

ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE

January 16, 2013

3:29 p.m.

MEMBERS PRESENT

Senator Cathy Giessel, Chair
Senator Fred Dyson, Vice Chair
Senator Peter Micciche
Senator Click Bishop
Senator Lesil McGuire
Senator Anna Fairclough
Senator Hollis French

MEMBERS ABSENT

All members present

COMMITTEE CALENDAR

Who's Keeping the Lights and Heat On? Problems and Solutions:

-Presentation: Petrotechnical Resources Alaska - Cook Inlet
Natural Gas Supply Update Today Looking at Natural Gas Needs

- HEARD

-Presentation: Analysis of Alaska natural gas supply issues

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to consider

WITNESS REGISTER

PETER STOKES, Petroleum Engineer and Commercial Analyst
Petrotechnical Resources Alaska (PRA)
Anchorage, AK

POSITION STATEMENT: Gave presentation on Cook Inlet natural gas supply.

ANTONY SCOTT, Senior Economist and Policy Analyst
University of Alaska Fairbanks
Fairbanks, AK

POSITION STATEMENT: Presented analysis of Alaska gas supply issues.

ACTION NARRATIVE

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CHAIR CATHY GIESSEL called the Senate Resources Standing Committee meeting to order at 3:29 p.m. Present at the call to order were Senators Dyson, Bishop, French, Micciche and Chair Giessel.

CHAIR GIESSEL introduced staff and said her goal was to begin the Senate Resources meetings punctually at 3:30 and adjourn at 5:00 p.m. on Mondays, Wednesdays and Fridays.

Who's Keeping the Lights and Heat On? Problems and Solutions

**Presentation: Cook Inlet natural gas supply update
by Petrotechnical Resources Alaska**

CHAIR GIESSEL said the agenda today was an informational review of the natural gas needs in Alaska. She had included a Southcentral Energy summary from the Institute of Social and Economic Research, dated 2006. It forecasted a shortage of natural gas pretty accurately then. Interestingly, she said, the 25th legislature's Resources Committee began its committee meetings on this same topic.

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SENATOR MCGUIRE joined the committee.

CHAIR GIESSEL said this was the beginning in a series of presentations entitled "'Who's Keeping the Lights and Heat On?' Problems and Solutions" and today they would take a look at the problems; with that she invited Peter Stokes to present studies he had been doing on the Cook Inlet natural gas supply shortage.

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PETER STOKES, Petroleum Engineer and Commercial Analyst, Petrotechnical Resources Alaska (PRA), said he had updated the study the utilities in Southcentral, Enstar, Chugach and ML&P, commissioned PRA to do in 2009. It was updated in 2010 as well as 2012. Today he would talk today about the Southcentral Alaska gas supply and demand forecast for 2012-2020 and discuss possibilities that would allow them to meet the Southcentral demand during that period, as well as the recent Cook Inlet

Natural Gas Storage Alaska (CINGSA) project operating in the mouth of the Kenai River.

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MR. STOKES stated that study allowed the utilities to better understand what the supply was for their gas needs as they are very gas dependent. To do it PRA looked at the Department of Natural Resources (DNR) 2009 forecast of existing wells and overlaid it with additional compression that could be achieved with very low reservoir pressures. That revealed several fields in Cook Inlet with some geologic gas potential, which was "feathered in" to meet Cook Inlet demand.

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PRA's current study found that in general both the study and DNR's forecast show a pretty comparable steady decline through 2020. PRA also looked at what wells and gas had been developed from 2000 to 2009 and used that information to project what additional development would be required to meet shortfalls in 2013 and beyond. DNR estimated another 185 similar wells would have to be developed and using a well cost of \$10 or \$15 million, that would added up to \$2 to 3 billion.

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MR. STOKES said in 2011, DNR did a follow on study to their geologic study of available resources looking at the costs of developing Cook Inlet Basin. They concluded that it was capable of meeting the needs through the 2018 to 2020 timeframe, but they also concluded that not making the investments in lock-step with demand would result in the need for alternative sources coming into Cook Inlet sooner.

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In 2012, the utilities asked PRA to update the 2010 study, which found that drilling and compressions had been done moving the predicted shortfall from 2013 to 2014.

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MR. STOKES added that Cook Inlet had about 200 bcf/yr. of production from 2000 to 2005. It supported not only the utilities for their Southcentral customers, but also two industrial export plants located in Nikiski: the Agrium Chemical Plant (originally the Union Oil Collier Plant) and the LNG export plant. In 2007 Agrium shut down, because they could not source gas at the price they needed to continue operations. That combined with the last few LNG exports have caused the production fall off from 2006 to 2012. The current LNG license

expires in March 2013 and nothing has been said publicly said about how it would extend or how the plant would be used in the future.

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Beyond 2014 the production for the Southcentral utilities will be the Tesoro refinery, fuel for the oil and gas facilities, and mining fuel in the out years. The 2014-19 demand plateau will come from ENSTAR with 44 percent with Chugach Electric, HEA, MEA, ML&P making up another 35-40 percent; Tesoro refinery makes up about 7 percent of that demand and providing fuel for the oil and gas production facilities is about 13 percent.

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SENATOR FRENCH asked if this study assumed any power from the Watana Dam.

MR. STOKES replied no; it assumes using Cook Inlet natural gas.

SENATOR FRENCH remarked that Watana Dam would "up-end" this dramatically.

MR. STOKES replied that was correct, depending on when it comes on. But he didn't think it would impact this particular timeframe.

SENATOR FRENCH said with Watana they could probably back out Chugach Electric, LNG fuel and gas, HEA and MEA, and maybe half of ML&P.

MR. STOKES said that was not part of the PRA study, so it wasn't addressed in this timeframe.

SENATOR DYSON asked what ML&P's "native load" means.

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MR. STOKES replied that it means their load in Anchorage without supporting other utilities.

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SENATOR FAIRCLOUGH joined the committee.

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MR. STOKES explained they assumed LNG exports would discontinue after March 2013 and then ramp up in 2019-20 and assumed there will be a gas pipeline to Donlin Creek.

He explained the reason the utilities were interested in updating the knowledge of future supplies in 2012 is because they are very dependent on gas: Enstar is 100 percent dependent on gas to provide customers with space heating; Chugach Electric currently uses 90 percent gas for fueling their generators and ML&P is about 88 percent dependent for generation. The other 10 percent are hydro or some other fuel.

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MR. STOKES showed a graph of what the utilities had and didn't have under contract for their demand going forward that highlighted the concern about securing gas contracts. He reviewed that they did a decline curve of existing wells on a well-by-well basis on the major fields and did a field-wide decline curve analysis on the smaller fields and summed them up together. It showed a 16-17 percent annual decline into the future starting in 2014. Whereas the 2010 study forecasted the need of 13 to 14 completions a year, they observed 5 to 8 wells being completed annually. Additional exploration wells have been drilled, but he counted only the wells that have been producing and are currently hooked up to pipelines.

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SENATOR DYSON asked if his analysis could have included an evaluation of individual wells or fields, some of which are more prolific than others.

MR. STOKES replied that he looked at each individual producing well and forecasted it based on the well's performance, but didn't look at the handful that had been drilled but aren't on stream yet; however, he had done some sensitivities to try and account for their impacts. They showed a projected shortfall starting in 2014 that increases annually. It's similar to the graph for the uncontracted amount of gas that the utilities require.

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He said he added the three years following the date of the study to the combination of Cook Inlet drilling results from 2001. It indicated an average of about 12.3 wells completed per year in Cook Inlet; on average each well added about 3.6 mmcf/day. Focusing on the last 2.5 years of that timeframe (2007-2009), 34 wells were completed, an average of 13.5 per year. The initial production of each was a little bit lower than the 9-year average. In the last 3 years he had observed 5 wells, 6 wells and 8 wells being added each year. In 2010 to October 2011 fewer wells were drilled and they weren't as good depending on where

they were drilled. So, they aren't at the 13 or 14 wells completed a year that are needed to mitigate the shortfall.

MR. STOKES said he did a "sensitivity" of adding 10 mmcf/day each year from 2013 to 2019 that would sort of equate to 3 or 4 new wells being completed each year. Once again, a shortfall was seen as early as 2014.

He had added a second sensitivity - adding 20 mmcf/day - which equated to about 6 to 8 new wells per year, which is similar to the last 3 years; that pushed the shortfall out a year, but it's still occurs in 2015 and stair-steps up through 2020. He said this could be changed by near-term in-field developments above and beyond 20 mmcf/day per year due to the activities of some of the new players as well as the old (Hilcorp, ConocoPhillips, Buccaneer, Armstrong and others).

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To meet the shortfall in Southcentral beyond what is in current wells the options would be:

- In-field development by fields currently being produced by Hilcorp, ConocoPhillips, Armstrong, Buccaneer, and others
- Exploration done on-shore by NordAq, Apache, and Buccaneer
- Exploration done off-shore by Furie and Buccaneer with a jack-up rig each
- The instate gas line (ASAP)
- Gas imports

He added that Apache is doing a large off-shore 3D program, as well, so no doubt, discoveries will be made off-shore in time.

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MR. STOKES related that Hilcorp (that had just taken over the Chevron assets in Cook Inlet) has publically said they would spend \$200 million in 2012 and \$150 million per year over the two following years to develop oil and gas. This is a marked increase over what had been getting spent by the previous owners. Red Pad is one development that just got hooked up last month and is now producing that is not in the analysis.

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SENATOR FRENCH asked if in-field development is also considered a development well.

MR. STOKES answered yes; that is if you already have a field and are doing some delineation or in-field development.

SENATOR FRENCH remarked that the 2010 report, on page 5, said that development wells in Cook Inlet have a 90 percent success rate.

MR. STOKES observed if you have a development and keep drilling wells and you run out of wells to drill, then it doesn't matter whether it's 80 or 90 percent.

SENATOR FRENCH pointed out that the report said 97 wells were permitted and drilled and 87 were completed, and he thought that was remarkable.

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SENATOR DYSON asked if it was likely that the producers would go deeper into the stratigraphic traps of a reservoir once they had started drilling an area.

MR. STOKES answered if they are able to drill and find gas they will do it. Typically they drill through all the estimated productive horizons and complete wells to maximize production.

He said ConocoPhillips had recently drilled two wells at Beluga River, one good and one bad. Buccaneer is currently completing Kenai Loop 4 following the Kenai Loop 1, which was good; the Kenai Loop 3 was not good. Armstrong has permitted four wells at North Fork and has drilled a couple wells and some smaller companies are doing additional development. But this will not solve their supply problem unless more wells are developed in-field.

SENATOR MICCICHE asked how he would define a successful in-field development gas well.

MR. STOKES answered a well that comes in at \$2 to \$3 million per day depending on the depth of the well. Drilling a \$20 million well on the west side of the Inlet and bringing in only \$1 million per day is not very successful. But drilling some shallow targets and maybe getting \$1 million per day might be very successful.

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SENATOR DYSON said a major component of the cost is how close wells are to infrastructure.

MR. STOKES responded that was correct and remarked that the Kenai Loop discovery is right in the city of Kenai at the Wall Mart parking lot.

SENATOR DYSON asked how they might differentiate between those that are close to infrastructure and those that aren't and said he could maybe respond in another venue.

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MR. STOKES said another avenue of getting new gas in Cook Inlet is through the ongoing offshore exploration. Furie is drilling exploration wells with Sparta 151 jack-up rig and announced a discovery at Kitchen Lights 1 last year. They drilled and suspended Kitchen Lights 2 and side tracked 2A this last summer. Buccaneer mobilized the Endeavor jack-up rig and plans to drill at cosmopolitan this winter. And as he mentioned, Apache is shooting 3D offshore and that could lead to future exploration drilling.

He estimated that it would take three to five years after a discovery to production from offshore areas due to permitting and construction lead times.

He explained that another option was the ASAP that could get gas to Southcentral by 2020 at the earliest.

Finally, bringing gas into Cook Inlet via LNG or compressed natural gas was another option that was being studied by a utility group, bringing it from the North Slope through trucking and compressed natural gas (CNG) were other options being studied and CNG might be cheaper.

MR. STOKES summarized that in-field drilling won't meet demands past 2015. Onshore exploration, if it's successful and near infrastructure, could impact the shortfall; the same for offshore and that would take three to five years to bring on line. The ASAP line would be operational in 2020 and beyond; importing of LNG or CNG could bridge the demand shortfall until the exploration is successful.

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He moved on to the Cook Inlet Natural Gas Storage Alaska (CINGSA) project update and explained that five horizontal wells were drilled and compression installed in the mouth of the Kenai River in the Old Cannery Loop Field. It allows for 11 bcf of active storage, which allows the utilities to meet 140 mmcf/day of peaking in the winter.

SENATOR FRENCH asked what would happen if the size of CINGSA doubled. Would it allow meeting peaking demands for a longer period of time?

MR. STOKES answered that storage projects need the right size container so gas getting put in can get pulled out as fast as needed.

SENATOR FRENCH said he meant five more wells, for example.

MR. STOKES responded that another container would allow more storage allowing more peak demand, but it wouldn't increase the supply.

SENATOR FRENCH asked if CINGSA is about half full.

MR. STOKES answered this is the first year it has been used and they are getting it filled up. It should be filled by next winter season.

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SENATOR BISHOP asked if there was enough base line data to say for sure that this reservoir is working.

MR. STOKES replied that it is being used right now to meet peaking demands and all equipment is working as advertised.

SENATOR DYSON said with the huge delta between gas and oil, they always worry that producers will go for oil at the expense of gas. Is that possible in Cook Inlet and how could they build incentives to make sure they stay focused on gas?

MR. STOKES answered they didn't study that in this report. However, prudent investors look for the best return on their investment. If they can make more money drilling an oil well than a gas well, they would drill the oil well.

CHAIR GIESSEL asked him to estimate what it would cost in money and time to bring in a first load of LNG.

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MR. STOKES replied that next week's group could answer that, but probably in the two to three year timeframe.

He concluded that Cook Inlet doesn't have large discoveries that can be brought on in the one to two year timeframe and there is a shortfall of natural gas as early as 2014. LNG or CNG imports

is the only certain method that the utilities have to know they can continue to meet their demand. CINGSA storage is capable of enough storing gas for the winter time. It would also be a way of handling any gas brought into the Inlet.

SENATOR MICCICHE said it has been helpful to learn that activity doesn't necessarily result in production.

CHAIR GIESSEL thanked him and invited Antony Scott to testify.

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At ease from 4:14 to 4:20 p.m.

Presentation: Analysis of Alaska natural gas supply issues

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ANTONY SCOTT, Senior Economist and Policy Analyst, University of Alaska Fairbanks, Fairbanks, AK, said prior to working at the University he had managed the commercial section of the State Division of Oil and Gas and that today he would present some results of a study he had been working on with the Alaska Center for Energy and Power comparing a range of different energy solutions for Fairbanks.

The list of projects was from a perspective of delivery cost to Fairbanks consumers, not cash flow to the state or any broader policy issues. He did not optimize anything; in many ways he extracted the project from the project's components and hadn't identified any sponsor as moving them forward, which impacted the modeling. Similar financing assumptions were made across all projects and the same cost indices to bring the project sponsor's cost estimates up to date in 2012 dollars were used and then projected forward. Some of the projects had particularly innovative proposals for how they would like to proceed, but they weren't used. For instance, the 12-inch fit-for-purpose project proposed by Arctic Fox suggested purchasing gas that had already been treated by the producers on the North Slope in a bundled commodity sense. That is potentially possible, but they didn't do that. Basically, he tried to consider projects on an infrastructure basis and then provided a way to compare them on an apples-to-apples basis.

Before going into the descriptions, he thanked the people who provided data for the study: Jim Dobbs and Steve Hagenson, Fairbanks Economic Development Corporation, the folks at Alaska Gasline Development Corporation (AGDC) who provided key underlying data, folks at Energy Acura at Fairbanks, experts at

Alaska Energy Authority (AEA) on the Susitna Dam, and people interested in high voltage direct current (HVDC) transmission of electricity off the North Slope.

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MR. SCOTT said he looked at trucking LNG off the North Slope and at different configurations of a bullet line project - when Bob Swenson looked at that project he looked at not just a 500 mmcf/day project (which is what AGDC is currently pursuing), but also smaller throughput configurations at 250 mmcf/day - more or less meeting the entire Railbelt energy demands as well as larger throughput configurations at 1 bcf/day; a spur line off a major gas sale (LNG project to Asia as opposed to an overland project into North America with its consequences for pricing in-state); a small diameter 12-inch fit-for-purpose pipeline from the North Slope to Fairbanks; the Beluga to Fairbanks option (piping gas from Cook Inlet north into Fairbanks); the possibility of heating by wire - the Susitna/Watana project; and a project configuration of HVDC which would provide both electricity and heat by wire to Fairbanks.

He underscored that he included the two electric projects for comparative purposes and to shed some light, but they are different, because meeting electricity needs and doing electricity planning is in many ways beyond the scope of this work and because it requires so many project integration considerations that exceeded the scope of his ability to address in this study. Finally, he looked at the possibility of making a liquids out of coal facility located in the Interior, which was the initial justification for the study to begin with in terms of its funding.

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MR. SCOTT said one of the things that drove the results in this project was the focus on commodity price piece. He explained that often projects are presented in terms of infrastructure cost and have a fixed assumption on how to minimize transportation costs - and while those costs are absolutely relevant, they clearly don't tell the whole story. So, some of his results were be surprising because they were a result of focusing on commodity pricing regimes within Alaska.

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SENATOR MICCICHE wondered why a couple of alternatives weren't mentioned: one was imported LNG and regasification and the second was the potential for Nenana Basin natural gas production.

MR. SCOTT answered that, in effect, he would present the results of a Beluga to Fairbanks project within the context of moving gas by pipeline from Cook Inlet into the Interior. He added also that he didn't have any public data to work with to try to mock up what the Interior energy development project would look like and that was very limiting.

SENATOR MICCICHE said it would be interesting to see the trucking option going north instead of just going south. The Beluga to Fairbanks pipeline was an interesting concept but LNG can be trucked both ways.

CHAIR GIESSEL added, "and by rail."

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MR. SCOTT said his assumptions that would significantly drive the results were only a model and not how the future would necessarily unfold. The working framework was based on actual transactions in the market and a good place to start.

He explained that today one can purchase (untreated) stranded gas on the North Slope and there is a market for that commodity. Much of it is transacted using his formula: the price of a barrel of ANS X 4.6 percent = price per mcf of the gas. This formula came from a DNR settlement for valuing gas that was agreed to in the early 1990s with the North Slope producers and then it started being used as a benchmark for a number of subsequent market transactions. Norgas Co.'s contract on the North Slope was referenced to this formula, for instance. One could do better than this formula by looking at royalty values and how the settlements work and then back out some of the values for gassing transactions. Some is higher and some is lower, but one of the patterns that emerges is that gas isn't purchased at a fixed price. It is typically indexed to oil and that is something that looks like his formula.

LNG pricing under long-term contracts (not spot) in the Asian Pacific is undergoing some change, he said, but the historical industry standard looks something like his formula, which is: ANS (or a waterborne crude) X 14.5 percent + \$.90 and that results in the price/mmbtu in Asia. The Alaska Gasline Development Corporation (AGDC) used a formula like this in their 2011 work. Other support for this kind of a pricing arrangement came from Gas Strategies that was hired for the AGIA process, which suggested similar formulas going forward for pricing, as well as Wood MacKenzie. He cautioned that prices could soften

and then the prospects for LNG exports dim considerably off of any project.

MR. SCOTT explained that his model for Fairbanks heating oil can be correlated tightly to ANS West Coast (WC) crude prices. The formula for retail Fairbanks heating oil is: the price of a barrel of ANS crude X 22.5 percent + \$4.20 equals the price/mmbtu. He used ANS oil price as a common denominator to look at these different commodity markets.

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He said slide 5 ran actual historical ANS oil prices through each of the formulae to produce different price paths. So the blue line was actually what ANS oil prices were; the red line was Fairbanks heating oil prices as a function of ANS oil prices, the green line was the cost of LNG in South Korea as a function of that formula; the purple line represented the cost of stranded North Slope gas at Prudhoe Bay. The locations of the commodities were different and the volatility of the pricing regimes were very different, which meant that the risk profiles of projects that access the resource from different places were going to be very different.

MR. SCOTT said that one of the driving assumptions in his work were three projects that export Alaskan gas as LNG: the bullet line at 500 mmcf/day, a bullet line at 1 bcf/day, and one at 3 bcf/day. All of those export projects bring North Slope gas to the LNG market. His working assumption in every case was no home town discount, which means a North Slope producer will not sell gas to Alaskans at a discount compared to the value they could receive if they exported that gas. That logic was based on economics and commercial behavior; there wouldn't be a problem if the opposite was the case.

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He modeled all the projects on slide 6 on a private ownership model, which means he assumed they were financed as 70 percent debt, 30 percent equity, and that the return on equity was 12 percent and that cost of equity was 6 percent. It showed delivered costs of energy in Fairbanks in 2023 (because that is when all or any one of the modeled projects would be on line). He added that he was trying to avoid discounted prices back to today. The oil prices on the horizontal axis were real prices per barrel for ANS crude, and that is because you can correlate crude oil prices with the gas prices being modeled.

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From the Fairbanks perspective, he said a couple things jumped out. Surprisingly, it turns out for the ASAP project (1 bcf/day), larger throughput doesn't mean cheaper prices to Fairbanks. For oil prices above \$70 barrel the delivered cost to Fairbanks consumers was greater than the ASAP project (assuming 100 percent load factor) at 250 mmcf/day. This was counter intuitive, because everyone knows that bigger throughput on the same line should reduce the cost of transportation, but the cost to consumers was a function not just of the cost of transportation but included the function of commodity price.

The larger configuration project hits the LNG export market and then Fairbanks consumers end up seeing the LNG export market formula, which rises much more steeply as a function of oil prices. So, at higher oil prices, it ends up that the lower cost commodity ends up getting overwhelmed by the increase in the commodities charge.

The black dash line represented Fairbanks heating oil, the status quo that many consumers rely on today. If an energy project does not come in below that line, it is not providing energy cost relief.

MR. SCOTT pointed out that one of the things they see for all of the projects at low enough oil prices is that none of them provide material energy cost relief except the major gas sale.

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SENATOR FRENCH asked which hash mark corresponds to which oil prices on the X axis (oil prices).

MR. SCOTT apologized for the "Excel foible" and said the labels should really be on dead center.

He continued explaining that for a privately owned project, if the only goal is providing energy cost relief for Fairbanks, there is the potential risk that the project doesn't do that. Further, he stated that everyone might believe that oil prices north of \$70 are here to stay, but that can be a wildly wrong assumption. How would that happen? Shale oil could take off worldwide, just like shale gas has.

He added that the dotted blue line looks at the cost of HVDC for a project that meets all of Fairbanks' heating and electrical needs if it were privately funded. In general, Mr. Scott explained, heating by wire is not a super duper proposition and the reason he didn't include the Susitna/Watana project is

because the cost of electricity from that project (once converted to mmbtu) "kind of blows out the scale" being 60 percent higher than anything else on the graph. He wasn't knocking the project, but its energy would be used for lights rather than heating homes.

SENATOR MICICCHE asked him to clarify HVDC as well as other acronyms.

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MR. SCOTT replied that HVDC would purchase stranded North Slope gas and generate electricity in very large turbines at very high efficiencies and transport that electricity on high voltage direct current (HVDC) lines into Fairbanks where the electricity would be transformed again into alternating current and be made available to consumers.

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He said slide 7 showed the public ownership case for Bradley Lake and assumed 100 percent state financing for everything, 4 percent debt for everything and no private capital. So there was a dramatic reduction in the cost of all the projects resulting in a large decrease in the cost of delivered energy. Here some of the projects started to separate out, which was a function of the large energy projects that are incredibly capital intensive. He said reducing the cost of capital across the projects makes an enormous difference. A clustering of projects using stranded North Slope gas results, so the fit-for-purpose pipeline, the smaller diameter ASAP project and the Fairbanks trucking project all deliver energy in a parallel cost environment and all pretty close together. Given cost uncertainties in terms of scope on any of these projects and using the assumption that they are all fully loaded, they are distinguishable.

The projects that use North Slope gas in an export function through the LNG market paralleled each other and had much steeper slopes and often delivered more expensive energy than the stranded gas projects. Not always - it depended on oil prices, but everything started looking a lot better compared to heating oil.

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He pointed out how the previous two slides showed two dynamics: the importance of how the projects are financed and the oil price risk and that the next slide (9) showed ramp-up risk, which means if you build a large infrastructure project and don't necessarily sign up all the customers at once (which you

can't), the cost of providing energy in the very first year to the customer will be much higher than it would be once the customer base was fully subscribed. That is a material risk for all the projects and it needs to get dealt with on a policy level.

The state funding he used on slide 9 was much less and he assumed \$100 oil. It highlighted how the energy solution would have to be enough below the black line that the customer wants to pay the conversion cost to natural gas or anything else.

Revolving loan funds would help some, but wouldn't solve the problems. In general, he said, these problems don't come up because infrastructure projects like this get built on the basis of very large industrial customers that create the economies of scale such that everyone else wants to get in. Fairbanks doesn't have that favorable of an environment for distributing natural gas in terms of initial economies of scale. But the more you can reduce costs through state financing and grants, or whatever, the less the ramp-up risk will exist - and that risk has to be dealt with. Slide 10 showed that ramp-up risk as a function of the rate of ramp-up for Fairbanks local gas distribution as well as the uncertainty in total Fairbanks heating demand. It was news to him that people don't really know what Fairbanks needs for heating load - unlike Anchorage where one can look up the total number of btus of natural gas that are consumed by just going to Enstar. As a result of that uncertainty the ramp-up risk can't be fully captured, but it does matter.

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Slide 11 provided a scale on the range of total capital costs associated with each project many of which are incredibly capital intensive and would stretch the state's credit capacity. So, choices have to be made about what the state wants to pursue. And slide 12 modeled start dates of the different projects, which for the Interior is an extremely relevant concern.

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In summary, Mr. Scott said, the analysis focused on dimensions of project risk, and he didn't have a chance to look at capital cost risk or escalation risk, and others, but the whole study does do that and he was trying to finish it. A key part is that the commodity price terms are crucial. In seeking any of these solutions, he urged them to focus on: the pricing terms and their duration, at what events they get renegotiated and if they are portable from one project to another. It's critically

important to nail those considerations down as soon as possible. There is nothing stopping anyone from negotiating gas sale contracts today - stranded North Slope gas contracts have been negotiated - and they should be done as soon as possible a home town discount is being considered. He advised that if they were considering using state money as a carrot to get it that the discount needs to be negotiated up front before spending the carrot.

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SENATOR MICCICHE noted that his coal to liquids delivered cost of energy price is the lowest in both cases, but dramatically lower at higher fuel prices under state ownership and asked if there was a reason he didn't include the ramp-up risk for that project.

MR. SCOTT replied yes; because there is a market for those liquid fuels today and conversions are not needed to build out the demand for it. So, the assumption is if the state were to build that project, it would have the ability to compete and fully sell all of its product in the market today. The volumes are less than the relevant total market demand in Alaska, so you don't need to worry about ramp-up risk. However, the real reason he didn't focus on the coal to liquids project is because it's almost impossible for that project to deliver energy cost relief. Why? Fuel oil, for example, is a commodity and in the event a state sponsored project sold fuel oil below market rates, people would purchase as much as they possibly could and then turn around and sell it on the open market at market rates. In other words, having price controls for a commodity like fuel oil while not necessarily impossible is fraught with difficulty and encourages fraud. It also raises enormous regulatory and legal issues.

Also a coal to liquids project comes out on the bottom, but that it is faced with very substantial technological risk and is an extremely large project; and assuming state funding, it would be extremely difficult to manage (much more so than a pipeline project), since the state doesn't have that particular expertise. And the capital cost associated with a coal to liquids project is the most uncertain of any project; the uncertainty bounds are plus or minus 40-50 percent, at least. CHAIR GIESSEL said he was quite informative and thanked him for his presentation.

[5:05:59 PM](#)

Finding no further business to come before the committee, Chair Giessel adjourned the Senate Resources Standing Committee meeting at 5:05 p.m.