ALASKA NATURAL GAS TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

QUESTIONS & ANSWERS

From the January 22 public forum

The following questions were answered by the panelists during the public forum.

Q: As the community concern builds over shale plays, hydraulic fracturing particularly in the Marcellus formation in Pennsylvania, have you started to see the pipeline industry pull back from their pipeline development plans in those regions because they don't see development of all that shale gas being a reality?

A: Jeff Wright, FERC: *"A lot of that action plays itself out when producers seek permits to drill. The midstream or the industry that FERC regulates reacts to people that want to ship. The easy answer is that we have seen areas of the country that are more accepting of drilling like Texas and the Gulf Coast region. We expect the mid-Atlantic region, which includes the Marcellus shale play and New York where there is currently a moratorium on development, to take a more cautious approach to pipeline development because not as much shale is coming on as quickly as expected."*

Q: What is going to have more effect on future demand of gas, the economy or environmental regulations?

A: Stefan Revielle, Credit Suisse: *"We see it being an interplay and tug of war between both. There is a lot of uncertainty right now but you can't pin it on either one. The economy is expected to grow but the timing is uncertain."*

Q: Would FERC issue a certificate of public convenience and necessity, the go-ahead for a project, without firm shipping commitments? Has it ever happened?

A: Jeff Wright, FERC: *"It has. Under our pipeline certificate policy of 1999, you have to show a public need for construction of a project. To show need you typically should have contracts or precedent agreements, which are firm shipping agreements for product in the future. But need can also be shown by having studies commissioned that show there is a need for the project in the area you want to develop. So, yes, you can receive a certificate without precedent agreements. But those are the easy way, the low-hanging fruit if you will. And I would point out that the Alaska Natural Gas Pipeline Act presumes need, so proving it is unnecessary."*

Q: If a certificate is granted, how long is it good for? Is it like a building permit that at some point expires if you don't use it?

A: Jeff Wright, FERC: *"Generally for larger, long-line pipelines, we will give a limit anywhere from three to four years to commence and complete construction. Just because we give a certificate doesn't mean you will break ground the next day, unless it is a small line. Instead, you go back and talk to your stakeholders and say OK, we now passed the FERC hurdle, should we still go ahead? And that said too, even if a pipeline is going to go ahead with the project, the FERC certificates are always conditioned on certain environmental and other factors being met. So, before you can proceed with construction, the project needs to demonstrate that those conditions have been met, and then my office will sign the notice-to-proceed order."*

Q: Has Credit Suisse looked at the consumption possibility for compressed natural gas vehicles and what market might be out there?

A: Stefan Revielle, Credit Suisse: *"We have looked at it and determined that it doesn't impact our medium demand growth. There of course is a growth percentage as the transportation sector tries to expand on the natural gas vehicles. But we saw it as a two-fold problem: Lack of infrastructure and drive-time make them uneconomic at this time."*

Q: You talk about reduced price volatility for natural gas. Is that making utilities feel more comfortable about using natural gas?

A: Stefan Revielle, Credit Suisse: *"Definitely yes. The big question mark for natural gas in the past was supply, but now having ample supply and storage that is readily available creates an environment where volatility is greatly reduced."*

Q: FERC talked about three U.S. LNG receiving terminals that have applied for export permits. Are they looking to permanently switch over or just to give themselves the flexibility in business over the next 30 years to move between the two, depending on where gas prices are better?

A: Jeff Wright, FERC: *"We have two of those plants that are in the pre-file stages of actually installing liquefaction facilities to export domestic supplies of gas. I don't think they are abandoning the import market, but instead are playing the global market."*

Q: If utilities switch to gas because of all the environmental restrictions, what happens to all the coal?

A: ***Stefan Revielle, Credit Suisse:*** *"We have not looked at what the future holds specifically for the coal industry. We have always looked at it from the side of what happens to gas. However, in my mind, coal will always carry the base-load of energy need during the medium-term and I really can't say about the long-term."*

Q: How far out does the pipeline industry look, 5 or 10 years?

A: ***Jeff Wright, FERC:*** *"When you are making significant investments of this type, you look long term. We have pipelines that are on the national register because of how long they have been there. It is a lot more interesting and volatile industry today. Just a couple years ago Kinder Morgan built the Rockies Express gas line that would deliver natural gas from the Rockies to the border of Ohio and Pennsylvania, right at the border of the Marcellus shale play. It was being finished just as the Marcellus shale gas exploded. I don't think that investment decision would be made again. And that is the kind of uncertainty that pipeline people are facing."*

Q: FERC talked about the cost of a 16-mile pipeline to bring shale gas into New York City costing $1.5 billion. Even Alaska can't top that, but why is it so expensive?

A: ***Jeff Wright, FERC:*** *"It is extending from an existing pipeline, through a very densely populated area of New Jersey and across the Hudson River. This is actually the first delivery of interstate gas directly into Manhattan. The problems there are densely populated areas. This is where our pre-file process was very helpful. We get all the stakeholders together to talk over issues. Most of the cost is coming from directionally drilling the pipeline for most of the way."*

Q: Credit Suisse price projections assume EPA regulations move forward. Have you considered what happens if Congress prevents that from happening?

A: ***Stefan Revielle, Credit Suisse:*** *"The assumption is that regardless of what Congress does, there will be enough change in the utility and other sectors in anticipation of new laws/regulations that the market will shift."*

Q: What will the price impact be of an additional 4+ Bcf/d into the saturated U.S. market?

A: ***Ed Kelly, Wood Mackenzie:*** *"Our models show that it will be about 79 cents to $1.25 on the Henry Hub price. It would take about two to four years of demand growth to work off the additional supply and stabilize the gas prices."*

Q: In the Credit Suisse presentation, there was mention of "only" a $2 increase in natural gas prices over the next few years but that looks like about a 50 percent increase. That's double-digit inflation each year. Can you explain more on this percentage?

A: ***Stefan Revielle, Credit Suisse:*** *"On a percentage basis, I don't think we are too far from the consensus. As I honed in on my presentation, the growth really is driven by the electric power sector as demand increases and the economy recovers. What I was referring to as only a $2 mmBtu increase is really we are not going to see $14 handle on gas prices in the near term so relatively it is small."*

Q: Right now U.S. gas markets are tied to the Henry Hub for pricing. As we see an increase in LNG and tanker traffic, do you see a blending of that, going to a world price?

A: ***Ed Kelly, Wood Mackenzie:*** *"I would caution against assuming a world price. Some could argue, that because of the volatility in the North American market over the past few years, even a North American price is tough. There may be occasional convergence of U.S. and world markets if and when more exports from the U.S. occur."*

A: ***Ron Denhardt, SEER:*** *"These LNG projects are very capital intensive and so they don't get financed unless there are some contracts to support them. So, a world spot market is unlikely because most of the traded gas is under long-term contract."*

A: ***Stefan Revielle, Credit Suisse:*** **"***We don't see a global gas price in the near term because of the different natural resource makeup of the countries involved. Some have domestic supplies of natural gas while others are deficient. Each of the countries uses different markets to meet their needs, which won't allow for the markets to combine into one in the near term."*

Q: With all of the uncertainty about prices and future regulations, why would anyone want to build a $30 billion to $40 billion pipeline? What kind of returns must the companies expect given the great risks? What price for gas do the producers need to make the pipeline feasible?

A: ***Jeff Wright, FERC:*** *"It is not a decision made in today's market. It will be made after the companies sit down and look at the market 10 to 15 years out. Maybe current market forces will have changed, maybe the electric market sorts itself out and we have carbon legislation. There will be an entirely different set of variables to look at post-FERC certification of the gas line. Maybe they are not looking at today's variables, there are tomorrow's to be worried about."*

Q: The profit on a pipeline is set by FERC, right?

A: ***Jeff Wright, FERC:*** *"That is true. Pipelines make a certain amount on fuel. But generally what is approved in a pipeline proceeding is the making of a cost-based rate, and that rate contains an agreed upon rate of return. That said, you see a number of pipelines that have the ability to negotiate rates. So, you may see a pipeline trying to be competitive by offering a discounted rate."*

Q: We see proposals in Canada and the U.S. to export gas. Is it possible that the future gas market will be one with LNG exports from Canada and the U.S. and an Alaska gas pipeline project to the Lower 48?

A: ***Ed Kelly, Wood Mackenzie:*** *"The proposed Kitimat, B.C., LNG export facility is very small and the proposed Gulf Coast LNG export facilities are in an area that could be considered stranded resources, so they would be very different then the Alaska project. I would say that if Kitimat moves forward it shows that there is a resource base that is much larger than anyone expected and that there isn't enough demand to move the gas to Alberta. I do think it is possible, but not likely, to have all three."*

Q: Is there any concern that Alaska gas will come on too soon and negatively affect the market? Has Credit Suisse's investors factored it in?

A: ***Stefan Revielle, Credit Suisse:*** *"It hasn't been priced in yet. Investors don't see it as a project in the near term. Our investors are short term, 5 years at the max, so they have not priced it in."*

Q: The existing Kenai LNG plant has been grandfathered from meeting current FERC LNG standards. Would that grandfathering still hold if it were to serve as an import facility with LNG regasification installed?

A: ***Jeff Wright, FERC:*** *"The project would have to come to FERC. Right now it has the authority for a liquefaction facility but not regasification. Marathon and ConocoPhillips would have to come before FERC and seek authority to build the facilities for regasification. In addition, they will have to go to the Department of Energy for approval to import gas."*

Q: If they bring in LNG to the Kenai plant aboard tankers that have the ability for regasification onboard the ship, would they still have to get approval from FERC?

A: ***Jeff Wright, FERC:*** *"It depends how far offshore. We are responsible for terminals onshore and in state waters. If you do it in federal waters then it is the jurisdiction of the U.S. Coast*

Guard and Maritime Administration. So, wherever the boat is a regas boat under the Excelerate onboard technology, then you will have to come to a federal authority for approval to use that boat as a LNG terminal in essence."

Q: In the SEER presentation, there was discussion of price spikes. What was the reason for the spike in Henry Hub prices between 2003 and 2008?

A: ***Ron Denhardt, SEER:*** *"It is interesting, in 2008, the economy was growing very fast and oil prices were being forecast to go to $200. Commodity prices were crazy. As a young economist you want to believe markets are efficient. As an old economist you understand they are not. So, I believe it had a lot to do with all the speculation at the time."*

Not all questions were answered during the forum; there just wasn't enough time. We gathered up those unanswered questions, shared them between staff at the Federal Coordinator's office and forum panelists, and compiled the following collective answers.

Q: One of the FERC slides regarding proposed LNG receiving terminals showed some marked as U.S.-MARAD/Coast Guard. Will those sites serve only federal agency needs?

A: *No, those terminals would serve all customers. The designation on the slide was to show which federal agencies would have jurisdiction over project development — the U.S. Maritime Administration and U.S. Coast Guard—because they are offshore terminals, not onshore.*

Q: Does the Alaska Pipeline Project pre-file application include an LNG export site for Valdez?

A: *Yes. The Alaska Pipeline Project pre-file application includes the option of a pipeline from Prudhoe Bay to Valdez or a line from Prudhoe Bay to Alberta.*

Q: Should the State of Alaska assign an individual in Washington, D.C., to deal with FERC on a daily basis?

A: *The state has a six-person Washington, D.C., office to assist the governor and state agencies. They work at the direction of the governor.*

Q: The FERC graphic of existing 24-inch pipelines did not show cross-border lines from Alberta. Why not?

A: *The graphic showed only pipelines under FERC jurisdiction. The agency regulates only pipelines within the U.S. However, several large-diameter pipelines extend across into Canada, where the Canadian regulatory authorities take over jurisdiction.*

Q: Why would anyone want to spend $40 billion to build a pipeline to reach a market that according to the Energy Information Administration and U.S. Geological Survey is flooded with gas and will remain flooded for at least 100 years?

A: *Estimates of technically recoverable natural gas do not necessarily represent when the gas is economically recoverable or environmentally acceptable for production. Many of the latest forecasts of U.S. natural gas resources include estimates of recoverable unconventional gas, such as shale and tight-sands gas, though how much of that actually can and will be produced is unknown.*

The Energy Information Administration at the U.S. Department of Energy in December released its 2011 forecast, predicting that if there are no additional changes in the nation's environmental laws or any significant change in coal vs. natural gas market shares for power generation, the United States would not need Alaska gas before 2035. Those assumptions drive the prediction that the U.S. gas markets will see only limited growth. It is likely, however, that there will be changes in the nation's environmental laws, which would increase the consumption of cleaner-burning natural gas relative to coal. Investors will make their own decisions based on their own view of supply-and-demand economics whether to build the Alaska gas pipeline.

Q: I would like to know why we would ever build a pipeline that is twice as long to Canada and twice as expensive, when we can just build our own much shorter pipeline in Alaska and sell all the gas we have at higher prices in the Pacific Rim markets and make it into other products here in Alaska?

A: *The Alaska Pipeline Project (the TransCanada/ExxonMobil venture) has estimated the 1,700-mile gas pipeline to Alberta at $32 billion to $41 billion, with the 800-mile pipeline to Valdez at $20 billion to $26 billion. There are a couple of caveats, however. The construction cost estimate for the Valdez option does not include the expense of building a gas liquefaction facility, LNG storage tanks, a shipping terminal/dock or LNG tankers. In addition, the Valdez pipeline would be sized to carry 3 billion cubic feet of gas per day vs. 4.5 billion cubic feet for the pipeline to Alberta. As for whether Alaska gas could command higher prices in the Pacific Rim, and whether there are sufficient buyers willing to sign binding, long-term contracts at those higher prices, those questions may be answered by the open season negotiations under way between potential gas shippers and the Alaska Pipeline Project.*

Q: What I want to know is where they are going to get the additional gas to fill a gas pipeline with 4.5 billion cubic feet of gas per day when the most anyone ever talks about from the North Slope is 2.7 billion cubic feet per day. Where is the other 1.8 billion cubic feet per day coming from?

A: *When oil production started on Alaska's North Slope in 1977, the Alaska Oil and Gas Conservation Commission set the maximum daily natural gas off-take from the Prudhoe Bay reservoir at 2.7 billion cubic feet per day. If the North Slope producers decide to proceed with a large-volume gas pipeline project, it is expected they would ask for a new off-take number appropriate for prudent reservoir management starting in the 2020s, after most of the oil at Prudhoe Bay had been drawn down in the preceding 43 years. It also is expected that additional gas would come from the Point Thomson field, which holds an additional 8 trillion cubic feet of gas (one-third as much as Prudhoe Bay). In addition, construction of a large-volume gas pipeline would promote new exploration and production on the North Slope.*

Q: What is going to prevent this state from experiencing a complete economic collapse – and oil bust – if the oil stops pumping and the gas isn't developed yet?

A: *A good question, but it would not be appropriate to ask the forum panelists — all of whom are from out of state — for their conjecture as to how Alaska might deal with its longstanding political and economic problem of relying so heavily on oil and gas revenues.*

Q: Canada is busily exporting its own gas to the Pacific Rim, so I would like to know what they are doing building a pipeline to Canada?

A: *It's important to note that the proposed Alaska North Slope pipeline to Alberta would not leave the gas in Canada, but rather would connect to an extensive network of existing gas pipelines with capacity to move Alaska gas across the United States. Also, Canada is not exporting any natural gas to any Pacific Rim nation, though a project is proposed for Kitimat, B.C., to ship shale gas converted to LNG to Asian markets. The project developers are still reviewing their options and have not committed to construction.*

Q: Have any of you estimated/calculated the total amount of capital that may have been "wasted" in LNG import plants as a result of bad calls on the Lower 48 gas markets?

A: *"Wasted" may not be the appropriate word. Yes, the United States currently has more LNG import capacity than it needs, and several terminals were added or expanded in recent years in anticipation that the nation would import larger volumes of natural gas from overseas suppliers. But the boom in domestic shale gas production, coupled with lower demand due in part to the* *economic recession, has rendered that additional LNG import capacity unnecessary at this time. That certainly could change in the decades ahead. Meanwhile, at least two of the new LNG import terminals on the U.S. Gulf Coast have applied to expand their facilities to accept U.S. gas, liquefy it, and load it on LNG tankers destined for foreign markets. It's a matter of making the best use of the investment and giving the terminal owner the option of going either way, depending on market conditions. Meanwhile, many of the terminal owners pre-sold their import capacity, so it may be gas marketers, not the terminal investors, who are paying the price of a wrong bet on the market. Having said all that, the international consulting firm IHS CERA estimates the capital expenditure for LNG import terminals in service for U.S. markets (including new terminals, recent expansions at existing terminals, and offshore buoy terminals) at about $9 billion.*

Q: If you lived in Fairbanks and paid several thousand dollars per month for heating costs, would you be content with the plan of being patient and waiting for the Lower 48 market to shift vs. going with LNG now?

A: *No one paying high heating costs is content to wait and hope for lower prices, whether in Fairbanks or in rural Alaska. Unfortunately, because of Alaska's small market size, expensive natural gas pipelines to Fairbanks or elsewhere in Alaska are not economic unless there are large-volume, long-term customers to pick up most of the cost. Those are likely out-of-state customers. The market will decide whether Lower 48 pipeline gas buyers or Pacific Rim LNG buyers are willing to sign the binding contracts worth tens of billions of dollars that will be required to finance an Alaska North Slope pipeline which, fortunately, would also bring gas right by Fairbanks to connect into a distribution system.*

Q: Some criticize LNG from Alaska because of the 800-mile pipeline required. However, every other LNG project has its own particular challenges. Gorgon LNG estimated over $40 billion for a 2 bcf/day project, yet Alaska LNG is less than that for a larger project. Wouldn't it make sense for Alaska's gas to go to the world market (premium Asian market) rather than into a single trading hub in Canada?

A: *Yes, all capital-intensive natural gas projects face hurdles. Australia's Gorgon LNG project is closer to Asian markets than Alaska, as are several LNG suppliers in the region. As for "a single trading hub in Canada," existing pipelines from that hub serve the entire North American natural gas market — the largest gas market in the world, by far.*

Q: Is placing Alaska's future in the hands of Congress passing stricter regulation on coal a better business plan than taking Alaska's gas to the world market as LNG?

A: *Both options depend on customers signing binding contracts to buy the gas. There is no guarantee that Alaska gas could compete in the Lower 48, even if Congress imposes tougher air quality rules on emissions from coal-fired power plants. Nor is there any guarantee that Alaska gas could compete on price in overseas LNG markets. Unless Alaskans want to spend billions of dollars of state money to build a pipeline and hope customers pay to use it, Alaska's natural gas future is in the hands of the market.*

Q: When you say Alaska gas competes at $6 to $7 per 1,000 cubic feet, does that leave a profit on Alaska or is Alaska breaking even?

A: *If building a gas pipeline to serve Lower 48 markets comes in on budget, as estimated by the two project development teams, gas prices at $6 to $7 per thousand cubic feet would provide a profit to the gas producers and production tax and royalty revenues to the state. That assumes the gas is coming from Prudhoe Bay, which is already developed as a producing field. Gas from future, unknown reservoirs requiring significant capital investment to come online could require higher prices to generate a reasonable profit.*

Q: What will happen to all that coal if more power plants burn natural gas to generate electricity?

A: *Coal, just like natural gas, will stay in the ground unless it has buyers. No doubt coal-producing states, coal companies and coal mine workers would be just as disappointed as Alaskans who have been waiting years for a North Slope natural gas pipeline.*

Q: Alaska oil leaves Alaska, is refined and then returned to Alaska at high prices. What was the mechanism which set up this situation? Why wasn't Alaska protected from this?

A: *Sorry, but the debate over gasoline prices at the pump, while of interest to Alaskans, is not within the expertise of the natural gas panelists.*

Q: When may the automotive fleet in the U.S. transition to gas?

A: *The straight answer is when it becomes less costly to run trucks and buses and cars on compressed natural gas rather than gasoline or diesel, or when government financial incentives tip that decision point in favor of natural gas. Though natural gas burns significantly cleaner than gasoline or diesel, vehicles owners have to weigh the higher purchase cost of natural gas-powered vehicles and, in some regions, building their own refueling stations. Though some refueling stations exist, they can be few and far between. The good news is that many public* *transit systems around the country already run their buses on natural gas, with more converting to natural gas each year, and there has been some movement by trucking fleet owners and even some taxi cab owners to convert to natural gas.*

Q: Will you personally invest in LNG export to Asia?

A: *We are not going to ask any of the panelists for their personal investment decisions. Besides, their employers would probably prohibit any such investment advice.*

Q: If Canadian gas is exported to the Pacific Rim as LNG instead of piped to the United States, why shouldn't Alaska gas be exported from Alaska?

A: *Currently, all of Canada's export natural gas goes to the United States, though there is a proposal by a project developer to sell LNG to Pacific Rim nations. The proposed LNG project at Kitimat, B.C., would cost almost $5 billion for the LNG plant and pipeline from the gas fields and have a maximum average daily capacity of 650 million cubic feet of gas, whereas Canadian producers in 2009 delivered about 9 billion cubic feet of gas per day to U.S. markets. Alaska gas, just as Canadian gas, would have to compete in the global LNG market to sign up buyers.*

Q: As North Slope gas is not considered "dry," please comment on the market for natural gas liquids and the petrochemical industry?

A: *Natural gas liquids, such as ethane, are the feedstock for a wide range of petrochemical products, such as plastics. It is a capital-intensive industry, however, requiring large investments in the facilities needed to "crack" and process the liquids out of the gas stream into useable components, and equally large investments in pipelines, rail cars and rail lines to move the products to market. Prudhoe Bay gas is rich in liquids, but the private-industry decision where to process those liquids likely will be made based on where the work can be performed and the products delivered to buyers at the lowest possible cost. As the state's natural gas production tax revenues and royalty payments are based on the value of the entire gas stream removed from the ground and sold on the market, a lower cost and higher value for the gas and all its components would mean more revenues to the state.*

Q: What is Canada's interest in this natural gas liquids resource for Alberta's essential feedstock?

A: *There are several large petrochemical plans in Alberta — many of which are running below capacity — that could process gas liquids at very competitive rates for delivery to market.*

Pipelines and rail cars are available and have spare capacity to move the products out of Alberta to markets across North America and worldwide.

Q: Why is there only a discussion of the Lower 48 option and no discussion about the LNG opportunity for Alaska?

A: *The Office of Federal Coordinator for Alaska Natural Gas Transportation Projects is limited by federal law to assisting only a pipeline that delivers gas to Lower 48 markets. A pipeline that exclusively serves an export terminal for overseas LNG markets is outside the purview of the office. Therefore, it did not seem appropriate to discuss a project over which the office has no jurisdiction or input.*

Q: Given the volatility of gas prices in the Lower 48 and associated risk, wouldn't it be better to enter into price collars in the premium Asian market on long-term contracts?

A: *Until buyers are willing to sign binding contracts to purchase Alaska gas, it's all conjecture as to which market might be best.*

Q: On Dec. 16, the Department of Energy's Energy Information Administration released a report that showed no gas from Alaska to Lower 48 out as far as 2035. Why are you not presenting anything on LNG?

A: *The Energy Information Administration 2011 forecast predicts that if there are no additional changes in the nation's environmental laws or any significant change in coal vs. natural gas market shares for power generation, the United States would not need Alaska gas before 2035. The agency's forecast is based on those assumptions because it is required to assume that these things do not change. It is likely, however, that the nation's environmental laws will change over time, tightening up the standards for air emissions. And while the agency sees strong growth in shale gas production, there, too, change is possible. Shale gas production is under review by the Environmental Protection Agency, the U.S. Department of Interior and several states. The cost of producing shale gas could increase due to regulatory restrictions, just as the coat of burning coal could increase due to stricter air quality laws.*

The purpose of the forum was to present Alaskans with the gas supply-and-demand issues that pipeline investors will consider. The Office of Federal Coordinator for Alaska Natural Gas Transportation Projects is limited by federal law to assisting only a pipeline that delivers gas to Lower 48 markets. A pipeline that exclusively serves an export terminal for overseas LNG markets is outside the purview of the office. Therefore, it did not seem appropriate to discuss a project over which the office has no jurisdiction or input.

Q: Do you believe waiting for the Lower 48 market to return is a better plan for Alaska than taking Alaska's gas to the world market as LNG now?

A: *Alaska is waiting for any market — the Lower 48 or overseas LNG buyers — to sign binding contracts worth tens of billions of dollars to underwrite the financing for a gas pipeline project. No company would take its gas to market without such contractual guarantees.*

Q: CNBC recently questioned whether or not TAPS would continue to operate in several years due to rapidly declining throughput. Do you believe that an Alaska gas pipeline can exist if TAPS is not operating?

A: *It would be up to North Slope producers to decide if it is economical to operate a natural gas pipeline without an oil pipeline, but it would pose serious economic problems for North Slope exploration and development if a producer had no way to deliver its oil to market.*

Q: Do any of the supply assumptions you've discussed apply to gas in Japan, China or Korea? Will Pacific Rim gas prices remain higher?

A: *Natural gas prices in Asian markets are generally — but not always — linked to oil prices, resulting in higher prices in recent years as oil is more valuable (on a per-Btu basis) than gas. Most analysts expect gas buyers in Asia, on average, to pay more than customers in the United States, where gas is priced on its own, separate from oil. But lower prices for natural gas in the United States have not always been the case, such as in July 2008, when the spot price for natural gas in the U.S. was three times the price of January 2011. As for supply, whereas U.S. markets will get much of their gas in the years ahead from domestic shale production, Asian markets will look to more than a dozen LNG exporting nations for their supply. In addition, China has its own domestic shale gas resources, and is looking to develop those reserves.*

Q: What long-term gas price in the Lower 48 do you think/assume is required to build the Alaska gas pipeline project? What certainty of that price is there?

A: *There is no certainty of price; that is one of the big problems for any expensive natural gas development. Looking at the estimated costs for treating North Slope gas (removing water, carbon dioxide and other impurities), plus the cost of a new pipeline to Alberta and the cost for moving the gas through existing pipelines to Lower 48 markets, producers would need to receive $6 or so per thousand cubic feet of gas just to cover their production, processing and shipping expenses, with a small profit.*

Q: What is FERC doing to help Hawaii and California get LNG imports? Or will they get coal?

A: *California natural gas customers are adequately served by several pipelines delivering gas from the U.S. Rockies and Southwest regions and Canadian gas fields, and could also benefit from Alaska gas flowing into the pipeline system. In addition, California receives gas from a large overseas LNG receiving terminal constructed just across the border in Mexico's Baja California. If a company sees a market need, it could apply to FERC for an additional LNG import terminal to serve California. It's a different story in Hawaii, which gets most of its electricity from burning diesel; Hawaii has no LNG receiving terminal. However, the state's policy is to bypass natural gas and move directly to renewable energy sources, such as solar and wind, to generate its electricity in the decades ahead.*

Q: Sounds like most agree on the 2020-2026 horizon for Alaska gas to come online. Best-case scenario, when would construction of the gas line and coordinating infrastructure start (jobs for Alaskans)? Or would they wait for oil production to decline and convert the existing oil line to a gas line?

A: *The Alaska Pipeline Project (TransCanada and ExxonMobil) and Denali (ConocoPhillips and BP) both expect the earliest construction would start is 2016. As for converting the Alaska oil pipeline to carry natural gas, it's not a viable solution. The wall of the oil line's steel pipe is too thin to contain the pressurized natural gas. In addition, most of the oil line is above ground, while the gas would be chilled for pipeline transport and the pipe would be buried in order to keep the gas cold.*