BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

STATE OF THE NATURAL GAS : AD08-12-000

INFRASTRUCTURE CONFERENCE :

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D.C.

Friday, November 21, 2008

9:40 a.m.

The above-entitled matter came on for conference pursuant to notice at 9:40 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN JOSEPH T. KELLIHER (Presiding)

COMMISSIONER SUEDEEN G. KELLY

COMMISSIONER MARC SPITZER

COMMISSIONER PHILIP MOELLER

COMMISSIONER JON WELLINGHOFF

P R O C E E D I N G S

(9:40 a.m.)

CHAIRMAN KELLIHER: Good morning and welcome to the State of the Natural Gas Infrastructure Technical Conference.

I just want to make some brief comments, I'll turn to my colleagues, and then I'll turn to Jeff Wright to describe some of the ground rules, and then we'll proceed.

From a high level point of view, I think the state of the U.S. natural gas market is very sound. We have a very high level of domestic gas production; we've seen recent increases over the past two years.

We have very significant gas reserves, especially shale and unconventional gas, and we have a robust infrastructure. We have the most robust pipeline network in the world; we have very significant storage capacity, both developed and potential, and we've increased our LNG import capacity by a thousand percent in recent years.

So there's a lot of good news. There is good news about the potential for significant increases in domestic gas production. The bad news is that we may only achieve that increase, if prices remain a higher plateau than in past years.

Much of the shale and the unconventional gas, will remain undeveloped, if prices fall to previous levels.

The U.S. gas market is very strong. We have an elegant structure. We have furious entry by producers. We have large networks with regional-scale pipelines. I think they're very attentive to meeting the needs of shippers.

You can see the percent of U.S. markets served by captive customers, is decreasing. It hasn't been eliminated but it's decreasing significantly. We do see significant competition among pipelines.

Now, the U.S. gas market is fully integrated with the Canadian market, and, properly speaking, we shouldn't really use the term, "U.S. gas market;" it really is a North American gas market.

I say that because it has the advantage of being true, but also out of respect to our Canadian brothers, who are represented here today and participating in our technical conference, that I probably will slip into the shorthand of "U.S. gas market," out of habit and custom, not out of any lack of understanding of the nature of the North American gas market.

But we are going to explore some significant questions here today, such as the size of the shale and unconventional gas in the U.S.; the likelihood that the U.S. will develop these reserves; what kind of price level is necessary to achieve production increases, and the timing of some of these production increases.

Also, what's the role of LNG in the future, particularly in light of the prospect of increased production in the lower 48. What will the impact of increased domestic 48 production be on the prospect of developing Alaska natural gas?

One issue that I think is important to all the Commissioners, is the impact of the current uncertainty on climate change policy on gas demand; also recognizing the possibility that that uncertainty may continue for some time, as well as the impact of what changes might actually occur in climate policy when the country finally does act.

Then, finally, the question that we're particularly interested in, is the view of the impact of the financial and credit crisis on gas infrastructure development. I look forward to hearing the views of the witnesses, and, of course, the views of my colleagues, as well.

Commissioner Moeller?

COMMISSIONER MOELLER: Thank you, Mr. Chairman. First, I want to thank all the panelists and Staff for putting together the program today. I think we have a great lineup of speakers. I know it takes an effort to get here, and we appreciate your effort.

As the Chairman laid it out, I think, quite well, we have a number of exciting issues and challenges before us. For the last couple of years, I have been in just about every public setting, trying to emphasize a point the Chairman just made: With the uncertainty over carbon legislation, we are, whether we like it or not, becoming more dependent on natural gas for electricity generation.

The numbers are really quite dramatic, if you look at them year to year, in terms of the change. I think this Commission is well aware of that. I'm not sure the general public or, necessarily, energy policymakers throughout the country are, but that is something that we should be focused on as we talk about the state of the infrastructure.

Is it adequate now? I think it is, but are there problems that we can anticipate, if we project increased demand for natural gas for either proactive policy reasons for policy reasons that are a result of inaction.

Thank you again for being here. I look forward to all your comments. Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Colleagues? Commissioner Spitzer?

COMMISSIONER SPITZER: Thank you, Mr. Chairman. I, too, am very excited about this. It's awfully important.

First, the FERC role is substantial. I think this Agency has a long tradition of being responsive to market signals, and that's certainly continued during my tenure. I commend the entire Commission for being attentive to issues of infrastructure, because, without the infrastructure, market signals are to no avail.

Secondly, those market signals are complex in the relationship between macroeconomic demand and supply. There is an interesting synergistic effect between the two, and I know we have divided, arbitrarily, the panelist, between demand and supply.

I'm particularly interested in the interrelationship. Sort of to simplify which come first, the chicken or the egg, are demand signals, macroeconomic demand, due to the downturn in the economy, going to, in turn, reduce the signals for supply, or are the long-term fundamentals of increased demand for energy, providing long-term supply signals that, in turn, may prevent some of the demand destruction that we've seen in the United States. I know the panelists have commented in the past on the issue of demand destruction.

Finally -- and this is very important for state commissions and consumers in the states -- back in Arizona, we are very attentive to these types of panels. Starting in, I suppose, 2001, when I first came to the Arizona Commission, we confronted the issue of volatility, how state commissions direct or encourage hedging policies, whether there's additional storage facilities proposed in the states in response to the volatility response and the market signals.

These hedging programs are dependent upon good information, and it's a benefit of this panel and those like it, where the states craft policies to protect their utilities and their consumers, to best try and deal with this trend for volatility.

We've seen quite a roller coaster in the last six months. There's nothing to suggest that those trends won't continue, but the best we can do, both here at FERC and for our state colleagues, is to assemble as much information and get the best and the brightest minds possible, which I think is the benefit of today's technical conference.

CHAIRMAN KELLIHER: Thank you. Commissioner Wellinghoff?

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman. I first want to apologize in advance; I'm going to have to leave at 10:30, but I am very interested in what our first panel has to say, so I'll keep my opening remarks very short.

I am, first of all, glad that we got this report and would commend the American Gas Foundation on the report of the direct use of natural gas. I think this is a very important issue and the implications for power generation and energy efficiency and carbon emissions, are all issues that I think we need to consider and analyze, to determine how, in fact, we can better use the natural gas we have in the most efficient way.

As most of you know, I have a great interest in efficiency of the gas pipeline infrastructure and delivery of gas. In addition, I am quite interested in the utilization of the gas itself, and I think we need to look at how we can make that more efficient.

We can use it in a power plant at 30 percent efficiency, or we can use it in the combined heat and power system at 85-90 percent efficiency. It's certainly obvious, which one is more efficacious and appropriate.

We can also use combined-cycle, a single-cycle combustion turbine to provide regulation services for wind, or we can use demand response and storage of various kinds to provide regulation services for wind. Again, I think we need to look at which one is more appropriate, which one is less environmentally damaging, which one has more benefits to consumers.

For example, Northwestern Power is proposing to build a 200 megawatt single-cycle turbine, simply to provide self-regulation services, because of the wind. To me, I think that's a very inappropriate way to go on doing something that could be done cheaper, faster, and with more benefit to consumers and less harm to the environment, through things like demand response and storage.

So, I think there are a number of options that we need to look at, as to how we can better and best utilize natural gas in this country, so that in a carbon-constrained world, it doesn't come back to bite us. Thank you.

CHAIRMAN KELLIHER: Thank you. Commissioner Kelly will join us shortly. She had another commitment, a previous commitment she had to honor, but when we get to questions, why don't you lead off with questions?

I want to turn to Jeff now, to lay out the ground rules.

MR. WRIGHT: Thank you, Chairman Kelliher. Again, I'd like to welcome everyone to this year's conference.

My name is Jeff Wright, Deputy Director of the office of Energy Projects. As your agenda states. we have two panel sessions, and, after delivering their prepared remarks, there will be an opportunity for the panelists to address each other, and the Commissioners may ask questions of the panelists, and, if time allows, there will be questions from the audience.

Let me go over just a couple of points: I'll ask the panelists to please adhere to a five- to seven-minute time limit for your prepared remarks. If you spill over, I may make an indication that you should wrap up. Please do not address any pending cases at the Commission, and, finally, breaks have not been built into the schedule, but please feel free to take your own break when you need it.

With that, we can begin our first panel. The first panel will address demand for natural gas in the U.S. These speakers represent different gas-using sectors in the U.S. -- residential, commercial, and power generation and industrial use.

Specifically, the panelists will address how they view their current and future gas demand, from their perspective.

With us today, are: Thomas Skains, Chairman, President, and CEO of Piedmont Natural Gas Company, and also, this year's incoming Chairman of the American Gas Association; Alexander Strawn, Jr., Chairman of the Process Gas Consumers Group; then we have Revis James, Director of the Energy Technology Assessment Center of the Electric Power Research Institute; and, finally, Kurtis Haeger, Managing Director of Wholesale Planning at Xcel Energy

Mr. Skains?

MR. SKAINS: Thank you, Mr. Chairman and Commissioners, for the opportunity to participate in this conference today. Again, I'm Tom Skains, Chairman, President, and CEO of Piedmont Natural Gas, and energy services and local distribution company serving approximately one million customers in the Carolinas and Tennessee.

I'm here today on behalf of Piedmont and more than 200 local utility company members of the American Gas Association, of which I am the incoming Chairman.

We're especially pleased this year that the state of the natural gas industry conference is appropriately focused on the state of infrastructure in our industry.

There could not be a more appropriate time to focus on supply and demand issues and how those issues will impact the infrastructure need of the industry.

With a new Administration and new Congress, likely new energy and environmental regulations and certainly a new environment in terms of accessing capital, it is now more important than ever that policy leaders take the time to assess the needs of our industry.

Natural gas, among all energy choices, is uniquely positioned to play a vital role in our nation's energy future, by providing both near-term and long-term solutions to America's energy and environmental roles.

My comments will focus on demand from the unique perspective of natural gas distribution companies that, of course, provide natural gas service to end-use energy consumers.

The number of American consumers who depend on natural gas, is growing. Natural gas is the cleanest burning of all fossil fuels. Its delivery from the source of production to the site of end use, is extremely efficient -- far more efficient than alternative forms of energy.

The comfort, convenience, and reliability that natural gas brings to customers, is unmatched by other energy sources, and, as a result, the total number of residential and commercial customers served by natural gas utilities, continues to grow.

From 2001 to 2006, the number of residential and commercial natural gas consumers, increased by six percent. To meet the resulting increase in peak winter day demand, our industry needs access to new supplies of natural gas at competitive prices, along with the infrastructure necessary to deliver those supplies efficiently and reliably to market.

Notably, while we continue to add new customers to our distribution systems and increase or peak winter day obligations, the average normalized use of our core customers, continues to decline. Even though natural gas utilities have added 26 million residential customers since 1980, the normalized annual use per customer, has fallen 29 percent.

What this means, is that, overall, natural gas consumption and greenhouse gas emissions from the residential sector, have remained virtually flat over the 1980 to 2007 period.

This decline in average per-customer consumption has been driven by greater efficiency of end-use appliances, tighter building envelopes, and, more recently, conservation practices in response to higher natural gas prices.

This presents and interesting challenge for infrastructure development, because it means developing infrastructure to meet higher peak-day obligations, while satisfying the customers' desire for greater energy efficiency and lower costs.

Specifically, it means more storage, more seasonal storage and more peak-day storage such as LNG peaking facilities, and more pipeline infrastructure to bring new diverse gas supply basins to market.

We must also recognize that natural gas is being used to fuel more and more electric power plants. As you know, that market has added significant new summer period demand over the past decade, translating to higher and more volatile wholesale commodity prices.

We believe that more thought needs to be given to how, as a nation, we can get the most energy value out of our diverse energy resources.

One way is to consider the most efficient use of each energy product. For example, electric lights are more fuel-efficient than natural gas lights, even if natural gas lights are more aesthetically pleasing.

Likewise, we believe the direct use of natural gas in homes and business, is more fuel-efficient than using natural gas to generate electricity for home space and water heating.

This is what we refer to as source-to-site or total energy efficiency, and it has an important place in today's national focus on our energy and environmental roles. Let's look at why:

The process of producing, transporting, and distributing natural gas from where that energy is produced -- its source -- to the delivery of that energy to the site in an end user's home or business, is 90-percent efficient.

On the other hand, the process of producing, transporting, and delivering natural gas to a power plant and then converting that energy to electricity, is only 30-percent efficient.

In addition, the direct use of natural gas in residential applications, results in approximately 40 percent fewer greenhouse gas emissions compared to using natural gas to generate electricity for home space and water heating. These findings and more are spelled out in a study released by the American Gas Foundation, earlier this year.

This study found that shifting 6 percent of the forecasted electricity load for the period 2007 to 2030, to natural gas, which is only half of the total switchable load, has the potential to produce energy savings of 1.25 to 2.0 quadrillion Btu, avoid incremental electricity generation of 63 to 80 gigawatts and avoid incremental investment costs in new power generation, of $49- to $112 billion. It could further reduce total energy costs by $12- to $29 billion, and reduce CO_2 emissions by 60- to 200 million tons.

If there are ways to create federal and state policies that help avoid up to $100 billion in new electric generation infrastructure and reduce greenhouse gas emissions, we should be pursuing them.

As simple as it sounds, if federal and state energy and environmental policy leaders start asking some tough questions about whether and how to craft comprehensive total energy efficiency programs across traditional natural gas and electric industry lines, this would help bring focus to an important potential means to increase overall energy efficiency and reduce overall energy use, energy cost, and greenhouse gas emissions.

And federal and state policies to encourage the pursuit of energy efficiency programs, are very important. For example, as distribution companies, we are focusing on energy efficiency programs such as weatherization and home energy audits and incentives for customers to install higher-efficiency gas appliances.

Many states have now recognized that the old way of setting volumetric rates, actually penalizes utilities for doing the right thing to reduce energy consumption and greenhouse gas emissions. As a result, many states have decoupled utility margin from volume, and utilities in these states are becoming more aligned with customers in promoting the wise and efficient use of energy.

Let me close by emphasizing my theme for next year as AGA Chairman, and that is, natural gas is America's responsible energy choice. Natural gas is clean, it's domestically abundant with access and infrastructure development, and it's efficient.

But it must be used responsibly, which means it should be devoted, first and foremost, to its best and most efficient use, directly in America's homes and businesses.

To the extent that federal and state regulatory and legislative policy support that goal, America will save money on energy, increase energy efficiency, and reduce greenhouse gas emissions.

Thank you for the opportunity to share these thoughts with you this morning and participate in this forum.

MR. WRIGHT: Thank you, Mr. Skains. Mr. Strawn?

MR. STRAWN: Good morning, Mr. Chairman and Commissioners. My name is Alex Strawn, the Chairman of Process Gas Consumers. It's a group that's been around. We celebrated recently, our 30-year anniversary, and we like to think of ourselves as the rational voice of the industrial end consumer.

Our principles stand for free market competition in the gas markets, open access, and we always participate in the pursuit of equitable legislation for all parties in the natural gas sector.

I speak on behalf of that group today and not on behalf of any individual company in our group, although they're names that you widely know -- Alcoa, Proctor and Gamble, GM, Ford, U.S. Gypsum.

We represent more than three-quarters of a Tcf of natural gas usage in the United States. We employ hundreds of thousands of people in these sectors.

We believe that later we're going to hear from the supply panel that's going to talk about some very robust supply predictions from Barnett, Fayetteville, and Marcellus Shale.

We're very happy about that, to say the least. We're happy that prices have moderated, but we view this as a time not to relax on any measure. It's a respite; it's good news for industrials.

We've been given, the way we look at it, a temporary reprieve, a respite, if you will, a time to really analyze what we need to do to evaluate and then to move and act quickly.

We are concerned about the future, even with these predictions of supply. We certainly appreciate all that FERC has done to streamline the regulation activity, the certification for new pipelines, but we're also concerned about the NIMBY -- not in my back yard -- effect, which seems to stymie so many projects that are trying to move forward in infrastructure development.

New expansions need to be made to protect the environment, but it takes energy, particularly natural gas, to run the economy. We'll need that new infrastructure to bring these new shale supplies to market.

In addition to protecting the environment for both existing and new pipeline infrastructure, pipeline rates also need to protect the consumer. We need to make sure that returns are set properly and refreshed periodically, and need to make sure that fuel is not used -- pipeline fuel is not used as a profit center.

Energy and environmental policies are linked, just as the Chairman has said and others have noted. I'm not sure what role FERC will have specifically in that debate, but at least we encourage FERC to be the voice of reason and explain to lawmakers, how various environmental initiatives will impact energy markets and energy availability, going forward.

Even accepting the need to address greenhouse gas issues and global warming, we are very concerned, to say the least, about upward price pressure. After all, it was only in July that we saw some record prices in the natural gas sector.

We are very concerned about that pressure. Any legislative fix that is placed on natural gas as the bridge fuel to get to alternative energy resources, most of us would probably agree that we can't run the U.S. economy on alternative sources alone -- solar, wind, or biomass.

We process gas consumers have always been for a full portfolio of energy sources, including those alternative means, as well as nuclear, and all other means necessary to power the U.S. economy, a portfolio, if you will.

If global warming legislation, overall, increases demand for natural gas, where are these supplies going to come from, other than the shale that we talked about? Where will additional infrastructure come from to deliver these supplies to market?

We're also concerned about cybersecurity, as well. We're also concerned about the lingering debate on global warming, and how it's injecting uncertainty into the energy markets for businesses like ours.

We want the United States to proceed responsibly. We're also eager to have the debate resolved, so that business can have clarity as to the policies, going forward; clarity that will give businesses the ability to make important business decisions.

Many projects hang in the balance of the price of natural gas and the availability. Some of those projects are supported by higher prices and lower prices, but what always throws it into a bit of concern, is when there's uncertainty about which way those prices will go and the uncertainty about the availability of supply.

That makes us suspend what we're doing in many cases, because we're not understanding what the future really holds for us.

With natural gas as the bridge fuel, the U.S. cannot back down on environmentally responsible exploration and production of increased energy sources. Here again, it's no time to relax.

We want everyone in the country and certainly FERC, to evaluate, plan, and then act on these issues, so that we can move forward. Thank you.

CHAIRMAN KELLIHER: Thank you very much. Why don't I recognize people and then you can cut them off if they go too long, so I'll be the good cop and you be the bad one?

(Laughter.)

CHAIRMAN KELLIHER: Let me now call on Revis James, Director of Energy Technology Assessment Center of the Electric Power Research Institute.

MR. JAMES: Thank you, Chairman Kelliher. I'm glad to be the first one to experience reorganization here. I'd like to thank Chairman Kelliher and the Commissioners for listening to EPRI's testimony here today.

I'm Revis James, Director of the Energy Technology Assessment Center at the Electric Power Research Institute. EPRI is a 30-year old nonprofit research organization that's been focused on the electric sector and all aspects of technology -- generation, transmission, and delivery of electricity, end use, and environmental consequences of all of those areas of electricity activity.

We appreciate the opportunity to address you on this issue of natural gas infrastructure. We'd like to provide you with some perspectives from the view of a consumer of gas and where we see some of the trends in the electric sector.

Given the anticipated emergence of CO2 constraints, our view is that there is unique convergence of challenges that we're facing in the electric sector.

Emissions constraints are one of them, but, coupled with that, we have the expectation of significant demand growth.

Even with conservative views about the direction of the economy over the long term, we expect significant growth and the added factor that the margin between our maximum ability to generate electricity and the maximum peak load we might experience, those margins have consistently been narrowing in every region of the United States.

That raises serious concerns, and addressing all of those challenges at once, is what we're looking at.

While significant expansion of electric generation capacity and of transmission systems are needed to support demand growth and maintain system reliability, accomplishing reductions in the CO_2 emissions is going to require some new technology capabilities and reorientation of the mix of technologies to accomplish that.

In our view, it's going to require a sustaining investment in RD&D, research and development and demonstration, over the next two decades to get to that point where we have that array of technologies.

We have done a series of analyses looking at the potential impact of CO_2 emissions constraints on the sector. Our analyses have shown that we'll be able to successfully carry out a focused R&D program and realize an advanced portfolio of technologies.

We could potentially reduce the otherwise increasing trend in CO_2 emissions for the electric sector, by 45 percent by the year 2030. That's relative to the Energy Information Administration's projections in a business-as-usual case.

However, something that we feel is very clear, is that there is no silver bullet or even a couple of silver bullets that we can rely on to achieve that.

We see that a full portfolio of technologies, ranging from baseload technologies to alternative energy sources, to end-use technologies, will all be needed, because of the magnitude of both demand and emissions reductions that we will have to achieve.

Furthermore, one of the major issues is that many of these technologies haven't yet reached the level of deployment or performance that are needed, in order to achieve the emissions reductions and need to demand that we see. That's the reason for a focused R&D program over the next 25 years.

With respect to natural gas, one of the important implications of this perspective on R&D and advanced technology portfolios, and the need to develop that portfolio at the time, is that we're facing an interim period of time.

I'm going to build on Alexander's remarks here.

We have this interim where we're going to have a more limited array of resources to draw upon to meet demand. In that interim, we anticipate that natural gas will be a principal factor in producing electricity, while achieving emissions reductions, despite questions that may arise with respect to infrastructure development or availability of supply.

We've done a series of economic analyses, looking at what the economically optimum technology mix is under a range of potential emissions constraint scenarios. In many of those scenarios, over half the scenarios we've analyzed, by 2030, gas consumption for power production could be 50 to 100 percent larger than it was in 2007, a very substantial increase.

We are not experts in natural gas supply, but we would think that that's going to drive increased prices of natural gas, which will ultimately be reflected in electricity costs. That is an area that then motivates us to then accelerate the R&D to the extent that we can, to shorten that interim period and reach the state where we do have the full portfolio of technologies.

There are other factors that we recognize are going to affect this interim period: The emergence of escalating labor and materials costs for a lot of the other capital-intensive technologies; increases in desirability of natural gas, from the utility perspective; the increasing reliance on natural gas, from the utility perspective.

There is the emergence of wind, which in some ways displaces generation that would otherwise be provided by natural gas, although there is a need for backup power to provide stability, and the output from wind resources, as was noted in one of the Commissioner's comments.

The other remark that we'd like to make, is that the goal here, in our minds, is to limit the economic impact of emissions constraints. Our view is that it will cost money to achieve emissions constraints. The question is how much it will cost.

A diverse portfolio of technologies can minimize that cost, based on the analysis that we have done, therefore, we think that it's extremely important to try and shorten this interim period where gas and efficiency are the principal facets of the strategy and to reach a state where we can rely on nuclear, coal, multiple types of renewables, substantial solar, wind, biomass, and a significant amount of energy efficiency and to reduce consumption at the same time.

Finally, the other aspect of our work that I think is very important to recognize, is that the decarbonization of electricity production, will have tremendous impact on the cost of the remainder of the U.S.

economy. The magnitude of emissions reductions that are being discussed right now, is so large that we will have to effectively decarbonize the electric sector two times over between now and 2050, to reach the scale of emissions reductions that we anticipate.

That's going to require emergency uses in many other areas of the economy beyond the electric sector, so decarbonized electricity can be a resource for that.

To summarize, our research concludes that in response to growing electricity demand and CO2 emissions goals, decarbonization of electricity generation, more efficient use of electricity by enabling technologies such as the "smart grid;" increasing use of electricity in other sectors, such as transportation, are viable strategies toward emissions reductions.

We're likely to see substantial increases in demand for natural gas in the interim period between now and 2030, in our view, before we're able to realize the full extent of the portfolio and the capabilities are realized.

If we begin now, timely, sustained R&D can enable a full range of electricity generation technologies, supporting a low-carbon future, meeting electricity demand and ensuring continued electricity grid reliability.

Mr. Chairman, thank you for the opportunity to speak.

CHAIRMAN KELLIHER: Thank you very much. Next, we'll hear from Kurtis Haeger, Managing Director of Wholesale Planning at Xcel Energy.

MR. HAEGER: Mr. Chairman and Commissioners, good morning. My name is Kurt Haeger. I'm Managing Director of Wholesale Planning at Xcel Energy.

I'm here today on behalf of the Edison Electric Institute to share my thoughts on the state of our country's natural gas infrastructure, in particular, with regard to the demand for natural gas from the electric generation sector.

The views I express here today, are based on Xcel Energy's experience in the Midwest United States. As a result of the deepening concerns regarding climate change, including greenhouse gas emissions, natural gas-fired generation appears to be the fuel of choice for many utilities over the next ten to 15 years.

As more states and the federal government move toward more stringent renewable portfolio standards and mandated reductions in greenhouse gas emissions, natural gas-fired generation appears to be the most economical and timely choice for generation additions.

With increasing pressure not to build new coal plants, to retire existing aging coal plants, and to increase the use of wind and solar energy, the ability to add relatively low-cost gas-fired generation capacity, is an appropriate bridge strategy until advances are made in developing other technologies such as carbon-capture and storage, or until additional baseload plants with longer lead times such as nuclear, can be constructed.

Natural gas-fired generation has the potential to be the necessary catalyst to bridge the power industry through this period, and then to continue to provide benefits for many years. As utilities look to the need to meet customer growth and possibly retire a portion of their existing coal capacity, gas-fired generation can be added in a fairly short period of time and has the flexibility to operate in a wide range of conditions.

As the potential for new technology is realized and new baseload facilities using those technologies are constructed in the future, these same natural gas facilities can move higher in the generation stack and continue to fulfill a very valuable role in the overall portfolio.

Looking to the future growth of renewable energy, possibly as high as five, ten, or even more as a percent of total generation, natural gas-fired generation is the logical choice for two critical functions: First, it provides critical backup capacity for variable renewable energy; and, second, it provides needed operational flexibility to manage the variable nature of wind and solar generation.

At Xcel Energy, we have one of the largest generation portfolios in the country, with approximately 3,000 megawatts of wind right now in our system. As a result, I know all too well, how important the flexibility of gas-fired generation can be in integrating wind generation into the grid.

As photovoltaic generation becomes more prevalent, we expect that natural gas-fired generation will also be necessary to integrate this variable resource into the network, yet the natural gas strategy is not without concerns.

Will an adequate supply base be developed? Will the pipeline capacity keep pace with demand? Will utilities be able to use the tools necessary to manage price volatility? Will enough natural gas storage be developed to allow the gas system, operational flexibility to respond to electric generators?

All of these questions need to be answered in the affirmative for natural gas to fulfill its potential as a fuel source for electric generation.

Focusing on the future needs of the electric generation sector regarding gas system infrastructure, electric generators will need increasing amounts of operational flexibility as we accommodate and integrate more renewable energy generation.

I am concerned that the need for increased gas flexibility to meet the electrical operating requirements, will not be available in the current NAESB cycles, which provide for nomination at 10:00 the day before the gas is actually needed.

Recognizing that wind generation is difficult to forecast, change abruptly and does not follow a reliable time sequence through the day or the year, the ability to nominate and schedule gas supplies through the current NAESB cycle, is not realistic.

Electric generators will have to have the ability to nominate and schedule gas outside of the current cycles and to combine both pipeline and storage services into a nearly automatically-nominated system.

From our experience in Minnesota, Colorado, and New Mexico, and Texas, we know that the electric generators will need the ability to dump or add gas-fired generation on a continuous basis throughout the day, with natural gas as the critical swing fuel.

It is not uncommon for our wind generation to swing by 500 megawatts or more in a matter of minutes. These swings equal a swing on the gas system of nearly 100,000 MmBtu on a daily basis.

As a result, generators will need tariffs and services that allow for changes in gas supplies throughout the day, with very limited notice periods.

Most likely, this operational flexibility will depend, in some fashion, on gas storage facilities. As the amount of wind generation that is added to the electric system, ramps up over the next ten years, so will the hourly swing demands on gas pipelines increase.

These demands will be met, in large part, through these additional gas storage facilities. To meet the future challenges of the electric industry, gas pipelines and storage projects must be developed on a timely basis, to keep pace with wind and solar generation, which can be constructed in as little as a one-year timeframe.

In addition to offering more flexible services, pipelines may also need to review their rules regarding the ability to hold open firm capacity for a generator that may need to schedule firm service, well past the time of the nomination cycle.

Along those same lines, generators may need the ability to shift gas from one generator location to another generator location, to compensate for the need to bring on or shut down different sized generators to follow the wind and solar generation.

In summary, I believe that the ability of the electric industry to successfully bridge the next ten to 15 years and to accommodate the desire for more renewable energy, is highly dependent on the ability of the gas transportation and storage industry to accommodate the increased reliance and operational flexibility of these new gas generators.

Thank you again for allowing me to appear today. I look forward to answering questions.

CHAIRMAN KELLIHER: Thank you very much. I think Commissioner Kelly is going to join us before 10:45. Why don't we allocate 30 minutes, and there are five of us, so that's six minutes each, I think.

Why don't we start with Commissioner Wellinghoff. Can you give us a one-minute warning for each of us? You're going to track the time, right, Jeff?

(Laughter.)

COMMISSIONER WELLINGHOFF: Please cut me off, Jeff.

(Laughter.)

COMMISSIONER WELLINGHOFF: Mr. Strawn, as I understand it, U.S. Gypsum is one of your members; is that correct?

MR. STRAWN: That's correct.

COMMISSIONER WELLINGHOFF: How many plants do they have in the country?

MR. STRAWN: I don't know the exact number.

COMMISSIONER WELLINGHOFF: Thirty-five or so, is my understanding.

MR. STRAWN: At least.

COMMISSIONER WELLINGHOFF: How do they use natural gas in those plants?

MR. STRAWN: In the production of their gypsum board, primarily.

COMMISSIONER WELLINGHOFF: Do they use it primarily for heating the gypsum board?

MR. STRAWN: It's used to dry the paper.

COMMISSIONER WELLINGHOFF: How many of those gypsum plants are using that gas in a cogeneration system where they're actually using the waste heat to do the process?

MR. STRAWN: A few them. There could probably be more.

COMMISSIONER WELLINGHOFF: The more they have, the less demand there would be for gas.

MR. STRAWN: Right. Several of our members use the cogeneration process to produce, yes.

COMMISSIONER WELLINGHOFF: Is this something you encourage with your members?

MR. STRAWN: Absolutely across the board. In fact, we are trying, whenever possible, to get those facilities sited and implemented. In some places around the country, a lot of that type of siting is not encouraged.

We're constantly trying to site our facilities, but they don't fit every process, they don't fit every region, and that's part of the problem.

COMMISSIONER WELLINGHOFF: I know there are some barriers out there in the states, that are causing your members to not be able to put those plants in place.

MR. STRAWN: Yes, there are some restrictions. California is not the easiest place to try to do that type of work.

Some of us have cogeneration facilities in those states, but what's difficult, is, the expansion of those facilities, specifically the expansion, so, yes, your point is well taken.

COMMISSIONER WELLINGHOFF: To the extent that you're actually able to do that, you're then utilizing the gas like at 85- to 90-percent efficiency with the electric generation on the one side, and the waste-heat use on the other side, as well; is that correct?

MR. STRAWN: That's correct.

COMMISSIONER WELLINGHOFF: Mr. James, I'm very interested in your testimony, interested in the scenarios that you have done for EPRI.

You talked about you'd like natural gas generation to represent 150 to 200 percent of 2007 levels.

In those scenarios, what was the percentage levels of combined heat and power systems?

MR. JAMES: We didn't make assumptions on deployment of technologies. What we do in those scenarios, is, we project CO_2 constraints. We put a price on each of the technologies, including combined heat and power.

Then what we do, is, we look -- we try to calculate an economic optimum mix of technologies at any given point in time, that will minimize the wholesale cost of electricity production, meet the CO_2 emissions constraints at the same time, and meet demand.

In some cases, you can't do all those at the same time, so you have to either increase the price and lower demand, or you'd have to redeploy technologies and get the mix.

So, the deployments are a result of the calculation, rather than an input.

COMMISSIONER WELLINGHOFF: To the extent some of the barriers Mr. Strawn talked about could be reduced through combined heat and power, and combined heat and power could be a larger part of the mix, that would reduce the total amount of gas use then, correct.

MR. JAMES: That would be true, yes. This is an economy-wide analysis. There are several variables driving the optimum mix. One of those barriers would be generally reducing -- generally speaking, from an overall mix standpoint, I would say the analysis tries to limit gas usage simply because gas is a relatively expensive way to place** electricity in relation to several other options. But there are other factors, such as the usage constraint.

COMMISSIONER WELLINGHOFF: To the extent you're using it for combined heat and power you've got the benefits of both electricity and using it for process heating. So your total costs would come down.

If I could go to you, Mr. Haeger. The discussion you had about utilizing gas for backup capability and flexible operation for wind and other variable resources, are there alternatives to doing that, like demand response and various storage systems?

MR. HAEGER: Yes. We're actually aggressively looking at multiple things. Battery storage. We're looking at compressed air, energy storage. We use pump hydro storage to do that.

We're also aggressively looking at demand response, which is also a tool. The difficulty we find a little bit with demand response, many customers who can handle demand response in the summertime find it difficult to sometimes shut down in the wintertime for a period of time because they need to heat the buildings. Wind variability happens so much in the Midwest in the winter and at night, as it does somewhat during the day, demand response can be somewhat difficult then.

COMMISSIONER WELLINGHOFF: Are you familiar with more advanced demand response techniques where you can in fact not shut down processes but just vary loads over wide ranging facilities and do that all year round?

MR. HAEGER: Yes. In fact, in Minnesota we have demand response of nearly 1000 megawatts on our system. We're actually very aggressive with our industrial customers to look at changes and be able to reduce and not completely shut down.

We have found from practical experience some difficulty in getting them to participate in something that is so variable in nature.

COMMISSIONER WELLINGHOFF: Are you familiar with the fact that a number of the ISOs and RTOs now have bidding for demand response for ancillary services?

MR. HAEGER: Yes.

COMMISSIONER WELLINGHOFF: Wouldn't that be an additional alternative to using gas generation for these purposes?

MR. HAEGER: I think it has to be a combination of both. Again, I think we're very aggressive right now.

In the MSP area, which is the Minnesota properties, they're part of the MISO group. They do bid into MISO for their generation. They're very aggressive in demand response. But we actually find the need for additional gas-fired generation to manage the amount of wind that we're talking about.

COMMISSIONER WELLINGHOFF: Last question.

On page three you talk about the need to add or dump gas-fired generation on a continuous basis throughout the day. Isn't that the result of those generators operating very inefficiently, ramping them up and ramping them down back and forth?

MR. HAEGER: There's two different types of generation. They do have quick response generators so they do operate more efficiently in that load. Also, depending upon where your wind and your gas combine cycles, they could still operate in a fairly efficient mode.

What we're finding, even with the integration of the amount of wind that we're talking about, ultimately on our systems we've got 7000 megawatts of wind in the Midwest. We can actually reduce the amount of gas usage on our system through this combination. We need the hardware there to be able to manage around the wind. But they, frankly, just don't want it as much.

COMMISSIONER WELLINGHOFF: You can reduce the total amount of gas usage. Wouldn't the generators operate more efficiently if they'd be able to operate at their optimum heat output level?

MR. HAEGER: One of the keys is to be able to actually stagger. That's why we say in generation size matters.

You have units that are maybe 150 megawatts. You also have units that are 45 megawatts. You can bring a generator up to a point where it's operating efficiently and then you can take the next step. You back that unit down and you put in another generator that can operate at its higher efficiency rate. You have to have a combination of those different sizes. That's why it's important to be able to move gas from one generator to another, so you do maximize your efficiency.

COMMISSIONER WELLINGHOFF: Thank you.

Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

I have a question for each of you, starting with Mr. Skains.

You mentioned decoupling, and in that theme weatherization, other types of energy efficiency. It's always been clear to me and many other people too that in order to properly send those signals of energy efficiency if the utility is doing the program they have to be properly rewarded for it and not penalized.

But also there's a state regulatory scheme that allows utilities to earn on those conservation investments.

Do you have a sense nationwide on the state of play of various regulatory schemes? And if not, maybe you can lever in on North Carolina.

MR. SKAINS: Thank you for the question. It's an excellent question.

There is on the gas side a prevailing trend towards revenue and margin decoupling rate mechanisms in lieu of traditional volumetric rates. That trend reduces the reliance where increased throughput is the basis for profitability for the enterprise. For shareholders that rate design is important to remove the disincentive for energy efficiency driving down energy consumptions, which is very important.

Your question also talks about incentives, which are very important as well.

My view of the state of the industry there on the gas side is at this point most energy efficiency and conservation programs merely allow the utility to flow through the costs of those programs and not make investments that the utility could earn on. So the utilities are largely financially neutral on affirmative as opposed to being awarded proactively for making investments in energy efficiency and conservation.

Despite that, the increase in energy efficiency programs in the gas distribution sector has continued to be prevalent. Last year about $334 million were spent by natural gas utilities across the nation on energy efficiency programs. I believe much more could be done.

And I think this is an issue not just for the regulatory model for gas, it's an issue regarding the regulatory model for electricity so that both the electric and gas utilities can work together in the future on behalf of customers. That's consistent with the duty we had to shareholders.

And I think if you look at the entire regulatory model and consider changes that incent utilities to make money off of energy efficiency and conservation and work together holistically towards comprehensive total energy efficiency programs across sector lines, I think the public would be rewarded and the planet would be rewarded and our shareholders can be rewarded at the same time.

COMMISSIONER MOELLER: Well said. I completely agree. This is -- obviously this isn't at the state level, but perhaps as we have dialogue with our state colleagues we can continue to emphasize the need precisely of what you spoke. Thank you.

Mr. Strawn, welcome back. Switching subjects completely here, you mentioned there are cybersecurity issues on the demand side of the system. I didn't expect that topic to come up today. Could you please elaborate?

MR. STRAWN: I think this is interesting because over the last several years there's been kind of a de-emphasis on the security aspect. I can recall addressing this body a few years ago where the security of the pipelines, the security of the overall infrastructure was paramount in that discussion.

So I think my remarks were really just to provide additional focus on that aspect and to encourage some exploration of the needed measures to make sure that we have this continued good period of non-threatening type situations here. We're not overly worried. But we always like to keep a continual focus not on that area alone, but on a variety of other areas like conservation.

COMMISSIONER MOELLER: Thank you. If you have more ideas on that, we do spend a lot of time on cybersecurity here. We think of it more as an electric issue. So thank you.

Mr. James, let me go back to that very interesting reference you made that in 2030 we could have 150 to 200 percent increase over the 2007 levels. Can you elaborate a little bit more on what you mean by that? I'm presuming you're assuming that perhaps carbon sequestration will not be a viable option by that time.

MR. JAMES: I understand the question. I'll try to be brief because I don't think we have time to go through the fact analysis that underlies this.

The essence of the approach is to look at the availability of CO2 capture storage. The fundamental assumption is that it is available but at different time frames, possibly for 2020, possibly 2030, at different costs. The costs for transporting storage costs for CO2 might be higher.

Let's say that you have improved storage sites but on a more limited basis because the criteria for approved storage sites are very strict, for example. So you have a variety of scenarios based on different scenarios about that.

Then you look at a variety of assumptions based on assumptions about the cost of producing electricity and nuclear power. Why nuclear power? Because those two sets of assumptions address the two base load technologies that produce the most electricity. So you find the other technologies -- such as gas -- respond very strongly to the assumptions you made about those base load technologies. So you get an array of responses for the other technologies -- gas, renewables, demand reduction.

And I basically tried to summarize what a consistent result was from a majority of those scenarios. That really jumped out at me with respect to the natural gas results.

COMMISSIONER MOELLER: Thank you.

Finally, Mr. Haeger, the NAESB cycles you referenced, we've been doing a lot of work with NAESB lately. Is it your contention that this is something that needs their attention or is NAESB on this one?

MR. HAEGER: They've obviously been working on it and tried to develop some sort of consensus about should there be changes and exactly what those changes are. I think they're on it.

The difficulty I think is right now it's so diverse throughout the United States with different technologies, people are looking at what flexibility although it's different on each pipeline system, and what kind of generation is coming on each of the pipeline systems, it's very difficult to get a comprehensive solution. I understand that.

I think as we move forward and get more focus on doing greenhouse gas emissions and potentially more renewable energy, whether it's solar or even photovoltaic, which is very variable in nature, I think we'll have more focus on that working through more of a regional solution. It might be some time until we get a little bit more specific rules and requirements before we have greenhouse gas emissions and a renewable portfolio on a natural basis.

CHAIRMAN KELLIHER: Commissioner Spitzer.

COMMISSIONER SPITZER: Thank you.

I'm going to take advantage of the diversity in demand here to pose a question that's a little bit of a puzzle to me. We obviously see pipeline applications, but not always the details regarding the underlying economics; and the applications that never are filed we don't ever see.

Is it your view -- Well, tell me: What is your view regarding the economic basis for pipeline expansions, whether it's from the demand side or the supply side? We'll go down and start with the gas utilities.

MR. SKAINS: Thank you, Commissioner.

From the distribution side the demand for projects is largely driven to meet our seasonal and peak day demand load. To the extent that distribution companies need additional peak day or seasonal capacity to meet our load profile for growth, then we would contract for and support those projects as shippers.

In the production area my view there is we've seen more supply push related projects rather than demand pull projects. These are projects designed to move new supply basins into the national network of pipeline infrastructure. They're driven largely by what the netbacks are in any given basin depending on the capacity restrictions out of that basin, or liquid hubs.

So I think you can see two different types of projects at work, some by the consuming demand side of the equation to meet seasonal peak day growth and by the production side to move additional supplies to liquid hubs.

COMMISSIONER SPITZER: When we had Marcellus available obviously eastern supply potential at that point, what you alluded to in the geographic push-pull, what would be the consequence of an eastern supply?

MR. SKAINS: That's a little more complex. It may be a hybrid type situation where distribution companies who had growth on the east coast may need supply coupled with capacity to meet growth.

Alternative, the producers in our region may need the capacity just to get to liquid points on existing pipelines to move the production. So that's an interesting situation where there could be a hybrid of both push and pull dynamics occurring.

COMMISSIONER SPITZER: Mr. Strawn.

MR. STRAWN: Let me respond generically to the question in the sense that all of our members are in full support of additional siting and expansion of infrastructure overall.

As I said in my opening remarks, we're a little bit concerned because we have these boom-bust cycles of pricing. And there seems to be all the focus on infrastructure siting and supply as we go into the boom cycle. As we start to go down that curve a little bit there's not the same level of excitement.

What we're concerned about is given the amount of time for siting and structuring and production of these facilities or these pipelines there's such a lag time. So I guess we just support them generically in the sense we just need the expansion now at all times and in all periods.

COMMISSIONER SPITZER: What do you see as having greater volatility, the supply side or the demand side? It's a moving target over the next five years.

MR. STRAWN: I would say the supply side because if you've got the shale but at the same time with the economy flattening right now, I think most people would agree -- I think you read something recently about the notion of the expansion of the infrastructure in that area is now being called into question.

So here you have one of the best finds of all time. We're all excited about it I think on this panel. Then you have a flattening of the economy that takes away some of that excitement. It diminishes the notion that we're going to have that supply in the areas that we need it.

So I guess I just have to continually maintain this mantra of we've got to develop it while we have the time, while we have the impetus because it's just amazing to me -- just a few months ago we were on the margin of supply and demand. Now we have just a little bit of breathing room and no one seems to be taking advantage of it.

I understand the economic reasons. But at the same time we want to implore the panel here, everyone, the Commissioners, to understand that from an industrial point of view we feel that we don't have any time to waste.

COMMISSIONER SPITZER: Mr. Haeger.

MR. HAEGER: I think it's difficult in the electric industry because we're just learning about some of these variable energy resources. Although we probably have one of the biggest, largest wind portfolios in the system, we're just learning about what it really requires to operate around wind and solar and the effect on the infrastructure.

I think what it really comes down to from the demand side is a real interest to make sure that you have pressure guarantees, to make sure that you have flexible delivery schedules, that it's timely to get gas to these plants.

I think there's going to be a big need to keep ahead of the curve. I don't see that happening. And we don't understand that variability with wind and solar needs today; other countries I think are farther advanced. We're struggling to understand how much flexibility is really necessary to manage all these variable resources. I think from that standpoint we've got to keep in front of the wave because once we get behind it it comes quickly.

COMMISSIONER SPITZER: Mr. James, you referred to plug-ins in your testimony.

Assuming a more widespread application to electrified transportation that would have a positive effect on carbon emissions. You've got a lot of variables to consider. But also reduced domestic demand for oil, which has a link with natural gas. So you've got greenhouse gas benefits. You've got some potential reductions in oil that may have impact.

If the application of plug-ins is expanded perhaps more so than you estimated what would be the consequences, what would be the consequences on natural gas demand and potentially price?

MR. JAMES: First of all, I think I can give you some perspectives on that by the relationship between natural gas and electricity production. I don't know if I can comment intelligently on the whole transportation sector.

But what I'm saying is that for example if you assume that you have a tremendous penetration of plug-in hybrid electric vehicles, say by 2030, let's say on the order of 30 percent of new vehicle purchases of PHEG, but all accounts that would be a tremendous level of penetration. You could create additional load on the order of 100 to 200 terawatt hours. It would be significant but it would be by no means a dominant factor in the overall US electricity situation.

So I think it would likely not have a tremendous impact on the overall balance of the US generation portfolio in terms of gas and base load technologies.

What it would do, though, I think it is would create some significant challenges on the electricity infrastructure side to accommodate a lot of devices that have mobile meters on them and need to have a communication with the electricity system to basically capture who is consuming that electricity.

So I don't think that will have a large effect on the natural gas demand for overall electricity production.

I think it will have more of an impact on the electricity infrastructure.

COMMISSIONER SPITZER: But it would reduce the burden on the electricity industry on meeting the carbon goals.

MR. JAMES: Okay. I see the direction of your question.

I would say it probably would make very little impact on that. The reason I would say that is because the magnitude of the emission reductions are so large, when you look at the levels like 80 percent below 1990 levels or 50 percent below 1990 levels are often discussed.

The difference between where that is and, say, where we are right now at this moment is so huge that, as I said earlier, you'll need to decarbonize essentially almost the entire electric sector or the equivalent of that. Plus an added amount of reduction equal to that from someplace else in the economy.

COMMISSIONER SPITZER: Thank you.

CHAIRMAN KELLIHER: Thank you.

Let me ask -- I wanted to ask Tom a few questions about infrastructure.

There have been some estimates of the infrastructure needs on the power side that range anywhere from 1.2 trillion to 1.5 or 2 trillion, depending on whether you're including climate change costs. One thing that's striking is that the biggest chunk of that is on distribution, the distribution side, not generation, not transmission.

I'm curious what the estimates are on the gas side, on aggregate infrastructure needs on the gas side and what the relevant needs are in distribution. Would the same be true, that distribution needs are greater than pipeline and production investments?

MR. SKAINS: Mr. Chairman, on that question we can provide you the data on that. I don't have it with me.

I think those estimates would be changing hourly in light of the economy that we're going to be in and what the forecasts are for growth in the near term. So I think we can certainly provide you data that has been developed before the current economic crisis.

CHAIRMAN KELLIHER: Another question is long term contracts.

I met with the CEO of one unnamed gas utility a while ago and he said their headquarters had pictures of consumers through the lobby and that was their focus. I asked him about their gas supply. He said they buy everything in short-term.

It just seemed that that wasn't necessarily in the best interest of consumers to buy everything on the short-term. I can see how from the point of view of a regulated utility you want to be able to minimize your regulatory risks and demonstrate to the state regulator that you're buying everything on short-term. If you're paying market you can easily demonstrate that.

But is that really the right approach for consumers to buy everything on the short-term? If not, what does a utility need to have the confidence that they're not going to be too exposed to regulatory risk?

MR. SKAINS: That's a difficult question.

I can tell you what the practices of most distribution companies are in this regard. That is to establish a portfolio for gas supplies, just like we recommend for power generators, a portfolio of assets. We buy gas from a variety of different suppliers, a variety of different basins under a variety of different terms.

Our company, for example, contracts for long-term capacity on pipelines to access flexible gas supplies in diverse locations across the nation. But then the gas supply that flows through it, some are long term contracts in terms of the contract agreement but the price is flexible.

When people talk about long term contracts it's often unclear as to what exactly the focus is on. Is it on price, is it on term, is it on volume? But there are I'd say intermediate term supply contracts in place, long term capacity contracts.

Most of the contracts that are assigned to the commodity have flexible market-based pricing. But then utilities overlay that with hedging programs, and these hedging programs have a variety of things which can turn a floating price into a fixed price. They do that through storage which is used both to meet seasonal and peak-day obligations. But it provides a physical hedge by buying gas at summer prices, which historically have been lower than winter prices -- other than this year where, as an industry, we're carrying above market gas costs in storage going into this winter.

So the hedge -- the prices are hedged. But the prices are not at market at this particular time.

We also have hedging programs which look at futures prices and use a variety of financial instruments to overlay the floating price under our contracts to lock in the price as fixed and the call and put options to put collars around our gas costs. The declining forward screen environment we will hedge out to two years. Up to 60 percent of our total sales market in a rising price environment we will hedge shorter periods for lesser quantities.

So we have a programmatic approach to hedging.

And most distribution companies do. But these hedging programs admittedly are a couple of years in length -- certainly not five, ten, 15 years in lengths.

The issue that many of us recall back in the '80s we were struggling through a scenario that the pipelines have long-term volume contracts with producers at fixed prices and created substantial take-or-pay obligations.

I don't think there's any entity or any sector in our industry that wants to take a long-term bet on both price and volume. That would put your supply portfolio out of the market and create severe dislocation.

CHAIRMAN KELLIHER: Thank you.

And I just want to make a comment before we go to the next panel. And that's to follow up on some of the conversation that's taken place so far just on climate change and what its impact will be on gas demand.

I think we recognize that during this uncertainty we're relying very heavily on natural gas to meet our incremental electricity supply needs. And that's probably irreversible at this point. The effect of uncertainty has been that we will rely on natural gas for I think maybe ten years or longer.

But even after we adopt some kind of plan on climate change and some portfolio of action we resolve to pursue, gas is going to stand behind each of those actions because whatever plan we adopt we're going to have assumptions embodied in that plan that may be implicit, not explicit. Every one of those assumptions that proves to be unduly optimistic is going to result in us leaning back on gas more.

Some of the climate change plans are designed to force early retirement of existing coal generation. And the assumption that we'll have CCS technologies readily available in 2020 to be developed across the entire power scepter. That's a pretty optimistic assumption.

But if that assumption doesn't bear out the result is going to be to rely on natural gas generation to fill in that hole in our climate change program. And that's really going to be true across the board.

If we don't meet our energy efficiency targets in a climate change program I think we'll end up relying more on gas. Gas is going to be the silent or maybe invisible swing man in a climate change program when we ultimately adopt one. So good luck to you.

(Laughter.)

CHAIRMAN KELLIHER: With that, I want to thank all the panelists for your help today. Why don't we call up the second panel.

Thank you very much. Have a good weekend.

(Pause.)

CHAIRMAN KELLIHER: I want to thank the second panel for coming forward.

Why don't we start at the beginning with Terrence Ruder, Senior Vice President, Marketing and Midstream Division with Devon Energy Corporation.

Welcome.

MR. RUDER: Mr. Chairman, Commissioners, good morning. Thank you very much for this opportunity to discuss the potential impact of shale developments on the U.S. natural gas supply.

I'm Terrence Ruder, Senior Vice President of the Marketing and Midstream Division and also Vice Chairman of the Natural Gas Supply Association.

From Devon's perspective, shale developments have the potential to reshape the traditional domestic gas supply mix and may even replace declining conventional production. These resources, however, are only part of what will be needed to meet the nation's growing demand for natural gas.

We will need to develop all of this country's natural gas resources, both onshore and offshore, if this country is going to move towards energy independence. Projections of shale's near-term and long-term potential in the U.S. gas supply are significant. The industry reserve estimates range from 250 to 750 trillion cubic feet.

Currently shale developments provide an estimated six to eight billion cubic feet a day, or roughly 10 to 12 percent of U.S. demand. Over the next 10 to 15 years U.S. shale production could triple from today's levels to an estimated 15 to 20 billion cubic feet a day. At those levels shale production will make up roughly one quarter of expected U.S. demand in 2008.

There are numerous technical and geological characteristics associated with shale. Ultimately, though, it gets down to how much gas is in place and recoverable, and is the shale capable of being fractured so the gas can flow at sustainable production rates. These characteristics can vary dramatically between shale plays, and within the sale play.

For example, the Barnett shale gas ranges from 200 Bcf per square mile to less than 50 Bcf per square mile. When Devon entered into the Barnett for 2002 we were seeing 10 to 15 recovery factors of the gas in place. However, our expectations are 30 percent or higher in some areas, primarily due to advancements in horizontal drilling, extensive use of 3D seismic surveys, application of large hydraulic fracture stimulations, and increased well density.

It should be noted that without hydraulic fraction stimulation shale would not be developed to any significant scale.

What has all this meant to Devon and to the natural gas industry? For Devon it's meant that it's total risk Barnet shale resource base has increased almost five-fold, from 3.9 Tcf equivalent in 2002 to more than 18.3 Tcf today. For industry it's allowed shale developments following the Barnett to grow production faster and with a shorter experimental drilling phase, resulting in lower costs.

We believe further advancements and accelerated growth rates can occur in many of the other yet to be developed U.S. shales such as the Marcellus and Haynesville, only if the right commercial clout exists, such as market access and price along with a business environment conducive to the development of oil and gas.

Although shale has proven to be a viable supply source, it has also proven to be very expensive to develop. Utility and completion costs are a big component to determine commerciality. Costs across different shale planes vary dramatically, ranging from less than three million dollars per well in Barnett to more than nine million dollars per well in deeper and more complex planes.

We estimate the industry will spend more than $150 billion in completion costs alone to fully develop the Barnett shale in the coming decades.

Infrastructure for shale is expensive. Due to scale and low pressure operating requirements for potential shale developments in basins not well connected to downstream markets or located in different terrain settings or in close proximity to more environmentally sensitive urban areas infrastructure costs will be higher.

To put infrastructure costs in perspective, Devon alone has invested $1.6 billion in gathering the processing systems in the Barnett shale since 2002, along with entry into contractual commitments for up to another $2.3 billion to secure and utilize gas pipeline capacity.

Each shale development has a different price threshold to provide commercial returns. Based on land acquisition costs, drilling completion costs, and the various technical factors mentioned previously, we estimate that today's industry can economically develop new shale clays with the NYMEX pricing band of between six and nine dollars per mmBtu.

Just as commercial as the commercial drivers is the need to have a stable business environment from a regulatory, financial, and tax perspective. Access to land will continue to be a potential restriction to the growth of shale resources in parts of the country where there are not established roles and responsibilities for local, state and federal agencies.

Especially for permitting and water access it will be difficult to duplicate the pace of growth experienced in the Barnett. Speeded up permitting for gas pipeline and related infrastructure projects is also needed to keep pace with the shale developments.

Finally, there must be a stable tax environment to facilitate steady supply growth. Any new taxes imposed on industry such as the carbon tax now being discussed in Congress will directly and immediately reduce investment in U.S. shale developments and adversely affect production. This also holds true of any existing tax deductions where drilling expenses are eliminated.

The final area I would briefly touch on concerns the current economic downturn that is already beginning to have an impact on business. Based on a recent study, gas-focused independent producing companies reinvested almost 130 percent of their cash flow to their drilling programs in the last three years.

This investment has been a driving force contributing to domestic natural gas supply growth, increasing from nearly 50 Bcf a day in 2005 to an estimated 56 Bcf a day in 2008, a significant portion of which has come through the development of shale.

This lack of credit, combined with the rapid decline in oil and gas prices the past four months will likely result in significantly fewer shale wells being drilled. How deep the cuts go and the resulting impact on domestic production will probably not be known for some time.

If the current situation persists beyond next year we can expect material production declines to continue for the next few years.

In closing, Devon's experience in developing natural gas shale clays in the U.S. and Canada gives us confidence in the potential for shale to become a cornerstone of domestic supply, reaching production levels of 15 to 20 Bcf a day in the next 10 to fifteen years is real and achievable from a technical perspective. Commercial and business factors as well as government policies will ultimately determine if industry can fully realize the potential of this promising new gas supply.

Thank you for the opportunity to present our views.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now call on David Bretches, Vice President for Marketing & Minerals with Anadarko Petroleum.

Welcome.

MR. BRETCHES: My name is Clay Bretches, Vice President of Marketing for Anadarko Petroleum Corporation. I'm also a board member of the Natural Gas Supply Association.

Anadarko is engaged in the exploration,

development, production, gathering, processing and marketing of natural gas, crude oil, and natural gas liquids. Anadarko produces approximately two million cubic feet of natural gas per day, 182,000 barrels per day of crude oil, and approximately 38,000 barrels per day of natural gas liquids.

Anadarko's principal areas of natural gas production include the Rockies, where we produce over a billion cubic feet per day, the Gulf of Mexico, where we produce 150 million cubic feet per day, and our southern region, which encompasses west Texas, east Texas, north Texas, and northern Louisiana, which approaches 550 million cubic feet per day. To put that into perspective, we produce enough natural gas to heat or cool about 11 million American homes each day.

Anadarko explores and produces in both conventional and unconventional reservoirs. We currently have operations in three shale clays, Haynesville, Marcellus, and Eagle in south Texas.

I'm here today to provide a brief overview of the composition of overall U.S. natural gas production now and going forward. I'll also cover some of the key issues facing the upstream sector. I'll start by identifying the U.S. supply mix now and extending over the next several years into 2020.

Over this time period indigenous U.S. supply is expected to grow at a compound annual growth rate of 1.6 percent. Onshore conventional gas presently is 42 percent of the total U.S. supply. That is expected to slide to 33 percent by 2020.

Sales will drive offshore and unconventional production from 32 percent to 44 percent in 2020. With continued success in the deep water Gulf of Mexico, we expect offshore gas will remain flat.

Alaskan gas is also expected to remain relatively flat through 2020. Canadian imports will decline from 12 percent to seven percent in 2020, even with some shale development in the Mackenzie Delta production. Canadian demand from oil sands and electric generation are expected to keep more supply in country.

Mexican exports are expected to increase from one percent to three percent.

Finally, LNG imports are expected to increase from just over one and a half percent to six percent. This is dependent on unconventional resource development in the U.S., also, LNG demand in developing countries.

When it comes to the oil and gas industry's ability to bring new projects online quickly, location of the resource greatly influences timing. Onshore production can generally be brought on in one to two years in areas with adequate transportation infrastructure, three to five years in areas where transportation is limited or non-existent. Deep water production is a longer term proposition that generally takes five to seven years from initial discovery to commercial sales.

Adequate and consistent natural gas supply is dependent on multiple factors such as commodity price, resources, both human and materials, transportation infrastructure, and finally, state and federal regulations.

Bringing on large scale projects is capital intensive and requires a high degree of risk. Certain risks can be mitigated; others cannot. Price risks can be mitigated by hedging, using futures or over the counter instruments.

Adequate human resources can be obtained by training, joint ventures, and partnering with educators. Adequate materials can be obtained by long term contracts and alliances. Transportation risks can be mitigated by long term firm transportation commitments.

However, we cannot mitigate the risks stemming from regulatory uncertainty.

One of the biggest regulatory hurdles blocking our ability to bring production on line relates to permitting, particularly in the Rockies. A valid resource management plan is the foundation. A project-specific environmental impact statement or environmental assessment based on the approved resource management plan comes next.

On top of that we're required to obtain an approved application for permit to drill, or APB. The time between initiation of this process and actual drilling is measured in years. Each step regularly involves litigation.

In its worst form, regulatory uncertainty can prevent efficient investment and timely production of resources.

It's these two, the inability of producers to commit to transportation projects followed by delays in construction of transportation capacity, followed by producers' inability to move gas to markets, followed by delays in getting production to consumers, that ultimately leads to fluctuations in supply availability and significant volatility in commodity prices due to inconsistent supply response to demand.

This inconsistent pricing causes higher prices to consumers due to inadequate pipeline delivery and less returns for producers and royalty owners, of which state and federal governments are the largest. Government, consumers and producers all lose.

I cannot emphasize enough the importance of a stable regulatory environment. When exploration and production companies spend billions of dollars on capital projects they can mitigate some of the risks stemming from price fluctuations and transportation constraints. But in the absence of a transparent and consistent regulatory environment, these projects may be delayed or, worse yet, never get off the drawing board.

What we need is regulatory certainty. That not only benefits the economics of such projects but also provides adequate and on-time supply to consumers.

Make no mistake about it: Regulatory uncertainty strongly impacts natural gas supply and price volatility, which ultimately impacts American consumers. We need policies that encourage exploration, production and transportation so that we can have a more secure energy future.

I would like to thank the Commission for the time this morning to present to you and your attention.

CHAIRMAN KELLIHER: Thank you very much.

I'll now recognize Claire Burum, Senior Vice President of Regulatory Affairs with NiSource Gas Transmission & Storage.

Thank you.

MS. BURUM: Thank you.

As you said, my name is Claire Burum, Senior Vice President for Regulatory and Government Affairs of NiSource Gas Transmission & Storage.

Our assets include Columbia Gas Transmission, Columbia Gulf, Crossroads, and partnerships in Hardy Storage and Millennium Pipeline. We operate more than 14,000 miles of pipeline, 37 storage fields with over 600 million cubic feet of capacity. Our assets stretch from the Gulf Coast to the Northeast and reach practically every significant shale play in the lower 48, either directly or indirectly.

Today I'm speaking on behalf of the Interstate Natural Gas Association of America, or INGAA, as you know it. INGAA represents virtually every interstate natural gas transmission company operating in the United States, as well as comparable companies in Canada and Mexico. Its members transport over 95 percent of the nation's natural gas that flows in interstate commerce through a 200,000 mile network of pipelines. Natural gas pipelines are a critical link to successful gas supply development and can dramatically affect the pace of supply development.

We develop, construct, own and operate the assets that link production to markets for consumption. As new supply basins are developed pipelines work closely with producers and the market to ensure that an adequate level of capacity is available for supply to get to markets on a cost-effective and timely basis. The inability to develop in those time frames results in pipeline bottlenecks that drive down producer prices for tract suppliers.

When these wide pricing potentials or basis blowout occur producers are incentivized to support new pipeline expansions. Thinking about it from the other end of the pipe, we provide access to gas supplies for markets to fuel their demands for energy. Markets value gas supply diversity and support pipeline expansions when they see supply growth add attractive delivered prices.

Today my comments are focused really on the interstate pipeline industry's role in linking new supplies -- conventional and unconventional -- to the markets where the gas supply is needed, and the important role that FERC plays in our ability to fulfill this role in the supply-demand chain successfully.

Overall we believe the FERC certificate process for developing new interstate pipeline capacity works well today, although there are other parts of the process -- primarily natural resource permitting with the other agencies and state and local government areas that many of the other speakers have mentioned as well -- that we think can be frustrating at times and need to evolve to a different level for us to be successful.

The FERC's Office of Energy Projects continues to do an excellent job processing pipeline applications in a timely manner. The process of providing the right amount of capacity to meet the needs of the market is very competitive and efficient.

In a market-driven rigorous competitive process producers, portfolio managers and expansion customers carefully choose the most efficient projects for capacity additions. Significant project optimization, competition and consolidation occur in the market before formal proposals are submitted for approval. Pipelines compete aggressively to meet increases in demand capacity.

From a customer perspective, pipelines compete for their business on the basis of cost, ability to execute a project, flexibility, timing, and other factors. The Commission should be confident that this a very competitive process works and results in the optimum solution from regulatory, public interest, customer, and ultimate consumer perspectives.

In the competition to be the winning provider of capacity the project with the best route, best markets, right timing, best economics, and fewest environmental land-owner and permitting constraints will typically be chosen by the customers on the strength of their transportation contract commitments to the project. A producer or marketer with gas ready to flow cannot afford to subscribe to a project that it perceives having more regulatory and permitting risk since those risks delay the in-service date and directly and negatively affect the risk for the producers and their bottom lines.

The market works very well to integrate natural gas supplies, demand, and the pipeline capacity that connects them all.

Some in Congress have suggested a fix to a process which we don't believe is broken. They have proposed legislation that would authorize a separate commission or oversight process to review and decide how many projects are needed and where they'll be built and on what timeline. This is a very misguided effort, we believe, that would result in much more harm than benefit. In fact, the way projects are developed in the market and reviewed by the Commission today is the right way to do it.

As new sources of supply and incremental demand develop new interstate pipeline projects will be presented in the marketplace. On point, a report released earlier this week by the INGAA Foundation demonstrates the huge potential for new gas supplies from unconventional natural gas resources located throughout the United States.

We should continue to let the market work in selecting which competing projects win and which are built to bring this gas to the marketplace. There's no need for an expanded regulatory role to determine which pipelines will be the winners and losers by examining or comparing competing pipeline projects or by anticipating a host of economic and regulatory contingencies that are outside the control of the Commission.

Firm contracts for proposed pipeline expansions provide market-based validation on the need for the new capacity and firm contracts are the market vote for the best projects. To do it in any other way would increase development risk and cost and time required to bring capacity online to move the new supplies to markets and will unsettle the market-driven balance we have today.

A regulatory process cannot take the place of the rigorous, competitive and complex process that takes place in the market to select winning projects today. For example, if we had undertaken a regional planning exercise regarding infrastructure five years ago we would have likely focused on the infrastructure needed to integrate LNG imports. We would have completely missed the infrastructure development that has occurred to bring unconventional supplies to markets.

Even if we focused more just on onshore production and beyond the LNG, the dynamics change as we sit here at this table. We've heard about changing priorities. Producers would focus on different basins depending on their economics and the capital constraints we face today. So the dynamics change too fast in terms of where producers will decide to invest their scarce resources which basins will be developed first and on which timeline.

So the market is too dynamic to believe that a centralized government process can accurately anticipate the development that will shape the need for natural gas infrastructure. This would obviously increase risks and costs to all the segments of the industry, including the producers, the pipelines and the consumers in the end.

Change away from the market-driven competitive process that works today and all the unintended consequences that would accompany it would have significant negative impact on the efficient development of supplies and capacity.

Thank you very much today for your time and engagement on these important issues.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now recognize John McCarthy, the Business Unit Leader, Commodities, at the National Energy Board of Canada.

MR. MC CARTHY: Thank you, Mr. Chairman, for this opportunity, an invitation to come down and share with you some of our views and some of our thoughts about natural gas in North America.

We've had a very long and productive relationship with the FERC. And Jeff, Mark and Rob are colleagues that we share informant on a regular basis. And it's very fruitful and productive information. And the relationship that we've developed over the years has helped us as an organization to be quite prepared for anything that's coming and make sure we have a consistent view of things in long-term planning.

The National Energy Board has two roles. The one you're probably most familiar with is the regulatory role. And we regulate the inter-provincial and international pipes, setting tolls and tariffs as well as siting both oil and gas. We also regulate international power lines.

And we have another role -- two other roles I think I just touched on. One is that we regulate the exploration and production the north areas where the provinces aren't organized and are the Federal Government's responsibility. The other is that we provide an advisory function for the government and keep under review energy matters. And that's mostly what I'm going to speak to today.

I've given you a note that we prepared and I'll just go through it, just picking out a few highlights on it. And then, of course, I'll be prepared to handle any questions on it.

First of all, the first page indicates a map of Canada with a little bit of the natural resource locations. Roughly 98 percent of our natural gas comes from the western

Canadian sedimentary basin. That area is shaded in blue and I think it's a salmon color. That really represents the bulk of natural resources that we have in Canada, natural gas resources.

Our estimates show that there is a very strong amount of conventional natural gas remaining. We've got about 49 Tcf of ultimate reserves, if you will. That number is economically dependent and has been around that level. In fact, in the last few years it has actually increased based upon the prices of gas. It does tend to be strong and steady as far as gas reserves. That's only the conventional side.

On the unconventional side that my colleagues have been talking about here today, certainly there's a vast amount of potential. There's a lot of discussion on it.

And we've heard the unconventional gas resources that we have most of are in the Horn River and Montney areas, but also in the Utica shale in the St. Lawrence area down around Montreal. These are new and exciting potential. But there hasn't been a lot of public exposure with respect to the potential and with respect to the deliverability we achieve from that. So we've kept it out of our assessment and our analysis to date.

The numbers that we've heard have been anywhere from 25 to 100 Tcf recoverable in the Montney and Horn River area, less so in some of the other areas, but quite substantial.

Looking at natural gas production trends now, Canada has produced 17 Bcf a day of gas over the last six years or so. And it is a mature basin in conventional terms. It is starting to decline where the average well we drill this year is not as productive as the average well that was drilled the year previous.

So we anticipate that that deliverability of 17 Bcf will decline over time. It's certainly been effective over the last little while with the volatility of prices. And one of the things we've noticed and that everyone has experienced is that we have extremely volatile prices.

But one thing that's happened in Canada that's a little bit unique is that our costs have steadily increased. They're increasing worldwide, of course, with respect to a lot of the input costs. What's unique to Alberta is that we get a lot of our companies involved in both oil and gas. And oil has been much more attractive, particularly oil sands. So it has been competing and bidding up import prices.

So now we sort of say in order to keep that level of activity that would be required to keep that 17 Bcf a day moving we'd have to be looking at about a nine dollar NYMEX price would kind of give the level of activity. Again, that's an average. Lots of people are making a good return at existing prices. But it's just our view with respect to having a significant rebound in drilling activity that we would need that level of pricing.

We've done a recent outlook of natural gas that takes a look for the next few years. We've done a well by well and sector by sector area, and we've looked at a variety of price ranges. From seven to eleven dollars was really the price ranges that we looked at.

We can see that the results varied across that from about 15 Bcf to 17.3, very much dependent upon price. We're seeing more and more of that production is coming from the unconventional areas, from those unconventional shale areas I spoke of. And in fact in our deliverability forecast about a Bcf a day is coming from those unconventional areas in 2010. Already Canada is producing about 700 million cubic feet a day of CBM, coal bed methane, coming from those areas as well.

Looking forward to demand, I picked up a few thoughts just listening to the previous panel. We look at Canadian demand to be fairly flat. A lot of our Canadian natural gas demand is driven by the weather. We use an awful lot of it -- perhaps 40 percent of it or so is used for space heating -- or more than that. Consequently with the recent spate of fairly mild winters we've actually seen a steady to slight decline in natural gas consumption.

The thing that's coming back to fill it up is natural gas for electricity generation. It's important to realize in Canada natural gas for electricity generation plays a fairly small part. Only about seven percent of electricity in Canada is generated by natural gas. Canada is blessed with a huge amount of hydro resources and about 60 percent of our electricity comes from hydroelectricity. Nonetheless the timeline to develop hydro, given some of those long term solutions, is quite long.

We see that electricity from natural gas will increase from about seven percent to about eleven percent in some of the work that we've done going out to about 2015. So the demand in Canada stays at about one percent increase, driven by that increase in electricity generation.

But also we need to provide a thermal energy source for oil sands. Right now we have about one Bcf a day used in that capacity. And we expect that will increase over time. It's increasing at a slower rate. We're being much more efficient. And the new projects are being much more economic with respect to using all energies. And there's a number of alternatives to natural gas that are being developed. But again, economics will dominate that decision.

LNG, just briefly, we have one facility just about ready to be commissioned. And it should be in service this winter in New Brunswick. And, of course, most of the LNG is anticipated to be going to the U.S. markets from that facility.

What does it mean for natural gas exports of the U.S. northeast market? Currently 50 percent or a little bit more of natural gas produced in Canada is exported. There's a graph or table there to show where it goes.

I think one thing to draw attention to is that about 1.6 Bcf a day comes back into Canada. Some of that is exported molecules that are sold and then repurchased and brought back into Canada, but some of that is U.S. production. So it really is an integrated North American gas market. The border does go both ways, and natural gas flows in both directions.

Looking at the long-term trends, we do a report that we do on about a four-year cycle. And we released one last year. It's called Canada's Energy Future. It's quite a consultative effort. We talked to a number of people, including folks across the country and internationally to get a sense of what are the long-term trends. We integrate all of the energies together from transportation through to heating through to natural gas to oil sands. All of it is integrated into a couple of scenarios.

What I presented here, we call this the

Continuing Trend Scenario. So it's sort of our steady as she goes, business as usual type scenario. The reason I want to use it today is because it was based upon that assumption of $50 U.S. per barrel oil and seven dollar gas. Sounds familiar.

What it does show is that again we've got -- if you take a look at the graph, you've got a steady decline in conventional, which is marked by the green line. And the increase for unconventional, take it to the pink line. So it's again still a steady decline. And LNG is added in on top.

What that would imply would be that there would be declining net exports to the United States in this scenario. In fact, what we show is that you can see, if you go over to the next figure 5, you can see that Canada actually becomes a zero net exporter, if you will, somewhere between 2025 and 2030.

I do put the main caution, as my colleague Claire just mentioned, about the accuracy of any assumptions going forward. We're going to be surprised no matter what happens. But nonetheless, this is one of the scenarios.

We did another scenario at higher prices. We get into more frontier resources. You get into more unconventional resources. And in fact the level of exports in that scenario stays the same as it is today. And that wasn't too outrageous; that was an $80 a barrel and $12 natural gas was what we used in that.

What does it mean for infrastructure? I think that it's clear, as deliverability has declined and the natural gas -- particularly the demand in western Canada has increased, there has been spare capacity developing coming out of the western Canadian sedimentary basin going to points east and south. Some of that long haul transmission has been converted to oil service. And there is a tendency to have a little bit more spare capacity than we've experienced in the past.

The infrastructure trends that we're saying is that clearly with these new resources that are located -- and they're vast new resources in northeast B.C. and points north -- that there's a strong interest in connecting those sources and there's a number of projects to connect that to the major grid. We're doing a little more detailed work on what the infrastructure requirements are and we'll be coming out with a report in April, which we'd be more than happy to share with you.

That completes my comments. And hopefully that gives you a sense of some of our thinking.

But I must say, it's quite interesting to be on this side of the table.

(Laughter.)

MR. MC CARTHY: It's very enjoyable.

Thank you again for inviting me and listening to my comments.

CHAIRMAN KELLIHER: Thank you very much for coming and participating.

I'd like to now recognize Mr. Zachariah Allen, President of the Pan EurAsian Enterprises.

MR. ALLEN: Good morning.

I sit in the unenviable position of being the last speaker before people get to eat. I've been there before. And on both sides, it's a stomach-growling experience.

I'm here to talk about the LNG issues. LNG is presently in a very interesting situation, I suppose. It is a perfect example of the old Chinese proverb about your enemy should live in interesting times.

The energy business is in interesting times at the moment. We talk about volatility of price. In the U.S. markets we've certainly seen that. But the volatility of price in the international LNG markets has been huge.

Consider that the Asian spot market prices for LNG were reported close to $25 a million Btu last winter. There was a certain amount of panic overbuying on the market which has led now to an oversupply situation along with a recession that's caused the prices to drop rather dramatically. How far and what they are is difficult to say.

The market is blessed with a certain amount of opaqueness. That means that nobody quite knows what anybody's paying for anything. This aggravates the situation, in my view.

The portfolio players who are the major players in the market, like BG, hedge against this simply by having lots of optionality. I think optionality is the key to success in the LNG business.

The price of LNG generally is heavily, closely linked to oil prices. That's a function of the Japanese and South Korean prices being linked to the Japan crude cocktail as well as the European prices being linked to prices in the long term contracts with Staatoil and Gazprom.

The situation has been further complicated by further problems of bringing on the supplies, materials. And engineering problems have aggravated the ability to forecast when supplies would come on. There have been constant delays, constant postponements.

This aggregates the market reliability, if you will. Presently LNG finds itself as a swing supplier, a swing supplier and a swing fuel that's at the end of the bull whip. It competes with oil, LPG in many countries, with coal, and, of course, with pipeline alternatives.

For example, in Europe the question in my mind is will suppliers like Gasprom simply stand by and watch market share deteriorate as Europe tries to achieve a certain amount of diversity of supply, which means reduction in market share at the gas pump.

One of the ways to get there is with LNG.

Gasprom has been pretty clever about protecting itself against the deterioration of its market share. The Blue Stream pipeline, which could connect into the Navuko supplies but they are threatened by the supplies in Azerbaijan or Iran. What has Gasprom done? They've formed the Gasprom troika with Qatar and Iran to try to take gas supplies out from Iran through Qatar's LNG.

They've been pretty clever. They've used the South Stream pipeline to try and forestall Navuko.

There's no question that LNG will grow. It's going to be a rough path because it is not an easy road for a lot of places to bring in LNG. For that reason infrastructure kind of seems to be chasing its tail. Let me give you a couple of examples of how this happens.

You're of course aware of the plans or the proposals from two LNG facilities that the U.S. recently commissioned to re-export imported cargoes. That's already been started.

In Belgium they loaded three cargoes, and the last cargo was loaded on a ship called the METHONIA, which loaded in late October. The ship then dispatched to Falmouth, which struck me as a big strange. I wasn't aware that there were any great LNG import facilities in Falmouth. And the ship sat there for three weeks.

Then finally Distrigas decided they'd made a mistake so they brought the cargo back two days ago to Belgium and reloaded it back into the tanks there. And I guess they'll be selling it into the European markets. That's an expensive mistake.

My colleague to my right here knows well about the u-turn that Kittimac proposal has made. I wonder if they're chasing their tail to change from LNG import. And now with dropping prices in the Asian market they may be wondering whether they made the right choice after all. It's hard to know.

Optionality would be great. Maybe you can both be an import and an export terminal. It's possible.

I think that the volatility is certainly demonstrated by this. The U.S. LNG consumption this year is down 55 percent from last year. In November alone it's minus-21 percent.

Spain, on the other hand, is up 22 percent a year on the year; in November it's only up eight percent because most of that was fuel-switching as they reduced the use of coal for probably mostly for emissions purposes to comply with European commitments. Most of that's been wrung out of the system. I don't see so much growth there next year.

And Japan has increased its LNG intake this year by 8.3 percent. Most of that growth is because of the outage of nuclear power plants, which are being rectified.

China, nobody knows what China's going to do. The Chinese are playing both markets against each other. Recently at a conference in -- I believe it was in Tajikistan -- the Chinese committed to take 30 Bcm a year, which would reduce essentially the need for LNG.

India has been a confusing situation for years due to pricing problems. And it's very hard to predict what India will take.

What we're reading every day in the press now is an enormous amount of demand destruction occurring. That means that there's a lot of LNG starting to float around on the market.

Yesterday I was invited to make a presentation, a telephone conference presentation to a group of basically hedge funds who were looking at the question of what's going to happen to gas supplies and LNG in particular. The question which was on their mind was not whether but when the surge of LNG imports into the U.S. would start next year.

They believe -- there seems to be a perception in the market that there's going to be a glut of LNG coming into the world market and that if the price gets down low enough -- the U.S. has the most liquid market and therefore is the last place that it can come. They don't want to shut down their liquefaction trains and anything north of three dollars probably is enough to keep operating.

With the NYMEX presently running in the six to seven to eight dollar range, that's certainly a price in which LNG can force its way into the market.

Will it happen? It all depends on how much future demand destruction there is in the rest of the world, particularly the Asian markets. It could well happen this year, I guess maybe in the late spring, early summer.

With that, I thank you for allowing me to make my presentation.

CHAIRMAN KELLIHER: Thank you very much, Mr. Allen.

Colleagues, anyone want to start?

(No response.)

CHAIRMAN KELLIHER: Okay. I'll start. Okay.

Wait. We have let's say 40 minutes. And there's four of us now. So that's ten minutes each. You have to nail those numbers down.

(Laughter.)

CHAIRMAN KELLIHER: Why don't I start and really ruthlessly cut me off -- a one-minute warning -- but cut me off at ten.

Let me start with Mr. Ruder. What price range do we have to be at really to develop the shale potential in the United States? Is it current prices, a little bit above current prices?

MR. RUDER: Thank you for the question.

It varies by each shale. I think that shales in conventional producing areas where there's infrastructure, there's take-away pipeline capacity and the shale is unknown -- Barnett shale, for example, the lower end of that six to nine dollar price range I spoke about is still viable for some producers in some of the acreage.

The Haynesville, for example, Devon has a significant position. The shales there are much deeper, but they're also much thicker. The depth and thickness together usually results in more gas in place.

So it's a fundamental economic situation with respect to the production rates from Haynesville shale. The infrastructure is there. That's not a six dollar price because of the depth; it's 90,000 feet versus seven to eight thousand with Barnett. So it's much more expensive to drill and compete. That is higher than the six dollar price most likely with the costs we've seen today.

The Marcellus is presently operating. It's closer to market. Prices are higher there. There are significant structure issues, of course. And on the regulatory side there are issues just in some of those states that aren't used to operating with their own gas industry.

We still think that's probably a six to nine dollar range.

CHAIRMAN KELLIHER: How is the rig count this year? Has it been moving up and down a lot? Has it been pretty steady?

MR. RUDER: It's been steady to increasing this year. Last week there was, of course, the announcement of a significant rate drop.

Our perspective with respect to the credit situation, there was a significant drop in oil and gas prices the last four months. We're most likely to see a significant rig drop in 2009 just because of the credit issue.

Independent producers in particular are having problems with their cash flow. Some of the independents have hedged their gas production for two or three years -- that's what we heard today -- and they may be able to sustain their drilling rig programs. It's just really how long the lack of access to credit for independents persists.

CHAIRMAN KELLIHER: Mr. Bretches, any comments about that?

Thank you, sir.

MR. BRETCHES: Yes.

On the shale economics I would echo what Mr. Ruder said. It really depends. It depends on where it is. It depends on the drilling complexity, the depth of the shale, the thickness of the shale; also the completion technology and the hydraulic fracturing that will need to take place in order to bring this gas to the surface.

When you take a look at that Marcellus and the fact that you don't have all the infrastructure and rigs available and service crews at this time -- they will get there -- but at this time to bring that to surface in an efficient and cost-effective well-practiced manner, it will cost more in the beginning. We'll see those prices go down.

To answer the question of what are the economics in a given area, again I would say it depends on the complexity.

I would also say that because Anadarko is relatively new in all of these areas -- the Marcellus, the Haynesville and the Eaglesville shales -- it's not something that we have our hands around yet to even give you a good range. We're in the exploration phase. We're trying to understand the reservoir and the characteristics, what we'll have to do in terms of spacing, et cetera. It's just too early for us to tell.

As for the rig count, the numbers speak for themselves. We've seen those actually increase over the year. Right now we're starting to see a decrease. I suspect what will happen in 2009 is we will see that number fall off substantially as capital programs for 2009 start coming out, so we start seeing what the E&P companies are doing in terms of their capital programs.

We expect to see significant reductions not only because of the financial crisis but also because of the natural gas prices.

CHAIRMAN KELLIHER: Is the fall-off in the rig count rigs that were looking at shale, or is it not clear?

MR. BRETCHES: Again, this is my hypothesis, but I would say yes. Because the shale gas is a higher priced gas at this time you will see a fall off there. You will also see that those are generally more shallow, less complex rigs. Those are the ones that don't necessarily have the long-term commitments. The rigs that fall off are the ones that have short-term commitments or just well to well type commitments.

For example, Anadarko has many deep water rigs in which we have four and five year commitments. Those will continue to drill.

So I believe what you'll see with the E&P companies, they'll focus not only on where the highest margins are but they'll also take a look at their rig suite and understand which contracts can be dropped and which ones cannot.

CHAIRMAN KELLIHER: Thank you.

I just have a question for Ms. Burum.

First of all, I agree with you entirely on the concept of regional planning. It comes up from time to time in different contexts. It's come up in the LNG context before really a few years ago in New England.

The New England states got together and decided where LNG projects should be built and everything would be harmonious. And I guess -- I tend to think if there were a New England regional process and they picked Weavers Cove, I don't think they'd have any different reaction than the one they've had to date.

If it's a government orchestrated or run planning process they're going to miss major projects. If FERC were in charge of planning the pipeline network I doubt we would identify the right project. It's so different from what has been developed in the past. I just want to say I agree with you on that.

I have a question really for you about the storage business given pricing levels and volatility.

Do you think the storage business is a better business than it used to be? Is it one that's going to expand, and, if so, is it going to be pipeline storage? Is it going to be independent? What are you general thoughts about the storage business?

MS. BURUM: I do see it expanding. And with the REX gas coming into the part of the country where it's going to expand, that looks like it's something that would drive the need for additional storage.

I do think what they're saying with prices where they are and what the credit rate is, it's going to trickle from the production area and into the pipeline sector as well. Pipelines have their own constrained access to capital as well. So there is a cumulative effect of those things on the table that is not fully sold.

I think you can say the market for those services is more short term. It's not like transportation capacity where people are willing to go out and buy five or ten or twelve years' services. They do it on a more short term basis.

As far as it being developed by pipeline companies versus independent developers, I think some of that is going to depend on the Commission's treatment of the traditional pipeline developers versus those independent developers and who's allowed to have market based pricing and who is not.

I truly believe that gives those other developers an upside advantage that will be a little difficult for us to compete in either bidding for new facilities or to invest in those projects. So I think you actually have a role in that.

CHAIRMAN KELLIHER: I have a question. As someone in the pipeline business let's assume we have a technological breakthrough in carbon capture and sequestration technologies. Let's assume Congress establishes some regulatory framework to actually set rates and site pipelines and storage projects.

What would be the company that would be operating these facilities? Is this a business that gas and oil pipelines would get into or is it something you think that coal generators would own the facilities? Is it waste disposal and therefore not attractive to the current pipeline network?

MS. BURUM: I don't know. That would be interesting to observe and participate in.

I do think that the people that operate reservoirs, which hold a variety of things today, there's a natural tendency that those would be logical owners, potentially. But again I think it's going to depend on risk and return and many other factors.

CHAIRMAN KELLIHER: I have one minute.

Mr. Allen, a question for you about pricing.

You pointed out that LNG pricing is very different in different markets. That just seems anomalous. We're dealing with a commodity. It's fungible. Other commodities -- the price of copper, really, there's not different pricing for copper in different continents. Commodity pricing, at some point there tends to be an international price for commodities. LNG right now is different.

Do you think we will end up with -- Will LNG be more like other commodities, more like an international price for it, and, if so, how do we get there?

MR. ALLEN: That's a really good question.

I agree with you that it is kind of an anomaly. But when you consider that we traded in oil for a long time without ever letting the NYMEX pick it up, it takes a while. You certain need some size.

There was an announcement in the paper the other day that the Qatari are proposing to start trading in LNG contracts on the London Exchange, which I think is a very good move for the market.

The development of the LNG business has been in real bilateral long term contracts. That is now changing, as you are seeing. This optionality, particularly develop the merging of cargoes, LNG is now starting to move into the markets where the netback to the producer is the best. This is a fight over the rents over that.

The change is not easy. But I think the development of an LME or a NYMEX or a Qatari exchange is inevitable and will be a positive development to keep down those prices.

CHAIRMAN KELLIHER: Thank you very much.

Colleagues?

Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

It's amazing that we've had this entire morning's discussion and basically no one has brought up the Alaska pipeline. I would like all of your perspectives on that, and different perspectives.

Mr. Ruder.

MR. RUDER: The Alaska pipeline, the free market is what works in this country and will work going forward. But time will probably terminate for the Alaskan pipeline. I don't know when that is; other pipelines have left Canada. But that has to be we think based on free market principles of supply and demand.

Power generation and growth in gas for power generation, if it's a level playing field and the fundamentals are right, that may happen some day.

COMMISSIONER MOELLER: Thank you.

Mr. Bretches.

MR. BRETCHES: My view on the Alaska pipeline, first there are a couple of competing projects. The TransCanada project. The earliest date we have seen for completion would be 2018. This is for a $30 billion pipeline, 30 billion-plus, probably, over ten years out.

We believe that a lot can happen in that time frame, as we have seen just over the past few years with the shale gas plays coming into play, pushing out LNG, which I don't think any of us would have predicted three or four years ago.

With that in mind, as Mr. Ruder points out, the market will decide, as long as there's abundance in domestic gas supply, I don't know that we'll see that gas coming from Alaska in order to support that $30 billion pipeline.

COMMISSIONER MOELLER: Ms. Burum.

MS. BURUM: I would agree completely with the perspectives of Mr. Bretches and Mr. Ruder. And when you combine what you just talked about regarding LNG, there's another variable.

There's a whole lot of money and it's such a long period of time, I think it's very difficult to say what the dynamics will be over time.

COMMISSIONER MOELLER: I should note that even though we called it the Alaska gas pipeline, even more it goes through Canada.

So Mr. McCarthy.

MR. MC CARTHY: We certainly are preparing to hear an application should one be filed. We're working with, as my co-panelist advises, there's a couple of different projects and we haven't quite seen the details yet.

MR. ALLEN: I'm very surprised. I think it's inevitable. There's too much gas in Alaska to ignore.

I will add to that, there's too much gas in northeastern Russia to ignore. You see Gazprom starting to wine and dine Sarah Palin. Why do you think they're doing that? It's because there is a lot of undeveloped reserves in northeastern Russia which are further from the Russian market than they are from the U.S. market.

A pipeline across the Bering Strait, that's a short shot. So, yes, it's inevitable.

COMMISSIONER MOELLER: Interesting. Thank you for your perspectives.

We were up there this summer and there is a significant amount of gas reinjection going on on an annual basis.

To go on with my questions, Ms. Burum, you pointed out that you would not like us to be in a position of picking projects. And I just wondered if anyone else on the panel had thoughts on that, that policy that we abandoned decades ago, essentially, at the Commission. Any other thoughts of agreement or disagreement?

I don't expect you to respond, Mr. McCarthy.

(Laughter.)

MR. BRETCHES: I completely support Ms. Burum's position. We do not see a role of government in picking projects.

MR. RUDER: I can only echo that message as well as far as the market determining it.

COMMISSIONER MOELLER: Mr. Allen, any perspectives?

MR. ALLEN: I was involved in the early 1980s with the start of the Syncor Corporation. Need I say more?

COMMISSIONER MOELLER: No. Nice reference.

Mr. Bretches, you pointed out that regulatory uncertainty is your biggest risk. I think what you're saying is that it's within state agencies and not this Agency's. If you could elaborate on that and anything we can do in your opinion to help mitigate that uncertainty.

MR. BRETCHES: The way that you just characterized it is exactly right. It is not this Agency. It really starts with the state oil and gas commissions, as well as the BLM.

Speaking again from an upstream perspective, I wanted to give you all an upstream perspective because you see so much of the midstream and the transportation infrastructure side. I wanted you to see what the upstream is facing.

This has a direct impact, though, on the transportation side. If we can get permits to drill in a timely manner -- and I'll use Utah as an example -- many times to get an application to drill it takes over 400 days. That's a tremendous amount of time in fields in which we drill each and every day.

We just are not seeing a timely response to our permits as we are in neighboring states, which can take one-tenth of the time in Colorado.

This process is further exacerbated by the fact that we have federal lands and federal permits that we get, and we have the state that tries to override those permits and impose state regulatory positions.

That said, it can be very complicated, particularly in the Rocky Mountains. I just wanted to give the Commission what we see in some of the untimely responses we see from the regulators which really prevents the timely supply to the markets. And we don't see a timely price response to demand.

COMMISSIONER MOELLER: If there's anything we can do please let us know.

Finally, for Mr. McCarthy, thank you for coming here. Please give my regards to the board. I met several of the members in April and they were delightful hosts.

Can you give us the latest snapshot of really what's happening -- I'll say Alberta Gas. But we've heard conflicting things about how the supply has been falling off lately. And I think it was a couple of weeks ago TransCanada announced that one of their five west to east pipelines is going to be converted to oil in a couple of years, indicating a lack of supply, and knowing that it's used for the tar sands production.

What's the latest that you can give us on that?

MR. MC CARTHY: That's exactly the situation.

As I mentioned, there's two things. The western Canada sedimentary production is about 16.5 Bcf a day. That's getting softer. We're seeing with the economics not promoting as much activity drilling for conventional sources as we have in the past. We're starting to anticipate that that will decline somewhat.

But at the same time we're seeing a continuing growth in Alberta demand. So coming out of Alberta, as I said, there's more excess capacity in all of the pipes coming out than there has been in the past.

TransCanada exactly has converted one of their lines to oil service. And that's the foundation of the Keystone project. The Canadian part of the Keystone project is primarily that new service or that existing gas pipeline.

COMMISSIONER MOELLER: I'd keep going but I'm out of time. Thank you very much.

CHAIRMAN KELLIHER: Thank you.

Commissioner Kelly.

COMMISSIONER KELLY: Thank you all for your testimony today.

I'd like to ask each of you to think about your understanding of the supply situation in the United States and Canada and in the LNG markets. Can you give us your thoughts on what that is likely to mean for us here at FERC?

Specifically, what kind of infrastructure activity do you think we're likely to see in the next three years, five years, pipelines, storage, LNG terminals, liquefaction terminals? What do you think we're going to see midstream?

MR. RUDER: If I may, I think assuming the pace of drilling in the shales, for example -- and there are many others -- but drilling for shale is very intensive. And activity in the production starts to become significant.

The Haynesville, for example, is just starting to get off the ground, if you will. The areal extent of that is very significant. We estimate that there's approximately one Bcf of capacity that is available out of that area on the Texas side of the play.

If you extrapolate any extension to the Barnett shale, there already is the need, because of the lead time, for more interstate pipelines out of Texas and Louisiana extending to the growing markets in the southeast United States in proximity to the Haynesville. But expediting new pipeline applications, additions to existing facilities, major capacity increases, is paramount.

The timeliness of that I think, the effect of that not happening, we see what we've seen in the Rockies today: the basis differentials will blow out two to three dollar basis differentials for NYMEX in the Rockies or more. We're experiencing that in mid-continent right now just because of pipeline capacity issues, some of which are a result of hurricane Ike still.

But the permit applications getting through market to pipelines, that applies to the Rockies, which of course has been the most severely restricted pipeline takeaway capacity. I'll let others comment on that.

COMMISSIONER KELLY: Thank you.

MR. BRETCHES: As a Rockies producer I'll start there. We will need more takeaway in the Rockies.

As you all know, we produce approximately nine Bcf a day. As an industry from the Rockies, we've already filled out pipeline capacity. We'll see severe constraints and congestion next summer. There's a regional demand of about 1.5 Bcf a day. That Rockies production is expected to grow to approximately 11 Bcf or 11.2 Bcf per day by 2013.

Obviously takeaway capacity is going to be huge in the Rockies. I would say that that would be an area that will deserve focus.

COMMISSIONER KELLY: Will that takeaway capacity go east, west or both?

MR. BRETCHES: It will probably go both. But I think what we will see is we will see more going to the east than we will the west. There will be a disproportionate amount going to the east rather than the west.

Of course over there will be a pipeline that will provide relief in 2011. We'll also see more pipelines and midstream requirements in the northeast because of the Marcellus. We will also see more takeaway at the terminus of REX.

There is clearly not enough takeaway to provide adequate response to all this Rockies gas that will flow all the way into Ohio at the end of 2009 when the pipeline becomes complete. More takeaway from the mid-continent, particularly in Haynesville and Barnett, and there's going to be more takeaway needed in the southeast and the developing markets there. And that provides some relief of congestion in the mid-continent area today.

COMMISSIONER KELLY: Thank you.

MS. BURUM: They probably have a better perspective from the supply side than I do. When I look at how the contracting has taken place most recently, in the last five years you see the producers signing up for capacity more to get their gas to a local point.

What happens beyond that, I think we can expect to see more medium size projects taking some of the REX gas away, all those six or seven BCF of shale gas and they'll sit in the Gulf Coast area. Recently we've seen a lot of those projects, but I don't see the end of them yet because there will be constraints of getting that gas distributed further into the grid.

I also think from a pipeline perspective I see us proposing more creative services and things that we haven't done before. I see the potential for creative or innovative contract structures. Whether that fits the negotiated rates or whether it requires tariff filings, I think you can expect to see more of that from us in the future.

COMMISSIONER KELLY: Is that because of the changes in the supply picture or because of the changes in the credit segment of our industry? Or both?

MS. BURUM: It could be those things. There even are some gas quality type issues.

There's an opportunity for the producers and the pipelines to collaborate between different services to handle things differently. We look at the risk and the investment at stake. And certainly in the market I think that's going to drive some different contract structures that you haven't necessarily seen as much of yet.

COMMISSIONER KELLY: Thank you.

MR. MC CARTHY: From my perspective we're seeing it now. It's very similar. There's a lot of interest in connecting to the major grid those new supply sources and their significant volumes. There's a lot of angst to get large capacity out of those areas.

I think it's interesting, though, from a regulator's perspective, that the speed those supply areas develop tended to be set up to satisfy growing demand. And we tended to think that there was an incremental growth in a particular market of two, three, four, five percent per year. The supply comes on -- boom -- very quickly.

I think that might be something that's unique from a regulator's perspective that we should be preparing for in the future.

COMMISSIONER KELLY: Have you seen that already in Canada or do you anticipate it?

MR. MC CARTHY: We are seeing it. As I said, we've got some very large projects.

If you look at the Montney and Horn River areas in northeast B.C. on the first page of my presentation, the existing capacity from the conventional production is very limited. If those shale plays come on at the volumes they're anticipating certainly you're going to see some large construction coming out of that area in a fairly brief period of time into the larger grid.

COMMISSIONER KELLY: Thank you.

MR. ALLEN: You ask what's in prospect. I would say fasten your seat belts; welcome to Kings Dominion.

I think it's going to be interesting. The reason I say this is the following.

The problem I see is a sort of growing cynicism over the tug of war that's inevitable. Major projects are always controversial from particularly a local standpoint.

You mentioned Weavers Cove. Having grown up on Narragansett Bay, I find myself bifurcated in terms of my views of projects like that.

The template seems to be when a project is needed the justification to incur a certain amount of compromise on environmental issues is this is necessary; it's absolutely essential to our country that we do this. This is the future. Alan Greenspan says we need LNG.

Today you're probably getting a lot of heat from people who say, 'Wait a minute, we need LNG. We've got all these pipes in there doing nothing. Why?'

I think you're going to see a growing tug of war over these projects. It's going to be more and more difficult to satisfy the cynics that optionality perhaps is the secret to keeping our price profile modest.

If you look at the futures curve for the U.S. prices versus the futures curve for U.K. prices, it's an enormous difference. They don't have the optionality we do. We have this great optionality. It does result in volatility, but it's nowhere near as much as the cost that other places like Japan and the continent have.

So I would say it's going to be interesting.

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: Commissioner Spitzer.

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

Ms. Burum, the prior panel talked about the full withdrawal from the pipeline applications. And we heard that you've got an interesting system. How do you analyze the push and pull? How does that change over time?

MS. BURUM: Where do you see a change?

I mean ten years ago producers did not sign up for expansion projects. It always was overseas. And then later it was power plants more and more.

You just didn't see producers signing up for the pipeline to build capacity expansion. That's completely changed. So I think the push and the pull are both there.

The producers will push only to where they lead to. They'd rather spend their money drilling than tied up in pipeline capacity long term.

But the LDCs, power plants, and other industrial end users are the ones that are willing to subscribe to the smaller children pipelines, if you want to think of it, of the big pipelines.

COMMISSIONER SPITZER: Is there a greater stability on the demand side rather than the supply side over the long term in terms of continuous support to get financing?

MS. BURUM: In my opinion there is. We're always going to have factories burning gas and industrial products being made with the gas they're delivering. There's some level of certainty there; it's not 100 percent, especially in today's economy. But certainly it is somewhat predictable.

COMMISSIONER SPITZER: On the financing -- and I'm asking you to put on your INGAA hat here -- you've got three corporations that have the same problem -- all entities do -- with regard to obtaining credit. And presumably there are some limitations on equity financing as well. The MLP structure raises funds in a different manner.

Have you observed any differences between the

MLPs and the C-corps in terms of the ability to obtain financing?

MS. BURUM: I can only speak at a high level. I'm not in the MLP business at this point.

But my observation is that all entities are having a difficult time accessing capital. If the MLPs do that and issue new equity, this is not a good time to do that because of the price of the units.

COMMISSIONER SPITZER: The potential purchasers of these units may not have access to capital themselves.

MS. BURUM: That too. But even more so that the price of the units are so low right now that the selling entity, it's not an appealing time to issue more equity at those low prices. It's undervalued I think in their opinion.

I think you're going to see every single bit of the industry having a difficult time accessing capital.

COMMISSIONER SPITZER: Mr. Allen, I think it was about a year ago we were told the shale plays are the demise of U.S. LNG. Now your hedge funds apparently -- was it last week you said?

MR. ALLEN: Two days.

COMMISSIONER SPITZER: Two days ago saw a different story.

For example, presumably that's because Qatar supply costs are very low. They've got the infrastructure for liquefaction already in place. They're going to keep running it out regardless of the global price as long as it reaches a certain threshold.

So which is the correct view long term, demise of LNG or glut in LNG supply?

MR. ALLEN: Let me say both.

The question is this. You asked the question earlier as to what is the price at which shales come into the market. The question that I think is more relevant to your question is at what price do the shales drop out of the market. At what point do you start to see shale production tailing off.

As I understand it -- I'm not an expert on the business but maybe these guys know more about it than I do -- the life profile of a shale well, you have a very strong production in the early year or two and after that it starts to taper off. You need to do more fractioning of the reserve to get that production back up again. That's an expensive process.

If you have that kind of a profile what are the economic decisions that the company is going to make about, A, reinvestment or even shutting the well in. Are you going to accept low prices or are you going to shut the well in and wait for better prices because you don't have that much life span to get that money out.

The question is when you see low prices start to come into the marketplace what is that going to do a year or two years out to shale production, new production, as well as maintaining existing production, in which case LNG then comes back into the market. Or LNG may force itself into the market and put the shale business in a difficult position if we have this glut of LNG which people are talking about.

COMMISSIONER SPITZER: Again, in the example of Qatari LNG, they've got favorable economics.

MR. ALLEN: They've all got favorable economics. The LNG, for example, from Equatorial Guinea was originally scheduled to come to Elba Island. It hasn't come into Elba Island. It's gone to Japan and South Korea. What price would they be willing to accept in order to bring it into the U.S.? They will force their way into the U.S. market if they have to.

COMMISSIONER SPITZER: Gas production is quite a bit different than oil production, more diffuse in terms of potential decline of shale.

Do you think the key variable is the credit issue with regard to particularly the independents who don't have -- they don't have cash like the majors in the oil, or is it the price?

MR. RUDER: If I may, I think it's a combination of both.

The typical shale well first year declines approximately 65 percent, 40 to 50 percent the second year. And you're probably looking at a 40 to 50 year life of that well. It's much different than a conventional well. It takes a lot of activity, a lot of wells to maintain that production profile with that type of early decline.

So the pricing is obviously a key driver to get that threshold level and the terms that producers need to invest and keep the program steady to maintain the decline rather than to increase production. The credit side of it coupled with the reduced prices will also impact it. Independents living within their cash flow, it will necessarily cut back on drilling.

As far as existing wells, the Barnett shale, which is producing three and a half Bcf a day, the wells that are currently producing, the marginal costs to produce them is much less, obviously, than the original investment. Those wells will most likely continue to produce in what we expect prices to do in the future in a low price scenario because they have access to market. And we have long term take-away capacity to give to market. So it will be competitive.

From Devon's perspective, we don't think it's necessarily one or the other. We think we need LNG; we think we need every source of energy -- imports. But it is going to take a stable price environment. Demand is obviously key. The economy and the current situation will be difficult for all of us. But we see a place for both.

COMMISSIONER SPITZER: I'm presuming your credit sources look at the same issue which Mr. Allen discussed, which is the potential glut of LNG. There's a potential adverse future consequence for new production.

MR. RUDER: If supply and demand fundamentals in fact supply those ships on the water come to the U.S. with that supply, it could drive prices down temporarily. But we don't see the fundamentals keeping prices down as long as we have a free market and an unrestricted market.

We think the cut-back in drilling that we'll probably see now probably won't last too long before prices have to come back up because we look at the decline risk for shales, we see a serious decline over the next year or two when the rig count drops dramatically. But we think there will be a rebound in price, too.

COMMISSIONER SPITZER: Clay.

MR. BRETCHES: First of all, I'd say price drives everything. Your highest cost projects will be backed out first. Generally speaking, what we believe will back out will be the shale gas projects because they are high cost and because they have a relatively quick decline curve.

As far as access to credit, that would be driven by price in order to access the credit markets, particularly independents, who need to go out and hedge their long term production. And when you see those prices, the ability to do so will be very difficult.

And the forward prices they will be able to receive will be relatively low, which means again they cannot participate in high cost projects. So this competition between LNG and shale gas could be interesting.

And I like Mr. Allen's answer on both because I agree with you. And I think what we'll see is some significant price decreases in the summertime when you don't see the global LNG demand in the countries that burn it for heating in the wintertime, particularly in Asia and in Europe. You'll see that LNG coming to the U.S. And we'll see some pretty big price differentials between the summer and the winter, perhaps even bigger than what we see today, which will beg for more storage, really.

We need something to do with that low priced gas when it comes into the U.S. and the markets will generally dictate that storage is the right answer, so you can harbor it in the higher priced winter months.

COMMISSIONER SPITZER: Mr. McCarthy, my last question:

You've got your graphs on the Canadian exports. What variables did you model that would be most likely to change that phenomenon and either flatten or cause an increase in exports?

MR. MC CARTHY: Price was the big variable that affected again.

COMMISSIONER SPITZER: LNG price?

MR. MC CARTHY: Energy prices. We just did natural gas energy prices.

We used MIMEX as our reference point. When we increased the MIMEX price, as I said, in those scenarios where we had a $12 MIMEX price long term we were able to access a lot of unconventional natural gas, including frontier and including offshore on the east coast. So all of that helped to promote a surplus, if you will, from Canadian needs and therefore the exports.

One of the things in our modeling was we talked about net exports. We always assumed there would be exports. The gas would flow where it economically made sense. So if the Midwest markets were closer to the production areas but the eastern markets would have to be satisfied by other means, that's sort of the model we used.

COMMISSIONER SPITZER: Thank you.

CHAIRMAN KELLIHER: Any other questions or comments?

Phil.

COMMISSIONER MOELLER: I've appreciated all the discussions we're in. It was great. Thanks to the panelists and the staff who set it up.

I think again my longstanding concern of being more dependent on natural gas, particularly for electricity production, has only been intensified by our discussions today.

Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: I think this has been a good discussion.

We reviewed some of the fundamentals of natural gas supply and demand and talked about the infrastructure needs of this country. But, of course, we don't know what the future holds for us, what will evolve, what will the flow of Alaska gas be, when will we see Alaska gas flow; what will the role of LNG be.

We are dealing with predictions. And predictions can be little more than well-dressed guesses sometimes. But we have to base our policies on some of these projections.

One thing is pretty clear: that the U.S. needs to continue to develop a very strong natural gas infrastructure. And current Commission policies and historic policies are very well suited to meet that need.

I'm not walking away from this conference thinking we have some longstanding Commission policy we need to correct in order to maintain a strong gas infrastructure. I didn't hear that from the panelists today.

This is your last chance to key up some major regulatory reform that we need.

(Laughter.)

CHAIRMAN KELLIHER: I'm walking away from this meeting with the assumption our policies are well suited to meet the needs for gas infrastructure. If you have an idea say so now. You can always tell us about it informally.

But it's been a good conference. And we really need to have some understanding of these kinds of fundamental issues as we're developing policy.

Mark, Rob, any comments? Jeff?

(No response.)

CHAIRMAN KELLIHER: Thanks for coming today, everyone. Have a good weekend.

(Whereupon, at 12:25 p.m., the conference in the above-entitled matter was adjourned.)