

ALASKA LEGISLATURE
JOINT COMMITTEE ON NATURAL GAS PIPELINES

November 7, 2001
10:00 a.m.

SENATE MEMBERS PRESENT

Senator John Torgerson, Chair
Senator Johnny Ellis
Senator Donald Olson

SENATE MEMBERS ABSENT

Senator Rick Halford
Senator Pete Kelly

HOUSE MEMBERS PRESENT

Representative Joe Green, Vice Chair
Representative Scott Ogan
Representative John Davies
Representative Hugh Fate

HOUSE MEMBERS ABSENT

Representative Brian Porter
Representative Reggie Joule

OTHER LEGISLATORS PRESENT

Representative Jim Whitaker

COMMITTEE CALENDAR

10:00 - 12:00 Washington D.C. update:
John Katz, Director, State/Federal Relations and Special Counsel to
the Governor; Duncan Smith and C.J. Zane, Legislative Advisors with
Dyer, Ellis and Joseph; Update on Senator Murkowski's energy
legislation

12:00 - 1:00 Lunch

1:00 - 3:45 Department of Revenue

1:00 - 3:00 Roger Marks, Economist, Department of Revenue
3:00 - 3:15 Ed Small, Cambridge Energy Research Associates
3:15 - 3:45 Larry Persily, Deputy Commissioner, Joint Pipeline

Office, Bill Britt, State Gas Pipeline Coordinator
4:15 - 4:45 U.S. Mineral Management Service
John Goll, Regional Director
John Larson, Geologist

PREVIOUS MEETINGS

July 17 & 18, August 14 & 15, September 19, 2001

ACTION NARRATIVE

TAPE 01-21, SIDE A

Number 001

CHAIRMAN JOHN TORGERSON called the Joint Senate and House Natural Gas Pipelines Committee meeting to order at 10:00 a.m.

MR. JOHN WILLIAMS, Mayor of Kenai, commented briefly, but due to transmission difficulties, his testimony is not audible on the tape.

CHAIRMAN TORGERSON recapped the Mayor's comments saying that the main emphasis of the meeting was to spend a substantial amount of time on the resources in Cook Inlet, existing industry, and other industry that has looked at Cook Inlet to either supply the resource or build their own industry. He continued:

This is very important to this community, since part of our deliberations is how we can [we] give them gas, if and when we need gas, to the Southcentral Basin. We've heard some exciting news about discoveries that have been bylines in the press. We hope to elevate those to guide us over the next couple of days to see what actually might be there and what we can count on for additional resources.

MR. JOHN KATZ, Director, State/Federal Relations and Special Counsel to Governor Tony Knowles, testified:

Let me start by briefly describing the public policy arena here in terms of five specific factors.

1. In terms of national energy legislation, I think it is pretty clear now that we will not see that legislation on the Senate floor before the Thanksgiving recess. Majority Leader, Senator Daschle, has indicated five priorities for Senate action in the immediate future and energy

legislation is not one of them. It seems increasingly likely, though not certain, that there will be a session of the Senate of the period between Thanksgiving and Christmas. If that is the case, it is possible that energy legislation will be introduced and perhaps brought to the Senate floor for debate and voting.

2. The second factor that I wanted to bring to your attention is that in a very rare parliamentary maneuver, the Majority Leader of the Senate has basically brought the development of energy legislation under his personal aegis. In essence, he has instructed the chairmen of the various committees that have jurisdiction over energy issues to make recommendations to him. He and his staff have taken the responsibility for putting those various provisions into final form for debate on the Senate floor. In the case of the natural gas pipeline, the Senate Energy Committee has discontinued its markup of energy legislation. Those markups began in August. Now the chairman of the committee, Senator Bingaman, and his staff are in the process of developing recommendations to provide to the majority leader. We've been told that their goal is to make those recommendations to the Majority Leader in the form of legislative language by this Friday. I'll come back to that later.

3. The third point that I wanted to bring to your attention is that the Republicans in the Senate have grown increasingly impatient with the pace of energy legislation in the Senate and at various times they have indicated their intention to develop an alternative bill of their own to bring to the Senate floor. That effort has not been totally successful so far. It has foundered perhaps on provisions relating to ethanol and to electrical energy restructuring, not anything that relates specifically to the natural gas pipeline. Another possibility in this scenario might be for the Republicans to take the House bill, HR 4, and propose that as amendments on the Senate floor to other fast moving legislative vehicles. As many of you will remember, HR 4 contains a specific prohibition against the over-the-top route for the natural gas pipeline and also includes provisions, which would authorize oil and gas exploration and development in the Coastal Plain of the Arctic National Wildlife Refuge.

Another factor that I think is quite relevant in this period is the relationship between the natural gas

pipeline and ANWR, itself. I think it is safe to say that in the Senate, there's broad bi-partisan support for the proposition of developing and commercializing Alaska North Slope natural gas. There are key questions concerning the legislation to accomplish that purpose, but the basic proposition is not in question. However, there are members of the Senate, including the Majority Leader, and the Chairman of the Senate Energy Committee who would like in essence to remove ANWR from the Senate debate and substitute in lieu thereof the natural gas provisions, perhaps some provisions relating to tax incentives for heavy oil, treatment of stripper wells, and other provisions relating to oil and gas, but not ANWR. The Senate Majority Leader in floor statements and in press briefings has indicated his strong support for the natural gas pipeline as a hydrocarbon alternative along with other provisions for ANWR. He talks about the jobs that would be created with the gas line and other advantages to the country. Conversely, there are other members of the Senate who want to make sure that that linkage doesn't occur and the parliamentary scenarios that they envision would ensure that the gas line and ANWR are considered separately and are both voted on in the Senate.

The final factor, which is relevant to the specifics of the natural gas pipeline is the position of the federal administration. I think it's safe to say that the formal position of the federal administration is to be project and route neutral and not to propose legislation relating to the gas line at this time. I believe that there's also a great deference to the political leadership of Alaska, the Congressional delegation, the Governor, the state legislature in terms of what we think and how that is factored in by the President and Vice President. They also support the commercialization of North Slope natural gas, but their principle focus, I think is safe to say, has been on ANWR.

There are, I believe, three pivots in the Senate - Senator Murkowski, Senator Bingaman, and Senator Daschle, as we consider natural gas pipeline legislation. There are several factors, I think to look at, as those parties consider the issue. The first is whether to include the producers' enabling legislation in the energy bill, itself. I won't elaborate on that legislation now unless you want me to since we've discussed it previously or the alternative to rely on the ANGTA regime, which was

enacted and decided in 1976 and 1977 by Congress and the President.

Another factor of chief determinant is whether the gas pipeline should be considered within the context of national energy legislation or perhaps as free-standing legislation. A fourth factor is should that legislation be route and project neutral or should it prohibit a particular route, for example, the over-the-top route. Finally, another very important determinant is whether there will be tax incentives in the final package in order to promote commercialization of North Slope gas generally or to influence the choice of route by perhaps providing tax incentives to only one route and not to others. You've just heard the chairman's comments on Senator Murkowski's work with respect to the gas pipeline and I would not presume to add very much to that description. Senator Murkowski is clearly looking at the advisability of introducing legislation and, if so, what the components of that legislation should be, whether it should rely on the matrix of the enabling legislation or in the alternative on the ANGTA regime. I think it's best to leave that at that junction pending anything further from Senator Murkowski or his staff that they would want to share with the committee later on.

The second determinant that I mentioned earlier, is Senator Bingaman. Even though markups are no longer occurring on energy legislation in the Senate Energy Committee, he and his staff are working very diligently on several different provisions including provisions concerning the natural gas pipeline and I believe it is their goal to make their recommendations to the Majority Leader at the end of this week, if that's at all possible.

My guess, and it is only a guess, and I may be contradicted by what actually comes out later, is that that legislation will rely very heavily on the producers' enabling legislation and that it will at this juncture stipulate a particular route. I believe that Chairman Bingaman is also very interested in developing some economic incentives or tax incentives to commercialize North Slope gas. I know that he and his staff are looking at a spectrum of possibilities which include accelerated depreciation on construction; secondly, reducing the commodity risk by establishing some sort of floor price and; third, even the possibility of an investment tax

credit, but those matters are not within the jurisdiction of the Senate Energy Committee. They are, in fact, province of the Senate Finance Committee, Senator Baucus' Committee. It is by no means clear at this point whether there will be any of these tax incentives in the Majority Leader's final bill and, if so, what provisions they might be.

The third pivot is the Majority Leader. He is pivotal obviously in two respects. One is within broad parameters, he will control the Senate floor; he will control the timing of Senate consideration. He will decide when to introduce legislation and then later when the debate will occur. Of course, those decisions could be overridden in various parliamentary ways on the Senate floor, but it is not usual that that would occur.

The second place where he will be very important is on the substance of natural gas legislation, itself. In various contexts, he has indicated his strong preference for the southern route. He has not yet, to my knowledge, indicated publicly whether he would support the ANGTA regime or the producers' enabling legislation, but he is clearly knowledgeable on this subject and, as I indicated earlier, would actually like to substitute the gas line and some other oil and gas provisions for ANWR. He wants to give a broad deference to his various committee chairmen as they formulate different elements of the energy package, but he has reserved to himself some of the final decisions on what that package will look like. There are other members of the Senate who have expressed an interest in natural gas legislation, some for the enabling legislation and some for the ANGTA regime, and specifically for the southern route and they are part of the dialogue now with Senator Bingaman and Senator Daschle about how this will ultimately proceed.

In terms of the various advocates in the process who are treating the Senate on the gas pipeline issue I think you're going to be hearing from various proponents and so I will only briefly for the purpose of this testimony characterize what I understand to be the position of the parties as they continue to advocate those positions. The North Slope natural gas producers have remained very strong advocates for their enabling legislation, which they allege to be route and project neutral and simply to present an alternative to the ANGTA regime. They have also indicated that that legislation is absolutely

crucial in their deliberations about whether to go forward in the effort to commercialize North Slope natural gas.

Foothills and some of the other previous partners in the Foothills project have indicated their strong preference for the ANGTA regime perhaps as amended by some legislative language that they proposed, which would focus on the environmental process and confirm the decisions made by the executive branch in 1977. They believe that that legislation is the quickest way to commercialize North Slope gas and to generate jobs and they also feel that if there's any alternative to that, the calendar may then become free to adopt an alternative to the ANGTA regime and the international agreements that form part of that regime. The State Administration has continued to advocate the Governor's 10 principles as described in his testimony to the Senate Energy Committee in October. We continue to place heavy emphasis on the ANGTA regime and particularly on the southern route. I think in those respects our advocacy has been quite similar to that of Chairman Torgerson and the principles that the Joint Committee has adopted. We've also emphasized the other principles in that package or policy. Recently, we have felt that for the most part our position and the position of the legislature are well understood by members of the Senate and so the Governor has shifted some of our focus to the commercial world. I should mention that when the Governor was here we met with many members of the Senate Energy Committee to express our support for the pipeline for the southern route and also for ANWR. We've since followed up on that.

In terms of the commercial situation you will hear in greater detail from the pipeline companies, themselves, but I think they would tell you that they are on track to reconstitute their partnership and to deal with the very important issue of the contingent liability, the \$4.2 billion matter that we've discussed previously and that sometime in the not too distant future they will be prepared to discuss more formally with the producers how they might jointly proceed, but I'll leave those commercial presentations to others.

Finally, I would say that I think I've accurately described what the situation is today, but it's very fluid. It could be influenced by any number of permutations and combinations in the Senate, itself, and

it also could be influenced by external events relating to supply price and possible supply dislocations.

10:24 a.m.

REPRESENTATIVE GREENE asked if the switch in leadership was good news or bad news in terms of getting this issue to the floor and not be bottled up in committee.

MR. KATZ replied that is a good question and that this is only the second time that anyone could recall that this parliamentary maneuver has occurred. He thought it was a setback. He said that Senator Daschle is on record as supporting the southern route and he thought Senator Bingaman was inclined toward a more route-neutral approach. He didn't know how that would be resolved. Also, the Majority Leader felt that the pace of activity in that committee and other committees with relevant jurisdiction was quite slow and maybe the best place to speed it up would be in his office inviting all the relevant committee chairmen to submit their recommendations to him. He commented, "It's not a particularly democratic process at this point, but I think it is an effort to get a comprehensive bill done."

MR. KATZ said it was a setback for everyone who supports opening ANWR, because they thought they had the votes in the Energy Committee. However, the Majority Leader who opposes ANWR did not want to see a bill come out of that committee with ANWR in it.

He guessed that there wasn't sufficient time in this session of Congress to both introduce a bill and debate it. He thought the best that would happen is that a bill will be introduced that would be debated some time next year unless the Senate adopts the House bill, which is highly unlikely, and then there would have to be a conference committee. There are a lot of factors that bear on the answer to this question.

CHAIRMAN TORGERSON asked if he had heard anything from the environmental community about routes.

MR. KATZ replied that they had commented, but not with great vigor yet. They are very much into the ANWR gas pipeline dynamic. They object to the northern route, some support the southern route and some simply don't oppose it. He thought it would help the democratic majority if they voiced their opinions.

CHAIRMAN TORGERSON said he asked that question because the producers' legislation mirrors many provisions in ANGTA. One is the limited judicial review process for challenges, which the

environmental community is not very enthusiastic about. He questioned, "...is it just something that we don't have a bill in front of us where they're holding back in the weeds until they see something actually in writing?"

MR. KATZ said it might be more of the later and he hadn't seen them get to the level of detail that is suggested by his question.

For the most part they're focusing on ANWR to the extent that they're focusing mainly on the choice of route. Although, when the details of the legislation come out, I would not be at all surprised to see them focus on the expedited judicial review issue. But it is in ANGTA and it is in enabling legislation. It's a principle that I think a lot of people endorse at this point.

CHAIRMAN TORGERSON asked where the legislation was that the Governor said he was going to have Mr. Katz draft and introduce to Congress as a guideline.

MR. KATZ replied that it is drafted, but it hadn't been given to anyone. He said it wouldn't be productive for them to propose actual legislative language at this point. If circumstances change, they can do it.

10:32

MR. DUNCAN SMITH, Dyer, Ellis and Joseph, Washington, D.C., (testifying via teleconference) said he placed the call, but C.J. Zane would comment.

MR. C.J. ZANE reported that, from their perspective, people in Washington D.C. are trying to figure out how to deal with ANWR. He noted, "There are lots of moving parts here." He said the energy bill could move quickly to the floor if ANWR were to be dealt with in some other way. He said that Senator Daschle was going to put some kind of energy bill on the Senate calendar, so it is available if favorable circumstances arise. He thought that Foothills would have more political momentum going if it could have the withdrawn partners issue resolved and it has been working diligently to pull the deal together.

MR. ZANE said that Senator Murkowski had draft legislation "that he wants to keep in his hip pocket, but my latest 'intel' is that it is not being laid on the table in any official capacity at this point."

MR. SMITH added that the last time a Majority Leader took a bill

out of committee and took control of it was in 1960. The situation is very fluid and it's all within the control of the Majority Leader.

REPRESENTATIVE GREEN asked if he foresaw sort of a quid pro quo that could pull ANWR out of the loop.

MR. ZANE said that the delegation is taking the position that, "You don't get our gas in exchange for us giving up ANWR. You'll get our gas, which you've already said you need, if we get ANWR. In the end ANWR will help continue the potential for even more gas delivered to the Lower 48."

He said that Senator Daschle would like to use this as a quid pro quo and the delegation is aware of that and is working very hard to see that that doesn't happen. They are considering attaching it to the economic stimulus package that the President really wants or by attaching HR 4, the House bill that contains ANWR, to one of the packages.

MR. ZANE said further that:

All of these moves and counter moves in the end are interrelated so that you could end up with an energy bill with ANWR and a gas line provision in it, but only after Daschle agrees to some parliamentary procedure that lets ANWR have its day on the floor. Some of the Democrats will make the argument that we'll vote against ANWR and vote for the gas line. I think that efforts will continue to separate the issues and I think that our delegation will not be comfortable with a gas line bill where there hasn't been some accommodation made on ANWR. If that combination and deal gets made, it could happen this year. If it doesn't get made, then the idea is to go into next year.

TAPE 01-21, SIDE B

10:26 a.m.

REPRESENTATIVE GREEN asked what the chances are of it happening this year.

MR. ZANE said there is about a 20 - 25% chance that the ANWR issue gets resolved satisfactorily so that we also get an energy bill this year.

REPRESENTATIVE DAVIES asked what the chances are that we get

neither this session.

MR. ZANE replied:

It's too simple to say it's the reverse of what I just said - that it's a 75% chance that we get neither, because I actually think that we have a little bit better than a 75% - I would say that we have about a 50/50 chance of getting ANWR dealt with this year on some other vehicle, some other legislative package. I say that because the delegation wants it; the White House wants to see it happen, in my view. We have a 50/50 chance of getting ANWR, but it doesn't necessarily translate then that we have a 50/50 chance of getting both. I do think our chances of getting both are much better once you have ANWR dealt with.

CHAIRMAN TORGERSON said:

Well, C.J., you know our position is just to reaffirm ANGTA. So we're not really pushing for gas legislation. I've heard two different stories on what might be in Senator Murkowski's legislation. One is starting with the producers' legislation and then three or four other provisions. The other one reaffirming ANGTA, well first the producers would have to [indisc.] Foothills and have to get their act together within a certain timeframe. So they would have the first right of refusal. My understanding is under the producers' legislation it would transfer to Foothills to do that and the other one that I heard is actually from Mr. Katz and it's just the opposite of that. It reaffirms ANGTA for a period of time and then if they didn't perform under ANGTA, they would revert to the Natural Gas Act and approve the producers' legislation.

CHAIRMAN TORGERSON asked them to chase down the answer to that question. He said:

This committee has voted to uphold the provisions of ANGTA, but if it's the wisdom of Congress to adopt the producers' legislation under the Natural Gas Act, then we've got several hundred pages of amendments that we want them to consider along with that.

MR. ZANE responded they understand and they have passed that on.

10:52 - 11:03 a.m. Break

MR. ZANE continued to say that Senator Murkowski's draft legislation was never something he was committed to; he wanted staff to put concepts down on a piece of paper to see what they would look like. He has heard from several people on that, but he is in no way ready to move. It would bar over-the-top; it would give prominence to the existing ANGTA law and the Foothills project, but only for a period of time, like a couple of years. He continued:

If an agency, like FERC, were to certify that an official application had not been filed by a certain date, then after that date, certain other provisions in this draft language would become effective, like the ability to file for a second southern route under the Natural Gas Act with its own set of judicial and environmental review provisions in it that are different than the ANGTA provisions. In other words, the environmental [indisc.] and expedited review provisions in ANGTA would stay in effect through the time where the FERC conditions would kick in if nothing gets going on the Foothills project.

CHAIRMAN TORGERSON said he thought there were a couple of other provisions; one was access by non-producers into the line. He said:

I'm not too sure this committee would oppose that as long as we do it in sequence of reaffirming ANGTA for a period of time, giving that period of time to the owners of the franchise, Foothills or whoever ends up gobbling up all of Foothills, Duke or West Coast or TransCanada, and give them a reasonable length of time to formulate their proposals, which we know they're working on now and then if that all boils up so that the project doesn't completely go away, then it would revert to the same sort of conditions to the producers. We haven't taken a position on that as this committee, but my guess is that isn't too far from our original point.

MR. ZANE said the important thing about the language is that Senator Murkowski is looking for a way to lock ANGTA in, at least for some period of time after which they get sunsetted out.

CHAIRMAN TORGERSON reiterated that they didn't oppose that as long as the timelines are right.

REPRESENTATIVE DAVIES asked if after the FERC certification happened, were the other provisions substantially similar to the producers' legislation that the committee has seen so far.

MR. ZANE said he thought it was more likely to be what Senator Bingaman proposes rather than the producers. He wasn't sure that the producers liked this. He knows they don't like the reauthorization of ANGTA.

REPRESENTATIVE DAVIES asked if it wouldn't be hard to actually put a project together under ANGTA if the producers were dragging their feet. "It still puts the producers' bill in the drivers' seat in my opinion. Could you comment on that?"

MR. ZANE replied, "I think you have to ask Senator Murkowski and his staff those questions."

He assumed if the Foothills project can really get going, major U.S. companies would be involved who on their own can be significant in terms of capital for the project and political clout. It's possible the producers would see that it's not beneficial to drag their feet.

CHAIRMAN TORGERSON said they should remember that the producers are authorized to be partners, also. They are the ones who are pushing for the 82 amendments. He asked if there were any further questions for Mr. Zane or Mr. Smith. There were none and he thanked them for keeping the committee informed.

[END OF TAPE]

11:19 a.m. - 1:08 p.m. Lunch Break

TAPE 01-22, SIDE A

MR. ROGER MARKS, Economist, Department of Revenue, was the next speaker. Chairman Torgerson had asked him to put together some models on netback and different aspects of the economics.

MR. MARKS said that he had presented the committee with an economic model in July and was asked to come back and present it in more detail. He said when looking at the models the focus is on what it means for something to be economically feasible. He explained:

One of the crucial issues that determine economic feasibility is how risky a project is and how that comes in to determining feasibility. That's why I really wanted to spend some time discussing how risk and especially in the context of this project, how commodity price risk, that is the price of gas and how it affects the riskiness

of the project and the economic feasibility of the project.

We're going to talk about the commodity price risk. It's useful to just pause for a second and discuss how the price of gas is established. Getting away from gas and just talking about any commodity, the price in the market for any commodity will equal the lowest cost to produce new supplies.

What does that mean? If we take an example of something that has nothing to do with gas, let's just say I invent a robot that will change the oil in your car and let's say I can produce that robot for \$100. I figure people will pay \$500 for this robot, so I manufacture these robots for \$100 and sell them for \$500 and make a lot of money. Well, pretty soon someone will come along and say, 'Gee, this guy is spending \$100 to produce something and selling it for \$500. I can produce that thing for \$100, too, and I'll sell it for \$400 and take all his business away. Pretty soon, someone else will come in and say, 'Well, I can sell it for \$300 and eventually the price will come down to the cost. In economic terms it's called the marginal cost and the marginal revenue. The marginal cost is the cost to produce the unit and the marginal revenue is the price. Basically, in markets, if they're operating properly, the price of that commodity will be for the lowest cost to produce new supplies.

How might this come into affect for North Slope gas? Let's say the price in the Midwest in the Chicago area is \$3.00 - the market price for natural gas, whether it comes from Alaska or whether it comes from Louisiana. Let's say that people figure out they can make money building a North Slope gas line if the price in Chicago is \$3.00. Then all of a sudden, Venezuela looks up and says, 'Gee, we have a lot of gas here and we're interested in selling LNG in the United States and we think we can bring LNG into the United States at a cost of \$2.00 and make money selling it for \$2.00. So what happens is at that point, if you have power plants in the United States or a local distribution company, you say, 'Gee, I can buy gas in Louisiana or Alaska for \$3.00 or I can buy gas from Venezuela for \$2.00. At that point, the same process that happened with the robot would happen with gas and eventually the price of gas would come down to \$2.00. With that sort of help the price is established and since if you're someone who's thinking about

producing gas and building a pipeline to bring North Slope gas to market, you have to be concerned about what the price of gas is going to be in the future. Because the price of gas is so volatile and so unknown, there is significant gas price risk facing someone who decides to build a project.

The question then becomes who will assume this gas price risk and how will they assume it. One way, and this is how if things are evolving the way I see it, I believe what will happen at some point in time is the North Slope producers decide to go ahead with this project, they will have a third party build and operate the pipeline and they will pay someone to build the pipeline and they will ship the gas, someone like Foothills, Enron, Duke or El Paso or Williams.

If the project is structured like that, the only way a pipeline company will get financing to go the project is if the producers make throughput guarantees if they guarantee they will pay to ship a certain amount of gas for a certain amount of time. That way the producers would assume the gas price risk. If the producers assume this risk and let's just decide Duke Energy, for instance, is going to build this, and they go to the bank and say we're going to build this and their bankers say to them, 'Okay, what you have to do is get a throughput agreement. It's going to be a 4 bcf/d line and we figure the tariff is going to be \$2.50. If the producers, Exxon, Gulfs and BP, say, 'No matter what, they will pay \$2.50 for 4 bcf/d for 20 years, if they guarantee to pay to do that, then we'll finance the project.'

Well, if that happens, let's say the producers commit to pay \$2.50 for 4 bcf/d for 20 years and then the price drops to \$2.00 like we talked about a few minutes ago, the producers could lose a lot of money. That's an extreme example, but if they lose a penny on 4 bcf/d for 20 years, that's \$300 million they would lose over 20 years, which is a lot of money. If they lost .50, like they have up here that would be \$15 billion.

Another way gas price might be assumed if, for instance, these pipeline companies instead of having the producers take the gas price risk, the pipeline companies come in and say, 'Okay, we'll buy the gas from the producers on the Slope for .50 or .75 or \$1.00, we'll buy it from them, we'll ship it and then we'll sell it ourselves in

Chicago. That way the pipeline companies would assume the gas price risk. Either way, someone assumes the gas price risk. If the pipeline companies assume it, then the project becomes much riskier for them. The whole lynchpin in this project is the gas price risk and who is going to assume it.

I've talked to several of the pipeline companies over the last couple of years and from what I understand them saying is they probably are not going to assume the gas price risk. That's not what they do. They build and operate pipelines and that's why I said earlier, as this project structure seems to be evolving, I believe the producers, if it's built, will probably assume the risk. But it's possible the pipeline companies could assume it, as well.

While thinking about the project and those different project structures that I presented, the question you need to ask yourself is who is assuming the gas price risk. It's also very important to understand that the gas price risk is different than the pipeline risk. If we have a project structure where if Duke is building the pipeline and the producers are assuming the gas price risk, the pipeline risk is much, much different than the risk of the producers would take. The pipeline company would certainly face risk. There's cost overrun risk, there's environmental liability contingencies, it's possible the regulators might not let them recover all their costs.

But these risks are much different than the risks assumed by someone who is going to live or die with gas price. I believe these risks are less, as well. It's important to understand, though, that someone building and operating the pipeline is going to face a whole different set of risks than a producer who is guaranteeing to pay the shipped gas, no matter what the price is.

So, if you think about this gas price risk, what companies are going to do is sit down and think about what might happen to the price of gas and even though the average price might be \$3.00, they might say, 'Well, there's a 50 percent chance prices might be \$3.00, but there might be a 40 percent chance it's \$2.00 and maybe a 10 percent chance it's \$7.00. That all averages out to \$3.00. But they'll look at that and say, 'Gee, there might be a 40 percent chance we're going to lose money

on this and loose a lot of money. So, they're going to look at what they see as their distribution of possible gas prices, look at what the loses might be, how big they might be and how frequently they might loose money and that's going to sort of shape how they view the whole riskiness of this project.

When a company is doing a feasibility study or an economic study on the viability of a project, the way they address risk is through what's called the discount rate. What the discount rate looks at is what kind of return do we have to give investors to make them feel comfortable investing money in this project. Every new project needs cash and they get that cash from investors, probably in the form of debt or the form of equity. The company, when it's getting cash for a project, is going to compete with investments from other projects. An investor can invest in a gas pipeline in Alaska or he can invest in an internet startup company in Silicon Valley. All these investments compete with each other and the investors are going to expect a certain rate of return before investing. The important thing about this is the amount of return that they expect to get for investing is going to be commensurate with the amount of risk in their project. For example, today I can buy a one-year T-bill from the federal government backed by the U.S. government. There's practically no chance that they'll default, so I can invest \$100 now and one year from now get back from the government, I think interest rates now are around 2 - 3 percent, and get \$102 or \$103 back a year from now. On the other hand, if I'm an investor and I'm trying to find an investment and I look on the internet, people looking for investors and suppose I see that some is starting up a travel agency that's going to specialize in bringing people to Afghanistan today and they're going to pay 3 percent. It cost them \$100 to bring people over, but they'll charge \$103. I'm going to look at that and say, 'You know, for the same \$100, I think it's a lot riskier investing in the Afghanistan project than buying a T-bill from the federal government. What kind of return would I expect to invest in the Afghanistan scheme? Maybe I'd want 100 percent return. If I put \$100 down, I'd expect \$200 back because the odds are so risky.

The question with this project becomes what kind of risk surrounds the price of gas. A project will generate cash flows. In this project you'll be selling gas in Chicago

and you'll make money on that, no matter what the price and you'll have costs. You'll have your tariff, you'll have operating costs, you'll have taxes to pay. What comes out of that are the net cash flows. The net cash flows go to both the debtors and the shareholders and this is the return paid to investors and this is called the cost of capital. It goes to both debtors and shareholders. It's sometimes called the weighted average cost of capital or the WAC. And the rate of return that these investors require to invest in this project is called the hurdle rate or it's also called the discount rate. In modeling projects, what a company will do is they'll have their own assessment of what kind of return given the risks that investors will expect from investing in the project and that will become the hurdle rate and if the cash flows don't generate a rate of return that exceeds that hurdle rate, they will not consider the project economic.

We might ask what happens if a project generates a rate of return less than what the shareholders expect. Let's say I expect a 15 percent rate of return in a project and I invest \$100 and it turns out it's only going to return 110 percent. What will then - if I'm still going to expect 15 percent, what that means is that the shareholder will only put \$95 down, if I'm going to get \$110 back rather than \$100. In essence, what that means is that value of the stock goes down and corporations these days are structured to make the lives of the managers very miserable if the value of the stock goes down. So, management is not going to do anything to make the value of the stock go down, which is why they need to earn a rate of return that investors expect given the risk.

Again, I'd like to point out that this discount rate, if we're addressing the project where someone like Exxon is figuring out whether or not to have someone build the project so they can sell gas and Exxon is assuming the gas price risk, the discount rate they have is going to be very different from the discount rate someone like Duke is going to have to build a project. Numbers have been thrown around that maybe there might be a 9 percent cost of capital on the pipeline and a 15 percent discount rate for the project. Those numbers are not inconsistent at all. What they are is two completely different investment decisions with different sets of risks.

Now the question is what might be the discount rate for this project. Generally, when you try to figure out the discount rate for a project, you want to figure out what the risk or discount rates are of comparable projects with similar business risks. It's not difficult these days to look at different companies just to see what their costs of capital are and see what discount rates companies use as a whole. One reason is that projects that have a discount rate, not companies. It's not hard to figure out what Exxon's cost of capital is. However, if Exxon decided to go into the airline business, they would not use the discount rate they use for exploration and development for oil and gas. They would use the discount rate the airline industry uses.

This project we're talking about here is very unique and it's difficult to find the proper analogue business risk that would be comparable. For instance, something like Enstar just has a gas distribution system in Southcentral Alaska is not an appropriate risk analogue. The exploration and development arms of these producers are really not an appropriate dialogue. One can make the case that a well-diversified exploration program is probably not that risky. If you can make a lot of money off of one well and you're drilling in five different places and you think one of them is going to come in, that's a whole different set of risks. Even other gas pipeline projects are not appropriate analogues for this project and the main reason why is simply their high transportation costs for gas from Alaska. If the Prudhoe Bay gas field were located in Indiana right now and it was 50 mile pipeline trip to Chicago, that gas would be commercialized by now, because it would be very unrisky. Alaska is geographically about the end of the line in terms of economics on gas projects. So, it's really difficult to say what the discount rate is and each company looks at it their own way. Each company will probably have a different assessment about what the discount rate is and I'll say right up front that I do not know what the proper discount rate should be for this project. I'll also say that this whole presentation has been sort of surrounded in gloom. I wanted to represent what the risks are and how bad the risk could be. Again, this is not to say that this couldn't be a splendid project and there's no advantage to companies to look at a project through more risky eyes than what it really is, because if there's an opportunity to make a lot of money, they will do that.

What I'd like to do is also talk about a couple other concepts before we get going, specifically in the model. I would like to put up the model to show those ideas.

CHAIRMAN TORGERSON asked if he was going to comment on the press releases where the producers say the gas lines are not economical, because they make 11 percent and not 15.

MR. MARKS replied:

Basically, my model if you put the producers inputs into them, I get the same outputs the producers get. As I said in July, we are certainly not specialists on what the capital costs of the project are and that's a big determinant about what the answer is. So, we really don't have an opinion on the veracity of the inputs. If the inputs the producers have represented are indeed the true inputs, I believe the outputs they have generated are indeed the outputs. When they put up 11 percent as a return, that is the return with those inputs. Again, I have no idea what the right discount rate is. That 15 percent is something the three of them put together for presentation purposes. I think each company has their own different idea on what that number is.

CHAIRMAN TORGERSON asked if they would characterize 11 percent return as a non-profitable project.

MR. MARKS replied, "There's a difference between profit and, again with my Algerian project, you could earn 3 percent and not be profitable. That does not necessarily make it feasible."

CHAIRMAN TORGERSON asked if they could explore that today, because they need to get past the news releases saying that 11 percent is not a profitable project. He knows the regulatory agencies generally give pipelines between 8 and 12 percent return as a built-in profit in their tariff. He assumed that they would like a higher number because of the risks that might be involved, but it's an uncharacteristically higher number as it relates to what our regulatory agency gives.

MR. MARKS replied:

Let me answer your second question first. Again, if the regulatory agency gives the pipeline a 9 - 12 percent rate of return, that is not inconsistent with a producer who needs 15 percent to make this project work, simply

because they're two different investment decisions. One, the return a regulator would give a pipeline company, if a regulator is going to give that return to the pipeline company based on the risk they face, the pipeline company is only going to get financing given the throughput guarantees. With those throughput guarantees, the risks the pipeline companies face, I believe, wants a lower rate of return than what the producers would want facing the commodity price risk. That's not to say that the pipeline company doesn't have any risk. They do. There's cost overruns; there's the possibility the regulators might not let them recover all their monies and there could be a gas explosion in the middle of downtown Fairbanks or Edmonton, for instance. So, building a pipeline is not riskless, but it's a less risky activity. Again, what we have here are two different projects facing two different profiles. One is a decision to build a pipeline with a throughput guarantee. The other is the decision to make that guarantee knowing you could possibly lose a lot of money if gas prices go low.

To answer your first question, again, I don't know what the discount rate is. It would be foolish for me to try and say what that is. I could probably give you a wide range, but the range would be too wide to be meaningful. What we can do with the model is look at what rate of return you get on your different inputs and how different inputs or tax regimes or prices affect the rate of return and see how close you get to a hypothetical target.

CHAIRMAN TORGERSON asked if the 11 percent rate of return includes things such as the loss of oil production, if any, if we take 4 bcf/d off the fields. Also, he wanted to know if they are including the netback of gas or is it just strictly pipe line economics.

MR. MARKS responded that he understood the 11 percent rate of return is not predicated on any oil losses. He explained with the use of his model.

REPRESENTATIVE GREEN asked what would happen to the rate of return if they set this up at \$2.50 and they find gas at \$2.00. He also wanted to know if the miscible liquids had been considered in the netback value to the state. Those liquids could be extracted before the gas goes through the pipeline and money could be made there.

MR. MARKS replied that in the example he used \$2.50 was the tariff. He didn't think it was possible to enter into real long-term gas sales contracts for significant volumes.

There is no real market out there. You can't go to the New York Mercantile Exchange and sort of hedge gas 20 years out. I don't think most power plants and local distribution companies are willing to enter into long-term contracts on the sales side.

On the second question, the liquids - this is what the producers have told me and this how I believe they have modeled it and how I've modeled it. They have told me that the composition of the residue gas would be 1080 BTUs per mcf. However, the gas distribution system in the Upper Midwest can only take 1040. For the other 40, they said the cost of extracting the liquids would offset the value of that extra 40 BTUs and it was a wash pretty much. Some people have said that the residue gas might have much higher BTUs; it's something the Department of Revenue is not an expert on. But that's the best information we have on that right now.

1:42 p.m.

REPRESENTATIVE FATE asked regarding the gas price risk if he or the producers had a constant in the formulas which says that in the future there may be a different process in establishing gas price making the gas price risk more tolerable in the computation of their return on investment.

MR. MARKS replied, "Yes, if you could lock in \$3.10 for 20 years on 4 bcf/d, that would reduce the risk of a project and the hurdle rate would be reduced as well."

REPRESENTATIVE FATE asked if there had been any constant computed on, at least, the expectation that might happen. He explained that he has heard people in the industry say that some type of pricing mechanism is needed to stabilize the price of gas. "If that's true, then the gas price risk would be leveled at some point and the computations would be more bearable relative to the return on investment."

MR. MARKS responded that he was not familiar with any proposed ideas to stabilize gas prices. Consumers want the price to be as low as possible and there would be resistance if there was any effort to put a floor on prices.

CHAIRMAN TORGERSON commented that one of the producers asked some members of Congress to entertain a floor on pricing.

If the price of gas went down to around \$1.50, then there would be some sort of royalty or dollar exchange to give them downside protection, but that hasn't materialized. I'm sure the answer to your question would be yes, it would be less risky if they would have a government guarantee. That goes without being said. I also don't think there's anybody entertaining that currently, but we don't know that either.

REPRESENTATIVE FATE responded that was why he wanted to know if it had been introduced as a variable in any modeling.

CHAIRMAN TORGERSON responded that it hadn't been introduced, but it hadn't been thrown out either. He thought it would be an upward battle.

REPRESENTATIVE DAVIES clarified that he thought part of the question was whether it was a factor in Mr. Marks' model and he heard the answer to be no.

REPRESENTATIVE OGAN asked if it was correct that a long term gas contract was for about one year.

MR. MARKS said he wasn't sure, but probably not much more than that.

REPRESENTATIVE OGAN asked if anyone had considered what the energy market would be in 2040.

MR. MARKS replied that the reason it's difficult to do that is because for years the gas price was \$2.00 until about a year and a half ago when prices shot up to \$10.00. That happened mainly because inventories were very low and last winter was the coldest winter in 100 years. "The big unknown is what happens to supply when you go from a \$2.00 well to a \$3.00 well. There's basically a continuous line at any time the price goes up."

He explained that all of a sudden the gas that cost \$2.50 - \$3.50 to produce that wasn't economic before becomes economic. No one knows what the shape of the line would be - whether a whole bunch of gas would come on line or a little bit. He thought that when prices shot up, most analysts underestimated the amount of additional gas that would come in. So, it's difficult to forecast what happens 10 years from now. "Alaska would be just about the most expensive gas on the market when it comes in."

MR. MARKS said he wanted to further explain the discount rate issue. He said that the discount rate represents the return to both

debtors and creditors. "It's a weighted cost of capital that's an average of your debt and your equity."

TAPE 01-21, SIDE B

1:55 p.m.

MR. MARKS said there might be a question of why there are no interest payments if you are incurring debt. He answered:

The way corporations do their modeling is they assume you have all equity financing with no explicit debt payments. Therefore, your cash flows go to pay off both the debt and the equity. That rate of return, the 11.1, is called the return on investment.

The alternative way to do this would have been to actually model in the debt payments. What happens then is since you're leveraging, since your rate of debt is less than your rate of equity, what you're left with then, your cash flows would be greater; but, since you paid off your debt, what you're left over with in the net cash flows goes on the equity. So your discount rate instead of being the average cost of capital, it's your average cost of equity, which is greater. But, in general, the results you have would be the same in terms of feasibility or not. But, what corporations do is model all equity with an average cost of capital as a discount rate.

The other thing I'd like to point out is from what people say, 'Why don't you just leverage the whole project? Why couldn't you borrow 100 percent at a low rate?'

What happens even if you could get 100 percent debt financing, which you couldn't, but, if you could, theoretically, what happens is that every time you incur more debt, the next set of debt you incur is more risky, because people who are incurring debt in the back of the line aren't in the back of the line. They're going to get paid off after the people in front of the line. If you incur more debt, what that does is make your cost of debt at the end of the line higher. Or, if you do have shareholders behind the debt holders, what that does is make the shareholders' investment even more risky, because there is not only more debt in line in front of them, but it's higher cost debt. The finance theory says and actually two economists want to help [indisc.] in

proving this that the weighted cost of that much capital is actually indifferent to your debt equity structure. If you try to do more debt to help a project, what happens is your cost of equity goes up and your weighted average cost of capital is unchanged.

CHAIRMAN TORGERSON asked how he treated property tax (ad valorem tax).

MR. MARKS replied that for the pipeline there was a four-year construction schedule and, "each year you start paying property tax as soon as it goes in the ground even before revenues are generated."

He said the model shows how things work and answers questions. He again read a caveat that he had read in July that says, "The following numbers do not represent what the Department of Revenue believes the economics of the project are. They simply represent what the economics would be and with the specified inputs. The Department especially claims limited expertise as to capital costs."

He explained that he just used the peak revenue year of 2015 for a project that starts in 2007 and state revenues would be \$626 million. He continued to explain his slides.

CHAIRMAN TORGERSON asked if the economic limit factor (ELF) kicked in immediately on Prudhoe Bay gas.

MR. MARKS replied that there is an ELF on Prudhoe Bay gas right now, although there are very small volumes that are sold to the refinery. The ELF gives approximately 300 tax-free barrels of oil a day or 3,000 MCF/D of gas.

If oil and gas come out of the same well, which they will in this case, the tax-free treatment is pro-rated between the oil and gas. So, with a gas sale, basically you have relatively less tax-free oil and so the oil ELF goes up.

CHAIRMAN TORGERSON asked if he was predicting there would be zero loss of oil after they depressurize the field. He also asked what they should use for a fair comparison of projects, like LNG Al-Can route and the GTL project. He asked, "Which one makes the producers more money and which one is best for the State of Alaska?"

MR. MARKS replied no to the first question. He said further:

If the producers are going to do the project, whether it's GTLs, LNG or a pipeline through Canada, there's no project that they will do if it's not economic to them. I don't see the state doing this project. If they're doing it, it has to make sense to them... So, the first thing you have to look at is the rate of return. Different projects, again, are going to face different risks and so each project will not have the same discount rate.

CHAIRMAN TORGERSON asked how he got his rate of return.

MR. MARKS replied that the rate of return was the internal rate of return from [indisc.]. "The reason it dropped from 11.11 to 10.77 is because I just put in the oil losses now.

CHAIRMAN TORGERSON asked if he compares three categories, the well-head, the total state revenues and the rate of return, between the different projects would they have a good feel for which one pays the state most and pays the producers the most.

MR. MARKS said that was fair, but to keep in mind that different projects have different discount rates.

2:06 p.m.

REPRESENTATIVE GREEN said the affects the loss of oil would have bring to mind the questions:

Will there be and when will there be a loss of oil? Is it going to be immediate or is it going to be down the road a ways. If it's down the road a ways, is the value of the lost oil discounted at the same rate that we're discounting these other things...

He also asked if the items in the model could be changed one at a time to find the sensitivity.

MR. MARKS replied, "Absolutely..."

He continued to explain that their oil loss model uses information in a document from ARCO's oil loss announcements during royalty litigation in 1992 (with their permission). The Department started modeling the commercialization of North Slope gas around 1996. ARCO said that it would be okay to publicly show the oil losses for this exercise, but that he couldn't show the actual model, itself. He has been told by oil companies now that thinking has changed and what they thought in 1992 for oil losses was too high, but they haven't talked about what they think quantitatively the losses are.

His model shows the oil losses as a function of when the gas sales start, how fast they ramp up, and how much gas is sold. It's basically a total amount of gas that has been depleted from the reservoir over time and that's why the losses start out small and grow.

CHAIRMAN TORGERSON asked why there was the NGL loss.

MR. MARKS replied that was because the gas was used to pressurize recovery in the reservoir for the NGLs as well as the oil.

CHAIRMAN TORGERSON said if we're producing more gas, we should have more NGLs. He continued to discuss figures in the model with Mr. Marks.

MR. MARKS said that the big utilities in Asia have traditionally structured their pricing with formulas tied to crude oil prices, which had nothing to do with the cost of producing the commodity, but that was changing.

Going forward, the whole gas purchase structure in Asia is being decentralized on a much more profit-oriented basis where individual power plants and individual gas distribution companies are going to be buying their gas. It's going to be deregulated. It's going to be much more competitive and I believe a gas structure in Asia will tend towards a structure where a purchase price will have something to do with the cost to produce it.

What that does is put Alaska at a tremendous disadvantage, because there's a tremendous amount of gas in competing jurisdictions in the Mid-East, Qatar, Abudabi (ph), Asia, Malaysia, Australia, Indonesia, Sakhalin Island and basically that gas is sitting at tidewater and doesn't have to bear the burden of a pipeline.

Pretty much you can liquefy gas for the same cost anywhere, ship it for the same cost anywhere. You can say that Alaska might have some distance advantage over the Mid-East. The cost of shipping LNG over the last two years has come down drastically, so even big differences in shipping distances are not that important. Furthermore, what we can tell pretty much is all of Asia's LNG contracting needs, at least to the end of this decade, have been met. Alaska, to bring the cost down, would have to sell a tremendous amount of LNG, which is

far more than anyone is going to be looking for, at least in this decade.

He said using this structure, you go for oil price risk instead of gas price risk as the risk factor. He thought over time, the price of gas in Asia would represent what the cost to get it there will be.

CHAIRMAN TORGERSON asked if he had included the Port Authority numbers in any models.

MR. MARKS replied that they are selling volumes that aren't even discovered, yet. Their model uses 6 bcf/d for 30 years, which is 65 tcf, almost twice as much as has been discovered.

CHAIRMAN TORGERSON asked him about the GTLs.

He commented on GTLs, that once the product is made on the North Slope, you would deliver it to the oil pipeline. So, there isn't the problem of scale that you would have with LNG or the Canadian pipeline. You don't need a huge project to bring the cost down. He said:

The other notable thing about gas to liquids is the big problem with Alaska gas that geographically, it's pretty much at the end of the line. In these LNG and Canadian gas projects the transportation costs just chew up the value. With oil, maybe 25 percent of the value gets eaten up by transportation; with gas it's about 90 percent. With a GTL project using the trans Alaska oil pipeline, the variable costs of using the oil pipeline are fairly low, in the order of maybe 20, 30 or 40 cents per barrel. Once you get the gas to tidewater in Valdez, you can compete with other projects in the world. You get on equal footing with other competing projects a lot easier since you have the oil pipeline to work with and the costs are low. Again, you don't have the transportation costs eating up the value like you do on the other one.

What we modeled was a three-train project - each train producing 100,000 barrels per day of this high value clean gas product, part diesel and naptha. The price Exxon was looking at two years ago was about \$35,000 per barrel capital costs at peak. I've reduced that to \$30,000. If you read the literature, people are even thinking about costs as low as 20,000 in projects going on in Africa now. People think it would cost more to build something in the Arctic. They put factors up to 50

percent or so on that. So, I've used \$30,000 here. There's talk about Shell and [indisc.] building up in Nigeria now for \$20,000. So, what that amounts to with 100,000 barrels per day peak, a total CAPEX of \$3 billion per train.

What you're getting is about .11 barrels of the product per thousand BTUs. These are the price premiums in the market today you can get for clean car diesel on the West Coast for naphtha. In Asia, you get about 30 percent over crude oil for car diesel and 15 percent over crude oil for naphtha. Again, what you're doing is playing the oil price risk roller coaster with a project like that.

Pretty much you have the same tax structure that we had in the other projects. Looking at the cash flows...

CHAIRMAN TORGERSON asked how many bcf/d 100,000 barrels was or was it all in BTUs.

MR. MARKS 872,000 MCF going in to produce 100,000 barrels of the product.

CHAIRMAN TORGERSON asked what the rate of return was.

MR. MARKS replied that it was 8.87 percent.

REPRESENTATIVE FATE asked what the equivalent was in bcf/d.

MR. MARKS replied, "Remember this is only a 2.6 bcf/d, so these are no comparables in terms of volumes."

CHAIRMAN TORGERSON asked if it is safe to say that the State makes more money on GTLs in the pipeline.

MR. MARKS replied:

In general I would say, with all things equal, generally a product that's tied to oil would probably be more profitable than one kind of gas, for no other reason than you have a cartel propping up the price on oil-based products. So, if indeed the price is tied to oil, that will affect the bottom line. It's just what the price of these commodities turns out to be.

REPRESENTATIVE GREEN asked, when he did this model, if he reduced the tariff on the oil, because there is more throughput.

MR. MARKS said that was right.

REPRESENTATIVE GREEN asked if other considerations were involved in his model, for instance if there were no new discoveries and they could still have GTLs coming through the pipeline, keeping it viable.

MR. MARKS showed him a chart of oil volumes and said:

Here's an example of what tariff reductions are as a result of the GTL volumes. It starts at 12 percent, but after the late years of the North Slope when oil volumes are low, the tariff reductions get sizeable. Who knows what the volumes are going to be, but just with the inputs I have here, you have a \$4 per barrel reduction in the year 2038. I'm sure it won't turn out that way, but at least it's being considered.

2:40 p.m.

REPRESENTATIVE OGAN asked when he figured the royalties to the state, whether he figured on well-head price on gas or the royalty based on a barrel by crude at processing.

MR. MARKS replied that he figured it based on gas:

It's 12.5 percent regardless of whether it's oil or gas, but what you have is gas being produced. You don't have the well-head, which is the point of production when they royalty is assessed and going through this processing activity. Your closest value at the end is just netted back and that total gross value is divided among the total units of gas going in.

REPRESENTATIVE OGAN asked if he was saying it would basically be awash after they [indisc.] the 40 percent of gas.

MR. MARKS replied:

It doesn't matter, you could take the gas and you could turn it into chairs and sell the chairs; and you have gross value just divided among the amount of gas going in. You recognize that it's sold as an oil based product and higher value, but in terms of administering the royalty, it's just divided among the gas units going in.

TAPE 01-23, SIDE A

REPRESENTATIVE GREEN asked, regarding the conversion from gas to liquid, whether Mr. Marks was using conversion estimates back in the late 90s or current ones. He thought that ratio is becoming more and more favorable.

MR. MARKS said he was using what Exxon's technology was in 1999.

CHAIRMAN TORGERSON thanked Mr. Marks for his testimony and announced a short break.

2:43 p.m. - 3:00 p.m.- BREAK
[END OF TAPE]

[THE FOLLOWING TESTIMONY WAS NOT RECORDED]

DEPARTMENT OF REVENUE DEPUTY COMMISSIONER LARRY PERSILY said that Cambridge Energy Research Associates (CERA) consultants would present an update on their vision of current and short-term gas prices in North America.

MR. ED SMALL, CERA, said that one of the most obvious things he sees is overall economic weakness, but that they expect to see some recovery in the mid part of next year and certainly in the second half. Until then, the economic weakness translates into soft demand. Demand is down in all sectors, especially steel and chemical, but these are the areas in which they expect to see recoveries in the third quarter. Demand losses next year due to a return to normal hydrogenation will offset some of the return of demand that was part of the fuel switching that occurred in the first half of this year. He clarified, "In other words, we are going to have offsetting factors next year to a certain extent..."

MR. SMALL told members that conservation has been a big factor, especially in the residential, but also in the commercial sectors. This is most apparent in the West where the local distribution company programs for conservation and the higher prices have had a big impact. He advised, "In fact, in the West we expect demand to be down between 1.3 and 1.5 bcf/d through this winter and on average next year."

MR. SMALL noted that CERA expects to see some demand strength in the area of power generation. There is a question as to whether the long-term demand for power generation has been impacted, which CERA believes has happened. Growth has not been as strong as had been anticipated. He stated, "Obviously, if you push demand down, it takes longer to get back to that point and then to grow to a lower point than where you had originally expected it to be."

MR. SMALL said CERA has seen roughly 55 gigawatts of new power generation this year, almost all gas fired, and another 95 gigawatts of proposed and under-construction generation for 2002. However, about 65 gigawatts will be built. In 2003, they are showing a larger number of proposed and under-construction projects of 110 gigawatts, but expect that number to get closer to 60. Certainly, in 2002 and 2003, there is power generation that will demand natural gas. The bigger question is how extensive will be the operation of those facilities.

[END OF UNRECORDED TESTIMONY]

TAPE 01-24, SIDE A

3:05 p.m.

MR. SMALL informed members if the economy does not recover as expected, then those facilities will not be operating at full capacity and will not provide demand strength.

He said the overall picture for the Lower 48 for 2002 is demand growth of about 1.6 bcf/d from both power and industrial consumption. Again, most of the growth is expected to occur during the last half of the year. In Canada, a similar demand decline is expected to couple with a slower recovery. This is due to the fact that the Canadian economy lags the Lower 48 and because there is less power generation built there to provide the demand growth for the up coming year.

MR. SMALL said that because the injection season in the U.S. has ended with almost 3.1 trillion cubic feet (tcf) or close to the absolute storage capacity of 3.2 tcf, storage in the Lower 48 will be a big major factor this winter and through 2002. There is a net inventory increase of 733 tcf this year over last. An obvious impact of this increase is to reduce winter prices. It will take an extremely cold winter to draw the gas reserves down a significant amount or to the level they were at the end of last winter. Additionally, they estimate that it will take a decrease of about 2 bcf/d to refill the storage reserves to the current level by the end of the 2002 injection season.

The situation in Canada is similar to the Lower 48 with record high storage levels in eastern Canada and near record levels in the west. Here too, prices will be depressed.

Drilling in particular has been affected by the lower prices. They estimate growth of about 400 million per day for 2001 and a decline of about 500 million per day in 2002 due to the decline in drilling they have seen over the last three months. Unless prices rise to a

sustainable \$3.00 level, they do not believe drilling will recover to the early 2001 level until later in 2002. However, the 500 million decline is more than offset by the increased storage levels outlined earlier.

MR. SMALL explained that the Deep Water Gulf and the Rockies are still growth areas while declines are being experienced in the more mature fields, the newer fields that are more expensive from a production perspective and the Shallow Shelf area in Mexico. Later in 2002 there should be some recovery in drilling levels and will provide a better picture of supply for 2003.

Canada differs in that drilling declines are typical in the fall and increase in the winter for remote and exploratory locations. Although it might be expected that remote and exploratory drilling would decline with lower prices, all of the deep grades were fully contracted last year for two and three year terms. Producers will pay for the drilling rigs whether they use them or not, but the odds are that they will use them. With the forgoing in mind, prices should decline but not as much as in the Lower 48. Next summer should not see a large drop because most of the drilling will be shallow and more than economical at today's prices.

Because of the decline in Canadian demand and the lower storage injection requirements for 2002, most of the anticipated 850-million supply-growth will be exported to the Lower 48. It's expected that the decline in Lower 48 supply will be more than offset by Canadian growth next year.

MR. SMALL said the combination of demand decline and high storage levels and increase in Canadian imports indicate continued soft prices. They have declined from \$3.25 to \$2.75 and they expect them to stay that way through the winter. With oil prices being lower and gas prices close to \$3.00, fuel switching becomes more attractive. Therefore, oil will probably provide a ceiling for gas prices through the winter.

Spring will bring even lower prices because there is a typical softening of demand at that time and the economy probably won't have recovered. This coupled with lower storage injection requirements for next year will probably see prices pushed to \$2.25 through early summer. If there is an economic recovery and the typical summer demand for power generation occurs, then they expect to see prices strengthen through the summer. A typical winter season in conjunction with a Lower 48 supply decline and the expected economic recovery should see prices back up to the \$3.00 to \$3.25 level for the winter period. This scenario should bring back fairly robust drilling activity in 2003.

The price of Henry Hub is expected to average \$2.71 in 2002 but for the longer term there are adequate drivers to keep prices above \$2.00. Of equal importance, there are drivers that will keep prices from staying much above \$3.00 for the long term. Although there will be some price volatility, they expect prices to range between \$2.50 and \$3.50 between now and 2005.

CHAIRMAN TORGERSON said the last update outlined several opportunities for Alaska gas to enter the market in 2008 and 2010. He asked for the current projection for opportunities for Alaska gas.

MR. SMALL thought the window of opportunity has shifted by about one year. When demand decreases, it takes awhile to get back to previous levels before you can grow beyond that point. Current expectations are that there is probably opportunity for frontier gas in the 2009 to 2010 time frame. Then in 2012 to 2014 there should be need for additional gas. It's the same issue of where the frontier gas will come from, but this is where the opportunity may lie for Alaska and Arctic gas.

CHAIRMAN TORGERSON then wanted to know how they were plugging LNG imports into their thought process.

MR. SMALL replied they were seeing the existing four LNG facilities in the Lower 48 all come back on stream. Three are active now and the last will come on stream next year. They expect those facilities to expand in 2003 to 2005. They also expect to see Greenfield LNG facilities built in the last half of this decade. They do see that new facilities will be built, but don't know how many.

Because of the September 11 attack, they are looking at the global economy. The fragile nature of the Middle East could impact both oil exports and LNG development from that region. This could have an impact on the entire global LNG balance in the latter part of this decade, but LNG is seen as being an integral part of new supply in the Lower 48 in that time frame.

CHAIRMAN TORGERSON commented that he sees LNG imports rather than other frontier gas as Alaska's biggest competition.

MR. SMALL responded that their definition of frontier gas is Arctic gas, which is both Alaska and Mackenzie, off shore East Canada and LNG. Of those three, they see growth in LNG imports and offshore East Canada. The questions now are what are the competitive forces of LNG? Is Arctic gas able to compete and if so how will it

compete?

CHAIRMAN TORGERSON then asked whether CERA tracks the petro-chemical industry.

MR. SMALL said it does.

CHAIRMAN TORGERSON asked if there is a market for polyethylene and the anticipated delivery date.

MR. SMALL said there is always the opportunity for a market, but here too the question of how the petro-chemical industry in Alaska would compete globally must be addressed. Due to the cost of transportation from the North Slope to tide water, Alaska would be at a disadvantage because there are cheaper sources of stranded gas globally. He was not sure about the window of opportunity, but doubted it would be before the latter part of this decade.

CHAIRMAN TORGERSON then asked whether they were tracking the fourteen countries that are starting GASPEC, which is patterned after OPEC and would control world gas prices. He first heard of this organization during his last trip to Washington D.C.

MR. SMALL replied that was outside his area of expertise, but that he would have someone from CERA investigate. He added that the success of such an organization would be more tenuous than OPEC because it's a smaller part of a global market and transportation costs would be more difficult to control. This said, it's not beyond the realm of possibility.

CHAIRMAN TORGERSON said because energy security is such a large issue, it's of greater concern that they are trying to do this than the possibility that they will be successful.

REPRESENTATIVE DAVIES asked what major risk factors CERA is looking at in terms of economic recovery in the next six months and if the recovery doesn't occur, what price sensitivities CERA is forecasting.

3:20 p.m.

MR. SMALL said consumer confidence and employment are major signposts and the current stock market malaise figures heavily in consumer confidence. In general, companies [are] starting to report positive earnings even though they aren't the earnings anticipated a year ago, which is a positive sign. Consumer confidence and spending are critical in terms of bringing back demand in steel and petrochemical sectors.

CERA does have a scenario that predicts recession lasting through 2004 and it shows prices of between \$2.50 and \$3.00 through that period. In the context of Arctic gas, the window of opportunity is pushed well beyond 2010, possibly to 2015.

CHAIRMAN TORGERSON thanked Mr. Small for his testimony and announced the pipeline ownership study would be discussed next.

MR. LARRY PERSILY explained part of his testimony would duplicate part of Roger Marks' testimony because risk is key in determining whether the state should become an owner or financier of the project. He then gave the following report:

Pursuant to your instructions in Senate Bill 158, the Department of Revenue and its consultants have been working for the past few months compiling a report for the legislature on the merits of state or public ownership and/or financing of a natural gas project. In addition to consulting with experts on debt financing and project financing, we've interviewed more than 30 individuals plus representatives from 10 companies in the oil and gas industry - not just the producers but the large and not-so-large players in the pipeline business. Our list of interviews also has included many Alaskans involved in banking, the oil and gas industry, legislators and business leaders.

Certainly, the Alaskans we interviewed all would like to see a gas line built to create jobs in Alaska, to generate tax revenues to pay for public services, and to promote the economic activity that would come with such a large construction project. Obviously, we don't need a study to tell us that. What we're looking at are the risks to the state - and the benefits - of becoming a member of any partnership that builds and operates the line. And we're looking at how - and what would happen - if the state wanted to raise the hundreds of millions or billions of dollars needed to buy into the project.

Here are some of the questions we're trying to answer:

What if we sign on as a partner and there are serious cost overruns during construction? What if the partners are all required to pay in more money to cover those overruns? Will the state be able to come up with the money? It's always possible that federal regulators - FERC - may not allow the pipeline owners to recover 100% of the cost of any overruns. Is it smart to commit to some possible unknown expense in the

future, given that the state already is running short of cash? Even worse, what if some unforeseen event blocks or stalls completion of the line? Granted, the risk is small judged by the odds of it happening, but the risk does exist. We need to consider that the Constitutional Budget Reserve Fund is at \$2.8 billion and falling. We're looking at less than \$2.5 billion by the end of the fiscal year next June 30, and perhaps as low as \$1.5 billion one year later. The Permanent Fund Earnings Reserve Account, which had \$6.1 billion just a couple of years ago, is around \$2.7 billion this week after a bad year in stocks while still continuing to pay full dividends.

After the pipeline is built and the gas is flowing, there are still risks to the owners of the line and/or the owners of the gas. This is the cost of getting the gas to market, and whether the market will be willing to pay that cost in full year after year. Whereas the cost of moving North Slope oil to market is about 25% of the sales price at the refinery, the cost of moving gas to Chicago is closer to 80%. There just isn't that much margin left after paying the transportation tariff on a gas pipeline. A small swing in the market price for gas could mean a loss for whoever is carrying the risk. That's the central issue in all this. Who takes the risk that, in any given year, the price for gas in Chicago will not be sufficient to cover the tariff of moving it from Alaska to the Midwest, plus the cost of production, taxes and a profit? Generally, gas producers (the shippers) take this risk, but in the case of the Alaska project, because of its size, we expect there may be some risk sharing between the producers and pipeline owners. Certainly, if the producers agree to take all of the price risk, pipeline ownership could be a good investment for the state, consistent with Permanent Fund earnings on a risk-adjusted basis.

As I said, we expect that the three North Slope producers are hesitant to take all the risk - the risk of construction cost overruns if they build the pipeline and the larger risk that some years the market will not pay enough to cover the \$2 plus pipeline tariff plus other costs. Even if you lose just a dime on every thousand cubic of gas in a 4 billion cubic foot per day line, that loss could total \$400,000 a day, or almost \$150 million over a full year.

Of course, pipeline companies would be happy to build the line if producers agree to take all the risk, signing "ship-or-pay contracts," committing to pay the pipeline companies a fixed tariff regardless of the market price.

The decision whether to build the gasline, and who will build it, will come down to a deal over who is willing to share how much of the price risk.

Also thinking about risk, does it make sense for the state, which is already heavily dependent on oil revenues, to take a large investment in gas? Should we instead diversify from the oil and gas sector in generating state revenues?

It's one thing for a corporation to take a risk that could mean no dividends to shareholders if it goes sour one year. It's another thing for a state to take a risk with providing essential public services. Remember, we expect the Budget Reserve to hit empty in 2005, and the Permanent Fund earnings reserve has taken a major hit in the stock market.

Would the state be better off letting someone else take all the risk, and we then would do what we do best - and that is tax the profits?

Putting aside the risk issues, we next will have to answer the questions: What can the state bring to table as a partner in the project? Would state government involvement actually slow down a commercial operation? Does the state gain anything worthwhile for taking a share of the risk?

In our research and analysis, and our interviews with producers and pipeline companies, here is what we've learned:

Project sponsors - be they gas producers or pipeline companies - already have access to all the capital they need if they decide to build the project. State involvement just isn't needed for financing.

State investment doesn't do anything to lessen the financial risks for the other partners, so they don't gain anything from having us as a partner. The marketplace dictates project risk, and the state has no control over that.

Alaska already has a significant future income risk in the energy sector. Why would people want to compound the situation by making a large, discretionary investment in energy? An executive said by investing in a project that will not be cash-flow positive for a number of years, the state is depriving its citizens of the present-income value of its limited investment capital.

Although some may believe the state would gain a "seat at the table" as a partner in the pipeline, we wouldn't really gain any more information than we would be able to get on our own - through the Federal Energy Regulatory Commission, which would regulate pipeline tariffs, and through the state's own regulatory agencies. We couldn't use confidential, proprietary information from the table against companies in tax cases, and we couldn't use the information to out-manuever our partners in gas marketing opportunities.

As a partner, the state might face the political temptation to meddle in the business operation.

As one pipeline company said, the state would need to recognize that board discussions are open, frank and confidential. Decisions would need to be made for the best interest of the project, not necessarily the state. Decisions of and debate of the joint venture board cannot be shared publicly. This might not be compatible with state ownership.

Another executive explained that a seat at the table is a fine political concept, but the state's participation likely will hurt the viability of the project. The decision-making process of the state on the joint venture governing board likely will be influenced by political, not business, concerns and will be slow. Management of any joint venture is, by its very nature, very difficult. A governmental entity will only increase the complexity because governments are not accustomed to making quick, unemotional decisions.

The state already can regulate much of the operations of the line through right-of-way permits and regulatory oversight functions.

Being a partner could put the state into a conflict of interest situation. What would be more important to the state - running the line at maximum profit, or following new, perhaps costly environmental or safety or regulatory rules?

A final question is, should the state own a piece of a project in a foreign country?

If the state decided to go ahead and take the risk as a partner in the project, where would we get our share of the cash to buy into the Gasline?

Under existing federal law, the state or any other public entity could not issue tax-exempt debt except for a very small portion of the project. Only those facilities available for public use, such as a dock or highway or distribution hub available for all users, would qualify under federal law for tax-exempt financing. Everything else would be financed with taxable bonds.

Federal law does allow the state to issue a limited amount of tax-exempt debt for private-activity uses, but that currently is set at \$187 million a year, and is used in full by AHFC, AIDEA, the student loan corporation and others.

Congress could change the tax laws as it has for other projects, but without a change in federal law, tax-free bonds do not appear to be possible for raising the state's share of buying into the project. The same restriction likely would apply to a port authority or other, similar public corporation or agency.

Another issue is that we don't believe the state could issue general obligation bonds for this project. State ownership in the Gasline likely would fail to meet the required standard of a capital improvement or public improvement.

But if we could issue GO bonds for our investment in the pipeline - assuming the state wants to preserve its existing AA credit rating - a conservative estimate of our debt capacity would allow us to commit no more than 5% to 8% of our general fund revenue stream to debt payments. That's been the state's target for years, and it has served us well in maintaining a good credit limit. At a limit of 8% of general fund revenue, the state could issue somewhere around \$200 million to \$300 million in 10- or 15-year bonds over the next six years. Those numbers are based on the state's current fiscal situation, meaning the budget gap. If the state were to adopt new revenue sources, be it taxes or using some Permanent Fund earnings, we would have the capacity to issue significantly more debt by the end of the decade.

But also keep in mind that any estimate of Alaska's bonding capacity today does not yet account for bonds under consideration, such as the new DEC seafood lab, deferred maintenance on public buildings, schools and harbors. The Gasline would have to compete with all those other needs for GO debt.

The state or another public entity could issue revenue bonds,

pledging the future revenue from the Gasline to pay back the debt. But there are some problems here, too.

One, if the state backed the revenue bonds with a moral obligation, we'd have to use tax money or Permanent Fund earnings if gas line revenues were insufficient in any given year to cover debt service. If we sold the bonds based solely on the gas line revenue - with no other assets or income at risk - we'd probably have to pay much higher interest rates to borrow that money. Much higher than what the producers or pipeline companies would have to pay on their own debt.

Two, the state would be at risk if the gas flow or revenue stream were disrupted. We would no longer have the revenue to pay back the debt.

Three, even with pledging future gas line revenues, the state still couldn't match the excellent credit rating and lower interest rates that companies such as Exxon and BP could get. For example, looking at taxable bonds, the difference between Exxon's AAA rating and the state's AA rating - if we could maintain that grade - would be \$20 million in interest payments in the first year on a \$10 billion debt.

Four, we don't believe 100% project financing is feasible for this project for any governmental entity. Regardless of what the port authority is told by its lawyers and financial advisers, our research indicates it is close to impossible to obtain 100% debt financing for a project operated by a government entity with no experience in such projects and with just a single source of revenue to repay the debt. The answer might be different if the producers were willing to absolutely guarantee a high enough price for a high enough volume of gas for a long enough period of time to pay back the debt, but if they're going to take all the risk, why would they want to work through the state or a port authority when they could issue their own debt at a lower cost?

One other comment I want to make is that back in 1978 the pipeline companies were encouraging state investment in the project. Federal law back then prohibited oil and gas producers from owning a pipeline, so that source of funding was not available. The project was estimated to cost \$20 billion or more, and that was more than the pipeline companies could afford. Simply put, they needed the state. But the law has changed and the producers can own the line. And the financial strength of many of the companies involved has grown. And the cost is much lower. No one really needs us

any more.

These are our preliminary findings and thoughts to date, and could change as we continue with our work. Our final report will be delivered in January, and we would be happy to give you an update next month at your convenience.

3:39 p.m.

CHAIRMAN TORGERSON commented he hoped the department and its consultants would be able to work through the concerns and list the pros and cons for each of the points set forth.

There are additional suggestions in SB 158 that he would like to have each addressed individually. One was the feasibility of forming a public corporation and another was whether forming a port authority is a good idea or not.

MR. PERSILY said they would address the other questions and list the pros and cons for each and look for solutions to problems.

CHAIRMAN TORGERSON pointed out this is the third report of its kind and none have recommended state ownership so it's doubtful that there would be a change but some of their questions are different.

The comments about "seat at the table" were interesting but most of the information is confidential not public. It is available to the Department of Revenue of course but he has not been able to get much tariff information on the oil pipeline due to the confidentiality requirement. Tariff fluctuation of one half of a percent could be a determinant. The shroud of confidentiality is certainly not good for those making decisions because they must simply accept figures given to them.

MR. PERSILY asked if this meant they needed to consider making as small an investment as possible in order to gain access to that confidential information.

CHAIRMAN TORGERSON said that has been suggested and perhaps the information wouldn't be available even then but he would like to know. He does look forward to state legislation in the upcoming session to deal with some of the shroud.

3:45 p.m.

REPRESENTATIVE GREEN said there was a strong difference of opinion on the tariffs on the oil pipeline and subsequent litigation. For a more open policy there would need to be some degree of ownership.

If this is a good idea and the accessibility question is not adequately addressed, then by owning 12.5 percent the State might be able to allow access. On the con side, the State usually does not compete with free enterprise.

MR. PERSILY said the law does not allow owners of a project to give any preference to themselves for capacity. If the State wants capacity, regardless of whether it's an owner or partner in the pipeline, it would have to bid for capacity during open season like everyone else. Then it is committed to filling that capacity just like anyone else. Therefore, 12.5 percent ownership could not be translated to 12.5 percent capacity of a regulated pipeline.

CHAIRMAN TORGERSON pointed out they have discussed owning a certain capacity in a certain location if they wanted to do a large volume user somewhere along the route.

MR. PERSILY replied that if the State was a contract carrier, it would have to bid for capacity, it would not get it by owning 12.5 percent. You could own it without having capacity or you could pay the capacity like any other shipper without owning it. It is his understanding that for a contract carrier, capacity does not come with ownership.

CHAIRMAN TORGERSON thought that was correct for going from Alaska to Alberta but a question arises as capacity is added interstate.

REPRESENTATIVE DAVIES asked whether shared risk wasn't a valuable element.

MR. PERSILY thought it might be but if there were so much risk that it's desirable to dilute it, then the project probably wouldn't be built. If they feel there is small enough risk to go ahead and build then they might not want to share the wealth by taking in other partners.

The State might bring more to the table without taking on risk by working federal angles, such as accelerated depreciation. Because producers have talked about fiscal certainty, the State could certainly bring that to the table without being a partner

3:50 p.m.

Tape 01-24, SIDE B

REPRESENTATIVE DAVIES then asked whether the discount rate would be affected to the extent that the State shares risk and whether an investing company would be looking at this.

MR. PERSILY said that is a question for Roger Marks but the company would be putting less of its own money at risk.

REPRESENTATIVE DAVIES said transportation costs are of concern with the oil pipeline with companies that both transport and distribute. Some suggest that if the State had some ownership, it could insulate itself from that concern because it would benefit in the same way. He asked if the State could shield itself if it had some ownership and, if so, what percentage ownership would be optimal.

MR. PERSILY replied that if the State were absorbing 100 percent of the transportation tariffs, the only way to offset that would be to get 100 percent of the profit on the other end owning the entire line. If the State took all the risk at the wellhead out but only got 12.5 percent of the pipeline profits because it owned just 12.5 percent, it would come up short.

The gas line will be different than the oil line because it will be regulated at a rate of return. No one foresees the problems that were encountered with the oil pipeline in terms of cost shifting.

All Alaskans interviewed wanted the State to have a seat at the table for the gas line because they thought there would be valuable information available and they lacked that information on the oil line and likely were cheated on the oil tariffs.

CHAIRMAN TORGERSON said there were also discussions about the State owning the oil line 25 years ago and it wouldn't have been a bad investment. He agreed that he wants a seat at the table but isn't sure what he will learn. Older studies say that the state shouldn't be an owner in the line, but that we should issue senior debt and he hoped their report would look at that concept.

He remarked:

The barrier to the pipeline is how to manage risk - whether it be fiscal [indisc.] from the state, whether it be environmental laws or whatever it is. Back to what Representative Davies said, if you have more folks to share that risk, your exposure is less. Not that that makes it a good deal, because I agree with you on that statement, but at some point in time, the report said that we should consider not owning the line, but helping control the risk by issuing senior debt if they had cost overruns.

CHAIRMAN TORGERSON said the oil pipeline started out costing \$700

million and ended up being \$10 billion. "They had a little bit of cost overrun on the pipeline, so it was a very serious problem on how to manage that cost overrun."

MR. PERSILY said that taking senior debt on this project might be an attractive option for the state.

CHAIRMAN TORGERSON commented, "Of course, that was before Exxon was making \$5 billion per quarter. So, they can pay for this in one year's profit."

MR. PERSILY said, "They owe us some of that."

CHAIRMAN TORGERSON said, "About all of that."

REPRESENTATIVE GREEN said the state has been historically getting about 8 percent.

MR. PERSILY responded that 8.25 percent is the long-term assumption for the Permanent Fund.

REPRESENTATIVE GREEN asked, "Since the state is obviously satisfied with a much lower rate of return, would that make a difference in making an investment in a portion of the pipeline?"

MR. PERSILY said it might, but the Permanent Fund Corporation's 8.25 percent long-term [indisc.] is much lower risk than the assessed base they are working on. The state looks at how this senior debt would compare to other debt the state is investing in as part of its portfolio. He noted, "It might be very attractive."

CHAIRMAN TORGERSON asked if they decide to do a state ownership, whether they are considering going through the Alaska Industrial Development & Export Authority (AIDEA).

MR. PERSILY replied that they are looking at the difference in tax laws. He explained:

If the state owned shares in a corporation, which we do through current [indisc.] other investments, we don't have to pay any federal income tax, but what if there were limited liability company or a limited partnership in those projects, would any of those projects flow to the state? Would they put us in a taxable situation that's any different if the state owns it or if we set up a corporation similar to what we do with the Northern Tobacco Securities Corporation, which is a dummy corporation to shield the state if there's any default on

the tobacco bonds. But it really is a state corporation. So, we'll be looking at those, too.

REPRESENTATIVE DAVIES asked if they were considering possible conflict of interest. The Alaska Railroad has the citizens' interest in environmental regulation handled by one state agency and the citizens' interest in efficient economic operation by another.

MR. PERSILY replied that was certainly possible, particularly after all the spills on the Railroad last year. The conflict issue is not an insurmountable one, such as federal laws that would prohibit tax exempt financing. The conflict is more of a public policy question to the legislature and to the governor. Is this such a concern that you don't walk into it or do you walk into it knowing the issues, knowing what you need to avoid with your eyes open?

CHAIRMAN TORGERSON thanked Mr. Persily for his testimony and asked if he could have a draft of his responses ready by the end of December or early January before he released the consultants.

MR. PERSILY agreed to do that.

4:02 p.m.

MR. BILL BRITT, Director, Pipeline Coordinator, reported that in January, the Governor signed Administrative Order 187 that set up the Gas Pipeline Office as a division of DNR and he assumed the directorship of that. In July, he testified before the committee and gave a summary of the proposals that were in play. None of that has really changed since that time. He told members:

Right now we are working with Foothills and the producer consortiums. With Foothills we are working on advancing their right-of-way applications. With the producers, it continues to be permitting for various aspects of their feasibility studies. Just as an aside, I am frequently asked about Yukon Pacific's conditional right-of-way and that's being administered in the Joint Pipeline Office as an existing lease. Should they choose to prove that up to an unconditional lease or otherwise move that forward aggressively, it might [indisc.] to hear, but for the time being it's in the Joint Pipeline Office.

Again, by way of background, we were provided with general funding by LBA in July. We signed reimbursement memoranda of understanding with Foothills in July and with the producers in August. Our funding is through the

ending of this calendar year and we are setting up discussion right now with our three funding sources for November and early December to discuss what happens in the second half of this year.

Staff at this point consists of nine folks. Four designated agencies have four additional people who have been hired and will report this month. The three remaining designated agencies are presently recruiting [indisc.] and that recruiting in some instances is proving to be fairly challenging. We have two assistant attorney generals assigned to assist us. We have liaisons from BLM and MMS. We are performing work with six other divisions of DNR - Mining, Land and Water for land title work, Land Records Information for land status work, the Office of History and Archaeology for permitting support, DGGs for research, Oil and Gas for technical assistance and the State Pipeline Coordinator's Office continues to provide us with administrative support. We're presently in the Atwood Building. We'll be moving toward the end of the year. The letter of interest has gone out, there have been I think around a half dozen expressions of interest and formal proposals will be received and evaluated next week.

The work planning with Foothills is probably the most intense effort that we have ongoing. In July, I received from Foothills a reconstituted application, which was a resubmittal of those aspects of the tons of papers we received previously that Foothills considered to be applicable to the existing project and applications. We've met and identified high priority items. Some of those are ongoing. A larger discussion is over the process itself that will take place and those things are now occurring about every other week in order to try and pin this stuff down and keep it moving.

Doing ancillary stuff, we're working on our directory, numbers and types of permits, not only for the state, but for the feds and we will soon be moving to Canadians - [indisc.] and private land owners as well. Critical issues associated with each - we're flow charting out these permits and beginning the process of synchronizing them. We're outreaching federal government in attempting to organize them since they are having difficulties in organizing themselves. We've made contact with the EPA, FAA, Coast Guard, Fish and Wildlife Service, DOT, National Marine Fisheries, FERC, the FCC and the Corps of

Engineers and are getting information from each. I expect Canada to be next. Probably toward the end of the year and early next year I plan to travel to Calgary and Ottawa and begin to make exactly the same sorts of contacts.

The next step is to begin working with local governments, native corporations, travel counsels. We need to do work with the [indisc.] and the Railroad Corporation, both of which we believe have land along the right-of-way. The University may as well; that's now being checked. Legislative session is coming up and I expect there to be probably more than one bill relating to gas pipelines. So, I'm expecting that to take some time. And in the next year I hope to begin a reasonably serious outreach program.

CHAIRMAN TORGERSON asked what was going on with YPC. He heard they had downsized their office.

MR. BRITT replied that he was meeting tomorrow with the Right-of-way Chief of the Joint Pipeline Office to get a briefing on that. They have submitted a request for about 17 minor realignments of their rights-of-way, which is now being processed. He hasn't heard that this is setting off anything large, such as a large deep evaluation over any serious reconsideration.

CHAIRMAN TORGERSON asked him to email anything he finds out about that. He asked where they are at in the Foothills process.

MR. BRITT replied Foothills submitted a multi-volume collection of exhibits that had been submitted previously that [Foothills] thought was applicable to the questions that are asked in a right-of-way lease application form. He is beginning the review.

CHAIRMAN TORGERSON asked what they were, stream crossing perhaps.

MR. BRITT replied that some of it is engineering work, a lot of it is like an engineering design criteria handbook. The federal grant of right-of-way under Stipulation 161 required in the neighborhood of 30 separate plans for a whole variety of topics from resources in Alaska to locations and excavations - a broad variety of topics. Some of those plans were mothballed.

CHAIRMAN TORGERSON asked if they were reviewing the engineering studies to see what needed to be repeated.

MR. BRITT replied that they need to critique them and determine

whether they are adequate and, if they are not, why. Perhaps they are out of date or more information is needed or the world has changed.

CHAIRMAN TORGERSON asked why they have more attorneys than engineers.

MR. BRITT replied that attorneys are easier to find.

CHAIRMAN TORGERSON thanked Mr. Britt for his testimony and asked him to keep the committee informed.

4:09 - 4:19 - BREAK

MR. JOHN LARSON, Geologist, U.S. Minerals Management Service (MMS), said they have two off shore leases sales in Cook Inlet scheduled for 2004 and 2006. Existing reserves in the Cook Inlet region have been explored and are 2.564 TCF of gas, about a 12 year reserve if gas in the area. There are about 6.6 years of oil reserves. Further, exploration shows that the Cook Inlet Basin has significant untapped natural gas resources.

Very few structures in the perspective OCS lease acreages involve tertiary age formations that are so productive in the Upper Cook Inlet. There are potential oil traps that can be seen on data, but they don't have reservoir characteristics. Hypothetical coal bed methane resources depend on the tertiary formations in Upper Cook Inlet. He had projections done by the U.S. Geological survey that he presented in a slide to the committee.

REPRESENTATIVE GREEN asked how they estimated their calculations.

MR. LARSON said they tried to use mean levels for their calculations.

REPRESENTATIVE GREEN said that they seemed to be specific numbers, but were still "guesstimates."

MR. LARSON concluded that the Cook Inlet basin has significant untapped natural gas resources and the MMS is proposing two gas lease sales in the area in 2004 and 2006.

CHAIRMAN TORGERSON asked what their responsibilities were for the state and whether they just guess at the resources from oil and gas numbers or do research.

MR. LARSON replied that the estimates on his slides were generated by the U.S. Geological survey, which has done some research.

CHAIRMAN TORGERSON asked about Phillips' drilling.

MR. LARSON replied that their target depth as a vertical concern is not that deep. "It's just that they're having to drill from on shore a long distance off shore in order to get to it."

REPRESENTATIVE GREEN asked if the estimates were primary reservoirs or oil associated.

MR. RANCE WALL, Regional Supervisor, MMS, replied that his estimates were the oil and gas plays they had analyzed in the northern part of the basin. It consisted of an interlude of a lot of oil; those have very little associated gas with them. There is a gas play in an interval above that which is nearly all gas. In that case, one wouldn't think about using the gas for oil pressurization.

REPRESENTATIVE GREEN asked if the gas would be available soon after development.

MR. LARSON said that is correct and that "Some of the deeper oil would have associated gas with it dissolved in the oil."

REPRESENTATIVE DAVIES said he thought the Inlet resources would be all used up in 17 years.

CHAIRMAN TORGERSON asked how close their Cook Inlet estimates were in the past.

MR. WALL responded that they started out being a lot bigger than they are now.

CHAIRMAN TORGERSON asked if they were sure that the 10 holes drilled in the OCS area were uneconomic so the chances of leasing in Shelikof Straits are probably slim.

MR. WALL responded that is correct. He also said the five-year plan is not official, it's just proposed.

REPRESENTATIVE DAVIES asked if there were any estimates that might significantly alter the numbers.

MR. WALL responded that it depended on what decisions were made on what to offer as they go through the NEPA process. One of the key issues will be what the State wants them to do.

CHAIRMAN TORGERSON said the tri-borough commission (Kodiak,

[indisc.] and the Kenai Borough) met in the early '90s on how they wanted to see development go forward. He thought that most of that information would be the same, like restrictions in the fishing areas and that kind of thing.

SENATOR OLSON asked if there were known reserves on federal lands.

MR. WALL responded that he thought there were, but they don't do assessments for that area. He suspected there would be potential in some areas if they were offered.

CHAIRMAN TORGERSON said he thought they did the work for BLM.

MR. WALL responded that they work with them.

CHAIRMAN TORGERSON asked if there were any further questions and there were none. He adjourned the meeting at 4:45 p.m.