ALASKA STATE LEGISLATURE
JOINT MEETING
HOUSE SPECIAL COMMITTEE ON ECONOMIC DEVELOPMENT, INTERNATIONAL TRADE AND TOURISM
HOUSE RESOURCES STANDING COMMITTEE
SENATE RESOURCES STANDING COMMITTEE
April 8, 2009
3:34 p.m.

MEMBERS PRESENT

HOUSE SPECIAL COMMITTEE ON ECONOMIC DEVELOPMENT, INTERNATIONAL TRADE AND TOURISM

Representative Jay Ramras, Chair
Representative Mike Chenault
Representative Mark Neuman
Representative Mike Doogan
Representative Chris Tuck

HOUSE RESOURCES STANDING COMMITTEE

Co-Chair Mark Neuman
Co-Chair Craig Johnson
Representative Scott Kawasaki
Representative Chris Tuck
Representative Peggy Wilson
Representative Paul Seaton
Representative Bryce Edgmon
Representative David Guttenberg

SENATE RESOURCES STANDING COMMITTEE

Co-Chair Bill Wielechowski
Co-Chair Lesil McGuire
Senator Hollis French
Senator Bert Stedman
Senator Gary Stevens
Senator Charlie Huggins
Senator Thomas Wagoner

MEMBERS ABSENT

HOUSE SPECIAL COMMITTEE ON ECONOMIC DEVELOPMENT, INTERNATIONAL TRADE AND TOURISM

Representative Nancy Dahlstrom
Representative Kyle Johansen
Representative Reggie Joule
Representative Lindsey Holmes

HOUSE RESOURCES STANDING COMMITTEE

Representative Kurt Olson

SENATE RESOURCES STANDING COMMITTEE

All members present

OTHER LEGISLATORS PRESENT

Senator Gene Therriault

COMMITTEE CALENDAR

Presentation(s): Porter Bennett, BENTEK Energy, "Technologies For Shale Gas Development in the U.S."; Dr. Mark Myers, AGIA, "Alaska's Natural Gas - Needed or Not?"

PREVIOUS COMMITTEE ACTION

No previous action to report

WITNESS REGISTER

MARK MYERS, Ph.D., AGIA Coordinator
Office of the Commissioner
Department of Natural Resources
Anchorage, Alaska
POSITION STATEMENT: Delivered a presentation on "Alaska's Natural Gas - Needed or Not?"

PORTER BENNETT, President and CEO
BENTEK Energy
Evergreen, CO
POSITION STATEMENT: Delivered a presentation on "How Horizontal Drilling $ Fracturing Technologies are Changing Natural Gas Markets."

ACTION NARRATIVE

3:34:03 PM

CO-CHAIR MCGUIRE called the joint meeting of the House Special Committee on Economic Development, International Trade and Tourism, the House Resources Standing Committee, and the Senate Resources Standing Committee to order at 3:34 p.m. Present at the call to order from the House Special Committee on Economic Development, International Trade and Tourism were Representatives Neuman, Doogan, and Tuck. Representatives Chenault and Ramras arrived as the meeting was in progress. Present at the call to order from the House Resources Standing Committee were Representatives Tuck, Wilson, Seaton, Edgmon, Guttenberg, Neuman, and Johnson. Representative Kawasaki arrived as the meeting was in progress. Present at the call to order from the Senate Resources Standing Committee were Senators French, Stedman, Stevens, Huggins, Wagoner, and McGuire. Senator Wielechowski arrived as the meeting was in progress. Also in attendance was Senator Therriault.

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PRESENTATION(S): PORTER BENNETT, BENTEK ENERGY, "TECHNOLOGIES FOR SHALE GAS DEVELOPMENT IN THE U.S."; PRESENTATION BY DR. MARK MYERS, AGIA, ALASKA'S NATURAL GAS, NEEDED OR NOT?

3:34:39 PM

CO-CHAIR MCGUIRE announced that the first order of business is a presentation by Dr. Mark Myers.

MARK MYERS, Ph.D., AGIA Coordinator, Office of the Commissioner, Department of Natural Resources, delivered a PowerPoint presentation titled "Alaska's Natural Gas - Needed or Not? What about Shale Gas and Carbon Regulation?"

Slide 1 stresses the importance of the changing world demand for energy due to urbanization, industrialization, and growing population. The world energy picture is one of growth and traditional sources are becoming supply limited. The maximum delivery time for Alaska gas is 20-30 years and over that long term the demand drive is intensive and growth is massive. Slide 2 illustrates the growth in energy demand for the different supplies - coal, oil, gas, nuclear, hydro, and other renewables. Historically increased demand has been accommodated by increasing oil production. He noted that there's also been a dramatic increase in the production of coal, a subtle increase in nuclear and a worldwide increase in the use of natural gas. A concern for the Alaska project is that energy demand might switch to other sources including renewables and alternative

sources of gas. Slide 3 illustrated that now and in the future the dominant energy source will be fossil fuels. Renewable sources simply cannot grow fast enough to offset the demand growth.

Slide 4 illustrates the shift from oil to the use of coal and nuclear for electrical generation in the 30 year period from 1974 to 2004. The use of natural gas for electrical generation increased just slightly because of limited supplies, but looking forward it's clear that massive supplies of new, low CO_2 energy will be needed. This pushes the U.S. toward a gas economy and argues for competition for an overseas LNG market. He highlighted that much of the demand growth that could theoretically be met will be limited by the environmental consequences of all types of energy, renewable or not.

Slide 5 shows that all new sources of energy have unique environmental challenges, particularly those that use an abundance of fresh water. For example, the irrigation of agricultural corn to produce ethanol is drawing down aquifers at an alarming rate and is non-sustainable. Oil shale and the growth of hydro have challenging water issues and in some ways shale gas will be limited by water issues. To sustain the life of a well it may be fraced up to 10 times and use up to 4 million gallons of water per frac. Because of resource limitations and environmental constraints past growth can't be assumed in the future.

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MR. MYERS displayed slide 6 highlighting the changes since the AGIA license was approved.

- The massive global recession has led to a decrease in the use of energy. Natural gas use in the U.S. has been reduced by about 1.3 percent and prices out of Henry Hub have dropped dramatically.
- There's been a rapid expansion of shale gas supplies in the U.S.
- The new administration's policy shift will potentially limit OCS and other access for oil and gas exploration and development.
- The first international Arctic oil and gas assessment shows Arctic Alaska leading with respect to gas and oil.
- There's increased likelihood of carbon regulation.

SENATOR WAGONER asked if the same gas-rich geologic structure in the Arctic extends to the Outer Continental Shelf.

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MR. MYERS replied the underlying geologic source rocks that generate oil and gas onshore continue out into the Beauford and Chukchi seas. Alaska is probably the most prolific generator of hydrocarbons in North America in terms of the number of source rocks, the richness of those source rocks and the great geologic structures both on and offshore. Alaska also has a promising continental margin that has a huge sedimentary cover and great structures. For example, the Berger structure had 14 Tcf of gas in the Chukchi Sea. The offshore potential is large. The production of associated gas prolongs the life of an oilfield and if production costs are shared between gas and oil it makes the gas cheaper to produce. The existing infrastructure in Prudhoe Bay and the potential of Point Thomson help make Alaska's gas very competitive at low prices. The ultimate cost of gas production comes from the transportation and operating costs additional to the field costs that are relatively minor.

MR. MYER displayed slide 7 showing that the number of gas rigs in use dropped 45 percent in the last year. Unless some of those are picked up in the near future, there will be a decline in production in the next two or three years.

MR. MYER said slide 8 outlines Jim Mulva's, viewpoint that a long-term view is needed as the driver for a pipeline. Look at long term demand and the long term price of getting the gas to market - the competitiveness of the project given alternative sources.

The line graphs on slide 9 reflect the EIA's most recent 2009 forecast and illustrate that both Lower 48 unconventional and Alaska North Slope gas will be needed in the future. He said it's important to realize that new gas supplies often replace existing conventional supplies that are in rapid decline so there's a balancing effect. The forecast for Alaska gas is that it will be a significant player. The second line graph showed historical and projected natural gas production for 1990-2030 in five cases - slow technology, low price, reference, rapid technology, and high price. The models show a dramatic increase in demand for gas in 2018, which is very good timing for Alaska gas.

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CO-CHAIR WIELECHOWSKI recognized that Representative Ramras had joined the committee and Commissioner Galvin was in the audience.

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MR. MYERS displayed slide 10 looking at the 2009 EIA forecasts of prices and said that none of the published forecasts he's seen indicate that the flood of new gas into the market will lower prices in the long term. In the short term prices absolutely will be affected. Lower 48 wellhead and Henry Hub Spot market prices out to 2030 are all well above the needed return to make an Alaska gas pipeline profitable. Slide 11 clarified that this is well within the range of expected outcomes that were modeled in the AGIA findings.

The chart on slide 12 illustrates that shale gas provides about five percent of domestic production. In 2007 about 47 percent of domestic production came from nonconventional gas. He explained that conventional resources in the Lower 48 - except for deep water offshore, Alaska and potentially Atlantic and West Coast margins - have been heavily explored and are in rapid decline. This has caused a shift to the unconventional resources - coalbed methane, tight gas sands, deep basin centered sands, and now shale gas. They are typically more expensive to produce.

Slide 13 depicts Wyoming gas reserves and the production history from 1977 to 2006. Conventional gas resources became more difficult to produce, accumulations were smaller and nonconventional gas increased. The same thing will happen in Alaska but conventional resources will come first, which is why Alaska gas has such great economics.

Slide 14 shows shale gas plays in the Lower 48. Some shale gas has to be de-watered and sometimes water has to be added for fracturing. There's a wide variety of heterogeneity to the reservoirs and they have a wide variety of economic costs and development strategies depending on the geochemistry, quality of the shale, the source rock, whether it's naturally fractured, ductile or brittle, the depth and ease of extraction due to surface conditions, access, water availability, land use policies, royalty rates and environmental policies of the local district. Overall there is wide variation on the cost structure; the equation is not simple.

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MR. MYERS displayed slide 15 showing the estimated break-even costs for Lower 48 shale gas and Alaska North Slope onshore gas. USGS modeled new field development and estimated breakeven costs at about $3 at the AECO Hub. For the Foothills, USGS generally used breakeven numbers of about $4.25. Bank of America NYMEX numbers showed Alaska gas either under or at the low end of the best Lower 48 shale gas. Low grade was $4.20, medium was $6.64 and the highest was $11.50. Lower drilling and steel costs today coupled with technology improvements enhance the economics of both. The balance is that development costs go up for everyone when fuel prices are high and go down for everyone when prices are low. It would be a good deal if steel could be purchased cheaply in the next few years because the base gas in Prudhoe Bay is currently being cycled.

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CO-CHAIR WIELECHOWSKI welcomed Speaker Chenault to the meeting. He then asked if the $3 figure for onshore North Slope gas reflects $2.76 for the tariff and $0.20 for capital and operating costs.

MR. MYERS agreed that operating and capital costs are small. $2.67 includes treatment plant costs and $4.25 is the cost of developing a new field, feeder pipelines, and associated operational costs in the Foothills onshore. Offshore numbers would be a bit higher.

CO-CHAIR WIELECHOWSKI asked if $4.25 is for a totally new field outside of Prudhoe/Kuparuk.

MR. MYERS said yes, on state lands onshore. He offered to provide the numbers that USGS used.

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MR. MYERS said Arctic Alaska is one of the two areas of highest potential for gas according to the most recent assessment. In fact, Alaska's gas resources represent about 36 percent of the national total for undiscovered, conventional estimates. Compared relative to continuous or nonconventional gas, the December 2008 USGS numbers indicate about 364 Tcf of technically recoverable gas - including coalbed methane. The price of gas would need to be between $11 and $12 coupled with lack of environmental restrictions on access to the resource. Slide 19

showed the mean continuous gas resources excluding coalbed methane to be about 275 Tcf.

The chart on slide 21 depicts USGS/MMS assessments of undiscovered, conventional natural gas in Arctic Alaska that are roughly at parity to Lower 48 gas resources. The graph on slide 22 showed 33 Tcf of undiscovered technically recoverable nonassociated gas in the central North Slope. Various price scenarios show that much of the gas is recoverable in the $4-$6 range. It takes about $4 gas to start recovering new field development away from infrastructure on the central North Slope. This is consistent with the $4.25 figure. Fields cost different amounts depending on location, the quality of gas, number of wells drilled, whether they are horizontal or vertical, and what's in the gas. This is a relatively good comparison between the two resources. The EIA price forecast similarly indicates that much of Alaska's gas is commercial.

MR. MYERS reviewed slide 24 and described the Arctic Alaska province as immature; just a handful of gas wells have been drilled for exploration. In comparison, the density of wells in Wyoming is 80 times that of Alaska. The assumption is that much more gas will be found as more wells are drilled. Slide 25 indicated about 100 Tcf of technically recoverable coalbed methane and natural gas hydrates. In neither Alaska nor the Lower 48 has the over-pressured basin-centered gas - the tight gas sands - been assessed. It is, however, potentially huge. Slide 26 reflects Alaska North Slope natural gas hydrate assessment results for nonconventional gas.

MR. MYERS displayed slide 27 to highlight what happens in a carbon constrained environment. The IPCC (International Panel and Climate Change) and the national CCSP (U.S. Climate Change Science Program) assessments say that if carbon isn't mitigated now there will be an increase in global temperatures. It is the consensus of the scientific community that if greenhouse gases increase there is a natural increase in temperature. To limit that, manmade CO_2 has to be mitigated. If Congress and the administration choose to do that, it will change fuel strategy dramatically toward natural gas. Slide 28 reflected a 14 Bcf/day increase in demand in a carbon managed growth case. More recent analysis show up to 20 Bcf/day, but the EIA forecast has yet to take that into account.

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CO-CHAIR WIELECHOWSKI asked what he assumes would be taxed under cap-and-trade.

MR. MYERS replied this model reflects a tax of about $35/ton of carbon for all sources.

CO-CHAIR WIELECHOWSKI asked how natural gas emissions compare to other sources.

MR. MYERS replied natural gas emits about one-third what a coal-fired power plant produces and capital costs are about one-third as well. To get to the growth that's modeled in all the scenarios lots more gas is necessary and the price has to be higher. EIS estimates that the price to consumers will drop about $0.63/Mcf off the Henry Hub Spot in 2018-2019 when Alaska gas comes to market. Over time the market will recalibrate and the price will increase, which will be good for Alaska's gas prospects.

The latest EIA model indicates that natural gas from LNG will increase until about 2018 after which it will decrease. Canadian production will continue to decline because of overall basin depletion, but the predicted increase in LNG hasn't materialized. One reason for that is that other areas of the world value LNG more; the U.S. has alternative gas sources.

MR. MYERS displayed slide 32 showing that the most recent EIA forecast is higher than the 2004 and 2006 forecasts used for AGIA. The price estimations are more bullish even with the increase in supply. He recapped the reasons include worldwide demand, population demand, national demand, decrease of conventional supplies and development of more expensive alternatives. This puts Alaska in a good position.

Slide 33 depicts Atigun Gorge along the gasline route including the Lisbon formation. This is a high potential target in limestones and is similar to what is seen in much of the Canadian Overthrust Belt.

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CO-CHAIR WIELECHOWSKI referenced slide 32 and noted that TransCanada yesterday said the new forecast adds about $125 billion in value to governments and producers. He asked Mr. Myers if that's his understanding

MR. MYERS said yes; once the infrastructure is constructed the tariff will remain fairly constant over the life of the pipeline so the cost will come from the variation in the cost to develop those resources. For example, if gas is coming out of Prudhoe Bay, the operating and capital costs stay the same and the pipeline tariff is pretty much the same. Conversely, when the price goes down you lose significantly. That is why it's important to understand the "break-even" formula - what the net present value of 10-15 percent gives you. The AGIA numbers said net present value of 10 percent, not break-even. The TransCanada numbers were probably also net present value of 10 percent.

CO-CHAIR WIELECHOWSKI thanked Mr. Myers for the presentation.

CO-CHAIR JOHNSON introduced Mr. Bennett and clarified that he is not being paid by the state. He highlighted that the gas presentation he delivered in Washington D.C. was simple and easy to understand for the lay person.

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PORTER BENNETT, President and CEO, BENTEK Energy LLC, said he would cover five key points.

- The energy world has changed radically over that last two years. Technology has changed the way natural gas is developed and produced, which is profoundly impacting the market.
- Natural gas should no longer be viewed as unavailable, unreliable or too expensive.
- Due to unconventional gas production, the U.S. has become supply-long. Prices are falling and consumers will benefit.
- The burgeoning supplies are overwhelming the nation's pipeline capacity. The impact of constraints is to drive prices lower by stimulating gas-on-gas competition.
- The production growth creates a unique opportunity to use gas and reduce carbon emissions.

MR. BENNETT displayed slide 5 showing that the production of gas began to increase rapidly beginning in the summer of 2007. In 2005 and 2006 it grew about 1.5 percent to 2 percent a year and in 2008 it grew nearly 7 percent. At the same time demand increased between 1 percent and 2 percent depending on the source. Slide 6 demonstrated that in 2008 Lower 48 production was at near historic levels. Had the recession not hit, levels would likely have been higher.

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MR. BENNETT displayed slide 7 showing that gas production increased everywhere but in the Gulf of Mexico and Gulf Coast basins and the Paradox and San Juan basins. He noted that the Gulf decreased about 600 Mcf/day. If it weren't for the impact of the hurricanes, he estimated that the decline would have been closer to 100 Mcf/day. Production in the Rockies grew by about 1 Bcf/day largely due to tight sands and coalbed methane. The South East Supply area, comprised of the Arkoma, Arcola, East Texas and Fort Worth basins, grew more than 3 bcf/day last year, primarily from shale. Production in the Appalachian Basin grew by 200 Mcf/day last year and the year before. That's where Marcellus is located and future grow is expected. Production in the Anadarko and Permian basins, which are primarily conventional, also grew some last year.

MR. BENNETT highlighted that the market share has changed quite radically over the last 20 years. In the 1980s the Rockies produced about 3 percent of the gas consumed in the U.S. and now it's about 20 percent. The South East supply area only produced about 9 percent of the gas produced in the country in 2000 and now it produces 25 percent. Appalachia production was less than 1 percent in 1980 and is now about 4 percent.

MR. BENNETT displayed slide 8 demonstrating that the type of drilling reflects the shift to unconventional gas production. He noted that the horizontal drilling is primarily shale gas and although it's been used since 1990, it's only in the last 2-3 years that it's started to take over. Directional drilling is a tight sands approach that allows multiple wells on a single pad. This new technology uses fracing, which produces gas from a considerably larger area. The fracs are a mix of sand, water and ceramic beads that are forced in under high pressure to break the dense shale and allow the gas to flow to the well stem. Today some wells are fraced 10 or 12 before they're brought on thereby bringing a tremendous amount of gas into the system. This has made a tremendous difference in the production of oil. In 2007 an average well generated about 900 Mcf/day after about 60 days of production. This year the same area was producing more than twice that amount just because of fracing.

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REPRESENTATIVE NEUMAN asked if that is why fewer wells will need to be drilled for shale gas.

MR. BENNETT replied no; this in itself won't be a problem unless there is some environmental regulation on fracing. Such regulation is being proposed and is a significant issue for the industry. Currently, the states regulate fracing but there is talk about bringing it under EPA supervision, which would not be good for either oil or gas production in the U.S.

MR. BENNETT displayed slide 10, a chart of exploration investment by producers totaling $1 trillion since 2003. That investment has been possible due to price levels over the past six or seven years and as a result, gas prices are on the way down. Slide 11 shows that the Henry Hub price per MMBtu in March 2009 was in the $3.40 to $3.50 range.

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MR. BENNETT explained how the geography of production has changed. Slide 12 illustrates where production was in 1980; the size of each circle is a function of the total production out of the field. Over half of U.S. gas production in 1980 was in the Gulf area and most of the pipeline structure was designed to move gas out of that area and the Anadarko/Permian to Northeast and Midwest markets. By 1990 production in the Rockies was increasing, but the production of Barnett Shale in the Fort Worth Basin was in decline. By 2000 there was a lot more production in the Rockies and still some growth in the Gulf, but the area along the coast of Louisiana had started to decline and Fort Worth was even smaller.

By the end of last year the situation was very different. Most of the gas is now coming from east Texas, Northern Louisiana, the Rockies and the emerging Marcellus production in Pennsylvania. However the pipeline structure has not changed very much and therein lie the capacity issues.

Slide 13 maps 2008 gas prices minus the Henry Hub settlement price by location, to reveal how pipeline constraints create price anomalies. In Boston or New York for example, the price averaged $1.23 more than the price at Henry Hub. In the producing areas of the west, prices were less than Henry hub. In other words, the areas noted in red had too much gas relative to demand, or were "supply long" while the areas in blue were "supply short". The market tries to balance those out by building pipelines.

Slide 14 illustrates new pipeline projects including the Rockies Express (REX) which is coming on line soon to bring low-cost gas

out of the Rockies to the higher-priced market. There are 75 pipeline projects going in the Gulf, more than 45 in the east and another 10 being considered in the Rockies.

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MR. BENNETT continued, slide 15 shows the movement of gas out of the Rockies; blue indicates daily flow on the pipelines and red indicates capacity. There are three major routes. On the Pacific Northwest route, capacity utilization rates have been in the area of 90 percent since 2005. The Southwest (Arizona, Nevada and California) is also full both directions. The flows going east out of Cheyenne were constrained but began to open up a little in 2007 when REX came on line. It dipped a little in 2008 and 2009 due to a maintenance event that caused part of the pipeline to be closed for a time. He noted that when they get cold weather in Colorado, that pipeline tends to open up.

SENATOR WAGONER asked about the breakdown of gas coming out of the Rockies.

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MR. BENNETT said it is driven by the Green River which is mostly tight sands. He guessed that it is approximately 75 percent unconventional; a lot of it is coal bed methane. He added that the Powder River and San Juan are also coal bed methane; Jonah and Pinedale are tight gas and Uinta and Piceance are tight gas with some conventional. DJ [Denver-Julesburg Basin] is an oily area; this is conventional but has a lot of horizontal drilling. It is a good example of how unconventional technologies have been applied successfully to a conventional reservoir to extend and expand its productive life.

Slide 17 shows capacity and flows in the Rockies on an aggregate basis. The blue area represents the amount of total supply that can be exported and the gold area the amount that is consumed or stored in the region. The red line is total capacity out of the Rockies and the green line is price measured at Opal, the primary pricing point in the Green River.

MR. BENNETT pointed out that the green line fluctuates dramatically. That fluctuation is due to maintenance which causes a loss in productive capacity causing the price to go down. During 2007 the average utilization rate was 103 percent, a period known as the "Rockies Experience." On more than one day that summer, producers in the Rockies received only $.05 for

their gas and on many others the price was less than $.75. When that happens, when there are more producer/sellers than there are consumers, they bid the price down. There are few long-term contracts there, so a constraint like this drives the price way down.

When REX came on, it alleviated the situation so that last year the utilization rate was 97 percent until the maintenance problems caused closures.

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SENATOR WAGONER questioned what the green line will look like in six months and 12 months from that time.

MR. BENNETT responded that the current price at Henry Hub is $3.50 and the price at Opal yesterday was $3.25; so it should be about where it is now.

MR. BENNETT said he expects the price to be below $1.00 on many days this summer because there is just too much gas.

Slide 20 displays first year production from an average well in the Piceance. The red bar represents first year production at about 500,000 per day, but it declines very quickly. Drilling the same well the next year results in an incremental increase of 244 Mcf/day because the balance goes to offset declines from the first year's well. So to answer Senator Wagoner's question, that line will eventually flatten out if they don't keep drilling more than one well.

The blue on this graph represents a projection that is based on drilling rate as of the end of January according to the announced plans of producers at that time. Since the end of January 2009 they have lost more rigs in the Rockies however, and when that happens it doesn't take long for production to decline. Based on the rigs projected for this year, they don't expect to produce enough gas to need the new pipeline that is being built. That does not mean those projects won't get built; producers will drill again when the price goes up, leading to new capacity issues next year. This capacity issue is what constrains the price of natural gas in the Lower 48.

Slide 21 indicates new pipelines that are unneeded at this point. Slide 22 shows about 1.6 Bcf/day coming into Lebanon and 325 million a day of unused space going east from Lebanon with about 250 MMcf/day of local demand. REX pipeline will bring in

another 1.6 Bcf/day and, because 1.6 B won't fit into 325 MMcf/day of space, the price will drop again.

At the end of the year when REX gets over to Eastern Ohio, there will be plenty of room to get gas into the pipelines but Marcellus production is growing. It all goes into storage fields and on a peak day in the winter there is only half a B of open capacity east of those storage fields. That gas is going to continue to sit in the storage field until the pipelines are expanded. Unfortunately, there are only about 100 million per day in expansions planned for development by 2011. That means a whole lot of surplus gas in the area, which means prices in Ohio will drop dramatically.

MR. BENNETT went on to discuss production in the Gulf as shown on slides 23 and 24. There are 15 projects bringing 7.3 Bcf/day of gas in and there is 6.4 Bcf/day of incremental capacity (it starts full). Some gas will be pushed back, leaving about 5 Bcf/day of gas without a home. It gets worse, because the impact of REX means that some of the gas flowing to that area will get pushed back and will have to be discounted 70 to 90 percent to make that equalize.

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SENATOR WAGONER asked why a producer would want to drill and produce gas at a loss.

MR. BENNETT explained that is why they are not drilling right now.

SENATOR WAGONER said, going back to the chart on the continuation of drilling production, he would expect to see the decline occur very quickly.

MR. BENNETT stressed that it is important to recognize that these are long-haul pipelines that have to be built, with an average cost of $6 to $7 billion and no one is talking about a solution. The only alternative is to increase demand in the area. This is different from the Rockies problem where there are new pipelines already planned. He predicted that with the new technologies available, producers in the Gulf will be able to choke off their wells so they can cut back production when prices are down.

Slide 26 shows drilling activity across the country. He pointed out that the Permian and Anadarko have lost about 80 percent of

their rigs since October 2008. Haynesville has actually increased but 14 others have lost rigs.

On slide 27 the basins are color-coded to indicate whether they are predominantly conventional or unconventional. The circles are sized based on average daily production over the first two years of the well and the figures denote number of rigs inactive since October 17, 2008. Mr. Bennett said the Haynesville has gained eight rigs because, while their wells cost about $10 million each, they can produce so much more out of those wells it makes sense to do so even with the price environment that exists. Another reason is that all of that is "fee land" on which most of the private three-year leases will soon be expiring.

He clarified that those rigs aren't just going down they are being moved around as the technology changes. The new technology is evolving quickly and creating rigs that are increasingly more productive; producers are putting their most efficient rigs on their most productive properties and learning how to use them effectively. He believes the magic of production technology is going to mean a lot of gas will be available at relatively low prices in the near future.

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MR. BENNETT said that drilling declines are going to curb production which will drive prices up a little bit, but they're not going to go up very far before the increased production they stimulate hits the constraints and starts to drive prices back down again. Technology and production will make it possible to recover from these cyclic changes more rapidly, so the price response will not be nearly as volatile as it has been historically. But new pipelines are critical in order to expand the industry, to expand production and demand; if something is not done to fix the pipelines and increase demand, it will become a real problem.

SENATOR WAGONER asked about projections on the replacement of aging coal plants and compressed gas for vehicles.

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MR. MYERS responded that about 50 percent of the energy generated in this country is from coal and the demand for energy keeps growing. Looking at a five or ten year period and disregarding the cyclic bumps, demand for energy is increasing

at a fairly predictable and steady rate as the population grows. Switching to compressed natural gas or to fuel cells driven by natural gas will create a dramatic increase in demand; that is more and more likely as the price of gas is de-coupled from oil. If people move to electric cars, the country still has to power the electrical grid; so such possible scenarios as carbon constraint, fuel-load switching and gas to liquids, can be realized if the ratio between gas and oil stays high and gas is abundant.

The key is maintaining an available source of supply that is relatively abundant and moderately priced. He agrees that a price in the $7 to $9 range, depending on what oil does, is a valuable sweet spot. Based on the economics of Alaska gas, it is also extremely profitable at those numbers. He believes there will be a dramatic increase in need if the country makes those policy decisions and if oil availability and oil demand overseas is difficult. The country is decreasing domestic production of oil generally. What they do in the Beaufort and Chukchi seas matters, but we can't drill ourselves out of the lack of energy.

As the demand for oil increases, competition will force prices up and as oil prices go high, he expects to see fuel-switching out of oil as there was for electrical generation and transportation fuel. The upside potential is that if gas is available and prices stay in that moderate range, it will become practical to build new gas power plants.

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MR. BENNETT said that, in looking at gas consumption for power generation, it is important to break it down by type. Gas is used by "peakers," the things that go up and down a lot, and in combined cycles, which are typically shoulder to base-load facilities running at 30 to 70 percent. Right now three quarters of the gas-fired combined cycles, the shoulder technology, is unused primarily because of the price over the past few years relative to coal. Now that gas prices are down, coal is having a little more difficulty competing. Unfortunately, long-term contracts underpin the coal market so it isn't as easy to switch away from it as it is gas, which is a spot-market fuel. Longer term, the obvious way to reduce carbon emissions is to reduce the use of coal immediately in favor of gas, but it all depends on where the plants are located. If the plants are in New York, there is not sufficient capacity on winter days

CO-CHAIR WIELECHOWSKI asked Mr. Meyers if Mr. Bennett's presentation had changed his opinion at all regarding the viability of the Alaska gas pipeline.

SENATOR THERRIAULT joined the meeting.

4:59:39 PM

MR. MYERS answered that he did not see a potential conflict but would like to make a few points. Long-term demand growth has occurred despite recession and alternative fuel sources. If the fuel is available and if we are environmentally constrained, there will be even more growth. There is an excess of supply in the current recessionary environment. Certainly the pipeline infrastructure is racing to keep up with localized deltas in the Lower 48; however Alaska gas has some fundamental differences. The first gas produced is coming out of gas that is being cycled at 8.4 Bcf per day. It is not a matter of drilling new wells to keep up; it is how wide they turn the valve open to produce the gas. So Alaska is looking at conventional wells that can be easily choked back or increased beyond the design capacity of the pipeline. The management techniques and approach are going to be different in conventional fields where there isn't the rapid decline and continual need to frac.

Much of the technology being used in the Lower 48 was developed in Alaska. For example, when he was the discovery geologist at the Meltwater field, they got zero flow on the first discovery wells prior to fracing; they got 4,000 barrels per day afterward. Much of the advanced fracture technology, horizontals and multi-lateral horizontals, are the way heavy oil is being developed on the North Slope. These are technologies that have evolved through a transfer of knowledge from Alaska to the gas fields of the Lower 48. He believes the technology is not revolutionary but evolutionary and has limits based on physics, geology, geochemistry, depth and water-use issues. So he disagreed a bit with Mr. Bennett on the rate at which technology enhancement lowers cost. Conventional gas, cost and structure will beat it every time, he asserted, if that conventional gas is available and if the pipeline tariffs are reasonable.

5:03:40 PM

MR. BENNETT said he absolutely disagrees with Mr. Meyer's last statement. He stated that the empirical evidence, the Securities Exchange filings and the producers that are actually doing this, show the cost of drilling in shales is dropping dramatically.

Producers he met with yesterday said their costs had gone from between $6 and $8 last summer to less than $3. A lot of them are looking at prices in the range of $1.10 to $1.20 in finding and development costs; lifting will add about $1. In many cases, their conventional properties are more expensive now than the unconventional. That is why drilling is off so badly at the Permian and Anadarko; that is a very expensive place to operate. He does not think it is correct to characterize unconventional gas as being more expensive any more.

He also said that the impact on the market is the big issue and, to him, it isn't certain at all. When they start building these projects, they need to watch how the market is evolving to see what that means. For example, people have speculated that LNG is going to be the big thing; right now two ships are scheduled to come into Cove Point within the next week or so that will knock about 20 percent off the price of gas. The only reason they are coming is that there is no demand anywhere else and we have the only available storage fields. The problem is that the producers who can't make any money now at a $3 price are going to Europe or Africa or China to figure out how to exploit shales in other parts of the world. It is entirely likely that ten years from now gas will be produced in places around the world that we don't even know have gas. It is the same on oil side; the new technology has already encouraged new development in the U.S.

5:07:36 PM

MR. MYERS said he would agree compared to coalbed methane, tight gas sands or shale gas. The Alaska reservoirs haven't been tapped and according to the test data the rates out of Prudhoe Bay and Pt. Thomson will far exceed the best shale gas areas. The only exceptions might be the deep subsalt exploration in the Gulf of Mexico and places where it is very expensive to set platforms.

REPRESENTATIVE SEATON asked if gas-to-liquids conversion makes sense here in Alaska.

5:09:48 PM

MR. MYERS replied it is important to start with an understanding that the Alaska project connects with an increasingly underutilized 14 Bcf/day natural gas distribution system in Alberta. Most scenarios show underuse of the capacity in that system because the basin is well past its peak. He made the

point that AGIA is expandable and said he believes that the producers designed their system to go into the liquid hub with lots of overbuilt capacity. Their highest net back is to get the gas to the first liquid market. Another point is that Alaska gas - at least out of Prudhoe Bay - is extremely rich in gas liquids and that has a lot of value in the petrochemical industry.

5:13:34 PM

MR. BENNETT said anything that can be done to consume the gas here in Alaska seems very logical.

REPRESENTATIVE RAMRAS expressed skepticism about the commercial viability of Alaska gas and spending $500 million when the markets ultimately prevail. He then asked Mr. Bennett to address the tax policies that are driving exploration and development in the different regions.

MR. BENNETT replied he isn't aware of any specific incentives, but the proposed budget eliminates intangible drilling costs and reduces the depletion allowance. If implemented that would be very detrimental to drilling activity in the Lower 48.

5:16:21 PM

CO-CHAIR JOHNSON asked Mr. Bennett if he agrees with Mr. Myers' statement that there's a race to build pipelines in the Lower 48.

MR. BENNETT replied there are lots of projects being proposed but they aren't being built right now. Smaller projects will help relieve the bottleneck by 2012-2013 but building a long-haul pipeline will take a fundamental change in demand.

5:18:41 PM

CO-CHAIR JOHNSON asked about the 5 Bcf of Alaska gas that potentially will go into the Midwestern U.S.

MR. BENNETT replied for that project to make sense demand has to increase by perhaps 6-8 Bcf/day. Perhaps in 30 years, but in the next 10 years it's dubious that an additional 5 Bcf would fit into the existing Lower 48 demand structure.

MR. MYERS added that the driver is the decline in western Canadian production and the push to increase use of natural gas for oil shales. Alaska gas will help supplement the traditional

demand that's been met from Canada. Once the gas gets to the underutilized liquid hub in Alberta it will flow to the best available market.

CO-CHAIR WIELECHOWSKI thanked Mr. Myers and Mr. Bennett for their testimony and turned the gavel to Co-Chair Johnson.

5:21:48 PM

CO-CHAIR JOHNSON observed that during the pipeline hearings in Anchorage the administration said the gas would go to Chicago and not to Alberta. He questioned whether there might now be opposition from environmentalists if the gas went to the oil sands.

MR. MYERS emphasized that gas molecules aren't branded and tracked. The gas will flow to the first liquid hub in Alberta after which it will either go to Chicago or offset gas that went to the oil sands. North Slope producers aren't forced to deliver their gas to a particular market.

5:23:24 PM

MR. BENNETT stated agreement.

SENATOR WAGONER commented that there is a lot of liquid in the gas and once it's removed there will be a large reduction in the cubic feet of methane put through to Chicago. Responding to a question, he said it's not established where the liquids will be removed, but preferably it would be in Alaska. He conceded that, that may be hard to do.

REPRESENTATIVE DOOGAN asked Mr. Bennett to elaborate on the checklist item, "state, local and federal government policies critical to realizing this fragile opportunity."

5:25:43 PM

MR. BENNETT said the federal energy policy that's currently being formulated doesn't just ignore natural gas it works against the production of incremental gas because of what appear to be growing restrictions in access to lands and how to deal with fracing.

Colorado provides an example at the state level. It is a proponent of wind energy, but it's an expensive way to produce peaking power. Using the combined cycle produces less carbon to

begin with as opposed to a single cycle turbine, which you need for wind power. As a consequence, part of Colorado's energy policy is reducing the demand for gas.

CO-CHAIR JOHNSON thanked Mr. Myers and Mr. Bennett for their presentations.

5:27:35 PM

ADJOURNMENT

There being no further business before the committees, the joint meeting of the House Special Committee on Economic Development, International Trade and Tourism, the House Resources Standing Committee, and the Senate Resources Standing Committee meeting was adjourned at 5:27 p.m.