ALASKA STATE LEGISLATURE
SENATE RESOURCES COMMITTEE
February 28, 2001
3:40 p.m.

MEMBERS PRESENT

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Robin Taylor
Senator Kim Elton
Senator Georgianna Lincoln

MEMBERS ABSENT

Senator Drue Pearce, Vice Chair

COMMITTEE CALENDAR

Supply and demand of Future Natural Gas Market by:
Cambridge Energy Research Associates (CERA)
Mr. Ed Kelly
Mr. Demetri Karousos

ACTION NARRATIVE

TAPE 01-17, SIDE A
Number 001

CHAIRMAN JOHN TORGERSON called the Senate Resources Committee meeting to order at 3:40 p.m. and announced a presentation by the Cambridge Energy Research Associates. He thanked Commissioner Condon for his willingness to work with the committee and make CERA available to them.

COMMISSIONER WILSON CONDON, Department of Revenue, explained that CERA is under contract to the State of Alaska to provide ongoing research relating to the North American natural gas permit. He introduced Mr. Ed Kelly, Director of Research for North American Gas, Mr. Demetri Karousos, the Associate Director of Research for Natural Gas and LNG, and Mr. Mark Silver, Account Representative.

MR. ED KELLY thanked the committee for allowing them to present their views. He said CERA was begun by partners out of Kennedy School of Government, Harvard University, as a company in 1982. They deal in all forms of energy world-wide and began the North

American gas practice during deregulation and low gas prices in the mid-1980s. They have approximately 195 North American gas retainer clients from all sectors of the business and 650 retainer clients of their services world-wide, including government entities, legislatures, producers, pipe lines, and distribution companies.

MR. KELLY said there are several stories in the gas market about why a pipeline project that for many years was "a rolling 20 years in the future is now a rolling seven to nine years to potentially 12 years in the future." He said the shorter story is a potential crisis this past winter in the U.S. Lower 48 that was averted by basically a warm January and February. He wanted to relate why that crisis developed, why interest in this project developed, and then go into the longer-term market conditions and the forces of supply and demand, price fundamentals and the environment problems this project would face. He would then turn to his colleague Demetri Karousos who is an expert in global liquefied natural gas (LNG) markets.

MR. KELLY explained the following:

> The story begins with this past winter when there was some uncertainty regarding U.S. gas production and its adequacy. This isn't the winter of 2000/2001; it was the winter of 1999/2000. January provided concrete evidence that something was wrong with production. The last of January was weather that would not have caused a great deal of demand in the U.S. Lower 48 market, but there was a record draw on storage inventories last January 2000. That was the first concrete indication that something was wrong with production. In reality, production hit a 20 year low in the U.S. Lower 48 during the year 2000.
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> Secondly, in March, given how low storage inventories went last March 2000, it became clear that it was going to be hard to satisfy both power generation demand in the summer and store enough in storage for the winter. The power market has developed a great deal over the last decade and has begun to burn more gas year after year. Each year, in fact, the power generation market burns about 1 (billion cubic feet per day) bcfd to 1.5 bcfd more gas if the economy simply grows normally.
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> We have begun to rely on gas by default. You can't build coal, you can't build nuclear plants, you cannot build hydro-electric plants, so we've eliminated all alternative sources of bulk power generation in the U.S. Lower 48. So utilities and independent power generators

are relying on natural gas. We actually began to burn natural gas in a big way in the late 1990s.

What that meant for this past fall was, in the storage section, by October 31, 2000 storage inventories were at a record low entering the winter. Gas is sort of the original ant-like industry. You store enough for the following winter. And you have to do that to make sure that small customers and businesses have the heat that they need through the coming winter.

October 31, whereas on average in the U.S. we would have about 3 trillion cubic feet (tcf) of workable gas in storage in underground, depleted fields or salt caverns, last October we had about 2,750 bcf. That doesn't sound like a great deal of exposure, but it is. That was a record low entering the winter.

A couple of other things we knew - wellhead supply was running at a 20-year low, still is running at a 20-year low. So we entered the winter with record low in storage, with low wellhead supply available in the U.S. Lower 48 market. A third thing we knew; we had had three warm winters in a row and that could change at any time. At the time, entering the winter, we estimated that a return to normal weather, and this was a 15-year normal weather (not a 30-year as the government measures) that took into account the warm 1990 - we estimated the demand would rebound by 3 - 4 bcfd in the U.S. Lower 48 on average. So we entered the winter exposed.

What happened prior to that was that gas rose in price to a point that demand was discouraged and destroyed in the market place. Gas had to rise above the price of competing fuels. That initially meant the price of residual fuel oil which can burn in certain boiler loads in both industries and older power generation equipment. So gas rose above the price of residual fuel oil over the summer as power generation markets ramped up and it became clear that supply was down.

Over the winter, gas also rose in price above distillate fuel oil. So again, we're standing at last October 31 and we enter the winter exposed to a great increase in demand in the face of record low storage inventories. In reality, November and December 2000 were not just a 15-year norm, were not just a 30-year norm, but they were the coldest November and December on the population

weighted basis in the U.S. Lower 48 in 106 years of record keeping. So demand did not rebound by 3 - 4 bcfd, but demand rebounded by 10 - 15 bcfd for the months of November and December, taking gas out of storage at a very quick rate. This basically removed 600 bcf from the Lower 48 natural gas market. So in order to assure supplies for the remainder of winter, as the month of December progressed and it stayed cold and it was clear the dimensions of the crisis, gas had to continue to rise in price so that more demand was destroyed. The demand that was destroyed as this was occurring includes things such as fertilizer plants shut down, aluminum plants in the Pacific Northwest shut down, and ethane that is normally removed from the gas stream was left in the gas stream. In fact, so many liquids were left in the gas stream that some local distribution companies had to call a halt to the process, because yours and my appliances cannot handle too many liquids in the natural gas stream. But these liquids were more valuable left in the gas than taken out as they normally are. In other words, all hands were on deck as far as gas supply available and gas demand destroyed. Gas rose above the price of distillate, rose above the price of clean liquid fuels and it even now is pricing very close to the price level of distillate.

Back then in November and December, if you recall, distillate, which is roughly equivalent to home heating oil, was also in short supply and was pricing at about the equivalent of $7 million per btu. So gas had to rise well above distillate, because no one had ever really switched from gas to distillate before. It had to rise well above the price of distillate so it would entice people that were not used to doing it and did not necessarily have the immediately available equipment to switch so that they would make the investments necessary to switch to alternate fuel so that more demand would be taken out of the market.

Where we were sitting December 31, 2000 was at a record low storage inventory, we weren't sure there was enough supply for the remainder of the winter in a physical sense. Gas was pricing at about $9.30 btu at the Henry Hub.

Over the course of January and February, those were warmer than normal months. So that storage withdrawals declined, slowed down, gas was able to price closer to

the level of distillate which, itself, was calming down as crude oil declined from the mid-30s into the upper-20s as January and February progressed. So oil products settled down, natural gas markets settled down somewhat, but still have stayed, and need to stay, above the price of enough oil products so that enough demand stays out on the market.

So we averted a physical crisis this past January and February. We have enough gas remaining in storage and producing to supply the remaining small home and commercial heating load that exists in the U.S. Lower 48 markets. So in a sense, there's enough gas to make it through the winter. The difficulty comes from getting enough gas in storage for next year at the point.

Then, Mr. Kelly showed the committee a chart of storage inventories over the last few years from October through October. "You can see the build up in inventories to October and the draw down in storage inventories over the course of the winter."

The bottom blue line is the 2000/2001 winter. He said we entered October 31 with a record low level in inventories. When we hit December 31, it looked like we were headed toward a low inventory of about 500 bcf in storage. This compares to a previous record low of 750. When that previous record low occurred, there were people who went without gas in pockets of the East Coast. There were operational difficulties created by a storage inventory that low.

MR. KELLY said:

It appears that we're still headed for a level below that. We think we'll head down toward 700 bcf as of the end of March 31, 2001. The system is more operationally flexible and the level of imports is increasing so that we don't think there will be physical shortage this winter and the gas price has calmed down. Warm weather also affects the market psychologically - affects the trading community psychologically. Nevertheless, the difficulty may not be the spring; it may be coming up for the remainder of 2001 and beyond. While we expect increased rig activity to result in increased supply this year and we believe the supply increase this year will be about 700 mcfd this year and increasing again next year.

Based on a record level of gas directed drilling activity and a record level that was reached last August, we also expect demand to continue to increase. We think demand

will increase by about an equivalent amount. It normally would be higher than that. Under normal economic growth, demand for power generation would increase by 1 to 1.5 bcfd. I just gave you a U.S. wellhead supply increase that we expect of about 700 mcfd. So a normal demand increase would be twice what we expect U.S. wellhead supply to increase.

Imports are increasing. We think the net import number will go up by .5 bcfd this year with the completion of a new pipeline out of Canada and evidence of increasing production in Canada, and a full year's production headed to U.S. markets in eastern Canada. Nevertheless, the demand increase normally would be about twice the U.S. wellhead supply increase that we expect for this year.

The slow down in the economy, however, is helping this situation out. If you still have your job, you'll be able to pay your gas bill easier, because the economic slow down slows down power demand growth and that hits gas demand growth directly. But we're still at that low in storage and we still have to prepare for next winter starting at a record low in inventory March 31.

Each of the last two years, we have managed to inject into storage 1.6 tcf. That's okay when you're starting at 1 or 1.1 tcf in storage to begin with in the summer. But this year we are starting at about 700 bcf in storage. You add 1.6 tcf that we've been able to inject each of the last two years, that gets you up to 2.3 tcf in storage. That's not enough for next winter. So we need to find some gas this summer to allow more to be injected into storage this summer in the face of higher demand, in the face of U.S. wellhead supply that is only beginning and struggling to recover from its historic lows during the years 2000.

So the supply increase needs to allow for more storage injections; it needs to at least keep pace with and exceed demand growth that under normal conditions is 1 to 1.5 bcfd each year and accumulating and, by the way, if gas is to return to its historic price levels, it needs to allow for some of that oil demand to come back to gas. Normally, those boilers and turbines would not be burning distillate or residual fuel oil. They would be burning gas. So if gas is to price again below residual fuel oil, and below distillate fuel oil, there needs to be enough supply to allow that demand to come back into the market

place. Those are three tall orders. Allow that demand back in the market place, exceed ongoing demand growth and power generation, and find extra gas to put in storage.

SENATOR TAYLOR said his fear has been with the tremendous demand and need that Northern California, Washington, and Oregon currently have for new generation. He asked will the utilization of natural gas by California as it installs new generation further exacerbate the supply (as he thought Mr. Kelly indicated it probably would.)

MR. KELLY answered that California is not alone. It is simply the shortest power market that exists nation-wide. There are power generation plants going on that are producing real pressures elsewhere. California is burning all the generation it has right now to satisfy power demand. Some of that generation is very old equipment that is very inefficient and is creating stress on the gas delivery infrastructure above and beyond what you would normally expect. So the gas price in California is abnormal as a result of burning all the old equipment that exists.

CHAIRMAN TORGERSON asked if in 1999 our rig count or exploration was at an all-time low.

MR. KELLY answered yes, in 1998.

CHAIRMAN TORGERSON asked if we've recovered to an all-time high.

MR. KELLY answered, "An all-time high in a gas directed sense. That's not entirely relevant, because you don't always know what you're getting down the hole. You can try for oil or for gas, but you can hit one or the other. In a gas directed sense, the number of rigs drilling for gas is about 900 and that is an all-time high. The number drilling for oil is between 200 - 300 and that is nowhere near a high level. That's still a very low level in the U.S. Lower 48."

Number 1267

MR. DEMETRI KAROUSOS added that, "What's fascinating about this is that 1998 and 1999 followed two of the highest priced years ever on record for natural gas. That meant that supply stayed flat. Gas prices were at $2.50 - $2.75 real dollar terms in 1996 and 1997. Then the decline started and we got through 1999 essentially by meeting demand for storage. In 2000 we met the supply challenge by destroying demand by backing off four to five percent out of 60 bcfd market. Those are the challenges Ed has laid out for you."

CHAIRMAN TORGERSON asked how many power plants are on the drawing board.

MR. KELLY answered that they are measured in mega wattage. It's about 270,000 megawatts and well above 90 percent of those would be gas fired. There's a high mortality rate associated with that. The power generation base in the U.S. Lower 48 is about 730,000 megawatts. "So clearly, add 270,000 in a reasonable time frame, and you have a power market that's oversupplied for generation. But this issue is very regional and very local in terms of which power markets are likely to be oversupplied and which will remain in equilibrium or undersupplied."

MR. KELLY continued to say that 1990 - 1992 monthly average demand moves from a low in the winter of 7 - 8 bcfd up to 10 -12 bcfd in the summer when power needs are highest. In the year 2000 gas demand for power generation varied from approximately 11 bcfd in January and February up to about 22 bcfd last August. This is quite a change from the early 1990 averages and stresses the ability of gas supply to meet that power generation demand and store enough for the following winter. MR. KELLY continued:

> Economic weakness has helped, in a perverse sense, in the year 2001, because we don't want power demand to increase then, based on an average economic growth for 2001 of 1.8 percent. A weak economic year hits power demand growth very directly. If the economy had grown normally, we would have expected that to result in an average demand growth of 1.2 - 1.3 bcfd in a given month for power generation and a higher summer peak in July and August. If the economy resumes a normal pattern of economic growth after this year, you can expect the stress on gas supplies in North America to move upward with it. If the remainder of the heating season is cold, we think we can get down to about 600 bcf [in storage]. Our outlook is for about 700 bcf under normal weather for the remainder of the heating season.
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> This creates a difficulty for the remaining year 2001 and that difficulty extends potentially into 2002, as well, because we're likely to enter next winter with another record low in storage inventories.

MR. KELLY said that power generation goes in patterns itself and moves where the business opportunity is and sometimes it moves all at once. There was a huge movement in power generation development in the mid-1990s in Asia. "With the 1997 - 98 Asian economic crisis, that opportunity was gone, a lot of money was lost and the development community moved somewhere else and that somewhere else was North America in the throes of an economic boom and growing power demand."

It moved from 40 - 50,000 megawatts of generation proposals in 1998

to well over 200,000 megawatts in the U.S. Lower 48 in 1999 and the number continues to increase. They do not see death notices of power generation projects since one never announces that they are dead. CERA thinks there will be an increasing mortality rate of independent power projects as some markets become overbuilt and as the gas price increases well above planning forecasts for fuel inputs in most of the power generation plants.

SENATOR KELLY asked him to explain more about the mortality rate of power developing.

MR. KELLY replied that developers don't need to and don't announce a project as dead. This is true of many projects, whether it's energy related or not. The number of plants may be high and accumulate, but in reality an increasing percentage of them may be dead. A lot of the proposals were based on a gas price forecast in historic norms of around $2.50 mbtu.

MR. KELLY said the reality is that more is going in the ground. Last year, around 30,000 megawatts of new power generation that was gas fired actually went into service. That's 4.5 bcfd of demand if they are all running at the same time, which never happens. This year, they think close to 40,000 megawatts of power generation that is gas fired will actually enter service. He continued:

> Next year they expect that pace to slow somewhat. The underlying pace the U.S. market needs to remain in balance and to keep something like a 15 percent reserve margin on generation is a straightforward calculation. If you have 730 - 740,000 megawatts in the U.S. as a whole, representing a reasonable reserve margin in most areas, California excluded, and the economy grows 2 - 3 percent, peak power demand grows about 75 percent of that level, 1.5 - 2 percent, you need 10 - 15,000 new megawatts each year simply to keep the power market overall in the U.S. Lower 48 in equilibrium. That's an invalid number in the sense that each power market has its own power demand and supply balance and needs associated with that. So we're exceeding underlying need and developing some overbuilt markets while some remain under-built. But there's strong pressure on gas-fired generation. There's no alternative for the underlying need.

Number 1700

SENATOR ELTON asked if the new gas fired power generation plants would be able to go back to distillate.

MR. KELLY answered, "Not as easily." Almost none of them are building tanks on sight, because it's a competitive free for all in

power generation development. The biggest way to disadvantage your project is to try and permit an oil tank along with your unregulated power generation power project. MR. KELLY continued:

> Secondly, it loads capital onto your project in comparison to those that don't. So somewhere about 90 percent of the new proposals don't have the physical support for distillate storage.
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> Thirdly, the turbines are designed on gas and they don't run quite as efficiently on a liquid fuel, even a clean one. There are warranty implications, as well. So there is a built-in reluctance, as well as emissions requirements that are higher even under clean liquids with a less efficient firing.

MR. KAROUSOS added that the older plants, usually the steam boiler plants burn residual fuel oil, not distillate fuel oil. That's a much cheaper fuel. Part of the story is that the competitive pressures are increasing with the higher price in the barrel, cleaner distillate fuels than traditional residual fuels burn. He thought there would be an increase in dual fuel capability in 2005 - 2010.

SENATOR TAYLOR noted that California and the western states have the smallest amount of new generation coming on line. This is where the problem is currently being faced. The Northeast, that is losing population, and the Midwest, have tremendous development and growth going on in capacity. He asked for the explanation.

MR. KELLY replied, "That gets into the power market structure and they vary." He explained:

> They vary from - you have some reasonable reassurance that your power output will enter the grid under objective terms and conditions that are available to everyone else. The Northeast and Texas are two of those regions to having relatively no assurance… Also, in the Southeast, for instance, those utilities are very confident that they will remain in the power development business, in general. That's relatively few independent developments in the Southeast. In the West, the power market is somewhat more of a hodge-podge and the California PX was developed over the course of this time frame. There is some ambiguities there. Mathematically, outside the State of California, the demonstrated need and number of days of need isn't as great in some areas of the West.

> The Midwest is a combination. It's power utility based, but its need is for peaking generation because of the base of coal and nuclear generation. So for most days of the year, the Midwest is adequately supplied. One of the most positive economic growth stories nation-wide has been happening in the Midwest.

MR. KELLY exhibited another slide showing CERA's outlook for need for the next five years and the outlook for generation development for the same time. It shows the West as being in equilibrium, but that disguises a lot of local variance. They believe Texas will be an overbuilt power market as early as this summer.

In North America, gas is one of the most high velocity commodities to be traded freely at a larger variety of points. There is both a futures market and a cash market at about 60 points on the North American gas grid which are generally major pipeline intersections. There can also be local demands in a supply area creating a price at a point in a supply area. In a market area or major metropolitan area, you'll have storage designed to satisfy that demand and you'll have infrastructure as the supply (i.e. the pipeline capacity). This creates a price differential (basis) between the two points and both of them are freely traded with some velocity every day. You can also trade the differential in price forward and derivatives. You can choose what risk you want to take and Alaska producers, when they sell their gas in the Alberta market place, will have a variety of risk options. It will affect the netback in royalty payments.

MR. KELLY said, "Once the gas does hit Alberta, there will be three major options in terms of marketing it from that point forward. They think there will be a need to market it from that point forward and move it physically from that point forward. The first is to move Pacific Gas Transmission to the West Coast and Pacific Northwest markets - the PGT line. That line is expandable and does offer some ability to move increased volumes to the West Coast. He continued:

> The second and major option in most people's minds is to move into the U.S. Midwest, into the Chicago area. Once that occurs, you're basically in the larger U.S. market. The reason for that is that the heavy industry that was in the Midwest until the mid-80s burned a lot of gas and created a lot of infrastructure from the Gulf Coast and from North Texas, Kansas, and Oklahoma into the Midwest. That industry went down, gas usage went down. It created a lot of available pipeline space from the Gulf Coast, North Texas, Kansas, and Oklahoma into the Midwest. So there's a lot of gas that can move very freely from the Midwest and from Southern Canada where the same dynamic

occurred (from the Gulf Coast, Mid Continent, to the Midwest and Southern Canada). Those prices never vary that much because there's a lot of free and available space in the pipe to move the gas around.

That's why Chicago is a destination for new supply. You have some assurance of market there and you'll get basically a North American average price. You can also move the gas directly into Northeastern markets via the Trans Canada pipeline system which has a lot of space available on it. That's sort of a third major option, but it's likely to be a higher cost option.

MR. KELLY illustrated some of the major pricing points. He said the Henry Hub in Southeast Louisiana is the site of delivery for the New York Mercantile Exchange futures contract. Other prices are generally addressed in terms of their relationship to the Henry Hub as a plus or minus to it.

SENATOR LINCOLN asked how difficult it was to expand a line.

MR. KELLY said he didn't mean to imply it was a difficult process; it generally isn't.

Federal regulation does not discourage additions to gas infrastructure, because it is clean and environmentally friendly. It is a matter of where there is existing right-of-way. You can use it and add to it. Generally, you have to expand right of way if you expand gas lines in it or you can add capacity through an existing line, itself. Gas is compressed physically and if you can compress it within what the outer wall of the pipe can hold, ultimately you can add to capacity in an existing line. There is some of both available.

CHAIRMAN TORGERSON asked if he was predicting the same space would be available on the Alliance line if an Alaskan line was hooked into that.

MR. KELLY replied, "No, the variable there is how much Western Canadian production can increase to fill existing capacity and expansion capability."

MR. KELLY said if Alaska gas comes in, it would add to the build that you need to really get gas to the market place which would mean another pipeline - either down an existing right-of-way or a brand new pipe.

SENATOR TAYLOR asked if the capital demand for construction of the new pipes diminished the value of the gas to the state or is that

amortized as future gas costs.

TAPE 01-17, SIDE B

MR. KELLY answered, "If that pipe weren't built, then the Alberta price would lower significantly with the addition of Alaskan gas and the netback in royalty would decline significantly. So if the pipe is built, there is a capital cost incurred to do it. But at the same time, there is a higher price at the other end of the pipe. Presumably, the pipe wouldn't be built unless the gain was greater than the cost."

CHAIRMAN TORGERSON said that no matter what pipeline the state uses, it's still going to affect the netback at wellhead.

MR. KELLY said, "It's an interesting question in terms of how the royalty is computed. We have a mixture of one large project to Alberta and several smaller projects to monetize the gas from Alberta forward."

He said, "In 2001 versus 2000, with the completion of the Alliance line and the beginning of supply increase in western Canada, we expect the net number that hits the U.S. Midwest to increase by 500 bcfd on average. The net amount that flows east on the Trans Canada system should decline by 400 bcfd and the net amount that flows to the West Coast should decline by a small amount - 75 mcfd. Additional capacity to the Midwest diverts supply and away from other outlets.

MR. KELLY used a chart to illustrate pricing differentials to the Henry Hub that they expect for 2000. He said they expect Alberta to price below 50 cents below the Henry Hub and slightly less for 2001.

The differential expanded as Alliance was completed adding supply out of Alberta. The reason had to do with the rate structure on the Trans Canada Pipeline system, which is fairly inflexible because it's so marginal. So you have to pay a good bit on that system whether you move it on a short-term basis or a long-term basis. Because the marginal molecules have to flow through the Trans Canada system at a fairly high rate, the pricing differential in Alberta recorded on a spot daily basis actually expanded to the Henry Hub. "So pipeline rates do matter in an expanding market."

MR. KELLY said:

> You can see the effects of new supplies on the Rockies on the price differential as Powder River coal bed methane supplies have expanded and net supplies in the Rockies have expanded, pipeline capacity has not expanded out of the Rockies for a couple of years. So the Rockies index

price has declined in relation to the Henry Hub price, has greater volume in the same amount of pipeline capacity exiting that region. You can also see the effects on the southern California border, Topock, which has exploded. Just upstream in the San Juan Basin, that differential has expanded negatively. You would expect that to - illustrating how the value can be had in short pieces of pipe when the market dynamic shifts.

CHAIRMAN TORGERSON asked him to clarify the price requirements versus proposed capacity.

SENATOR KELLY asked if the price differential was from the perspective of the consumer to Henry Hub.

MR. KELLY replied that was wholesale, cash, physical trading. Not really to the consumer.

SENATOR ELTON asked if there is a difference between San Juan and Southern California because there is no transportation system that can move gas from San Juan into Southern California.

MR. KELLY replied that, "There is no transportation system that can move any more gas from the San Juan Basin into Southern California."

SENATOR ELTON asked if there is an effort to increase the capacity of the transportation systems.

MR. KELLY replied that the crisis is current and the ability to increase capacity goes through a regulatory and permitting process and there's generally a two-year lag.

Number 2126

SENATOR ELTON said as we talk about moving Alaska natural gas into the market place we can assume there will be new transportation systems that will change the market conditions by the time Alaska gas arrives.

MR. KELLY answered, "Absolutely. There are a number of proposals to move additional gas from the San Juan Basin into Southern California."

CHAIRMAN TORGERSON asked what the 4 bcfd of Alaska gas would do in this market - ballpark.

MR. KELLY answered:

It would have some effect on pricing, certainly. Keep in mind, the overall U.S. market place is about 61 bcfd. So 4 bcfd hitting at once seven years hence…Normal rates of economic growth of 1 to 1.5 bcfd each year - we're looking at a 70 bcfd market. So 4 bcfd all at once into a 70 bcfd market, 6 percent supply addition, offset by some supply flexibility that Mr. Karousos would address in the LNG market place. Also offset with time with an ongoing increase in power generation load. Four bcfd at once is roughly three to four years of overall demand growth, if the economy is growing in a healthy direction.

Supply events like this do seem large and are large, but demand growth can absorb it. For instance, the Alliance pipeline it was feared would lower the price in the Chicago market place. In reality, when we looked at it, we saw that a return to normal winter weather would more than offset the new supply coming down the Alliance pipeline for two or three years.

Ongoing power generation demand in the Midwest is one of the markets that is actually in equilibrium. Proposals don't exceed need over the next five years by that much. There's a need for new build. Power demand growth is very strong there and the economy has been fairly healthy there.

Number 1900

MR. KAROUSOS said:

We like to talk about marginal production and incremental supply and the distinction is that marginal supply is the last mcf that's called on to meet demand on a daily basis. Incremental supply means when a new project is coming on, where is that supply coming from. Something like 70 - 80 percent of incremental supply into the U.S. has come from Canadian supply. That supply, once it came on, typically led to the pipeline infrastructure delivering at very high utilization rates which means that even though it was new supply, it was running base load and the marginal (or high cost) supply. Therefore, that supply that's brought on to meet that last supply continues to be the U.S. Gulf Coast. This is a dynamic we think will continue for the next five - 15 or 20 years. The high cost supply will adjust and take the swing. That's important to know, because it really suggests

> whether there's a volume risk in addition to a price risk associated with an Alaskan project. And we think the answer is flatly no, that there isn't a volume risk associated with serving the North American market. Within a year or two years, that kind of supply adjustment takes place among the traditional higher cost producers. That's without getting into some of the new supply that we'd be serving the market like LNG, serving primarily the U.S. East Coast. Over time it creates a flexible supply potential that can on a fairly quick notice move to a higher value market should prices fall to levels that aren't attractive. The flexibility of this market place is only increasing in terms of demand flexibility and in terms of supply flexibility.

CHAIRMAN TORGERSON asked if he understood correctly that there would be stagnant growth for a couple of years before there would be an increase or dip in price.

MR. KELLY stated, "We know the gas is available immediately which is one distinction in Alaska versus other supply efforts."

SENATOR TAYLOR asked what crystal ball they were using to say that Alaska gas would come on line seven years hence.

MR. KELLY replied that was their most optimistic scenario in which things would have to start fast and now.

SENATOR ELTON said that he was struck by how few of the projects have financing or are under construction. He wanted to know if he was wrong in assuming if Alaska gas hits the market place, it will be easier for power generators to get financing because of an increased supply and, therefore, the number of generating plants might increase.

MR. KELLY answered that he, "wouldn't oversell that personally, but I think that's legitimate in the sense it would increase the confidence in the long term supply of availability of natural gas."

SENATOR ELTON asked if it didn't necessarily drive expansion.

MR. KELLY said he didn't think it would have that kind of price effect immediately. He showed the committee a chart of the regional power markets illustrating that the power transmission system is not designed to move bulk power among the local utilities.

> Region by region, the clearest evidence of overbuild is clearly in the Northeast where even the actual construction is greater than projected need for new power generation given a normal reserve margin of 15 - 20

percent range over peak power demand for the next five years.

In the South, it looks like a market where build may be in equilibrium if a reasonable percentage of project proposals shift to be financed and under construction. That's a large region stretching from west Texas to Virginia and disguises variants between an overbuild in Texas and continuing need for new construction in Florida and parts of the Carolinas.

In the West, there's obviously huge variants disguised, as well, between need for continuing build in California and power surplus on most days of most years in much of the rest of the West.

The Midwest is a market which might be able to use a few more proposals, because given the mortality rate on power generation proposals, we might need some more proposals turn to new construction in the Midwest. The character of power generation build in the Midwest is very different because of the coal and nuclear generation base. They tend to be peaking which is a combustion turbine base generation plant.

MR. KELLY said that producers have to look at the market beginning seven years hence and make a belief fundamentally that the netback to the wellhead provides an attractive rate of return on their investment in the pipe based on the market dynamic starting at least seven years from now.

Demand pressure is strong. In the U.S. gas market place, it's now at 22 trillion cubic feet (tcf). We know in an 22 tcfd world, that varies from 11 - 20 bcfd in a given month. It's easy to get to 30 tcf as far as demand potential for natural gas in the U.S. goes. All you have to do is assume normal rates of economic growth and assume gas's current share of new power generation development and you can make some reasonable assumptions and get to 30 tcf of demand. This is kind of a shining goal on the hill held by much of the industry. What has to happen on the ground in terms of working day to day operations, however, is a real challenge in that environment. Rather than demand for power generation varying from 11 - 21 bcfd in a 30 tcf world, it would vary from 21 - 40 or 45 bcfd and would seriously stress the ability to store gas for each winter.

Rather than proven reserves of about 200 tcf in the U.S. and Canada and in order to support 30 tcf of annual demand in the U.S. proven reserves would need to increase reserve additions over the course of the decade 2000 - 2010 by more than the proven reserve level.

MR. KELLY continued:

This implies an annual reserve addition that rather than just replacing production of 21 - 22 tcf, we would need an annual reserve addition level of close to 35 tcf in the U.S. and Canada. So this represents a larger industry and much larger production effort than we have now. The potential is easy to see out there.

That also implies a movement to the frontiers and there are a variety of frontiers, not just Alaska. One of them is eastern Canada and LNG. Supply addition include the deep water Gulf, the Rocky Mountains, and western Canada in addition to Arctic gas.

The range of frontier production we would expect from Atlantic Canada by 2010 varies from 1.5 bcfd to 2.5 bcfd off-shore Nova Scotia, a new producing province that is producing about .5 bcfd.

SENATOR LINCOLN asked what would have to happen in the nation that would drive the need down.

MR. KELLY answered that within the decade there could be a resurgence of coal-based generation and there are clean coal technologies that are thoroughly exciting. Coal is economic with the current price of natural gas, but it takes a while to get permitted and built. If this happened, it could take a larger share of new generation than it does now and that would take some of the market growth directly off the top. Any economic weakness or any increase in the efficiency or conservation driven by high real energy costs would slow down the rate of growth.

SENATOR LINCOLN asked, even with new coal generation, would there be a gradual decline or a significant decline.

MR. KELLY replied that there would be a slow-down in the rate of growth. They accounted for some of that in their outlook. "The earliest they foresee reaching a 30 tcf market, in the most optimistic of supply scenarios, is 2012, as a company."

SENATOR LINCOLN asked if they took into account the new more efficient power plants.

MR. KELLY answered, "Yes."

MR. KAROUSOS added that they have conservative assessments of what fuels will actually meet new generation as opposed to new capacity. Coal is already built into their 2012 timetable and captures 40 - 50 percent of new generation with expansion of current facilities (brown field facilities). Gas accounts for 12 - 13 percent of the power market today. Their assumptions do not have gas suddenly jumping to 40 - 50 percent of the power market. But even small increases in the large power market have a big impact in the gas market. "That's what we're seeing with these numbers."

MR. KAROUSOS said that another vulnerability for long-term demand growth is confidence in gas supply on the part of large industrial players who are considering their investment options. "They will seek a home overseas, if the growing consensus is that gas can't be supplied in the U.S. below $4 - $5 Mmbtu."

He added that supply additions, particularly those that are communicated in advance, lead to demand creation, primarily as a perception of supply availability and economic growth.

CHAIRMAN TORGERSON asked if supply was more important than price.

MR. KELLY answered that supply is evidenced through price.

MR. KAROUSOS said that the degree to which higher prices are realized in the short term has implications to the long term.

MR. KELLY said, "Given there is a need, the market is supply constrained right now. The market would be larger if there were historically normal relationships between supply and demand for natural gas right now." There are risks to any venture that aren't peculiar to just Alaska. They think that a cooperative stance between the Alaskan and Canadian government will help. "The need for downstream capacity is a big unknown."

He said that transporting the liquids can support the economics of a pipeline, itself, because you're moving more in the btu's per given unit of space if the liquids are included in the pipeline. He said, "It adds to the cost somewhat of a new pipeline, however."

MR. KELLY concluded that they believe the producers will be the drivers of this project, if it is worth it to them. He turned the presentation over to Mr. Karousos who dealt with the LNG market place.

Number 900

MR. KAROUSOS said that the LNG industry is enjoying a renaissance right now in terms of renewed interest on the part of consumers,

producers, and new third party players. He said that:

> Three driving forces are focusing attention on the LNG industry. First, a real shrinking of the cost structure along the LNG value chain has reinvigorated the potential of LNG to serve new markets, particularly North America, where LNG was considered uneconomic for the last 20 years. Primarily, those cost declines have occurred in the capital-intensive liquefaction phase and in the capital intensive shipping segment.
>
> Next, the renewed interest is partly exciting markets because of the increase in available suppliers and all the new players in the market. The LNG industry has been characterized as being a club of relatively small, fairly sophisticated players and that club is expanding largely by the day. Four new suppliers just came on to the scene in 1999 - 2000, one named Cutter, Amont LNG, and in the Atlantic Basin for the first time in almost 20 years, Nigerian LNG and Trinidad.
>
> The list of new players is mushrooming every day - from Angola, Venezuela, Norway, Egypt (four projects proposed) - expansions at all the current facilities that we're talking about - the Persian Gulf supply eager to jump off and really increase market share, as well as expansion in the largest supply basin of the Pacific Rim. This is where a lot of supply is looking for a new market.

MR. KAROUSOS said that there is a willingness to take merchant risk in LNG investment, meaning to build new liquefaction capability with some of the capacity not contracted. There is new investment in merchant shipping that isn't part of a contract project proposal. All that suggests a real change in traditional project oriented thinking - things like pricing relationships, terms of new contracts and new contract renewals, and it really begs the question of a spot market developing in the LNG industry over the next 10 - 20 years. This would probably happen earlier in the Atlantic Basin, which is serving well established pipeline gas markets primarily and, then, in the Pacific Basin.

Specific regional questions are being asked primarily due to cost decline in the LNG industry. In North America the question is: Will high prices and tight current supply and imbalances make LNG an attractive option and will that continue?

"They have seen two responses - an acceleration in the supply developments in the Atlantic Basin and the expansions plans at new suppliers in Nigeria and Trinidad with new suppliers really

chomping at the bits in Venezuela, Egypt, potentially Norway, and potentially Angola by the end of the decade."

MR. KAROUSOS said that they are seeing supply development take place and an acceleration in reopening of shuttered LNG facilities that have lain dormant for 20 years in North America.

A second reaction has been a reignited interest in Greenfield (new) import facilities into North American, primarily, and Mexican markets. Asia accounts for 75 percent of the global LNG market. The LNG market total is about 13 bcfd, a fifth of the U.S. market. For those countries where LNG is a major source of supply, it meets roughly .5 - 1.0 percent of U.S. supply. It meets 100 percent of supply in Japan, which accounts for 65 percent of the LNG market.

The Pacific Basin is an area of focus and is obviously the relevant focus for Alaskan LNG potential. They think there is a very strong demand potential in Asia driven by both existing countries of Japan, Korea, and Taiwan and by new market potential. China, particularly the southern part, and India which have been receiving a lot of attention for their challenges in reforming the power market will be the linchpin of LNG imports.

> With that potential demand opportunity in Asia are significant challenges posed by the multiplicity of supply projects targeting this area that raise the question of who will achieve that market, under what terms. The traditional contract in Asia is already under review. Newer contracts have tended to be more favorable to consumers, which is showing a greater shift of the negotiating leverage from the producer community to the consumer community. There is the question of oil, which is the current index for LNG delivered into Asia, whether it will remain the sole index or whether it will be the appropriate index use. This is highly relevant not just because of the new demand, but because the existing 20 year contracts are starting to reach contract renewal time over the next few years, particularly starting in 2004 in Japan and lasting through 2015.

MR. KAROUSOS showed the committee a map of where the LNG production takes place.

> Indonesia is the world's largest LNG producer and serves primarily Japan, Korea, and Taiwan. The second largest producer is the original producer (in the world) in Algeria. But, by far all the large production facilities are in the Asia/Pacific region and over time there will be a gradual shift in the axis of supply to the Atlantic Basin, because of the potential for market growth there.

Most of the facilities are traditionally in the tropic area.

LNG is the gas monetization strategy. Typically, where there are no pipeline options and one area of the world that is eager to increase it's market share and may do so strategically, and therefore accepting a lower price for its natural gas, is the Persian Gulf, which is sitting on hundreds and hundreds of thousands of reserves.

SENATOR LINCOLN asked if the areas where LNG projects are approved, but not under development, are relatively new approvals or have they been sitting there for a long time.

MR. KAROUSOS answered they were the Pangu project in Indonesia, Yemen LNG, and Venezuela. LNG projects sometimes have 20 - 25 year histories of when reserves were developed and identified. Nigeria is an example of a project that took 25 years to be realized. He explained that the approval process is a little bit of a misnomer. It's easy to get projects approved, but the real issue is when does the market develop for that LNG and when does the contract get signed that leads to its development.

TAPE 01-18, SIDE A

SENATOR LINCOLN asked how they determined which areas would be developed in 2005 - 2010.

MR. KAROUSOS answered that the considerations they use to sequence potential supply additions are as follows:

- Geography which plays a critical role in LNG development, because transportation of it is more expensive than transportation of gas. Every 2,000 nautical miles adds 40 - 50 cents to the cost structure and, therefore, is a subtraction from the potential netback to any LNG project.
- Supply diversification and security concerns are major drivers so that sometimes higher cost supplies are developed to maintain diversification. They expect China to use that strategy, not offering all its LNG to just one player. Japan has consistently supported the Australian LNG supply development on this basis.
- Associated gas pressures transforms LNG development, because in some cases in some parts of the world, oil development which sometimes yields lots of natural gas development brings natural gas in a place where there's absolutely no market for it. In some cases it's reinjected and in other cases it's flared. Flaring is increasingly a problem and not accepted by the host countries.
- The gas sometimes has a negative value. When doing a netback

analysis, you can almost assign a $0 value to the gas, itself, in the desirability to see that project come to fruition. A good example of this is the kind of pressures facing west African producers in Angola and Nigeria.

- How wet the gas is or how many liquids are in the gas stream is another consideration for all gas projects.
- Alternative gas monetization strategies come into play and the decision of host countries to see all of their resources being channeled into one [indisc.] This represents the competition brought to LNG from gas to liquids (GTL) development.

SENATOR ELTON said he thought one of the supply considerations would be internal to a single producer. For instance, a North Slope producer might not want to compete North Slope LNG with LNG they are producing elsewhere.

MR. KAROUSOS answered because of the capital intensity of the LNG projects, there are often consortia of producers who cannot dictate single handedly which projects will go forward and which won't. In many of the projects, the host country has a large equity stake in the liquefaction facility and has a driving say in what projects go forward or who is an important constituent to pay attention to. There are also capital allocation decisions that every producer must make including decisions on which kinds of properties to invest in (oil vs. gas or natural gas that has a pipeline access to market vs. natural gas that has to be monetized through LNG or GTL). Their decisions are constrained by the fact that most of these projects have multiple players. "The ultimate consideration is what supply is competitive."

MR. KAROUSOS said that LNG has a fairly simple cost structure and that:

> First the gas is developed, then it's gathered, then it's liquefied, shipped to market, vaporized at the market place and either consumed on-site in a very local power plant or entered into the pipeline grid. The parts of the chain that have really shrunken the most over the past 5 -10 years have really been the liquefaction phase and the shipping phase.
>
> Liquefaction has seen up to a 30 - 40 percent cost decline and part of that has been maturation of the LNG business, which is only 20 - 30 years old. There's been a tremendous amount of experience gained among the contractors, the EPC players (engineers, procurement, and construction firms). There's a greater number of those players who have experience or just competition in that sector. That accounts for a significant amount of the cost decline.

> There has also been an adjustment in philosophy of design, not so much an engineering or technological breakthrough. This has simply been the realization that LNG, particularly as supplies increase, the reliability question becomes somewhat less critical. It doesn't need to have the same kind of gold plating and duplication of parts. The real best of practice LNG plants that have come on stream have been in the Atlantic Basin which are serving slightly different markets that have pipeline gas access. This has reduced best practice, green field costs associated with just the pure liquefaction part of the business to the .90 - $1.10 range.
>
> Shipping has undergone cost declines partly as a shift away from the traditional Asian market.

MR. KAROUSOS noted that his graph showed the cost of building a ship going from the $260 million range down to $225 - $250 million in the mid-90s down to $150 million for the last two ships that were chartered. These are the largest tankers that have been built, 135,000 cubic meters. The union call declines have been more significant. Part of this has been accomplished because new development has been outside the Asian arena and is not dominated by the traditional Asian model of relying on the construction to take place in favored terms.

> A consistent characterization of the Japanese LNG contracting negotiations was that to bring in the supply to the Japanese market, the ship building had to be done by the Japanese players and while LNG tankers aren't as simple as oil tankers, they're hardly a technological marvel, and multiple players can build these ships and that is being done today by the Spanish, by the Koreans, by others.

MR. KAROUSOS said they expect the cost of LNG tankers to average $150 - $200 million over the next 5 - 6 years.

CHAIRMAN TORGERSON asked if it was safe to assume that pipelines had gone down also.

MR. KAROUSOS replied yes.

MR. KELLY interjected that there's a right-of-way associated with pipelines that hasn't gotten any cheaper.

SENATOR ELTON said that none of the LNG tankers are built in the U.S, so none of them can serve between Alaska and the West Coast.

MR. KAROUSOS replied that the U.S. currently imports LNG.

SENATOR ELTON said it was because of the Jones Act restrictions.

MR. KELLY added that even if the U.S. did build tankers, the West Coast would not let them in.

MR. KAROUSOS said because of the underlying fundamentals and the underlying supply pressures of North America, we might want to consider that LNG import capacity to North America may be the short commodity by the end of the decade and green field activity may take hold. El Paso has just announced intentions to build six import facilities targeting North America and the Caribbean. There are clever ways around citing facilities.

Number 1200

SENATOR ELTON noted that northern Baja is connected into the southern California power structure and it's also a way around the Jones Act.

MR. KAROUSOS said the next chart summarized how the playing field has changed for LNG. They chose a theoretical Caribbean supply and assumed a minimum acceptable netback for LNG for natural gas reserves that don't face the associated gas flaring pressures. A typical industry standard is 50 - 60 cents netback to the producer, .90 - $1.10 for green field (new) projects, shipping for 40 - 70 cents (roughly 2,000 nautical miles), and regasification at the facilities that have been mothballed and are fully depreciated and have been fully paid for by consumers through pipeline tariffs that have been passed through to utility bills, and therefore have lower regasification costs. A new facility would call for 20 - 30 cents per Mmbtu. An average range in the market place is $2.30 which really makes LNG attractive.

MR. KAROUSOS said:

> In our view, the markets both at Lake Charles which is very much an Henry Hub kind of price and Elba Island, Cove Point, and Everett, if you just look at the spot price, LNG base load supply probably has higher value than just a pure spot price at that market delivery. But if you just look at the spot price, it obviously leads to a much higher netback to producers. This really explains why there's three trains under construction after only a year of operation at both the players in Nigeria and Trinidad and why there's so much interest in the Atlantic Basin on top of the European growth story which we really think takes off after 2010. So the range associated with that netback is an important consideration because it

speaks to the structure of the market, who is taking capacity in the market place.

Let me be clear about this. When the producers take a position in the import facility as BP has done at Cove Point, for example, and as Shell has done through Coral (ph) in Cove Point, then that producer has paid for that tariff rate and faces the market directly. When instead the producer is negotiating with the marketer who's taken that vaporization capacity, they are dealing with a marketer who is savvy and will try to capture as much rent as possible from the market price in that market. That's, hence, the range that we show of where the competitive bounds of how much may be split between the producer interest and the marketers who have taken capacity positions.

MR. KAROUSOS said that all the port facilities are on the East Coast and Gulf Coast. There are some new facilities in Mexico and they think that each of them is feasible. Mexico has a very strong gas demand potential. So even if they can overcome the constitutional challenge of opening up the upstream in Mexico which is currently a monopoly by Pemex; and, if they were bringing capital draw in of foreign investors by some compromise in the current constitutional limits to doing so, that supply would not in any short order, serve the U.S. markets. It would desperately be needed in Mexico and that's why LNG imports into Mexico are not attractive even despite the known reserve base in this country.

Both the Northern Baja and the Bahamas are U.S. LNG projects in sheep's clothing, because they will primarily go to serve U.S. markets.

MR. KELLY said that the North American gas market is so unrelated, that Mexico's needs directly affect Alaska's netback - and Mexico appears set to increase its imports from the United States substantially over the next five years.

CHAIRMAN TORGERSON recapped that there's a large demand growth in Asia, but he wanted to know if there was enough supply and construction to take care of that demand or are there other opportunities for LNG facilities to meet that demand growth.

MR. KAROUSOS answered:

There's a lot of potential supply chasing markets in Asia and the Asia Pacific Basin. Facilities under construction meet some anticipated demand. They don't meet all the demand that we think will come on line. The potential supply more than overweighs the potential demand in Asia.

A real wild card is the Persian Gulf and the willingness of the Persian Gulf to develop its LNG potential at market with merchant risk and the willingness of East Asian producers, who are using LNG partly to diversify their oil dependency from the Persian Gulf, whether they're willing to sign up new contracts.

There are Persian Gulf contracts into Japan and Korea. How much they are willing to increase - that is a key question for Alaska which represents a different kind of diversification play and a stable political diversification play from the Southeast Asian sources of supply (i.e. Indonesia, Malaysia, Brunei). What is it's competitive position vis-à-vis Australia, which is the other stable political regime that is really competing.

There is a slight distance advantage that Alaska LNG has over Australia. LNG into Japan advantage is eroded. When looking at Korea or China it swings into Australia's favor.

When you look at the overall cost structure, because most of that supply is fairly close to the liquefaction facilities, there aren't hundreds of miles of pipe that need to bring that gas just to be liquefied. That's a significant amount of capital that lends an advantage in terms of cost competitiveness to Australia.

MR. KAROUSOS said the Persian Gulf producers would be affected if their primary market of India doesn't materialize soon. This is a very strong risk in CERA's outlook.

CHAIRMAN TORGERSON recapped that Japan was investing in facilities as a financier to guarantee supply, he assumed. He asked if they weren't planning on doing it that much any more.

MR. KAROUSOS answered that the power industry is in various stages of deregulation, as is the gas business, and the challenges that all utilities face when their market is under threat is a retrenchment in a willingness to spend capital on new supply and a reluctance to sign up new longer term contracts, particularly at the traditional contract terms. This is not a unique situation to Japan. It is partly why California utilities did not build any power plants.

There is a real uncertainty in Japan as to whether major capital will be expended and depend on a fairly certain market that will be available to absorb that supply or some regulatory structure such

that new supply contracts are disposed of to suppliers who have captured the market. That kind of uncertainty is never good for new supply contracts being signed in the traditional manner.

SENATOR TAYLOR said he thought the only thing that would bring this to a head was if one of our producers actually walked into this building with a signed contract with someone. He asked what CERA saw the market forces doing to producers in Alaska to drive the decision to enter into a contract of a sufficient magnitude that would justify the capital expenditures necessary for a pipeline up here.

MR. KELLY answered that for a pipeline, they simply would have to have confidence in the price, an attractive netback. That's all there is. They would have to sign a contract before the pipe is financed. In LNG it may require more of a downstream contract.

MR. KAROUSOS added, "Most certainly a downstream contract." He continued to say that it would have to be a strong diversification play on the part of the market to have it happen. There are a lot of competitive pressures to seeing that realized.

SENATOR TAYLOR said as long as there is long term confidence in price, someone should develop the pipeline.

CHAIRMAN TORGERSON asked, "What in the short term would be indicators that may solidify a price in the long term? One is the summer weather, delineating the fields around the world that are being drilled right now. Delineate a couple of those."

MR. KELLY answered:

> There are a couple of key things they will know about in the next six months. We will know what 900 - 1,000 gas directed rigs really does to the Lower 48 supply. We will have undergone the usual lag time between drilling activity and new supply. And if the U.S. doesn't start to show clear indication of a rebound in production, then there's sort of an [indisc.] going on, because we're close to rig capacity in the U.S. It would take time to add a whole lot of rigs. That's probably the leading indicator.
>
> Number two would be if the economy picks up again and demand pressure resumes again. The price, therefore, stays above distillate fuel oil for a full year. I think that would do a lot for longer term confidence in price in the U.S. market place.

SENATOR TAYLOR asked if they, "had given any thought or analysis to

advising the state whether we should be the ones moving forward to take that risk at this point in time and to build that pipeline ourselves."

MR. KELLY answered if the producing community doesn't believe the netback is attractive in their own capital allocation process, he would think long and hard before doing it.

SENATOR TAYLOR said his concern was the constraints upon the producers may be driven by forces that are totally proprietary to them and the state will never have any information on it.

MR. KAROUSOS said that broadly speaking there has been a push to the frontiers and this is partly in recognition that the price story is real and enduring and it's been led by the majors. They have been moving out of the traditional basins, abandoning them to the independents.

MR. KELLY said the seriousness of the money spent by the consortium indicates that they are obviously looking at it.

SENATOR TAYLOR said in retrospect he was wondering if we would have been better advised to have built the oil pipeline ourselves than to rely on the utilization of capital provided by the majors with capital provided by the majors. "Are we getting a good deal today with the charge back being charged against us for the transportation of our oil down that pipeline that they own? Should the people of Alaska, themselves, own that transportation system or be seated at the table so we know what's being charged and whether or not we're getting a square deal out of it?"

MR. KELLY said he thought the technical challenges were much less today for a natural gas pipeline. The uncertainties are much less than 20 years ago. The structure of the natural gas business is different from the structure of the oil business 25 - 30 years ago. These companies are not very aggressive in participation downstream unlike oil counterparts.

MR. KELLY said the state should consider table stakes and that would get them better information.

MR. KAROUSOS said that you often see national or state bodies take a position so they can get information.

CHAIRMAN TORGERSON said that was on a lot of people's minds. He thanked everyone for their participation and adjourned the meeting at 6:00 p.m.