Stranded Gas Hearings

(0409021415 Minutes)

Panel Discussion on the Regulation of Physical and Economic Waste

Daniel Seamount, Commissioner, Alaska Oil & Gas Conservation Commission (AOGCC)
Mark Myers, Director, Division of Oil & Gas, Dept. of Natural Resources, September 2, 2004.

COMMISSIONER DANIEL SEAMOUNT, ALASKA OIL AND GAS CONSERVATION COMMISSION (AOGCC), said he would begin by giving an overview of a preliminary study done by the owners and how AOGCC fits into that. He also would talk about the statute and the orders that would be appropriate to the North Slope gas project and give more details about a review of a study the owners did to determine what kinds of volumes to expect from major gas sales out of Prudhoe Bay, which resulted in an estimate of what the impact would be on liquids recovery as a result of bringing the project on. He would then recommend what future work would be needed.

If Prudhoe Bay were to be developed for oil only, recovery would be over 13 billion barrels of hydrocarbon liquids. That includes oil condensate and natural gas liquids. Currently, the cumulative production from Prudhoe Bay has been over 11 billion barrels, which exceed the original 1977 reserve estimates by 2 billion barrels. The field has been managed very well – very efficiently. It has been a world-class operation up to this point. Gas sales will add about 3.5 billion barrels of oil equivalent. You can put gas on now or 30 years from now probably and you're not going to have any conservation problems with bringing the gas on. There is a question about the timing and rate that would affect how much oil you're going to recover.

Just a short technical explanation of where the concerns might be – this is a cartoon of a slice through Prudhoe Bay field. It can be any oil and gas field in the world. But normally, oil field practices produce as much of the oil as possible and then produce the gas later – after you're done with the oil and that way you'll maximize recovery of both oil and gas and you'll minimize the waste of the oil. So, what you want to do is produce all this oil down here; the gas cap will expand. After the gas cap has expanded as far as it will reasonably go and you've gotten all your oil, then you blow down the gas cap.

Normally, you need this to recycle the gas back into the reservoir to maintain pressure. This allows for mixing of EOR (enhanced oil recovery) fluids to cause the oil to flow easier and also maintaining pressure that pushes the oil out of the ground up to the well bores and into the pipeline. Generally, early gas withdrawal causes some challenges regarding loss of oil. What we're talking about now with the North Slope gas pipeline project is actually an early withdrawal of oil.

Where the AOGCC comes in is we have statutory responsibility to regulate reservoir management including the timing and off-take rates for conservation purposes. From this preliminary study that the owners did, the result was it looks like gas sales will negatively impact total liquid hydrocarbon recovery. The reduction could be in the hundreds of millions of barrels. It's a very preliminary study. More study needs to be done to see if it's actually going to be that high or not. The greatest impact would occur with earlier sales of higher off take rates. However, the good news is that the timing of the sales and the gas production rate doesn't appear to significantly affect the total hydrocarbon recovery. That's when you consider both oil and gas and total barrels of oil in place if you look at a reasonable life of the field. If you don't think the field is going to last – if the infrastructure is going to go down, if it's aging and you don't last past 2050, you probably won't lose that much oil in reality, less than 100 million barrels. But further evaluation is required to validate these preliminary findings.

So, where do we fit in? This is a pretty busy slide. It compares industry with DNR, with AOGCC's roles. There's been a lot of confusion about where an AOGCC fits in especially since all of the bru-ha-ha that's been going on in the Valley regarding coalbed methane. The AOGCC's role is only regulatory; it's not proprietary. DNR's role is proprietary. It manages the resource and

Director Myers might have some comment on this later. The DNR manages its resources for revenue and other values and promotes prevention of both physical and economic waste through unitization. The AOGCC doesn't worry about value and economics, it regulates for conservation issues, prevent waste, protect relative rights and promote greater recovery. It's worried more about saving the resource than what the economic implications are. A lot of times both the economic and physical waste issues are intertwined. Mostly the AOGCC regulates subsurface activities. DNR, DEC and other agencies have regulatory authority over most the surface activities.

AOGCC was established under the Oil and Gas Conservation Act, AS 31, before statehood in the late 50s. It's an independent quasi-judicial agency where we report to the people of the state as represented by you, the legislature. We have authority over all lands in Alaska, not just state lands - state, federal and private lands. Our duties are to protect, prevent physical waste of the resource, insure greater ultimate recovery, protect relative rights and protect underground sources of drinking water.

As far as relating to the major gas sales project, our main concerns are to prevent waste and insure a greater ultimate recovery. We have been investigating to determine whether or not waste exists or is eminent and, as I say, the operators have done a very good job on Prudhoe Bay. We have had very few concerns over waste in the last 20 years. We have required plans of reservoir development and operation and we will require plans for the future development. Under the statute, this would include regulating the quantity and rate of production of oil and gas.

The definition of waste in the statute is the inefficient, excessive or improper use of or unnecessary dissipation of reservoir energy or operating or producing in a way that reduces the amount of oil or gas recovered under operations conducted in accordance with good oil field engineering practices. Like I said before, gas blow down or gas production is normally delayed to the end of a productive oil life to maximize the oil recovery. While Prudhoe Bay is very unique, it's in a very hostile environment. The oil infrastructure – you've got to be able to handle the oil. It's not that simple at Prudhoe Bay. This is something that needs to be looked at really carefully.

Under applicable rules, Conservation Order 341(d) is the pool rules that govern Prudhoe Bay. The three rules under that conservation order that would be applicable to the gas line project would be rule 9, which gives a maximum off take rate of 2.7 billion standard cubic feet per day. This was written in 1977. It contemplated 2 BCF/day pipeline saleable gas rate. Right now about 300 MCF/day of that 2 BCF are used for enhanced oil projects within the field and in the satellite fields.

Rule 12 basically says that the operator has to maintain reservoir pressure high enough so that the EOR gas mixes with the oil to make it flow easier and also to keep the pressure up so that the oil can flow out of the well bores.

Rule 17 is a more recent rule and it deals with – it's a very ingenious idea where you inject water into the gas cap to displace the gas to keep the pressure up. This could be a very important mitigation measure when you start taking the gas off. It may save up to 100 million barrels of oil just by replacing the gas you're taking out with the water.

Things about Rule 9 – AOGCC approval is required for sales rates in excess of 2.7 BCF/day. It also may be advisable that we revisit rule 9 assumptions, since that rule was written in 1977 at the field's start up. It's a very old model. It's now obsolete; there was very little information on the production at that time. Now we have so much more information and the technology is so much better. The vitals are so much more improved that it's time to relook at this. When we come up with the off take rules, we hope they will be based on current knowledge and sound reservoir management. With a project of this magnitude and cost, it's critical that we be given adequate time to evaluate prior to approval. We started that evaluation in August 2002 when we hired an expert consultant on reservoir simulations, Frank Vlaskovich, who has experience in working on the North Slope in the Prudhoe Bay reservoir. He completed a report in June 2003 and we have to emphasize that the results were based on very preliminary work by the owners and a very rough projection; so, today we can't come up with an answer of what the exact effect will be on the liquids recovery. We looked at sensitivities, the effect of a sales rate between 2.9 and 4.3 BCF/day, the effect of sales timings looking at starting dates between 2010 and 2020 and a number of options to mitigate the oil loss. One of them I mentioned earlier was gas cap water injection – increasing that. That could mitigate the oil loss by up to 100 million barrels. And then CO_2 injection. Prudhoe Bay gas is 12 percent CO_2, which is about 3.5 to 4.5 TCF of CO_2. CO_2 has been very successful in other parts of the world as an enhanced oil recovery fluid. Further studies could show that much of the oil could be recovered just by injecting the CO_2. There are also potential uses of the CO_2 because of the recent scare over global warming and CO_2 sequestration. People are starting to look at places like Oklahoma where 55 billion barrels of oil have been left in the ground because it was not produced correctly. Now they're thinking that putting CO_2 in those reservoirs will recover a lot more of the oil. If they had produced the fields in Oklahoma at the beginning of the last century the same way that Prudhoe Bay has been produced, they probably could have recovered 30 billion barrels of that lost 55 billion. So, that just goes back to the fact that this field has been operated in a very efficient way.

This next slide is probably redundant. I've beat it to death enough. As far as the reduction in liquid hydrocarbons, that's dependent on a number of factors – field depletion optimization, mitigation measures – a couple of which I just described and also just by producing the gas, the field life will be extended. So, that gives more opportunity to produce more of the oil. I'm not saying that the end result is we're going to lose hundreds of millions of barrels. It's we just need to do more study on it.

CHAIR SAMUELS said he assumed that was specific to certain fields.

MR. SEAMOUNT replied yes, but he was just at the beginning of looking at Prudhoe Bay and hasn't looked at Pt. Thompson at all, except for some initial discussions of possible ways of developing it.

MR. MARK MYERS, Director, Division of Oil and Gas, Department of Natural Resources (DNR), said there are two plausible development centers at Pt. Thompson.

One is a gas cycling project where you take the high-pressure gas and condensate. You cycle it out of the well to the surface, take out the liquids and put the gas back in. You continue to just pull out the liquids. Then you later blow down as Dan was describing.

The second scenario would be to immediately start with gas sales, in which case, you recover less liquids, but you recover most of the energy back in gas. So, again, there's economic and physical trade offs. It's a very different reservoir mechanism that is present at Prudhoe Bay. Pt. Thompson pressure is almost double that of the original Prudhoe Bay reservoir pressure. It's a very high-pressure reservoir. Prudhoe is a more standard pressure reservoir. Prudhoe has a much larger oil lake under laid by a water lake with a gas cap and Pt. Thompson is a condensate with a little lake and then a little bit of water underneath it. So, they are different animals and each field has to be looked individually and optimized. It's not a simple equation, but for the gas line, it's mainly those two fields, at least for initial production.

CHAIR SAMUELS asked if he had the geologic information he needs on the various fields to make the trade off decision.

MR. MYERS replied that he has the information from Prudhoe Bay; there's lots of production data.

The question is of optimization. With that the amount of oil loss you'll see is directly proportional to the amount of mitigation. The more water you put in the gas cap, the more efficient, but it costs money to reinject more water, but it maintains the pressure higher. More in injection in oil lake of water or CO_2, a faster cycling time on the reservoir. All of those would increase ultimate recovery, but they cost money and they trade off energy used in compression versus gas you could sell. So, there's an optimization issue that goes on and really Prudhoe Bay is at the stage where the knowledge base isn't going to increase dramatically. It's merely a matter of optimizing the time of sales and then optimizing the amount of money you spend on the various mitigation strategies.

Pt. Thompson has yet to be developed. So, we have some good well control and we have some seismic; we have no production history and a lot less certainty about the reservoir. So, there's more uncertainty around that and as you start in production you gain more and more certainty. So, some tough decisions will have to be made on Pt. Thompson that are economic and they are also reservoir related. We have some good reservoir modeling that was done by the partners. We have a fair amount of good well control, but there is still a lot of uncertainty on the fringes of the reservoir of the ultimate size of the prize and the best technology to use to produce it.

CHAIR SAMUELS asked if the CO2 injection technology has already been developed and does it cost more to operate.

MR. MYERS replied that all the technologies talked about today are existing technologies, but the biggest challenge with CO2 is corrosion and requires use of stainless steel and changing out some parts and pumps; there is money involved in doing that.

MR. SEAMOUNT explained another point:

That with proper engineering, total hydrocarbon recovery – that's barrels of oil equivalent – is relative insensitive to gas sales and sales rate if you assume a reasonable end of life of the field. This is where Prudhoe Bay may be unique in that there may be a time element where you have to get this gas out before everything craters or something goes wrong and 2050 is a long time out. It's insensitive out to 2050 when you bring on the gas sales and what rate it is.

Some of our recommendations here is with the AOGCC you should be part of a process of further evaluation. We need to participate before a decision is made to spend all this money starting the project up. We should be active in setting the producing rate or at least according to the statutes. We must have adequate lead time to complete due diligence and this will insure a good technical review that will help the legislature and others make informed decisions. The owners have told us they plan to continue updating the existing reservoir and facilities models. So far the work they've done is a very good start. We need to continue on this work, update our predictive tools and optimize our operating strategies to maximize oil recovery. Can oil losses be effectively mitigated? What are the effects on the other pools and reservoirs that depend upon Prudhoe Bay gas for their EOR projects for their future pools and reservoirs? The owners have told us we will be part of the reservoir evaluation process.

REPRESENTATIVE REGGIE JOULE asked him to explain updating predictive tools.

MR. SEAMOUNT replied:

These would be the reservoir model, the software, the programs run to predict what kinds of rates to expect and what kinds of recoveries to expect. You take raw information from the wells, from the production, from pressure data and you run it through a computer simulator and it will spit out predictions as to what kinds of recoveries you can expect of oil, what kinds of gas, natural gas liquids.

REPRESENTATIVE JOULE asked if AOGCC has all this information.

MR. SEAMOUNT replied, "Yes we do. We have access to it."

REPRESENTATIVE JOULE asked if it had been interpreted.

MR. SEAMOUNT replied, "No, it takes a lot of man power, a lot of computer time to take all this raw information, stick it in the computer. It gets very expensive."

REPRESENTATIVE JOULE asked if AOGCC has the resources to do it.

MR. SEAMOUNT replied that it doesn't have the resources, but industry does. That's why he is proposing to work with industry when they are doing the evaluations. He has been talking with the owners now and then and they are getting along pretty well.

REPRESENTATIVE JOULE asked how far behind are we?

MR. MYERS replied:

> There are varying levels of accuracy in which you do this. Think of a computer model; think of a grid – think of a grid the size of a chessboard or you can have a grid with thousands of little squares. The more detail, the more computer intense and the more certain your model is. So, the level of detail, the model we have right now is pretty good at smaller than the chess board size, but not the tiny dot size. As you go through and get closer to the reality of a gas line, you get more and more detail. What we have now is pretty darn good. It gives you confidence in the initial conclusions that there will be a minimal amount of oil loss, but there will be some. Then it's the obligation of what mitigation you put in. So, the results we have now show us ... if we start gas sales at this date, we expect to have this much oil loss, if no additional mitigation. If more water goes in the gas cap, it might be this much; if more cycling occurs, it'll be this much. But we can't predict what investments companies are going to be willing to make at the time. That's why this joint work that Dan is talking about. So, you have to start running the what- ifs and the optimization of gas off take. For instance, if the producers propose 2.5 BCF out of Prudhoe Bay versus 3.5 BCF, there's a big impact in oil loss differential unless you pump a lot more water into the gas cap.... The baseline model work is done and we're pretty confident that the oil loss if nothing is done and the gas sales in the 2012 timeframe, the maximum oil loss might be 500 million barrels, but you recover a lot more energy in gas. Conversely, there are cases where you can run scenarios with enough pressure injection where that is way down to less than 100 million barrels. We already know that and we already have good production decline curves for Prudhoe given the current level of investment. But if that level of investment changes, if they change the rate of production in Prudhoe, any number of things could happen. If they do commit to reinject CO_2 as miscible injectant, that changes the equation. Current development plans don't have any of those long-term things in there. There is sort of a segregation in the companies between those working the oil issue and those working the gas line and the gas sales. So, right now Prudhoe is managed as an oil reservoir to maximize oil recovery. They haven't made the switch over to gas, yet. So, all of these scenarios are hypothetical.... Both agencies have a say in what oil loss should be to meet the requirements of physical and economic waste.

CHAIR SAMUELS asked if they are going to participate before the decision in reference to page 15.

MR. SEAMOUNT replied:

> We have been participating. We haven't got into the next stage of final evaluation, yet, but we were able to participate. We were able to at least review the first simulation that was run.

SENATOR LINCOLN asked how AOGCC is going to achieve the goals he listed to be part of a review.

MR. SEAMOUNT replied:

> We reviewed their first simulation study and they allowed us in to review it and come back with some information. That was the first step. The next step is when they begin building their final new and improved model. We would like to be a part of that. We haven't made any agreements on that yet.

CHAIR SAMUELS asked if there was a barrier to their participation now that he needs help with.

MR. SEAMOUNT replied that he didn't see a barrier as the owners are working with him now.

SENATOR ELTON said he assumed that the state had a lot of the information on throughput already, but if it doesn't, how much more time does the AOGCC need to advise the legislature so it can make a good decision.

MR. SEAMOUNT answered that part of it depends on industry and how soon they would do their final evaluation. It would take AOGCC two years and $2 million to do it on its own.

SENATOR DYSON asked if gas sales and other waste might be useful in recovery of the heavy oil in West Sak.

MR. MYERS replied:

> The gas line, again, until there is final approval by AOGCC and by DNR on state lands, there will be no authority to authorize any significant off take of gas. So, fundamentally, there's a separate process independent of the pipeline proposals, because that sale event won't occur until 2010 to 2016, depending on who you talk to. So, fundamentally, that process of approval will occur much later that probably a sanctioning of the pipeline project. There will be a period of time in which folks will determine what gas they want to nominate knowing full well they still need agencies' approvals. It won't be a carte blanche that once you cut a deal that a pipeline will go and the pipeline goes to open season and people nominate gas. They will be taking risk in nominating that gas if they do not have approval to off take that gas. So, the processes are separate. The companies must believe at the point they nominate gas that they can demonstrate there will not be physical or economic waste or they're taking a big risk in that process. Again, DNR's & AOGCC's processes are separate and distinct, but they are somewhat aligned in the issue of having to deal with physical waste. The closer you are to the final development is when you run your final simulations and you go for agency approval....[end of tape]

MR. MYERS continued:

> We won't have that distinct information or a blessing and approval at the open season time for this pipeline, because that final engineering work won't have been done, because it'll be years and years in advance and they know they're going to have to run their models again later, because they'll have that much more information to find and they would have done that much more mitigation in the field. In the meantime, the field will be managed for minimizing oil loss, which again is AOGCC's responsibility through their pool rules....
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> In a sense of the amount of gas and where it gets used, certainly a miscible injectant into the heavy oil will help recovery. The question is where is that miscible injectant going to come from and the timing of it. Ultimately, if you have a gas pipeline, you will put that down the pipeline. So, what's happened is in all these fields like Kuparak and Prudhoe Bay, miscible injectant has been created and injected into the main reservoir. At some point, it's less economic to put that miscible injectant into the main reservoir and they'll shift it over to the West Sak, in the case of Kuparak or Milne from the Kuparak formation into the Schrader Bluff. So, we'll see MI (miscible injectant) moving around the field that's already being used. They'll keep recycling and reinjecting at Kuparak, at some time, when it becomes more economically efficient to put in the heavy oil zone. At the same time, CO2 is a wonderful miscible injectant for heavy oil. So, they could, if it was optimized, just use a CO2 flood in a lot of the heavy oil. So, there'll be this optimization between sales and delivery of gas and where they take and the timing of that versus the use of miscible injectant. It's a balancing act. It's coming from multiple sources; it's already in the fields and they'll probably use that as their first miscible injectant for the heavy oil zones.

SENATOR DYSON said he has followed the Canadian efforts with their heavy oil and there is some talk about in situ combustion. He asked if that is a scenario that could work with Alaska's heavy oil.

MR. MYERS replied probably not – for two reasons. One is that our heavy oil is actually at the light end, 16 – 23 API (American Petroleum Institute) gravity, which can be produced better through conventional means in multi-lateral wells.

> In situ burning would only be applicable, hypothetically, for some of the shallower parts of the heavy oil in the Ugnu Formation that is at 8 – 12 API that probably isn't very moveable.
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> The problem is that you've got cold temperatures and permafrost.... My gut feeling is that there's a whole lot more studies that need to be done before you even consider it.... Most of the oil in the next 15 will probably be this lighter end of the heavy oil, which is volumetrically where they can get out of a multi-lateral well 15,000 barrels per day. That far exceeds the advantage of an in situ burning or a huff and puff steam type mechanism that they use in Alberta.

SENATOR DYSON mentioned that Representative Berkowitz has discussed a win-win where the state gets paid for sequestering CO2 and use that for driving oil recovery and asked if he thought that might work for us sometime.

MR. SEAMOUNT answered that there are a lot of CO2 emissions on the North Slope through flue-gas.

> If they come up with credits for CO2 sequestration to industry, that would be the first place to start. Then if you get really creative, possibly re-injection of the produced CO2 that'll get you both enhanced oil recovery and some tax credits. But that may be pushing it a bit.

MR. MYERS said there would be another opportunity in the gas hydrate zones where gas is present in crystalline form that's just below the permafrost. The estimates are that those volumes exceed that of the conventional gas at Prudhoe Bay. CO2 replacement of hydrates is very efficient.

> So, there are all sorts of other potential advance technologies and uses for CO2 sequestration, which could aid additional methane production as well as heavy oil production. CO2 will become extremely valuable rather than being a nuisance on the North Slope.

MR. SEAMOUNT said they didn't know what kind of mitigation measures are going to be required or even be possible. A more in-depth study is needed.

MR. MYERS said that DNR and the AOGCC have some overlapping authority. DNR's authority is limited to state lands and AOGCC's authority goes to federal and private ownership. DNR's authority is established in AS 38 and it is a broad mandate over economic and physical waste, conservation of resource and protections of the state's best interest. The Supreme Court has confirmed that. A lot of DNR's authority comes through its ability through unitization, which is putting oil and gas property together, multiple leases to produce from a single set of facilities.

> The Supreme Court said that unitization development and conservation of all natural resources belong to the state for the maximum benefit of its people....
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> We also have regulatory functions.... A lot of them focus around unitization.... The commissioner may establish, change, revoke drilling producing and royalty requirements of leases. So the state has an active role. It can help regulate the rate of drilling, the number of exploration wells in a unit. The commissioner can also modify that through plans of development over time – and development of the quantity and the rate of production within the units....
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> We're, again, required under unitization to make a public finding that it's in the public interest and to meet certain standards. Those standards that we have to justify in unitization or in plans of development promote conservation of the resource...promote, prevent, economic and physical waste.
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> An example of physical waste is when you flare gas instead of paying to have it reinjected. A pure economic waste is like at Prudhoe Bay if the operator chose to put the gas down a pipeline rather than reinject it and we lost economic value because we produced less oil. Drilling too many wells in an area is economic waste of resources.

MR. MYERS explained a slide of optimizing oil and gas geologic structures.

CHAIR SAMUELS asked if there are any other mechanisms the state has to insure access to the pipeline other than RIK or RIV.

MR. MYERS replied RIK and RIV are the only mechanisms in which the state would have total control. With proper negotiations it is possible to do things like require mandatory seasons for expansion at various times. The federal legislation gives FERC the ability to mandate access if it passes.

REPRESENTATIVE GARA had a question on page 9 of Mr. Seamount's presentation regarding rule 9 on the maximum gas off take that's allowed. Some people are talking about a 3.5 BCF/day gas pipeline and the current rule says the maximum allowable rate is 2.7 BCF/day. "Why isn't it absolutely time to revisit that to provide people with some certainty who are considering investing in a gas pipeline?"

MR. SEAMOUNT replied that a hearing would probably happen soon.

REPRESENTATIVE GARA asked when he anticipated having a reliable ruling.

MR. SEAMOUNT said that is difficult to answer until the testimony at the hearing is complete. He said the answer would be easier if the AOGCC had a new complete reservoir model that it could rely upon and it does not have that yet.

REPRESENTATIVE GARA commented, "And there are two flip sides. One is the rule that says as the leaseholder, you're allowed to produce this amount of gas and so maybe after the hearing process, it would be increased from 2.7 bcf/day to the amount needed for the pipeline. What about the flip side? Would the rule also say to the lessees that you're required to allow the release of that amount of gas or else that would be waste if you don't allow the release of that amount of gas?"

MR. SEAMOUNT said he cannot see how producing more gas would be required. He asked Representative Gara if he was saying it would aid in the ultimate recovery.

REPRESENTATIVE GARA asked if it could be seen that not allowing enough gas out to make a pipeline feasible could be a waste.

MR. SEAMOUNT said it could be an economic waste. Regarding physical waste, he said he could see that if one could foresee that the infrastructure is going to go down in a few years so that if it is not taken out now, it never will be.

REPRESENTATIVE GARA said if Rule 9 was updated to the 3.5 number as Mr. Seamount anticipates, all Rule 9 would say is that leaseholders would be allowed to send 3.5 bcf/day but would not be required to.

MR. SEAMOUNT said that is correct.

MR. MYERS pointed out that the size of the pipeline is determined by the pipeline builders who will be heavily influenced by the nomination process. The pipeline will have limited specifications - it will only have certain optimum ranges that are economically feasible. However, within that range, the builders will ask who wants to send gas through that line. If only 3 bcf is nominated, the builders will design a pipeline that can provide a reasonable tariff for 3 bcf. The companies nominating that gas will have to believe they can get regulatory approval to produce from those fields and prevent physical and economic waste. If they don't have the gas, they will be exploring to get the gas from the NPRA or Foothills if they can't get the gas from Prudhoe Bay. He emphasized that it is the individual companies, not the fields that will nominate the gas in and they will have to believe and have agreements to produce that gas and regulatory approval. Therefore, just because the pipeline is designed for 4.5 bcf does not mean at the end of the open season process it will be a 4.5 bcf pipeline. For example, if 6 bcf gets nominated from credit-worthy parties, the builders will try to build a 6 bcf pipeline from day one. He noted it is a commercial process that is used to design the size of the pipeline but that must be backstopped by good faith that the regulatory approval will come and that the economic standards can be met in the future.

REPRESENTATIVE GARA asked if the estimated available 3.5 bcf of natural gas includes Point Thomson.

MR. MYERS said the public numbers for the North Slope range from 33 and 35 trillion cubic feet of known proven reserves, largely from Prudhoe Bay and Point Thomson with some associated gas with other oil fields. He noted the undiscovered resource potential in the NPRA is significantly larger. He said the Prudhoe Bay and Point Thomson gas would supply 18 to 20 years at the 4 to 4.5 range and the rest of the gas would come from elsewhere. Or by the time of the actual development of the pipeline, the companies will be taking less gas from those two fields and more from other sources.