reduces carbon emissions, offsets petroleum imports, and provides an economic boost here at home by using natural gas in place of imported petroleum. Given the recent findings concerning the increased availability of natural gas supplies in North America and here in the U.S. should we be doing more to advance the use of natural gas as a transportation fuel?

Answer. TransCanada believes that North American natural gas reserves are sufficient to support an increase in demand created by a policies designed to advance the use of natural gas both in the transportation sector and, more importantly, in the power sector.

Particularly in the short and medium term, TransCanada believes that emission reductions can be most effectively achieved by moving from high emission power resources, like coal, to lower emission resources, like natural gas, nuclear, and renewables. One approach that TransCanada supports to achieve these reductions is a Low Carbon Electricity Standard, described in Murkowski Question #3.

With respect to natural gas as a transportation fuel, TransCanada supports appropriately designed federal policies designed to increase the use of natural gas as a transportation fuel because such fuel switching will result in less dependence on crude oil from overseas and reduced GHG emissions. However, TransCanada strongly recommends that such policies be limited to the government, commercial and industrial fleets components of the in the transportation sector. The necessity for specialized fuel storage and handling equipment in natural gas vehicles and refueling stations, makes conversion of large numbers of private automobiles unlikely and prohibitively expensive. By comparison, incentives and/or mandates targeted at fleet operators are likely to result in the greatest level of vehicle conversions from petroleum based fuels to natural gas.

*Question 2.* Currently there are serious regulatory obstacles positioning in front of domestic energy development. Particularly, surface coal mining rules are under serious assault and offshore oil and gas development is facing increasing scrutiny from at least three different federal agencies. Can the panel speak to how we ever get to a point of more natural gas power plants or, for that matter, clean coal if, despite policies encouraging the advancement of these new and exciting power sources, we simply can't access and produce the basic resource?

Answer. TransCanada believes the goals of energy / climate change legislation should be to reduce the overall level of greenhouse gas emissions and lessen dependence on fossil fuels imported from overseas in a manner that is environmentally and economically sound. To accomplish these goals, it is necessary that the U.S. embrace energy / climate change policies that allow maximum use of all domestic North American energy resources as well as encourage greater conservation and efficiency.

Development and production of energy resources, whether renewable or fossil fueled, should not be limited arbitrarily. The U.S. energy industry consistently has demonstrated that it possesses the technology and experience to effectively and efficiently manage the environmental risks posed by energy production. The starting point for any debate over access to and development of a particular area or resource should be whether the risks posed by such access and development can be appropriately managed and mitigated. If it is determined that they can, access and development should be permitted. TransCanada is confident that if the process for making access and development decisions is based on sound scientific and technical analysis and designed to yield expeditious and predictable results, such a process will lead to a fundamentally well-balanced energy / climate change policy.

*Question 3.* What would be your opinion about a Low Carbon Electricity Standard that would allow electric utilities to use a variety of alternatives to reduce greenhouse gas emissions, including renewables, natural gas, nuclear and hydroelectric?

Answer. TransCanada believes that if Congress is to pursue a clean energy mandate either as a stand-alone policy or as a complement to a cap-and-trade framework, a Low Carbon Electricity Standard (LCES) is a better policy approach than a standard devoted solely to renewable energy sources. A broad mandate, like an LCES, provides certainty that there will be a credible and significant substitution of clean resources in place of higher emission sources.

Unlike current Renewable Electricity Standard (RES) proposals, which focus only on achieving a specified percentage of renewable electricity each year, the LCES would provide an opportunity for a meaningful down payment on GHG emission reductions by relying on a full menu of clean energy options, including energy efficiency; renewable energy; new and incremental nuclear; new and incremental hydroelectricity; coal with CCS; and high-efficiency natural gas generation. Any credible climate strategy must include an explicit role for natural gas. Natural gas is the cleanest domestic fossil fuel. The carbon content of natural gas is almost 50% less than coal, and it can be used at substantially greater thermal efficiencies. Natural gas produces less $SO_X$, $NO_X$, mercury, and particulate matter than coal. Recent major additions to natural gas reserves mean that domestic gas will be abundant, affordable, and available for electric generation.

If Congress cannot reach a consensus on a cap-and-trade climate change bill, adoption of the LCES would provide a path to increased energy and environmental security through power resource diversification. With its broader base of eligible resources, the LCES would yield more GHG emission reductions and within a shorter time horizon than an RES due to the difficulties of renewable energy sources to reach meaningful scale in any near or intermediate term. The LCES would also provide retail suppliers greater compliance flexibility than and RES, which in turn would help keep power prices lower in comparison to an RES. While an RES may point us in the right direction, the LCES would actually achieve tangible progress in our efforts to address climate change while also advancing development of renewable energy.

In the context of a cap-and-trade bill that allocates a significant percentage of free allowances, an LCES would provide all the benefits described above plus act as a meaningful balance to free -allowance incentives to continue to burn higher emission resources like coal. Free allowances not only minimize the incentive to reduce emissions, but they also distort the price of carbon. In the early years of a cap-and-trade program with a large distribution of free allocations, it is likely that allowance prices may not be high enough to encourage deployment of low-carbon generation. Without the additional policy determinations embodied in the LCES, it is unlikely the electric power sector will have the economic motivation to make the investments in low carbon technology necessary to address in any significant way actual reductions in carbon emissions; an RES alone would only partially address this risk.

If the primary goal of energy and climate legislation is to increase security and reduce GHG emissions, then adoption of a low carbon standard will make a real down payment on a clean energy future by weighting technologies by their carbon content. Limiting that down payment to a subset of only a few renewable clean power choices, such as with an RES, would be short changing and unnecessarily delaying our clean energy future.

*Question 4.* To the extent that deliverability of natural gas to markets has been an issue in the past, should recent improvements in pipeline infrastructure, as well as prospects for additional projects coming online, serve as any comfort to those with concerns about spikes in natural gas prices?

Answer. The past and projected expansion of natural gas pipelines certainly plays an important role in reducing price volatility by improving the deliverability of additional supplies into major consuming markets. Indeed, the multi-billion dollar expansion of the Nation's pipeline infrastructure underscores the confidence of the natural gas markets in the "game changer" character of the shale reserves as well as the prolific Rocky Mountain reserves. Even with expanded pipelines, however, not all volatility can be eliminated.

Price volatility caused by the physical fundamentals of the market can be of two types. There is price volatility driven by temporary imbalances in continental supply and demand. This type of volatility affects the general level of gas prices across the continent and is reflected in higher prices at Henry Hub. A second type of volatility is regional, as opposed to continental. For example, prices in areas of the U.S. Northeast may spike for periods when storage facilities and/or transportation facilities are operating at full capacity and are unable to keep up with demand.

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The natural gas pipeline industry is increasing substantially the transportation infrastructure needed to help reduce volatility. In 2007 through the first 9 months of 2009 5808 miles of pipelines and 39.2 Bcf/day of capacity were added o the nation's pipeline grid.

In addition, substantial increases in gas storage over the past three years should reduce seasonal volatility in prices. Total U.S. gas storage capacity has increased by 187 Bcf or 55 per cent over this period.

Although new gas supplies and expanded infrastructure will moderate price volatility, TransCanada believes that it is equally true that they will not eliminate price volatility. As with other commodities, natural gas will continue to exhibit price volatility characteristic of well-functioning markets reflecting supply and demand fundamentals. Natural gas prices will continue to respond to seasonal changes in demand, hurricane-related disruptions in supply, unanticipated changes in the demand for natural gas fired electricity as well as overall demand due to general economic conditions, and, to reactions of speculative commodity traders to these events.

TransCanada believes, however, that the size and nature of the shale resource together with the development of vast Alaskan and Canadian reserves over the next decade will assure sufficient supplies to assist in maintaining supply-demand balance for decades to come. These additional supplies together with sizeable new investments in pipelines and storage will continue to moderate price volatility in natural gas markets in the years to come.

Although substantial increases in gas demand over the next decade will mean somewhat higher prices (compared to a scenario without durable demand increases), TransCanada believes that the natural gas industries continued development of conventional resources together with distant Alaskan and other Arctic supplies will, together with the "game-changing" shale gas resource will mean that prices will remain moderate and that volatility will also exhibit characteristics of moderation.

RESPONSES OF DENNIS MCCONAGHY TO QUESTIONS FROM SENATOR SESSIONS

*Question 1.* If the transportation sector moves towards natural gas, how will this affect the price of natural gas, the United States' crude oil imports, greenhouse gas emissions, other energy sectors that currently use this energy source?

Answer. TransCanada believes that North American natural gas reserves are sufficient to support an increase in demand created by a policies designed to advance the use of natural gas both in the transportation sector and, more importantly, in the power sector.

Particularly in the short and medium term, TransCanada believes that emission reductions can be most effectively achieved by moving from high emission power resources, like coal, to lower emission resources, like natural gas, nuclear, and renewables. One approach that TransCanada supports to achieve these reductions is a Low Carbon Electricity Standard, described in Murkowski Question #3.

With respect to natural gas as a transportation fuel, TransCanada supports appropriately designed federal policies designed to increase the use of natural gas as a transportation fuel. Greater use of natural gas as a transportation fuel will also reduce the United States' dependence on crude oil imports and the level of emissions of greenhouse gases from the transportation sector. The degree to which these reductions occur will depend upon the level of vehicle conversions that occur.

TransCanada strongly recommends that policies promoting the use of natural gas for vehicle use be limited to government, commercial and industrial fleets components of the in the transportation sector. The necessity for specialized fuel storage and handling equipment in natural gas vehicles and refueling stations, makes conversion of large numbers of private automobiles unlikely and prohibitively expensive. By comparison, incentives and/or mandates targeted at fleet operators are likely to result in the greatest level of vehicle conversions from petroleum based fuels to natural gas.

With respect to increased gas demand for fleet vehicle use, TransCanada believes that such an increase in natural gas demand is not sufficient to have a material impact on gas prices. Although any increase in gas demand, other things equal, will increase price, the volumes in this instance will be small to modest and slow to build as infrastructure is added and vehicles replaced. Consequently, the increase in price related to more use of natural gas by fleets should be insignificant.

As noted above, in the absence of an increase in supply of natural gas, any policy that increases demand will result in an increase in the price of natural gas. However, TransCanada believes that the significantly improved methods of economically and efficiently producing natural gas from shale formations, complemented by the likely introduction of Arctic reserves, have fundamentally changed the continental natural gas supply outlook. These robust supplies will support and respond to a substantial increase in natural gas demand that is driven by policies designed to advance the use of natural gas as a transportation fuel without greatly affecting the price of natural gas. As we testified at the hearing, TransCanada believes that a natural gas price in the $6—$8/mmBTU range is likely to achieve equilibrium between ensuring development and production of natural gas supplies and increasing demand.

*Question 2.* What incentives or regulatory changes are necessary to effectively enhance the use of natural gas over coal, diesel, or gasoline? And the cost associated with the switch?

Answer. TransCanada has not conducted any direct study or analysis of regulatory barriers to increasing use of natural gas in the transportation sector and therefore is not in a position to offer any recommendations in that regard. Similarly, TransCanada has not invested any resources in exploring potential incentives to enhance the use of natural gas in the transportation sector.

RESPONSES OF DENNIS MCCONAGHY TO QUESTIONS FROM SENATOR CANTWELL

*Question 1.* I think it is very important that we ensure that climate policy doesn't introduce unnecessary volatility into markets for oil and natural gas. We've seen gas prices fluctuate sharply over the past two years, from $5.90 up to $10.82 and then back down to around $3.40 where we are now. I think we all agree that this sort of uncertainty isn't good for energy producers or consumers.

What do modeling results and forecasts tell us about what would actually happen in the real world with regard to fuel mix, energy costs and investment under this kind of price volatility?

Could a well-designed price collar mitigate this sort of volatility?

Answer. TransCanada acknowledges that extreme volatility in energy prices can cause hardship for businesses and households. However, all commodity markets—no matter how well-regulated—are susceptible to some degree of volatility, and the natural gas market is no exception. Rather than engage in a futile attempt to stamp out volatility in energy markets, sound energy policy should seek to ensure that prices reflect genuine forces of supply and demand and well-functioning competitive markets. Without taking any position here on pending legislation, TransCanada notes that both the Senate and the House of Representatives have been actively pursuing legislation—in addition to the market manipulation provisions you spearheaded in the Energy Policy Act of 2005—to prevent misconduct in the commodity derivatives markets. If properly designed, such legislation should provide additional transparency in a well-functioning market in energy commodities, including natural gas.

In addition, as discussed elsewhere in these responses, recent developments in natural gas supply and transportation infrastructure should avert a recurrence of the rapid increase in natural gas prices observed from 2005-2008. Indeed, the key to moderating volatility is maintaining reasonable balance between supply and demand. The referenced price run-up was caused in part, not by a lack of supply, but by a lack of pipeline capacity to satisfy growing demand for natural gas during this period. Since 2007, the natural gas supply and delivery situation has changed dramatically.

The unprecedented expansion of the U.S. gas pipeline network in 2008, and the simultaneous expansion of U.S. gas reserves, should moderate price volatility in the gas markets with supply being delivered to consuming markets and should reduce the chance of a similar supply constraint in the foreseeable future. Of course, the recent dramatic decline in prices in 2008 and 2009 is due in part to increased supply hitting the market at the same time demand has been weakened by the general economic situation.

TransCanada submits that most observers believe that the natural gas markets are well-functioning and that periods of price volatility have been of relative short duration and a function of supply-and-demand situations that generally correct quickly either with resolution of supply interruption, break in a cold snap or greater supply responding to greater demand as reflected in price increases.

TransCanada interprets the question regarding the efficacy of a price collar as applying to a price collar on carbon prices; we assume that it is not a reference to price collars on natural gas. TransCanada believes that any attempt to regulate the price of natural gas, whether through a price collar or otherwise, would lead to extreme disruptions in the market.

TransCanada does believe that price predictability in carbon pricing is warranted and deserves closer scrutiny by the Congress. If the cost of purchasing $CO_2$ emission allowances in a cap-and-trade program is reflected in the unit price of energy delivered to consumers, then volatility in the $CO_2$ allowance market has the potential to add to overall volatility in energy markets generally. A "price collar" mechanism that places a firm ceiling and a firm floor on allowance will help mitigate or avoid this additional volatility in energy prices, by reducing volatility in the component of energy prices that is attributable to emission allowances. TransCanada strongly supports efforts to provide type of stability and predictability to any carbon price.

In TransCanada's opinion, which is shared by a number of economists and industry participants, a carbon tax that sets a specific price for carbon would be the most efficient method to address GHG emissions. If the paramount goal is to set a clear price on carbon to induce behaviors that reduce GHG emissions, then a carbon tax would arguably be the clearest path to achieving that goal. A properly set and maintained carbon tax would incent GHG reductions, provide businesses certainty, and would not create the degree of administrative difficulty that can be anticipated under a that a cap-and-trade / offsets program regime.

*Question 2.* In thinking about alternative approaches to climate change policy, one important consideration is the point of regulation, especially with regard to an emissions cap. Both the House and Senate bills propose downstream caps by regulating thousands of emitting entities.

But an upstream cap for natural gas seems like it could achieve the same broad coverage much more simply, by regulating less than a thousand entities. What is the most efficient point of regulation to achieve broad coverage of fossil carbon for natural gas?

Are there any problems with mixing upstream caps for some fossil fuels and downstream caps for others? Does an upstream cap on all fossil fuels help to promote a consistent, economy-wide carbon price signal necessary to transition to a low-carbon economy?

Answer. The optimal point of regulation in a cap-and-trade program is one that (a) covers an adequate proportion of greenhouse gas emissions, (b) affects a manageable number of carbon-regulated entities, and (c) transmits an appropriate price signal to consumers of carbon-intensive fuels and products. There is no reason to believe that the best point of regulation will be the same for all fossil fuels, given that each fuel has a different supply chain and market structure. Indeed, both the Waxman-Markey and Kerry-Boxer climate change bills recognize the need for a nuanced point of regulation by specifying an "upstream" point of regulation for some fossil fuels (such as petroleum-based liquid fuels) and a "downstream" point of regulation for others (large users of coal and natural gas).

In the case of natural gas, TransCanada believes that a "downstream" point of regulation (at the point of emission) is generally most appropriate. Making upstream producers of natural gas accountable for GHG emissions from gas combustion would introduce several significant problems. First, there are several hundred thousand facilities that produce natural gas in the United States, making an allowance requirement difficult to administer at the point of natural gas production. Second, natural gas has substantial uses (as a chemical feedstock, for example) that do not result in GHG emissions—meaning that an "upstream" point of regulation would require a supplemental mechanism for thousands of natural gas users to claim a rebate for non-emissive uses of natural gas. Pipelines are an inappropriate point of regulation for the same reasons, but also because the complexity of pipeline networks makes it difficult to define a pipeline point of regulation that would avoid double-counting (or under-counting) natural gas emissions.

By contrast, a "downstream" point of regulation for natural gas would still affect a limited number of large entities (such as power plants and large industrial users of natural gas), while ensuring that non-emissive uses of natural gas do not fall under the cap. For the numerous residential and commercial consumers of natural gas, the most efficient point of regulation is probably at the local distribution company (LDC). This is more or less the approach taken in the Kerry-Boxer and Waxman-Markey bill, and—according to a recent study by the Pew Center on Global Climate Change[1]—would cover 95% of $CO_2$ emissions from natural gas while affecting a reasonable number of facilities.

In the case of natural gas markets, however, regulation of large emitters of combusted natural gas does present some significant issues for regulated entities to recover allowance costs and to avoid duplicative, diverse state programs. Thus, while a purely upstream point of regulation for natural gas may avoid some of the recovery issues for downstream regulated entities, TransCanada believes these transition issues can be address with a clear statutory provision directing regulators to all for tracking of carbon allowance compliance costs as well as a strong pre-emption provision which preempts not only individual state efforts to further regulate carbon emissions but also preempts the EPA from any further regulation of carbon emissions under the Clean Air Act or any other federal statute or regulation.

*Question 3.* With the recent advances in drilling technology in the gas industry, domestic gas reserves shot up by more than 35 percent this year, which of course is terrific news for the gas industry and potentially for our efforts to address climate change by reducing greenhouse gas emissions.

But I'm wondering about the broader environmental implications of the use of technologies such as hydraulic fracturing to produce unconventional shale gas resources. What are the implications of shale gas production for ground water and drinking water quality? How do these environmental risks compare to those of other energy sources?

Also, from an economic perspective, at what price is shale gas production viable for the industry? Would the price certainty of a carbon price floor be necessary for shale gas to be economic? How do the two prices—the natural gas price and the carbon price—interrelate and affect shale gas production?

Answer. TransCanada transports natural gas through its pipelines and consumes natural gas in its electric generation facilities. We are not involved in the production of natural gas. As such, TransCanada has had no experience with the regulation of hydraulic fracturing and will defer to views of BP and other natural gas producers on this issue.

TransCanada does believe, however, that the environmental impacts of natural gas extraction from tight sands and shale formations can be managed effectively and efficiently without unduly limiting the production potential of these sources. To ensure this is the case, the regulatory process for managing environmental risks must be guided fundamentally by scientific and technical considerations and must yield expeditious and predictable results.

There are many different shale plays in the US and across the continent. These plays differ in their production economics. Even within individual plays there are

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[1] Joel Bluestein, Coverage of Natural Gas Emissions and Flows Under a Greenhouse Gas Cap-and-Trade Program (Pew Center on Global Climate Change, December 2008) http://www.pewclimate.org/docUploads/NaturalGasPointofRegulation09.pdf.

substantial differences in the cost of production depending on exact location. Furthermore, some shale formations (e.g. the Marcellus) are closer to market and, consequently, receive higher net back prices than other, more remote shales.

TransCanada believes that at a gas price of $6 to $8/mmBtu range shale gas will make a large and growing contribution to US and continental supply over the next decade and beyond. We also believe that this price range generally can be maintained in the absence of very high carbon prices.

It is not clear that a carbon price, by itself, will improve the economics of shale gas or natural gas in general. Indeed, TransCanada's assessment is that the Waxman / Markey bill does not increase the demand for gas and therefore does not improve the economics of gas. This is because, under the bill, alternatives to natural gas either receive substantial incentives or are insulated from true carbon prices, or both, leaving little or no scope for increases in natural gas demand.

The interplay between carbon prices and natural gas prices is both direct and indirect. First, the carbon price as it applies to natural gas increases the gas price to the consumer but not for the producer. Second, there can be an indirect affect. Institution of any system that results in carbon prices of $30 per ton or more, if applied to all fossil fuels completely and equally, have the potential to cause switching of natural gas for coal. The extent of switching will depend primarily on the price of natural gas and the magnitude of the carbon price.

*Question 4.* Since natural gas has the lowest carbon content among fossil fuels, I would expect that a carbon price would not lead to a decline in the natural gas industry. But over the longer term, as the economy decarbonizes, there will be pressure on gas-fired utilities, as with coal-fired ones, to adopt carbon capture and sequestration technologies.

What is your assessment of the feasibility of commercial scale carbon capture and sequestration with natural gas?

Are the economics of CCS likely to be comparable for gas and coal consumers?

Could reimbursements in the form of allowances in excess of the cap for the amount of carbon captured and sequestered make CCS economic? And would this framework treat both coal and natural gas fairly?

Answer. TransCanada has been actively involved in the study and development of CCS projects for the past 5 to 6 years. Our involvement has included front end development on both pre-combustion capture and post combustion capture plants fuelled with varied grades of petcoke and coal. TransCanada has also been involved in a number of industry and government committees and initiatives which focused on CCS technologies, costs and policy.

TransCanada's experience in developing pre-combustion capture of $CO_2$ through proven gasification technology indicates that in order to recover costs on the $CO_2$ capture portion of a facility in today's markets, carbon prices in the range of $90 to $150 per ton would be required. The range of cost is related to the technology employed, whether the facility produced a single product (e.g. electricity or hydrogen—$150 pre ton) or multiple products (i.e. polygeneration—$90 per ton) and the market price for natural gas. The current natural gas price forecasts of $6-8/mmBtu push the carbon price very high as natural gas pricing has an inverse effect on the price of carbon. The reason for this is that the outputs from gasification (e.g. electricity, hydrogen, synthetic natural gas) are currently produced using natural gas as the primary feedstock and output from a gasification process would be required to compete with the prevailing market price of natural gas.

TransCanada's experience in developing post-combustion capture of $CO_2$ is gained through our exposure to the capture of 20% $CO_2$ from an existing sub-critical coal plant in Alberta. Our work indicated that carbon prices in the range of $150-$200 per ton would be required in order to recover costs on post combustion $CO_2$ capture facilities. The higher carbon price over gasification based technologies is required due to the lower pressure and less concentrated $CO_2$ stream leaving a post combustion plant. This requires larger equipment and more compression horsepower over a gasification facility. Our carbon costs also account for parasitic electrical and steam load loss from the base plant.

There has been some discussion regarding utilizing captured $CO_2$ for application in enhanced oil recovery (EOR) operations. The total cost of carbon required does not change in this application but the economic value attached to $CO_2$ for EOR application can offset a portion of the total carbon price required.

The following table demonstrates some key comparative carbon cost findings TransCanada has made as part of our CCS experience. This shows that the lowest cost of emissions reduction results from the utilization of natural gas itself without carbon capture. Natural gas based power production will result in an emission reduction of approximately 60% compared to a coal plant utilizing sub-critical coal with no capture.

| Plant | Carbon reduction | Natural Gas Price | Capture Cost ($/ton captured) |
|---|---|---|---|
| SubCritical Coal (Baseline) | baseline | $6-8 | N/A |
| Add on 20% Post Combustion Capture | 20% | $6-8 | $150-$200 |
| New Natural Gas Combined Cycle | 60% | $6-8 | $0 |
| Polygeneration/IGCC with 90% Capture | 90% | $6-8 | $90-$150 |

With respect to the question regarding the use of allowances for CCS, TransCanada questions the efficacy of using free allowance allocations to provide incentives for CCS research and development. We recognize the considerable capital expense required for CCS research and development, but we believe that a mechanism that establishes a transparent price for carbon combined with direct subsidies for CCS research and development will be more effective and economically efficient. Such an approach will allow all emitters of GHG to determine the best means to control GHG emissions through CCS technologies and / or fuel-switching and will not mask or skew the true price of carbon.

If, however, the Congress decides to pursue a program of free allowances to promote CCS technology, TransCanada recommends that the current proposals should be modified to create a level playing field for all fossil fueled facilities that emit GHG.

The Kerry-Boxer and Waxman-Markey bills reserve 85% of the CCS bonus allowances for coal-fired power plants. This bias in favor of clearly will discourage other industrial $CO_2$ emitters from attempting to deploy CCS at their facilities.

In certain situations, facilities other than coal-fired power plants present more cost-effective and energy-efficient opportunities to capture and sequester $CO_2$ than coal-fired power plants. The exhaust streams from natural gas processors and hydrogen producers, for example, have a higher concentration of carbon dioxide than most coal-fired power plants - meaning that it is less expensive and less energy-intensive on a per unit of $CO_2$ to capture $CO_2$ from these facilities than from a coal-fired power plant. From an environmental perspective, a ton of sequestered $CO_2$ is just as beneficial whether it is emitted from a coal-fired facility or from a facility utilizing natural gas for an industrial process.

If the CCS bonus allowance program is artificially restricted to coal-fired facilities, it could end up needlessly spending more resources to achieve fewer emission reductions than it would absent the restriction.

RESPONSE OF DENNIS MCCONAGHY TO QUESTION FROM MARK UDALL

*Question 1.* You mentioned that the new gas shale resources would provide a more stable resource than traditional natural gas resources, thereby reducing the volatility in gas prices. Specifically you mentioned that gas shale is a different kind of resource and that geology is less of an issue. Could you please elaborate more on this?

Answer. TransCanada does believe that the natural gas industry will be able to develop sufficient natural gas supplies to support increased use of natural gas in the electricity sector as well as the transportation sector. This supply will come from continued technological developments which will support production of both conventional and unconventional supplies.

Shale production, in particular, is a "game changer" in terms of natural gas supplies. Because producers generally know where shale reserves are located they are not confronted with the same "finding" risk that exists in the case of conventional natural gas reserves. Rather, the limitations on shale gas supply are "production" risks. In this regard, production of shale gas is similar to a "manufacturing process". A vertical well is drilled into a shale formation and then the formation is drilled horizontally. This technique permits multiple perforations along a horizontal axis as opposed to conventional vertical perforations through gas bearing formations. With horizontal drilling and horizontal completions, the odds of increasing production are dramatically higher.

With non conventional gas, specifically shale gas, vast amounts of resource have been identified. If prices spike, increased drilling can occur immediately (i.e. additional "manufacturing" assembly lines can be added) and result in timely increases in gas supply. With horizontal drilling, the exploration process at the front end is not required.

RESPONSES OF DAVID WILKS TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* I continue to hear concerns that placing a price on carbon through climate legislation will result in significant fuel switching, or what has been referred to as a "dash to gas". The implication is that fuel-switching will result in sharp increases in electricity prices. Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation? What is the likelihood of a large-scale transition to natural gas, and what timeframe could that potentially occur on?

Answer. With the imposition of a $CO_2$ allowance price, the costs to operate all fossil resources will increase, but to varying extent depending on each fuel's carbon intensity (emissions per MWh). Efficient combined cycle natural gas has approximately half or less of the emissions per MWh of typical pulverized coal-fired power generation. Thus, although the cost of gas generation will increase with the cost of $CO_2$, the $CO_2$ cost impact on coal generation will be approximately twice as much.

The $CO_2$ allowance price at which using natural gas to generate electricity becomes comparable in cost to coal generation is intuitively the price at which all costs—capital, O&M, fuel, and carbon costs—sum to the same $/MWh for coal and gas. Natural gas tends to have lower capital, higher fuel, and approximately half the carbon costs of coal. In theory, at a high enough $CO_2$ price, gas could push coal out of the dispatch order even though gas also must hold allowances. The exact carbon price at which this substitution could occur is hard to predict, and will depend on a variety of factors, including (1) the projected cost of natural gas; (2) the projected cost of coal; and (3) the efficiency and operating costs of existing coal facilities and any replacement natural gas facilities.

For specific carbon values at which the cost to generate electricity with natural gas is equivalent to coal fired generation, the time frame needs to be considered. In the near-term, coal to natural gas switching would occur through the re-dispatching of the existing generation fleet and would occur economically (when it is less expensive to generate electricity from natural gas rather than coal) with a $CO_2$ cost of roughly $45/ton depending on specific plant characteristics and assuming, among other things, $7.00/MMBtu natural gas.

In the intermediate term, when new construction is required to meet electricity generation needs, capital costs and utilization of the plant must be considered in the natural gas vs. coal assessment. In a scenario where natural gas generation displaces coal generation, the utilization of each plant type would change from current levels and by extension the cost per unit of electricity would change as the fixed costs are spread over greater (gas) or fewer (coal) units of electricity. The amount of potential displacement would vary depending on capital costs, fuel costs and the details of the system in which the plant operates. Using current utilization rates the break-even $CO_2$ cost for new natural gas generation vs. new coal generation is roughly $25/ton assuming, among other things, $7.00/MMBtu gas.

In both examples, the $CO_2$ "break-even" cost is sensitive to natural gas prices where a $1 increase in natural gas prices would add roughly $10—$12/ton to the $CO_2$ "break-even" cost.

As I testified, the retirement of at least some coal plants and increased reliance on natural gas for electricity generation is an inevitable result of a cap and trade program. The likelihood and timing of a large-scale transition to natural gas for baseload power generation, however, depends on many factors other than the price of $CO_2$ allowances. Recent advancements in unlocking shale gas will increase economically recoverable supplies and could reduce gas price volatility; however, at the moment, there are a number of regulatory uncertainties as well as uncertainty about what gas price is needed to incentivize shale gas exploration and production. Expanded use of natural gas for power generation, vehicles, intermittent renewable energy balancing, and other demands will put upward pressure on prices. Under $CO_2$ regulation it seems likely that there will be increased reliance on natural gas for power generation in the early years of the program, particularly if carbon offsets are in short supply,[1] but beyond 2020 natural gas generation could again decrease

[1] As suggested in the USDOE Energy Information Administration's analysis of the energy market and economic impacts of H.R. 2454, the American Clean Energy and Security Act of 2009. See http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html. Only in EIA's scenarios in

as carbon capture and storage (CCS) technologies for coal become commercial and with possible investments in new nuclear generating capacity. Also, achieving $CO_2$ emission reductions of around 80% by 2050 will not be possible even by replacing all coal generation with gas. Thus, increased natural gas power generation appears to be a "bridge" strategy that would begin immediately and continue through 2020 or 2025, and the magnitude of this change will probably depend on the availability and timing of carbon offsets, CCS and other low-and zero-carbon generation technologies. At the same time, as our own experience with the Minnesota Emission Reduction Program demonstrates, state policies can promote earlier retirement of coal and replacement with natural gas in some circumstances independent of any federal climate change strategy.

*Question 2.* One area of concern about depending on natural gas resources is that gas has been prone to strong price spikes over the past decade. The most recent one was just in 2008, with prices soaring to about $13 per million BTU. In Dr. Newell's testimony, he mentioned that the expanded reserves and greater ability to receive LNG shipments could mitigate future price spikes. Please comment on the factors that resulted in the 2008 price spike and other recent spikes. Is the supply situation now such that we will be insulated from such volatility in the future? Are there policy options we could pursue to reduce price volatility?

Answer. There have been three significant price spikes in the past decade. The first one occurred in December 2000 when NYMEX prices spiked to just under $10.00 per million British thermal units (mmBtu). This price spike was a result of an extremely cold start to the winter heating season and below average storage levels. The second price spike occurred in the fall of 2005 when the combination of hurricanes Katrina and Rita disrupted a significant amount of production in the Gulf of Mexico and NYMEX prices spiked as to just over $14.00 per mmBtu. The third spike occurred in June and July of 2008 when prices spiked to over $13.00 per mmBtu. However this one was unique as there was no obvious underlying disruption in the natural gas market that would account for the price spike.

The expanded reserves associated with shale gas and the ability of the nation to receive larger quantities of LNG should insulate the market from extended periods of extreme volatility, but they cannot eliminate the possibility of price spikes altogether due to the lag times associated with drilling activity in order to access the expanded reserves and the global market forces that drive the pricing of LNG.

Below are four policies that could reduce natural gas price volatility:

- First, Congress should encourage practices by state regulators and large players in the natural gas market that result in a more stable, predictable price. In addition to ensuring that companies that trade in natural gas markets do not engage in abusive trading practices, Congress should encourage utilities to use, and state regulators to allow, prudent and appropriate hedging strategies.
- Second, as I testified, climate policy will inevitably rely in part on repowering of existing coal plants to natural gas. A volatile carbon dioxide allowance price could exacerbate the volatility of natural gas prices. In designing climate policy, Congress should use price collars and other mechanisms to control the volatility of the price of a carbon dioxide allowance. Such mechanisms will assist in controlling the volatility of natural gas prices.
- Third, adopting a policy that would encourage the development of additional storage facilities or the expansion of existing facilities would have the potential to limit future price volatility. The development of additional storage capacity would provide a supply buffer to help offset periodic disruptions of supply or periods of increased demand and in addition it could act as balancing mechanism for the physical market during periods of excess production.
- Finally, the best way to avoid volatility of natural gas prices is to assure a stable supply and reduce the barriers to development of new natural gas resources. Even with expanded supply options, sudden changes in demand for natural gas could result in a significant short-term increase in natural gas prices unless natural gas supply can rise to meet that demand. Congress should avoid creating unnecessary permitting barriers to the development of both conventional and shale gas, as well as pipelines and other supporting infrastructure.

*Question 3.* Reducing the volatility of the price of natural gas is an important goal if we are to lean more heavily on this resource. For producers, independent generators, and utilities to enter into long-term contracts for gas supply would seem to be one way to reduce pricing volatility. Could you describe your willingness to enter into such long-term contracts, and what obstacles may stand in the way of them?

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which offsets and technology are constrained did the electric sector use significantly more gas and less coal than in the reference case by 2030.

Answer. Long-term commitments for gas supply at a fixed price could alleviate concerns related to fuel price changes over the long term for a generating unit or group of units. Fixed price contracts eliminate the opportunity for upside market price movement for the seller and the benefit of lower market prices for the utility. State regulated utilities must be prudent in fuel purchase decisions and utilities would need the support of regulators to commit to long-term contracts that could be priced above the spot market in the future. Long-term contracts would need to address security issues related to financial performance through collateral or margin posting as well as the commitment of both parties to perform operationally. If satisfactory contractual and regulatory arrangements could be implemented, Xcel Energy would be interested in long term fixed price contracts for natural gas.

*Question 4.* Is it your opinion that the advanced CCS bonus allocations in the Kerry/Boxer bill are enough to jumpstart broad deployment of CCS? I've noticed that only a maximum of 15% of the advance allocations can be given to projects that do not employ coal. Do you think that this will potentially restrict other industrial $CO_2$ emitters from being able to deploy CCS at their facility? Are the CCS allocations enough, in your opinion, to incentivize the gas industry to try and deploy this technology? If not, how would you improve the CCS bonus allowance to open up the field to all industrial stationary source emitters?

Answer. In our opinion:

- The advanced bonus allocations under the Kerry/Boxer bill are enough to jumpstart the deployment of CCS, and such a provision is an important feature of any policy to address major emission sources of $CO_2$. However, the key phrase of the question is "broad deployment." Kerry/Boxer's incentives and advanced allocation will increase certainty, buy down the cost of CCS, and help make fossil-fueled facilities with CCS more competitive, but only within the limits set in the bill regarding percentage of allowances provided, economic value of the bonus to an individual project, and overall capacity threshold. The larger issues are (1) whether the support provided to CCS is sufficient considering the cost of sequestration and regulatory requirements yet to be established, and (2) whether the support is sufficient to create the impetus for CCS technological advances that will, in time, make CCS economically viable beyond the scope of the bonus program. These issues remain to be determined and will require continuing evaluation and possible adjustment to the program in the future.
- Coal is the major source of $CO_2$ emissions and directing 85% of the advance allocations toward coal appears sensible. Moreover, the experience gained and technology improvements achieved applying CCS to coal will also be of significant value in enabling CCS in the gas industry and other industrial stationary source emitters.

*Question 5.* All of the natural gas we're discussing here today will come from both conventional and unconventional extraction methods. A major stake of the gas future sits in extracting natural gas from tight gas sands/shales. There has been some discussion here in Congress that the Safe Drinking Water Act exemption for hydraulic fracturing should be reconsidered. Do you think a repeal of this exemption would dramatically affect the future of natural gas extraction of these unconventional gas sources?

Answer. Xcel Energy is not involved in the natural gas extraction industry. We have no direct experience with the hydraulic fracturing and production of natural gas from conventional or unconventional resources. We have no experience to allow us to comment on the impact a repeal of the Safe Water Drinking Act hydraulic fracturing exemption may have on the natural gas extraction industry. As a significant participant in the purchasing of natural gas, however, we are concerned that any change to the regulations governing the development of unconventional gas may create significant and sustained challenges to the production of natural gas from shale formations. These in turn may have an impact on the volatility of the market price for natural gas. Consequently, we encourage Congress to consider whether the environmental benefits of additional regulation of hydraulic fracturing would outweigh the lost environmental and potential economic opportunity associated with expanded gas production.

*Question 6.* What is the marginal cost of Combined Cycle Gas Turbine (CCGT) electricity vs. that generated with pulverized coal? At what price for gas is it lower for CCGT? How do these numbers compare for old, relatively inefficient coal plants vs. new gas plants?

Answer. The term marginal cost is typically used to describe the cost to operate an electric generating plant which includes the cost of fuel and certain operations and maintenance (O&M) costs. The CCGT plants operating on Xcel Energy's systems today would typically generate electricity in the neighborhood of $50/MWh to

$55/MWh (burning $7.00/MMBtu natural gas). In comparison, Xcel Energy's pulverized coal plants typically generate electricity in the range of $12/MWh to $20/MWh depending on coal type. In both the CCGT and pulverized coal values above, approximately 90% of these costs are associated with the fuel and the remaining 10% are related to O&M. Note that these costs do not include the capital cost required to construct the plants nor do they include any cost for $CO_2$.

When the capital costs to construct new generating plants are factored into the pricing (creating an "all-in" cost), the CCGT costs are in the $80-$85/MWh range (at 50% capacity factor) with pulverized coal falling in the range of $55/MWh to $65/MWh (at 90% capacity factor). These pricing estimates assume the capital cost of a new CCGT to be in the range of $800-$1000/kW of nameplate generating capacity and a new pulverized coal unit (without carbon capture) to be in the range of $2400-$3000/kW of nameplate generating capacity.

These $/MWh "all-in" cost estimates are heavily dependent on how often the unit is utilized. The basic cost characteristics of thermal generation resource technologies are illustrated in the following table.

| Costs | Gas Turbine (GT) | CCGT | Coal |
|---|---|---|---|
| Capital Costs | Low | Mid | High |
| Operating Costs | High | Mid | Low |
| Intended Use | Peaking | Intermediate | Baseload |
| Hours of Use | Low | Medium | High |

The figure* below provides an illustration of how the general cost characteristics of GT, gas CCGT, and coal generators might compare with one another based on how they are utilized (i.e., peaking, intermediate, or baseload) on the system. The figure shows that the "all-in" cost of electric energy per MWh depends highly on the number of hours a unit is operated, (i.e., the unit's capacity factor). The "all-in" cost curves decline as the fixed costs (capital and fixed O&M) are distributed over more hours of operation.

Assuming the mid-point of $60/MWh for the "all-in" cost from a new pulverized coal plant described above, a new CCGT with capital costs of $900/kW and operating at a 50% capacity factor would have an "all-in" cost of $60/MWh at a gas price of approximately $4.00/MMBtu.

While older coal plants may be relatively inefficient compared to newer coal plants, the capital cost to construct the older coal plants was often significantly lower than the $2400-$3000/kW cost range estimated for construction of a new coal plant today. These older coal plants can have "all-in" costs for electricity in the $40/MWh to $50/MWh range since the lower capital costs more than offset the lower efficiencies. The gas cost needed to make a new CCGT plant have a $45/MWh all-in cost is approximately $1.80/MMBtu.

*Question 7.* How much does conversion from coal to CCGT cost per megawatt?

Answer. Although general information regarding the cost of conversion of a coal plant is discussed above, the actual cost is very case specific. The cost depends on several factors including how much of the existing coal plant facilities can be utilized by the CCGT plant. For example, it is often possible for the CCGT facility to reuse the coal plant's steam turbine. While the reuse of certain components results in a savings of capital dollars to the CCGT facility, there can be additional design and construction costs that erode a portion of these capital savings. Furthermore, a CCGT plant that uses an existing steam turbine is often less efficient than a CCGT that utilizes a steam turbine that has been specifically engineered and designed to be used in a combined cycle application. The loss in efficiency results in higher operating costs which can also erode a portion of the capital savings. The end result can be a converted CCGT plant that has essentially the same "all in" cost as a new CCGT facility that does not utilize components from an existing coal plant.

*Question 8.* What is the primary obstacle to CHP?

Answer. CHP technology has some very good applications, but for Xcel Energy there are some recognized obstacles including a process need (for the heat) and a

* Graph has been retained in committee files.

power need that must be at the same location. The economics of the project decline as the distance between the process and power needs increase. It is also a technology better suited for an industrial site, not a residential or commercial site thus further limiting suitable locations. Most of our industrial customers have already taken advantage of CHP in the form of cogeneration. Hence the likelihood that CHP could be a big contributor to carbon reduction is remote.

RESPONSES OF DAVID WILKS TO QUESTIONS FROM SENATOR MURKOWSKI

*Question 1.* You may know that Senator Mendendez and I are both on a bill to promote the development of natural gas vehicles. NGV advocates, myself included, have pointed out that natural gas as a transportation fuel reduces carbon emissions, offsets petroleum imports and provides an economic boost here at home by using natural gas in place of imported petroleum. Given the recent findings concerning the increased availability of natural gas supplies in North America and here in the U.S. should we be doing more to advance the use of natural gas as a transportation fuel?

Answer. The technology exists to reduce the use of petroleum in the transportation sector through either natural gas vehicles or electric vehicles among other developing technologies. Both technologies require significant investment in infrastructure to be successful. There are very good uses for both of these types of transportation fuel technology. For the automobile sector electrified transportation is a technology solution that has the additional benefit of providing an off-peak load for electric utilities and the ability to support off-peak renewable energy generation and storage. We are supporting the development of transportation electrification through our commitment to the Edison Electric Institute industry-wide pledge to the full scale deployment and commercialization of an electrified transportation sector as illustrated in the industry pledge attached as Exhibit 1.

*Question 2.* Currently there are serious regulatory obstacles positioning in front of domestic energy development. Particularly, surface coal mining rules are under serious assault and offshore oil and gas development is facing increasing scrutiny from at least three different federal agencies. Can the panel speak to how we ever get to a point of more natural gas power plants or, for that matter, clean coal if, despite policies encouraging the advancement of these new and exciting power sources, we simply can't access and produce the basic resource?

Answer. To make the transition to a low-carbon, clean energy future, the utility industry must rely on a diverse portfolio of clean energy resources, including natural gas, clean coal, nuclear, renewable energy and energy efficiency. At Xcel Energy, we have already begun to reduce our emissions and have plans in place to achieve a 15% reduction in $CO_2$ across the system by 2020, relying on almost all of these clean resources. Our strategy today shows how the industry will likely respond to the challenge of federal climate legislation tomorrow. However, the success of that strategy depends on unfettered access to capital, steel and other construction materials, and, of course, coal, natural gas, and uranium fuels.

*Question 3.* What is your opinion about a Low Carbon Electricity Standard that would allow utilities to use a variety of alternatives to reduce greenhouse gas emissions, including renewables, natural gas, nuclear and hydroelectric?

Answer. Xcel Energy has long been an advocate of such a standard. Several years ago, in an effort to break the logjam on climate and energy policy, Xcel Energy became a proponent of a Clean Energy Portfolio Standard, or CEPS. Under CEPS, utilities would have been required to derive a portion of the electricity provided to their customers from clean energy resources, which would have included renewables, new nuclear, clean coal and energy efficiency. EIA analyzed the policy and found it to be a very cost-effective method of promoting new technologies and reducing emissions. Although we designed CEPS prior to the recent shale gas discoveries, the policy can easily be modified to accommodate natural gas repowering as a clean energy alternative. More information regarding CEPS is attached as Exhibit 2.

*Question 4.* To the extent that deliverability of natural gas to markets has been an issue in the past, should recent improvements in pipeline infrastructure, as well as prospects for additional projects coming online, serve as any comfort to those with concerns about spikes in natural gas prices?

Answer. The pipeline improvements that have recently been completed or are in the process of being permitted and constructed have or will alleviate a number of regional pricing anomalies including many of the spikes seen over the last 3-5 years. The improvements that are complete have resulted in a number of regional markets that are functioning and falling more inline with national pricing trends. Geographic changes to the natural gas producing areas, like the new shale basins (Pennsylvania shale vs. Wyoming traditional production), as well as the geographic changes to the market demand for gas caused by power generators moving from coal or other fuels to natural gas could result in regional pricing differentials becoming greater than they are now. These regional production and demand shifts may again cause gas pipeline constraints that could result in regional price spikes.

The continued development and use of natural gas storage in and around the market demand areas has the potential to reduce the short duration impacts of increased natural gas demand by allowing for the efficient use of the pipeline infrastructure. Natural gas storage can help the natural gas generator avoid short duration price spikes by having storage gas available rather than going to the market during periods of high gas demand and the corresponding price increases. Natural gas storage does not have a significant impact on long term price trends as storage must eventually be refilled after it has been consumed.

*Question 5.* Please give me a sense of the relative challenges in choosing fuel investments from the perspective of a regulated versus non-regulated utility-I understand Xcel is the regulated utility.

Answer. In selecting fuel investments, a non-regulated entity must choose the project only after considering the needs and desires of its stakeholders (e.g. shareholders, customers and policy makers). The decision is made based on a number of factors, including the impact of the investment on the environment, its consistency with state policy, its feasibility and risk, additional transmission and other supporting infrastructure associated with the investment, its community acceptance and, of course, its cost.

A regulated utility in selecting fuel investments has to work within the rules of its federal, state or local regulatory construct and in some cases receive regulatory approval of the need for such fuel investment. These rules may require the utility to follow a certain bidding process, allow interested third parties to intervene and/ or mandate a preference for certain types of projects (i.e. renewables), in addition to meeting the needs of its stakeholders.

*Question 6.* I was interested in Mr. Wilks' testimony about SmartGrid City in Boulder, Colorado, as well as the solar work that Xcel is doing in Colorado. Can you talk about why natural gas is so important as a backup, or baseload generator, for intermittent solar or wind power?

Answer. We are very proud of SmartGridCity and believe that it will allow us to test a variety of new ways to run a utility. We believe that the Smart Grid will be an important tool to help us integrate renewable energy onto our system.

As your question implies, natural gas is important as a backup to intermittent solar or wind power because of the unpredictable nature of those generation resources. Renewable energy "integration" refers to those ancillary activities necessary to absorb increasing penetration of intermittent renewable generation while maintaining overall electric system stability and reliability. To support this integration Xcel Energy relies heavily on natural gas fired power plants, which can be brought online with fairly short notice. However, integrating the renewable resources into our system with the help of the back up natural gas resources inevitably imposes additional costs on our customers. These costs are variable, but studies of utilities across the country conclude that these costs can exceed $5.00/MWh for utilities like Xcel Energy with high levels of renewable energy penetration.

To help reduce the burden of these costs on our customers, Xcel Energy is encouraging the adoption of new federal renewable tax incentive policies. These policies should recognize that integrating a substantial amount of renewable generation-in particular wind and solar-on the grid imposes significant burdens on the utilities that transmit and distribute electricity from such resources to customers. To account for these burdens and encourage utilities to make necessary system upgrades and ongoing integration expenditures, including those in SmartGrid technology, Congress should enact a "Renewable Integration Credit" (RIC). The RIC would provide utilities with a tax credit based on the kilowatt hours of "intermittent renewable electricity" generated on the system. Unlike the production tax credit, the RIC would be directed toward defraying the integration costs incurred by the utility system. More detail regarding the RIC is attached as Exhibit 3.

## Responses of David Wilks to Questions From Senator Sessions

*Question 1.* If the transportation sector moves towards natural gas, how will this affect the price of natural gas, the United States' crude oil imports, greenhouse gas emissions, other energy sectors that currently use this energy source.

Answer. Fleets vehicles which consume a consistent daily amount of fuel will be the early users of natural gas as transportation fuel. These vehicles return to their terminal every evening and can utilize the large central natural gas fueling facility. The use of natural gas as a motor fuel by the general public is expected come later as there would be a need for a significant change in the fueling infrastructure and the increase in the availability of factory built natural gas vehicles.

Each MMBTU of natural gas used by vehicles will displace approximately 8 gallons of gasoline and reduce carbon emissions by 20-30%. The use of natural gas by the transportation sector will increase natural gas consumption which may place upward pressure on natural gas pricing similar to any increase in consumption.

*Question 2.* What incentives or regulatory changes are necessary to effectively enhance the use of natural gas over coal, diesel, or gasoline? And the cost associated with the switch?

Answer. At the present time there are no major restrictions on the use of natural gas as a fuel in any economic sector, in contrast to the 1970s when such restrictions were in place. Economic considerations tend to dominate decisions about the use of natural gas, along with the fuel's physical availability (tied to the deployment of delivery infrastructure). Natural gas has some inherent advantages in terms of its handling and combustion characteristics, so if cost is close to even natural gas is often a preferred choice. Policies to incent fuel switching in the electric utility sector include:

- credit for early action if a switch is made prior to a new GHG regulatory program;
- allowance trading for other air emissions, as natural gas has lower or no emissions of $SO_2$, $NO_X$ or mercury or particulates, but such reductions may not be valued in a 'command and control' regulatory system;
- enhanced regulatory support for regulated utilities in terms of accelerated rate recovery, higher allowed return on invested capital, etc.;
- robust support for storage and delivery infrastructure including positive tax treatment for investment, streamlined siting and permitting processes, and a consistent safety and inspection regime; and
- properly regulated commodity markets in order to ensure price discovery, product innovation, and access to risk management mechanisms such as hedging.

RESPONSES OF DAVID WILKS TO QUESTIONS FROM SENATOR CANTWELL

*Question 1.* I think it is very important that we ensure that climate policy doesn't introduce unnecessary volatility into markets for oil and natural gas. We've seen gas prices fluctuate sharply over the past two years from $5.90 up to $10.82 and then back down to around $3.40 where we are now. I think we all agree that this sort of uncertainty isn't good for energy producers or consumers.

- What do modeling results and forecasts tell us about what would actually happen in the real world with regard to fuel mix, energy costs and investment under this kind of price volatility?
- Could a well designed price collar mitigate this sort of volatility?

Answer. With regard to natural gas price volatility, we agree that recent years have seen significant ups and downs. In that context there has nonetheless been strong investment in new natural gas power plants. Thus, even without $CO_2$ regulation and with natural gas prices remaining volatile, we expect trends would be similar to recent years: utilities will continue to invest in gas generation to meet peak demand and increasingly as a resource to balance higher levels of intermittent renewable power. The national energy mix would likely transition incrementally toward renewables with natural gas, and incrementally away from coal, but this transition would be gradual.

With volatile gas prices and $CO_2$ regulation, one recent analysis—EIA's analysis of the American Clean Energy and Security Act of 2009—suggests that natural gas power generation and natural gas's share of the national energy mix would increase; however, differences from the reference case are only significant if offsets and low-carbon technologies are constrained. In this scenario investment in new natural gas generation could increase significantly during a transition period in which utilities use gas as a "bridge" strategy until offsets, CCS or new nuclear become available. Otherwise, EIA describes a future in which emissions are in decline, even without changes in the fuel mix, due to energy efficiency and a slow economic recovery, and in which many of the reductions needed for compliance come from offsets rather than internal abatement.

Xcel Energy believes a well-designed carbon dioxide allowance price collar could mitigate $CO_2$ allowance price volatility. A price collar would establish a ceiling and floor on the prices regulated entities pay for allowances, with the ceiling designed to avoid economic harm and the floor designed to ensure an adequate price to incentivize carbon reductions and energy efficiency. A price collar would provide some cost certainty for regulated entities, reduce price volatility and market manipulation. A carbon dioxide price collar would by extension help reduce the potential volatility of natural gas prices under a cap and trade program.

*Question 2.* In thinking about alternative approaches to climate change policy, one important consideration is the point of regulation, especially with regard to an emissions cap. Both the House and Senate bills propose downstream caps by regulating thousands of emitting entities.

- But an upstream cap for natural gas seems like it could achieve the same broad coverage much more simply, by regulating less than a thousand entities. What is the most efficient point of regulation to achieve broad coverage of fossil carbon for natural gas?
- Are there any problems with mixing upstream caps for some fossil fuels and downstream caps for others? Does an upstream cap on all fossil fuels help to promote consistent, economy wide carbon price signal necessary to transition to a low-carbon economy?

Answer. Natural gas does pose special issues in terms of point of regulation for GHG emissions. Natural gas is a uniquely pervasive fuel, ranging across economic sectors from electric utilities, to heavy industry, to large commercial and small residential end users. In general, given this usage profile, an upstream point of GHG regulation for natural gas seems preferable and easier to administer. However, it would also be possible to regulate large stationary sources at the point of use, while regulating the remainder of natural gas upstream. GHG and regulatory accounting systems can be used to facilitate either approach.

Nearly all proposals for a GHG cap and trade system have used a so-called 'hybrid upstream-downstream' approach to the point of regulation issue. While sectoral definitions and entity size criteria vary, these hybrid approaches all make the common assumption that any problems that may arise from combining upstream and downstream approaches will be more manageable than the problems that could result from imposing an inappropriate point of regulation on some major portion of the economy. In practice, we simply don't know much about the real tradeoffs underlying this policy decision. Both upstream and downstream approaches serve to limit GHGs and thus create price signals; it does not appear to be necessary for all fossil fuels to be regulated in the same manner for this price (scarcity) signaling to have an economic effect.

*Question 3.* With the recent advances in drilling technology in the gas industry, domestic gas reserves shot up by more than 35 percent this year, which of course is terrific news for the gas industry and potentially for our efforts to address climate change by reducing greenhouse gas emissions.

- But I'm wondering about the broader environmental implications of the use of technologies such as hydraulic fracturing to produce unconventional shale gas resources. What are the implications of shale gas production on ground water and drinking water quality? How do these environmental risks compare to those of other energy sources?
- Also, from an economic perspective, at what price is shale gas production viable for the industry? Would the price certainty of a carbon price floor be necessary for shale gas to be economic? How do the two prices-the natural gas price and the carbon price-interrelate and affect shale gas production?

Answer. Reliable and environmentally beneficial energy production is in the public interest. Whatever the implications are for ground water associated with hydraulic fracturing, they need to be balanced with whatever environmental risks are associated with other energy sources. As indicated above, we support policies that allow for the responsible development of clean energy options such as unconventional natural gas.

Since Xcel Energy is not a producer we do not have the necessary insight into determining at what price shale gas production is viable. The interrelation of natural gas and carbon prices can affect shale gas only to the extent that carbon prices positively or negatively impact the underlying price of natural gas, which in turn impacts the economic viability of shale gas production.

*Question 4.* Since natural gas has the lowest carbon among fossil fuels, I would expect that a carbon price would not lead to a decline in the natural gas industry. But over the longer term, as the economy decarbonizes, there will be pressure on gas-fired utilities, as with coal-fired ones, to adopt carbon capture and sequestration technologies.

- What is your assessment of the feasibility of commercial scale carbon capture and sequestration with natural gas?
- Are the economics of CCS likely to be comparable for gas and coal consumers?

- Could reimbursements in the form of allowances in excess of the cap for the amount of carbon captured and sequestered make CCS economic? And would this framework treat both coal and natural gas fairly?

Answer. We believe that with current CCS technology, CCS with natural gas is technically feasible but significantly less economical than with coal, primarily because of the lower concentration of $CO_2$ in the exhaust gas from a natural gas facility. In terms of cost-effectiveness with respect to both investments and the impact of CCS allowance incentives, we therefore feel CCS should be supported on behalf of coal consumers, at least in the short and mid-term. The experience gained and technological advance achieved in applying CCS to coal will also be of significant value to gas consumers going in the future.

RESPONSE OF DAVID WILKS TO QUESTION FROM SENATOR LINCOLN

*Question 1.* As you know, several recent studies have projected that our natural gas supply is much larger than previous estimates. For example, the Potential Gas Committee esimtates that the U.S. now has a 35% increase in supply estimates from just two years ago, which is enough they say to supply the U.S. market for a century. The Energy Information Agency (EIA) has also predicted a 99-year natural gas supply. I am proud that the Fayetteville Shale in Arkansas is already producing over one billion cubic feet of natural gas per day, while only in its fifth year of development. What role do you believe the improvement in drilling technologies such as horizontal drilling and hydraulic fracturing played in the estimated increase in natural gas supply?

Answer. Improved drilling technology has played a very significant role in the increase in natural gas supply. According to America's Natural Gas Alliance, advances in geoscience, drilling and well completion technology as well as 3-D seismic technology now allow production companies to "see" the resource and to tap underground reservoirs with less surface disturbance. The development of the Fayetteville Shale (and the benefits it provides to Arkansas and the people of the United States) and other unconventional formations is made possible by this new technology.

RESPONSE OF DAVID WILKS TO QUESTION FROM SENATOR MARK UDALL

*Question 1.* It was mentioned that some coal utilities are already switching over to gas without incentive in place, could you elaborate on this dynamic? Does low gas price and region play any role in some of these changes?

Answer. In our experience, state legislatures may create programs that offer cost recovery and other incentives to encourage utilities to reduce emissions in part by retiring older coal plants and replacing them with natural gas generation. Senator Udall himself cosponsored legislation creating such a program in Colorado when he was a state legislator in 1998. These programs are designed to achieve different, state specific goals, including improving air quality, promoting economic development, or helping to achieve the state's own greenhouse gas reduction goals. As indicated in my testimony, at Xcel Energy, we have undertaken retirement and gas replacement programs in Minnesota (the MERP) and are in the process of implementing a similar plan in Colorado.

In our experience, however, these programs do not give utilities unlimited discretion to undertake such projects. Instead, they require the state public utilities commission to oversee the projects and approve them only if they have reasonable cost and customer benefits. In evaluating these projects, state commissions must evaluate the potential cost of the project, including the potential cost of fuel. Thus, lower projected gas prices will make these projects less costly and thus more likely to be approved by the state commissions. In other words, lower gas prices encourage states and utilities to undertake gas replacement projects.

EXHIBIT 1.—NEWS RELEASE FROM EDISON ELECTRIC INSTITUTE, OCTOBER 21, 2009

INDUSTRY-WIDE PLUG-IN ELECTRIC VEHICLE MARKET READINESS PLEDGE

DETROIT—EEI member companies are committed to making electric transportation a success. At the center of these efforts is the industry-wide pledge to plug-in electric vehicle market readiness. The pledge represents a culmination of efforts by EEI member companies to survey the current state of electric transportation initiatives among utilities, evaluate how those initiatives fit in with the overall goal of advancing transportation electrification and determine what more is needed. There are five areas of focus:

1. Infrastructure: Utilities pledge to proactively work with their state regulatory and legislative bodies to assess and address any potential system impacts from fueling large numbers of plug-in vehicles from the electrical grid. Further, utilities will work collaboratively with state and local officials, public/private entities, automakers, and other stakeholders to help develop a comprehensive local charging infrastructure deployment plan.

2. Customer Support: Utilities pledge to assure that a robust customer service process is in place that can scale up to support large numbers of plug-in vehicle customer service requests ranging from charging infrastructure installations to utility-specific rate options and incentive plans. Utilities will work with stakeholders to facilitate a streamlined charging installation process.

3. Customer and Stakeholder Education: Utilities pledge to collaborate with state and local officials, public/private entities and automakers to help implement a broad nationwide education program highlighting the benefits of electric transportation (energy security, reduction in greenhouse gases and air pollutants); the benefits of electricity as an alternative fuel; the creation of public-access charging infrastructure; steps cities and individual customers need to take to get plug-in ready; and the importance and benefits of off-peak charging.

4. Vehicle and Infrastructure Incentives: Utilities pledge to work with federal, state and local stakeholders to help develop purchase and ownership incentives (monetary/non-monetary) supporting both vehicles and infrastructure deployment. Incentives could include purchase incentives, tax rebates, off-peak charging rates, preferential and/or free parking, and grants for charging infrastructure installation, all designed to encourage a significant penetration of electric transportation solutions.

5. Utility Fleets: Utilities pledge to develop new sustainable fleet acquisition and operations plans, helping drive development and significant deployment of electric transportation solutions in light-, medium-and heavy-duty utility applications. These efforts could include development of industry-wide vehicle specifications by weight class; industry-wide fuel economy requirements; fleet user education programs; and industry-wide best practices, all designed to help achieve a significant increase in fleet fuel efficiency and a commensurate decrease in GHG and other emissions.

## EXHIBIT 2.—NATIONAL CLEAN ENERGY PORTFOLIO STANDARD

### A CLIMATE CHANGE AND ENERGY POLICY FOR THE UTILITY INDUSTRY

Climate change is of significant interest and concern to our customers, the states we serve and our nation. How our country deals with this issue is critical to achieving real environmental improvement while keeping electricity affordable for all consumers.

We propose a clean energy approach through a Clean Energy Portfolio Standard (CEPS). A CEPS is an increasing requirement for a utility's energy sales to come from non-$CO_2$-emitting generation. Utilities would meet a 25 percent CEPS requirement in 2025 by choosing from a portfolio of eligible technologies. The policy sets later technology targets to achieve 1990-level $CO_2$ emissions.

*CEPS*

- Reduces utility $CO_2$ emissions at low cost.
- Encourages clean technology and transforms the utility industry.
- Promotes national energy security.
- Reduces natural gas consumption.
- Manages cost through flexibility and resource diversity.
- Rewards early action.
- Protects economic growth and national competitiveness.

*CEPS Specifics*

- 10% by 2015; 17% by 2020; 25% by 2025 of energy sales.
- Post-2025, the CEPS targets are adjusted to achieve 2005 emissions levels by 2030, 1996 levels by 2035, and 1990 levels (2 billion tons per year) by 2040.
- Compliance occurs through tradable Clean Energy Credits (CECs).

  —Credit for renewable energy or "low emission" generating facilities
  —Acquisition of CECs from national trading market
  —Purchase of "safety valve" CECs from Department of Energy (2.5 cents/kilowatt-hour (kwh), indexed for inflation)

- Early credit beginning in 2010 for renewable resources
- Three-year borrowing forward allowed

- Cost recovery for:
  - —Clean energy generation or CECs
  - —Ancillary costs (firming, shaping, backup) for intermittent resources
  - —Transmission and distribution
- State opt-out provision for excessive cost

CEPS eligible technologies and values:

- Renewable energy = 1 CEC/kwh
- Advanced fossil w/ carbon capture = 1 CEC/carbon-free kwh
- New nuclear = 1 CEC/kwh
- Energy efficiency/conservation investments = CECs awarded at safety valve price
- Carbon offsets—carbon sequestration, plant efficiency improvements, other offsets = 1000 CECs per ton of $CO_2$, with limit at 10% of compliance

EXHIBIT 3.—UTILITY RENEWABLE ENERGY INTEGRATION COST RECOVERY MECHANISMS—BASED UPON XCEL ENERGY'S THREE OPERATING COMPANIES: PSCO, NSP AND SPS

Renewable energy "integration" refers to those ancillary activities necessary to absorb increasing penetration levels of intermittent renewable generation while maintaining overall electric system stability and reliability. Integration does not include project costs incurred by developers of intermittent renewable energy (capital, O&M, etc.), but rather the additional costs of incremental electric production and incremental gas supply to account for the renewable energy on a utility system. These costs are borne by utilities through four primary activities: load following, unit commitment, generating facilities for balancing, and increased operations and maintenance costs for existing plants.

These costs are variable, but studies of utilities across the country conclude that these costs exceed $5.00/MWh on average. Only the highest levels of intermittent generation requiring over 20% of retail sales coming from solar or wind generation would be eligible for $5.00/MWh credit. At least 4% renewable generation would need to be achieved to earn $1.00/MWh credit.

1. Load Following—this activity includes adjusting generation to follow the changes in total customer demand versus the variability in wind output as well as regulation of the output of generation units to maintain system frequency.

   Cost Recovery: Resulting increased fuel costs are passed through directly to customers through periodic fuel cost adjustments. Additional load following costs resulting from less than optimal system operations and higher power production costs are also incurred by the customer through increased electric rates.

2. Unit Commitment—the process of determining which generators should be operated each day to meet the daily demand of the system including maintaining adequate reserve capacity.

   Cost Recovery: The cost of forecasting and planning for the daily expected wind generation is incurred by utility customers through adjustments to their electric cost of service. More accurate wind forecasting will be critical to successfully integrate higher levels of wind and this will increase the unit commitment costs.

3. Investments—Utilities may need new quick-start natural gas generating facilities, and supporting natural gas infrastructure, storage and fuel, in order to balance the intermittency of renewable generation.

   Cost Recovery: Investments in generation are recovered through rate increases if approved by state utility commissions. If additional generation is acquired through purchased power, those costs are passed through to customers through periodic electric cost adjustments and base rate increases.

4. O&M—Increased O&M costs for existing coal and gas plants, due to more frequent changes in operating rates to balance renewable generation.

Cost Recovery: The increased costs of O&M are borne by the customer once included in approved rate increases. Increased electric costs that result from purchasing electricity when company owned units are out of service for maintenance are also passed through to the customer. This cost can increase substantially when power must be purchased to fulfill our reserve requirements in addition to meeting load.

RENEWABLE ENERGY TAX CREDITS

Utility commissions set utility rates based so that the utility recovers the cost of operating its system plus a reasonable rate of return. These costs include the cost of taxes imposed on the utility; utility rates are set to assure that the utility can recover its tax liability. As a general rule, if the utility receives a tax benefit, such as a tax credit related to renewable energy, the value of those tax credits are passed through to customers.

For example, when Xcel Energy constructed the Grand Meadow Wind Farm in Minnesota, it reduced its charge to customers by the value of the wind production tax credit (see attached, page 12). The Renewable Integration Credit would be subject to similar regulatory treatment.

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RESPONSES OF LAMAR MCKAY TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* I continue to hear concerns that placing a price on carbon through climate legislation will result in significant fuel-switching, or what has been referred to as a “dash to gas”. The implication is that fuel-switching will result in sharp increases in electricity prices. Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation? What is the likelihood of a large-scale transition to natural gas, and what timeframe could that potentially occur on?

Answer. The price at which natural gas competes with coal in electricity generation is dependent on the relative price of coal and gas and the relative efficiencies of the respective coal-and natural gas-fired power plants under consideration. For electricity dispatch from the existing coal generation fleet, based on a coal price of $40ton and using the thermal efficiency of representative US coal-and natural gas-fired (combined-cycle gas turbine) power plants, new natural gas plant capacity would be competitive with coal at prices around $4/Mmbtu. With a $CO_2$ price of $20/ton, natural gas prices of around $6/Mmbtu would be competitive (holding all other factors constant).

Any large-scale change in the nation’s energy use would take decades to play out, given the long lead times needed to invest in new equipment to both produce and consume energy. Based on this, coal will continue to play the dominant role in US electricity generation for decades to come. The proposals I discussed in my testimony were more modest but quicker to have an impact: the incremental natural gas demand that could potentially deliver 10% of the carbon savings required by proposed legislation by 2020 are about 1 Tcf per year—less than the increase seen in 2008 US natural gas production alone. And this could be done partially by using existing natural gas-fired power generating capacity.

The switching from coal-fired generation to gas provides a material option in the short/medium term which has the added benefit of contributing carbon emissions reductions while CCS technologies on both coal and gas are fully demonstrated. However, whether the option is actually realized will ultimately depend on the relationship between coal, gas and carbon prices, which may be different from those illustrated.

*Question 2.* One area of concern about depending on our natural gas resources is that gas has been prone to strong price spikes over the past decade. The most recent one was just in 2008, with prices soaring to about $13 per million BTU. In Dr. Newell’s testimony, he mentioned that the expanded reserves and greater ability to receive LNG shipments could mitigate future price spikes. Please comment on the factors that resulted in the 2008 price spike and other recent spikes. Is the supply situation now such that we will be insulated from such volatility in the future? Are there policy options we could pursue to reduce price volatility?

Answer. Prices for all forms of fossil fuels increased in the first half of 2008. Central Appalachian coal spot prices, for example, rose from about $58/short ton at the beginning of 2008 to $140/ton by August and now stand near $55/ton. (Source: US DOE/EIA) Even as natural gas prices in the US rose in the first half of last year, they remained well below oil prices (when compared on a comparable basis).

To a large extent, these increases were due to a period of strong economic growth—not just in the US, but around the world—that pushed prices for energy and many other commodities to record levels by the middle of 2008. And the recession that has followed has led to lower prices for all forms of fossil fuels as well as many other commodities. So the primary driver of natural gas—and other fossil energy—price increases up to mid-2008 was a strong economy. In the face of strong demand, investment lags and government policies that constrained the ability of producers to respond to higher prices hindered the supply response, resulting in higher prices (through the middle of last year).

As noted in my testimony, US natural gas supply has undergone a quiet revolution in recent years. Technological innovation has allowed resources previously deemed to be "unconventional" to play a larger role, with the result being that US-proved reserves of natural gas over the past decade have increased by 45% at a time when proved reserves of oil have increased by just 7%. So we now have the domestic resource base to grow supply substantially if demand increases—and if investment is permitted to occur.

In addition, natural gas demand in the US has a much more pronounced seasonality to it—which has historically been a key driver of greater natural gas price volatility. For example, looking at the range of demand from month-to-month in 2008, oil consumption varied by 18%, coal by 25%, and natural gas by a massive 87%. This is a key reason why unusually cold weather—or other unexpected disruptions such as hurricanes—can have an out-sized impact on natural gas prices. If natural gas consumption increased for power generation (since power demand tends to peak in the summer for air conditioning, rather than in winter), it would tend to reduce the seasonality in domestic natural gas demand and could therefore help to reduce seasonal price volatility. It would have a smoothing effect.

Any market is uncertain—and we can never insulate ourselves completely from unexpected events that cause price volatility—but we at BP believe that government does have tools to help limit price volatility and to help market participants manage their exposure to unexpected changes in price. First, an expanded diversity of supply options has the potential to improve energy security and reduce price volatility; thus, measures to permit industry access to potential domestic gas resources, while developing those resources in an environmentally sound manner, would help. Similarly, as Energy Information Administration (EIA) Administrator Newell has noted, access to international LNG can help to limit price spikes by allowing US gas consumers access to global suppliers. At the same time, we should encourage US power producers to maintain a diverse set of power-generating facilities, to allow a greater degree of competition between energy sources. Finally, regulators should allow both producers and consumers (including utilities) to manage short-term price risk by hedging in (appropriately regulated) forward markets.

*Question 3.* Reducing the volatility in the price of natural gas is an important goal if we are to lean more heavily on this resource. For producers, independent generators, and utilities to enter into long-term contracts for gas supply would seem to be one way to reduce pricing volatility. Could you describe your willingness to enter into such long-term contracts, and what obstacles may stand in the way of them?

Answer. This question has long involved a chicken and egg discussion. The incorporation of long-term supply contracts in a fuel portfolio can indeed help to mitigate overall volatility, but wholesale market participants are often reluctant to engage in them because of the perceived volatility.

Because natural gas demand is weather-sensitive in both winter and summer, with limited opportunity for on-site storage, it has been, and will likely remain, susceptible to some degree of price volatility. BP and other suppliers do offer hedging and risk-management services, however, to help ensure competitive fuel price certainty. While these options may not eliminate volatility, they can serve to insulate customers from their exposure to it. Innovative gas recovery techniques have significantly expanded the U.S. resource base and hopefully will serve to mitigate these concerns going forward. Nonetheless, the longer the term, the greater the market risk, and potentially the need for additional policy incentives to secure additional market receptivity.

For instance, utility companies often find it prudent to rely more on market-indexed commodity pricing for their customers, since regulatory pass-through of these costs might not otherwise be assured. Another barrier tends to be the increased credit requirements and rating thresholds associated with longer-term transactions.

Another factor contributing to shorter-term transactions is the reliance on fuel for limited peaking needs and power dispatch. Peaking units tend to buy their fuel and transportation capacity on an "as-needed" basis only via interruptible transportation. Longer-term deals often result in the perceived sunk cost of un-used transportation capacity.

*Question 4.* Is it your opinion that the advanced CCS bonus allocations in the Kerry/Boxer bill are enough to jumpstart broad deployment of CCS? I've noticed that only a maximum of 15% of the advance allocations can be given to projects that do not employ coal. Do you think that this will potentially restrict other industrial $CO_2$ emitters from being able to deploy CCS at their facility? Are the CCS allocations enough, in your opinion, to incentivize the gas industry to try and deploy this technology? If not, how would you improve the CCS bonus allowance to open up the field to all industrial stationary source emitters?

Answer. The Kerry/Boxer bill should provide enough financial incentives to help initiate and illustrate the potential of large-scale deployment of CCS. Under the bill, Section 780, "Commercial Deployment of Carbon Capture and Permanent Sequestration Technologies," will provide an average of 90 million allowances (1 allowance = 1 metric ton of carbon dioxide equivalent emissions) from 2014 through 2017 for CCS incentives. Between 2018-2022 this will increase to an average of 240 million allowances. These allowances are in addition to the $1 billion per annum provided by Section 125, "Carbon Capture and Sequestration Demonstration and Deployment." Assuming $20/ton carbon allowance price, this should be sufficient funding for approximately 30 coal-fired projects with CCS and 5-7 gas-fired projects, assuming that 15% of the allowances are provided for gas-fired technologies. This should be enough to prove the CCS concept and spur further efforts to deepen its application in the power sector.

The 15% limitation for the allowance pool under Section 780 will limit the application to natural gas-fired power generation. Ideally, all power sources would compete for funding based on the lowest cost of abatement balanced against the overall cost to electricity consumers. On a carbon abatement cost basis, coal-fired CCS has the potential to lower emissions at lower incremental costs compared to gas-fired CCS ($55/ton vs. $110/ton for coal and gas CCS, respectively) primarily because of much smaller inherent $CO_2$ emissions by natural gas to begin with. However, from an overall cost per kilowatt hour, gas-fired CCS will cost less to the consumer ($95/MWh for coal vs. $81/MWh for gas assuming $2/mmbtu for coal and $6/mmbtu for gas). While the current level of allowances could be sufficient for the gas industry, 5-7 projects, an equal playing field in gas generation will ensure that both coal and gas compete in both abatement costs and overall cost to consumers.

We are encouraged that Section 182, "Advanced Natural Gas Technologies" has been included in the bill. It provides funding for natural gas end-use technologies, and including funding for CCS technology for natural gas-fired power generation.

*Question 5.* All of the natural gas we're discussing here today will come from both conventional and unconventional extraction methods. A major stake of the gas future sits in extracting natural gas from tight gas sands/shales.

There has been some discussion here in Congress that the Safe Drinking Water Act exemption for hydraulic fracturing should be reconsidered. Do you think a repeal of this exemption would dramatically affect the future of natural gas extraction of these unconventional gas sources?

Answer. Repealing the current exemption of hydraulic fracturing from being defined as underground injection under the Safe Drinking Water Act (SDWA) would have a dramatic negative effect on natural gas development in the US. The repeal would result in the permitting requirements of the SDWA being applied to hydraulic fracturing operations which would result in significant delays (up to a year) and preclude the highly efficient drilling/stimulation operations and practices necessary to access and produce unconventional resources, such as shale and tight sand gas, in a cost efficient manner. The increased costs coupled with permitting delay will raise the cost of developing these resources and make much of the unconventional gas resource uneconomic at a natural gas price the economy can afford. All of this will occur in an environment where the country should be using more natural gas to reduce greenhouse gas and other air pollutant emissions.

A more appropriate approach would be for the States, who currently effectively oversee and manage hydraulic fracturing operations, to adopt other State and industry best practices into their programs. These might include:

a. Well construction standards to ensure aquifer protection—including:

- Setting the well bore surface casing below the lowest drinking water aquifer and cementing it back to surface.
- Pressure testing the casing/well head to confirm that there are is no annular communication or leaks.
- Running cement bond logs to confirm that the cement is bonded to the well steel casing and re-cementing any voids.

b. Testing of drinking water wells within a ¼ mile radius of the proposed well before drilling and again after completion (hydraulic fracturing).

c. Using lined pits and steel tanks on the surface to prevent hydraulic fracturing fluids at the surface from contaminating soils or groundwater.

*Question 6a.* What safeguards do you currently undertake in your upstream gas recovery to protect ground and surface water resources during and after utilization of hydraulic fracturing? Do you have any modifications or improvements that you are planning to implement in this area?

Answer. BP employs a variety of methods and practices in our overall operations, and during hydraulic fracturing, to protect soils, groundwater, and the environment. These include:

- Conducting various tests to verify well integrity.
- Where appropriate, conducting routine annular pressure testing to identify any pressure build-up and verify casing and well-head integrity.
- Routinely running and evaluating cement bond logs (test results from the drilling process) to confirm that the cement in the well is properly adhered to the well casing and that the annulus is properly filled.
- Groundwater monitoring
- Protecting wellbores, pipelines and tanks to prevent corrosion of equipment where appropriate.
- Using infrared camera and other optical gas imaging technology to scan pipelines and identify small leaks before they could become big leaks.
- Providing adequate containment for tanks and equipment
- Quickly responding to and cleaning up any spills or leaks which do occur along with determining and fixing the causes.
- Using tanks for produced water handling.
- Using "closed loop" drilling fluid systems where appropriate
- Properly constructing and lining reserve pits used for handling of drilling cuttings and fluids where these are used.
- Injection disposal, in UIC permitted Class 2 wells, of produced water rather than surface discharge.
- Properly handling, treating and disposing of wastes generated during the development and operation of our fields and facilities.

*Question 6b.* In the last few years, BP has focused their company image on being good environmental citizens. As such, have you begun to apply this to your subsurface operations? More specifically, what (if any) technological advancements have you invested in or started to use in your operations, to address the issues of managing or reusing flowback water and the use of non-potable water for hydraulic fracturing fluid?

Answer. Reducing and re-use of both flow-back (hydraulic fracturing) and produced fluids (water) is a priority for BP. Examples of activities underway:

- Reducing the amount of fresh water used during drilling and hydraulic fracturing by using produced water in lieu of fresh water where possible.
- Recycling/re-use of drilling and fracturing fluids.
- Active field testing of on-site water/fluid treatment technologies to allow beneficial reuse of water.
- Piloting advanced technologies to reduce water usage.

*Question 6c.* Additionally, several groups have been discussing the use of "green frac'ing fluids". This would imply that the frac'ing fluids currently being used in the industry are perhaps unsafe to the environment and public health. It has come to my attention that it is required that employees at a site are entitled to know what chemicals are being used in the process of fracturing, but the public is not entitled to the same information (more specifically, material safety data sheets). What are you doing to address these concerns, are you making your chemical data available for public inquiry? Or are you considering a switch to "green frac'ing fluids"? I would hope that with the growing concerns around fresh water availability that the industry, more broadly, would routinely make this information available to the public (at a minimum) and start to look for other "greener" fluids for the gas extraction process.

Answer. BP strongly supports measures to ensure that agencies and medical professionals have timely access to chemical products information to facilitate responses to and potential environmental incidents and medical emergencies, subject to appropriate safeguards for proprietary information consistent with federal laws. Operators presently comply with a range of federal chemical recordkeeping and reporting requirements, including the OSHA Hazard Communication Standard, and requirements under SARA Title III, and CERCLA. These regulations require operators to maintain plans and processes for the safe handling, storage and transportation of chemical products in order to protect employees, the general public and environmental resources. These regulations also contain reporting and disclosure requirements (including maintaining MSDS sheets for chemicals) to make chemical information available in a timely manner to employees, contractors and emergency responders.

Regarding green fracturing fluids, BP will continue to encourage our hydraulic fracturing contractors to reduce the toxicity and volume of the chemicals used. We believe progress has been made in the past with this objective and will continue as we work with our contractors.

RESPONSES OF LAMAR MCKAY TO QUESTIONS FROM SENATOR MURKOWSKI

*Question 1.* You may know that Senator Menendez and I are both on a bill to promote the development of natural gas vehicles. NGV advocates, myself included, have pointed out that natural gas as a transportation fuel reduces carbon emissions, offsets petroleum imports, and provides an economic boost here at home by using natural gas in place of imported petroleum. Given the recent findings concerning the increased availability of natural gas supplies in North America and here in the U.S. should we be doing more to advance the use of natural gas as a transportation fuel?

Answer. BP expects compressed natural gas application in light-duty vehicle service will grow but be limited due to a number of factors. Specifically, the incremental cost of the vehicle relative to conventional cars and hybrids; NGV driving range being only 50-60% of a gasoline vehicle, reduced storage capacity in the vehicle (trunk space) due to use of compressed natural gas tanks, the lack of wide spread natural gas retail distribution infrastructure and the incremental cost of fuelling infrastructure to provide natural gas at the high pressures required for refueling.

For these reasons, natural gas is more suitable for short range fleets, such as buses and delivery vehicles, which can re-fuel at a dedicated natural gas compression and storage facility at a central fleet depot. Short range urban fleets, such as buses and commercial delivery vans, can overcome many of the passenger NGV disadvantages due to this larger scale that enables efficient cost spreading and amortization.

A large compressor and storage system at a depot will benefit from economies of scale resulting in per "gallon" CNG costs that are ~50-60% less expensive than those expected from residential/home units. Because of high vehicle miles traveled, CNG fueled fleets will realize fuel cost savings versus those expected from gasoline or diesel fuel use. However, a significant number of miles (approx. 300,000) must be traveled in order to recoup the infrastructure associated with NGVs.

On an equivalent tail pipe emission basis, NGVs emit 65-70% of the $CO_2$ as a conventional vehicle. However, NGVs also emit fewer tail pipe criteria pollutants such as CO (carbon monoxide), particulates and $NO_X$.

*Question 2.* Currently there are serious regulatory obstacles positioning in front of domestic energy development. Particularly, surface coal mining rules are under serious assault and offshore oil and gas development is facing increasing scrutiny from at least three different federal agencies. Can the panel speak to how we ever get to a point of more natural gas power plants or, for that matter, clean coal if, despite policies encouraging the advancement of these new and exciting power sources, we simply can't access and produce the basic resource?

Answer. Access to domestic energy resources is fundamental to meeting society's energy demands while enhancing the domestic economy, jobs, and energy security. Congress is uniquely positioned to take a leadership position to ensure access to domestic resources remains achievable while ensuring that the appropriate and needed environmental safeguards are in place. While we cannot comment on the challenges that the coal mining industry faces, we do have ideas for actions Congress should take to enhance the ability of American business to access domestic oil and gas resources in a responsible and cost effective manner:

- Maintain exclusion of hydraulic fracturing stimulation from the Safe Drinking Water Act permitting: The ability to artificially stimulate the non traditional fuel reservoirs, which are the bulk of new domestic oil and gas resource potential, through fracture stimulation is critical to production of oil and gas from these resources.
- Open areas excluded from leasing, such as the OCS waters, for additional leasing and potential development.
- Perform regional analysis of rural and high country ozone: Regional analyses of rural and high country ozone, particularly in the Western US, by the EPA will inform sound policy regarding the lowering of the current National Ambient Air Quality standard for ozone.

- Air quality evaluation of offshore development: A comprehensive air quality analysis by the EPA, with the participation of relevant stakeholders, of the potential for offshore development to impact onshore air quality and public health prior to imposing CAA permit and control programs to offshore development.
- Cost ceiling for $CO_2$ reductions: A cost ceiling per metric ton of $CO_2$ equivalent reduction could be used in the economic reasonableness analysis under the Clean Air Act; Prevention of Significant Deterioration (PSD); Best Available Control Technology (BACT) requirements.
- Reform the implementation of the National Environmental Policy Act: Steps can be taken to bring the implementation of the National Environmental Policy Act back to its original purpose of informing decision making and to streamline the analysis process.

*Question 3.* What would be your opinion about a Low Carbon Electricity Standard that would allow electric utilities to use a variety of alternatives to reduce greenhouse gas emissions, including renewables, natural gas, nuclear and hydroelectric?

Answer. BP believes pricing carbon is fundamental and has a preference for an economy-wide cap and trade system that, if equitably designed, would expose all energy sectors to a uniform carbon price. This approach, we believe, will deliver the most certain environmental outcome, at the least cost to the economy. Depending on how they are structured, standards, mandates and obligations are likely to imply a higher carbon price in sectors where they are used than in the rest of the economy, and a higher carbon price for some fossil fuels within those sectors. BP does support transitional standards for emerging low-carbon technologies, like renewables, that have significant potential for future cost reduction and carbon savings, but are not yet commercial-scale. Such standards, and the implied higher carbon price, can be justified in these cases to provide transitional support for innovation and deployment but not permanent support for carbon reduction per se. Carbon reduction should be achieved through an economy-wide carbon price.

*Question 4.* To the extent that deliverability of natural gas to markets has been an issue in the past, should recent improvements in pipeline infrastructure, as well as prospects for additional projects coming online, serve as any comfort to those with concerns about spikes in natural gas prices?

Answer. All facets of the natural gas industry have been actively engaged in mitigating customer price risks. In addition to the producer supply activities mentioned previously, there have been significant pipeline and storage capacity additions in response to the resource additions and infrastructure constraints witnessed in recent years—and these investments are continuing at all levels. Natural gas inventories will hit a new record high before the withdrawal season begins a few days from now. According to the EIA, this level was made possible by recent capacity additions that have brought the total available inventories for the heating season to almost 4 Tcf.

Completion of the eastern leg of the new Rockies Express pipeline in time for this winter will further extend access to less-expensive resources in the intermountain West that were previously out of reach for many. The pending Ruby pipeline will extend those benefits further west into northern California—and these are just two examples of the significant investments that are being made by the pipeline industry to ensure consistent and reliable service to new and existing markets.

From a policy perspective, continuing to provide access to the most economic resources will be a key factor, as will regulatory willingness to consider and accept the initial or periodic premiums associated with any expansion of longer-term supply deals.

*Question 5.* In your written and oral testimony, you appear to have a level of confidence about the U.S. resource base. Can the U.S. continue to be about 90% independent for its natural gas purposes?

Answer. We are confident that the US has the resource base to support much higher production for decades to come. As discussed in an earlier answer, US proved reserves of natural gas have increased by 45% over the past decade—to 238 Tcf—largely due to technological advances that have allowed the industry to develop "unconventional" resources cost-effectively. Based on these same innovations, the Potential Gas Committee earlier this year revised its estimate of the US potential gas resource—resources in addition to the proved reserves mentioned earlier—up by 39%, to 1,836 Tcf.

International natural gas markets also have been rapidly developing. While we support robust efforts to increase domestic production, it also stands to reason that US consumers could benefit by tapping into abundant global resources of natural gas.

*Question 6.* Why do you believe natural gas can play such an important role in mitigating climate change when it is, in reality, still a fossil fuel?

Answer. Natural gas can be a key component in mitigating GHG emissions. Natural gas is the cleanest burning fossil fuel in the energy portfolio; delivering 50% less $CO_2$ than coal per kilowatt hour when used for electrical generation. Increasing the use of natural gas in power generation provides an affordable, efficient, and immediate step towards reducing $CO_2$ emissions from the power generating sector today. Additionally, natural gas powered generation lowers emissions of $NO_X$ by 85%+; virtually eliminates emissions of $SO_X$, and particulate matter; and eliminates mercury emissions and ash waste. These attributes make natural gas a key component of the US energy mix that can help mitigate climate change, especially within the power sector, in the most efficient and cost-effective way.

*Question 7.* We have heard a great deal about how unless the United States passes one of the current cap and trade bills under consideration, China and other nations are going to outpace us in renewable energy development. But China certainly doesn't have any carbon laws on the books. My question is, do we truly require more mandates to drive us to a lower carbon economy?

Answer. Without the appropriate policy mechanisms in place, there is little expectation that the economy will see significant efforts to reduce carbon emissions in China or the US. China does not have comprehensive climate legislation, but, driven by security and economic as well as climate objectives, China has undertaken a number of domestic carbon reduction initiatives, including setting renewable energy and energy intensity reduction targets, and is building institutional capacity for lower carbon technologies.

Existing mandates here in the US, at both state and federal levels, focus mainly on renewable fuels and power, and vehicle efficiency. Renewable standards will help new low-carbon technologies become commercial and compete without support in the future but will make only a small contribution to carbon reduction today. Vehicle efficiency standards are very important by reducing carbon at a relatively low cost. However, the best and least-cost way to kick-start a move to a lower carbon economy is to put a price on carbon—potentially through a well-designed, equitable economy-wide cap and trade system, supplemented by efficiency mandates across a range of demand-side activities that do not fit within a cap and trade market.

RESPONSES OF LAMAR MCKAY TO QUESTIONS FROM SENATOR CANTWELL

*Question 1a.* I think it is very important that we ensure that climate policy doesn't introduce unnecessary volatility into markets for oil and natural gas. We've seen gas prices fluctuate sharply over the past two years, from $5.90 up to $10.82 and then back down to around $3.40 where we are now. I think we all agree that this sort of uncertainty isn't good for energy producers or consumers.

What do modeling results and forecasts tell us about what would actually happen in the real world with regard to fuel mix, energy costs and investment under this kind of price volatility?

Answer. While greater price volatility—that is, greater uncertainty—can impact the investment decisions of both producers and consumers, it's important to note that investments, and therefore, ultimately the fuel mix tend to be based on long-term expectations—and long-term price expectations are considerably less volatile than spot prices. The equipment employed to produce and consume energy tends to be long-lived, and to have long lead-times.

Accordingly, long-term relative price expectations are what really matters. For example, when BP considers investments, we are more concerned with the price of natural gas relative to other, competing energy sources. Both producers and consumers can limit their exposure to short-term price volatility through well-regulated futures markets.

All fossil fuels and many other commodities have seen volatile spot prices in recent years, due in large part to an unusually strong global economy. Central Appalachian coal spot prices, for example, rose from about $58/short ton at the beginning of 2008, to $140/ton by August and now stand near $55/ton. (Source: US DOE/EIA)

*Question 1b.* Could a well-designed price collar mitigate this sort of volatility?

Answer. In principle, BP would prefer to allow markets to operate with minimal constraints to promote efficiency. In practice, especially during the early phase of operation of carbon allowance markets, when uncertainty is greater, measures can be used to reduce price risk of various kinds. However, such measures should be designed to work with the market, rather than against it, and can be seen as addressing three related, but different issues: allowance price level; volatility; and transparency.

Price level.—High carbon prices can provide a powerful incentive for low-carbon investment, innovation and energy conservation. But if there is a concern about carbon prices above a certain level, or the effects of carbon prices on demand and price for conventional fuels, there are several market-compatible means of addressing the concern. For example, the concern can be addressed by making multiple alternative compliance units such as offsets available or by introducing extra compliance units into the market if the allowance price reaches a certain level. If extra units are borrowed from the future or compensated by purchasing international offsets (as in the strategic reserve) the cap does not need to be compromised. Less desirable, because it introduces uncertainty and compromises the environmental goal, the target can actually be lowered (cap raised) if the price goes too high. Or a buy-out price can be used, which sets a firm price cap and raises revenues for government, but this inhibits the market and also risks compromising the cap.

In all cases in which some kind of price cap or buy-out price is employed, it is preferable for it to be set quite high, as a kind of safety valve, or it will effectively become a tax that has high transaction costs, and will reduce the incentive for low carbon investment and innovation and energy conservation.

To guard against allowance prices falling too low, and removing the incentive for obligated parties to invest in carbon reduction activities, a floor price can also be established.

Allowance price controls or allocation mechanisms may also be used to address the competitive disadvantage that occurs when domestic industries are competing with the same industries in countries without a carbon price.

Price volatility.—Price volatility can be addressed by different market instruments, including banking of allowances and limited borrowing of allowances from future years, provided the long-term targets are not eroded. Further mitigation of price volatility is possible by linking emission trading schemes together.

Price transparency can be achieved in several ways, ranging from the regular publication of allowance auction prices to a daily price index for allowances traded via an exchange.

Problems of price level, volatility and transparency can all be reduced by good, fundamental cap and trade system design. This should include:

- Eventually, the widest feasible coverage across the economy
- A cap that starts high and declines slowly, to provide time to adjust
- The creation of a deep and liquid market for allowances, with multiple participants regularly engaged in trading. Note that the free distribution of allowances to entities that are not covered in the cap and trade system accomplish this goal.
- An accurate assessment of emissions from all sectors included in the program to determine the baseline and understand the market scope.
- An accurate assessment of the availability and cost of emission reduction opportunities to reduce the risk of unacceptable/surprise sustained high prices
- Allocation/compliance periods that are set to allow adequate investment lead time for emission reductions to come online.

*Question 2a.* In thinking about alternative approaches to climate change policy, one important consideration is the point of regulation, especially with regard to an emissions cap. Both the House and Senate bills propose downstream caps by regulating thousands of emitting entities.

But an upstream cap for natural gas seems like it could achieve the same broad coverage much more simply, by regulating less than a thousand entities. What is the most efficient point of regulation to achieve broad coverage of fossil carbon for natural gas?

Answer. The optimal point of regulation is the physical point of emission (i.e. where the combustion of the fossil fuel occurs), because information and opportunities to reduce emissions are greatest, and supply chain distortions smallest. Also, combining the economic signal with active participation in the trading scheme will provide the greatest catalyst for action.

However, practicalities and transaction costs currently limit the number of entities that can be directly regulated. If these policy considerations lead to a shift in the point of regulation, it should still be kept as close as possible to the physical point of emission, subject to reducing the number of regulated entities to a manageable level while still preserving a liquid market with multiple participants. Selection of a point of regulation should also limit the potential for double counting or missing fuel borne emissions and not disrupt the supply chain.

Using the example of emissions from the use of oil products (such as gasoline and diesel), this balance point is logically the fuel supplier, providing that liability for the emissions is not attached to the supplier, and the costs of the regulation continue to be borne by the true emitter. Key considerations in this regard will be to ensure that, for example, imported and domestically produced or refined fuels are treated in exactly equivalent ways and that an adequate supply of allowances will be available in the market for the supplier to meet the requirement at a well defined price. Moving the point of regulation any further upstream than is necessary is likely to magnify distortions in the supply chain, distort economic signals to the emitter, reduce incentives and opportunities for carbon abatement, and reduce the number of participants in the market.

For these reasons, BP supports striking a practical balance between downstream and upstream regulation and would not support a move to upstream regulation only.

*Question 2b.* Are there any problems with mixing upstream caps for some fossil fuels and downstream caps for others? Does an upstream cap on all fossil fuels help to promote a consistent, economy-wide carbon price signal necessary to transition to a low-carbon economy?

Answer. The principles described in the previous answer apply economy-wide, so moving the point of regulation further upstream from the physical point of emission than is necessary for any sector is likely to diminish the effectiveness of the overall system. To the extent that commodity fuel prices and competition, both domestic and international, inhibit a clear carbon price signal to the decision making consumer, and upstream cap does not provide incentives for lower carbon decisions.

For these reasons, we see no problem with hybrid downstream and upstream regulation, with the balance struck on pragmatic grounds.

*Question 3a.* With the recent advances in drilling technology in the gas industry, domestic gas reserves shot up by more than 35 percent this year, which of course is terrific news for the gas industry and potentially for our efforts to address climate change by reducing greenhouse gas emissions.

But I'm wondering about the broader environmental implications of the use of technologies such as hydraulic fracturing to produce unconventional shale gas resources. What are the implications of shale gas production for ground water and drinking water quality? How do these environmental risks compare to those of other energy sources?

Answer. Hydraulic fracturing has been done for decades on approximately one million wells in the US with, to my knowledge, no case documented where contamination of groundwater was conclusively linked to hydraulic fracturing operations. In the very few known complaints of groundwater contamination made by individuals, it appears that the contamination occurred due to loss of well integrity from corroded well pipes, spills of chemicals and products at the surface, or leaking surface facilities (pits, tanks, piping and hoses)—unrelated to hydraulic fracturing.

*Question 3b.* Also, from an economic perspective, at what price is shale gas production viable for the industry? Would the price certainty of a carbon price floor be necessary for shale gas to be economic? How do the two prices—the natural gas price and the carbon price—interrelate and affect shale gas production?

Answer. There are a variety of industry, academic and government estimates for the breakeven price for shale gas production depending upon the particular basin (Barnett, Fayetteville, Woodford, Marcellus, etc.). However, most of these ranges are in the $4/mmbtu to $7/mmbtu range, with the average between $4 and $5/mmbtu. However, this is based on today's technology and today's pipeline transport and storage infrastructure. As both technology and infrastructure continue to improve, these breakeven costs could drop over time—similar to the decrease in development and production costs of coal-bed methane and tight sand gas over the last decade.

Given the current view of shale development economics, a carbon price will not be required to make this exciting new source of natural gas available.

Natural gas and carbon price are interrelated to the extent that a carbon price makes natural gas more attractive for power generation vs. coal. It is difficult to place any firm numerical relationships to carbon and gas price and the details of specific policies will affect the overall relationship between the two prices.

*Question 4a.* Since natural gas has the lowest carbon content among fossil fuels, I would expect that a carbon price would not lead to a decline in the natural gas industry. But over the longer term, as the economy decarbonizes, there will be pressure on gas-fired utilities, as with coal-fired ones, to adopt carbon capture and sequestration technologies.

What is your assessment of the feasibility of commercial scale carbon capture and sequestration with natural gas?

Answer. With sustained technology development efforts, commercial scale carbon capture and sequestration for both coal and natural gas could be available for widescale deployment after 2020. It is more expensive, on a dollar per metric ton basis, to capture and sequester carbon from natural gas-fired power than from coal-fired power (primarily due to lower inherent $CO_2$ concentration). However, on a total cost of electricity basis, natural gas CCS should be less expensive than coal with CCS. Both of these factors will play in to the timing of commercial scale deployment of both coal and gas-fired CCS.

*Question 4b.* Are the economics of CCS likely to be comparable for gas and coal consumers?

Answer. It is more expensive, on a dollar per metric ton of $CO_2$ captured basis, to capture carbon from natural gas-fired power than from coal-fired power. However, depending upon coal and gas prices, gas-fired CCS should be less expensive on a total cost of electricity basis. The following table shows the comparison of total electricity costs for gas with CCS and coal with CCS for a variety of gas prices:

| $ per MWh | Natural Gas Prices ($/mmbtu) | | | |
|---|---|---|---|---|
| | $4 | $6 | $8 | $10 |
| Coal w/ CCS ($2/mmbtu cost) | 95 | 95 | 95 | 95 |
| Gas w/ CCS | 67 | 81 | 96 | 110 |

*Question 4c.* Could reimbursements in the form of allowances in excess of the cap for the amount of carbon captured and sequestered make CCS economic? And would this framework treat both coal and natural gas fairly?

Answer. Both the Waxman-Markey and Kerry-Boxer bills allow for a significant amount of domestic and international offsets. Providing credit from this offset pool to CCS projects on the basis of carbon captured and permanently sequestered could help make CCS economic, without increasing the cap for the entire economy. Allowing all CCS projects to compete for these offset credits will provide a level-playing field for CCS incentives.

RESPONSES OF LAMAR MCKAY TO QUESTIONS FROM SENATOR MARK UDALL

*Question 1.* You mentioned that the new gas shale resources would provide a more stable resource than traditional natural gas resources, thereby reducing the volatility in gas prices. Specifically you mentioned that gas shale is a different kind of resource and that geology is less of an issue. Could you please elaborate more on this?

Answer. First, gas shale is known as a "resource play" in contrast to an "exploration play." A resource play carries low geological risk of not finding natural gas. The limiting factor is economics. The application of hydraulic fracturing and horizontal drilling has made shale gas economically viable and now allows the US to tap the enormous potential of the shale basins.

The production volumes from a shale gas well can be higher than a "good" conventional well allowing a quicker response to demand. Evidence of this is the ability of the industry to produce record volumes of gas with fewer rigs. Historically, rig count served as a good indicator of expected gas volumes but the gas shales have changed this dynamic and a new index is being developed taking into account where rigs are drilling.

Finally, many of the basins for shale gas are located near large gas markets or in areas with existing pipeline infrastructure—giving shale gas resources an ability to respond quickly.

*Question 2.* It was mentioned that some coal utilities are already switching over to gas without incentive in place, could you elaborate on this dynamic? Does low gas price and region play any role in some of these changes?

Answer. Through July of this year, net US electricity generation has fallen by 5.4% compared with the same period last year. (Source: US DOE/EIA) Electricity generated by coal has fallen by 13.1%, while electricity generated by natural gas has grown by 1.7%. This has been primarily due to lower natural gas prices relative to coal prices: Through July, average coal prices paid by US power generators rose by 13% compared with the same period last year, while natural gas prices paid by US power generators fell by 52%. (In fact, US natural gas consumption has fallen in other sectors of the economy this year due to the recession, but has increased slightly in power generation.)

As you note, it is important to recognize that both natural gas and coal prices vary widely by region. In the case of natural gas, transportation costs are the key driver of regional price differentials; in the case of coal, both transportation costs and coal quality vary significantly by region.

A final factor to consider when assessing the competition between natural gas and coal in power generation is the efficiency of the respective power plants, which also varies widely.

*Question 3.* Do you believe that a transparent, market price for carbon will help reduce volatility in the natural gas market?

Answer. A robust, economy wide carbon price could help to reduce the volatility of natural gas prices by increasing and stabilizing gas demand for power, the more important drivers of lower volatility will be the game-changing gas reserves picture, significant amount of LNG re-gas capacity (approximately 20% of current US gas demand in next few years will be available) and gas pipeline and storage projects due to come on line in the next few years.

A robust, economy-wide price for carbon should naturally advantage natural gas over coal-fired power generation. In this scenario, natural gas could play a greater role in providing electricity, allowing for different contract structures that could bring volatility in line with that of coal.

RESPONSE OF LAMAR MCKAY TO QUESTION FROM SENATOR LINCOLN

*Question 1.* As you know, several recent studies have projected that our natural gas supply is much larger than previous estimates. For example, the Potential Gas Committee estimates that the U.S. now has a 35% increase in supply estimates from just two years ago, which is enough they say to supply the U.S. market for a century. The Energy Information Agency (EIA) has also predicted a 99-year natural gas supply. I am proud that the Fayetteville Shale in Arkansas is already producing over one billion cubic feet of natural gas per day, while only in its fifth year of development. What role do you believe the improvement in drilling technologies such as horizontal drilling and hydraulic fracturing played in the estimated increase in natural gas supply?

Answer. The use of horizontal drilling and hydraulic fracturing technologies enables the commercial production of natural gas from shale reservoirs. These improvements in drilling and completion technologies have had a substantial effect on the amount of recoverable natural gas in the US. Shale gas alone is responsible for approximately 40% of the increase in US natural gas reserves. Hydraulic fracture stimulation of the other non-conventional gas resources (tight sands and coal beds) is also necessary to enable commercial natural gas production. Collectively, these non-conventional resource plays represent most of the potential future domestic gas supply for the US. This supply is only accessible utilizing techniques such as horizontal drilling and hydraulic fracturing.

RESPONSES OF LAMAR MCKAY TO QUESTIONS FROM SENATOR SESSIONS

*Question 1.* If the transportation sector moves towards natural gas, how will this affect the price of natural gas, the United States' crude oil imports, greenhouse gas emissions, other energy sectors that currently use this energy source?

Answer. BP believes that the US has the domestic resource base to support much higher levels of domestic production over the next several decades. How that incremental supply will be used within the US economy is best sorted by the domestic market, which has proved efficient in directing gas supply to end-uses that have the highest value-added.

To date, transportation has not been a large consumer of natural gas. In 2008, about one-tenth of one percent of US natural gas consumption was for vehicle transportation. To reduce US oil imports by 1 million b/d (net imports were 11.1 Mb/d in 2008) would require just over 5 bcf/d of natural gas—or nearly 2 Tcf per year—just under 10% of 2008 consumption.

By converting one half of America's commercial and municipal fleets (e.g. delivery services, municipal utility services, buses and corporate fleets) to CNG, the US could reduce oil imports by 500,000 b/d. This would require an additional 2.5 bcf/day, or 1 Tcf/year, or 5% of current gas production. It would reduce US emissions by 0.5%, or 30 Mt/year.

*Question 2.* What incentives or regulatory changes are necessary to effectively enhance the use of natural gas over coal, diesel, or gasoline? And the cost associated with the switch?

Answer. BP believes that with a level playing field and uniform carbon price for all fossil fuels, natural gas will be able to compete effectively in the power sector. In lieu of a level playing field, BP believes that targeted incentives to retire the least efficient coal-fired generation are needed. With a level playing field for carbon, we believe the market will choose gas to replace the retired capacity because it offers the lowest-cost option. However, to incentivize the conversion to natural gas via the bonus of award of carbon allowances would cost approximately $5bn-$10bn over three years, assuming a $20/ton carbon price. This conversion has the potential to reduce emissions by 700 million tons between 2012 and 2020, or $15/ton.

In the transport sector, tax incentives for the conversion of vehicle fleets (buses, long-haul trucks) could support conversion to natural gas over gasoline. Targeted investments in infrastructure for natural gas transport may also be required to support the switch.

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RESPONSES OF EDWARD STONES TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* I continue to hear concerns that placing a price on carbon through climate legislation will result in significant fuel-switching, or what has been referred to as a "dash to gas". The implication is that fuel-switching will result in sharp increases in electricity prices. Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation? What is the likelihood of a large-scale transition to natural gas, and what time frame could that potentially occur on?

Answer. The price of carbon at which using natural gas to generate electricity becomes comparable in cost to that from coal generation depends on three factors:

1) The price of natural gas
2) The price of coal
3) Capital costs required to maintain or build new coal power plants relative to natural gas fired generation.

Although many projections assume increases in natural gas prices, few project changes in coal prices. This is despite the fact that the most likely coal power plants to be displaced by new gas fired generation facilities use Appalachian coal, which has traded between $42/ST and $142/ST over the last eighteen months. We believe that coal fired power generation has been displaced by gas generation for most of the period since August, 2008. Said another way, during this period, the cost of carbon at which using natural gas to generate electricity was comparable or better than that from coal was zero.

The cost of generating electricity from coal is driven to a large extent by the capital costs required to build and maintain highly capital intensive coal fired power generation plants. Dow believes the carbon cost which will force construction of gas fired generation plants in place of coal fired power plants is between $10/MT of $CO_2$ and $25/MT of $CO_2$ over the period 2015-2020. Testimony by Xcel Energy suggested the cost of carbon at which gas fired generation displaces coal is zero today, at least for the marginal plants, as they have shut down three coal facilities (producing more than a Gigawatt of electricity) and replaced them with natural gas fired generation. Similarly, Calpine states: "Compared to many other generation sources, natural gas power plants can be permitted quickly and they have a much smaller footprint. In addition, they can be built more quickly and cost less to build on a per megawatt of capacity basis."

Given widely proclaimed attractive economics for natural gas fired power generation, high capital costs and uncertain costs for carbon mitigation from coal fired generation, we believe there is a high likelihood for a continued large scale transition to natural gas in the power generation sector. If 80 coal fired power plants were shut down (as advocated by other witnesses), approximately 1.8 Trillion Cubic Feet (TCF)/yr of additional gas demand would be created. This is but one third of the increase in gas for power consumption expected over the period 2008-2020, however. Natural gas burned for electric generation grew from 4.3 TCF in 1996 to 6.8 TCF in 2008 (a change of 2.5 TCF/yr), a cumulative growth rate of 4.84)/01yr. Over the same period, power generation from coal increased from 1,795,000 GWH in 1996 to 1,994,000 GWH in 2008, which would require the equivalent of almost 1.4 TCF/yr more gas for power generation to displace. Factoring all three likely causes for increased gas demand for power generation (i.e. 5.8 TCF/yr), increases in gas use for power could exceed 28% of the current natural gas supply by 2020.

Effect of Shutting 80 Coal Fired Power Plants

| | |
|---|---|
| 30 | GW of Power Capacity |
| 365 | Days/year |
| 24 | Hours/day |
| 262,800 | GWH Power Produced per Year |
| 1,000 | MWh/GWh |
| 262,800,000 | MWh |
| 7 | MMBTU/MWh |
| 1,839,600,000 | MMBTU |
| 1,000 | MMCF/MMBTU |
| 1,839,600 | MMCF |
| 1,000 | MMCF/BCF |
| 1,840 | BCF / Year |

Effect of Displacing Coal Build from 1996 - 2008 With Gas

| | |
|---|---|
| 1,994,000 | 2008 Power Generated from Coal (GWH) |
| 1,795,000 | 1996 Power Generated from Coal (GWH) |
| 199,000 | Change in Power Production Per Year |
| 1,000 | MWh/GWh |
| 199,000,000 | MWh |
| 7 | MMBTU/MWh |
| 1,393,000,000 | MMBTU |
| 1,000 | MMCF/MMBTU |
| 1,393,000 | MMCF |
| 1,000 | MMCF/BCF |
| 1,393 | BCF / Year |

Effect of Continued Gas Fired Power Generation Trend

| | |
|---|---|
| 6,833 | 2008 Gas for Power Generation Use (BCF/YR) |
| 4,312 | 1996 Gas for Power Generation Use (BCF/YR) |
| 2,521 | Change (BCF/YR) |

Total Change in Gas Use For Power Generation by 2020

| | |
|---|---|
| 1,840 | Change From Retiring Old Coal (BCF/ YR) |
| 1,393 | Avoided New Coal Build (BCF/YR) |
| 2,521 | Change From Power Generation Trend (BCF/YR) |
| 5,754 | Total Change (BCF/YR) |

Total Change in Gas Supply

| | |
|---|---|
| 20,377 | Total Supply 2008 (BCF) |
| 18,854 | Total Supply 1996 (BCF) |
| 1,523 | Change (BCF) |
| 28% | Total Projected Change (2020 vs 2008) as a Fraction of Gas Supply |
| 8% | Total Gas Supply Change (2008 vs 1996) as a fraction of Gas Supply |

(Power data from: http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm. Production data from: http://tonto.eia.doe.gov/dnav/ng/hist/n9070us2a.htm)

*Question 2a.* One area of concern about depending on our natural gas resources is that gas has been prone to strong price spikes over the past decade. The most recent one was just in 2008, with prices soaring to about $13 per million BTU. In Dr. Newell's testimony, he mentioned that the expanded reserves and greater ability to receive LNG shipments could mitigate future price spikes.

Please comment on the factors that resulted in the 2008 price spike and other recent spikes.

Answer. Since 1997, there have been five natural gas price spikes, each caused by lags between price signals and production response. The lag between changes in drilling and changes in production has been remarkably consistent, at about six months. This is the time required to fund drilling programs, site wells, schedule crews, drill and tie new wells into the grid. When the gas market is over supplied, producers respond by reducing drilling, leading to a reduction in supply. The reduction in supply eventually leads to a price spike as demand increases.

*Question 2b.* Is the supply situation now such that we will be insulated from such volatility in the future?

Answer. No. In 2009, as in 2002, 2004 and 2006, drilling has declined dramatically as price has fallen. After each trough, natural gas demand and price rise once the economy turns, signaling the production community to increase drilling. During the lag between the pricing signals and new production, only one mechanism exists to rebalance supply and demand: demand destruction brought about by price spikes.

Some claim that the lags between price signals and drilling response expected for shale gas will be shorter due to the reduced drilling scope of shale type wells. However the latest available data show natural gas production peaked with the same delay from the start of drilling reductions as in other cycles. Clearly, the new shale gas production was unable to mitigate the 2008 spike, which occurred less than 18 months ago. LNG may mitigate very high gas price spikes, but only if US gas prices are higher than elsewhere in the world. During the 2008 spike, LNG prices in Asia and Europe were $1-2/mmbtu higher than in the US. As a result, LNG imports in 2008 (during the spike) were less than 50% of those in 2007 (when gas prices were more normal). The inherent lags between changes in drilling and production created natural gas spikes over the last ten years, and will continue to do so after this and every trough.

Finally, weather shocks (be they hurricane damage, very cold winters, or very warm summers) will continue, and will continue to stress test our energy markets. Growth in supply is important, but the best chance for reductions in volatility lie in building a flexible demand sector (see below).

*Question 2c.* Are there policy options we could pursue to reduce price volatility?

Answer. When it comes to natural gas and climate policy, Dow favors policies that will avoid the demand destruction that occurs in natural gas price spikes, along with policies that will allow the US to use all of its low-carbon resources. Such policies will maintain industrial competitiveness.

Dow also believes that the US needs a sustainable energy policy. Climate change is an important component of a sustainable energy policy, but it is not the only part. We have developed a list of specific recommendations that, if implemented, would form the basis of a sustainable energy policy.

First, aggressively promote the cleanest, most reliable, and most affordable "fuel"—energy efficiency. Energy efficiency is the consensus solution to advance energy security, reduce GHGs, and keep energy prices low. It is often underappreciated for its value. Of particular importance is improving the energy efficiency of buildings. Buildings are responsible for 38% of $CO_2$ emissions, 40% of energy use, and 70% of electricity use. A combination of federal incentives and local energy efficiency building codes is needed.

Second, increase and diversify domestic energy supplies, including natural gas. Nuclear energy and clean coal with carbon capture and sequestration (CCS) should be part of the solution, as should solar, wind, biomass, and other renewable energy sources. We believe a price on carbon will advantage natural gas, and further incentives would only dangerously increase inelastic demand. Therefore, Congress should not provide free allowances or other incentive payments for the purpose of promoting fuel switching from coal to natural gas in the power sector.

An estimated 86 billion barrels of oil and 420 trillion cubic feet of natural gas are not being tapped. History suggests that the more we explore, the more we know, and the more our estimates of resources grow. EIA has said that "the estimate of ultimate recovery increases over time for most reservoirs, the vast majority of fields, all regions, all countries, and the world." And we have the technology that allows us to produce both oil and natural gas in an entirely safe and environmentally sound manner. Any new fossil energy resources must be used as efficiently as possible.

One way to maximize the transformational value of increased oil and gas production is to share the royalty revenue with coastal states and use the federal share to help fund research, development and deployment in such areas as energy efficiency and renewable energy. Production of oil and gas on federal lands has brought billions of dollars of revenue into state and federal treasuries. Expanding access could put billions of additional dollars into state and federal budgets.

Third, act boldly on technology policy through long-term tax credits, and increased investment in R&D and deployment. These are costly but necessary to provide the certainty that the business community needs to spur investment. We didn't respond to Sputnik with half-measures. We can't afford to respond to our energy challenges with half-measures, either.

Fourth, employ market mechanisms to address climate change in the most cost-effective way. There is a need for direct action now to slow, stop, and then reverse the growth of greenhouse gas levels in the atmosphere. We concur with the principles and recommendations of the US Climate Action Partnership (USCAP), of which Dow is a proud member. And we recognize that concerted action is needed by the rest of the world to adequately address this global problem. Particular attention must be paid to cost containment and the availability of offsets (both domestic and international). Also, climate policy should not penalize the use of fossil energy as feedstock materials to make products that are not intended to be used as a fuel.

To minimize the downsides of natural gas price volatility, Congress should adopt policies to increase the number of elastic users of natural gas, and consider policies to increase US supply of natural gas. A resilient natural gas market would empower US manufacturers to create high value jobs as they did from 1983-1996, during which period US industrial gas use grew at an average rate of 2.7%/yr.

Finally, the country must advance all low carbon emitting energy sources and ensure the availability of offsets under any cap and trade program. EIA modeling of the House-passed energy and climate bill indicate how to avoid a "dash to gas" in the power sector under a cap and trade program. New power plants using nuclear, renewable, and coal with associated carbon capture and sequestration (CCS) must be developed and deployed in a timeframe consistent with emission reduction requirements. Otherwise, covered entities will respond by increasing their use of offsets, if available and by turning to increased use of natural gas in lieu of coal-fired generation.

*Question 3.* Is it your opinion that the advanced CCS bonus allocations in the Kerry/Boxer bill are enough to jumpstart broad deployment of CCS? I've noticed that only a maximum of 15% of the advance allocations can be given to projects that do not employ coal. Do you think that this will potentially restrict other industrial $CO_2$ emitters from being able to deploy CCS at their facility? Are the CCS allocations enough, in your opinion, to incentivize the gas industry to try and deploy this technology? If not, how would you improve the CCS bonus allowance to open up the field to all industrial stationary source emitters?

Answer. Dow supports the recommendations of the US Climate Action Partnership (USCAP) with respect to advancing CCS, which are listed in the USCAP Blueprint for Action (www.us-cap.org). Although many of these recommendations focus on CCS at coal-fired power plants, other recommendations cover CCS at industrial facilities. USCAP has not, however, developed a recommendation regarding the allocation of CCS bonus allowances between coal-fired power producers and other stationary sources.

*Question 4.* You mentioned that you utilize natural gas as a chemical feedstock Will the shift towards a more gas intensive energy economy impact the availability of the resource for yours and others chemical industries? If there is a large impact to your business structure, is there another viable feedstock alternative for your chemical business?

Answer. There are currently no other viable feedstock materials commercially available at the scale that our company and industry requires. Dow is exploring alternative feedstocks via both biochemical and thermochemical (gasification) routes. For example, Dow plans to operate a world scale polyethylene plant in Brazil using ethylene feedstock derived from sugar cane ethanol. In exploring possibilities for this feedstock in the US we found that the domestic sugar cane crop and more limited growing season can not support such a plant. Dow testified before this committee in 2007 that coal gasification could produce feedstocks at sufficient scale to substitute for natural gas liquids. However, the capital cost of such technology is prohibitive. A $19 Billion US chemical industry trade surplus in 1997 became a deficit from 2001-2007 as resources became economically unavailable for industry. Over this period, nearly 135,000 jobs were lost in our industry. If the economy becomes more gas intensive without a carefully considered plan to foster a resilient supply and demand balance, spikes will continue, our business structure will require relocation to other areas, and US manufacturing will continue to deteriorate. The key to continued manufacturing competitiveness is a well executed, comprehensive energy policy which addresses supply and demand, energy security, and environmental objectives.

*Question 5.* All of the natural gas we're discussing here today will come from both conventional and unconventional extraction methods. A major stake of the gas future sits in extracting natural gas from tight gas sands/shales.

There has been some discussion here in Congress that the Safe Drinking Water Act exemption for hydraulic fracturing should be reconsidered. Do you think a repeal of this exemption would dramatically affect the future of natural gas extraction of these unconventional gas sources?

Answer. We support the environmentally sound production of domestic supplies of natural gas. However, history has shown that Congress has a proclivity for legislating policies that increase natural gas demand while at the same time constraining access to adequate supply. We are not convinced that all of the natural gas that has been identified as recoverable can overcome local resistance and other obstacles to full production of this valuable resource. This is a major reason why we believe that proposals to legislate incentives for increased natural gas demand are misguided. The key to continued manufacturing competitiveness is a well executed, comprehensive energy policy which addresses supply and demand, energy security, and environmental objectives.

RESPONSES OF EDWARD STONES TO QUESTIONS FROM SENATOR MURKOWSKI

*Question 1.* You may know that Senator Mendendez and I are both on a bill to promote the development of natural gas vehicles. NGV advocates, myself included, have pointed out that natural gas as a transportation fuel reduces carbon emissions, offsets petroleum imports, and provides an economic boost here at home by using natural gas in place of imported petroleum. Given the recent findings concerning the increased availability of natural gas supplies in North America and here in the U.S. should we be doing more to advance the use of natural gas as a transportation fuel?

Answer. History has shown that consumption of transportation fuels is largely unresponsive to price inputs. As a result, the consumption of natural gas for vehicles will be largely unaffected when prices spike—potentially exacerbating shortage conditions. The key to continued manufacturing competitiveness is a well executed, comprehensive energy policy which addresses supply and demand, energy security, and environmental objectives.

Dow believes there are other more prudent approaches to reduce our dependence on foreign sources of transportation fuel while reducing GHG emissions. For example, a combination of more efficient use of gasoline engines (higher fuel economy), and electrification of the vehicle fleet would be a better plan. If we built a smart electric grid which could optimize charging plug-in electric vehicles when power was available from base-load power (i.e. new clean coal or nuclear) or could take advantage of the wind/solar power if available, then plug-in vehicles could greatly reduce the reliance on oil while simultaneously reducing the volatility of power prices. Dow is applying its long history in electrochemistry in support of the development of an advanced automotive battery manufacturing infrastructure in the U.S. Dow and its Dow Kokam joint venture are beneficiaries of federal and state incentives to help develop this new industry. We would in effect, build an interruptible source of energy which could store solar/wind power in a usable form while not creating a huge need for additional peaking power. The key is the development of the advanced battery systems, a smart grid and the increased base-load power from coal and nuclear. In this scenario, we should also increase home energy efficiency, and by so doing would free up base-load power for plug-in hybrids.

*Question 2.* Currently there are serious regulatory obstacles positioning in front of domestic energy development. Particularly, surface coal mining rules are under serious assault and offshore oil and gas development is facing increasing scrutiny from at least three different federal agencies. Can the panel speak to how we ever get to a point of more natural gas power plants or for that matter, clean coal if, despite policies encouraging the advancement of these new and exciting power sources, we simply can't access and produce the basic resource?

Answer. It is important to note that the share of new electricity generation capacity from natural gas is growing. It is also true that CCS technologies are being developed and moving toward commercialization. A policy that imposes a price on carbon would hasten these trends.

History has shown that Congress has a proclivity for legislating policies that increase natural gas demand whil at the same time constraining access to adequate supply. We are not convinced that all of the natural gas that has been identified as recoverable can overcome local resistance and other obstacles to full production of this valuable resource. This a major reason why we believe that proposals to legislate incentives for increased natural gas demand are misguided.

Nonetheless, Dow believes it is important for the US to enhance its energy security by increasing the diversity and supply of all domestic energy sources. With respect to oil and gas exploration in the Outer Continental Shelf, Dow believes Congress can impact the domestic energy supply through these actions:

- Congress should not re-impose the moratoria on offshore drilling, but create a statutory construct under which drilling can go forward in a safe and effective manner.
- Any offshore energy access policy should be flexible enough to assure that coastal views are protected and that access is provided in areas expected to offer the greatest prospect for productive oil and gas wells. It makes no sense to establish a 50-mile ban that closes off a huge natural gas held 35 miles from shore.
- States should share in the revenue from offshore energy production. Given the current fiscal strain on state budgets, offshore oil and gas revenue sharing can be of enormous benefit to state economies if used prudently.
- The granting of states the right to opt-in to offshore drilling should be explored. This must be balanced against the national energy security imperative and the fact that the energy off our shores is federal land and the resource belongs to all of the American people
- The federal share of royalty and bonus bid revenues should be dedicated to promoting energy efficiency, renewable energy and other low-carbon technology development.

*Question 3.* What would be your opinion about a Low Carbon Electricity Standard that would allow electric utilities to use a variety of alternatives to reduce greenhouse gas emissions, including renewables, natural gas, nuclear and hydroelectric?

Answer. If Congress imposes a federal portfolio standard on electricity utilities, then the standard should emphasize energy efficiency, which is the quickest, cheapest and often the easiest way to improve the U.S. energy situation. Therefore, any low-carbon electricity standard should allow energy efficiency to meet a significant share of the target/goal, and that the energy efficiency share should be beyond business as usual".

*Questions 4 and 5a.* To the extent that deliverability of natural gas to markets has been an issue in the past, should recent improvements in pipeline infrastructure, as well as prospects for additional projects coming online, serve as any comfort to those with concerns about spikes in natural gas prices? I am sensitive to the concept of our domestic industries losing global competitive advantage under a climate bill so I want to get a sense of how your realities play with the facts we're hearing about supply.

Answer. In general, infrastructure limitations are not the source of spikes which affect the manufacturing industry. In the short term, improved pipeline infrastructure within the lower 48 states may help mitigate price disparities caused by regional shortages for gas, especially in Northeast consuming markets. They will do little to offset the cyclical nature of the gas market, however, which is fundamentally inherent. Since 1997, there have been five natural gas price spikes across all US markets, each caused by lags between price signals and production response. The lag between changes in drilling and changes in production has been remarkably consistent, at about six months. This is the time required to fund drilling programs, site wells, schedule crews, drill and tie new wells into the grid. When the gas market is over supplied, producers respond by reducing drilling, leading to a reduction in supply. The reduction in supply eventually leads to a price spike as demand increases.

In the longer term, projects such as the Alaska Pipeline would provide a more robust energy supply to the United States, and as such, would help reduce concerns about natural gas spikes. Dow would support tangible action to bring this project on line.

*Question 5b.* Do you have reason to disagree with any of the increased natural gas supply figures cited by the witnesses today?

Answer. We believe that all sources of supply for the North American market are important, and that trends in the more traditional sources of natural gas, which constitute 83% of 2008 consumption, bear increased scrutiny.

While we acknowledge that production of shale gas looks encouraging today, other plays have looked highly encouraging only to disappoint later. In 2008, EIA data show that gas produced from shale supplies less than 10% of total consumption. We share the concerns expressed in Dr. Newell's testimony:

More recently, some have raised concerns about whether shale can continue to deliver relatively low-cost supply to domestic customers. Concerns expressed relate to the relative newness of the large-scale application of horizontal drilling and hydraulic fracturing technologies to shales. Shales in different parts of the country are not the same, and differences in techniques and technology are actively being developed by the industry. This creates uncertainty in assessing the overall resource base. Horizontal wells with fracturing to stimulate the flow of natural gas in shale also tend to deliver their greatest volumes in the first few years. This raises questions as to the ability of the industry to continue to drill productively over the long term, which is necessary to sustain higher, or even constant, levels of production.

Long term, the natural gas supply for the United States will depend on domestic conventional and unconventional production, and imports. Although production from unconventional sources such as shales has been increasing, gas recoveries from some conventional sources have been declining dramatically. Marketed production from the Gulf of Mexico has been declining since 2001, and now is close to half the level in those years.

Similarly, natural gas imports from Canada have declined dramatically, and YTD (through August) 2009 imports are down 15% from those in the same period in 2007. Imports are likely to decline further in 2010 and beyond as drilling in Canada has fallen dramatically and consumption for oil sands converters increases. Similarly, over the same period, LNG imports are down 50%.

While we agree recent developments in shale gas are encouraging, we believe caution is warranted for the overall supply picture.

*Question 6.* You have cited in your testimony serious concerns with the increased use of natural gas for power generation. Does that concern extend to increased use of natural gas as a backup source to renewable fuels? Does it extend to increased use of natural gas as a vehicle fuel?

Answer. If electric power generation by renewable fuels with natural gas as a back up reduces the overall demand for natural gas, we are supportive of its use there.

Dow is concerned about the implementation of plans to use natural gas as a vehicle fuel. Poorly executed plans might greatly increase demand for natural gas and could, in the absence of increased supply, drive up prices for manufacturers. As discussed in the testimony, price spikes due to sudden increases in demand due to weather events already occur. The use of natural gas as a vehicle fuel would likely further amplify natural gas volatility during weather events like cold winters, hot summers or supply disruptions unless concerted effort were made to increase the flexibility of demand from other applications (such as the implementation of smart grid technologies or the development of industrial demand based on competitive and stable natural gas pricing). A comprehensive policy approach must consider all sources of demand in the context of both normal and extreme situations to ensure the market is resilient to both supply and demand shocks.

It is possible that successful development of advanced energy storage technology could provide a superior long term alternative to natural gas as a backup source for renewables. Dow envisions its work on advanced automotive batteries to include applications for stationary energy storage.

*Question 7.* I understand that under the Kerry/Boxer bill, owners of natural gas liquids, or NGLs like propane and butane extracted from natural gas, are required to buy allowances as though 100% of those NGLs are actually combusted. In practice, however, I'm told about 50% of those liquids are used by petrochemical companies in the manufacture of things like plastics where they aren't burned, so no emissions ever occur. I also understand that petrochemical companies would get compensated in the form of free allowances for liquids used in these processes where there is no combustion. Is my understanding accurate?

Answer. The Kerry Boxer bill defines a covered entity to be any stationary source that produces a natural gas liquid (ethane, propane, butane, isobutene, and natural gasoline), the combustion of which would emit 25,000 tons or more of carbon dioxide equivalent. These NGLs can and are used as a feedstock material by the chemical industry, and many of these NGLs are also used to produce transportation fuel. We do not know the percentages, but it varies by NGL. (For example, ethane is used almost entirely as a feedstock material for chemical companies). The Kerry Boxer bill provides compensatory allowances for the non-emissive use of NGLs as a feedstock, if allowances or offset credits were retired for the GHGs that would have been emitted from their combustion.

*Question 8.* If Congress were to enact legislation that somehow promoted natural gas use, and natural gas was available at a consistent $6-8 dollar per MMBtu range, how would that impact your competitiveness?

Answer. US petrochemical competitiveness depends on a multitude of factors, such as the relative cost of energy (including crude oil, coal, etc.), the relative cost of new facility construction, the strength of the economy in each global area, and the extent to which local industry is protected by local government policies. In general, we believe that if crude were in the $75-$100 range, and natural gas were available at a consistent $6-$8 dollar per MMBtu range, US petrochemical facilities could be globally competitive. We believe the best way to achieve consistent natural gas pricing is to adopt a comprehensive policy approach which considers all sources of demand in the context of both normal and extreme situations to ensure the market is resilient to both supply and demand shocks. This presumes there are enough price-sensitive (demand-elastic) natural gas users to assure minimal volatility. We cannot effectively plan major long term petrochemical investments in the U.S. if the historical pattern of natural gas price spikes persists.

RESPONSES OF EDWARD STONES TO QUESTIONS FROM SENATOR SESSIONS

*Question 1.* If the transportation sector moves towards natural gas, how will this affect the price of natural gas, the United States' crude oil imports, greenhouse gas emissions, other energy sectors that currently use this energy source.

Answer. History has shown that consumption of transportation fuels is largely unresponsive to price inputs. As a result, the consumption of natural gas for vehicles will be largely unaffected when prices spike—potentially exacerbating shortage conditions.

As part of the a comprehensive plan, Dow believes there are other more prudent approaches to reduce our dependence on foreign sources of transportation fuel while reducing GHG emissions. For example, a combination of more efficient use of gasoline engines (higher fuel economy), and electrification of the vehicle fleet would be a better plan. If we built a smart electric grid which could optimize charging plug-in electric vehicles when power was available from base-load power (i.e. new clean coal or nuclear) or could take advantage of the wind/solar power if available, then plug-in vehicles could greatly reduce the reliance on oil while simultaneously reducing the volatility of power prices. Dow is applying its long history in electrochemistry in support of the development of an advanced automotive batter manufacturing infrastructure in the U.S. Dow and its Dow Kokam joint venture are beneficiaries of federal and state incentives to help develop this new industry. We would in effect, build an interruptible source of energy which could store solar/wind power in a usable form while not creating a huge need for additional peaking power. The key is the development of the advanced battery systems, a smart grid and the increased base-load power from coal and nuclear. In this scenario, we should also increase home energy efficiency, and by so doing would free up base-load power for plug-in hybrids.

*Question 2.* What incentives or regulatory changes are necessary to effectively enhance the use of natural gas over coal, diesel, or gasoline? And the cost associated with the switch?

Answer. We believe that current market incentives already support the transition of demand historically supplied by coal and diesel to natural gas, as evidenced by the shut down of coal fired generation plants described in the testimony of Xcel Energy. A price on carbon will also accelerate fuel switching to natural gas. As a result, we believe no further incentives are necessary.

The cost of too rapid a transition to the use of natural gas in power generation and transportation (a "dash to gas") would dramatically increased prices and volatility for natural gas and demand destruction in the industrial sector, as was seen in the period 1997-2007, when nearly 4 million US manufacturing jobs were lost.

RESPONSES OF EDWARD STONES TO QUESTIONS FROM SENATOR CANTWELL

*Question 1.* I think it is very important that we ensure that climate policy doesn't introduce unnecessary volatility into markets for oil and natural gas. We've seen gas prices fluctuate sharply over the past two years, from $5.90 up to $10.82 and then back down to around $3.40 where we are now. I think we all agree that this sort of uncertainty isn't good for energy producers or consumers.

What do modeling results and forecasts tell us about what would actually happen in the real world with regard to fuel mix, energy costs and investment under this kind of price volatility?

Could a well-designed price collar mitigate this sort of volatility?

Answer. Pricing volatility increases the uncertainty of investment returns, and therefore, the cost of borrowing money and the required returns for energy projects. As a result, total investment decreases, fewer projects are built, and average costs for energy increase as demand continues to grow.

The volatility cycle is made worse because projects with lower capital costs (i.e. natural gas fired power generation) but higher variable costs are favored over those with higher capital costs (coal and/or nuclear based generation) and lower variable costs. Over time, only gas fired generation is built, worsening the impact of weather events on the power market, further increasing the volatility in both natural gas and power markets. Consumers pay the price through more volatile and higher cost power and natural gas.

Price collars can help reduce volatility, but they introduce significant additional costs to energy consumers which would be reduced if volatility were more muted, and are available to only the largest users. Since natural gas is a market in which daily prices are below the mean 80% of the time, the strike price of purchased calls (which protect consumers) are further from the underlying price than the strike price of sold puts (which potentially obligate consumers to pay higher than market prices). For example, on November 9th 2009, one can purchase a $7/mmbtu call for 2010 and sell a $4.50/mmbtu put to fund it. The underlying price for this period is $5.46/mmbtu, so the call is about $1.50/mmbtu from the expected price, whereas the put is less than one dollar lower. The costs to consumers are even higher if one considers the shape of the forward curve, which is higher over time (i.e. in contango). Natural gas for delivery on the morning of November 10th cost $3.78/mmbtu at Henry Hub. So, a consumer would incur the obligation to purchase gas at a price $0.75/mmbtu higher than current cost to protect against prices rising to almost double current costs ($7/mmbtu). Executing hedges in financial markets requires a trained staff to manage volatile energy market positions, significant accounting expertise to comply with complicated Financial Accounting Standard Board (FASB) requirements, and large amounts of capital to cover margin requirements.

Large consumers can, and do, incur these costs to reduce volatility to levels at which they are able to stay in business. Smaller industrial, commercial and residential consumers are unable to participate in the financial energy markets. The best solution is to obviate the need for these "Band Aid" management tools by establishing a comprehensive energy policy which addresses both supply and demand for energy in both the short and long term, and has a sufficient number of price-sensitive consumers. If both energy supply and demand become resilient to shocks, volatility will be reduced. Financial instruments will become more affordable for those who need them and unnecessary for most.

*Question 2a.* In thinking about alternative approaches to climate change policy, one important consideration is the point of regulation, especially with regard to an emissions cap. Both the House and Senate bills propose downstream caps by regulating thousands of emitting entities

But an upstream cap for natural gas seems like it could achieve the same broad coverage much more simply, by regulating less than a thousand entities. What is the most efficient point of regulation to achieve broad coverage of fossil carbon for natural gas?

Answer. Policymakers should consider several factors when determining the point of regulation for a program to control GHG emissions, including coverage, administrative complexity, equity, and efficiency. Dow supports the recommendations of the US Climate Action Partnership (USCAP) regarding the point of regulation for an economy-wide cap and trade program: on transportation fuel providers, on Local Distribution Companies (LDCs) for natural gas, and on large stationary sources.

*Question 2b.* Are there any problems with mixing upstream caps for some fossil fuels and downstream caps for others? Does an upstream cap on all fossil fuels help to promote a consistent, economy-wide carbon price signal necessary to transition to a low-carbon economy?

Answer. Dow supports the USCAP recommendation of a hybrid (i.e., combination of upstream and downstream) point of regulation for fossil energy, as described previously. However, an "upstream" point of regulation runs the risk of covering fossil energy that is used in non-emissive ways, such as a feedstock for chemical production. Dow believes there should not be a price signal for fossil energy used as a feedstock material, where the carbon is embedded in a manufactured product not intended for use as a fuel. Any such price signal could be avoided by either (1) an exemption from coverage or (2) the awarding of compensatory allowances.

*Question 3a.* With the recent advances in drilling technology in the gas industry, domestic gas reserves shot up by more than 35 percent this year, which of course is terrific news for the gas industry and potentially for our efforts to address climate change by reducing greenhouse gas emissions.

But I'm wondering about the broader environmental implications of the use of technologies such as hydraulic fracturing to produce unconventional shale gas resources. What are the implications of shale gas production for ground water and drinking water quality? How do these environmental risks compare to those of other energy sources?

Answer. We support the environmentally sound production of domestic supplies of natural gas. We defer to others with more expertise on the environmental impacts of hydraulic fracturing to answers these questions."

*Question 3b.* Also, from an economic perspective, at what price is shale gas production viable for the industry? Would the price certainty of a carbon price floor be necessary for shale gas to be economic? How do the two prices—the natural gas price and the carbon price—interrelate and affect shale gas production?

Answer. We believe the current natural gas market dynamics suggest that many shale gas resources are economic at the current (or slightly higher) pricing levels. We are concerned that proposed policies will require higher cost increments be produced, and expect volatility to continue. In either case, we do not believe that a carbon price floor is necessary for shale gas resources to be economic.

*Question 4a.* Since natural gas has the lowest carbon content among fossil fuels, I would expect that a carbon price would not lead to a decline in the natural gas industry. But over the longer term, as the economy decarbonizes, there will be pressure on gas-fired utilities, as with coal-fired ones, to adopt carbon capture and sequestration technologies.

What is your assessment of the feasibility of commercial scale carbon capture and sequestration with natural gas?

Answer. It is as feasible as commercial scale carbon capture and sequestration for coal. Capture will be more difficult due to the lower concentration of $CO_2$ (3-4% vs. 11-12% for coal fired plants) in the effluent from natural gas power plant turbines. However, capture for natural gas will not have to deal with some of the impurities (fly ash, Hg, sulfur, etc.) associated with pulverized coal. Once capture is accomplished downstream unit operations will be similar for natural gas.

*Question 4b.* Are the economics of CCS likely to be comparable for gas and coal consumers?

Answer. Yes they are comparable. See H. de Conninck, Cost and Economics of $CO_2$ Capture & Storage, ECN & Princeton, Near Zero Emissions Coal workshop, Beijing 2006.

*Question 4c.* Could reimbursements in the form of allowances in excess of the cap for the amount of carbon captured and sequestered make CCS economic? And would this framework treat both coal and natural gas fairly?

Answer. Dow supports the USCAP recommendations for deployment of CCS. These recommendations call for a wide variety of policies. It is unclear what is meant by “allowances in excess of the cap”. If it means “offset”, then Dow believes it will not be sufficient to drive rapid, cost-effective deployment of CCS as there are other barriers to CCS (see USCAP recommendations) that must also be addressed.

*Question 5a.* With an upstream cap on fossil carbon, industries that use fossil fuels as feedstocks will see an increase in input prices. Does it make sense to reimburse these industries for the fossil carbon that they embed into their products and prevent from emission into the atmosphere?

Answer. YES.

*Question 5b.* Do these reimbursements in the form of allowances in excess of the cap make sense?

Answer. Yes it makes sense in that the net effect (of covering feedstock fossil energy and providing compensatory allowances) should be the same as not covering feedstock fossil energy and not providing compensatory allowances.

RESPONSE OF EDWARD STONES TO QUESTION FROM SENATOR LINCOLN

*Question 1.* Mr. Stones, in your testimony you state that natural gas price spikes have contributed to manufacturing job losses, including a significant reduction in jobs related to the U.S. fertilizer production capacity. How do you believe that the fertilizer industry, and other industries that use natural gas as a feedstock, will respond to potential price increases in natural gas?

Answer. Raising the price of energy for energy-intensive, trade-exposed manufacturers will hurt their ability to compete against manufacturers in countries that do not have policies to control GHG emissions. History has shown that when faced with high and volatile domestic process, these industries shut down and/or move to countries with lower energy and feedstock costs. Dow is an example, wherein high US natural gas prices in this decade have resulted in our decision to preferentially invest in projects in Brazil, China, Kuwait, Saudi Arabia and Libya. However, if the projections of abundant U.S. natural gas are accurate and the gas is not forced into inelastic uses such as power generation and transportation, we can envision the U.S. once again as a preferred location for world scale petrochemical manufacturing investment.

Dow believes that any climate policy that puts a price on carbon will need to prevent carbon leakage by energy-intensive, trade-exposed (EITE) manufacturers. We support a set aside of sufficient allowances for EITE manufacturers until there is a globally level playing field. Ultimately, the solution is to garner an international effort by all major-emitting countries to reduce GHG emissions.

RESPONSES OF RICHARD NEWELL TO QUESTIONS FROM SENATOR BINGAMAN

*Question 1.* I continue to hear concerns that placing a price on carbon through climate legislation will result in significant fuel-switching, or what has been referred to as a "dash to gas". The implication is that fuel-switching will result in sharp increases in electricity prices. Could you please give us a sense of at what carbon price using natural gas to generate electricity becomes comparable in cost to coal generation? What is the likelihood of a large-scale transition to natural gas, and what timeframe could that potentially occur on?

Answer. In our analysis of H.R. 2454, we found that in most cases the major compliance options were the use of international offsets and increased investment in low-emitting electricity generating technologies such as nuclear, fossil with carbon capture and storage (CCS) and biomass. However, we did see a large increase in projected natural gas use in cases where these offsets and low-emitting electricity generation are either unavailable or very costly.

The attractiveness of natural gas versus coal as a fuel for electricity generation depends heavily on the level of future natural gas prices and the price of greenhouse gas emission allowances. If natural gas prices were approximately $5 per million Btu it would make sense to dispatch an existing natural gas combined cycle plant before an existing coal plant when the greenhouse gas allowance price reached a little over $30 per metric ton of $CO_2$. However, this crossover point rises to around $60 with $7 natural gas prices and to around $100 with $10 natural gas prices. In the Reference Case in our analysis of H.R. 2454, natural gas prices to electricity generators are just over $7 per million Btu in 2020 and just over $8.30 per million Btu in 2030 (2007 dollars).

Under market and policy conditions that favor displacement of generation from existing coal-fired plants to gas-fired generation, a transition could occur quite rapidly, given the potential to increase the supply of natural gas from unconventional resources, including shale resources. Existing natural gas combined-cycle power plants can be operated at higher utilizations rates. Experience in the first seven years of this decade, when nearly 142 GW of new natural gas combined cycle capacity was added in the United States, also suggests an ability to quickly add significant amounts of new gas-fired capacity.

*Question 2.* One area of concern about depending on our natural gas resources is that gas has been prone to strong price spikes over the past decade. The most recent one was just in 2008, with prices soaring to about $13 per million BTU. In Dr. Newell's testimony, he mentioned that the expanded reserves and greater ability to receive LNG shipments could mitigate future price spikes. Please comment on the factors that resulted in the 2008 price spike and other recent spikes. Is the supply situation now such that we will be insulated from such volatility in the future? Are there policy options we could pursue to reduce price volatility?

Answer. The Henry Hub natural gas spot price peaked at a monthly average of $12.69 per million Btu in June 2008, an increase of over $5 from the average of $7.35 in June 2007. Over the last 10 years similar price spikes occurred in October 2005 because of hurricanes Rita and Katrina, and in December 2000 and February 2003 because of very cold weather combined with lower-than-normal natural gas inventories.

Physical fundamentals that contributed to higher natural gas prices during the first half of 2008 included relative inventories, high consumption, and uncertainty about future supply growth. End-of-winter (March 31) natural gas working inventory in 2008 was 2.1 percent below the 5-year (2003-07) average for that time, 22 percent below the end-of-March level in 2007, and the lowest winter-exit level recorded since 2004. Weekly natural gas inventories remained below their corresponding 5-year average levels until natural gas consumption began to fall in August 2008. A large increase in natural gas consumption in the electric power sector, which was 18 percent above the 5-year average during the first half of 2008, was driven in part by the surge in coal spot prices, which more than doubled between January and July 2008. While the supply response to lower inventories and higher consumption over this period is clear in retrospect, there was tremendous uncertainty about the supply potential at the time-particularly for domestic production. Although EIA expected domestic natural gas production to increase in 2008, the extent of the growth in supply was initially underestimated.

As noted in the Federal Regulatory Commission (FERC) 2008 State of the Markets report, a review of natural gas markets in 2008 is not complete without an analysis of financial market developments. According to FERC, the two key financial fundamental drivers of natural gas prices during the first half of 2008 were the large influx of passive investments into commodities and technical trading strategies based on trading around the prevailing market momentum. As EIA has noted in response to earlier inquiries from Congress, the rapid increase in natural gas prices during the first half of 2008 paralleled movements in the prices for a wide range of commodities including crude oil, corn, and metals. EIA's Energy and Financial Markets Initiative, launched in September 2009, builds upon EIA's traditional coverage of physical fundamentals, such as energy consumption, production, inventories, spare production capacity, and geopolitical risks, to also assess other influences such as speculation, hedging, investment and exchange rates, as we seek to fully understand energy price movements.

The natural gas supply situation today is noticeably different from that of early 2008. Natural gas inventories at the start of the 2009-2010 winter season were at record levels. Improved technology and increased efficiency have enhanced the supply capabilities and lowered the marginal costs for production from shale, tight gas, and coal-bed methane formations located in States such as Texas, Louisiana, Oklahoma, Pennsylvania, and Wyoming. Furthermore, while U.S. liquefied natural gas (LNG) import capacity utilization was below 10 percent in 2008, LNG imports represent an additional option for increased natural gas supplies to the United States, particularly as new LNG supply projects are brought into service around the world. While periods of significant price volatility cannot be ruled out due to uncertainties associated with weather and economic growth, sustained periods of high prices should be mitigated by the enhanced capability to develop domestic supply. Price volatility would tend to be lowered by increasing the responsiveness of supply and demand to prices changes, and by dampening forces that may amplify price changes.

*Question 3.* Is it your opinion that the advanced CCS bonus allocations in the Kerry/Boxer bill are enough to jumpstart broad deployment of CCS? I've noticed that only a maximum of 15% of the advance allocations can be given to projects that do not employ coal. Do you think that this will potentially restrict other industrial $CO_2$ emitters from being able to deploy CCS at their facility? Are the CCS allocations enough, in your opinion, to incentivize the gas industry to try and deploy this technology? If not, how would you improve the CCS bonus allowance to open up the field to all industrial stationary source emitters?

Answer. We have not analyzed the CCS provisions of the Kerry/Boxer bill and how these may accelerate or expand carbon capture at industrial facilities and power plants.

A broad deployment of CCS at certain industrial facilities is included in the AEO 2009 reference case to supply $CO_2$ for enhanced oil recovery (EOR) operations to produce crude oil. This activity occurs under current laws and regulations without the enactment of the proposed legislation, and is motivated by the current state of the technology and the projected level of crude oil prices. The cost of carbon capture is dependent on the particular industrial process being employed, distance from suitable EOR opportunities, quantity of $CO_2$ produced, capability and willingness to invest in an existing or planned industrial facility and other factors. We are aware that a few such projects are already in operation or are being considered by industry, but it remain unclear as to how bonus allocations might incentivize additional projects.

In our analysis of H.R. 2454, the American Clean Energy and Security Act of 2009, we did find that the CCS provisions could lead to significant investment in that technology by 2030. Approximately 69,000 megawatts of new coal plants with CCS were projected to be built by 2030 in our Basic Case. However, the cost and pace of development of commercial-scale CCS projects are very uncertain. As a result, alternative cases which assumed higher costs and/or limited availability of the technology through 2030 were also prepared. The total additions of coal plants with CCS through 2030 varied from 2,000 megawatts to 69,000 megawatts in the main cases in our report. While some new natural gas plants with CCS were also added in our analysis of H.R. 2454, the additions were generally much smaller than those for coal-based plants. In our modeling and analysis of that legislation, we did not explicitly represent the CCS credit to industrial sources, but did find that its provisions also lead to an increase in $CO_2$ from industrial sources for enhanced oil recovery.

*Question 4a.* ICF: ANGA Climate Policy Analysis: Has EIA had an opportunity to review the ICF International analysis of the policies proposed by ANGA ( America's Natural Gas Alliance—large independents) Can you provide comments for the hearing record?

*Question 4b.* LNG Terminals/ Gas prices: Eight terminals (7 import and 1 export) are already operating on the East Coast, Gulf Coast, Puerto Rico and Alaska (export). Also a terminal in Mexico serving California markets. There are about 40 LNG terminals that are either before FERC or being discussed by the LNG industry for North America. What is EIA's estimate of how many LNG terminals will be in operation by 2030. If domestic gas prices spike in the future, under what conditions can LNG imports act as a safety valve to moderate prices?

Answer. 4a. EIA has seen a summary presentation of the ANGA analysis, which does not provide sufficient detail to comment, particularly regarding their ANGA Gas Supply Case. EIA would need more information and would have to conduct its own analyses of the proposed policy scenarios to provide a basis for commentary on the reasonableness of the results.

Answer. 4b. The LNG capacity existing and under construction is more than adequate to handle EIA's projected LNG import levels through 2030. Our projections suggest that LNG terminal capacity will not be fully utilized as a "baseload" source of natural gas supply. Rather, imports of LNG are expected to vary with conditions in the global LNG market. So far, LNG import increases have not coincided with U.S. gas price increases, but rather with events elsewhere in the world. There may be future circumstances, however, where relatively high United States gas prices induce additional LNG volumes.

*Question 5.* All of the natural gas we're discussing here today will come from both conventional and unconventional extraction methods. A major stake of the gas future sits in extracting natural gas from tight gas sands/shales.

There has been some discussion here in Congress that the Safe Drinking Water Act exemption for hydraulic fracturing should be reconsidered. Do you think a repeal of this exemption would dramatically affect the future of natural gas extraction of these unconventional gas sources?

Answer. Virtually all natural gas production from unconventional resources, and a significant amount of production from conventional resources, relies on the application of hydraulic fracturing techniques. The impact of a repeal of the Safe Water Drinking Act (SWDA) exemption for hydraulic fracturing would depend largely on the specific provisions of that repeal and any subsequent regulatory action that might be taken.

*Question 6.* To your knowledge, are there any reliable "life-cycle analyses" of greenhouse gas emissions from current and anticipated future natural gas development in the United States? By "life-cycle analyses" I mean GHG emissions from all sources that accompany the exploration, development (ex., diesel exhaust from compressor stations), and production (ex., fugitive methane emissions from production activities) of natural gas resources, as well as the combustion of nature gas in boilers and other uses.

Answer. In 2002, a study entitled "Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis," was prepared by Paul J. Meier at the University of Wisconsin. This study takes into consideration the factors you mention above. Based on that study, when only combustion is taken into account, natural gas generation has 50 percent of the GHG emissions of coal. When the full life cycle is taken into consideration, natural gas generation has 60 percent of the emissions of coal. However, while EIA has not reviewed this study in detail, it appears that the results do not fully account for the thermal efficiency advantage (lower heat rate) of natural gas combined cycle generators relative to existing coal plants.

*Question 7.* A recent published analysis of the life-cycle greenhouse gas emissions of the natural gas industry indicates that, "The natural gas supply chain is the second largest source of greenhouse gas emissions in the U.S., generating around 132 million tons of $CO_2$ equivalents annually." (EPA "Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2002," Office of Global Warming, 2004, quoted in Jaramillo, et al., "Comparative Life Cycle Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation," 2007) Has EIA performed any similar analyses of life-cycle GHG emissions from the development and use of natural gas as compared to coal? If so, please share such analyses with the Committee.

Answer. EIA has not conducted a formal life-cycle analysis of greenhouse gas emissions from natural gas. However, the latest EIA and EPA data do not appear to support the quote cited in your question. For example, according to EIA's 2007 greenhouse gas (GHG) emissions inventory, total U.S. greenhouse gas emissions in 2007 were 7,282.4 million metric tons of carbon dioxide equivalent ($MMTCO_2e$). Total carbon dioxide emissions from combustion of fossil fuels were 5,990.9 MMT in 2007, with oil, coal and natural gas accounting for 2,579.9 MMT, 2,162.4 MMT, 1,237.0 MMT, respectively. According to EPA, emissions from the natural gas supply chain encompassing production processing, transportation, and distribution but excluding end-use consumption were 133,4 $MMTCO_2e$ in 2007. The natural gas supply chain excluding combustion is clearly a much smaller GHG emissions source than combustion of any of the three fossil fuels. By way of comparison, EPA reports that non-combustion emissions from coal mining were 57.6 $MMTCO_2e$ in 2007, all of which consisted of methane. That estimate does not include emissions from the transportation of coal. In 2007, coal was roughly 40 percent of total freight rail ton-miles in the United States. Using this share to allocate a portion of total freight rail fuel use to coal, coal transport by rail is estimated to account for an additional 17.5 MMT of carbon dioxide emissions, for a total of at east 75.1 MMT.

RESPONSES OF RICHARD NEWELL TO QUESTIONS FROM SENATOR MURKOWSKI

*Question 1.* You may know that Senator Menendez and I are both on a bill to promote the development of natural gas vehicles. NGV advocates, myself included, have pointed out that natural gas as a transportation fuel reduces carbon emissions, offsets petroleum imports, and provides an economic boost here at home by using natural gas in place of imported petroleum. Given the recent findings concerning the increased availability of natural gas supplies in North America and here in the U.S. should we be doing more to advance the use of natural gas as a transportation fuel?

Answer. The EIA does not advocate policy. However, our prior analysis has shown that market forces alone would not be sufficient to increase natural gas use in the transportation sector. For light-duty vehicles, impediments to increased market penetration include a lack of natural gas vehicle (NGV) offerings by vehicle manufacturers, less driving range, less cargo capacity, higher vehicle costs, and an actual and perceived lack of refueling infrastructure. While natural gas use has increased significantly in transit buses, success in other heavy truck applications has been limited due to the reasons stated above. Incentives that reduce the net cost of NGVs or NGV refueling infrastructure to potential purchasers would tend to increase the rate of NGV penetration.

*Question 2.* Currently there are serious regulatory obstacles positioning in front of domestic energy development. Particularly, surface coal mining rules are under serious assault and offshore oil and gas development is facing increasing scrutiny from at least three different federal agencies. Can the panel speak to how we ever get to a point of more natural gas power plants or., for that matter, clean coal if, despite policies encouraging the advancement of these new and exciting power sources, we simply can't access and produce the basic resource?

Answer. While EIA takes no position on the appropriate regulatory treatment for approving the development of natural gas and coal resources, in EIA's projections both of these fuels play an important role in energy markets in the Nation for many years. In 2008, coal accounted for 49 percent and natural gas accounted for 21 percent of total electricity generation. Despite growth in the use of other fuels, coal and natural gas accounted for 84 percent of the increase in electricity generation between 1990 and 2008. Analysis of specific proposed limitations would be required to assess their possible impacts.

*Question 3.* What would be your opinion about a Low Carbon Electricity Standard that would allow electric utilities to use a variety of alternatives to reduce greenhouse gas emissions, including renewables, natural gas, nuclear and hydroelectric?

Answer. Without a specific proposal it is difficult to speculate on possible impact. A low-carbon electricity standard, like a greenhouse gas cap-and-trade program or carbon tax, would provide an incentive to electricity producers to increase their use of low-to zero-emitting technologies. However, an output-based low-carbon electricity standard might not provide as large an incentive to electricity consumers to invest in energy efficiency because it would generally lead to a smaller increase in electricity prices than would a comparable greenhouse gas cap-and-trade program or carbon tax.

*Question 4.* To the extent that deliverability of natural gas to markets has been an issue in the past, should recent improvements in pipeline infrastructure, as well as prospects for additional projects coming online, serve as any comfort to those with concerns about spikes in natural gas prices?

Answer. Natural gas price spikes occur for a number of reasons, one of which involves limitations imposed by pipeline infrastructure. Pipeline-induced price spikes are generally the result of insufficient capacity into a region experiencing particularly cold temperatures. Pipeline constraints tend to raise prices at the receiving end and lower them at the supply source to enable markets to balance.

EIA estimates that natural gas pipeline capacity additions totaled approximately 45 billion cubic feet per day (Bcf/d) in 2008, roughly triple the amount of capacity added in 2007 and the greatest amount of pipeline construction activity in more than 10 years. While EIA expects another sizeable increase in pipeline capacity in 2009, it likely will be smaller than the increase recorded in 2008. Recent natural gas pipeline expansion has created enhanced connectivity between regions that have historically been net sellers, producing more than they consume, with those that have been net buyers of natural gas. For example, the Rockies Express (REX) pipeline, which provides 1.8 Bcf/d of transport service between Wyoming and Ohio, now offers a crucial outlet for previously constrained production in Wyoming, Colorado and Utah. As pipeline infrastructure has expanded and bottlenecks have been removed, regional price differentials (known as "basis spreads") have narrowed and in some eases prices have been reduced.

However, despite the robust increase in pipeline capacity in recent years, temporary periods may persist when demand exceeds available supply in some regions due to local limitations in the pipeline network. This is particularly relevant for the Northeast, where peak winter heating demand can reach 30 Bcfld on extremely cold days (Northeast natural gas consumption averaged 10.9 Bcf/d during the summer of 2008). While pipeline infrastructure is extensive in the Northeast, and capacity additions continue, the regional network remains vulnerable to constraints that result in high prices when demand temporarily surges during the coldest periods in winter.

RESPONSES OF RICHARD NEWELL TO QUESTIONS FROM SENATOR SESSIONS

*Question 1.* If the transportation sector moves towards natural gas, how will this affect the price of natural gas, the United States' crude oil imports, greenhouse gas emissions, other energy sectors that currently use this energy source?

Answer. Any increase in natural gas demand would be expected to increase natural gas prices. Since increased natural gas use in transportation would likely displace petroleum, which currently provides 96 percent of all energy used for transportation in the United States, imports of petroleum would be apt to decrease. Since natural gas has a lower carbon content per unit of energy than oil, the direct effect would be to reduce greenhouse gas emissions in the transportation sector.

Recent experience suggests that the electric power sector would be the most responsive to changes to natural gas prices, potentially inducing an increased use of coal, nuclear, as well as renewable sources. As such, the potential impact on greenhouse gas emissions in the electric power sector is hard to assess without a clearer definition of market and/or policy changes.

*Question 2.* What incentives or regulatory changes are necessary to effectively enhance the use of natural gas over coal, diesel, or gasoline? And the cost associated with the switch?

Answer. Key impediments to significant increases in natural gas use in the transportation sector are the lack of refueling infrastructure, the higher cost of natural gas vehicles (NGVs), limited vehicle offerings by manufacturers, reduced driving range, and reduced cargo capacity. Incentives that reduce the net cost of NGVs or NGV refueling infrastructure to potential purchasers would tend to increase the rate of penetration of natural gas into the transportation sector.

EIA's previous analyses have shown that placing an implicit or explicit value on carbon dioxide emissions tends to dissuade the use of coal in the electric sector. However, such policies do not necessarily increase the amount of generation fueled by natural gas in the long term given the combination of a projected reduction in total electricity consumption and the possibility of increased supply from non-fossil generation sources such as nuclear and renewables. Energy and Natural Resources.

*Question 3.* Could you please explain in further detail why the increase in natural gas and oil production off the Outer Continental Shelf would have no impact on the price of these commodities?

Answer. The increase in natural gas and oil production would likely have a small impact on the price of these commodities. The fact that the production change for both crude oil and natural gas is modest and gradually introduced to the market over a 20-year period limits the price impact. For crude oil, the main factor is that the market is global and one for which the projected increase of 0.54 million barrels per day in production by 2030 from OCS areas that were under moratoria until late 2008 represents a 0.5 percent increase in projected global world oil supply. According to EIA analysis included in the *Annual Energy Outlook 2009 (AE02009)* this amount of additional supply would result in about a $1.33 decline in the world oil price, from $131.76 per barrel to $130.43 per barrel (in 2007 dollars). Crude oil producers could also react to this level of increase by delaying the production of other fields that are similar in size around the world, which would lessen the price impact.

For natural gas, the 0.6 trillion cubic feet increase in OCS production expected by 2030 in EIA's *AE02009* analysis represents a 2.6 percent increase in projected domestic gas production, resulting in a decline in that year's projected price of $0.21 per thousand cubic feet (Mcf), from $8.61 per Mcf to $8.40 per Mcf (in 2007 dollars).

RESPONSES OF RICHARD NEWELL TO QUESTIONS FROM SENATOR CANTWELL

*Question 1.* I think it is very important that we ensure that climate policy doesn't introduce unnecessary volatility into markets for oil and natural gas. We've seen gas prices fluctuate sharply over the past two years, from $5.90 up to $10.82 and then back down to around $3.40 where we are now. I think we all agree that this sort of uncertainty isn't good for energy producers or consumers.

- What do modeling results and forecasts tell us about what would actually happen in the real world with regard to fuel mix, energy costs and investment under this kind of price volatility?
- Could a well-designed price collar mitigate this sort of volatility?

Answer. Price volatility has the effect of inducing uncertainty in producer and end-user investments in long-lived capital assets. In EIA's analysis of H.R. 2454, it is assumed that allowance prices will rise smoothly at the rate of return that investors would require. Our analysis does not address the volatility in allowance prices that might occur in the actual market. A well designed price collar could dampen the volatility in prices that might otherwise occur.

*Question 2.* In thinking about alternative approaches to climate change policy, one important consideration is the point of regulation, especially with regard to an emissions cap. Both the House and Senate bills propose downstream caps by regulating thousands of emitting entities.

- But an upstream cap for natural gas seems like it could achieve the same broad coverage much more simply, by regulating less than a thousand entities. What is the most efficient point of regulation to achieve broad coverage of fossil carbon for natural gas?
- Are there any problems with mixing upstream caps for some fossil fuels and downstream caps for others? Does an upstream cap on all fossil fuels help to promote a consistent, economy-wide carbon price signal necessary to transition to a low-carbon economy?

Answer. An important characteristic of any cap-and-trade system is how comprehensively it covers all sources of emissions. The point of regulation decision is generally made to ensure comprehensive coverage while also minimizing the number of reporting entities and the burden placed on them. For natural gas this can be difficult because natural gas can take so many paths between production wells and the end-users. Any single point of regulation—i.e., wellhead, re-gasification plants, processing plants, pipelines, or local distribution companies—would not be comprehensive because some portion of the natural gas consumed does not pass through each point. As a result, comprehensive coverage of natural-gas-related greenhouse gas emissions may require a mix of regulatory points.

*Question 3.* With the recent advances in drilling technology in the gas industry, domestic gas reserves shot up by more than 35 percent this year, which of course is terrific news for the gas industry and potentially for our efforts to address climate change by reducing greenhouse gas emissions.

- But I'm wondering about the broader environmental implications of the use of technologies such as hydraulic fracturing to produce unconventional shale gas resources. What are the implications of shale gas production for ground water and drinking water quality? How do these environmental risks compare to those of other energy sources?
- Also, from an economic perspective, at what price is shale gas production viable for the industry? Would the price certainty of a carbon price floor be necessary for shale gas to be economic? How do the two prices—the natural gas price and the carbon price—interrelate and affect shale gas production?

Answer. In June of 2009, the Potential Gas Committee (PGC) estimated that, as of the end of 2008, the total natural gas resource base of the United States was 2,074 trillion cubic feet (Tcf)—35 percent more than the PGC had estimated as recently as 2006. EIA has reported that end-of-year proved reserves of natural gas not only covered production, but increased 13 percent in 2007 and a further 3 percent in 2008, largely as a result of the recognition of shale gas resources. Proved reserves are a relatively small subset of the ultimately recoverable resource base. They are those volumes of natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Technically recoverable resources are less certain, can be uneconomic, and include estimates of undiscovered volumes.

Extraction and use of any energy source involves local environmental concerns. For natural gas from shale, these concerns have centered primarily on water.

Observers have raised several water issues related to hydraulic fracturing:

- fracturing fluids might enter ground water and fresh water aquifers from a well bore during the hydraulic fracturing operation itself;
- waste water might enter ground water because of improper treatment and release of fluids that return up the well bore after the treatment; and
- the volume of water drawn for the treatment might stress an area's resources, or the returned waste water overwhelm local water treatment capabilities.

Leakage directly from the fractured shale into groundwater is unlikely. The major shale gas plays range in depth from 5,000 feet to 13,000 feet. Most fresh water aquifers lie at much shallower depths—typically, less than 1,000 feet. It is unlikely that hydraulic fracturing of shale would force fracturing fluids through thousands of feet of rock up into a fresh water aquifer.

Leakage is possible if a well's integrity were compromised through a variety of mechanisms, including casing leaks, tubing leaks, insufficient cementing, or surface casing set too shallow, in which case fluids could circulate up the outside of the casing and into an aquifer (or other groundwater formations). Operators can minimize these risks through inspection and testing of the well and downhole equipment before high-pressure pumping of the fracturing treatment begins. Under current law, State and local authorities manage the likelihood of such incidents through regulation and enforcement of well construction, including the casing and cementing program.

After operators finish a fracturing job on a well, some of the injected fluid flows back to the surface. This returned fluid, though mainly water and sand, includes small amounts of added chemicals (typically less than 1 percent of the total volume) and can include contaminants leached from the shale formation. Operators can address wastewater problems in several ways: by treating and recycling produced fracturing fluids for use in other fracturing treatments, by injecting this wastewater into deep underground disposal wells, or by sufficiently treating the wastewater making it suitable for release back into the natural environment. Where central treatment or disposal facilities do not have the capacity to deal with large volumes, operators can and do use mobile treatment and recycling systems. Nonetheless, surface spills are possible through careless handling of materials and equipment, poorly trained personnel, and poorly maintained equipment. Operators generally have an incentive to avoid such spills, which can be costly.

With regard to the second part of the question, development of natural gas from shales through horizontal drilling and hydraulic fracturing is still a relatively new technological development, and each shale play in the United States has different individual characteristics. Few shale plays (other than the Barnett in Texas) have seen substantial development, so the price at which shale development will be economically viable in a given shale play is extremely difficult to assess with any degree of confidence.

That said, prevailing prices in 2009, which dropped at the Henry Hub in Louisiana below $5 per million British thermal units (MMBtu) early in the year and averaged only about $4, did have significant effects on drilling although they did not impact shale plays to the same degree. Our most recent review of the available literature regarding breakeven costs for major U.S. natural gas shale plays shows a range from the relatively lower-cost Haynesville play (about $3 to a little over $4 per MMBtu) to the relatively high-cost Woodford shale (a little over $4 to about $7 per MMBtu). The well-developed Barnett play, and the Fayetteville play, range from about $4 to about $5 per MMBtu and the Marcellus play in the Northeast is at a little below $4 per MMbtu. These estimates, collated from Deutsche Bank, Ross Smith Energy Group, Bentek Energy Consulting, and Range Resources do not necessarily reflect the same assumptions about ultimately recoverable reserves, upfront capital cost, or return on investment. Furthermore, financial factors such as hedging could allow producers to lock in a rate of return and maintain production activities even if prices fall.

From a technology-application perspective, as a play develops, costs tend to decline and well performance tends to increase as companies figure out what works and what doesn't in that particular play. This would suggest a lower economically viable price. On the other hand, the initial wells reported in the literature will tend to be drilled on the best prospects or in the best areas, and so the gas price required for economic viability could ultimately be higher for the average well in the play. There often is a significant economic difference between the core and non-core areas of any natural gas play.

Shale gas price and carbon prices are likely to be interrelated to the extent that natural gas can be used in combined-cycle power plants, which benefit from improved efficiency and reduced $CO_2$ emissions when compared to coal-fired power plants. Significant carbon prices are likely to discourage the use of coal for electric power generation. The availability of domestic shale gas resources, combined with significant carbon prices, could encourage the use of natural gas as a substitute for coal, especially if renewables, nuclear power, carbon capture and sequestration, and offsets are either too costly or otherwise unavailable for use to comply with a cap and trade program.

*Question 4.* Since natural gas has the lowest carbon content among fossil fuels, I would expect that a carbon price would not lead to a decline in the natural gas industry. But over the longer term, as the economy decarbonizes, there will be pressure on gas-fired utilities, as with coal-fired ones, to adopt carbon capture and sequestration technologies.

- What is your assessment of the feasibility of commercial scale carbon capture and sequestration with natural gas?
- Are the economics of CCS likely to be comparable for gas and coal consumers?
- Could reimbursements in the form of allowances in excess of the cap for the amount of carbon captured and sequestered make CCS economic? And would this framework treat both coal and natural gas fairly?

Answer. In our analysis of H.R. 2454, we found that in most cases the major compliance options were the use of international offsets and increased investment in low-or zero-emitting electricity generating technologies like nuclear, fossil with carbon capture and storage (CCS), and biomass. However, if these options were less available than expected we did see a large increase in natural gas use. The reason that we did not project a large increase in natural gas use in most analysis cases is that it generally takes a fairly significant greenhouse gas allowance price to make that attractive, and other options can become economical at a lower allowance price. The attractiveness of natural gas versus coal depends heavily on what happens to future natural gas prices. We find that if natural gas prices were approximately $5 per million Btu it would make sense to dispatch a natural gas combined-cycle plant before a coal plant when the greenhouse gas allowance price reached a little over $30 per metric ton of $CO_2$. However, this crossover point rises to around $60 with $7 natural gas prices and to around $100 with $10 natural gas prices. In the Reference Case in our analysis of H.R. 2454, natural gas prices to electricity generators are just over $7.00 per million Btu in 2020 and just over $8.30 per million Btu in 2030 (2007 dollars).

While we have not analyzed the CCS provisions of the Kerry/Boxer bill, in our analysis of the H.R. 2454 we did find that the CCS provisions could lead to significant investment in the technology by 2030. Approximately 69,000 megawatts of new coal plants with CCS were projected to be built by 2030 in our Basic Case. However, the cost and pace of development of commercial scale CCS projects are very uncertain. As a result, alternative cases which assumed higher costs and/or limited availability of the technology through 2030 were also prepared. The total additions of coal plants with CCS through 2030 varied from 2,000 megawatts to 69,000 megawatts in the main cases in our report. While some new natural gas plants with CCS were also added in our analysis of H.R. 2454, the additions were generally much smaller than those for coal-based plants because of the higher price of natural gas relative to coal.

*Question 5.* I was intrigued that a price on carbon did not necessarily result in fuel switching from coal to natural gas. When the carbon price is high due to limited availability of offsets for example, however, EIA projects substantial fuel switching.

- Are there factors, other than international offset availability, that can lead to similar fuel switching?
- If the cap were to decline at a substantially slower rate than the House-passed bill initially, would such a policy provide sufficient lead time to avoid or mitigate such a risk of rapid fuel switching and premature retirement of existing power plants in the near term?

Answer. As noted in the previous answer, the attractiveness of natural gas versus coal depends heavily on future natural gas prices. We find that if natural gas prices were approximately $5 per million Btu it would make sense to dispatch a natural gas combined-cycle plant before a coal plant when the greenhouse gas allowance price reached a little over $30 per metric ton of $CO_2$. However, this crossover point rises to around $60 with $7 natural gas prices and to around $100 with $10 natural gas prices. In the Reference Case in our analysis of H.R. 2454, natural gas prices to electricity generators are just over $7.00 per million Btu in 2020 and just over $8.30 per million Btu in 2030 (2007 dollars).

Since fossil fuels account for virtually all of the greenhouse gas emissions in the electric power sector, the emissions reductions in the House bill cannot be achieved without substantial switching to low-or zero-carbon options such as nuclear and renewables. Taking account of differences in the carbon content of coal and natural gas and the greater efficiency of modern gas-fired generators, the emission rate for natural gas is about 40 percent of the corresponding rate for coal so the potential emissions reductions due to switching from coal to natural gas are not sufficient to meet the specified long term caps. Furthermore, the carbon prices add considerably to the cost of all fossil-fired generation so that these plants are less economic compared to nuclear and renewables. However, a slower emissions cap trajectory would decrease the required emissions reductions in the near term and likely necessitate fewer retirements of existing plants and less switching out of fossil fuels during that initial period. The higher caps during that period would also decrease the corresponding carbon prices and lessen the impact on the generation costs for fossil-fuel capacity. EIA, however, has not evaluated any scenarios that assumed differing levels of greenhouse gas caps than those specified in the legislation.

RESPONSE OF RICHARD NEWELL TO QUESTION FROM SENATOR LINCOLN

*Question 1.* According to your testimony, the EIA estimated that about 1/3rd of the natural gas consumed in 2007 was used for electric power generation, 1/3rd for industrial purposes and the remaining 1/3rd in residential and commercial buildings. However, only a small portion is used in the transportation sector, predominantly at compressor stations, although some is used for vehicles. How do you view the use of natural gas in our transportation sector changing or increasing in the future, particularly with heavy duty or fleet vehicles?

Answer. The *AE02009* projects modest growth in natural gas use in highway vehicles, increasing from 0.02 quadrillion Btu in 2007 to 0.08 quadrillion Btu in 2030. The majority of this growth occurs in heavy-duty vehicles, but incremental vehicles costs, lack of retail refueling infrastructure, and costs associated with installation of on-site natural gas refueling impede significant gains in market share. Without significant increases in natural gas refueling infrastructure and reductions in incremental vehicle costs, market penetration will likely be limited to fleet applications where the economic benefits of natural gas can be captured by owners, or to fleet applications legislatively required to use alternative fuels like natural gas.

RESPONSE OF RICHARD NEWELL TO QUESTION FROM SENATOR MARK UDALL

*Question 1.* It was mentioned that some coal utilities are already switching over to gas without incentive in place, could you elaborate on this dynamic? Does low gas price and region play any role in some of these changes?

Answer. The key factor in recent fuel switching from coal to natural gas has been the dramatic fall in natural gas prices that has occurred during the economic downturn as industrial demand for natural gas has fallen. For a brief time in recent months, average spot natural gas prices actually fell below $3 per thousand cubic feet. At these prices, modern natural gas combined-cycle plants can operate at a lower cost than many coal plants. However, since natural gas prices to electricity generators are projected to exceed $5 per million Btu in 2010 and reach just over $7 per million Btu in 2020 and just over $8.30 per million Btu in 2030 (2007 dollars) in our latest Reference Case, we expect that it will soon become cheaper to dispatch coal plants ahead of combined-cycle plants fueled with natural gas when both types of units are available for use.

# APPENDIX II

## Additional Material Submitted for the Record

STATEMENT OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. Chairman and Members of the Committee: The Interstate Natural Gas Association of America (INGAA) asks that this written testimony be included in the record of the hearing held on October 28th, 2009. The members of INGAA appreciate the Committee conducting a hearing on natural gas and its role in reducing greenhouse gas emissions. As the Senate develops climate change policy, we ask that the Committee keep in mind that natural gas is available now, and will be available in the coming decades, in sufficient quantity to play a major role in reducing greenhouse gas emissions in the Unites States.

Mr. Chairman, INGAA represents the interstate and interprovincial natural gas pipeline companies in North America. Our members operate approximately 220,000 miles of large-diameter, natural gas transmission pipeline in the U.S. alone. This infrastructure continues to grow, especially in response to recent development of supplies of unconventional natural gas. According to the Energy Information Administration (EIA), almost 4,000 miles of new natural gas transmission pipeline was completed in 2008—a level of construction that EIA has called "exceptional." Much has been said about the dramatic increase in natural gas supply in recent years. It is also worth noting that natural gas infrastructure, especially new gas transmission pipeline capacity, has increased dramatically as well.

Given the prospects for continued growth in unconventional natural gas supply (principally, shale gas), INGAA believes that billions of dollars in additional investment in pipeline, storage and other midstream infrastructure will be required through 2030. The INGAA Foundation recently released a study, *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*, which uses multiple market scenarios to estimate the range of infrastructure investment that will be needed in coming decades. The key findings of this report include:

- A range of between $133 and $210 billion will need to be invested in midstream natural gas infrastructure over the next 20 years (between $6 and $10 billion annually), primarily to attach increased domestic natural gas production from unconventional shale basins and tight sands to the existing pipeline network.
- The U.S. and Canada will need to construct between approximately 29,000 and 62,000 miles of additional natural gas transmission pipelines, and between 370 and 600 billion cubic feet (Bcf) of additional storage capacity.
- In the Base Case projection, annual natural gas consumption in the U.S. and Canada is projected to grow from about 26.8 trillion cubic feet (Tcf) in 2008 to 31.8 Tcf by 2030, which equates to total market growth of 18 percent, or an annual growth rate of 0.8 percent. The two alternative cases, High Gas Growth and Low Electric Load Growth, bracket reasonable ranges of future natural gas consumption.
- About three-fourths of the market growth will occur in the power sector. The growth rate of natural gas consumption in the electric generation sector is the predominant determinate of the growth rate of the entire natural gas market. Electric load growth, the timing and development of renewable generation technologies, the deployment of clean coal with carbon capture and storage, and the expansion of nuclear generation are areas of uncertainty.
- Interregional transmission pipeline capacity between major areas in the U.S. and Canada currently is approximately 130 Bcf per day. By 2030, the need for interregional natural gas transport is likely to increase by between 21 and 37 Bcf per day, which will drive the development of additional pipeline and storage capacity. Interregional natural gas transport capacity will be needed even without a growing North American natural gas market due to shifts in the location of natural gas production. The need for laterals to access new production and

deliver natural gas to new customers, such as new gas-fired power plants, also will drive investment.

The record of natural gas supply AND infrastructure development in recent years provide a strong foundation for policymakers to move beyond to old assumptions about natural gas. Today, natural gas is domestically abundant, reliable and cost effective. The pipeline industry continues to attract billions of dollars in private capital to expand infrastructure, due in large part to the stable regulatory environment for natural gas pipelines. The Federal Energy Regulatory Commission process for reviewing, approving and siting natural gas infrastructure generally works well in supporting the construction of necessary infrastructure on a timely basis. The ability to develop natural gas infrastructure on a timely and efficient basis reduces natural gas price volatility and creates additional competitive opportunities for natural gas consumers. In short, the natural gas model works well for the nation. And given its environmental attributes as the cleanest fossil fuel, natural gas can and should play a larger role in achieving compliance with climate change mandates than is suggested by the economic modeling of the climate bills introduced to date.

Two issues regarding natural gas pipelines and climate change legislation bears specific mention to this Committee:

First, both S. 1733 (the Clean Energy, Jobs and American Power Act) and H.R. 2454 (the American Clean Energy and Security Act, as passed by the House) define FERC-jurisdictional interstate natural gas pipelines as regulated industrial entities, and therefore require pipelines to purchase emission allowances and incur other compliance costs. These pipelines, however, would be the only regulated industrial entities that could not unilaterally adjust the price of their product or service to reflect the cost of compliance. Instead, these pipelines must seek approval from the Federal Energy Regulatory Commission (FERC) to recover such costs in the rates charged for pipeline transportation service. Traditional rate case proceedings are ill-suited to addressing these costs, because such costs are likely to be unpredictable and are likely to vary from year to year. In addition, pipelines will be price takers in the allowance market and will have little practical ability to control the magnitude of such costs. What's more, the current market environment for pipeline transportation service has been one in which many pipelines and their customers have negotiated rates or settlements wherein the pipeline has contractually agreed not to seek a rate adjustment for years into the future. In fact, many of the new pipelines built to transport unconventional natural gas production to consumers are premised on negotiated rate contracts with terms that last a decade or more. This legislation would add a significant new cost that was not anticipated when such contracts were entered. Yet, if these compliance costs cannot be recovered by the pipelines, their ability to meet investor expectations and attract capital in the future would be negatively impacted.

INGAA urges the Congress to clarify this situation by directing the FERC to create a rate "tracker" that would allow pipelines to recover the costs associated with a cap-and-trade program, notwithstanding current contractual arrangements. Without such a tracker mechanism, many pipelines could face financial stress not of their own making, as a result of a change in national policy. This would be an unintended consequence that requires Congressional action as climate change legislation moves forward.

Second, INGAA members operate pipeline systems that span multiple states and often multiple regions of the country. A hodge-podge of state or regional greenhouse gas regulations would undermine the cost-effective management of these pipeline systems and ignores the inherently interstate nature of our facilities and this commerce. To provide an effective response to what is, after all, a global issue, INGAA believes that federal climate change policy must preempt state and regional cap-and-trade systems, greenhouse gas reporting requirements, and greenhouse gas reduction performance standards. S. 1733, unfortunately, goes in the wrong direction by encouraging states to develop their own greenhouse gas programs and regulations. INGAA hopes that you will support a federal response that includes clear federal preemption of duplicative state regulations and that also supersedes any inconsistent regulations adopted pursuant to other federal statutes.

Mr. Chairman, thank you for the opportunity to submit written comments on this important set of issues. Please let us know if you have any questions.

STATEMENT OF THE AMERICAN PUBLIC GAS ASSOCIATION

The American Public Gas Association (APGA) appreciates this opportunity to submit testimony and commends the Committee for holding this important hearing on the role of natural gas in mitigating climate change.

APGA is the national association for publicly-owned natural gas distribution systems. There are approximately 1,000 public gas systems in 36 states and over 720 of these systems are APGA members. Publicly-owned gas systems are not-for-profit, retail distribution entities owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

APGA remains extremely concerned in regard to the potential impacts climate change legislation will have on public gas systems. Climate change legislation will certainly have a significant impact upon the natural gas industry as well as on the price of natural gas.

Natural gas is the cleanest, safest, and most useful of all fossil fuels. It is also domestically produced, abundant and reliable. The inherent cleanliness of natural gas compared to other fossil fuels, a growing domestic supply and superior wells-to-wheels efficiency of natural gas equipment, means that substituting gas for the other fuels will reduce the emissions of the air pollutants that produce smog, acid rain and exacerbate the "greenhouse" effect. For these reasons, it is logical to assume that natural gas will play a critical role in the reduction in greenhouse gas emissions.

Natural gas is the lowest $CO_2$ emission source per BTU delivered of any fossil fuel. National policy should facilitate the use of natural gas instead of other more carbon-intensive fuels where appropriate. For example, using gas-fired water heaters for homes instead of electric resistance water heaters ultimately reduces greenhouse gas emissions by one-half to two thirds. Simply put, increasing the direct-use of natural gas is the surest, quickest and most cost-effective avenue to achieve significant reductions in greenhouse gases and therefore should be a critical component of any climate change legislation.

In June, 2009 APGA, the Interstate Natural Gas Association of America and others released a study conducted by the Gas Technology Institute (GTI) entitled "Validation of Direct Natural Gas Use to Reduce $CO_2$ Emissions". A copy of the study is attached to this testimony. The study analyzed the benefits of increased direct use of natural gas as a cost-effective means to increase full fuel cycle energy efficiency and reduce greenhouse gas emissions. Using the National Energy Modeling System (NEMS), the study concluded that the increased direct use of natural gas will reduce primary energy consumption, consumer energy costs, and national $CO_2$ emissions. A win-win-win for U.S. environmental and energy policy.

The study demonstrated, among other things, that using revenues such as allowances from a cap-and-trade program to provide incentives for original natural gas end-use applications and conversions to natural gas appliances from their electric counterparts will provide substantially higher and immediate return values in energy efficiency and carbon output reductions than an equal investment in electric applications. Another finding of the study was that subsidies provided to increase the direct use of natural gas, together with increased efforts in consumer education and R&D funding, would provide the following benefits by 2030:

- 1.9 Quads energy savings per year;
- 96 million metric tons $CO_2$ emission reduction per year;
- $213 billion cumulative consumer savings;
- 200,000 GWh electricity savings per year; and
- 50 GW cumulative power generation capacity additions avoided, with avoided capital expenditures of $110 billion at $2,200/kW.

Unfortunately, APGA is concerned that over the years federal policies have moved toward an all-electric society and have not recognized the benefits of the direct-use of natural gas. One example of this can be found in the manner in which the Department of Energy (DOE) calculates appliance efficiency. The DOE measurement takes into account energy solely consumed at the "site", measuring the energy used by the product itself.

The site-based measurement of energy consumption ignores the energy spent in production, generation, transmission and distribution. For example, according to DOE's point of use consumer disclosure labels for appliances, an electric water heater may appear to consumers to be over 60% more efficient than a gas water heater despite the fact that current national generation, transmission and distribution efficiency for central station electricity is, according to the U.S. Energy Information Agency, only 29.3% efficient while the transmission and distribution of natural gas directly to the consumer is 90.1% efficient. Ignoring these energy losses makes electric-resistance heating appliances appear more efficient (allowing them to receive a superior DOE efficiency rating).

This site-based measurement has placed natural gas appliances at an unfair marketing disadvantage and as a result there has been a marked increase in shipments of electric water heaters and a decrease in shipments of natural gas water heaters. This increase in electric water heaters will come with an increase in greenhouse gas emissions given that electric water heaters emit 2.5 times the amount of greenhouse gas emissions as natural gas water heaters given the current make up of the sources of U.S. electric generation today. Renewable energy generation is poised to grow in the future, but makes up less than 2% (excluding hydro-electric) of generation today. Conversion from electric to natural gas appliances will provide a more immediate emissions reduction strategy than the many years it will take for large scale deployment of wind, solar and other renewable technologies.

Rather than a site-based measurement for energy consumption, APGA has advocated a "source-based" or "total energy" analysis that measures energy from the point at which energy is extracted through the point at which it is used. A total energy analysis provides a more accurate assessment of energy use, efficiency, as well as greenhouse gas emissions.

In May, the National Academies of Sciences (NAS) completed a study that recommended that DOE move to a full-fuel-cycle measurement of energy consumption stating that this measurement would "provide the public with more comprehensive information about the impacts of energy consumption on the environment, the economy, and other national concerns. . ." APGA strongly supports this recommendation and looks forward to working with the Committee towards its adoption.

Another recently completed study from the Potential Gas Committee (PGC) shows the largest ever recoverable domestic resource base for natural gas at nearly 2,100 TCF. This is a 35% increase from the previous finding released two years ago and largest ever estimate from the PGC. Federal policy should seek to maximize every BTU of this domestic and low-carbon fuel by encouraging greater direct use into our homes and businesses for heating and cooking and other appropriate uses. Direct use into the home is the highest and best use of this country's precious natural gas resources.

APGA appreciates this opportunity to submit comments and looks forward to working with the Committee towards fully utilizing the benefits of the direct-use of natural gas in efforts to reduce greenhouse gas emissions.

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## STATEMENT OF THE AMERICAN GAS ASSOCIATION

### EXECUTIVE SUMMARY

- Natural gas is America's clean, secure, efficient, and abundant fossil fuel.
- Residential natural gas consumers, who use the fuel for essential human needs, have a 30-year record of reducing consumption and greenhouse gas emissions, and have shown the critical role that natural gas can play in addressing climate change.
- Natural gas, because it has the smallest carbon footprint of any fossil fuel is part of the energy efficiency and climate change solution.
- Natural gas has the potential to make major contributions to attaining the nation's climate change goals, and these contributions will be maximized if they nation makes the right policy choices, including:

—Making efficiency and resource decisions based upon full-fuel-cycle data that gives a complete picture of resources used and carbon emissions

—Requiring carbon-footprint labeling on appliances so that consumers realize the consequences of their choices

### INTRODUCTION

The American Gas Association (AGA) represents 202 local energy utility companies that deliver natural gas to more than 65 million homes, small businesses, and industries throughout the United States. AGA member companies deliver gas to approximately 170 million Americans in all fifty states. Natural gas meets one-fourth of the United States' energy needs.

AGA commends the Committee for exploring the role of natural gas in mitigating carbon emissions and climate change. In the conversations on these important topics that have occurred over the last two years in both chambers of Congress the critical role that natural gas can play has been largely overlooked. In recent months the importance of natural gas has at last been recognized, but it has focused on the role of natural gas in generating electricity. AGA believes that increased focus is necessary on the ways that the direct use of natural gas—in furnaces, hot water heaters, and kitchen stoves—can reduce the nation's carbon footprint—not twenty years from now but today. The irony is that this 19th Century technology is available to solve a 21st Century problem.

NATURAL GAS IS AMERICA'S CLEAN, SECURE, EFFICIENT, AND ABUNDANT FOSSIL FUEL

Natural gas is America's cleanest and most secure fossil fuel. Natural gas is essentially methane, a naturally-occurring substance that contains only one carbon atom. When burned, natural gas is the most environmentally-friendly fossil fuel because it produces low levels of unwanted byproducts ($SO_X$, particulate matter, and $NO_X$) and less carbon dioxide ($CO_2$) than other fuels. Upon combustion natural gas produces 43% less $CO_2$ than coal and 28% less than fuel oil. Moreover, almost all of the natural gas that is consumed in America is produced in North America, either in the United States or Canada, with the vast majority of that being produced in the United States. Only a small portion—1 to 2%—is imported from abroad as liquefied natural gas.

Natural gas is also the most efficient of the fossil fuels. Approximately 90% of the energy value of natural gas is delivered to consumers. In contrast less than 30% of the primary energy involved in producing electricity reaches the consumer. Additionally, natural gas is an abundant fuel. Recent prodigious discoveries of shale gas have significantly added to this abundant resource base. As the Potential Gas Committee recently reported, gas reserves have grown nearly fifty percent in the last several years. Indeed, America has at least 100 years of natural gas in the ground in North America. Moreover, changes in economics and technology will continue to increase our resource base estimates in the future, as they have consistently done in the past.

Natural gas is used to meet essential human needs for small-volume customers. The majority of the homes in this country use natural gas, and in this sector 98% of all gas is used for space heating, water heating, and cooking, while the remaining 2% is used for clothes drying and other purposes. This fuel is, therefore, used for essential human needs rather than for luxuries. Natural gas is, therefore, an essential fuel for America.

There are two important facts about natural gas that are either little known or often overlooked:

- America's residential natural gas customers have led the nation in reducing their consumption of natural gas—and their greenhouse gas emissions—over the last 30 years and can continue, with appropriate policies, to reduce consumption further. It takes less natural gas to serve 65 million homes today than it took to serve 38 million homes in 1970.
- Natural gas is not part of the climate change problem; rather, it is part of the climate change solution because it offers an immediate answer to reducing greenhouse gas emissions with existing technology, and it has the smallest carbon footprint of all fossil fuels.

RESIDENTIAL GAS CONSUMERS HAVE DEMONSTRATED THAT THE DIRECT USE OF NATURAL GAS CAN LEAD THE WAY IN REDUCING AMERICA'S GREENHOUSE GAS EMISSIONS

Residential natural gas customers provide a sterling example of the role natural gas can play in addressing climate change. This group has consistently reduced its per-household consumption of this fuel—and the carbon emissions resulting from its use—for more than 30 years. On a national basis, residential customers have reduced their average natural gas consumption by approximately 30% since 1980. The success of residential and commercial natural gas consumers is illustrated by the fact that they have reduced their per-household consumption so dramatically that there has been virtually no growth in sectoral emissions in nearly four decades despite an increase in natural gas households of over 70%. Stated another way, total annual residential natural gas consumption is lower today than it was in the 1970s, despite the fact that the number of natural gas households has increased more than 70% from 38 million to 65 million. Consumption of natural gas in the residential sector, on a national average basis, is shown in the following graph:*

Both research and anecdotal evidence make clear that there are proven drivers for reducing natural gas consumption and the carbon emissions associated with natural gas consumption—increased appliance efficiency and increased building efficiency, supplemented by a variety of education and incentive programs. AGA be-

* Graph has been retained in committee files.

lieves that continuing to pursue appliance efficiency and building efficiency policies is the optimal means to achieve further reductions in consumption in this sector. This admirable record of reducing consumption can continue by employing an intensive focus upon energy efficiency and building codes and standards measures, which for three decades have led to dramatically reduced natural gas consumption (and emissions).

The reductions in consumption per household experienced over the past three decades are largely attributable to tighter homes and more efficient natural gas appliances. These factors will undoubtedly provide the foundation for continued future reductions in consumption and, hence, greenhouse gas emissions. Moreover, natural gas utilities are aggressively promoting decoupled rate structures that allow them to promote conservation and efficiency consistent with shareholder interests. Nearly 40% of all residential natural gas customers are served by gas utilities that have decoupled rates or that are engaged in state proceedings that are presently considering decoupled rates. Rate decoupling is important to energy efficiency because it breaks the link between utility revenue recovery and customers' energy consumption.

USING NATURAL GAS IN HOMES AND BUSINESSES IS ART OF THE ENERGY EFFICIENCY AND CLIMATE CHANGE SOLUTION

Many misguidedly believe that because natural gas is a fossil fuel it is one of the causes of greenhouse gas emissions and, as result, a contributing factor to climate change. In fact, however, natural gas is part of the climate change solution. As mentioned previously, natural gas is a fuel that emits low levels of traditional pollutants such as $NO_X$ and $SO_X$. With regard to greenhouse gas emissions, natural gas, because it has only one carbon atom, emits less carbon when consumed than any other fossil fuel. As a result, natural gas has the potential to be a vehicle to move the nation toward its greenhouse gas reduction goals. For the same reasons, natural gas is an essential element in the push for optimizing our natural resources and increasing our energy efficiency.

There are significant differences in efficiency between natural gas and electricity. Approximately 90 percent of the energy value in natural gas is delivered to the home. With electricity less than 30 percent of the primary energy value reaches the customer. The largest difference in efficiency for electricity is lost as waste heat at the generating station, as well as line losses in transmission and distribution. These radically different efficiencies produce the significant differences in both efficiency and carbon emissions between electric and natural gas appliances.

The full potential for natural gas efficiencies is demonstrated most dramatically by the carbon footprint of the natural gas water heater. The average natural gas water heater emits approximately 1.7 tons of $CO_2$ per year. In contrast, the average electric water heater results in more than twice as much—3.8 tons per year. The difference between the two could not be more dramatic, and it becomes a multiple of three when the comparison is made between a high-efficiency natural gas water heater and a high-efficiency electric water heater. These numbers are based on national averages, and, as a result, actual differences will vary from area to area.

The same differences in efficiency and emissions follow when comparing an all-electric home with a natural gas home. A typical all-electric home on average produces 10.8 tons of $CO_2$ per year, while an all-natural-gas home produces 7.2 tons of $CO_2$ per year. Again, these numbers reflect national averages, and actual experience will necessarily differ, but the order of magnitude of difference remains.

The plain consequence is that the nation can improve its overall energy efficiency as well as reduce its carbon footprint by opting for appliances that use natural gas in direct applications (i.e., where the natural gas is used to heat air, water, or food). There is the opportunity, on a national basis, to improve efficiency dramatically and reduce carbon emissions by millions upon millions of tons if we utilize more natural gas directly in homes and businesses as the fuel for the future.

Converting small-volume customers to high-efficiency natural gas applications is one of the best ways available today to leap forward in efficiency and reduce greenhouse gas emissions. As the example above demonstrates, converting electric resistance water heaters to natural gas can increase efficiency and reduce greenhouse gas emissions by one-half to two-thirds. Doing so would have the benefit of reducing overall energy consumption, costs, and the need to construct new electricity generating plants—a critical problem in a carbon-constrained environment—and electric transmission lines.

Encouraging the direct use of natural gas by consumers is, therefore, an important tool to meet the nation's greenhouse gas goals. In other sectors of the energy industry, the steps necessary to reduce greenhouse gas emissions are years or decades away—e.g. deployment of additional nuclear generating stations or carbon capture and sequestration. In contract, natural gas is here today to reduce greenhouse gas emissions in the immediate future. It is not only the increased use of natural gas for electricity generation (which is not an issue central to AGA) that promises reductions in greenhouse gas emissions, but also the increased usage of natural gas in home heating, water heating, and cooking that has the potential to bring near-term reductions in greenhouse gas emissions.

MEASURING ENERGY EFFICIENCY AND CONSUMPTION ON A "FULL-FUEL CYCLE" ASIS WILL MAXIMIZE NATURAL GAS AS A POTENT CLIMATE CHANGE TOOL

This spring the National Academy of Sciences completed a study under contract with the U.S. Department of Energy as required by the Energy Policy Act of 2005. The study was to determine whether the more appropriate means of measuring energy efficiency was "sited-based" or "source-based" measurement of consumption and efficiency. The former looks only to the site of the appliance consuming energy. The latter looks to the full fuel cycle—in the case of natural gas from the wellhead to the burner tip. In the case of natural gas, site-based analysis looks to the relative efficiency of a particular appliance. Source-based analysis instead looks to see how much of the energy taken from a gas well does productive work at the site of the appliance. In essence the source-based analysis leads to the conclusion that in the case of natural gas 90% or so of the primary energy results in productive effort while in the case of electricity only 30% or so of the primary energy results in productive effort.

The report of the National Academy of Sciences concludes that, where different fuel sources can be utilized for a particular appliance (e.g., hot water heaters), the full-fuel-cycle (or source-based) analysis is most appropriate because it presents the most complete picture of the relative usage of primary resources. With today's focus on reducing greenhouse gas emissions, the results of the National Academy Study take on particular relevance because carbon (greenhouse gas) emissions in a particular application closely parallel the full-fuel-cycle analysis. (A copy of the National Academy of Sciences report is attached.)

If the nation establishes a goal of reducing its carbon emissions, it is essential that the nation's policy decisions be based on information that will promote that goal. Site-based measurements of energy usage and energy efficiency will not lead to maximum reductions in carbon dioxide. Those will only be achieved by measuring energy usage and energy efficiency on a source, or full-fuel cycle basis. Congress here faces a fork in the road—one way leads down the traditional path, which will result in erroneous decisions. The other way leads down the path of new and fresh analysis that maximizes carbon reductions.

A simple example illustrates the point. Let us look again at water heaters. If we compare water heaters on a site basis, we can see that a natural gas water heater and an electric water heater are each 90% efficient. This comparison ignores, however, the modest energy losses in delivery for natural gas and the major losses (70%) for electricity. This picture, even using source-based energy, gives only the efficiency comparison. As noted previously, when one looks at it from a carbon perspective it is starker—the electric water heater is responsible for twice as much carbon dioxide as the natural gas water heater. If Congress does not change the nation's course on this very fundamental issue it will have missed a historic opportunity to do the right thing—from both an efficiency and a carbon perspective.

Attached is a short piece of legislative language that would implement this important change in approach for both energy efficiency policy and carbon policy.

CARBON FOOTPRINT LABELING FOR APPLIANCES WILL PROMOTE CARBON REDUCTIONS

Currently major home appliances bear labels, called EnergyGuide labels, that show the yearly estimate operating cost of an appliance. For simplicity, these labels are based upon national averages for energy prices. The EnergyGuide label allows the consumer to compare the relative annual operating costs of the various appliances from which he or she might chose. The purpose of the EnergyGuide label is to give the consumer relevant information on the comparative operating costs and first-costs of the appliances available so that he or she can make an optimal decision.

H.R. 2454, the American Clean Energy and Security Act of 2009, passed by the House on June 26, 2009 (the Waxman-Markey climate change bill takes the Energy Guide labels one step further in the dawning carbon-reduction age. Section 234(h) of the Waxman-Markey bill requires that EnergyGuide labels be expanded to include the carbon emissions associated with appliances. For an American public increasingly interested in climate change issues and that will, as we move forward, be increasingly attentive to carbon emissions, providing this additional information will be more than useful. Consumers will be able to assess the carbon consequences of their appliance purchases. They will, for the first time, be able to balance relative carbon emissions with first-costs.

Mandating this additional information will provide useful information to consumers. Doing so will undoubtedly result in carbon reductions. Moreover, requiring carbon labeling will not impose costs on either manufacturers or consumers. The necessary data for creating these labels is readily available, and the requisite calculations are not unduly complex. As the labels are already required, it is simply a matter of adding one data point to the labels. AGA urges the Committee to embrace the carbon labeling provision found in the H.R. 2454.

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## STATEMENT OF THE AMERICAN TRUCKING ASSOCIATIONS, INC

The American Trucking Associations (ATA) appreciates the opportunity to submit written testimony concerning the use of natural gas in over the road trucking fleets. ATA is a federation of motor carriers, state trucking associations, and national trucking conferences created to promote and protect the interests of the trucking industry. ATA's membership includes trucking companies and industry suppliers of equipment and services. Directly and through its affiliated organizations, ATA encompasses over 7,000 companies and every type and class of motor carrier operation.

For the reasons set forth below, natural gas currently is not a viable solution for most long-haul trucking operations; however, natural gas could be an acceptable fuel alternative for certain short-haul applications within an industry as diverse as trucking.

### BACKGROUND

The trucking industry is the lynchpin of the transportation system, hauling nearly 70% of all the domestic freight transportation tonnage in the United States and accounting for more than 80% of the nation's freight bill. Over 80% of the communities in the U.S. receive their goods exclusively from trucks. Trucking also accounts for over 70% of the value of trade between the U.S. and Mexico and Canada. Simply put, without the trucking industry, the U.S. economy would come to a grinding halt.

Diesel fuel is the lifeblood of the trucking industry. The trucking industry consumes 39 billion gallons of diesel fuel each year. For most companies, diesel fuel is the second highest operating expense after labor. As the price of diesel fuel has increased, the trucking industry has searched for ways to increase its fuel economy andvhas pursued several alternative fuel options. The search continues, as we have not found viable alternative to diesel fuel; although the industry continues to experiment with using natural gas in certain applications.

Natural gas is a fuel comprised mostly of methane, with small amounts of propane, ethane, helium and water. Like certain other alternative fuels, natural gas could be an acceptable fuel choice for specific applications within an industry as diverse as trucking. Natural gas engines can either be spark ignition or compression ignition with pilot injection (i.e., using a 5% diesel injection to initiate combustion), with the later retaining the general properties of a diesel engine but requiring a dual-fueling system.

Natural gas may be used as a transportation fuel in its compressed form (CNG) or liquefied form (LNG). Because of low energy density, CNG is not practical for long distance, heavy-duty truck applications. CNG is being successfully used in shorter range, heavy-duty applications such as refuse trucks, concrete mixers, and municipal buses.

LNG may present a viable alternative for certain trucking applications. LNG is cryogenically liquefied (i.e., converted to a liquid by reducing its temperature to approximately -260°F) and has higher energy content per volume than CNG (although still significantly lower than diesel). LNG's energy density makes it more acceptable for longer routes, although the lack of a competitive refueling infrastructure suggests that this alternative is not currently viable for long-haul applications.

### DISCUSSION

As with most alternative fuels, natural gas has certain advantages and disadvantages compared to diesel fuel. We discuss each of these in more detail below.

*A. The Economics of Natural Gas*

One of the biggest obstacles to using natural gas in the trucking industry is the cost of a natural gas truck. Natural gas trucks sell at a premium to heavy duty dieselngines for Class 8 trucks ($40,000—$70,000 more).[1] Federal (and state) tax incentives are available to purchasers of natural gas trucks to narrow the price differential between diesel and natural gas trucks; however, these incentives are not sufficient to completely offset the natural gas truck price premium.

The trucking industry is incredibly competitive. There are more than 600,000 companies registered with the U.S. Department of Transportation and 96 percent of them are small businesses that operate fewer than 20 trucks. In an industry with operating expenses that often exceed 98% of collected revenue, trucking companies cannot afford to increase their capital expenses by purchasing natural gas trucks that cost significantly more than the trucks that their competitors are operating.

LNG fuel tanks are constructed from ¼" thick stainless steel and add significant weight to the truck, which may negatively impact truck productivity.[2] For example, two 119 gallon tanks weighing approximately 1,000 pounds would reduce the payload of a cargo tank truck carrying ethanol by over 150 gallons. Thus, more trucks would be required to haul an equivalent amount of product, which negatively impacts fuel consumption, emissions, and the cost of transporting freight. It should be noted that many trucking operations do not operate at the maximum legal weight and the productivity of these operations would not be adversely impacted by the weight penalty associated with natural gas trucks.

One positive economic aspect of natural gas trucks is that natural gas currently sells at a significant discount to diesel fuel on a diesel gallon BTU equivalent basis. While both diesel and natural gas prices fluctuate, through 2009 LNG sold at a significant discount to ultra low sulfur diesel fuel (i.e., approximately 75 cents to $1/gallon cheaper). Natural gas trucks, however, are less fuel efficient than their diesel counterparts. Spark ignited natural gas engines have a reduced fuel economy of 7% to 10%, while compression-ignition natural gas engines have about a 1% fuel economy penalty. As a result, some of the economic benefit of less expensive natural gas is given up in the form of lower fuel efficiency.

Notwithstanding the fact that natural gas is less expensive than diesel fuel, the additional capital cost associated with purchasing natural gas trucks compared to diesel trucks makes natural gas a challenging economic alternative for most trucking companies. Due to the competitive nature of the trucking industry, significant financial incentives would be required to address the higher cost of natural gas trucks, before they can be considered a viable alternative to diesel trucks.

*B. Infrastructure Concerns*

The second major obstacle to the use of natural gas as an alternative fuel for the trucking industry is the lack of a competitive refueling infrastructure. Most long-haul trucks are not centrally refueled and do not travel regular routes. Running out of gas on the side of the road is a significant challenge, as LNG mobile refueling is not an option and the truck would have to be towed to a refueling station. The ubiquitous nature of diesel refueling stations accommodates that uncertainty. Unfortunately, it is virtually impossible for over-the-road fleets to find LNG fueling outlets.

LNG trucks must be refueled at specialized stations that are configured for the specific truck. Putting aside the issue of refueling compatibility, many of the natural gas fuel stations in this country are owned and operated by municipalities, and prior contractual arrangements would have to be made before commercial trucks could use these municipal LNG refueling stations. Since the product is dispensed at -260 degrees Fahrenheit, employee training and the provision of personal protective equipment also may be necessary.

Building out an LNG refueling infrastructure will take time and an enormous amount of money. An LNG filling outlet with a refill capability that is comparable to the time necessary to refuel a diesel truck costs over $500,000. There also may be permitting challenges associated with the construction of an LNG refueling system, as government officials and permitting authorities have limited exposure to LNG refueling stations.

It is not sufficient to have a single LNG vendor with stations built at strategic locations along key freight corridors. Absent a competitive refueling infrastructure, trucking companies could face unreasonably high prices at individual retail LNG stations that have no competition in a particular geographic area. While competition exists in the natural gas industry, the high barriers to entry for retail LNG refuel-

[1] There are currently two natural gas engine classes: (1) a spark ignition, 320 horsepower version that sells at a $40,000 premium to its diesel counterpart; and (2) a 450 horsepower, compression ignition version that sells at a $70,000 premium to its diesel counterpart.

[2] A 119 gallon tank weighs approximately 500 lbs., while a 72 gallon tank weighs approximately 270 lbs.

ing stations may slow the development of a competitive refueling infrastructure. A competitive LNG refueling model would require the presence of multiple entities selling LNG in the same geographic area.

*C. Operational Challenges*

Using LNG as an alternative fuel also creates operational and maintenance challenges for the trucking industry.

LNG On-Board Tanks.—Some fleets have experienced significant problems with LNG fuel tanks. These tanks are double-walled construction with a vacuum between the two walls (like a giant thermos bottle). The vacuum serves as a temperature barrier. In some cases, fleets reported a loss of the vacuum due to tank manufacturing issues that manifest themselves months and even years after being placed into service. The vacuum can be replenished, but the process is costly and is not a permanent solution. Impacting a tank (such as during a collision or accident) can also result in a lost vacuum. As vacuum pressure decreases, fuel temperature rises, causing internal tank pressure to rise. The pressure relief valve built into the tank vents natural gas into the atmosphere, which affects the amount of fuel available for use and offsets the environmental advantages of using LNG.

Operating Range.—An LNG truck equipped with two 119 gallon tanks has an operating range of approximately half of the typical diesel long-haul truck. These tanks are extremely heavy and negatively impact truck productivity for those fleets that haul freight at the truck's legal weight limit.

Maintenance Costs.—A natural gas engine may require injectors to be replaced more frequently than a diesel engine, which increases operating expenses. For spark-ignition natural gas engines, replacement of spark plugs, ignition modules and various sensors also add additional maintenance costs.

On the positive side of the maintenance expense ledger, natural gas engines require fewer oil changes. Oil change intervals for LNG trucks are three times longer than diesel engines.

Training.—Natural gas engines operate differently than diesel engines and in-house mechanics will require approximately 60 hours of specialized training. Finding a qualified natural gas mechanic is more difficult than finding a diesel mechanic. The local truck dealer may not have the requisite experience, tools or parts to quickly perform repairs. As a result, some fleets have reported that the downtime for repairs is significantly longer for natural gas engines.

Methane Exposure.—Maintenance shops that will work on natural gas-fueled vehicles should include a methane detection system and a methane evacuation system. Recommendations on the safe operation and maintenance of natural gas vehicles are available from the National Fire Protection Association and the Society of Automotive Engineers. One ATA member reports spending over $150,000 on infra-red sensors, modified lighting and electrical systems, and an air evacuation system.

*D. Environmental Implications*

Particulate matter (PM) and nitrogen oxide ($NO_X$) emissions from LNG-fueled trucks are similar to diesel trucks manufactured in compliance with EPA's 2010 diesel emission standards.

Lifecycle carbon emissions from a natural gas engine compare favorably to diesel engines. Depending upon the source of the natural gas and the liquefaction efficiency rate, natural gas can reduce $CO_2$ emissions by 15%-23%. Note, however, that methane is 20-times more potent than $CO_2$ as a greenhouse gas. As LNG in fuel tanks warms, methane is released to the environment through a pressure relief valve. In fact, depending upon ambient temperatures, an LNG truck could vent most of its fuel over a 7-10 day period. The venting of methane from trucks parked over an extended period could result in a net increase in greenhouse gas emissions compared to diesel fuel.[3]

## CONCLUSION

Natural gas is a plentiful, domestically-produced energy source that could help to reduce our dependence on petroleum imports. There are numerous hurdles that must be overcome, however, before LNG trucks become a truly viable alternative for mainstream trucking. The most significant obstacles to LNG are the enormous purchase price premium associated with a natural gas truck compared to an equivalent diesel truck and the lack of a competitive LNG refueling infrastructure. If Congress enacts financial incentives to ensure that the price of an LNG truck is equivalent

[3] While trucking companies strive to improve utilization rates of their capital equipment, the current low demand for freight transportation services provides an immediate example of circumstances where trucks may be parked for an extended period of time.

to a diesel truck and that cost-effective LNG refueling facilities can be constructed, then LNG trucks may be a viable alternative for the small segment of the industry that is centrally-refueled.

For LNG to achieve greater penetration in the trucking industry, additional incentives are necessary to ensure the development of an adequate competitive refueling infrastructure.

ATA appreciates this opportunity to discuss potential to increase the use of natural gas in the over the road trucking fleets. If you have any questions concerning the issues raised in this statement, please contact Richard Moskowitz at (703) 838-1910.

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STATEMENT OF HON. SEAN PARNELL, GOVERNOR, STATE OF ALASKA

Dear Chairman Bingaman and Ranking Member Murkowski,

The State of Alaska commends the Senate Committee on Energy and Natural Resources for its recent hearing on the role of natural gas in mitigating climate change. We wish to comment on this and other topics related to the Clean Energy Jobs and American Power Act (S. 1733). S. 1733, which aims to drastically modify U.S. fossil fuel consumption, stimulate greater use of renewable energy resources, and address the challenges of climate change adaptation, involves some of the most important issues facing the State of Alaska.

Alaska supports the transition to lower-carbon and renewable energy. However, as a major exporter of carbon-based energy, producing approximately 13 percent of the nation's oil supply and receiving more than 80 percent of its unrestricted general fund revenues directly from oil and gas operations, the State cannot ignore the potential economic consequences of a "cap-and-trade" system. We are currently preparing analyses that assess the possible impacts of this legislation on State revenues, the economic viability of our oil refineries, and future construction of an Alaska natural gas pipeline. The State fears this act may disadvantage domestic fossil fuel producers and shift production overseas, resulting in lost revenues and jobs while reducing our nation's energy security.

While climate change legislation could pose economic threats to our state, Alaska is also primed to help lead a clean energy economy. In the Alaska natural gas pipeline, the State of Alaska offers a promising low-carbon energy option, which could provide a vital bridge to other clean energy alternatives. Alaska also holds vast renewable energy potential, from hydropower, to biomass, wind, geothermal, solar, and ocean power.

In the area of adaptation, Alaska is already facing a host of serious developments related to climate change. This includes addressing the impacts to critical infrastructure associated with accelerated coastal erosion, increased storm effects, sea ice retreat, and permafrost melt. Efforts to protect and relocate Alaskan communities are already underway and the State values the partnerships we have formed with many federal agencies and other entities. More resources, however, are needed along with a designated federal agency lead to coordinate the federal efforts.

Coupled with climate change impacts are opportunities, including the potential for increased marine access to Arctic waters and the resources they contain. The United States is slowly waking to the fact it is an Arctic nation and the importance of the Arctic in general. It is imperative that this legislation not foreclose possible opportunities in the Arctic.

Enclosed you will find the State's analysis of provisions in S. 1733. This document identifies key priorities for Alaska and a number of areas for improvement. Some of the items the State advocates for in this bill include:

- Adequate funding for climate change adaptation: the State supports sufficient funding to address Alaska's pressing adaptation needs on various fronts, including protecting critical and valuable infrastructure.
- Measures to preserve domestic refineries: Alaska calls for provisions aimed to protect Alaska's refineries, which are essential to our economy and cold weather fuel needs, as well as uniquely vulnerable to increased costs posed by cap-and-trade legislation.
- Fair allocations for Alaska: the State is concerned that the Environmental Protection Agency (EPA) has underestimated emissions in Alaska, based on estimates provided to Senator Feingold by EPA. This could disadvantage the state as a whole in the distribution of allowances.
- Avoidance of unfunded mandates: Alaska opposes burdensome and unrealistic unfunded mandates that may be created through new climate change programs.

- Respect for states' rights: the State supports the protection of states' rights and notably recognition of the State of Alaska's role as primary trustee over fish and wildlife.
- Exclusion of problematic broad policy statements: Alaska opposes broad policy statements that open the door to stricter enforceable regulations and future litigation.
- Emphasis on domestic production: the State supports expanding access and incentives for responsible domestic onshore and offshore oil and gas exploration as part of a strategy for creating a secure energy future.
- Promotion of the natural gas pipeline: the State seeks to promote the Alaska natural gas pipeline as a clean and reliable fuel source which would provide significant economic benefits for the nation, consistent with the Alaska Natural Gas Pipeline Act of 2004 (P.L. 108-324, 118 Stat. 1220).
- Carbon capture and sequestration incentives: Alaska supports the commercial deployment of carbon capture and sequestration (CCS) technologies, and in particular, sequestration as a result of Enhanced Oil Recovery (EOR) projects.
- Program flexibility: The State believes that effective mitigation and adaptation programs must acknowledge regional differences. Alaska has particular concerns regarding the proposed natural resources adaptation framework.
- Focus on monitoring and research: Alaska supports collaborations among federal, State, and other partners in monitoring and research that will lead to better decisions in the management of land and marine resources.
- Exclusive role of climate change legislation: We believe climate change legislation should be the sole instrument for addressing climate change mitigation, not the strained use of existing statutes such as the Endangered Species Act or the Clean Air Act.

We respectfully request that this material be included in the hearing record and appreciate the opportunity to share our views.

## ATTACHMENT.—STATE OF ALASKA COMMENTS ON CLEAN ENERGY JOBS AND AMERICAN POWER ACT (S. 1733)

### *senator boxer's chairman's mark*

#### INTRODUCTORY NOTES

This document describes the positions of the State of Alaska on notable elements of Senator Barbara Boxer's Chairman's Mark of the Clean Energy Jobs and American Power Act (S. 1733), which was introduced by Senators John Kerry and Barbara Boxer. The Alaska Departments of Environmental Conservation, Fish and Game, Law, Natural Resources, Revenue, Transportation and Public Facilities, and the Governor's Washington, DC office contributed to the analysis of this bill.

While particular design elements of "cap-and-trade" legislation, like S. 1733 and the American Clean Energy and Security Act of 2009 (H.R. 2454), raise broad concerns about the economic interests of Alaska, this document focuses instead on specific provisions of S. 1733. The State is currently preparing separate analyses of the possible impacts of this legislation on State revenues, the economic viability of Alaska's oil refineries, and future construction of an Alaska natural gas pipeline.

In many ways, Alaska is ground zero for obvious and costly climate change impacts. Alaska is currently experiencing coastal erosion, increased storm effects, sea ice retreat and permafrost melt. The villages of Shishmaref, Kivalina, and Newtok have already begun relocation plans and the U.S. Army Corps of Engineers has identified over 160 additional rural Alaskan communities threatened by erosion.

The effects of climate change are expected to occur most rapidly and be most pronounced at higher latitudes. Thus, no discussion about climate change is complete without recognition of the issues facing the Arctic. Surprisingly, in the 925-page bill, offered as a U.S. response to climate change, the word "Arctic" appears only once.

The State of Alaska strongly encourages that the following key components be incorporated in any climate change legislation:

- Mitigation and adaptation strategies that account for regional differences and avoid a "top-down" approach, likely to produce inflexible and inefficient policy;
- avoidance of broad policy statements that open the door to stricter enforceable regulations and future litigation;
- an effort to spare states from burdensome and unrealistic unfunded mandates;
- emphasis on climate change legislation as the sole instrument for addressing climate change mitigation, rather than the strained use of existing statutes, such as the Endangered Species Act or the Clean Air Act;
- incentives for a diverse spectrum of clean energy alternatives;

- respect for states' rights, and notably recognition of a state's role as primary trustee over fish and wildlife;
- a focus on studying the Arctic climate and environment;
- appropriate funding for adaptation efforts in Alaska where there is a pressing need to respond on numerous fronts, including the protection of critical infrastructure;
- aid for consumers burdened by climate change-related regulations;
- provisions aimed to protect Alaska's refineries, which are essential to our economy and cold weather fuel needs, as well as uniquely vulnerable to increased costs posed by cap-and-trade legislation; and
- promotion of Alaska's natural gas pipeline as a clean, reliable, long-term fuel source.

In the remainder of this document, the State considers how S. 1733 addresses these and other priorities important to Alaska.

## STATE POSITIONS AND ANALYSIS OF S. 1733

### SECTION 1. SHORT TITLE; TABLE OF CONTENTS

*Findings. (Sec. 2)*

- Alaska Natural Gas Pipeline Projects. The State supports the addition of a finding, that the completion of the Alaska Natural Gas Transportation Projects is vital to the country to provide a clean fuel alternative to coal and petroleum as a bridge to power generation that does not involve the combustion of fossil fuels. This finding would be consistent with the Alaska Natural Gas Pipeline Act of 2004 (P.L. 108-324, 118 Stat. 1220).
- Arctic Impacts. The State supports the addition of a finding that the impacts of climate change are expected to occur first and be most severe in the Arctic and in the higher latitudes, creating unique adaptation needs in these areas.

## DIVISION A—AUTHORIZATIONS FOR POLLUTION REDUCTION, TRANSITION, AND ADAPTATION

### TITLE I—GREENHOUSE GAS REDUCTION PROGRAMS

*Subtitle A—Clean Transportation*

*Greenhouse Gas Reductions through Transportation Efficiency; Transportation Greenhouse Gas Emission Reduction Program Grants. (Sec. 112-113)*

- Funding. The State fears Section 112 would create a substantial unfunded mandate and shift resources away from Alaska's transportation priorities. S. 1733 would amend Title VIII of the Clean Air Act to require the EPA Administrator, in consultation with the Alaska Department of Transportation and Public Facilities (DOT), to establish national greenhouse gas (GHG) emission reduction goals. States and metropolitan planning organizations (MPOs) would, in turn, be required to develop targets consistent with the national goals. The State would need to perform extensive data gathering and modeling, compute baseline emissions, and develop new strategies and programs to meet their goals. Section 113, which outlines a grant program for transportation GHG reduction, does not clearly provide funding to states for planning. If Alaska is unable to secure sufficient funding, it would be forced to divert resources from other programs, such as transit and road improvements, in order to absorb the new costs. The State supports a funding mechanism that will ensure adequate assistance to states working to comply with this new mandate.
- Adequate Time Frame. The State has concerns about the time requirements for data production and analysis. Adequate time is necessary to produce data on local conditions. Default national data does not accurately reflect Alaska's environmental conditions and emissions. The State believes this legislation should contain provisions ensuring states have sufficient time to collect and incorporate local data.

  The State also supports inclusion of a statutory process to extend State target deadlines should federal agencies fail to meet deadlines or should there be legal changes to models or methodologies. New standardized models and methods adopted may differ from those used to establish the 2005 emissions reduction baseline. If this is the case, analysis would be necessary to properly compare new results with the 2005 baseline. If EPA and DOT lag in making this adjustment, it will shorten the timeframe states have to meet their deadlines.

  Furthermore, the State fears the timeline for new regulations in this section is not realistic. Regulations must be proposed within 12 months and promulgated within 18 months of enactment. Preparing regulations and completing the public process for adopting the regulations can take months under ideal circumstances. If the regulation process is not completed on schedule, states and MPOs would be left with insufficient time to achieve emission reduction targets.

- Authority. The State also questions whether states possess the requisite authority to carry out their new duties under this section. State transportation programs generally do not operate transit, rail, or intercity bus systems, control land use, or regulate the amount of driving or method of vehicular propulsion. This authority is traditionally reserved for local government planning and zoning departments. Yet it will be impossible to meet ambitious emissions targets without regulating these activities. Furthermore, Section 112 holds MPOs to a lesser standard than states, though MPO emission plans are central to meeting state targets.
- Public Health. The State also has reservations about use of the term "public health," which has certain connotations within the Clean Air Act. A provision may be necessary to ensure the term does not invoke actions related to the Clean Air Act Section 109(b)(1), which directs EPA to set ambient air quality standards to "protect the public health" and allow for an adequate margin of safety. Recent EPA actions have shown an increased propensity for moving beyond the agency's traditional authority.
- Surface Transportation. The State believes the language of this section should be clarified to describe "surface" transportation-related greenhouse gas emissions reduction targets in all cases. Further, the term "surface transportation-related" should be defined to specifically exclude maritime (except ferries), rail, and off-road vehicles.
- Lead Planning/Modeling Agency. The State supports establishing the U.S. Department of Transportation, not the EPA, as the lead agency regarding the development of transportation planning and modeling tools. S. 1733 does this.
- Vehicle Miles Traveled. The State is concerned by provisions creating goals for reduced "vehicle miles traveled." Construction of the natural gas pipeline may create large short-term increases in vehicle miles traveled, but will generate benefits that far outweigh these increases. The State supports an exception for large construction projects promoting clean energy.
- Clean Air Act Incorporation. Section 112 also raises concern because of its incorporation into the Clean Air Act. The provision could subject planning and activities to burdensome Clean Air Act statutes and regulations.

*Subtitle F—Energy Efficiency and Renewable Energy*

*Renewable Energy. (Sec. 161)*

- Grants for Renewable Resource Programs. The State supports the nation's transition to increased reliance on renewable energy. Alaska possesses vast renewable energy potential, including hydro, biomass, wind, geothermal, solar, and ocean power. S. 1733 authorizes EPA grants for projects that increase the quantity of energy that a state uses from renewable resources, with priority to applicants in states with a binding Renewable Portfolio Standard. The State approves of the provision's goal.

  The State, however, has concerns about the definition of "qualified hydropower," used in Section 102. It appears hydropower can be considered "qualified" in two ways. First, incremental gains or capacity additions to projects in place before 1988 are considered qualified hydropower. Second, energy produced from capacity added after 1988 to a dam that was originally in place for reasons other than power generation qualifies. This narrow definition would exclude large portions of existing hydropower, making it difficult for Alaska to meet a Renewable Portfolio Standard and compete for grants under Section 161, despite having an abundance of hydropower. The definition would also leave out new hydro projects. The State supports the expansion of the definition of "qualified hydropower."

*Energy Efficiency in Building Codes. (Sec. 163)*

- National Building Codes. The State opposes setting national energy efficiency building codes. S. 1733 would create national codes for residential and commercial buildings, in order to meet national energy efficiency targets. The EPA Administrator would publish an annual report on energy efficiency building code adoption and compliance by states. Though penalties for noncompliance are not defined in S. 1733, Alaska opposes the existence of national standards in this area. A federally mandated, universal energy code is a poor fit for a state with Alaska's vast size and varied conditions.

*Subtitle H—Clean Energy and Natural Resources*

*Clean Energy and Accelerated Emission Reduction Programs. (Sec. 181)*

- Clean Energy Incentives. The State supports Section 181, which rewards companies that switch from power sources with higher emissions than the 2007 power sector average to cleaner fuels, including natural gas, and Section 182, which would establish a new federal grant program encouraging investment in advanced natural gas technologies.

TITLE III—TRANSITION AND ADAPTATION

PART 1—DOMESTIC ADAPTATION

*Subpart A—National Climate Change Adaptation Program*

*National Climate Change Adaptation Program. (Sec. 341)*

- Existing Programs. The State supports the inclusion of language to clarify that the proposed National Climate Change Adaptation Program (NCCAF) will not replace existing federal programs already providing state and local governments and tribes with funds for projects that will assist in adaptation. The NCCAF should be a supplemental source of funding that prioritizes meeting urgent needs.

*Climate Services. (Sec. 342)*

- Coordination. The State believes a lack of specificity in the bill's natural resources adaptation strategy could hamper coordination and produce a duplication of efforts. In this section, the Department of Commerce (NOAA) is tasked with developing a National Climate Service. Section 365 creates a Natural Resources Climate Change Adaptation Panel, chaired by the Council for Environmental Quality. Section 367 establishes a National Climate Change and Wildlife Science Center. These provisions leave ambiguity as to how the bodies will interact. At the State level, federal agencies have competed for leadership and funds in the climate change arena. The vagueness in these provisions could produce a similar dynamic.

*Subpart B—Public Health and Climate Change*

*National Strategic Action Plan; Advisory Board. (Sec. 353-354)*

- Public Health. The State supports the inclusion of a section dedicated to addressing public health. However, the bill calls for development of a Health Impact Assessment. The requirement that Health Impact Assessments be conducted by the federal government within the National Environmental Policy Act (NEPA) process has produced challenges in Alaska. Additionally, no funding mechanism is provided to develop these assessments or the strategic plan called for by the bill. The section also lacks a mandate for State or Native representation on the Advisory Board.

*Subpart C—Climate Change Safeguards for Natural Resources Conservation*

*Natural Resources Climate Change Adaptation Plan; Natural Resources Climate Change Adaptation Strategy; Natural Resources Adaptation Science and Information. (Sec. 365-367)*

- Mission of Panel. The State believes the purpose of the Natural Resources Climate Change Adaptation Panel should be expanded to address other forms of adaptation, such as infrastructure. As introduced, the bill lacks a strategy for coordinating federal policy on climate change effects outside of the natural resources area.

*Federal Natural Resource Agency Adaptation Plans; State Natural Resources Adaptation Plans. (Sec. 368-369)*

- Flexibility. The State fears the natural resource adaptation framework in S. 1733, like that in H.R. 2454, is too top-down driven for success. The bill calls for each federal agency to develop a natural resource adaptation plan, with which subsequently-formed state plans must be consistent. Climate impacts, however, differ regionally and locally, requiring maximum flexibility. Development of a national plan will hamstring local identification and prioritization of issues and associated strategies to address them, stifle innovation, and prevent the local "buy-in" vital to effective implementation. A national focus also impedes the development of regional strategies.

  States should be allowed to negotiate cooperative natural resource agreements with the federal government on a state-by-state basis with maximum flexibility.

In the face of significant intrusion by the federal government on a state's authority to regulate fish and game, states may reasonably prefer departing from the national strategy. If a state does so, however, it will be penalized through denial of funding under programs in this subtitle and potentially other federal programs. The scenario is counterproductive and could be alleviated with greater flexibility.

- Competing Interests. The State fears efforts to assist species in adapting to climate change and ocean acidification will require controlling human activities to reduce other stressors on these species. Large new conservation units may be carved out and human activities in migration corridors could be substantially limited. The bill does not state how the adaptation strategy and planning called for is to be reconciled with human population growth, resource development, commercial, and other human activities. With this approach, other competing interests of importance to the people of Alaska will be marginalized.

*National Resources Climate Change Adaptation Account. (Sec. 370)*

- Other Statutes. The State believes the bill should specifically de-link existing statutes, such as the Endangered Species Act (ESA), from the climate change policy process. The State opposes use of the ESA as a vehicle for carrying out climate change policy. Section 370 provides for an expansion of ESA programs, which, without further guidance, could result in significant increases in listings that provide little benefit to those species. The bill should include language affirming that climate change legislation is the appropriate instrument for responding to climate change and that ESA should retain its traditional role of conserving species most at risk.
- Corps of Engineers. The State also believes this section should be modified to explicitly grant the U.S. Army Corps of Engineers the authority to use Natural Resources Climate Change Adaptation Account funding for coastal erosion reduction projects and infrastructure adaptation.
- Funding Allocation. The State appreciates that, of the funds made available to states in this account, a portion (six percent) is set aside for coastal agencies. Coastal states will have unique adaptation needs. To ensure adequate funding where climate change impacts are most severe, though, the State advocates for a separate allocation for Arctic adaptation efforts.

*National Wildlife Habitat and Corridors Information Program. (Sec. 371)*

- State's Role. The State fears this section undermines the State's role as primary trustee over fish and wildlife. The proposed National Fish and Wildlife Habitat and Corridors Information Program centers around developing Geographic Information System (GIS) databases and maps to support decision-making in this area. The State approves of this approach. The stated purpose of the effort, however, is to allow the Secretary of the Interior to recommend how the information developed "may be incorporated" into relevant State and federal plans that affect fish and wildlife including land management plans, and the State Comprehensive Wildlife Conservation Strategies. Further, the Secretary is granted authority to "ensure that relevant State and federal plans that affect fish and wildlife (1) prevent unnecessary habitat fragmentation and disruption of corridors; (2) promote the landscape connectivity necessary to allow wildlife to move as necessary to meet biological needs, adjust to shifts in habitat, and adapt to climate change; and (3) minimize the impacts of energy, development, water, transportation, and transmission projects and other activities expected to impact habitat and corridors." The State is leery of this expansion of federal authority. To be successful, adaptation efforts must respect the primary roles and authorities of State fish and wildlife agencies in managing fish and wildlife and be built on this precept.
- Landscape Conservation Planning Programs. The relationship of this program to existing landscape conservation planning programs (such as the Landscape Conservation Cooperatives) should also be clarified.

*Subpart D—Additional Climate Change Adaptation Programs*

*Coastal and Great Lakes State Adaptation Program. (Sec. 384)*

- Funding Formula. The State approves of this program's focus on coastal states. By factoring in the proportion of shoreline miles, the formula also acknowledges that a state's amount of coastline is an important consideration in assessing adaptation needs. Once again, however, the State feels the formula should account for the unique needs experienced in the Arctic and high latitudes.

## DIVISION B—POLLUTION REDUCTION AND INVESTMENT

### TITLE I—REDUCING GLOBAL WARMING POLLUTION

*Subtitle A—Reducing Global Warming Pollution*

*Reducing Global Warming Pollution. (Sec. 101)*

"International Offset Credits." (Clean Air Act [CAA] Sec. 744)

- International Offsets. The State supports the inclusion of international offsets (the ability for companies to reduce emissions outside the U.S. and have it count towards domestic reductions). Like H.R. 2454, S. 1733 allows international offsets, though the portion of overall offsets comprised by international offsets is smaller in S. 1733 than in H.R. 2454.

*Definitions. (Sec. 102)*

"Definitions." (CAA Sec. 700)

- Alaska Refineries. Alaskans are uniquely dependant on in-state refineries for their fuel needs. Alaska has limited fuel storage and is located thousands of miles from the nearest non-Alaskan refinery. The state's refineries are particularly vulnerable to increased costs because they are relatively simple on the Nelson Complexity Index, meaning they operate at lower levels of economic efficiency than more sophisticated refineries which can extract more refined product from a barrel of crude oil. If Alaska's refineries are disadvantaged to the point of closing, it would likely produce a wide range of negative consequences across the state. These may include higher costs associated with importing fuel by tanker and building storage tanks in addition to increased economic burdens on Alaska's rural communities.
  The Chairman's Mark includes provisions granting small business refiners additional time to comply with the Pollution Reduction and Investment program and distributes additional allowances to small business and medium refineries. These provisions could help Alaska's refineries, but may not be sufficient to protect them from substantial costs.
  The State would support an exemption for certain domestic refineries to prevent regional market failures and promote the interest of regional energy security. One way of achieving this is through modifications to the definition of "covered entities" in the Clean Air Act. First, the language in S. 1733 could be amended to match the corresponding language in H.R. 2454, requiring that a stationary source producing petroleum products do so in "interstate commerce" to be covered under CAA Section 700(13)(B). Second, CAA Section 700(1)(F) subsection (viii) for "petroleum refining" could be removed. These modifications would exempt refineries, like those in Alaska, that sell virtually all of their saleable product in-state.
- Embedded Emissions, Direct Emissions, and Fossil Fuel Based Carbon Dioxide. The State supports adding definitions for Embedded Emissions, Direct Emissions, and Fossil Fuel Based Carbon Dioxide to clarify that natural gas produced at the wellhead or flowing through a pipeline will not be burdened with the requirement of emission allowances for the carbon dioxide that may one day be produced when the natural gas is burned.
- Natural Gas Liquids. The State seeks clarification on this section, which differs from H.R. 2454 in its definition of natural gas liquids as being "ready for commercial sale or use." This change raises concern given the value natural gas liquids bring in a major gas sale scenario.

*Disposition of Allowances for Global Warming Pollution Reduction Program. (Sec. 111)*

- Fair Allocation of Allowances. The State is very concerned about the disposition of allowances for Alaska under a cap-and-trade regime. An EPA memo provided to Senator Feingold indicated that the agency drastically underestimated emissions in Alaska. The document gave the false impression that Alaska would be sufficiently accommodated through the provision of free allowances under H.R. 2454. EPA's estimates for capped emissions in 2012 appear to have been based exclusively on Alaska's electric generation, primarily electricity generated for retail electricity sales, leaving out all facilities that generate their own power, such as oil and gas fields and some military bases. As a result, EPA estimated the state's emissions at three million tons per year (MMt/yr). For the same year, the State's models estimated capped emissions at 24.2 MMt/yr. This inaccuracy could substantially disadvantage Alaska in the distribution of allowances.

- Emission Allowances for Alaska Natural Gas Transportation Projects. The State supports specific free emission allowances for the operation of Alaska Natural Gas Transportation Projects. The 1,700 mile Alaska Gas Pipeline will be a source of substantial $CO_2$ emissions, estimated to be between 20-50 percent of total Alaskan capped emissions.

"Electricity Consumers." (CAA Sec. 772)

- Regulatory Commission Approval. This section describes an allocation process for allowances to electric utilities with a requirement that applicants first seek approval from the Regulatory Commission of Alaska. This requirement could create a costly unfunded mandate for the State as regulatory proceedings have become contentious and expensive.
- Hydropower Projects. See discussion for section 161.

"Home Heating Oil and Propane Consumers." (CAA Sec. 774)

- Heating Oil Allocation. CAA Section 774 addresses allocations to states based on domestic oil and propane consumption and, as written, is unfavorable to Alaska. Free allowances for heating oil and propane would be allocated to the states based on each state's relative share of total domestic heating oil and propane consumption. Alaska consumes a significant amount of oil due to heating degree days and the prevalence of heating oil use across the state. Heating oil and propane, however, appear to be weighted equally. Thus, states like California and Texas that may consume more propane for barbecue grills and hot tubs than Alaska consumes heating oil, would receive larger shares. The State believes heating oil and propane should be separated for allocation purposes.

Exchange of State-Issued Allowances." (CAA Sec. 777)

- State-Issued Emission Allowances. Although Alaska is only an observer of the Western Climate Initiative (WCI), it supports WCI's position that the work of the states should be integrated into a new climate regime, rather than completely preempted. This bill would integrate state efforts by exchanging regional allowances for federal allowances.

"Commercial Deployment of Carbon Capture and Sequestration Technologies." (CAA Sec. 780)

- CCS in High-Cost Locations. The State supports the commercial deployment of carbon capture and sequestration (CCS) technologies, and in particular, sequestration as a result of Enhanced Oil Recovery (EOR) projects. CCS is afforded special treatment through the "bonus allowance value," which is essentially a subsidy when compared to the value of purchased or freely distributed allowances.
  The State supports EOR activities in Alaska, especially on the North Slope. This activity produces multiple benefits. Sequestration of $CO_2$ in a known, well-defined hydrocarbon reservoir and trap is inherently safer than in those that are less defined. Furthermore, increased production due to EOR will lengthen oil field life. Since a gas pipeline from the North Slope is economically dependent on the oil field facilities, increasing oil field life improves the economics of a gas pipeline. Gas, as a fuel source, is more environmentally friendly than other carbon fuel sources.
  The costs of CCS on the North Slope may still be prohibitive, however, even with a boost from these allowances and incentives through carbon costs. Costs have been found to be significantly higher for CCS on the North Slope than the averages published for the Lower 48, primarily due to the North Slope's location and weather. The State supports inclusion of provisions that account for greater expenses in high-cost locations in order to make CCS economically feasible in these areas.

*Ensuring Real Reductions in Industrial Emissions. (Sec. 141)*

"Definitions; Eligible Industrial Sectors." (CAA Sec. 762, 763)

- Foreign Competition for Domestic Refineries. These sections protect certain manufacturing industries from "off-shoring" and foreign competition, but specifically exclude domestic refineries. The State believes domestic refineries should be protected as well.

TITLE II—PROGRAM ALLOCATIONS

*State and Local Investment in Energy Efficiency and Renewable Energy. (Sec. 202)*

- Allocation Formula. The allocation method in this section unfairly disadvantages Alaska. While 30 percent of the allowances are granted to states on an equal basis, 30 percent is allocated based on population and another 40 percent is allocated based on state energy consumption as a share of total domestic consumption. By these standards, Alaska would receive fewer allowances than almost any other state. This proposal is unfair to Alaska because the state has more heating degree days and thus Alaskans use more energy on average than residents of other states, costs are highest in rural Alaska where incomes are typically lowest, and switching to other fuel sources is not possible or cost effective in most cases for rural Alaskans. The State would support an increased percentage distributed equally among states, measuring energy consumption per capita rather than as a share of total consumption, or allocating some allowances based on energy costs as a share of per capita income using Census data.
- Indian Tribes. In addition, the State supports Section 202, which provides for the distribution of allowances to Indian tribes, which may benefit some rural areas of Alaska.

ADDITIONAL ISSUES

Domestic Production.—The State believes S. 1733 should be modified to expand access and incentives for responsible domestic onshore and offshore oil and gas exploration and production. The U.S. Department of Energy's recent forecast for growth in the energy sectors shows demand for fossil energy continuing to increase in the nation, and to remain above 80 percent of the total portfolio of energy supply through 2030 and beyond. Therefore, it is clear that fossil fuels will be needed as a bridging fuel in the coming decades, and access to domestic production, and specifically clean-burning natural gas, is imperative. Increased domestic production, carbon mitigation, expanded development of renewables, and long-term nuclear energy planning is the only viable path to a secure energy future.

OMB Funding Criteria.—The State believes the Office of Management and Budget should be tasked with developing common criteria federal agencies can use to prioritize funding to state and local governments and tribes for infrastructure and other projects addressing climate change vulnerabilities. Existing funding criteria may not be appropriate for this purpose. For example, in sparsely populated but more vulnerable areas like western Alaska, federal assistance may be withheld despite great vulnerability if the primary criterion for funding is the number of people or the dollar value of infrastructure at risk.

EPA Limitation Provision.—S. 1733 does not include important language related to the Environmental Protection Agency that appeared in H.R. 2454. The House bill contains language preventing the EPA from requiring performance standards on stationary sources under the federal cap. The State feels limitation language like that in the House bill should be included in S. 1733 and that EPA officials should not set climate change policy.

Adaptation Priorities.—The State has identified the following as high priorities and areas of need with respect to adaptation:

- Changing Risks. The State supports collaboration between the states, federal agencies, and academia to challenge traditional assumptions on weather and climate. This effort should focus on data collection and analysis, forecasting models, hydrology, flood plains and inundation, coastal and riverine erosion, critical infrastructure, and related topics.
- Community Profile. The State believes the initial focus and study on adaptation should be on Alaskan coastal and riverine communities. These communities are currently threatened due to climate change and cannot relocate without extreme disruption and costs.
- Evacuation Routes. The State seeks federal assistance in identifying, designing, constructing, and maintaining all-weather evacuation routes from endangered communities to safe havens from approaching storms.
- Safe Havens. The State seeks federal assistance in selecting and equipping safe havens near the endangered communities, with full consideration of the hydrology, geology, and current and more accurate digital mapping. These safe havens should be outfitted with sufficient housing, water and fuel sources, and communications capabilities.
- Shoreline Protection and Stabilization. The State supports a program of shoreline protection and stabilization and considers such projects as the most effective means of protecting against the sudden onslaught of storms.

- Science, Analysis, and Informed Decisions. The State calls for creating and sustaining a program of coordinated, collaborative scientific examination and study of the Arctic climate and environment.
- Other Key Areas. Alaska's needs will also encompass other key areas such as consequences to natural resources, national security, infrastructure, emergency response capacity, etc., resulting from climate change impacts due to diminishing Arctic sea ice and from ocean acidification.

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## STATEMENT OF DAIMLER TRUCKS NORTH AMERICA

Daimler Trucks North America (DTNA) appreciates Chairman Bingaman and Ranking Member Murkowski for holding an important hearing on the role of natural gas in mitigating climate change. DTNA is a leader among US truck manufacturers in introducing natural gas technology in its lineup of trucks. We strongly believe that natural gas, particularly in the truck sector, is a viable solution to reducing greenhouse gas emissions, lowering diesel consumption, and reducing fuel costs.

Earlier this year Daimler's Freightliner brand introduced its first natural gas-powered truck. The Freightliner Business Class M2 112 NG is ideal for port operations, utilities, and municipalities and other short and medium-haul trucking applications. By next year Freightliner will offer natural gas technology in 90 percent of its truck applications.

Daimler is committed to natural gas because of its inherent advantages over petroleum-based fuel. For example, it produces lower fuel costs both today and for tomorrow. Today diesel averages $2.54/gallon whereas CNG averages $1.73/gallon. And annually, natural gas technology can save an estimated $10,000 in fuel and operating costs per truck. Freightliner's natural gas trucks are cleaner too. Our trucks already meet the Environmental Protection Agency's (EPA) 2010 standards with 85 percent lower $NO_X$ emissions than its diesel counterpart. Most importantly, the United States has an abundant supply of natural gas that may allow natural gas vehicle operation for years to come. According to the Energy Information Administration, proven reserves in the US are continuing to increase.

Natural gas powered trucks are perfect for short and medium-haul trucking. Today's natural gas trucks are ideally suited for 300 miles a day usage. For companies that rely on short and medium-haul distances, for example at ports and in local municipalities, natural gas is both economical and efficient.

Although natural gas trucks have distinct advantages, we recognize challenges continue to exist, particularly for long-haul trucking. The lack of a national network of natural gas stations is the leading obstacle facing natural gas long-haul trucking. Less than 1,000 natural gas stations exist in the US. By comparison, there are over 120,000 gas stations. Technology costs still remain high too. The incremental cost of a typical natural gas truck is $45,000 more expensive than a comparable truck with a conventional diesel engine. Engine technology is still a work in process, especially for long-haul heavy trucks that need a lot of power and must meet 2010 EPA emissions standards.

Daimler Trucks believes these challenges can be overcome in a relatively short period of time given the right mix of vehicle, fuel, and infrastructure incentives. The alternative motor vehicle tax credit and natural gas refueling property credit are both important tools for stimulating demand. New grant opportunities for natural gas vehicle and engine development are also critical to natural gas' future.

Daimler Trucks urges the Congress is support natural gas technology and recognize its value as a clean, abundant, domestically-produced fuel in the debate over climate change.

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## STATEMENT OF NGVAMERICA

### I. INTRODUCTION

NGVAmerica appreciates the opportunity to provide the following statement concerning the role of natural gas in mitigating climate change. NGVAmerica is a national organization dedicated to the development of a growing and sustainable market for vehicles powered by natural gas, biomethane and natural gas-derived hydrogen. NGVAmerica represents more than 100 member companies, including: vehicle manufacturers; natural gas vehicle (NGV) component manufacturers; natural gas distribution, transmission, and production companies; natural gas development organizations; environmental and non-profit advocacy organizations; state and local government agencies; and fleet operators.

On October 28, 2009, the Senate Energy & Natural Resources Committee conducted a hearing to review the role of natural gas in mitigating climate change. A number of industry representatives were on hand to discuss the potential positive impact of increased natural gas use. NGVAmerica's statement specifically addresses how the increased use of natural gas vehicles (NGV) can play an important role in reducing greenhouse gas emissions from the transportation sector and provide other important benefits.

One of the most important points to consider when assessing the potential role of natural gas in mitigating climate change associated with the transportation sector is the recent findings concerning the increased availability of domestic natural gas supplies. This point is critical because, in the past, questions have been raised about whether the U.S. has sufficient domestic resources to support the increased use of natural gas as a transportation fuel. Those concerns have now been dispelled given the recent extraordinary expansion of the U.S. natural gas resource base. Over 85 percent of natural gas used in the U.S. today in produced in the U.S. (most of the rest is produced in Canada). By 2030, the U.S. Energy Information Administration forecasts that 97 percent of the natural gas used will be produced in the U.S. Therefore, the U.S. natural gas resource base could easily support a growing NGV market. Increasing the use of NGVs will help reduce greenhouse gas emissions and lessen reliance on foreign oil imports.

Natural gas is widely recognized as a low-carbon fuel, the cleanest of all the fossil fuels. Extensive analysis indicates that the natural gas when used as a transportation fuel reduces carbon dioxide equivalent emissions by 20—30 percent compared to gasoline and diesel. These benefits are based on full-fuel cycle analyses that have been conducted by federal and state environmental authorities. In addition, natural gas when used as a transportation fuel is quite competitive with the current generation of renewable fuels and is capable of being blended with renewable fuel or sourced completely from renewable feedstocks (e.g., landfill methane gas). Renewable natural gas currently is the cleanest transportation option available anywhere. The benefits of renewable natural gas often are overlooked due to the focus on liquid biofuels. NGVs also provide benefits in terms of reductions in criteria pollutants as well, a point underscored by the fact that some of the cleanest internal combustion engines in the world are fueled by natural gas.

In addition to the public policy advantages, NGVs are a proven technology that is available today. In fact, in most areas of the world, NGV use is growing at a rapid pace. In the U.S. the market is growing but at a much slower pace than elsewhere. Because the technology is available now, NGVs can help offset greenhouse gas emissions, and petroleum imports immediately without delay. Accelerating the use of natural gas for transportation will lead to increased economic activity associated with increased production of domestic natural gas, installation of fueling infrastructure and vehicle development. Natural gas sells as a considerable discount to petroleum motor fuels and all other alternative fuels, so its use can help businesses save money. With the right policies in place, the U.S. could rapidly accelerate the use of NGV.

Congress already has taken a number of steps to encourage greater use of natural gas and other alternative transportation fuels. These steps were enacted as part of the Energy Policy Act of 2005 and SAFETEA-LU. These incentives include tax credits for alternative fueled vehicles, alternative fuel infrastructure and alternative fuel use. Consumers and businesses alike are benefiting from the congressional action that was taken to encourage the increased use of alternative fuels. However, much more must be done if the U.S. is going to address climate change and reduce its reliance on petroleum. This effort will require sustained and significant federal support since the risks associated with this effort are simply too great for private industry to undertake alone in the timeframe needed. Moreover, this effort will require a mix of different transportation fuels to fill the void provided by petroleum, since no one single fuel appears likely to supplant petroleum. Natural gas in particular can play an important role in fueling medium- and heavy-duty vehicles and high fuel use passenger car and light truck fleets.

*Summary of Recommendations*

1. Extend the current tax incentives for natural gas as a transportation fuel. These incentives were adopted as part of the Energy Policy Act of 2005 and SAFETEA-LU 2005. Most of these incentives are set to expire at the end of 2010. The NAT GAS Act of 2009 (S. 1408) would extend these incentives and improve on them by making certain modifications. We urge the Senate Energy & Natural Resources Committee members to support enactment of this law.

2. Encourage the production of renewable natural gas by providing a tax credit for renewable energy projects that inject renewable natural gas into the natural gas pipeline system.

3. Provide appropriate treatment for NGVs in the climate change bill. Previous versions of the bill have encouraged electric-drive vehicles and liquid biofuels over all other alternative fuel options. There are many reasons to support the increased use of electric vehicles and liquid biofuels. However, transportation policy also should include a strong role for NGVs. That means ensuring that federal R&D efforts aid in improving the next generation NGVs and developing hybrid vehicles that use natural gas engines. Moreover, it is important to adopt policies that encourage public utilities to play a role in developing the market for NGVs.

## II. U.S. DOMESTIC SUPPLY OF NATURAL GAS

The U.S. is fortunate to have a significant resource base of natural gas. As recently as several years ago, there was concern that U.S. and North American production would soon start to decline due to a rapidly dwindling resource base. However, the past year has seen an almost complete turn around in the outlook for natural gas. Energy analysts from across the spectrum are now heralding the new age of natural gas production here in the U.S. and possibly elsewhere in the world as shale gas production is now economically feasible. Many now point to the Colorado School of Mines' Potential Gas Committee's report[1] issued in June to highlight the changing outlook. Based on the figures published by the PGC, the U.S. now has a 90-plus year resource base of natural gas instead of the 65 year resource base believed to exist in 2006.

MIT's *Technology Review* devotes its November/December cover page story to discussing the remarkable turn of events here in the U.S.[2] The article describes how some analysts think the assessments of the production capabilities of the northeast's Marcellus Shale are much larger than estimated by PGC. The article describes how the Marcellus could be the second largest natural gas field in the world, second only to a massive offshore field shared by Iran and Qatar. Daniel Yergin and Robert Ineson, of the respected Cambridge Energy Research Associates, recently authored an article for the Wall Street Journal, entitled, "*America's Natural Gas Revolution—A 'shale gale of unconventional and abundant U.S. gas is transforming the energy market*.'"[3] The article claims that the biggest energy innovation of the decade is the development of unconventional natural gas. The article also indicates that "shale gas plays around the world could be equivalent to or even greater than current proven natural gas reserves." The conclusion of this article is that natural gas is likely to play a much larger role in the world's energy mix in future years.

With abundant domestic supplies, natural gas use in transportation becomes increasingly attractive. Policy makers should no longer be wary about whether we have the natural gas supplies to support its use as a transportation fuel. To put the potential in perspective, consider that we currently use roughly about the same amount of total energy for on-road transportation as we do for all natural gas purposes (e.g., electric generation, commercial, residential). Therefore, replacing 10–20 percent of transportation fuel use with natural gas would increase natural gas use by only 10–20. The U.S. natural gas vehicle industry is focusing its marketing efforts on capturing an increased share of the medium-and heavy-duty market and a share of the light-duty high-fuel fleet market. Since 30 percent of the petroleum used for transportation is diesel fuel and since NGVs are the only alternative fuel that can capture a significant share of the diesel market, the industry's strategy makes sense for the NGV industry and public policy.

## III. CLIMATE CHANGE BENEFITS OF NATURAL GAS VEHICLES

Natural gas is a recognized low-carbon fuel. In the past several years, extensive analyses have been conducted to determine the full fuel cycle emissions impact of NGVs. These reports indicate that natural gas reduces greenhouse gas emissions by up to 30 percent when compared with gasoline and diesel fuel. The most recent reviews have been conducted by the California Air Resources Board (CARB), which conducted an exhaustive review of different transportation fuels as part of its effort

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[1] See Potential Gas Committee Press Release—http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base.

[2] "Natural Gas Changes the Energy Map", *MIT Technology Review* (November/December 2009).

[3] WallStreet Journal (November 3, 2009).

to develop the nation's first low-carbon fuel standard.[4] This standard requires a 10 percent reduction in carbon intensity of transportations fuels by 2020. CARB has determined that natural gas exceeds the requirements of the program and, therefore, has exempted it from the regulatory requirements. Businesses that supply natural gas for the transportation market, however, are free to become regulated entities if they wish to earn credits under the program.

The LCFS assigns a carbon intensity factor to different fuels based on a full fuel cycle analysis, i.e., well-to-wheels. According to CARB, the carbon intensity of natural gas is 68 $gCO_2e$ per mega-joule (MJ). The carbon intensity for gasoline and diesel fuel is 95.85 and 94.71, respectively. Thus, natural gas is estimated to be 29 percent less carbon intensive when compared with gasoline. Natural gas is estimated to be 20 percent less intensive than diesel fuel when used in medium or heavy duty vehicles; CARB currently assumes a 10 percent fuel efficiency penalty for heavy-duty NGVs, thus the reason for the reduced carbon benefits. The carbon intensity of renewable natural gas (i.e., biomethane produced from organic waste) is estimated to be 11–13 $gCO_2e$ per MJ. At 11.25 $gCO_2e$/MJ, renewable CNG from landfill gas has the lowest of any fuel reviewed by CARB—even lower than biodiesel (unadjusted for indirect land-use) at 13.70 $gCO_2e$/MJ. The reductions for renewable natural gas are nearly 90 percent when compared with gasoline and diesel fuel. To highlight the viability of renewable natural gas, a short summary of existing projects involving biomethane is provided below.

The greenhouse gas emission benefit of NGVs is expected to continue to improve in the future as new automotive technologies become available. In fact, a recent National Academy of Science (NAS) report, entitled *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*[5] includes some very positive findings concerning natural gas vehicles. The report, which analyzed vehicle technologies as of 2005 and 2030, essentially projects that with further expected improvements in vehicle technology and fuel efficiency, natural gas powered vehicles will provide superior benefits in terms of criteria pollutant reductions and greenhouse gas emissions compared to nearly all other types of vehicles, even electric and plug-in electric vehicles. The report's findings include an assessment of the full fuel cycle benefits of different transportation fuels and vehicles, and include an assessment of the energy and emissions associated with producing motor vehicles. The NAS report's assessment of natural gas calculates the emissions in terms of grams of $CO_2$-equivalent per mile, not per mega-joule. The total emission reduction benefits projected in the NAS report are more modest than those reported by CARB, which did not include emission associated with vehicle production. The NAS report indicates that natural gas vehicles currently provide about an 11 percent reduction in $CO_2$-equivalent emissions compared with gasoline passenger vehicles, but it projects that this benefit will grow to 21 percent by 2030 with improvements in fuel efficiency.

Natural gas also can be used to provide hydrogen for fuel cell vehicles. Nearly all of the hydrogen used in the U.S. today is reformed from natural gas. We previously have provided statements to Congress on the role natural gas can play in accelerating the introduction of hydrogen fuel cell vehicles. We would be happy to provide such information to the committee if it is interested.

IV. EXAMPLE OF RENEWABLE NATURAL GAS TRANSPORTATION PROJECTS

While the number of renewable natural gas projects in the U.S. remains small, it is worth highlighting several of these projects to show that this fuel has real potential.[6]

The McCommis Landfill in Dallas, Texas is currently supplying 4.5 million cubic feet of natural gas per day. This is the energy equivalent of producing 35,000 gallons of gasoline per day. The biomethane is currently being injected into the natural gas pipeline system nearby. However, Clean Energy, a major provider of natural gas

[4] See CARB Low Carbon Fuel Standard—http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. CARB's website includes numerous documents detailing the greenhouse gas impacts of different transportation fuels including assessments of LNG, CNG, and renewable natural gas. The renewable natural gas papers include assessments of CNG and LNG from biomethane. The California Energy Commission similarly has published an extensive review of the well-to-wheel analysis of different transportation fuels. The results of the CEC analysis are contained here: http://www.energy.ca.gov/2007publications/CEC-600-2007-004/CEC-600-2007-004-REV.PDF.

[5] National Academy of Science (October 2009): http://www.nap.edu/catalog/12794.html

[6] One of primary reasons that the number of biomethane projects in the U.S. is growing slowly is that the federal government provides a significant tax incentive from producing electricity from biogas on site, but no incentive for producing and using biomethane. The size of the tax incentive has skewed the use of biogas toward on-site electricity generation. Legislation has been introduced in the House and the Senate (HR 1158 and S. 306) to provide a more level playing field for biomethane production.

for transportation use, owns the rights to the natural gas and has plans for someday using this fuel as a transportation fuel.

In California, Waste Management, North America's largest waste management company, and Linde North America, recently began producing LNG at the Altamont Landfill near Livermore, California. The LNG will be used to fuel hundreds of refuse collection trucks. Waste Management and Linde have said the facility is expected to produce up to 13,000 gallons a day of LNG.

In Texas, manure from dairy farming operations is being converted into methane at the Huckabay Ridge facility. The facility is capable of processing manure from up to 10,000 cows. According to published reports, this facility produces 650,000 million BTU a year, which is equates to a gasoline gallon production rate of almost 14,000 gallons per day. The biomethane at this facility is sold as pipeline-grade natural gas.

In Ohio, the Solid Waste Authority of Central Ohio (SWACO) is currently producing biomethane from landfill waste and converting it to CNG. The fuel is then used to fuel a small number of vehicles at the company's Green Energy Center. The production at this facility currently is only about 250,000 gallons per year, much smaller than other facilities identified. However, SWACO plans to expand its operations, and will have the capability of annually producing 5—10 million gasoline gallons. SWACO currently plans to sell the biomethane to local utility pipelines.

Prometheus Energy and the Bowerman Landfill in Orange County, California have partnered to turn landfill gas into LNG. The fuel is being used to fuel local transit buses and garbage trucks. The plant installed at the site is currently producing about 1,000 gallons of LNG per day, but is expected to increase daily production to 5,000 gallons.

In Europe, biomethane for transport is catching on much faster than in the U.S. In fact, Sweden currently estimates that fifty-five percent of the natural gas used in vehicles in that country is biomethane. To facilitate the use of biomethane, several European countries also have policies that require pipelines to accept the transport of biomethane. An excellent summary of developments in Europe was prepared by the Goteborg Business Region and Biomethane West.[7]

The U.S. Department Office of Energy Efficiency & Renewable Energy recently prepared a white paper on the potential of using renewable natural gas.[8] The document provides an excellent overview of the benefits and potential for renewable natural gas.

### V. ENACT INCENTIVES THAT ENCOURAGE THE USE OF NATURAL GAS VEHICLES

In order to achieve the potential benefits of increased natural gas use, NGVAmerica urges the Finance Committee and Congress to enact the NAT GAS Act (S. 1408, HR 1835). In addition, we also would urge the Congress to enact legislation supporting the production of renewable natural gas.

### NAT GAS ACT

Both the House and Senate have introduced legislation to advance the use of NGVs. The bills, S. 1408 and H.R. 1835, are very similar. Importantly, both would extend the current incentives for natural gas users that have been in place since 2006. The bill's also modify and expand the incentives to make them more effective. These incentives are about to expire at the end of this year (in the case of the credit for sale of CNG or LNG) and next year (in the case of the incentive NGV purchases and fueling infrastructure development). The bills also include federal authority to carry-out much needed research and development (R&D) necessary to improving the quality and performance of the next generation of NGVs. Extending the effective dates of these expiring provisions would help continue the progress made by natural gas fueled vehicles in displacing gasoline and diesel. Extending the effective date also would send a clear message to fleets and other vehicle owners that Congress supports the use of alternative fuels like natural gas as an energy security and climate change strategy for the mid-and long term. Adoption of these incentives is critical to ensuring that the U.S. takes advantage of the significant opportunity provided by its large natural gas resource base. NGVs are a solution that can have an immediate impact on petroleum imports, economic activity and greenhouse gas emission reductions. For all these reasons, it is imperative that the Congress enact the NAT GAS Act.

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[7] See Fueling the Future; http://www.businessregiongoteborg.com/download/18.450110ae10c3994eae68000922/BiomethaneV__FuelingTheFuture.pdf.

[8] Renewable Natural Gas: Current Status, Challenges, and Issues (Sept. 2009); http://www1.eere.energy.gov/cleancities/pdfs/renewable__natural__gas.pdf.

*Renewable Natural Gas Legislation*

S. 306, the Biogas Production Incentive Act, introduced by Senator Nelson (D-NE), would establish a $4.27 per MMBTU tax credit for the production of renewable gas. Representative Higgins (D-NY) also has introduced similar legislation in the House (H.R. 1158). The U.S. Congress currently supports the expanded use of domestic renewable resources through a variety of tax incentives and other programs. Up to this point, Congress has focused primarily on measures that support the production of renewable liquid transportation fuels or renewable electricity. In the U.S., however, natural gas represents 23 percent of the energy consumed. Natural gas is the fuel of choice to provide residential and commercial heat for space and hot water in most applications and is used to produce steam in a variety of commercial and industrial applications.

Natural gas is also the fuel that provides the energy to manufacture many industrial products including aluminum, steel, glass, chemicals, fertilizer, and ethanol. Incentivizing the production of renewable gas from sources that include animal manure, landfills, renewable biomass and agricultural wastes will support expanding the role of renewables into this existing energy sector, where little opportunity exists today. It will also create another business investment prospect for renewable project developers and the potential to expand rural economies while supporting existing industrial jobs and dramatically reducing carbon emissions.

Renewable natural gas is a versatile form of bio-energy. It can be used directly at the site of production, or placed in the pipeline to support a variety of residential commercial or industrial applications. Renewable natural gas produced from renewable sources, including animal manure, landfills, renewable biomass and agricultural waste, can be produced at high efficiencies, ranging from 60–70 percent. Additionally, all of the technology components to produce renewable gas from this variety of sources exist today. Renewable natural gas can be delivered to customers via the existing U.S. pipeline infrastructure. It can provide a renewable option for many heavy industries, which could save existing industrial jobs in a carbon constrained economy—while creating new rural green jobs. As noted earlier, renewable natural gas also can be an excellent transportation fuel. Renewable natural gas production in digesters provides the agricultural sector additional environmental benefits by improving waste management and nutrient control.

For all the reasons discussed here, the Congress should adopt a new tax credit specifically encouraging the production of renewable natural gas.

## VI. CLIMATE CHANGE LEGISLATION

The Congress currently is considering a number of proposals to address climate change. At this point, it is difficult to determine which proposals likely will be enacted into legislation. However, we offer the following comments in regards to some of the major themes that have been put forward. Several of the introduced proposals call for accelerated introduction of more fuel efficient vehicles and specifically encourage efforts to commercialize electric vehicles. We support such efforts but believe that the legislation should be expanded to specifically include NGVs. As noted above, the Congress should extend the current tax incentives for NGVs. This would accelerate their introduction and deliver immediate greenhouse gas emission reductions. Some climate change proposals also would allocate a portion of the proceeds from carbon allowance sales to the Department of Energy or Environmental Protection Agency for advanced vehicle research. These proposals again have largely focused on the role of electric vehicles and their contribution to reducing greenhouse gas emissions. Such efforts also should include NGVs. There also have been proposals to encourage electric utilities to facilitate the development of electric charging infrastructure. Natural gas utilities also could play a major role in facilitating the use of low-carbon fuels and their infrastructure. Legislation should encourage natural gas utilities to make investments in natural gas fueling infrastructure and upgrades to their distribution systems that will enable greater use of natural gas vehicles and use of renewable natural gas.

Climate change legislation also should not discourage businesses from selling more natural gas for transportation purposes. Natural gas is a low-carbon fuel and its use should be encouraged, not discouraged. As described above, substituting natural gas for petroleum provides significant climate change benefits. Therefore, cap-and-trade provisions should not include natural gas sales for transportation when capping utilities sales of natural gas. If sales of natural gas for transportation are included in the cap imposed on utilities, gas utilities will have no incentive to grow new markets for natural gas as this will only increase their burden to obtain offsets so that they can continue to serve their traditional customers (e.g., residential, commercial). Rather than working to facilitate a transition to greater natural gas use in transportation, climate change legislation, if not correctly drafted, could result in utilities viewing increased use of natural gas for transportations as a burden to them.

VII. CONCLUSION

NGVAmerica appreciates the opportunity to provide this statement. We look forward to working with the committee as it crafts legislative proposals to address climate change and energy security in ways that will diversify the mix of fuels used in transportation.

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