ALASKA STATE LEGISLATURE
JOINT MEETING
SENATE SPECIAL COMMITTEE ON ENERGY
HOUSE RULES STANDING COMMITTEE
Anchorage, Alaska
June 18, 2008
9:05 a.m.

MEMBERS PRESENT

SENATE SPECIAL COMMITTEE ON ENERGY

Senator Charlie Huggins, Chair
Senator Bert Stedman, Vice Chair
Senator Lyman Hoffman
Senator Lesil McGuire
Senator Gary Stevens
Senator Joe Thomas
Senator Bill Wielechowski
Senator Fred Dyson
Senator Thomas Wagoner

HOUSE RULES

Representative John Coghill
Representation Anna Fairclough
Representative Craig Johnson
Representative Ralph Samuels
Representative Beth Kerttula

MEMBERS ABSENT

SENATE SPECIAL COMMITTEE ON ENERGY

Senator Kim Elton
Senator Lyda Green
Senator Donald Olson

HOUSE RULES

Representative John Harris
Representative David Guttenberg

OTHER LEGISLATORS PRESENT

Senator Con Bunde
Senator Bettye Davis

Senator Johnny Ellis
Senator Hollis French
Representative Bob Buch
Representative Harry Crawford
Representative Nancy Dahlstrom
Representative Mike Doogan
Representative Les Gara
Representative Berta Gardner
Representative Carl Gatto
Representative Mike Hawker
Representative Lindsey Holmes
Representative Reggie Joule
Representative Wes Keller
Representative Kevin Meyer
Representative Mark Neuman
Representative Kurt Olson
Representative Jay Ramras
Representative Bill Stoltze
Representative Bob Lynn
Representative Max Gruenberg

COMMITTEE CALENDAR

SENATE BILL NO. 3001
"An Act approving issuance of a license by the commissioner of revenue and the commissioner of natural resources to TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd., jointly as licensee, under the Alaska Gasline Inducement Act; and providing for an effective date."
HEARD AND HELD

HOUSE BILL NO. 3001
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HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: SB3001
SHORT TITLE: APPROVING AGIA LICENSE
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

06/03/08	(S)	READ THE FIRST TIME - REFERRALS
06/03/08	(S)	ENR

06/03/08	(S)	REPORT ON FINDINGS AND DETERMINATION
06/04/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
06/04/08	(S)	Heard & Held
06/04/08	(S)	MINUTE(ENR)
06/05/08	(S)	ENR AT 9:00 AM TERRY MILLER GYM
06/05/08	(S)	Heard & Held
06/05/08	(S)	MINUTE(ENR)
06/06/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
06/06/08	(S)	Heard & Held
06/06/08	(S)	MINUTE(ENR)
06/07/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
06/07/08	(S)	Heard & Held
06/07/08	(S)	MINUTE(ENR)
06/08/08	(S)	ENR AT 1:00 PM TERRY MILLER GYM
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06/12/08	(S)	ENR AT 10:00 AM FBX Carlson Center
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06/16/08	(S)	ENR AT 9:00 AM ANCHORAGE
06/16/08	(S)	Heard & Held
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06/17/08	(S)	ENR AT 9:00 AM ANCHORAGE
06/17/08	(S)	Heard & Held
06/17/08	(S)	MINUTE(ENR)
06/18/08	(S)	ENR AT 9:00 AM ANCHORAGE

BILL: HB3001
SHORT TITLE: APPROVING AGIA LICENSE
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

06/03/08	(H)	READ THE FIRST TIME - REFERRALS
06/03/08	(H)	RLS
06/03/08	(H)	WRITTEN FINDINGS & DETERMINATION
06/04/08	(H)	RLS AT 9:00 AM CAPITOL 120

06/04/08	(H)	Heard & Held; Subcommittee Assigned
06/04/08	(H)	MINUTE(RLS)
06/04/08	(H)	RLS AT 10:00 AM TERRY MILLER GYM
06/04/08	(H)	Heard & Held
06/04/08	(H)	MINUTE(RLS)
06/05/08	(H)	RLS AT 9:00 AM TERRY MILLER GYM
06/05/08	(H)	Heard & Held
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06/14/08	(H)	MINUTE(RLS)
06/16/08	(H)	RLS AT 9:00 AM ANCHORAGE
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06/17/08	(H)	RLS AT 9:00 AM ANCHORAGE
06/17/08	(H)	Heard & Held
06/17/08	(H)	MINUTE(RLS)
06/18/08	(H)	RLS AT 9:00 AM ANCHORAGE

WITNESS REGISTER

GOVERNOR WALTER J. HICKEL [former governor]
POSITION STATEMENT: Opposed exclusive license to TransCanada under SB 3001 and HB 3001; emphasized gas to Alaskans.

PATRICK GALVIN, Commissioner

Department of Revenue
Juneau, AK
POSITION STATEMENT: Participated during the net present value (NPV) portion of the hearing on SB 3001 and HB 3001.

SCOTT SMITH, Vice President
Black & Veatch Corp.
POSITION STATEMENT: Gave PowerPoint presentation on NPV and answered questions during hearing on SB 3001 and HB 3001.

DEEPA PODUVAL
Black & Veatch Corp.
POSITION STATEMENT: Assisted with PowerPoint presentation and answered questions during hearing on SB 3001 and HB 3001.

MIKE ELENBAAS
Black & Veatch Corp.
POSITION STATEMENT: Assisted with PowerPoint presentation and answered questions during hearing on SB 3001 and HB 3001.

NANETTE THOMPSON, Unit/Tech Support
Division of Oil & Gas
Department of Natural Resources
Anchorage, AK
POSITION STATEMENT: Participated in roundtable discussion during hearing on SB 3001 and HB 3001.

JULIE HOULE, Section Chief
Resource Evaluation
Division of Oil & Gas
Department of Natural Resources
Anchorage, AK
POSITION STATEMENT: Participated in roundtable discussion during hearing on SB 3001 and HB 3001.

CATHY FOERSTER, Commissioner
Alaska Oil and Gas Conservation Commission (AOGCC)
Department of Administration
Anchorage, AK
POSITION STATEMENT: Participated in roundtable discussion during hearing on SB 3001 and HB 3001.

CRAIG HAYMES, Alaska Production Manager
ExxonMobil
POSITION STATEMENT: Participated in roundtable discussion during hearing on SB 3001 and HB 3001.

ANIL CHOPRA, Ph.D., President
PetroTel Inc.
Dallas, TX
POSITION STATEMENT: Participated in roundtable discussion during hearing on SB 3001 and HB 3001.

JOHN ZAGER, General Manager
Chevron - Alaska Area
POSITION STATEMENT: Participated in roundtable discussion during hearing on SB 3001 and HB 3001.

CHARLES McKEE
Anchorage, AK
POSITION STATEMENT: Testified during public hearing on SB 3001 and HB 3001.

PAUL LAIRD, General Manager
Alaska Support Industry Alliance
POSITION STATEMENT: Voiced opposition to AGIA license under SB 3001 and HB 3001 as well as support for Denali project.

JERRY McCUTCHEON
Anchorage, AK
POSITION STATEMENT: Spoke against AGIA and Denali project during public hearing on SB 3001 and HB 3001.

MATTHEW FAGNANI
Anchorage, AK
POSITION STATEMENT: Opposed approving a license under SB 3001 and HB 3001.

MAYNARD TAPP
Anchorage, AK
POSITION STATEMENT: Opposed the AGIA proposal under SB 3001 and HB 3001 and requested support for the producers and Denali.

MIKE ROGERS
Anchorage, AK
POSITION STATEMENT: Spoke against AGIA and Denali project during hearing on SB 3001 and HB 3001, saying if a license is approved, it should be amended.

BARBARA BACHMEIER
Anchorage, AK
POSITION STATEMENT: Highlighted jobs and opposed AGIA, TransCanada, and Denali during hearing on SB 3001 and HB 3001.

JOHN WOOD
Willow, AK
POSITION STATEMENT: Testified on SB 3001 and HB 3001, saying he doesn't favor the AGIA process except as a negotiation tool.

KATE TROLL, Executive Director
Alaska Conservation Alliance
Anchorage, AK
POSITION STATEMENT: Supported AGIA proposal under SB 3001 and HB 3001, but expressed some concerns.

CAMILLE CONTE
Anchorage, AK
POSITION STATEMENT: Suggested saying no to TransCanada and yes to a line to Valdez during hearing on SB 3001 and HB 3001.

BRIAN DAVIES
Anchorage, AK
POSITION STATEMENT: Opposed granting license under SB 3001 and HB 3001 because it might prevent parties from coming together.

RON AKSAMIT
Anchorage, AK
POSITION STATEMENT: Supported approving license under SB 3001 and HB 3001 to keep TransCanada in the game.

TOM LAKOSH
Anchorage, AK
POSITION STATEMENT: Voiced support for SB 3001 and HB 3001 and for developing Point Thomson.

SHANNYN MOORE
Anchorage, AK
POSITION STATEMENT: Testified on SB 3001 and HB 3001, saying AGIA should be amended.

RON ALLEVA
Anchorage, AK
POSITION STATEMENT: Testified during hearing on SB 3001 and HB 3001, saying he is against AGIA and in favor of Denali.

CHRISTOPHER CONSTANT
Anchorage, AK
POSITION STATEMENT: During hearing on SB 3001 and HB 3001, encouraged amending AGIA to assure jobs for Alaskans.

ACTION NARRATIVE

CHAIR CHARLIE HUGGINS called the joint meeting of the Senate Special Committee on Energy and the House Rules Standing Committee to order at 9:05:49 AM.

SB3001-APPROVING AGIA LICENSE
HB3001-APPROVING AGIA LICENSE

9:05:49 AM
CHAIR HUGGINS brought SB 3001 and HB 3001 before the committees. He welcomed former Governor Walter J. Hickel and referenced that there would be discussion of net present value (NPV) by the administration and Black & Veatch. A roundtable discussion to answer questions about Point Thomson was scheduled later, and public testimony was to begin at 6 p.m.

9:07:04 AM
GOVERNOR WALTER J. HICKEL testified as follows:

> Let me begin with my bottom line. The State of Alaska represents all of our people, the owners of the resources on the state lands at the North Slope, and ... should build the Alaska natural gas pipeline.
>
> We should hire a pipeline company, perhaps TransCanada, and build it and own it. That's the only way we can keep control of this resource that is worth untold billions. Anytime you yield control of public assets to a private company, you have to be content to sit and wait, because they are in control. And if you yield control to foreign governments and their regulatory agencies, just move to the back of the bus.
>
> Before I expand on this, I want to salute you, Mr. Chairman, and your colleagues for holding these hearings. The issue is how to achieve maximum benefit from North Slope natural gas resources. That's your assignment under the constitution.
>
> As citizens of our owner state, all Alaskans also have this obligation to follow this issue and make their views known. Billions upon billions of dollars are at stake. We need to get Alaska gas to Alaskans, and to make that gas affordable we need to access the world's markets. That means an all-Alaska gasline to Valdez and LNG exports to the world. Our neighbor nations on the Pacific Rim are ready to pay twice as much as

Alberta or Chicago. This week. Japan is paying over $20.00 per Mcf. They are paying $11.69 in Alberta.

The last time I saw you, Mr. Chairman, was in Beijing, where we met with leaders in China oil and gas. That was an important trip. We must understand the world, and we need vision. Vision is the key to a pioneering country. And to me the vision is clear and is based on reality.

For 50 years of statehood, Alaska's political ties have been with America - and thank God for that - but our economic ties are with Asia. We offered our timber, coal, LNG to the South 48, but we couldn't get them past Seattle. So we made friends and contacts in Japan and Korea, and we built our young economy based on those relationships. In 1969, we pioneered the first LNG shipments to Japan from anywhere, shipments that continue from Kenai today.

I just say, wake up, America. It's a world economy. Check the labels on your T-shirt and names on your TV and automobiles. Chances are, they weren't made in America. Our national economy - that means our standard of living - depends on our productivity and our ability to compete. We won't survive by just playing the stock market. There is no wealth without production.

I commend Governor Sarah Palin for introducing a wide-open, transparent process on the gasline issue. For years, the North Slope [producers] claimed ... that Alaska natural gas was not economic. They said there was no market. But AGIA produced five eager applicants, and the producers changed their tune. They cobbled together yet another public relations campaign about a gasline project that I promise you will never happen.

We've seen this before, over and over. And they still badmouth LNG. You know, ladies and gentlemen, if LNG is so bad, why are they heavily involved? ConocoPhillips has invested $60 billion in the largest LNG [liquefaction] plant in the world in Qatar; BP has an LNG project in Tangguh, Indonesia; and Exxon has a new project in Papua New Guinea. And that's only part of the story.

Ladies and gentlemen, they don't oppose LNG. They oppose Alaska's LNG because our LNG competes with their LNG. And the truth is, LNG is changing the world. You can't build a pipeline to Australia, Japan, India, or China.

9:12:27 AM
GOVERNOR HICKEL continued:

It's no secret that I'm opposed to giving the exclusive license to TransCanada. The public thinks that they plan to ship North Slope gas to America. But their goal, and they don't deny it, is to use most of our gas to heat the Alberta tar sands to create synthetic oil. And they face obstacles and delays beyond our control. And the key word is "control."

They admit that the Mackenzie River pipeline, mired in problems, will go ahead of an Alaska gasline - just more delay. The Canadian Supreme Court has ruled, and rightfully so, that the Canadian government must consult and accommodate even those First Nations that have not resolved their land claims when it comes to issues such as a pipeline that impact their traditional territory - more delay. TransCanada cannot build a 4.5 billion-cubic-feet-per-day pipeline without gas from the producers - more delay.

And producers' gas carries the bombshell of demands for "fiscal certainty," and you know what that means. What's more, without even so much as a mention, TransCanada plans to export millions of barrels of valuable North Slope gas liquids to Alberta. Those gas liquids should stay in Alaska. Billions of dollars of state revenue and hundreds of value-added jobs for Alaskans for decades rest on this great issue.

There is no reason to hold up the Alaska LNG line while we wait for TransCanada to sort out their problems in Canada. Last week, Commissioner Pat Galvin and others from the Palin gasline team informed me that TransCanada is prepared to hold a simultaneous open season. This means that those who control North Slope gas will be invited to reserve space at the same

time in either a Canadian pipeline or an all-Alaska pipeline to Valdez.

If the market wants to ship LNG first, TransCanada will build the all-Alaska line first. They didn't mention, by the way, [to] which route the state will dedicate its gas. But I was somewhat encouraged by what ... the commissioner said, only to learn this week that TransCanada has refused to clarify any such commitment to hold a simultaneous open season.

9:15:33 AM
GOVERNOR HICKEL continued:

This illustrates and underlines my message today. If TransCanada is granted a license by the state, the state will lose control. Alaska appears to be caught between the producers on one side and a bad deal on the other. So what do we do? Fortunately, there's another option.

Ever since the people of Alaska voted six years ago in favor of an all-Alaska gasline, they have been waiting. And now, with a crisis in Alaska fuel and energy costs, they are getting frustrated. How much longer can we ask them to wait?

In Fairbanks last week, you heard loud and clear that we need Alaska's gas for Alaska's people now. And the crisis in rural Alaska is worse. But it's no good to have the Alaska gas if it comes very sky-high. The way to lower the price is through volume. We must move our gas in a pipeline big enough to serve large markets. The best way to do that is build an all-Alaska gasline to Valdez. And the state should build it and really should own it.

Without the Canadian government or FERC making us jump through a thousand hoops, we could build that gasline in five or six years to Alaskans. And the ... entire project can [be] completed soon thereafter. If you hold a hearing on how the state can build and own our own gasline, please ask me to come back. It's not rocket science.

So I urge you to deny that TransCanada plan. If you don't, we will lose control of our gas and Alaska will

be locked into the market at the end of that pipeline in Alberta.

As we meet here, there is a rush going on for ... new gas plays in Pennsylvania, West Virginia, Texas, and the Rockies. Alaska gas in the South 48 will face severe competition in a few years. That means that our gas, instead of serving America as Governor Palin sincerely hopes it will, will stay in Alberta and be used to heat the tar sands.

So ... let's take the faster, better, and more beneficial alternative. Let's build the Alaska gasline ourselves. With LNG, we will serve the world. We will move our [gas] to the highest and best markets, and we will keep the jobs ... here at home. That's "maximum benefit" for our people. And that's your responsibility and your opportunity, and the mission of this generation. God bless you and thank you a lot.

9:18:45 AM
SENATOR DYSON expressed appreciation for the perspective. He reported that when he and Senator Therriault met with Bud Albright of the U.S. Department of Energy (DOE) a few months ago, they raised the question of getting a liquefied natural gas (LNG) export license; Mr. Albright and his staff seemed to think that while it might make economic sense, it would be difficult politically with the national mood and this Congress. Recalling a similar situation regarding oil when he worked for BP in the early 1970s, Senator Dyson asked Governor Hickel what his sense is of Alaska's ability to get such a license now.

GOVERNOR HICKEL replied he believes it is absolutely necessary and totally available. He emphasized that Alaska should lead in this regard, rather than getting led in the wrong direction.

SENATOR DYSON said he wasn't quite as confident about the outcome nationally. He asked Governor Hickel what he thought about a strategy such as building a facility and letting the market determine where the gas goes.

GOVERNOR HICKEL answered that the market is there. Meeting with top people in China a month ago, he was told they have two thousand billion dollars and are willing to help build a pipeline; they don't want to own it, but want a guarantee that they can buy some of the LNG. He stressed that the market isn't

the Lower 48, where there is lots of competition, but is China, India, Japan, Hawaii, and so on. It won't happen without LNG, he said, which is changing the world.

SENATOR DYSON asked: Is the lack of a great market for Alaska's natural gas on the West Coast because of the existing supply and because regasification permitting in that area is difficult?

GOVERNOR HICKEL affirmed that, adding that the best way to get it from the arctic to a world market is by sea from Valdez.

SENATOR DYSON told Governor Hickel that if he can influence the federal government to allow exploration in the eastern portion of the Cook Inlet basin on federal land, he'd appreciate it.

CHAIR HUGGINS thanked Governor Hickel and asked that he continue to provide counsel.

The committees took an at-ease from 9:26:42 AM to 9:47:37 AM.

Net Present Value - Black & Veatch

PATRICK GALVIN, Commissioner, Department of Revenue (DOR), began by saying today's presentations provide perspective on how the evaluation criteria fit into the decision legislators must make. The economic analysis comes out of the Alaska Gasline Inducement Act (AGIA) statute. For any AGIA license application, the state is obligated to review the project's NPV to the state. While the primary purpose is to identify what maximizes the economics to the state, it also allows comparisons among projects.

COMMISSIONER GALVIN said more important now is how the economic/NPV analysis factors into the likelihood of success. Much of what has been presented in Juneau and Anchorage looked at risk sensitivities to projected factors such as gas price, cost, and available gas. Today, the sensitivity analysis would be shown in the context of the likelihood of success even under worst-case scenarios. Black & Veatch had been asked to focus on low-gas scenarios, for instance.

COMMISSIONER GALVIN emphasized that all of the runs were done assuming no expansion in the 25 years. Whereas yesterday there was discussion of when Point Thomson gas might be available, today's analysis assumes if it isn't available at the beginning, it won't come in at all, an extremely conservative assumption. This analysis doesn't try to identify the optimal pipeline. He turned the presentation over to Black & Veatch.

9:52:42 AM
CHAIR HUGGINS asked why AGIA says "sufficiently maximize" rather than "maximize" and whether that can be done.

COMMISSIONER GALVIN replied that he didn't recall much discussion of that qualifier. In other contexts, he has seen that the idea of maximizing benefits can be taken to an impossible extreme; thus a qualifier often allows a reasonable case. He indicated the administration took its obligation under AGIA in this respect to be the obligation to identify and look at alternatives and then decide whether going forward with the license would be better than those alternatives.

CHAIR HUGGINS, in reply to Representative Gardner, deferred response to Governor Hickel's testimony until later.

9:56:05 AM
SCOTT SMITH, Vice President, Black & Veatch Corp., gave his background, noting that Black & Veatch focuses on the energy sector worldwide. As part of the consulting organization that focuses primarily on the energy sector in North America, he leads the market analysis portion, dealing with markets; pricing; and valuation of assets, midstream assets in particular. With Black & Veatch and its predecessor consulting firms about 10 years, he worked for upstream exploration and production (E&P) and marketing companies in the prior 15 years.

MR. SMITH began a PowerPoint presentation titled "Overview of the Methodology Utilized to Determine the Net Present Value to Stakeholders"; a hard copy was provided. He addressed slide 2, which said:

> What are the key factors to determine NPV?
> 1. An estimate of cash flows, net, by year:
> - Includes capital expenditures, operating expenses and revenue
> 2. An assumption about the discount rate.

He added that variations in capital spending, pricing, tax revenue splits, and so forth create different cash flow splits for parties over the years. He turned to slide 3, which had the following points and a footnote citing Section 4.1 of the "NPV Report" for discussion of discount rates in the NPV analysis:

> A discount rate is needed to calculate NPV for each project stakeholder

Discount rate is a price. It is the price associated with waiting to get a benefit, versus getting a benefit today.

Many factors can influence the price of waiting (discount rate). These include: alternative investment returns, [one's] cost of capital, general inflation conditions, concern for the well being of future generations

Discount rates vary by stakeholder:
- State - 5% (Sensitivities of 0%, 2%, 6%, 8% were also used)
- TransCanada - 8.8%
- Producers - 10% and 15%

MR. SMITH suggested thinking of the discount rate as the amount someone is willing to take today instead of waiting to receive dollars over time in an annuity-type structure, acknowledging a dollar is worth more today. Because the producers, the state, and TransCanada are all different, the assumptions used different rates for each, for the reasons shown.

MR. SMITH explained that AGIA requires several discount rate assumptions to be used to test the sensitivity of the NPV benefits to the state. While a rational argument could be made that 5 percent may be too low - since alternate investments such as the permanent fund might yield 8 percent - 5 percent was settled on for this analysis, partly because it is consistent with earlier analyses.

MR. SMITH indicated the nearly 9 percent used for TransCanada is a blended rate based on TransCanada's cost of equity, the return on equity expected for the pipeline coupled with debt costs for the project. And while 15 percent is more typically used by the producers for evaluating projects, a lower rate of 10 percent was also run to understand the sensitivity for this particular project. There isn't much capital investment required to get Prudhoe Bay into production, he noted, although shipping commitments must be signed, assuming it is a third-party pipe.

10:03:30 AM
MR. SMITH added that by being consistent, this allows comparisons of a 4.5 billion cubic feet a day (Bcf/d) pipeline versus 4.0 Bcf/d for the state. If looking at different pipe assumptions, it allows understanding how the NPV would vary.

However, it makes it harder to compare the state and producer NPVs because of the different discount rates. Thus when comparing among all entities, cash flows provide a better comparison than NPVs.

The committees took a brief at-ease at 10:06:03 AM.

MR. SMITH addressed slides 4-6, illustrating the decreased value of cash flows over time due to inflation. Highlighting slide 5, "Net Present Value (NPV) calculates how much a stream of future cash flows are worth today," he said at a discount rate of 5 percent, $100 today will be worth half that much in 20 years from an NPV standpoint. As shown on slide 6, $245 billion of undiscounted cash flow for a 4.0 Bcf/d project for the state is equivalent to a $61 billion NPV.

10:08:55 AM
MR. SMITH turned to the second presentation, "Net Present Value (NPV) Analysis"; a hard copy was provided. Noting that AGIA requires an analysis of the NPV benefits to the state and arguably the different stakeholders, as well as the likelihood of success, he explained that Black & Veatch was asked to run calculations under different scenarios.

MR. SMITH explained the process. He said first they interfaced with Goldman Sachs for inputs into the model, worked with the technical team to understand cost estimates, and then aggregated the information into the economic analysis. They used prices and costs to figure cash flows and then converted that into NPV. Then they did scenario or risk analysis, for instance, what happens to cash flows and NPV benefits to the state and other stakeholders if production or prices don't match the estimates.

MR. SMITH discussed slide 2 of the second presentation, which had the following points:

Project Economics are Robust

NPV for Key Stakeholders Indicates Positive NPV for 4.0 Bcf/d project that does not rely on Pt Thomson

NPV Results are Sensitive to Many Factors with Commodity Prices being the Most Significant
- Producer NPV Remains Positive with Low Market Price Assumptions

4.0 Bcf/d project has acceptable netback risks, lower reserve risk than 4.5 Bcf/d project with Pt Thomson gas

NPV positive across wide range of project cost outcomes, cost escalation scenarios

Tariffs for Smaller Pipeline Configurations (4.0 & 3.5 Bcf/d) Increase by 13% to 21% Relative to the 4.5 Bcf/d Proposal Base Case

MR. SMITH elaborated. He said overall, given the base assumptions and variations, Black & Veatch sees a robust project. Last week in Juneau there was discussion of a liquefied natural gas (LNG) scenario, different pipeline sizes, and supply cases of 4.0 Bcf/d and 3.5 Bcf/d, to understand whether the project is economic to the state, the producers, and TransCanada.

MR. SMITH pointed out that it was found to be economic for all scenarios looked at, with significant cash flows and NPVs. For instance, the 4.0 Bcf/d case has a significant benefit to the state, more than $60 billion, and sizable benefits to the producers.

MR. SMITH added that the biggest risk is the price of gas when it is finally sold. So scenarios included various price assumptions, and a risk assessment was done to understand the implications of escalation, inflation, and so on; this would be addressed in more detail. The effort was to make it as transparent as possible to highlight risk and benefits.

10:14:49 AM
CHAIR HUGGINS asked what is meant by "lower reserve risk" with respect to the 4.0 Bcf/d case discussed on the slide.

MR. SMITH indicated Black & Veatch had looked at scenarios where the pipeline is full over the entire evaluation period and then what happens if the contract period is cut from 25 years, as proposed by TransCanada, to 20 years. That reduces the reserves required to fill the pipeline over time.

MR. SMITH reported that the amount of yet-to-find (YTF) gas for the 4.5 Bcf/d case is approximately 25 percent; that includes Point Thomson. But for a 4.0 Bcf/d project over 20 years, without Point Thomson, the YTF gas drops to 15 percent. So

there is lower risk because of the lower volume and the shorter contract term.

10:15:53 AM
REPRESENTATIVE SAMUELS expressed concern because this changes two variables. He asked why that wasn't done with the 25- or 20-year term with respect to the YTF gas, as well as the difference in the tariff without changing the length of time.

MR. SMITH replied that information in the back of the packet details this; he also would provide further information to make it an apples-to-apples comparison. He agreed that the base assumption for a 4.5 Bcf/d case and a 25-year contract term proposed by TransCanada is different from the Black & Veatch base assumption for the 4.0 Bcf/d at 20 years.

10:17:02 AM
MR. SMITH continued with slide 2, noting Black & Veatch sees positive NPV benefits and cash flows across different outcomes and scenarios. Emphasizing tariff differences, he said they'd started with a tariff around $4.70, given the technical team's input for the 4.5 Bcf/d case. That tariff increases 13-20 percent as volumes decrease; at 3.5 Bcf/d it's about $1.00 more. They looked at those sensitivities, cash flow differences, and related NPV benefits. Ms. Poduval would address cash flows, NPV projections, and the production scenarios.

10:18:08 AM
SENATOR STEDMAN asked Mr. Smith to spend a little time on price, including historical data.

MR. SMITH directed attention to a graph for 2008-2044 labeled "Various Price Forecasts were Considered in Analysis." The following were depicted: Wood Mackenzie AECO forecast; estimated Energy Information Administration (EIA) AECO Forecast; and Black & Veatch base case, "P10," and "P90."

MR. SMITH explained that the Wood Mackenzie base case, used for the apples-to-apples comparison across different projects, was selected after discussion with the state. It's an independent forecast; that independent consultancy does worldwide market analyses and provides views to players across the world - including the North Slope producers - on prices for oil, natural gas, and so on. That forecast is well known and paid for. In addition, Wood Mackenzie provides a specific forecast to AECO.

MR. SMITH noted the projected price for 2008 is around $6.00, lower than current prices. This is a fundamental base case for expected supply and demand. While the project must be looked at for a 25-year period, that isn't expected to start until 2018-2020; market prices don't go out past that, so they rely on forecasts. The chart shows supply and demand starting off fairly low compared with today and increasing so that by 2045 it's around $30.00.

MR. SMITH said prices over the last 3 or 4 years have been in the $5.00 to $6.00 range. In the late 1990s and early 2000s, prices were $2.00 to $3.00, with a gas surplus, whereas today there is no production shut in and LNG supposedly is a new marginal source of supply for North America. So there are higher price expectations than historically, but the forecasts start at a lower price point than the current market.

10:22:40 AM
SENATOR STEDMAN noted the legislature spent time looking at oil prices and hadn't received forecasts close to what has happened. He expressed concerned that if they go back before 2008, forecasts won't reflect future gas prices, and that an ever increasing price makes an NPV analysis more positive. He requested that time be spent looking at price sensitivity if prices stop rising so much. He also recalled that folks from the Federal Energy Regulatory Commission (FERC) had indicated there is a lot of momentum with respect to Lower 48 gas and LNG.

MR. SMITH replied that the end of the presentation gets into an analysis that removes the forecasting element. Forecasts aren't spot on. Also on the slide is an EIA forecast; these are published annually by the U.S. Department of Energy and provided free to the public. Black & Veatch estimated what EIA would project for AECO prices; EIA doesn't provide projections for Canada but provides one for Louisiana, which Black & Veatch converted after finding that EIA forecasts had underestimated prices over the last 15 or more years.

MR. SMITH explained, for example, that the EIA forecast doesn't include assumptions about carbon costs and carbon emissions. General predictions of industry consultants such as Black & Veatch and Wood Mackenzie include a general expectation of repercussions from environmental legislation that potentially will push the demand for natural gas, thus pushing prices upward because natural gas generates less carbon as a whole.

MR. SMITH, while agreeing that prices don't always behave in this linear fashion, said Black & Veatch generally believes prices will be higher rather than lower. In large part, this is because of cost of finding reserves has increased substantially over the last 5 or so years.

10:27:54 AM
SENATOR STEDMAN asked about concern about downward price pressure because of increasing volumes from the Rockies and Alaska.

MR. SMITH replied that he agrees there would be some impact on prices from Alaska's gas. After looking at pricing forecasts by Wood Mackenzie and EIA, Black & Veatch sees prices dropping around 20 cents in North America because of that supply; it is imbedded in these prices.

MR. SMITH turned to new supplies from the Rockies or Pennsylvania and New York, as mentioned by Governor Hickel. Mr. Smith said while those are new resource potential for the Lower 48 or North America as a whole, the question is how much they'll cost to produce. Through technology and higher prices, these shale plays and nonconventional resources are now becoming economic. If prices were $4.00 like 5 years ago, however, the cost to recover them would be too high. Thus those are more supportive to the price.

10:29:55 AM
REPRESENTATIVE BUCH gave his understanding that Henry Hub prices were established primarily because of proximity, since 17 pipelines crossed at that point. Referring to Senator Stedman's question about price, he asked: If we continue in the same vein, where will we be with the AECO Hub market? Will it change how natural gas is priced if Alaska starts bringing in a substantial volume across Canada to the Lower 48?

MR. SMITH replied that the New York Mercantile Exchange (NYMEX) uses Henry Hub in Louisiana as a delivery mechanism for contracts being bought and sold, so it tends to be a well referenced point for pricing; it's prices in southern Louisiana and nowhere else. Although EIA doesn't do it explicitly, each forecast has to factor in increased gas in a particular part of the pipeline grid and how that price relates to Henry Hub.

MR. SMITH provided an example of what was assumed. Noting the AECO price is the price delivered into Canada, he said Wood Mackenzie believes by the late 2025-2030 time period, prices

will be higher in Canada than Louisiana; this relates to expectations for LNG import into Louisiana and declines in Western Canadian production.

MR. SMITH said looking at the EIA forecast, however, Black & Veatch assumed a flat discount for AECO prices because that's traditionally been seen there and also for consistency with how TransCanada evaluated its application; thus 75 cents was deducted when comparing that with Louisiana prices.

MR. SMITH relayed his opinion and that of Black & Veatch, that they expect prices in Canada to be slightly lower than in southern Louisiana, more in the traditional range of 50 cents to a dollar, depending on the time period. Referring to Henry Hub, he emphasized factoring in the supply-and-demand drivers in Canada when the gas is delivered, to ensure the price is appropriate for that point and to value the economics to that.

MR. SMITH added that Black & Veatch does factor in such elements, recognizing there are different and distinct markets and trying to understand the pricing pressures in Canada as these fundamentals change, including gas from Alaska showing up if a pipeline is built in the 2020 timeframe.

10:34:32 AM
REPRESENTATIVE NEUMAN surmised that the demand wouldn't be as steep as shown here in the outer years because of the growing global demand for renewable resources such as solar energy, wind power, hydroelectric power, and so on. He asked how much of that is factored into the price forecasts.

MR. SMITH explained that demand has three main components. First, the core North American demand - residential and commercial heating of spaces and water - traditionally has been population-driven and slow growing, about 1 percent a year. Second, industrial demand has been flat or declining slightly because of high prices since 2000, when there was lots of ammonia production for fertilizer by companies like Agrium; depending on the scenario viewed, that won't significantly drive demand or growth. Third is power generation, which for natural gas is three to four times larger in size, although it is small in aggregate compared with coal-fired or nuclear generation.

MR. SMITH highlighted the different opinions, saying it is uncertain. The base projection from EIA's current forecast has substantial renewable-energy growth, relatively flat gas-demand growth, and nuclear generation at the tail end of the period.

By contrast, Wood Mackenzie has a more robust view of how much gas-fired electrical generation will be put in place to meet the growth.

MR. SMITH also said nobody knows what legislation relating to carbon will influence choices that electric utilities make for generation, or what will happen with respect to renewable energy and demand-side management. It is factored in, in some sense, in the scenarios Black & Veatch includes, as well as the other sensitivity analyses on pricing that will be detailed later.

REPRESENTATIVE NEUMAN suggested the uncertainty is what Senator Stedman was getting at. While many forecasts appear to be based on past demand, he said renewable resources are starting to gain momentum now, particularly in the industrial area. He predicted this will change even more.

10:39:49 AM
SENATOR STEDMAN asked about forecasts for oil, since it has a relationship with gas.

MR. SMITH replied it isn't in the presentation, but Black & Veatch has a fairly conservative assumption for oil prices, looking at EIA and Wood Mackenzie. Wood Mackenzie's forecast for oil is around $75, escalating to about $200 in the 2044 timeframe. It has a profile similar to gas, starting at a fairly low level, although today's spot prices are substantially higher than the base forecast.

MR. SMITH said for oil and natural gas prices, there has been volatility over the years; one could argue either way, that there is or isn't a relationship. For example, there was a low oil-to-gas price relationship when hurricanes Rita and Katrina caused gas prices to shoot up to $15; today, oil prices are 10 times higher than gas prices, and sometimes that has gone up to 12 or 13 times higher. The markets are related, but not in all regards.

MR. SMITH addressed average prices, noting over the past 10 or so years those have been around 8:1, meaning if gas were at $10, it would equate to $80 a barrel for oil. As a general expectation, the forecasts of Wood Mackenzie, EIA, and Black & Veatch have shown a higher oil-to-gas relationship initially, through the evaluation period of 2008-2020, and then declining to a more traditional type of range and the 8:1 ratio.

10:43:26 AM

REPRESENTATIVE GATTO suggested a fourth component of demand, transportation. He opined that natural gas for automobiles would cost the equivalent of $1.80 a gallon if there were that ability. He asked whether this is a possibility, whether it is included in the model, and whether Black & Veatch has even considered it.

MR. SMITH answered that the general expectation, from what he recalled in assumptions used by Wood Mackenzie or EIA, is that fuel for transportation would be a relatively minor component of natural gas demand through time. The bulk of the demand will come from space heating for residential and commercial customers, even though it's growing slowly, and from fueling power-generation facilities for electricity. He turned the presentation over to Ms. Poduval.

10:44:54 AM
DEEPA PODUVAL, Black & Veatch Corp., explained that today's focus would be on scenarios that assume Point Thomson gas won't be available, smaller pipeline configurations than shown previously for the 4.5 Bcf/d proposed by TransCanada. Black & Veatch had looked at 4.0 Bcf/d and 3.5 Bcf/d cases.

MS. PODUVAL showed slide 3, "Production Assumptions: 4.0 Bcf/d Case," a graph showing years 2020-2044 and the following areas: Prudhoe Bay Unit (PBU)/state existing, state yet-to-find, and federal onshore, with this note for the latter two: "Yet-to-find production assumes a 50/50 mix of State/Fed Onshore reflecting ratio of available reserves."

MS. PODUVAL explained that this assumes Prudhoe Bay produces about 3.5 Bcf/d of gas initially to flow through the pipeline, with other state existing fields supplying 0.5 Bcf/d. As production declines from those, it assumes gas from onshore YTF fields in the Foothills and National Petroleum Reserve-Alaska (NPR-A) will become available around 2030, split 50/50 between those two, which appear to be head-to-head from an exploration and development perspective now.

10:48:00 AM
REPRESENTATIVE SAMUELS asked: So, after 12 years the flows would drop significantly, and the thinking is to get financing on a project in 2020 based on those other two areas?

MS. PODUVAL specified that this assumes after 10 years of production, starting in 2020-2030, proven reserves at Prudhoe Bay and the state existing fields will start declining and YTF

gas will become available to fill the pipeline. She noted that later Mike Elenbaas would address the economics of a really conservative assumption that has no Point Thomson gas and not even 1 Mcf of YTF gas.

10:49:13 AM
SENATOR STEDMAN highlighted firm transportation (FT) commitments to get the pipeline financed. He said Chevron and other producers had indicated they weren't excited about committing to YTF gas at the open season. He asked how the financing mechanism would play into YTF gas when someone would have to bid that for 10-11 years.

MR. SMITH answered that there are a couple of issues. TransCanada's proposal assumes a 25-year contract term, with recovery of the asset over that time; it puts all the risk of reserves and producing that on the initial shippers. An initial shipper isn't necessarily precluded from assigning capacity to another party; FERC regulations allow that to get rid of the contract risk, although no one has to buy it.

MR. SMITH said furthermore, as shown in the Black & Veatch report, initial shippers may negotiate with TransCanada for a contract term different from the depreciable life, say, 20 or 15 years. It isn't uncommon for Lower 48 pipeline projects to have some reserve risk on the back end. For this analysis, however, at least for the base case scenarios, Black & Veatch assumed 25 years, or, in this case, a 20-year contract period and 20-year life.

10:52:16 AM
SENATOR STEDMAN asked about initial financing to build it.

MR. SMITH replied that obviously there have to be initial contracts for that capacity. The question is whether they'll take all of the risk on the back end or whether some mechanisms contractually put some risk back onto the pipeline itself; that is subject to negotiation, and Black & Veatch has looked at scenarios to understand what happens to an initial shipper's expected cash flow and NPV benefit if that shipper is on the hook and has to pay for transportation in the out years but doesn't have gas to fill it.

COMMISSIONER GALVIN, in response to Chair Huggins, explained that the runs are in the Black & Veatch report and the "finding" chapter; he offered to present those as slides. Regarding Senator Stedman's concern, he said a number of mechanisms will

be worked out among the parties between now and the point of financing. The state can't anticipate what that arrangement will be, but can look at whether there is enough of an economic opportunity for the parties to find such an arrangement.

COMMISSIONER GALVIN said this will be financed based on FT commitments. Whether those FT commitments will be made was analyzed from different perspectives, including whether sufficient cash flow from the project will justify somebody taking on that risk. The analysis included the risk and economics associated with finding the additional gas or the conservative case of finding none, to see whether this would still be an economic opportunity. It was found that, yes, it would still pay for itself.

MR. SMITH noted that a related slide is part of the sensitivity analysis.

10:56:58 AM
MS. PODUVAL added that the Black & Veatch modeling for the risk of having no YTF gas assumes that initial shippers would bear the risk for the transportation capacity through the contract period. That would be addressed by Mr. Elenbaas.

MS. PODUVAL showed slide 4, "Production Assumptions: 3.5 Bcf/d Case," a graph like slide 3. She said this assumes 3.0 Bcf/d from Prudhoe Bay and 0.5 Bcf/d from other state existing fields at the start of operations in 2020. Similar to the 4.0 Bcf/d case, as production declines at those fields, YTF gas is assumed to keep the pipeline full.

MS. PODUVAL pointed out that while both these cases are very conservative in assuming no expansion of this pipeline, other producers such as Chevron or Shell that are on the North Slope exploring could have production during this period that triggers expansion.

MS. PODUVAL discussed slide 5, "Production Assumptions used in the NPV Analysis for the 4.0 Bcf/d Conservative Base Case," which had the following points:

Prudhoe Bay
- 24.5 Tcf
- Initial production rate - 3.5 Bcf/d

State existing
- 3.7 Tcf:

- Colville River - 0.4 Tcf
- Duck Island - 0.8 Tcf
- Kuparuk - 1.2 Tcf
- Northstar - 0.5 Tcf
- GPMA - 0.9 Tcf

- Initial production rate - 0.5 Bcf/d

Note - this case assumes NO Point Thomson production

MS. PODUVAL said the reserve assumptions were 24.5 trillion cubic feet (Tcf) of hydrocarbon gas available from Prudhoe Bay and 3.7 Tcf at the state existing fields, as shown. She recalled that PetroTel talked about maybe cycling the Point Thomson reservoir for 10-15 years, extracting the liquid oil as well as condensate production, at which point it begins to make economic sense to start producing gas to optimize hydrocarbons there. But she said that isn't taken into account under this very conservative assumption of no Point Thomson gas.

COMMISSIONER GALVIN, in response to Chair Huggins, specified that this is throughput. He offered to go through the technical report to find what production would satisfy the throughput for both production consumption as well as the fuel consumption on the line. As Mr. Smith had indicated, he said the Black & Veatch economic model aggregates the various reports; the associated technical report is a separate sub-basis.

11:02:27 AM
REPRESENTATIVE NEUMAN referred to the 4.0 Bcf/d assumptions and the fact that it takes energy to produce this gas. Suggesting there'll be gas taken for Alaskans and expressing hope for a spur line using 2.0 Bcf/d of LNG, he said there are existing LNG plants to keep running, he'd like more value-added products, and gas-to-liquids (GTL) production will be required by the federal government. Thus there'll be competition for the 4.0 Bcf/d in the mainline to Canada, hopefully for in-state use. He asked that those be brought into the picture.

COMMISSIONER GALVIN replied that he sees the root of the question as whether, for this analysis, FT commitments and investments will result in a pipeline. The administration isn't saying a 4.0 Bcf/d line is the optimal size and has said a Y-line with LNG and these other components is the big goal. The reason for this particular analysis, however, is to see whether it can get off the ground with just the known resources at Prudhoe Bay and the surrounding fields, without Point Thomson.

COMMISSIONER GALVIN added that where those molecules end up will be a function of where the economic benefits are realized. From this stream there'll be some royalty gas, and the state may decide to take it off before it ultimately gets to market. But that market value will have to be obtained. As for LNG and other opportunities, the hope is to find additional gas to fill those needs as well. Those are separate questions. This particular analysis looks at a whether a 4.0 Bcf/d pipeline to market can be financed even in a worst-case scenario.

MS. PODUVAL specified that Black & Veatch assumed about 5 percent fuel loss at the gas treatment plant (GTP), which was provided by the technical team. The volumes shown are going into the pipeline after the GTP. The production volumes will actually be greater than the 3.5 Bcf/d from Prudhoe Bay and the 0.5 Bcf/d from state existing fields.

11:07:04 AM
CHAIR HUGGINS said the committee would still like the numbers. He asked whether the administration has discussed with TransCanada what minimum volumes TransCanada is looking to get to AECO.

COMMISSIONER GALVIN recalled that Mr. Palmer of TransCanada said the open season will be open to in-state gas, LNG, and Canadian destinations and that TransCanada hasn't put a minimum that would be required to go to AECO. What TransCanada described in its application is a pipeline that will be appropriately sized for everything down to 3.5 Bcf/d. That's for getting it to the ultimate destination.

11:08:14 AM
REPRESENTATIVE GARA asked the reason for this analysis, since nobody knows what gas will be available for this pipeline and if it is or isn't available for TransCanada, the same is true for the producers' project. It seems the uncertainty will be resolved as the project moves ahead, he suggested.

COMMISSIONER GALVIN replied that is correct for comparing the Denali and TransCanada projects, which clearly deal with the same gas-supply issues and whether that affects their viability. However, this analysis relates to whether to grant this license and commit the state's matching funds. The administration wouldn't advocate for granting a license if they didn't believe there is a good likelihood of success. So it goes to whether there is sufficient gas at only Prudhoe Bay and the surrounding

fields to possibly finance and get this project off the ground. They'd found the answer is yes.

COMMISSIONER GALVIN added that while the ultimate prize is all the YTF gas that will be encouraged through the open-access provisions and ultimately discovered so the pipeline will expand, the first objective is to get a pipeline. As to whether issuing a license will likely result in a pipeline, the administration believes from this analysis that the answer is yes, even in the most conservative case.

CHAIR HUGGINS said $19 million has been spent to get this information, and he'd like to understand what it is; that's the reason for his question.

11:11:34 AM
MS. PODUVAL addressed slide 6, "Expected Tariffs from the North Slope to the AECO Market," a graph labeled "AECO Tariff" that showed tariffs of $4.73 at 4.5 Bcf/d, $5.33 at 4.0 Bcf/d, and $5.71 at 3.5 Bcf/d. Noting 4.5 Bcf/d is the base case proposed by TransCanada, she said the tariff increases by about 13 percent for 4.0 Bcf/d and about 20 percent for 3.5 Bcf/d.

MS. PODUVAL explained that the assumptions behind the tariffs are capital costs estimated by the technical team. They'd assumed the pipe size is 48 inches all the way from the North Slope to Alberta. However, they'd changed the assumption of how much compression would be needed. Capital costs go from about $31.3 billion down to $29.4 billion when going from 4.5 to 4.0 Bcf/d. However, the volume is reduced over which those costs are spread, thereby causing the tariffs to increase as shown, 13 to 20 percent over the 4.5 Bcf/d case.

11:13:38 AM
REPRESENTATIVE SAMUELS recalled that a 2005 Econ One presentation showed a $2.65 tariff to AECO. He asked why costs have nearly doubled since then and how confident Black & Veatch is about this cost estimate.

MS. PODUVAL answered that over the last four or five years there has been an enormous increase in capital costs and the cost of steel. She mentioned an estimate that from 2005 to 2008, costs rose about 80 percent on the upstream side. So these estimates take that escalation into account, as well as 4 percent escalation year over year, about 65 percent from 2008 to when the pipeline is constructed. That is the technical team's assessment of what capital costs will be.

MS. PODUVAL explained that Black & Veatch did a risk assessment, asking what happens to the project economics if costs are much higher or lower than base estimates; Mr. Elenbaas would discuss the analysis results. While nobody can accurately predict the cost by the time this pipeline is constructed, she said Black & Veatch tried to use the best information available to see whether the project still works even if costs aren't as expected. The analysis seems to show it will work.

REPRESENTATIVE SAMUELS expressed concern from the standpoint of someone with a 20-year FT commitment whose costs have doubled in two years and whose future costs are likely to rise so much.

MS. PODUVAL pointed out that as costs rise, so do prices tend to rise. That's one reason the project remains profitable despite a twofold increase in tariffs since they were last estimated.

REPRESENTATIVE SAMUELS asked how long a lag time is anticipated if prices drop. He suggested the worst case would be if steel were bought at high prices.

MR. SMITH replied that he didn't recall what the lag would be in some of the analyses Ms. Poduval referred to. Recent history has shown dramatic increases in prices and capital costs. Also, he didn't recall whether the GTP was included in the Econ One analysis number. For instance, if the reference point on the $4.73 has about $1.25 of tariff associated with the GTP, that could explain some difference. However, he'd expect the tariff to be higher regardless because of the increased capital costs.

SENATOR STEDMAN highlighted tables in the Black & Veatch report, noting one on page 121 gives a breakdown of the tariff with the GTP in the Alaska section, Yukon, and Alberta, and then a total tariff of $4.73. He indicated a table on page 31 addresses the five-year equity reduction if there's a cost overrun, looks at whether or not the federal loan guarantees are used, and then looks at a 40 percent cost overrun. He said that marginal spread on the tariff from $4.73 to $5.90 ends at $1.24.

SENATOR STEDMAN surmised a 40 percent cost overrun might not be unreasonable and thus that $1.24 tacked on to the tariff would push the 4.0 Bcf/d tariff to $6.57 and the 3.5 Bcf/d tariff to $6.95. He recalled that for the old estimates the legislature was working with, it was $2.65 and a $3.50 stress price. He asked: If there were a 40 percent overrun and a tariff of about $6.60, what stress price would collapse this project?

11:20:13 AM
MR. SMITH responded that TransCanada's proposal tries to mitigate exposure, but doesn't do so completely; scenarios can be seen where that $4.73 in the base case can get to around $6.00 for a tariff if there is a 40 percent overrun in certain instances. Also, given existing price scenarios and those for NPVs that were run, the economics still are favorable with a 40 percent cost overrun. The price expectations start in the $7.00 range in 2008 and rise to over $10.00. Thus a $6.00 tariff still gives a netback margin to the stakeholders.

SENATOR STEDMAN said one issue is risk exposure. Page 30 of the report says this project doesn't insulate shippers from cost overruns, although page 31 has a table that reflects in TransCanada's proposal its five-year reduction on equity and use of the U.S. federal loan guarantees, which Goldman Sachs had talked about. He said compared with the project proposed by the previous administration, there doesn't seem to be as much emphasis in reviewing the sensitivity of the tariff versus the stress price. He clarified that he was looking for some comfort that the analysis isn't being driven by the desired solution.

MR. SMITH answered that Black & Veatch had tried to look at pricing independently with respect to different scenarios and costs, relying on the cost overruns in a couple of ways. First, the analysis of projected costs was developed by the technical team, which projected a range higher than TransCanada had proposed; these were based on schedule shifts and so on. That could lead to changes in the tariff.

MR. SMITH said secondarily Black & Veatch looked at tariff implications for 20-40 percent cost overruns. They'd looked at what happens if one doesn't believe the price forecasts of Wood Mackenzie or EIA and instead the project is just stressed relative to a price of $5.00 today. They'd looked at analysis around the base price case assumptions relative to tariffs at those price levels, but hadn't combined them. They'd looked at stressing the project at $5.00, $6.00, and $7.00, leaving those effectively flat through time. He offered to get into that now or wait until that point is reached in the slide presentation.

SENATOR STEDMAN said it could be done in the presentation. He suggested he was perhaps looking at it too simply, with a tariff of $7.00, since $7.00 plus gas would be needed.

MR. SMITH concurred. He said there are a lot of moving parts. Keeping it specific is a clear way to understand the risk for the stakeholders. This would be detailed in the price sensitivity analysis.

11:26:17 AM
MS. PODUVAL discussed slide 7, "4.0 Bcf/d Conservative Base Case Cash Flows," which had an upper graph labeled "Cash-flows to Stakeholders" and a pie chart labeled "Total Net Cash Flow for Project by Stakeholder (Non-Discounted, 2008-2044)." The latter showed the following: U.S. Government $107 billion, 19%; Canadian Government $10 billion, 2%; State of Alaska $245 billion, 44%; TransCanada $55 billion, 10%; and Producer $137 billion, 25%.

MS. PODUVAL noted the pie chart showed TransCanada's cash flows as it spends capital to build the pipeline and cash flows from tariff revenues. The top graph showed cash flows through time for the state, producers, and U.S. government, with a little sliver for the Canadian government.

MS. PODUVAL emphasized that the state's cash flows from this project will grow through time. This is driven by increased prices and progressivity on the ACES production tax - from the Act known as Alaska's Clear and Equitable Share - that kicks in at higher prices. Since over time the state's production tax increases, its share of the total cash flows increases accordingly.

MS. PODUVAL relayed the percentages for each stakeholder shown on the pie chart, noting this is through the 25-year analysis time period and is in nominal dollars, not discounted back to 2008 to be expressed as an NPV yet. This is just total, year-to-year cash flows, amounting to $245 billion to the state, 44 percent of the total cash flows from this project.

11:28:51 AM
SENATOR STEDMAN returned attention to a previous slide and mentioned the tax progressivity that also relates to oil. He asked: When the analysis was done on future gas prices, what oil price assumptions were used for the chart from 2008-2044?

MS. PODUVAL replied this goes back to the oil price forecasts from Wood Mackenzie mentioned by Mr. Smith, which are tied into its gas price assumptions. Those oil price assumptions are about $81 in 2020 and $227 in 2044.

MR. SMITH added that page 106 of the NPV report shows those, which Black & Veatch used as a basis in this analysis.

COMMISSIONER GALVIN highlighted the importance with regard to progressivity that the state must address at some point. The administration had to build into the model the current tax code, he noted, which has progressivity based on a fixed $30 trigger for the margin; that doesn't change with time, inflation, or expected costs. When it gets to where the projections have both gas and oil prices rising with inflation, particularly in 2030-2040, the state portion of the revenue stream increases fairly dramatically because that progressivity isn't being adjusted for inflation.

SENATOR STEDMAN inferred that this chart might be a little optimistic.

COMMISSIONER GALVIN agreed. In response to Chair Huggins, he clarified that the tax regime is fine in terms of the economics of this project. Whether it needs to be adjusted for other reasons is open to further discussion.

11:32:45 AM
REPRESENTATIVE DOOGAN asked whether this assumes TransCanada is building the GTP.

MS. PODUVAL affirmed that.

REPRESENTATIVE DOOGAN, noting TransCanada's proposal states a preference that someone else build the GTP, asked: If we assume instead that the producers build it because of tax credits, would the state's revenue profile look more like TransCanada's, with negative cash flow from this project to start with?

COMMISSIONER GALVIN replied that the GTP is outside the tax credit program right now. The only change would be that the cash flows for the producers and TransCanada would shift a bit.

11:34:11 AM
MS. PODUVAL elaborated on slide 8, "The State's NPV5 is Lower with Smaller Project Capacity but Remains Significant," a graph showing $66.1 billion at 4.5 Bcf/d in 2008 dollars, $60.7 billion at 4.0 Bcf/d, and $51.6 billion at 3.5 Bcf/d.

MS. PODUVAL said the approximately $61 billion represents the $245 billion on the previous slide, cash flows through time to the state over 25 years, discounted back to 2008. Thus it would

be neutral between receiving $61 billion today or $245 billion over 25 years, from 2020 to 2044; that's the NPV to the state for the 4.0 Bcf/d project, and the NPV to the state from the 3.5 Bcf/d project is still $52 billion. These are significant NPVs and returns to the state, even with smaller projects without Point Thomson gas.

MS. PODUVAL discussed slide 9, "Producer NPV Shows a Similar Trend When Compared to the State," which had two graphs. The one labeled "Aggregate Producer NPV10" showed $13.5 billion at 4.5 Bcf/d, $12.3 billion at 4.0 Bcf/d, and $10.5 billion at 3.5 Bcf/d, all in 2008 dollars. The one labeled "Aggregate Producer NPV15" showed $5.2 billion at 4.5 Bcf/d, $4.7 billion at 4.0 Bcf/d, and $4.0 at 3.5 Bcf/d.

MS. PODUVAL noted for the smaller projects without Point Thomson gas, when cash flows are discounted back at 10 percent, the producers' NPV is about $12 billion; at 15 percent, it's still $4.7 billion. So the smaller pipeline cases reduce the producers' NPVs but not significantly, as shown above.

11:36:28 AM
REPRESENTATIVE SAMUELS asked whether this assumes YTF gas will be found by someone other than the current producers.

MS. PODUVAL affirmed that. In further reply, she said this assumes the YTF gas is found to fill the pipeline and is actually found by the initial shippers on the pipeline during the contract period of 25 or 20 years. After that, it transitions to what they're calling "yet-to-find producers." Black & Veatch is assuming a 20-year contract period for the smaller pipeline cases of 4.0 or 3.5 Bcf/d.

11:38:07 AM
SENATOR FRENCH referred to a previous slide and asked: If there are 20-year contracts, why is the assumption for a 36-year project life, from 2008 to 2044? He surmised the gas pipeline would last even longer than the oil pipeline because of fewer corrosion issues and so on.

MS. PODUVAL answered that Black & Veatch is assuming the pipeline becomes operational in 2020. So the 25-year analysis period is from 2020 through 2044. Taken into account are the capital spent by TransCanada even before 2020 and the state's matching contribution. Because the discussion is today, they've discounted all those cash flows back to 2008.

SENATOR FRENCH asked why the 20-year period was expanded to 25 years.

MS. PODUVAL replied they'd kept the 25-year analysis period standardized as an assumption throughout the analysis, representing the 25-year depreciation life that TransCanada proposed in its application.

COMMISSIONER GALVIN added that for an NPV analysis, it makes a difference in the amount of cash flows that will be calculated. If the NPV numbers were shifted between a 25-year and 20-year period, it wouldn't be an apples-to-apples comparison because the cash flow for one scenario would be 5 years shorter. Thus 25 years was retained for the NPV comparison.

COMMISSIONER GALVIN also pointed out that because of the shortened contract, in these scenarios the capital costs for TransCanada are collected over a shorter time, so tariffs are higher than for a 25-year period. When it gets to that 20th year, TransCanada's cash flow ends up "falling off the cliff" because the tariff is recalculated based on the cost at that time, and the tariff in the 21st year is very small. So the cash flows for the last 5 years aren't to TransCanada's benefit.

COMMISSIONER GALVIN said for a smaller-capacity line, the issue is reserve risk. It is expected that commercial players will look to address that by having a shorter contract. The effort here is to anticipate where that will go. The tariff would be higher, but the exposure on the reserve side would be lower. So that's shown here. But to compare NPVs for a 4.5, 4.0, and 3.5 Bcf/d case, they had to keep the same timeframe for cash flows.

SENATOR FRENCH asked about the reduced tariff in the last years of the 25-year period.

11:42:10 AM
MIKE ELENBAAS, Black & Veatch Corp., specified it goes down to about $1.00. While all the capital will have been recovered by TransCanada through the first 20 years, operating expenses for the pipeline still will need to be recovered. In that last 5 years, rates get reset just to recover those.

SENATOR FRENCH asked what happens to the state's revenues after that first 25 years, since there might be another 25 years of life for the pipeline.

MR. SMITH answered that cash flows don't automatically drop then, but continue. What isn't shown is the discounted value of those cash flows in year 25, which adds to the NPV. Everything is for NPV 2008. For 2044, 35 years down the line, discounted at 5 percent, those cash flows add just a little to the NPV. If they ran a 26-year or 30-year NPV, it wouldn't be a great deal different from the 25-year NPV. Particularly when the producers are brought in at 10 or 15 percent, it's practically nothing because of being discounted back 35 years.

11:44:35 AM
MS. PODUVAL turned attention to slide 10, "Project NPV is Affected by Many Factors," which had the following points:

- Prices
- Project cost
- Project cost escalation
- Interest rates
- Cost of finding and developing "new gas"
- Etc.

Bottom line: Understanding how project economics are affected by uncertainty in inputs that affect cash flows.

MS. PODUVAL noted these uncertainties impacting the NPVs to the state and the producers are the main factors, with prices being the largest one. The previous slides had shown NPVs to the state and the producers under baseline assumptions of costs, prices, and so on.

MS. PODUVAL said the Black & Veatch analysis varied each of these, recognizing it isn't known what they'll actually be in 2020 when the pipeline is operational. Thus each factor was risk assessed, looking at what happens to the project economics if these are much lower or higher than estimated in the base case. Mr. Elenbaas would address the NPV sensitivity analysis.

11:45:46 AM
MR. ELENBAAS discussed slide 11, a tornado diagram labeled "Price is a Key Driver to Variations in the NPV5 to the State of Alaska" that listed these sensitivity factors on the left: commodity prices, cost escalation, upstream capital costs, TransCanada capital costs, pipeline interest rate, TransCanada schedule, and production scenarios. As Mr. Smith had mentioned, Black & Veatch wanted to explicitly analyze risk under different

assumptions to make more transparent how that risk impacts the project stakeholders, Mr. Elenbaas told members.

MR. ELENBAAS explained that Black & Veatch had looked at key factors listed on the previous slide and the range of uncertainty for those, asking how that impacts the state's NPV. The line in the center of this diagram shows the base case state NPV for the 4.5 Bcf/d case. Although they hadn't run the 4.0 Bcf/d case, it would show similar relative outputs. On the "x" axis, NPV to the state is plotted using a 5 percent discount rate; that varies from zero up to about $140. Then each bar of the chart looks at a different factor.

MR. ELENBAAS emphasized that based on their estimates, commodity prices have the largest impact with respect to uncertainty for the project, particularly for the state and the producers. The base case assumptions are on the right, and the Wood Mackenzie prices are in that center base line number. The far left of this price-related bar shows a very low uncertainty and a low probability of 10 percent that the state NPV for this project could be about $20 billion; on the upside is a 10 percent chance of its being nearly $120 billion.

MR. ELENBAAS noted the range for cost escalation is much less, but is obviously another big risk. The bars are in this order so higher-risk issues rise to the top. The base numbers include compounding cost escalation of 4 percent, year over year, until the project goes into service. On the high end, it was increased significantly, to 6 percent for capital costs, which increased the tariff by a little over $1.00. So cost is a big issue, modeled in a couple of ways, looking at both cost-escalation risk and cost-scope risk.

MR. ELENBAAS told members this is looking at escalation only. If the project costs $31 billion and year-over-year escalation is 6 percent for 12 years before this goes into service, there'll be a very high tariff and less money to the state, $45 billion - still a significant amount.

MR. ELENBAAS said also looked at were upstream capital costs to the yet-to-find producers that will help fill the pipe. In the base case on the center line, Black & Veatch found doubling those capital costs decreased the state's NPV somewhat, but not nearly as significantly as prices. Also looked at were the other issues shown, modeling them explicitly to look at those risks. The key take-away here is that price is the biggest uncertainty, with cost also a large uncertainty.

11:53:00 AM
SENATOR STEDMAN asked about upstream capital costs versus the capital expenditures (CAPEX) shown as 6 percent and the 100 percent increase as they relate to escalation.

MR. ELENBAAS answered that Black & Veatch looked at a baseline of 4 percent cost escalation for not only the pipeline project, but also upstream capital costs. This sensitivity looks at increasing that for all stakeholders including TransCanada and the producers, primarily the producers of YTF production that is needed. That's where most of the capital costs are.

SENATOR STEDMAN asked how a 20 or 40 percent cost overrun would fit in.

MS. PODUVAL responded that a 20 percent cost overrun is included under TransCanada's capital costs, the fourth factor from the top on the chart. Upstream capital costs are production costs at the field. Cost escalation is the year-over-year escalation applied to both TransCanada's capital costs to build the pipeline and the producers' costs to develop and produce from the different fields. On one hand, this looks at the baseline assumption for the pipeline capital costs as well as upstream production. On the other hand, it looks at cost escalation associated with the upstream and the pipeline.

SENATOR STEDMAN asked about sensitivity to cost overruns for the midstream when the line is built. With a 20 or 40 percent cost overrun, he said from this chart it appears the state shouldn't be concerned about that. He asked why the producers would be concerned about it, since they seem very sensitive to not having a cost overrun of 40 percent.

MS. PODUVAL replied this shows the NPV to the state, whereas Mr. Elenbaas has another chart showing the NPVs to the producers from varying the capital costs.

MR. SMITH added that throughout this analysis, the framework for the modeling is comparing an oil-only world to an oil-plus-gas world and thus some of the cost risk isn't as large. Higher cost escalation decreases the economics of the pipeline project to the producers, playing into it a little bit.

COMMISSIONER GALVIN surmised that Senator Stedman was addressing what happens with regard to predicted costs versus the ultimate costs, and that Ms. Poduval was saying it depends on the cause

of that difference. If it is because original cost estimates weren't fully fleshed out and additional engineering was needed, for instance, that is within TransCanada's capital costs; that has relatively less significant impact on it. If it is because costs in general escalate faster than anticipated, the costs would end up at the same point, but that would be the bar on the graph associated with cost escalation, a fairly significant bar.

The meeting was recessed from 11:58:34 AM to 1:38:45 PM.

Roundtable Discussion including Producers

CHAIR HUGGINS announced a roundtable discussion to answer questions. At his invitation, the following introduced themselves: Cathy Foerster of the Alaska Oil and Gas Conservation Commission (AOGCC); Nan Thompson, Julie Houle, and Steve Moothart of the Division of Oil & Gas, Department of Natural Resources (DNR); Craig Haymes of ExxonMobil; John Zager of Chevron - Alaska Area; and Dr. Anil Chopra of PetroTel Inc. (via teleconference).

1:41:38 PM
NANETTE THOMPSON, Unit/Tech Support, Division of Oil & Gas, Department of Natural Resources, noted she was asked three questions yesterday and had two answers but needed more time to research Senator Wielechowski's question.

MS. THOMPSON reminded members that Representative Samuels had asked DNR's opinion on the 23rd Plan of Development (POD) and she'd responded that the attorney general had advised to not comment on what DNR Commissioner Irwin substantively had decided, but instead defer to pages in the POD. Noting those are pages 29-63, she offered a copy for Representative Samuels, saying she'd testify under the same restriction today, which she has been advised is in the state's best interest.

MS. THOMPSON also noted that Representative Fairclough had asked about DNR's position on the permits, since ExxonMobil's presentation discussed the permitting process. In response, Ms. Thompson said a pre-application meeting will start in about half an hour at DNR. The pre-application process is available to anyone who potentially plans to do work on state lands.

MS. THOMPSON explained that this is an opportunity for the applicant to present information once to all potentially affected state agencies. ExxonMobil had called to say it had a project in this area and wanted a pre-application meeting; all

the different state agencies were invited to come listen. It's show-and-tell. No permits are issued until much later, after complete applications are filed.

MS. THOMPSON said DNR's position is that permits won't be issued for lands for which it doesn't have leasehold rights. But until hearing the presentation at the pre-application meeting and getting a clear idea of which leases are affected, DNR can't say whether these operations will be permitted. So this is the start of a process with the attorneys general to determine if issuing any permit is appropriate, based on the legal status of the leases. She noted yesterday she'd said the lease status is an open legal issue that DNR is actively working on.

1:44:12 PM
JULIE HOULE, Section Chief, Resource Evaluation, Division of Oil & Gas, Department of Natural Resources, addressed a question asked by Representative Roses about what gas could be put into a pipeline besides that from Point Thomson and Prudhoe Bay. She said approximate other available sources of recoverable reserves, based on DNR's annual report, are: Colville River, 400 Bcf; Duck Island, 843 Bcf; Kuparuk, 1,150 Bcf; Northstar, 450 Bcf; and the greater Point McIntyre area, 880 Bcf.

CHAIR HUGGINS noted this was covered this morning, though the figures on the slide were rounded up. He asked Ms. Foerster whether she concurred with those numbers.

1:34:28 PM
CATHY FOERSTER, Commissioner, Alaska Oil and Gas Conservation Commission (AOGCC), Department of Administration, replied she hadn't reviewed the gas reserves numbers for these fields recently and thus couldn't verify their validity. She pointed out that these are oil fields, not gas fields, and her related testimony holds true for the gas in these oil fields.

CHAIR HUGGINS requested that Ms. Foerster review those and then get back to the committee.

1:46:39 PM
REPRESENTATIVE SAMUELS recalled that yesterday Dr. Chopra talked about Point Thomson with respect to 50 percent oil recovery and then Mr. Haymes said there's probably 5 percent on the rim. He asked whether AOGCC agrees with the assumptions and conclusions that DNR and the administration's consultants have come up with.

MS. FOERSTER replied that AOGCC hasn't reviewed in detail the analysis by PetroTel, but did a cursory review of some of the assumptions and conclusions. Furthermore, AOGCC hasn't reviewed ExxonMobil's analysis in its entirety. However, AOGCC is in the process of performing an independent analysis of Point Thomson, using Gaffney Cline & Associates, which does reservoir engineering consulting and has geologists, for instance.

MS. FOERSTER noted as part of that analysis, AOGCC has access to all confidential and non-confidential data from ExxonMobil, BP, Chevron, and so forth, as well as the opportunity to review the analysis done by ExxonMobil. This allows AOGCC's analysis to be validated.

MS. FOERSTER offered her experience that whenever two separate technically competent groups take the same raw data, they'll analyze it differently, based on their assumptions and techniques because of education, experience, technical tools, and so on, and will adamantly believe theirs is correct. Because of the little data available and all the assumptions and forecasts, the only guarantee is that neither will be right. She said data AOGCC has looked at so far, and the part of the analysis AOGCC has done independently, is somewhere between the two and probably closer to ExxonMobil's.

REPRESENTATIVE SAMUELS suggested that at a policy level, if the unit is dissolved because it is believed the ExxonMobil/Chevron proposal was analyzed wrong, somebody else such as Shell will see it the state's way and develop the field that way. He asked what that accomplishes for development and getting a gas line.

MS. FOERSTER replied that she doubts Shell would come in with exactly the same analysis as ExxonMobil or Texaco because Shell would start from scratch and use its own tools and experiences.

REPRESENTATIVE SAMUELS asked when AOGCC would be done with its analysis.

MS. FOERSTER answered that right now AOGCC is at the mercy of ExxonMobil, which is setting the schedule.

1:51:42 PM

CRAIG HAYMES, Alaska Production Manager, ExxonMobil, said ExxonMobil has been underway since last August and plans to try to finish sharing the data by the end of this year. There is a significant amount to share, and it's a lengthy process because of the amount and because it's a complex field. The process is

to ensure it shares all the right information in a logical, sequential order. While there have been scheduling challenges and it might be a bit longer, the end of this year is targeted.

MS. THOMPSON said while the question intimated that Commissioner Irwin's decision to terminate the unit was based on the PetroTel study, that study wasn't part of the commissioner's decision or the record of that decision. That litigation was the end product of the company's appeal of the original decision to terminate it.

REPRESENTATIVE SAMUELS replied he understood that, but this is the information under which the administration will proceed, believing what PetroTel says and using that as the parameters with respect to Point Thomson. Thus he'd asked when AOGCC would come out with its own independent view.

1:54:06 PM
ANIL CHOPRA, Ph.D., President, PetroTel Inc., told members he wanted to address the dominant issue of data that arose yesterday and today. He drew attention to a PowerPoint presentation titled "Response to Testimony and Q/A Discussions Held on June 17, 2008"; a hard copy showed logos for both PetroTel and DNR's Division of Oil & Gas.

DR. CHOPRA relayed information from a slide labeled "Do we have enough data in Point Thomson to define a Full Field Plan of Development for both the oil and gas reserves?" that had the following points:

- 19 wells have been drilled
- 14 wells penetrated Point Thomson reservoirs
- 3600 ft of high quality core has been taken and analyzed
- 20 well tests have been completed, defining rates and pressures
- Eight 3D seismic surveys have been acquired and interpreted
- Multiple fluid samples have been taken and fluid property evaluations have been conducted

- Conclusion: The type and amount of reservoir data is sufficient to develop a Full Field Plan of Development for oil and gas development at the Point Thomson Field

DR. CHOPRA added that because yesterday it appeared some folks felt there was hardly any data, he'd gone back and compiled a list. He said ExxonMobil's testimony also spoke to what data is available and has been used.

DR. CHOPRA highlighted the tremendous amount of core, saying at least 10 wells have been cored and analyzed; 20 well tests have been completed, defining oil rate, condensate rate, gas rate, and pressures, so there is a pretty good idea of pressure throughout this high-pressure reservoir, with pressure around 10,200 pounds per square inch (psi) and excellent continuity in the reservoir.

DR. CHOPRA noted PetroTel works worldwide, having done more than 200 studies, and has seen many field plans produced with one-third of this amount of data. Thus PetroTel concluded that the type and amount of reservoir data available today is sufficient to develop a full field POD for both oil and gas in the Point Thomson field. Referring to a report from ExxonMobil, he said there is so much data already that it will take the next six months for the data transfer from ExxonMobil.

DR. CHOPRA referred again to yesterday's testimony and said the range was bracketed for gas in place; if Brookian and Pre-Mississippian are added, it could go even higher. It is known that there is gas, a gas condensate, and there is oil in this gas cap, about 660 million barrels. He emphasized that there is absolutely no reason to say there isn't enough data to do something about this field.

1:59:22 PM
DR. CHOPRA addressed a slide labeled "Response to Exxon Presentation," which had the following points:

- Exxon presented yesterday that they did not see a reduction in Pt Thomson well productivity due to condensate dropout.

- Their own published work on the Arun Field in Indonesia (with a condensate yield of 65 STB/MMSCF) shows a 50% reduction in well productivity occurring during blowdown.

- As a result, Exxon initiated lean gas injection in Arun, as soon as production began, to minimize liquid drop out and to maximize condensate recovery.

- In a blowdown scenario, 2 to 3 times the number of wells will be required to maintain the same rate. Producing oil earlier will require fewer number of wells in the long term.

- Condensate will be trapped in the reservoir in a blowdown scenario, thereby reducing liquid recovery.

DR. CHOPRA added with respect to the first point that he was really surprised by that. If Point Thomson has gas condensate and the company has taken 20 well tests showing condensate dropout and high pressure with a yield of 66, it is very similar to the Arun Field, which had a 50 percent reduction in well productivity during blowdown and a condensate yield of 65.

DR. CHOPRA addressed a graph labeled "Point Thomson Well Productivity During Blowdown." He said if there's a blowdown there, PetroTel's position is that it will require 2 to 3 times the number of wells to maintain the same rate. If gas is sold to any pipeline coming in at 1.5 Bcf/d and 15 wells are drilled, the rates will start dropping quickly and within 10-15 years it will be at one-third the gas rate and require drilling 45-50 wells because of the liquid dropout around the well bores. He asked why ExxonMobil sees the condensate drop out.

DR. CHOPRA relayed information from a slide labeled "Take Home Point: Point Thomson Blowdown" that said:

- It will require very aggressive additional drilling schedule ($100 Million/well) for up to 50 wells to maintain a stable gas rate for the pipeline for the next twenty-five years.

- This is because of the condensate dropout and the drop in reservoir pressure over time.

DR. CHOPRA indicated PetroTel's proposal for gas cycling mitigates that by getting the liquids out first so they get out of the way of the gas production and maximize liquid recovery. Half a billion barrels of oil can be produced, worth $70 billion in today's market.

DR. CHOPRA suggested implementing that field development plan and then going back to start doing the blowdown of gas. He said that gas will still be available for a future pipeline because it won't be going anywhere. As stated yesterday, the drilling could cost $50 million to $100 million per well.

2:02:11 PM
DR. CHOPRA addressed a slide labeled "Exxon Description of Gas Cycling" that said:

> "What do we mean by cycling gas to produced condensate? The cycling of gas requires two wells: a production well and an injection well. These wells will be placed four miles apart in the heart of the reservoir to provide a true test on the effectiveness of cycling gas at Point Thomson...."

This was followed by a depiction labeled "Gas Cycling" and a slide labeled "What is Gas Cycling" that had these points:

- Exxon's gas cycling description is NOT a gas cycling project by industry definition. Their depiction of fluid movement is wrong by laws of physics. The dry gas will go to the top and gravity tongue. It will break through to high permeability zones to the producing well resulting in poor sweep. They show dry gas which is lighter going to the bottom of the reservoir.

- In PetroTel's design of gas cycling, the injectors are placed at the apex or at the highest points in the structure to maximize sweep.

- Exxon's 4 miles distance (per their written testimony) is too long a distance to observe pressure support in a reasonable amount of time.

2:02:25 PM
DR. CHOPRA explained that ExxonMobil's gas cycling process for these two wells - four miles apart in the heart of the reservoir, a very large distance - was shown in ExxonMobil's diagram as injecting dry gas down and then going to the projection well. He said that's not physically correct.

DR. CHOPRA explained that the dry gas is much lighter, since the condensate has all come out, if it was processed right. Dry gas always goes to the top and tends to go towards the producer

hugging the top. He suggested the ExxonMobil diagram showed more of a gas displacement, rather than gas cycling.

DR. CHOPRA noted these two proposed wells are at the highest point in the structure; thus the gas will follow a circuitous route. Recalling it was stated that they'd be finding out whether the gas cycling process works, Dr. Chopra said this won't be found out for a very long time because of the way it's injected and where it's injected.

DR. CHOPRA said typically everyone in the industry knows gas cycling is where dry gas is injected at the highest point in the structure, the apex, like at Prudhoe Bay. It displaces the heavier gas towards the producers that produce the liquids and recycle the dry gas. That's dry cycling. So the plan PetroTel has come up with, with extensive gas cycling to recover all this condensate from the fields, is highly desirable.

DR. CHOPRA added that based on the pressures seen, permeability levels, and so on, PetroTel doesn't see any reason it won't work as long as there is intelligent design of the position of the injectors and so forth, looking at the seismic data and structure. He emphasized that there is plenty of data to do that; in fact, it's a large database.

2:04:49 PM
DR. CHOPRA addressed the final slide, "Prudhoe Bay Gas Requirements," which had the following points:

- Prudhoe Bay is undergoing a major APEX water injection program to maintain pressure.

- The purpose of water injection project was to facilitate gas sales.

- AOGCC have quantified the effect of different gas offtakes based on modeling work.

- This work was used to justify the offtake in 2019 for AGIA pipeline requirements from Prudhoe Bay.

- Black and Veatch study shows the AGIA pipeline is still robust without Point Thomson gas.

DR. CHOPRA added that he was on the advisory board for that water injection project. A key reason it was put together was for future gas sales; at the time, 15 years ago, the operators

decided if they were going to sell gas, they'd have to maintain pressure using water, which is a lot cheaper solvent than gas. The AOGCC project mentioned was confidential.

DR. CHOPRA referred to yesterday's discussion of offtake in Prudhoe Bay and whether there will be enough gas. He said the Black & Veatch modeling showed the AGIA pipeline is robust even without Point Thomson gas. Thus this scenario had been taken into account to some extent by the AOGCC study.

CHAIR HUGGINS thanked Dr. Chopra. Referring to 2019 and the discussion of AOGCC, he asked to hear from Ms. Foerster.

2:07:01 PM
MS. FOERSTER noted DNR was allowed access to the results of the AOGCC study and thus took that data and did its own analysis; the 2019 is from an analysis by DNR, not AOGCC. She said AOGCC signed a confidentiality agreement, as did DNR, that prohibits quoting any numbers. But as she said yesterday, the later the gas is taken, the less will be taken, and the more mitigation the operator has done in the meantime, the more likely it is that the losses will be lower and thus acceptable. She declined to comment further because of the confidentiality agreement.

DR. CHOPRA explained that water injection has become a very important part of Prudhoe Bay's life. It was expected originally that a ballpark number of 1 million barrels a day of water would be injected into the Prudhoe Bay gas cap to maintain pressure. The pressure is good for Prudhoe Bay, and water injection will have taken the place of gas there.

DR. CHOPRA said by 2019, the incremental value of gas versus water injection to maintain pressure and recover oil would have gone down significantly; that was the modeling work done by AOGCC. PetroTel has made a tool to study the effect of different offtakes to see the optimal amount of gas to take from Prudhoe Bay. While that work needs to be quantified further, there are 10 years when so much water would have been injected because they've been displacing the gas with water.

MS. FOERSTER remarked that she didn't know how uncomfortable she should feel and whether she should seek legal advice about data AOGCC gave to DNR under this confidentiality understanding. She said she wasn't happy.

CHAIR HUGGINS called on Ms. Thompson as the DNR representative.

MS. THOMPSON deferred to Ms. Houle to talk about the technical work, which was done by PetroTel.

MS. HOULE responded that Jack Hartz, the DNR reservoir engineer who worked with PetroTel on its study, was out of state. She suggested that she get back to the committee and have Mr. Hartz answer any questions.

CHAIR HUGGINS indicated he would let AOGCC and DNR work out any differences about proprietary information.

2:10:57 PM
CHAIR HUGGINS asked Ms. Thompson whether anything except the legal proceeding keeps ExxonMobil and PetroTel from conferring about the $700,000 worth of reservoir information. He gave his understanding from yesterday that ExxonMobil disagrees with PetroTel's conclusion to some degree and wants to confer, thinking PetroTel might agree with its findings in such a case.

MS. THOMPSON replied she couldn't answer without understanding the scope of the confidentiality agreement. For instance, she didn't know whether ExxonMobil was the only party that gave DNR and AOGCC the data protected by this agreement. Thus she didn't know whether it was okay for them to confer, since other parties' interests might be compromised by such a discussion.

CHAIR HUGGINS encouraged facilitating communications about this key piece of topography when it comes to oil and gas, suggesting it would benefit Alaskans.

2:12:44 PM
MS. THOMPSON concurred. Responding to comments yesterday by Chevron and ExxonMobil about how DNR wouldn't speak to them about the handling of this reservoir, she explained that discussions with Commissioner Irwin during the pendency of the remand proceeding were not appropriate. When that was going on, DNR was under an order from Judge Gleason to consider a specific legal question; Commissioner Irwin was directed to adjudicate that question and so acted in the role of a judge. Just as someone cannot negotiate with a judge when there is ongoing litigation, it wouldn't have been appropriate for the parties, individually or as a group, to negotiate with him.

MS. THOMPSON said there has been extensive negotiation over the history of the unit. When the 22nd POD was reconsidered repeatedly by the department, for instance, negotiations extended over a couple of years about what the acceptable POD

would be. The final plan wasn't consistent with that, and the decision was made to terminate the unit. Thus DNR was put in a litigation posture by the parties that appealed. So it's not that DNR is averse to negotiating. When the time is ripe, when the case is no longer before DNR as an adjudicator, those discussions may again be appropriate.

2:14:16 PM
CHAIR HUGGINS suggested having Mr. Zager of Chevron address one of his bullet points about discussions with DNR. First, however, he invited Mr. Haymes of ExxonMobil to respond to Dr. Chopra's testimony.

MR. HAYMES read from the last bullet point on Dr. Chopra's first slide, which said:

- Conclusion: The type and amount of reservoir data is sufficient to develop a Full Field Plan of Development for oil and gas development at the Point Thomson Field.

MR. HAYMES responded that it depends on the POD. For gas sales development, it is correct that there is enough information to move into that with relatively low risk; when straws are put into that high-pressure reservoir, regardless of the discontinuity, baffles, or quality differences, it will drain the gas. The gas is extremely mobile, and with that high pressure, it will eventually migrate to the wells.

MR. HAYMES added, however, that for development of cycling or a very thin, discontinuous, heavy oil column, there isn't enough information to bring forward a full field POD. Thus this POD recognizes there isn't enough information, and it focuses on learning more for cycling and more about the oil rim, potentially delineating and producing that.

MR. HAYMES suggested that caveats or key boundaries be put on the PetroTel report. He said ExxonMobil hadn't seen PetroTel's detailed technical report and wasn't privy to its information and assumptions; thus he would go off DNR's summary of it, which is an appendix to the gas pipeline findings documents.

2:16:34 PM
MR. HAYMES read four portions from that DNR summary of the PetroTel report, as follows:

> A good understanding of the special economics involved is therefore required for optimum engineering of gas condensate reservoirs. ...
>
> Technical issues remain to be resolved. Economic evaluation still needs to be done to validate conceptual conclusions and refine potential development scenarios. ...
>
> At this stage of the analysis, scenarios were designed and run to discover and evaluate key sensitivities to recovery, rather than to derive optimal production economics. ...
>
> A large factor in this will be the number of development wells that can be economically drilled and operated.

MR. HAYMES reminded members that yesterday he'd said ExxonMobil, BP, Chevron, and ConocoPhillips operate tens of thousands of fields and reservoirs around the world and have an ownership in the majority of high-pressure gas fields worldwide. They've used state-of-the-art technology and modeling and have leveraged the expertise of thousands of people; this resource assessment and development plan is a conglomerate of that expertise.

MR. HAYMES also noted that yesterday he'd said they have a lot of incentive to produce hydrocarbons. All around the world, wherever he has worked, it has been in their lifeblood to get as much oil and gas out of the ground as possible. He indicated ExxonMobil has done this at Prudhoe Bay and Kuparuk as an active partner, as well as Duck Island, Granite Point, and many other reservoirs around the world. He said Point Thomson is no different in this respect, although it has unique challenges and there is a unique field POD to move it forward.

MR. HAYMES specified that ExxonMobil would be prepared to share its information with PetroTel, although it would need to be done through a confidentiality agreement, as currently done with AOGCC. The data ExxonMobil provided to DNR is indeed already under a confidentiality agreement, and the company would need to look at that agreement to share the data. He said ExxonMobil is more than willing to sit down and share its work with anybody.

2:19:11 PM
CHAIR HUGGINS encouraged maximum cooperation to bring benefits to Alaskans in the near term.

DR. CHOPRA informed members he'd found interesting information on the General Electric (GE) website. He said they implemented high-pressure reinjection in 1975 at 10,000 pounds per square inch absolute (psia). In 1995, such reinjection was implemented in Venezuela at 9,150 psia, and in 2005, such reinjection was at 10,700 psia. He said high-pressure gas reinjection has been there, as and when required, as a choice to produce more oil.

MR. HAYMES asked for a copy of those documents. He indicated ExxonMobil had done a worldwide search, but hadn't found anything operating today over 7,000 psi.

DR. CHOPRA responded that he'd sent the PDF document with his slides. On the website it says "high-pressure gas reinjection" and then gives the timeline for 1973, 1975, 1995, 1999, and 2005. For 1975, it says 10,000 psi North Sea, and for 1995 it says 9,150 psi in Venezuela. He asked that this document be shared with Mr. Haymes and others.

CHAIR HUGGINS indicated the committee would take care of it. He asked whether Mr. Zager had anything to add with respect to conferring with the state.

2:21:48 PM
JOHN ZAGER, General Manager, Chevron - Alaska Area, responded that it has been a frustrating process, likely on the state's side as well, and he was glad to hear of the possibility for dialogue in the relatively near future. He noted his attorneys tell him that when two parties are highly motivated, they can figure out a way to have some dialogue.

2:22:34 PM
REPRESENTATIVE DAHLSTROM asked whether Mr. Haymes would like legislators to sign a confidentiality form, after which ExxonMobil would be willing to release information to those legislators individually.

MR. HAYMES answered that the offer on the confidentiality agreement was with PetroTel and DNR, as was done with AOGCC. There is a lot of information. If there is something a legislator is interested in, ExxonMobil could look at that on an individual-by-individual basis. While not closed to the idea, ExxonMobil would need to determine the purpose, given that the data is confidential. With AOGCC and DNR, there's an end point.

REPRESENTATIVE DAHLSTROM said her purpose would be to make the correct decision here, certainly not for pleasure reading.

2:24:30 PM
SENATOR STEDMAN asked Mr. Haymes and Mr. Zager: If there were a 20-year supply of gas for a 4.0 or 3.5 Bcf/d line, how would the corporations handle the issue of YTF gas at the time of the initial open season when trying to get FT commitments to finance the line and get it built? Does it create a liability? If so, how much, and how is that dealt with?

MR. HAYMES replied that for YTF gas, Appendix J of the gasline decision document talks about an estimated need for gas of 70-80 Tcf for a 4.5 Bcf/d pipeline for 35 years; at 4.5 Bcf/d for 25 years, it would be 50-57 Tcf; and at 3.5 Bcf/d for 25 years, 40-50 Tcf. It depends on how long that commitment is. So much is needed because a gas field declines. An FT commitment for 25 or 35 years is made at 3.5 or 4.5 Bcf/d for that entire duration. But as the field declines, another must be found to fill that, allowing for the decline of that field as well.

MR. HAYMES said if Point Thomson is out of the equation and just Prudhoe Bay is looked at along with other gas, which there isn't a lot of, then another Prudhoe Bay equivalent is required. Thus any shipper will make a FT commitment with an unknown amount of YTF gas; that's just for the initial shipment, not expansions.

MR. HAYMES noted ExxonMobil would back that, finance it, and carry it as a liability, reporting it as a liability under Securities and Exchange Commission (SEC) guidelines. It has to be factored into the economics. He indicated the economics that legislators have seen to date, not including those from ExxonMobil, don't take that into account.

MR. HAYMES added that this provides incentive to explore for more gas and to encourage others to do so. Indicating ExxonMobil would be on the hook to pay for over half of the gas that doesn't exist as known reserves today, he asked: To find a Prudhoe Bay equivalent in time for the next open season or the one after, who is drilling for that today? Where is it?

2:29:01 PM
MR. HAYMES continued. He said ExxonMobil's share of the FT commitments is more than $100 billion. Without commitments, there is no financing and a pipeline won't be built. Before any molecule of gas goes into the pipeline, the state and the producers will need to sit down and work together.

MR. HAYMES emphasized that ExxonMobil is willing to work with the state, is honoring this AGIA process, and has been at every public hearing and forum with both a commercial and a public affairs representative. Furthermore, ExxonMobil has written three letters saying it will commit its gas to pipelines, whether at the wellhead or even at Point Thomson, as stated on February 19, when ExxonMobil said it would commit its share of Point Thomson gas to any pipeline, whoever holds an open season.

MR. HAYMES pointed out, however, that anywhere in the world one makes a commitment of gas, it is with commercial conditions that FERC also reviews to see what makes sense. That's why FERC issues its own conditions on the certificate. There's a lot of exposure in an FT commitment because of the need for YTF gas. While the gas potential in Alaska is huge, it's remote, in an environmentally challenging area, capital-intensive, and will take a long time.

2:31:30 PM
MR. HAYMES, in further response, explained that the market seeks long-term FT commitment. If it's 1.5 Bcf/d for 25 or 30 years, ExxonMobil doesn't have that much gas. While it has about a third of the North Slope gas, its FT commitment will be that plus lots more. So ExxonMobil will carry that and cover the liability. If the company runs out of gas in year 20, it will still pay as though it is shipping 1.5 Bcf/d.

MR. HAYMES emphasized that this is probably the world's largest gas pipeline project in terms of commitments. While ExxonMobil can underwrite those and the banks will believe the company can pay those bills, it is a massive risk to put $100-plus billion of liability on its balance sheet and report it, not knowing whether there will be gas to cover it.

2:34:13 PM
SENATOR STEDMAN asked about the positive side, that ExxonMobil would get to book some reserves.

MR. HAYMES replied that three quarters of the undiscovered resource potential in North American is in Alaska, according to the federal assessment. Although it may not be economic or actually there, this potential is estimated to be hundreds of Tcf. Some, but not a lot, is onshore, but most is in federal waters, at least six miles offshore and in an extremely harsh environment. It will cost a lot of money and entail huge environmental concerns to eventually get that to market, but it

will happen, since technology allows the industry a step change in what it does every 10 years.

SENATOR STEDMAN asked Mr. Haymes to focus on the value of booking the reserves.

MR. HAYMES answered that with ExxonMobil's share of the gas, if it brings on a gas pipeline at 4.5 Bcf/d, it will double its U.S. gas production and increase its worldwide gas production by 15 percent. So there is a lot of incentive to do it. But today there are no reserves on its books for gas at Prudhoe Bay, Point Thompson, or anywhere because it's stranded gas. The only reserves ExxonMobil puts on its books are those burned as fuel, which are put on and then taken off because the gas was used.

MR. HAYMES said the amount of reserves the company will add equates to over 1 billion oil-equivalent barrels, about the average ExxonMobil has replaced around the world per year for the last 5 years. So yes, there absolutely is a benefit in that ExxonMobil can book those reserves, but that's only about half of the FT commitment it will have to make. It cannot book the yet-to-find gas. So there is a balance.

2:37:28 PM
MR. ZAGER noted that Chevron is much smaller than ExxonMobil. He said the YTF gas is a huge issue. How to share that risk, many billions of dollars, will need to be addressed.

2:38:29 PM
REPRESENTATIVE DOOGAN gave his understanding that who should develop Point Thomson has to be decided, with a separate question of how this should occur; PetroTel has done studies, but ExxonMobil proposes a slightly different way. In addition, there are questions about how much the gas will be worth and so on. He asked: If TransCanada is licensed and goes to an open season, taking 36 months instead of 24, is there any way gas can be nominated from Point Thomson in that timeframe?

MR. HAYMES replied first with regard to who should develop Point Thomson, saying there are four of the largest oil and gas companies in the world with extensive experience with high-pressure operations. As for how, he said everyone including PetroTel, DNR, AOGCC, and the owners agree cycling is the next best step along with delineating the oil rim and, if that's productive, bringing it on to production. The agreement on that is very encouraging, he said, and ExxonMobil has a project underway to do that, hoping it can continue to proceed.

MR. HAYMES noted ExxonMobil already has completed a confidential data room pools process with AOGCC for Prudhoe Bay and is underway with Point Thomson as well. Roughly by the end of this year, AOGCC will have sufficient information to at least have a ballpark idea of the impacts of gas offtake on liquids recovery for both. Over time, impacts lessen because more of the liquids will have been produced. There are substantially more liquids at Prudhoe Bay, by a factor of 10 to 20, than at Point Thomson.

MR. HAYMES affirmed that ExxonMobil could make FT commitments in any open season in 1-3 years. As anywhere in the world, those would be conditional, based on reasonable commercial terms and reaching a unanimous conclusion among the agencies on the right offtake rate. He said progressing with the AOGCC pool-rules process is critical for Point Thomson and Prudhoe Bay so everyone can sit down and make an informed decision.

MR. HAYMES said AOGCC's mantra is to maximize resource recovery and not quite, but almost, ignore economics. At some point balancing between gas and oil must be looked at. While in an ideal world there'd be both, no reservoir in the world ever gets all the oil and gas out of the ground - he said it's a fact of physics - and every retrograde condensate reservoir loses condensate. If it were otherwise, there'd be lots to go around for a long, long time. So ExxonMobil will be there, but with commercial conditions and critical technical work as well.

2:44:07 PM

MS. FOERSTER also responded, saying it is possible AOGCC will have gained enough confidence after the study to grant pool rules that include an allowable offtake of gas. However, questions may remain about the producibility of the oil rim, the success of cycling, and how long cycling will take, and thus only by drilling, producing, cycling, and testing will a ruling be possible. While she didn't know if there could be an open season without an allowable gas offtake, she said perhaps only by producing the field would AOGCC get the needed information.

AN UNIDENTIFIED SPEAKER said one point of agreement seems to be that the sooner the field is in production and wells drilled, the better the information will be to make decisions during the open season or subsequently. He suggested if the full legal process is gone through, nobody will make an open season nomination for years.

MS. THOMPSON, with respect to whether Point Thomson gas would be there in 36 months for an open season, said her answer is maybe but it doesn't matter for this AGIA license. She explained that she says "maybe" because she is an optimist. It clearly isn't headed in that direction right now, but over time she has seen dramatic changes happen quickly, and there are a lot of changes and shifts in opportunities now. And while it is an important debate on the future of the reservoir, it doesn't matter for this license because the studies submitted in the appendices say the project can be built without Point Thomson gas.

MS. THOMPSON said while the companies that want to enhance their bargaining leverage in the contentious Point Thomson litigation might say that gas is essential, she doesn't believe it is true. It also shouldn't surprise legislators that they are hearing an aggressive position on development from the companies, because of the prices. Citing a recent Wall Street Journal article, she said those issues are much more complex than the question right now. She reiterated her answer: "Maybe but it doesn't matter."

2:48:58 PM
MR. ZAGER said when he hears it is still economic, he looks at the $16 billion of NPV that is reduced in value and thinks that's a lot of money if the pipe is downsized from 4.5 to 3.5 Bcf/d. He surmised there is a way to capture a lot of that value by making the right decision on Point Thomson. Mentioning discussion of discounting the risk of developing Point Thomson, he said maybe when Chevron is putting its own money on the table it is a little more risk-sensitive, having been in situations that failed after being confident going in.

MR. ZAGER added that Point Thomson is a place where the waters have to be tested before committing that it won't be made available for gas and that oil is being counted on absolutely. He told members that if the wrong decision is made there, there will be too small of a pipeline and the knowledge that Point Thomson could have been in the mix.

2:50:23 PM
DR. CHOPRA responded to Representative Doogan as well. With respect to a 3.5 Bcf/d pipeline, he mentioned compression to increase the flow rate and said it's not like it would be a smaller pipeline. As for Point Thomson gas, he noted PetroTel's study says the oil needs to be produced first. Saying he'd heard 25, 35, or 45 years, he added that the state can nominate that gas; it will be there, and the sooner the liquids are extracted out of the gas cap, the sooner that will be.

DR. CHOPRA emphasized that PetroTel's study doesn't take Point Thomson gas out of the equation, but says that during the 45 years of the pipeline, that gas will be there. He said PetroTel sees that the oil rim can be significantly enhanced. Its lower-gravity oil is missing gas. If gas is added, it swells and decreases the viscosity and thus can produce the oil.

DR. CHOPRA said if there is a timeframe of 45-50 years and Alaska has these great discoveries of gas, the pipeline will last indefinitely and Point Thomson gas will come sooner or later. He cautioned, however, that if folks get greedy and start putting the Point Thomson gas first, half a billion barrels of liquid will be lost there forever.

REPRESENTATIVE DOOGAN expressed appreciation for the time and effort the participants had put into this, saying he now understands why the administration took the Point Thomson gas out of the calculations for this pipeline.

2:53:31 PM
SENATOR WAGONER highlighted the importance of AOGCC's information and returned to the question of when AOGCC's study of the reservoir and modeling will be complete.

MS. FOERSTER answered that AOGCC expects to complete its analysis within six months of final receipt of all the data from ExxonMobil, which Mr. Haymes has indicated should be the end of this year or a little later. In further response, she said the legislature provided funds in an earlier session to do studies at Prudhoe Bay and Point Thomson; right now AOGCC predicts those funds are sufficient, but the longer things drag on, the more costly they become.

2:55:38 PM
SENATOR WAGONER recalled some confusion during yesterday's discussion. He gave his understanding that AOGCC will allow a drawdown of 2.7 Bcf of gas, of which 0.7 Bcf would go into other areas for fuel and other purposes, leaving 2.0 Bcf. He recalled when the Stranded Gas Development Act was being considered a few years ago, there was testimony that Point Thomson could supply more than 4.5 Bcf of gas. He said he understands the value of the liquids and oil, but asked why there is trouble now getting 1.5 Bcf within 10 years or so.

MR. HAYMES offered that Prudhoe Bay and Point Thomson together have the potential to produce 4.5 Bcf/d, but that is subject to

AOGCC's approval of the offtake rate and depends on the timeline. On a sustainable basis, Point Thomson doesn't have that capability on its own.

SENATOR WAGONER said he'd been somewhat shocked by the difference between the estimates of PetroTel and the industry for recoverable reserves of condensates and oil, given that everyone is using the same database for the same oil fields.

MS. FOERSTER responded that anytime one develops a new field, different groups do estimates. First, exploration geologists give oil-in-place estimates and so on. Next, a reservoir engineer like Dr. Chopra does the model and gives another estimate. Then a development engineer comes along, using further information; offering a fishing analogy that compared the development engineer to the person who actually puts the fish on a scale and takes a knife to it, she said that wasn't the role Dr. Chopra had.

3:01:26 PM
DR. CHOPRA told members he hasn't heard anyone dispute that Point Thomson is a big field with 10 Tcf of gas; some say it might produce 4.5 Bcf/d. So PetroTel looked at that 10 Tcf, not even knowing it was classified as an oil field by the State of Alaska. He said everyone also agrees this is a gas condensate, averaging 66 stock tank barrels (STB) of condensate per million cubic feet of gas. The two can be multiplied together, giving 660 million barrels of condensate.

DR. CHOPRA highlighted maximizing recovery of the condensate, predicting Prudhoe Bay oil recovery will reach 65-75 percent when it's done. So when PetroTel started looking at it, he said, the objective was to provide self-sufficiency and reduce dependence on foreign oil and, therefore, the question was how to get the oil out.

DR. CHOPRA added that gas cycling is a simple process. The gas is produced, and then dry gas is reinjected and the liquids are taken out. Typically, people may not do that because they think it might take 100 years. When PetroTel set up its simulations, however, it found 75 percent of that condensate could be recovered within 15 years, a very high recovery. Others have done the work but not looked at recovery through gas cycling and thus expect to recover only 24-25 percent. That's the difference between the two numbers, he suggested.

DR. CHOPRA noted PetroTel looked at the upside. To get the number for the condensate is fairly easy; PetroTel has done it all over the world, and ExxonMobil and Chevron have done it as well. It's a matter of cycling the gas. While folks worry about pressure, he said PetroTel's research shows there has been high-pressure injection since the 1970s, as mentioned earlier. If that technology can be brought to the North Slope, getting 75 percent of the condensate should be easy.

DR. CHOPRA also pointed out that folks worry about the oil rim. But PetroTel looked at the well tests and found these wells flow if gas is added, with the oil becoming fine like oil at Kuparuk or Prudhoe Bay. If that can be done, there's another 900 million barrels in the oil rim. That's how PetroTel is looking at the field versus how others may view it, he said. PetroTel always tries to objectively maximize the value for its client, in this case the State of Alaska.

3:05:52 PM
MS. FOERSTER returned to her fishing analogy, saying the PetroTel analysis, as noted in its study, assesses resource potential, not economically recoverable oil and gas. She read, "It should be noted that no physical constraints to the development well, such as location of surface drill sites and facilities or drilling departures from surface location, have been applied during this modeling." Ms. Foerster said when field development begins, it won't be done with a reservoir model. It will be done with gravel and drill bits, constrained by depths, pressures, and so on.

MS. FOERSTER added that other important aspects include geologic conditions, rock properties, well deliverability, well costs and spacing, well pattern geometry, and the plant; that's the knife and scale in the analogy. An optimum number of wells will economically recover the maximum oil and gas within a reasonable drilling budget; however, the scope of this study did not include optimization of development, but was designed to estimate resource volumes and quantify the range of recoverable resource using conceptual development scenarios. There is no knife or scale in this work, she emphasized.

DR. CHOPRA offered clarification, saying many things in the oil industry terminology have to be stated by SEC guidelines. There is a strict definition of what can be called reserves, and there are rules regarding resource potential and objectivity to the client. He agreed PetroTel wasn't out there on the Point Thomson site, didn't take a survey there and look at the tundra

and weather conditions, didn't design the plant, and didn't optimize; those weren't within the scope of the study. But even without optimizing, PetroTel was able to get that much oil.

DR. CHOPRA suggested imagining what additional potential could be obtained if optimization of this field occurred. He said PetroTel looked at it and used common sense about where to place wells and what to do. That is the result of the study. If this is a reservoir that could be done, then this is the resource potential that could be recovered.

3:09:36 PM
SENATOR WAGONER characterized this as a tangle of information and asked, perhaps of TransCanada or the Denali group later: If there won't be enough gas for a 48-inch pipeline, why does a world-renowned, major pipeline company want to build a 48-inch pipeline and, at the same time, Denali want to do the same?

MS. THOMPSON agreed that this is a great question to ask TransCanada and the Denali group if the opportunity arises.

SENATOR WAGONER asked how many 25-year FT transportation deals ExxonMobil has in the Lower 48 and requested documentation so legislators can see how those work.

MR. HAYMES answered he would follow up if that information is allowed to be shared.

The committees took an at-ease from 3:11:45 PM to 3:30:36 PM.

REPRESENTATIVE GATTO asked Ms. Foerster whether the order for Prudhoe Bay, which says 2.7 is the amount of offtake, dates from the 1970s.

MS. FOERSTER affirmed that.

REPRESENTATIVE GATTO said it strikes him that an offtake order in 2018 would allow substantially more gas because the liquids are declining.

MS. FOERSTER replied it isn't that simple. This presupposes that the current commission agrees the 2.7 allowable offtake was appropriate for the last 30 years and would have been good for the reservoir and ultimate recovery if it had been used. However, that isn't true.

REPRESENTATIVE GATTO said he is only presupposing that the offtake order was in the 1970s, not some other time.

MS. FOERSTER pointed out that there is no gas pipeline and 2.7 of offtake hasn't happened. She said it's faulty logic to say a higher number would be good for the reservoir later.

3:34:47 PM
REPRESENTATIVE GATTO asked if ExxonMobil makes FT commitments worldwide for gas it doesn't have but expects to get.

MR. HAYMES replied it's complex. ExxonMobil tries to match the gas it has or might have with the market demands, which may be for 25 years or 1 year, depending on the location; for this kind of volume, it typically is longer rather than shorter. Various companies want different volumes for specific lengths of time. Those are stacked together and a commitment is made to transport gas to support the financing, trying to match it with reserves and resources. There's not always a match. If there is more gas, the effort is to find more buyers in time. If there isn't enough gas, ExxonMobil carries that risk.

MR. HAYMES said this unique pipeline will be the largest private infrastructure project in North American history, hundreds of billions of dollars. ExxonMobil believes it's important to have an equity share of the pipeline and appreciates that TransCanada recognizes that as well. ExxonMobil is looking for an equity share equal to its throughput, which will help to manage upstream, mid-term, and downstream risks.

MR. HAYMES added that when TransCanada seeks financing for the pipeline, it will need to take the commitments made by the companies. Noting he didn't know those amounts and could only speak for ExxonMobil, he said if there only is Prudhoe Bay gas and the owners commit their relative shares, for example, that isn't enough to finance this pipeline.

3:37:29 PM
REPRESENTATIVE GATTO asked whether the commercial terms Mr. Haymes had mentioned earlier include tax terms that the state would impose.

MR. HAYMES answered that this refers to all commercial terms impacting economics or cash flow for a producer like ExxonMobil. They're looking for predictable terms, just as someone approaching a bank for a home loan wants to know the interest rate. This is just on a much larger scale.

REPRESENTATIVE GATTO observed that a bank loan also figures in property taxes and insurance, which likely increase each year. Giving his understanding that 10 years is specified under AGIA, he asked whether that is sufficient time, since he surmised the first 10-year period is the most important.

MR. HAYMES replied if ExxonMobil had FT commitments for 10 years, that would be sufficient, but they'll likely be much longer. He said that the gasline findings documents talk about how changing the tax terms by 50 percent after 10 years has no substantial impact on NPV for the shippers, and that if changing the taxes doesn't impact the shippers, then it wouldn't impact the state. However, ExxonMobil looks at cash flows as well. Saying nobody intentionally operates a pipeline at a loss, he recalled that a graph in Appendix G-1 or G-2 of the decision documents shows a negative cash flow after year 10. He suggested this needs to be considered.

3:40:45 PM
SENATOR DYSON remarked that historically in Alaska, the resource has been harvested and taken elsewhere to be refined; it seems not much of the money stays in Alaska. He also relayed his understanding that in North America the gas liquids, ethanes, propanes, and so forth are generally refined near the market, rather than near the production, for economic reasons. He asked: Is there any way it could work economically to keep the refining and value-added jobs in Alaska, given the logistics and transportation issues?

MR. ZAGER replied he hadn't looked at that particular issue, but generally there is excellent transportation for these liquids, the pipeline that has been built. If the products are refined in Alaska, separate products will need to be transported individually to keep their value. From a macro-economic perspective, Alaska is fairly disadvantaged in that market.

MR. HAYMES concurred, saying while not impossible, it would be extremely challenging because Alaska is so remote from the consumers, with a small population and huge land mass. Whereas high-end products would require a transportation system for each product, now it can all go down the oil pipeline, with economies of scale for transportation, and then be refined elsewhere. He added he hadn't looked at it in detail.

3:44:00 PM

REPRESENTATIVE GARA asked about what seems to be an inconsistently. Noting he doesn't necessarily buy that the Point Thomson gas is needed for a pipeline, he recalled in 2005 ExxonMobil proposed a 4.5 Bcf/d pipeline under the Stranded Gas Development Act. He asked why that isn't the case now.

MR. HAYMES agreed under that Act a proposed 4.5 Bcf/d pipeline was supported by the major shippers and producers. He said it was recognized then that there were yet-to-be-discovered resources, although he wasn't there for that extremely complex contract. He opined that this can work, but requires everybody sitting down together, including all the producers, the government, and any other party that can add value, not just TransCanada. He noted a recent deal to sell gas to Fairbanks Natural Gas took a year to settle to the satisfaction of both parties. He said ExxonMobil's position hasn't changed.

REPRESENTATIVE GARA asked whether it's fair to say Mr. Haymes believes there can be 4.5 Bcf/d today if all parties align.

MR. HAYMES replied that's fair to say, but it will take a lot of work from everybody to get there. The 4.5 Bcf/d included Point Thomson gas.

REPRESENTATIVE GARA suggested there may be areas where the state's interests align more with ExxonMobil than ExxonMobil's interests align with BP and ConocoPhillips at this point. Noting only ExxonMobil had responded to a letter sent to all three producers asking whether they'd be willing to commit gas to an independently owned pipeline, he said ExxonMobil had answered yes, with the caveats Representative Gatto discussed.

REPRESENTATIVE GARA gave his understanding that BP and ConocoPhillips oppose the TransCanada proposal, whereas he isn't hearing ExxonMobil be as vocal on that, and that whereas ExxonMobil is seeking an equity share in the TransCanada project, BP and ConocoPhillips aren't. He asked: Is it correct that ExxonMobil at this point isn't interested in the BP-ConocoPhillips deal, but is interested in possibly becoming part owner of the TransCanada project?

MR. HAYMES answered that ExxonMobil is evaluating both proposals carefully and believes eventually a gas pipeline will need all the producers and the state to come together; otherwise, there'll be no pipeline. At this point, neither proposal has been ruled out. He added that ExxonMobil recognizes and is

honoring the AGIA process that the state is going through and wants to work with the state to make it happen.

3:49:15 PM
REPRESENTATIVE GARA highlighted the commitment stated in the letter to him and other legislators that said ExxonMobil would sell gas. He asked about caveats.

MR. HAYMES specified that ExxonMobil meant it would commit its gas on reasonable commercial terms.

REPRESENTATIVE GARA gave his understanding that part of that means long-term fiscal certainty, as Representative Gatto talked about. He asked: Apart from fiscal certainty, will you demand production tax cuts from the state?

MR. HAYMES replied he wasn't sure yet what those reasonable commercial terms would be. They'd be worked by ExxonMobil's gas marketing company on the same basis as for every gas deal in the world. He said he wasn't privy to what that would be at this point, but clearly it would be an engagement discussion point in order to work that together.

REPRESENTATIVE GARA referred to the fact that the Denali project of BP and ConocoPhillips proposes a competing line. He asked whether perhaps they haven't offered to commit gas to an independent line, even with caveats, because they'd rather sell gas into their own line and maybe block the TransCanada deal.

MR. HAYMES suggested that question would be best put to those companies.

3:51:27 PM
REPRESENTATIVE FAIRCLOUGH noted she isn't a lawyer and thanked participants for their decorum while legislators try to understand everyone's positions. She asked how many plans of development have been approved at Point Thomson.

MS. THOMPSON replied that 20 PODs were approved. The 12th, 22nd, and 23rd were not.

REPRESENTATIVE FAIRCLOUGH asked: When the state started accepting PODs at Point Thomson in the first five years, were they just for moving the ball forward, rather than actual plans for production?

MS. THOMPSON responded that within the first five years there was discussion about production. While there wasn't a specific plan to put oil into the Trans-Alaska Pipeline System (TAPS), the first POD talked about doing so. Recalling a statement yesterday, she clarified that the regulation specifically references production as a requirement in a POD; she would provide the regulation to Mr. Haymes after today's meeting.

REPRESENTATIVE FAIRCLOUGH gave her understanding that although Commissioner Irwin decided to deny development at Point Thomson, some previous administrations had consequences in the form of penalties and had accepted development there.

MS. THOMPSON, replying to further questions from Representative Fairclough, explained that each lease sale usually has a different primary term of five, seven, or ten years, depending on where the lease is located and how long the department feels is reasonable to get the land into production. While lease terms have changed over time, this isn't necessarily to hold a particular unit accountable. She said she believes the decision about the terms is made before every lease sale; it depends on the location and what is known about the resource already.

3:56:05 PM
REPRESENTATIVE FAIRCLOUGH highlighted concern about access to the pipeline and a public perception that access has been denied to TAPS. She noted she'd received an e-mail from a constituent about the Texas Railroad Commission, which for common carriage - as opposed to contract carriage - allows throughput proportionate to reported reserves. Suggesting such a system for the gas pipeline would allow explorers to open the basin to show they have proven reserves in order to acquire space on the line, she asked what Ms. Foerster knew anything about that.

MR. FOERSTER responded that the only company that isn't an owner of TAPS that has requested access is Pioneer at Oooguruk; Pioneer started production in the last week or two, and now its oil is going into TAPS. She agreed that lack of access to TAPS is a perception. Noting she'd worked in Texas many years ago but has been in Alaska more than 16 years, she surmised how the Texas Railroad Commission conducts its business has changed and said she didn't recall details; she declined to speculate.

AN UNIDENTIFIED SPEAKER gave his understanding that whereas an oil pipeline is usually prorated according to the amount of reserves one has, a gas pipeline takes long-term commitments and

thus the company putting up the financing wants to be assured that it can actually move its gas.

REPRESENTATIVE FAIRCLOUGH said that's why she'd indicated she understood the difference between contract and common carriage. She reiterated that she'd thought it perhaps could be applied to provide access and assurance that one owner wouldn't have a majority interest that could push others out.

4:00:19 PM
REPRESENTATIVE FAIRCLOUGH asked about the difference between the administration's model using a Monte Carlo approach and the Wood Mackenzie model. She said she'd asked various presenters for an explanation, but hadn't received an answer.

MS. FOERSTER replied she has no expertise in uncertainty modeling but has benefited from Monte Carlo simulations, which are commonly accepted as an appropriate way to model uncertainty. She didn't know what was used in the Wood Mackenzie study.

CHAIR HUGGINS asked Commissioner Galvin to bring an answer tomorrow during the presentation.

4:02:18 PM
REPRESENTATIVE FAIRCLOUGH recalled yesterday it was said that applications for permits had been submitted to DNR for wells and an ice road. Noting the administration says having two competing projects isn't a problem, she asked: Will the regular process and timeframe occur, and will the permit applications just received from the producers sitting at the table be thoroughly vetted and then either approved or denied in an appropriate time period?

MS. THOMPSON, noting she'd addressed this at the beginning of the roundtable discussion, observed that the pre-application meeting should be wrapping up now and opined that no applications have been submitted yet. She reiterated some of her earlier explanation.

MS. THOMPSON added that what will happen to the permits depends on the leases they'll operate on. As she'd explained yesterday, there are 45 separate leases in the former Point Thomson unit, and whether they still retain the rights to develop those lands depends on what they're going to do; when they're going to do it; and, most significantly, what land they're going to do it

on. That's something her agency found out this afternoon when looking at the pre-application finding.

MS. THOMPSON emphasized that while DNR's position is to not interfere with valid leasehold rights, there is a difference of opinion as to what those rights are. The department is beginning the process to understand which leases will be affected and then will work with its legal counsel to figure out whether they have the right to develop it. That will be resolved in the coming months.

4:05:02 PM
MS. HOULE suggested Mr. Zager could speak to this also, but said many times companies have leases and form a unit, doing surface permitting through DNR's lease-permitting group for a lot of wells and sites. On the North Slope, for example, companies will permit maybe a dozen locations because they aren't exactly sure until they look again at their seismic data and so on. Many sites that receive permits may never be drilled.

4:06:00 PM
REPRESENTATIVE FAIRCLOUGH asked whether it's accurate that Commissioner Irwin and the administration are in the process of exerting the state's rights at Point Thomson from the administration's perspective, taking away those leases and shutting down the unit.

MS. THOMPSON answered that the commissioner has issued a decision that the unit is terminated. Consequently, because almost all the leases are beyond their primary terms and some are held just because they're in the unit, the legal process to terminate the leases will also begin. As she'd explained yesterday, there are different arguments. Some leases have had wells drilled; some have not. They're all being looked at individually to determine the correct resolution.

4:06:52 PM
REPRESENTATIVE FAIRCLOUGH said she takes seriously her oath to protect the State of Alaska. Expressing concern with the genuineness of saying there can be competing pipelines if someone is submitting permits for development and those are under litigation, she asked: As we try to move a commercial private project forward, will it be put at bay because of the legal process, even if rightfully so? Does taking back possession of Alaska's natural resource in essence makes it impossible for the private sector to compete?

MS. THOMPSON responded that the competing pipeline is from BP and ConocoPhillips, not ExxonMobil. Also, the administration believes this AGIA project can proceed with or without gas from Point Thomson. The effort isn't to interrelate the two. The effort to regain the leases in Point Thomson is based on what has happened in that unit since it was formed in 1977, not any particular objective that has to do with AGIA.

MS. THOMPSON added that the administration will give them a fair shake. If the permit applications eventually submitted are for leases that they have the right to continue operations on, those will be granted. Referring to Ms. Houle's comments, she said plenty of lease operations continue even without a unit on the North Slope. She pointed out that she doesn't yet know what the application says and must see it in order to provide an answer.

REPRESENTATIVE FAIRCLOUGH replied she appreciates that, but today they've heard having more data will allow knowing more precisely what Point Thomson has. If acquiring that information is postponed, it becomes more costly; if it is received sooner, it drives the tariff down because there'll be more gas commitments and a better financing package to take to market.

REPRESENTATIVE FAIRCLOUGH said although she understands the distinction between the competing pipelines, there is a benefit to better understanding the reserves and the reservoir, to know when it can deliver. She questioned just letting the free market work when more information is needed and yet the ability to get that information is being pushed outward in time. She asked Mr. Haymes about the permits.

4:10:39 PM
MR. HAYMES said ExxonMobil submitted permitted applications last week and he personally signed the checks to go with those permit application letters. As the operator, ExxonMobil submitted those permits on behalf of all the leaseholders at Point Thomson, including BP, ConocoPhillips, Chevron, and 24 others.

REPRESENTATIVE FAIRCLOUGH gave her understanding that the state believes there is a high probability it can win and take back the leases. She asked, however, whether there isn't potential increased risk for the state in denying a permit, should ExxonMobil win in court.

MS. THOMPSON replied that's a question the legal team working on Point Thomson is very carefully evaluating.

4:12:20 PM
CHAIR HUGGINS asked whether the permitting is for two pieces: the wells and the ice road.

MR. HAYMES answered that there are permit requirements across quite a number of fronts, and those two are correct. There also are land-use permits, coastal water permits, and a number of different agencies with permitting requirements to undertake field activities on the leases at Point Thomson.

CHAIR HUGGINS told Ms. Thompson he'd be interested in basic infrastructure that he surmised won't rest on whether a well will be honored. He asked what the state's position will likely be on an ice road.

MS. THOMPSON replied it depends on its location and who has the right to build it on the land where it is proposed. She said she couldn't answer without knowing the location, but could provide that information if the committee so desires.

CHAIR HUGGINS said his interest is simply wanting to get Point Thomson into production as soon as possible.

4:13:42 PM
REPRESENTATIVE FAIRCLOUGH requested that the administration have a conversation with the legislature about denying permits. She said there must be a way to protect the state legally and let the state do what it believes is in the best interests; she mentioned offering a credit, for instance. She emphasized that denying a permit seems to put the state further behind with respect to having Point Thomson on line.

4:14:33 PM
REPRESENTATIVE KERTTULA relayed her understanding that projects such as the ice road can be phased, which has frequently been done in Alaska following a series of court cases. She asked whether this has helped to speed up the projects and suggested the state certainly would look at that.

MS. THOMPSON concurred, also agreeing with Mr. Haymes that there are a lot of different permits potentially at issue. She said there can't be a general answer; it may be different for each. She indicated it is something the administration is looking at carefully with the legal team working on the Point Thomson litigation. In further response, she said the administration hasn't shut the door and said it isn't taking any applications from ExxonMobil.

4:15:47 PM
REPRESENTATIVE KERTTULA pointed out that it was the previous administration that finally put its foot down, specifically, Commissioner Menge. She said she couldn't recall how many PODs had been put forward during the Murkowski Administration, but it didn't begin here when the final denial came.

MS. THOMPSON agreed it was then-Commissioner Menge; the unit was terminated at the end of the Murkowski Administration. The owners asked for reconsideration, and Commissioner Irwin wasn't there yet, so it was then-Acting Commissioner Rutherford who affirmed on reconsideration.

4:16:27 PM
REPRESENTATIVE KERTTULA recalled hearing yesterday that AOGCC had supported this POD, but offered her own recollection that AOGCC had actually stayed neutral.

MS. FOERSTER said Representative Kerttula was right. She explained that AOGCC needs to stay neutral in these sorts of things. Ms. Foerster noted at the Point Thomson hearings with DNR, someone quoted her as saying she loved the plan. Clarifying that on a technical basis she believes it is a fabulous plan, she remarked, "If three of the biggest and most successful oil companies on the planet can't come up with a technically fabulous plan, then God help the industry." She said the POD also answers the questions AOGCC needs answered.

MS. FOERSTER pointed out, however, that DNR and not AOGCC approves plans of development. While DNR looks at some of the same things as AOGCC, it also looks at different things and looks differently at some of the same things. "Not my job, with all due respect," she concluded.

4:17:59 PM
REPRESENTATIVE COGHILL followed up on Representative Fairclough's questions regarding permits. He said he understands the ticklish issue with Point Thomson, but with respect to a competing pipeline application, TransCanada and Denali may both be seeking permits for everything from crossing rivers to getting access to resources within DNR. He asked whether the state is able and willing to work with both and whether there is sufficient staffing capacity.

MS. THOMPSON replied certainly there is a willingness to work with whatever pipeline applicant there is. Agreeing there is a

whole array of permits, she noted Representative Fairclough had inquired about the specific permit applications from ExxonMobil to develop Point Thomson.

MS. THOMPSON said permits for rights-of-way and so forth will need to be resolved by whichever project goes forward, and the state stands ready. Pointing out that she isn't the person to answer about staffing, she suggested Commissioner Irwin would inform the legislature if additional resources are needed to process two applications.

4:20:00 PM
REPRESENTATIVE COGHILL asked: Does approving the AGIA license preclude DNR's ability to assist the Denali project?

MS. THOMPSON replied that specific provisions in AGIA talk about what can't be done and associated penalties. Noting that Commissioner Galvin was listening, she suggested he could answer better tomorrow.

REPRESENTATIVE COGHILL said at least one vote hangs on that answer.

4:21:23 PM
MR. ZAGER closed by expressing concern that Ms. Thompson had implied Chevron's motive for its position was because it would somehow enhance its leverage in the Point Thomson issue. He said Chevron has been consistent year after year in its view of Point Thomson and has agreed with every administration until a couple of weeks ago. The position has changed on the other side, however. He suggested it benefits the administration's position on Point Thomson to now say that gas isn't needed for a gas pipeline.

4:22:22 PM
MR. HAYMES closed by saying ExxonMobil wants to work with DNR to resolve the Point Thomson dispute, believing its POD does everything needed to prudently develop the resource and manage the risks for the state and the leaseholders. He said he was encouraged to hear Ms. Thompson say that of course the state wants to develop this resource.

MR. HAYMES added that this gas is critical for a gas pipeline and the sooner it can be moved forward, the better. ExxonMobil has a real project underway, with people employed and working that today, and will be awarding more contracts in the next two

weeks, Alaskan contractors. The permit applications are in, and those are essential to continue.

4:23:30 PM
MS. THOMPSON offered an example to follow up Representative Fairclough's question about access denied to TAPS. Ms. Thompson recalled that the then-president of Conoco, before Conoco owned an interest in TAPS, said he'd sold his interest in the Milne Point unit and it broke his heart to do it; he couldn't make that production economic unless the company also owned an interest in the pipeline.

4:24:42 PM
CHAIR HUGGINS thanked participants, noting the administration would continue its presentation on NPV tomorrow.

The meeting was recessed from 4:27:39 PM to 6:02:31 PM.

Public Testimony

CHAIR HUGGINS called the meeting back to order. He welcomed the public, noting that because there were relatively few testifiers, each would be allowed about five minutes.

6:04:07 PM
CHARLES McKEE told members he'd listened to some of the Black & Veatch discussion of estimated expenditures based on dollars today and the discounted rate. He spoke about a 2 percent charge on Federal Reserve notes, talked about the Treasury seal, and said part of American history was abdicated because of not wanting the U.S. to break away from that rental policy imposed in 1913.

MR. McKEE said while oil is traded in dollars, the Euro is gaining influence in the U.S. and the world. Expressing concern that the producers have attempted to stifle development outside of their control, he shared a map, discussed his website, and asked: If we're going to have an open market, what currency will we use and how will it be devalued?

6:11:21 PM
PAUL LAIRD, General Manager, Alaska Support Industry Alliance, noted his trade association of companies provides goods and services to Alaska's oil, gas and mining industries. He was testifying on behalf of its 430 member organizations that have approximately 35,000 Alaskan employees.

MR. LAIRD, assisted by others, sang a song to the tune of "How Do You Solve a Problem like Maria?" from The Sound of Music. It began, "How do you solve a problem like AGIA? How do you tell the truth from all the hype?" The lyrics expressed numerous concerns - including that Point Thomson gas is off the table, that the state subsidy is wrong, and that the power lies with FERC - and asked legislators to vote against the AGIA license and instead support the Denali project.

6:15:22 PM
JERRY McCUTCHEON began by claiming he'd killed the gas pipeline in the 1980s. He said he'd tried to tell the legislature in 1976-1977 that a gas pipeline isn't in Alaska's best interests and that gas offtake could only come at the expense of oil production. Opining that the oil companies lied about Prudhoe Bay production, he said Ms. Foerster, when pressed for an amount and date for gas offtake, told the legislature Prudhoe Bay had already produced 6 billion barrels of oil more than if a gasline had been built in the 1980s.

MR. McCUTCHEON said the parameters today are the same as 30 years ago and will continue 30 years more. He voiced concern about information presented during the Murkowski Administration's efforts to get a gasline. He also suggested suing the oil companies to find out how much oil is in Prudhoe Bay; he estimated another 10 billion barrels.

MR. McCUTCHEON concluded by calling AGIA a disaster and saying it will only get worse. He cited testimony that the responsibilities need to be memorialized and that Chair Huggins had suggested the need for a contract as well as a license. Noting he doesn't support the Denali project either, he opined that discussion of a gasline is at least a decade premature.

6:24:18 PM
MATTHEW FAGNANI told members that constructing a natural gas pipeline is critical to the state's economy. Characterizing the administration's presentations as propaganda, however, he asked that legislators listen closely to the industry and vote no to this license

MR. FAGNANI inquired why the state downgraded the project to a 3.5 Bcf/d line and expressed surprise at hearing that 2.0 Bcf/d from Prudhoe Bay and yet-to-be-identified fields can be counted on. He asked why the pipeline isn't built to handle Alaska's full known gas capacity.

MR. FAGNANI expressed concern that Commissioner Irwin is holding up production of Point Thomson in the courts. He said Point Thomson needs to be in production; there will be lower oil revenues if Prudhoe Bay is tapped prematurely for gas, which isn't managing the resource for the maximum benefit.

MR. FAGNANI also said a private-sector gasline of this magnitude should be viable without monetary inducements; a $500 million state subsidy should be of great concern for budgetary reasons and because it isn't contingent on actually building a pipeline. Highlighting jobs and not more taxation of the industry, he urged members to reject the AGIA proposal and let the competitive marketplace work.

6:28:12 PM
MAYNARD TAPP told members he is against the AGIA proposal and believes in supporting the tried-and-true companies of BP, ConocoPhillips, and ExxonMobil that have invested so much to help Alaska become an enviable place with a surplus of tax revenues. Saying he doesn't doubt TransCanada's integrity or strength, he expressed hope that TransCanada can become partners with Denali and others to build this project.

MR. TAPP said because of financial risk to the state, he can't see providing $500 million to do something that is already being done. He also doesn't believe AGIA offers the correct incentives to avoid failure. However, he believes AGIA is a success in that the Denali project has been formed and is progressing.

MR. TAPP opined that the only economic reason for a gasline is to grow the oil-based business upon which the state's wealth depends. Financing will be through proven reserves of gas, including Point Thomson. He said building a gasline enables oil and gas development because there'll be two transportation systems to market: TAPS and the Denali gas pipeline.

MR. TAPP offered his belief that state revenues from gas are best protected by commercial entities influenced by the risks of the project; those owners have a stake in controlling the costs of pipeline construction, and ultimately transportation, to ensure the most competitive product in the market. With oil declining 6 percent a year, he said the gasline must not be delayed and the state must work with the producers to encourage more oil production.

6:32:01 PM

MIKE ROGERS indicated he believes in August 2010 the people of Alaska should vote up or down on treble damages on the $500 million and conditional approval. Mentioning FERC testimony, he said consensus has emerged as a dominant concern because two pipelines could receive regulatory approval. Reasonable people have raised questions that can't be answered in the 60-day limit provided in AGIA.

MR. ROGERS said it makes no sense at this time to give carte blanche approval to development, when real doubts exist regarding both the science of gas fields and the financing of gas pipelines. With conditional approval, Alaskans could preserve their rights to continue to negotiate while others with obscure agendas maneuver for advantage. If the legislature approves this license, he asked that it be amended to allow Alaskan citizens to vote and said he would vote no. Adding he doesn't support the Denali project either, he sang a song dedicated to the "victims of AGIA."

REPRESENTATIVE GARDNER clarified that the treble damages provision, should the state grant a license and then materially support another project, doesn't apply to the $500 million.

MR. ROGERS replied that was good to hear, since he believes the only project that will eventually get built, unless the Alberta tar sands become highly profitable, is an all-Alaskan pipeline to Valdez.

6:39:05 PM
BARBARA BACHMEIER, speaking on her own behalf, noted she is affiliated with a statewide nonprofit organization providing services to Alaskan veterans, many disabled. She'd read in the Anchorage Daily News on April 9 that the BP-ConocoPhillips project called Denali was offering 150 jobs to Anchorage-based employees by year's end. She said she was delighted, thinking about putting veterans to work.

MS. BACHMEIER said, however, Denali's website didn't give employment information, so she'd called the contact person, who on April 23 said it would be two weeks; on May 8 he didn't know when it would be. Yesterday the website still didn't list employment information, but the June 18 paper said the 150 employees to be assembled by year's end will be from BP, ConocoPhillips, and outside contractors. Noting she wasn't happy about that, she said 150 jobs were promised.

MS. BACHMEIER also said TransCanada Alaska has no office space at this time, no business plan, and no employment plan, although she'd been told the opportunity for jobs may be known in about 18 months. She suggested Alaskans deserve better in both instances. When jobs are promised, they should be delivered. She closed by saying she'd prefer that the state do this on its own and that she doesn't support AGIA, TransCanada, or Denali.

6:44:01 PM
JOHN WOOD told members he isn't affiliated with oil companies or the state and believes this is one of the most important issues the state has ever faced. He opined that AGIA's shortcoming is that the $500 million would have made more sense if additional competitive bids had been received; its strength is that it has shown the oil industry it isn't the only game in town and thus will bring the companies to the table.

MR. WOOD expressed disappointment that the administration wasn't represented at this public hearing. He said TransCanada appears to be the company that could bring a pipeline down the highway route, since TransCanada appears to know what it is doing and has the industry contacts to pull it off. From a public perspective, he doesn't know what project is best for Alaska. He requested a side-by-side comparison of in-state LNG from Valdez versus the TransCanada line to Alberta.

MR. WOOD highlighted ensuring that the oil fields aren't impacted. Saying this is the time to negotiate with the producers, LNG companies, and TransCanada, he said if it isn't successful, then the Point Thomson decision should be followed up. Suggesting a win-win situation can be created with all players at the table with an incentive to go forward, he said there is no need for the state to lay out $500 million to do it. Mr. Wood specified that he isn't in favor of the AGIA process, but wants it on the table as a negotiation tool.

6:48:39 PM
KATE TROLL, Executive Director, Alaska Conservation Alliance (ACA), noted her umbrella organization is composed of 40 state-based conservation groups with about 38,000 Alaskan members. Since how energy is used is highly important to the conservation community, last year ACA developed a position paper supporting a gas pipeline. They see Alaska's natural gas as a bridge to a future with clean, renewable energy for Alaska and the U.S.

MS. TROLL said while wanting more information before deciding on a stand-alone LNG proposal, ACA was pleased to see TransCanada

is willing to consider an LNG option. Based on available information, ACA supports a pipeline that meets its criteria and principles, finding TransCanada's proposal more closely aligns with those, compared with the Denali proposal. She said ACA supports the AGIA project, tempered with concerns it hopes to work with the Palin administration to address.

MS. TROLL detailed the concerns: incentivizing the flow of gas to the Lower 48 to offset coal-fired generation and away from the Alberta tar sands, where producing energy generates three times more greenhouse gas emissions than producing oil and is highly inefficient; ensuring in-state use and a more thorough analysis of greenhouse gas emissions; maximizing benefits to Alaskans, which ACA believes an open-access pipeline that spurs competition will do, providing billions more in revenues than a pipeline controlled by the producers; considering an oversight council; and providing incentives for clean, renewable energy, for which ACA believes this pipeline will be the bridge.

REPRESENTATIVE GATTO asked whether the 38,000 Alaskans are dues-paying members.

MS. TROLL affirmed that.

REPRESENTATIVE GATTO surmised ACA also supports solar, wind, geothermal, and hydroelectric power, but not coal, nuclear, and diesel.

MS. TROLL replied that was a good summation. The gas is the bridge, since there cannot just be a shift into renewables because of the fossil-fuel dependency.

6:57:48 PM
CHAIR HUGGINS recognized DOR Commissioner Galvin representing the administration and Tony Palmer of TransCanada.

6:58:15 PM
CAMILLE CONTE gave her understanding that last Friday the governor's gas team recognized that the comparison between the analysis of TransCanada's proposal and the in-state line was based on a mathematical model that inadvertently produced skewed numbers. She urged legislators to find out the accuracy of that and report back to the public.

MS. CONTE also gave her understanding that some time ago the governor said the state would use the in-state line put together by the Alaska Gasline Port Authority ("Port Authority") for an

apples-to-apples comparison with TransCanada's project. While Ms. Conte said she isn't against AGIA, which sets a framework and has good aspects like the open season and items that put the state in the driver's seat, she suggested possibly amending it, looking at what may be transferable for what is done next.

MS. CONTE told members she doesn't support giving a license to TransCanada. If the pipeline ends in landlocked Alberta, it only allows shipping within North America, whereas an in-state line to Valdez allows barging the gas to markets that pay the most, such as Asia. She said ConocoPhillips is one of the companies that own the majority of the tar sands, and to her understanding AGIA doesn't guarantee that the state can control how the gas is used once it leaves Alaska. Also, for an in-state line the existing TAPS corridor doesn't require dealing with the rights-of-way or environmental factors in a way that can trip this up. And it doesn't require dealing with FERC.

MS. CONTE suggested this is a powerful time for Alaska to take hold of this project, since AGIA has brought Alaskans to understand that the TransCanada proposal doesn't give Alaskans what they want. She opined that 80 percent of Alaskans say they want the state to explore a line to Valdez. Highlighting the importance of having an open mind, she asked the legislature to thank TransCanada for its work, say no to the license, get the numbers about the in-state pipeline, and get going on that line.

SENATOR BUNDE relayed what he understands from Washington, D.C., that an in-state line won't receive an export license to send gas to Asia when the Lower 48 needs Alaska's energy. After there's a line to the rest of the country, a spur line is possible. An in-state line alone won't get an export license.

7:06:24 PM
BRIAN DAVIES told members he'd worked for BP over 30 years and retired in 1994. He suggested there are four major players: the State of Alaska, the producers, TransCanada, and Enbridge or another pipeline company; each could delay the project, and all except the state are signaling that they know they must come together.

MR. DAVIES said while it now appears there'll be two competing projects, only one can succeed at the open season because gas can be committed to only one; he surmised that will be Denali. He opined that Denali will need to deal with TransCanada, which claims exclusive rights to build across Canada, as well as

Enbridge and other entities that are disputing TransCanada's rights.

MR. DAVIES specified that he opposes granting an AGIA license because he believes it will inhibit the necessary coming together of these players and greatly delay the pipeline. He urged legislators to focus on those impacts to Alaska and the nation. While applauding AGIA for changing the nature of the conversation, he said the process has limitations. He asked legislators to think about a role for the state in facilitating that coming together, rather than driving the projects apart.

MR. DAVIES agreed with Senator Bunde's response to Ms. Conte about exporting natural gas. With energy supplies so critical for the nation, Mr. Davies said he believes there is no hope for exporting Alaska's gas.

7:12:04 PM
SENATOR McGUIRE noted some legislators have talked about facilitating negotiations, but the result seems to be pushing folks further apart. She asked whether Mr. Davies had any ideas on how such negotiation might be facilitated.

MR. DAVIES replied he didn't, but cited the conversation about the coming together of interests years ago for TAPS. He said he believes the state and administration could really help this project move forward. It is inefficient to have two separate entities spend money on the same thing, with one spending the state's money as well. He said TransCanada undoubtedly has a huge database on how to build pipelines in Canada, but not in Alaska. The producers have spent millions or billions of dollars in the 1980s and now. These two entities should come together as soon as possible.

SENATOR McGUIRE opined that the travesty is that the competing companies do have complementary expertise in building pipelines and production and were in the same room together as little as three years ago. Now an up-or-down vote will change the face of the state forever, with few tools. She said she has thought about whether there could be an arbitrator with expertise, for instance. She said they all deserve a seat at the table.

7:15:25 PM
REPRESENTATIVE GARA thanked Mr. Davies for his community service, but asked why AGIA prevents the companies from coming together, or the $500 million from the state, or rolled-in

rates, even though the major companies would rather have a lower rate on their own gas and a higher rate on somebody else's.

REPRESENTATIVE GARA, while recalling that some major players also oppose the five offtake points, said it doesn't prevent them from coming into this line. He opined that if the legislature voted no and just left it to Denali, the producers would have the state over a barrel and demand tax concessions and so forth.

MR. DAVIES replied that he had no specific items in mind with respect to AGIA and that the aspects Representative Gara had mentioned would be part of any pipeline project. He said his concern is the constraints from granting an exclusive license. It isn't really about the treble damages. It's about erecting a barrier so folks aren't talking.

MR. DAVIES predicted that if granting the AGIA license keeps the Denali project rolling, it would lead to an unsuccessful TransCanada open season and a successful Denali open season; however, TransCanada still would have to get on board because of its claim in Canada, which he surmised will lead to the Canadian courts and delay. Reiterating that the parties must come together, he asked legislators to look at that and, if they vote yes in order to keep the Denali project going forward, look for some way to lift those constraints at some stage.

7:20:07 PM
REPRESENTATIVE GRUENBERG surmised that bringing people to the table would mean voting down the current AGIA application, putting the state back where it was. He asked how people would be brought together then.

MR. DAVIES suggested, for instance, it could be voted down and then the legislature could say everyone needs to come together.
REPRESENTATIVE GRUENBERG suggested approving it and then they could come together afterwards.

MR. DAVIES asked that the legislature make sure it isn't erecting another barrier.

7:22:10 PM
RON AKSAMIT asked that legislators approve AGIA, which he believes won't impede TransCanada and the producers from getting together. He said they need each other, whether they admit it or not.

MR. AKSAMIT explained that while he isn't wildly in favor of AGIA and is less enthusiastic about giving away $500 million, it is important to keep TransCanada in the game. Prior to this, the producers weren't enthusiastic about building a pipeline. If AGIA didn't go forward, the producers could find 100 reasons to halt the Denali project. He suggested when it's economical to build a line and fill it with gas, it will happen.

MR. AKSAMIT told members he doesn't think government should try to facilitate this partnership; in general, government impedes private industry. He believes the ideal is that the producers and TransCanada get together to build a line and fill it with gas; there is little the state can do to in this regard that they cannot do themselves. Economics will be the driver.

MR. AKSAMIT opined that the Denali project will stop at the border when it gets to Canada unless a Canadian company is involved. As for a line to Valdez for natural gas, he agreed with Senator Bunde that it won't happen first. Citing the history of failed government projects in Alaska, he spoke against state involvement in this one. He surmised when the economics and politics allow, there can be a spur line.

7:26:23 PM
TOM LAKOSH told members while there are numerous environmental reasons why legislators should vote against AGIA, he would put on his consumer-and-citizen hat today. He said only TransCanada has all the pieces of the puzzle. The state turned to AGIA because the producers failed to honor their lease at Point Thomson and timely develop the oil and natural gas liquids.

MR. LAKOSH said while the producers complain about the $800 million they invested, it will cost the state more. This is because of not only lost revenues to date, but also paying more for an oversized pipe in financing and so on. The major underpinning of the leases is the requirement to drill until it isn't profitable.

MR. LAKOSH proposed declaring Point Thomson a state scientific study area and developing the natural gas liquids and oil as quickly as possible to meet AOGCC requirements before taking off the gas; the state could hire its own drillers and develop new techniques for high-pressure gas fields and for using the condensate to extract heavy oil.

MR. LAKOSH lauded AGIA for proving the gas is economical to develop and ship to the Lower 48, for forcing the producers to

start Denali, and for providing resources to the DNR commissioner. He asked legislators to honor their commitment to develop the natural resources to the benefit of the people and to vote yes on the TransCanada license.

7:32:10 PM
SHANNYN MOORE informed members that she has been talking to Bill Walker and others about why an all-Alaska gas pipeline is best for the state. No matter what, she said the experts that testify all want to go forward. Saying over 40 million acres of offshore leases have been granted in the last nine years but only 10 million are being tapped right now, Ms. Moore asked why some feel that incentives should be provided. She also said existing refineries are at 89 percent capacity.

MS. MOORE expressed concern that global companies have colonized the state and, in the past at least, took over legislators' seats. Characterizing the $500 million incentive as money an unpopular person would spend on a date, she said, "You're hot. You've got it. You don't have to pay someone else to do this." She encouraged legislators to amend AGIA. She also asked why the attorney general hasn't investigated what she considers sabotage with respect to the Port Authority's bid last year.

7:35:11 PM
RON ALLEVA, a 35-year resident, said he was appalled at the poor turnout, especially of younger people. He spoke against AGIA and in favor of the Denali project, saying he believes the producers have the knowledge and Alaskans have a legislature they cannot trust.

MR. ALLEVA expressed concern about the competence of Governor Palin and the commissioner to negotiate, as well as wasting $500 million as an incentive. He suggested the need for an intellectual wave of students who will be interested in defending the state now and in the future, saying the court case with Point Thomson has nothing to do with producing gas, but gives jobs to attorneys and is disgraceful.

MR. ALLEVA voiced concern that whereas he hears about ethics and transparency from Governor Palin, she hides the polar bear data. He suggested the state should go back to the table to get the gas produced. Characterizing the Canadian courts as brothers who know the gas industry, he said the Canadians are concerned with jobs as well and Alaskans can get along with them. Noting that the Denali project is moving forward, he proposed getting

out of the courtroom, going back to the drawing board, and talking to the producers.

7:41:16 PM
CHRISTOPHER CONSTANT told members he has never been more inspired about the future of Alaska. He believes it's a new day, the house has been cleaned, Alaska has money in the bank, and it's time to get to work and secure the future. Saying he trusts that this body will do the right thing, he encouraged making some changes to AGIA to ensure that Alaskan kids can get the long-term benefit, which is the jobs and skills.

CHAIR HUGGINS thanked the testifiers. SB 3001 and HB 3001 were held over.

CHAIR HUGGINS adjourned the joint meeting of the Senate Special Committee on Energy and the House Rules Standing Committee at 7:43:32 PM.