ALASKA STATE LEGISLATURE
HOUSE SPECIAL COMMITTEE ON OIL AND GAS
October 22, 2007
9:06 a.m.

MEMBERS PRESENT

Representative Kurt Olson, Chair
Representative Nancy Dahlstrom
Representative Mark Neuman
Representative Jay Ramras
Representative Ralph Samuels
Representative Mike Doogan
Representative Scott Kawasaki

MEMBERS ABSENT

All members present

OTHER LEGISLATORS PRESENT

Representative Bob Buch
Representative Mike Chenault
Representative John Coghill
Representative Harry Crawford
Representative Andrea Doll
Representative Bryce Edgmon
Representative Anna Fairclough
Representative Les Gara
Representative Carl Gatto
Representative David Guttenberg
Representative Lindsey Holmes
Representative Wes Keller
Representative Mike Kelly
Representative Bob Roses
Representative Paul Seaton
Representative Peggy Wilson
Senator Con Bunde
Senator Joe Thomas

COMMITTEE CALENDAR

HOUSE BILL NO. 2001
"An Act relating to the production tax on oil and gas and to conservation surcharges on oil; relating to the issuance of advisory bulletins and the disclosure of certain information relating to the production tax and the sharing between agencies

of certain information relating to the production tax and to oil and gas or gas only leases; amending the State Personnel Act to place in the exempt service certain state oil and gas auditors and their immediate supervisors; establishing an oil and gas tax credit fund and authorizing payment from that fund; providing for retroactive application of certain statutory and regulatory provisions relating to the production tax on oil and gas and conservation surcharges on oil; making conforming amendments; and providing for an effective date."

- HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 2001
SHORT TITLE: OIL & GAS TAX AMENDMENTS
SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

10/18/07	(H)	READ THE FIRST TIME - REFERRALS
10/18/07	(H)	O&G, RES, FIN
10/19/07	(H)	O&G AT 1:30 PM HOUSE FINANCE 519
10/19/07	(H)	Heard & Held
10/19/07	(H)	MINUTE(O&G)
10/20/07	(H)	O&G AT 12:00 AM HOUSE FINANCE 519
10/20/07	(H)	Heard & Held
10/20/07	(H)	MINUTE(O&G)
10/21/07	(H)	O&G AT 1:00 PM HOUSE FINANCE 519
10/21/07	(H)	Heard & Held
10/21/07	(H)	MINUTE(O&G)

WITNESS REGISTER

CLAIRE FITZPATRICK, Commercial Senior Vice President
BP Exploration (Alaska) Inc. (BP)
(No address provided)
POSITION STATEMENT: Provided comments during the hearing on HB 2001.

MIKE UTSLER, Senior Vice President - Prudhoe Bay
BP Exploration (Alaska) Inc. (BP)
(No address provided)
POSITION STATEMENT: Provided comments during the hearing on HB 2001.

KEVIN MITCHELL, Vice President
Finance & Administration
ConocoPhillips Alaska, Inc.

(No address provided)
POSITION STATEMENT: Provided comments during the hearing on HB 2001.

JIM TAYLOR, Vice President
Commercial Assets
ConocoPhillips Alaska, Inc.
(No address provided)
POSITION STATEMENT: Provided comments during the hearing on HB 2001.

KEN THOMPSON, Managing Director
Alaska Venture Capital Group (AVCG) LLC
Anchorage, Alaska
POSITION STATEMENT: Provided comments during the hearing on HB 2001.

ACTION NARRATIVE

CHAIR KURT OLSON called the House Special Committee on Oil and Gas meeting to order at 9:06:22 AM. Present at the call to order were Representatives Dahlstrom, Doogan, Samuels, Olson, Ramras, and Kawasaki. Representative Neuman arrived as the meeting was in progress. Also in attendance were Representatives Buch, Chenault, Coghill, Crawford, Doll, Edgmon, Fairclough, Gara, Gatto, Guttenberg, Holmes, Keller, Kelly, Roses, Seaton, and Wilson, and Senators Bunde and Thomas.

HB 2001 - OIL & GAS TAX AMENDMENTS

9:07:35 AM

CHAIR OLSON announced that the only order of business would be HOUSE BILL NO. 2001, "An Act relating to the production tax on oil and gas and to conservation surcharges on oil; relating to the issuance of advisory bulletins and the disclosure of certain information relating to the production tax and the sharing between agencies of certain information relating to the production tax and to oil and gas or gas only leases; amending the State Personnel Act to place in the exempt service certain state oil and gas auditors and their immediate supervisors; establishing an oil and gas tax credit fund and authorizing payment from that fund; providing for retroactive application of certain statutory and regulatory provisions relating to the production tax on oil and gas and conservation surcharges on oil; making conforming amendments; and providing for an effective date."

9:07:42 AM

CLAIRE FITZPATRICK, Commercial Senior Vice President, BP Exploration (Alaska) Inc. (BP), began BP's PowerPoint presentation by stating that the debate is about Alaska's economic future. She stressed that the common objective for both BP and the State of Alaska is to stem the decline in production. Her presentation, she advised, would be from the perspective of Alaska's resources, climate, costs, and geography - in terms of the 800 miles of pipe and the 2000 miles of shipping to West Coast refineries - because, she opined, that is the perspective legislators should use in determining what the state's fiscal policy should be.

MS. FITZPATRICK relayed that BP supports the net tax structure under the current petroleum production tax (PPT) statute, but continues to think that the [tax] rate is too high. Based upon conversations with colleagues who were present during the original discussions of the PPT legislation, Ms. Fitzpatrick offered her belief that the policy behind the PPT was to encourage investment in terms of getting barrels into the pipeline. She then requested that BP be allowed another opportunity for testimony should subsequent witnesses offer differing economic viewpoints than BP's.

MS. FITZPATRICK stressed that the proposed changes will not result in BP stopping further investment or leaving the state. She said BP has done good business in Alaska for 48 years and wants to do more; therefore, the discussion is about scale and pace, not about there being no more investment.

9:11:31 AM

MS. FITZPATRICK noted that along with the PPT, royalty rates also have a significant impact on the state's revenue and, therefore, production will impact both royalty payments and production tax. Delivering production will require billions of dollars in investment, and that level of investment will need to be higher than it has been in the last 20 years, she advised. Price has been a huge benefit in recent years; however, BP is not sure that basing fiscal policy purely on price is the right approach.

MS. FITZPATRICK emphasized that fiscal stability is an important consideration when making investment decisions. Having three tax changes in three years does not increase Alaska's

attractiveness. The proposed bill will actually deteriorate the economics of these investment decisions, and this, she maintained, is recognized by both BP and the Department of Revenue (DOR). She said that the sustained high oil prices of recent years makes prospects more attractive now than they were in the past, and while BP knows the resource is there, the key issue is how to get it out of the ground economically, and that is what enters into BP's investment decisions. Without substantial reinvestment in existing resources, she explained, it becomes harder to invest in new resources. So, the debate for BP centers on investment because the profiles currently being looked at are not yet "banked," she said. For Alaska's economic future, now is not the right time to change the state's fiscal policy.

REPRESENTATIVE DOOGAN requested a definition for the word "strategy" as used in the third bullet point regarding investment decisions on slide 2.

MS. FITZPATRICK explained that as a global company, BP looks at strategic perspectives at the group level in terms of the global risk that it is willing to take in a particular geographic area of the world. The company also looks at its competitive position and at where there is the greatest prospect in terms of the resource base. On a group level, there are more strategic decisions [to be made], often revolving around new country entry or new location entry, and that is different than economic or project specificity, so there are elements of both in any investment decision.

9:14:41 AM

REPRESENTATIVE DAHLSTROM asked whether Ms. Fitzpatrick was referencing the state's revenue department or BP's when she said it was recognized that the bill could deteriorate the economics of investment decisions.

MS. FITZPATRICK replied that she is referring to the State of Alaska's DOR, and that it made that statement during its [public] presentation on the bill.

REPRESENTATIVE DOOGAN asked whether "deteriorates the economics" means that the projects would "make less money later."

MS. FITZPATRICK responded that it depends on the specific project and its relative position to any other project, as well as the very nature of the project. It does not specifically

make projects less economic later because that depends [on numerous factors], but in overall terms it will make them less economic. She acknowledged that this means it could result in less money at any point along the line.

9:16:41 AM

MS. FITZPATRICK, referring to BP's PowerPoint presentation, pointed out that production declined about 6 percent per year between 1992 and 2000. However, she noted, the decline was reduced to 1.5 percent per year between 2001 and 2004 because of BP's increased investment in the late 1990s. The decline then returned to about 6 percent per year from 2004 to 2007.

MS. FITZPATRICK, responding to a question from Representative Samuels, confirmed that the investment in the late 1990s came from Alpine and Northstar, and that the production decline flattened out when these two units came on-stream. Once Alpine and Northstar reached their plateau and started declining, she continued, production returned to its historical annual rate of decline of approximately 6 percent. In response to a further question from Representative Samuels, she directed attention to the graph on slide 3 depicting the plateau as lasting Three to four years before production again began declining.

REPRESENTATIVE SAMUELS asked whether a two to three year peak before the start of a decline is the norm for most reservoirs.

MS. FITZPATRICK replied that a peak, plateau, and then decline are normal.

9:18:41 AM

MIKE UTSLER, Senior Vice President - Prudhoe Bay, BP Exploration (Alaska) Inc. (BP), concurred that such is normal for a field. And while it depends on the size and scale of the reservoir, he said, a field will produce for as short as 9-12 months to for as long as 7-8 years before beginning to decline, and that decline then becomes a function of how the reservoir is managed and how its performance continues to be developed and optimized.

REPRESENTATIVE SAMUELS asked how many barrels a day Northstar produced at its peak.

MR. UTSLER offered to get back to the committee with that information.

REPRESENTATIVE NEUMAN noted that recent information from the administration shows a doubling of operating and capital costs on the North Slope over the past year. He asked if that was typical of what happens at BP, and whether it was all due to cost increases or whether an increase in capital investment - and thus the creation of more jobs and having more people working - was the cause.

MS. FITZPATRICK explained that the doubling of operating and capital costs on the North Slope over the past year was due to both increased activity and increased costs. Activity increased between 2005 and 2007, she said, with the number of BP contractors increasing from about 5,000 to about 7,000, and with the number of BP employees in Alaska increasing about 40-50 percent. High worldwide demand increased the costs of steel rigs and skilled labor for the original activity, however some of the increased costs were specific to Alaska. Part of BP's long-term plan for addressing high labor costs, she continued, includes hiring younger, less experienced talent and then providing on-the-job training.

MS. FITZPATRICK then reiterated that the management of a reservoir after it moves off its production plateau and goes into decline is key to stemming that decline.

9:22:31 AM

REPRESENTATIVE SAMUELS asked whether a 15 percent decline rate - if nothing is done - is typical for reservoirs around the world.

MR. UTSLER responded that around the world, typical natural decline rates are 16-18 percent for a water-flooded reservoir environment. And while it depends on the field, it is not an unrealistic assumption to use a 16-18 percent natural decline rate for most reservoirs that are under "secondary recovery," which is the term for operations that are under water-flooded pressure support.

MS. FITZPATRICK added that the reason for the difference between the 15 percent natural field production decline and [Alaska's] current 6 percent decline is investment. In 2006, BP drilled about 100 new wells, and about another 100 wells will be drilled in 2007. Thus, between new wells and "well work" - the maintenance necessary for keeping wells running at their best - BP added about 70,000 barrels in 2006.

REPRESENTATIVE NEUMAN inquired whether any of the incentives in PPT were factors in BP's decision to make new investments.

MS. FITZPATRICK replied that that decision was based on the fiscal policy in place at the time. Currently, she said, BP is looking at the next 50 years and at building a sustainable business plan of activity, and [the state's] fiscal policy will impact that. She submitted that it is impossible to say whether, if BP had drilled 110 wells rather than 100, BP's fiscal policy would have been different since she does not have a retroactive viewpoint.

9:25:47 AM

MS. FITZPATRICK continued her discussion of new wells and well work by noting that 70,000 barrels is equivalent to developing the fourth largest producing field in Alaska, and that going forward, BP is set to do it again. Over the last 10 years, BP has invested about $4 billion in the drilling of 800 wells in Prudhoe Bay and is also investing in facilities to pick up the newer, heavier crude oil. Thus there has been lots of activity to get the decline down to 6 percent, and because the best prospects in any field are drilled first, BP must spend more money and drill more wells just to keep that current decline rate. The current level of spending on the North Slope will not sustain a 6 percent rate of decline - it needs to be higher, she opined, and even higher still in order to reduce the decline rate further.

MS. FITZPATRICK, in response to a question from Representative Neuman, confirmed her statement that BP drilled 800 wells in the last 10 years.

REPRESENTATIVE NEUMAN questioned the discrepancy between 800 wells and a map he received the previous evening showing that only 7 exploration wells had been drilled.

MS. FITZPATRICK explained that there is a difference between drilling exploration wells in order to locate new discoveries and drilling wells in existing reservoir areas.

MR. UTSLER further explained that undeveloped areas are identified as exploration opportunities. In areas that are already developed, productivity is optimized by drilling new wells and "re-completing" existing wells. The aforementioned 800 wells have largely been in the existing, producing legacy fields.

REPRESENTATIVE NEUMAN inquired as to how many well drilling rigs are currently in Prudhoe Bay, in total between BP and other companies.

MS. FITZPATRICK responded that BP currently has around 10 rigs in the fields on the North Slope in which it has interest, including Kuparuk.

MR. UTSLER further responded that at any given time, there are about 21 rigs that are designed and equipped for operation on the North Slope, and about 5 of those rigs are specifically geared for winter-only exploration. About 16 rigs are available at any given time to operate in existing fields, he continued, 10 of which are operated by BP.

9:29:34 AM

REPRESENTATIVE NEUMAN asked whether BP will be bringing any more drilling rigs to Prudhoe Bay.

MR. UTSLER stated that BP is studying opportunities in the Liberty Field. In order to drill that operation, he said, BP is looking at building the largest land rig in the world. And along with others in the industry, BP is also looking at bringing new rigs to the North Slope to replace the aging fleet and to increase capacity.

REPRESENTATIVE SAMUELS asked which areas BP held interest in.

MS. FITZPATRICK listed those areas as being Prudhoe Bay, Kuparuk, Endicott, Milne Point, Northstar, Badami, and Liberty.

REPRESENTATIVE SAMUELS asked what BP's total Alaska oil percentage is for each of those fields, adding that he assumes that the vast majority comes from Prudhoe Bay and Kuparuk.

MS. FITZPATRICK agreed that the vast majority does come from Prudhoe Bay and Kuparuk, and said she would provide the exact percentages to the committee soon.

REPRESENTATIVE SAMUELS also requested nonproprietary information regarding the percentage of BP's spending figures for each of the fields, adding that he would like to know if costs correlate with income.

MS. FITZPATRICK said she would provide that information once she verifies that it is not proprietary.

9:32:15 AM

REPRESENTATIVE DOOGAN asked for further explanation of slide 3 of BP's presentation.

MS. FITZPATRICK explained that the numbers in orange on the right side of the chart pertain to investment; the numbers in green on the left side of the chart pertain to production; and the bars depicted on the bottom of the chart indicate that historically investment rates were around $1 billion, and that in recent years the rate has risen above $1.5 billion.

MR. UTSLER clarified that the numbers in green represent barrels of production per day and the numbers in orange represent annual investment in billions of dollars.

REPRESENTATIVE DOOGAN asked what BP's profits were last year - the time during which BP drilled 100 wells.

MS. FITZPATRICK said that BP recorded a profit of $2.15 billion for last year.

REPRESENTATIVE RAMRAS asked what BP's posture would be should production decline to the point where the State of Alaska does not have enough royalty oil available to sell to the Flint Hills Resources Alaska ("Flint Hills") refinery. He then offered his understanding that there are two crossover points. The first is when the state does not have enough royalty oil to fulfill its commitment to Flint Hills, which would then require the state to look to producers for augmenting the state's share. The second is the notion of "batching" oil two to three times a week because there is not enough oil to flow down the Trans-Alaska Pipeline System (TAPS) seven days a week. Given that production is declining, at what point does it become uneconomic to operate the TAPS, he asked. Further, he asked, what happens to the tariff cost per barrel of oil when production declines to 500,000 barrels per day, a volume at which the TAPS can still operate but is a stress point for the state insofar as its [one-eighth] share.

MS. FITZPATRICK, with regard to the tariff question, stated that many of the costs associated with transportation are fixed; thus, the fewer barrels going in, the higher the tariff. Getting barrels into the pipeline is important, she said,

regardless of whether they are from state or federal leases, because doing so lowers the unit costs which in turn is better for everyone. With regard to what would happen should the state's royalty share not meet its commitment to Flint Hills, she said that [BP's posture] would depend on the circumstances at the time since BP has no set policy in this regard. As for what happens at various stress points, she said that that is a question for Alyeska Pipeline Service Company ("Alyeska"), which has been working to have flexibility as flow rates decline and is looking at what is happening at the various points in terms of investment.

MR. UTSLER further explained that with regard to Representative Ramras's first question, the majority of Alaska crude oil goes to the West Coast refinery market, three refineries in particular. Those refineries are currently set up and designed to take a particular blend of crude oil, and Alaskan crude plays an important part for them. On a short term basis, those refineries have the capacity to utilize the global market should there be a disruption or variation in the Alaska crude oil supply.

9:39:14 AM

REPRESENTATIVE RAMRAS offered his opinion that Alyeska is becoming relevant to this discussion because an unstable tax regime could diminish production, thereby moving Alyeska to a stress point that would affect core jobs in the Interior. He relayed that at a recent conference in Fairbanks, U.S. Senator Ted Stevens advised the state to think about getting the next barrel of oil, not the number of dollars being received in taxes from the current barrel of oil. He requested BP's opinion on what Alaska should do to best foster an environment that will lead to that next barrel of oil.

MS. FITZPATRICK remarked that in order to get the barrels into the TAPS, investment is required; thus any changes the legislature makes should be considered in the context of whether a particular change will increase or decrease the risk of meeting the objective of getting more barrels into the pipe. Again, the key is investment.

REPRESENTATIVE RAMRAS asked what BP's sentiment is when making decisions for long-term development plans.

9:44:03 AM

MR. UTSLER remarked that because BP is operating above the Arctic Circle in very harsh conditions, investment in exploration and development - and specifically investment in those technologies that will enhance the application of technologies related to finding the oil and gas resources - is an imperative for both BP and the state, both in the non-explored areas of Alaska and in the existing fields. He went on to say:

> Secondly, then, you have the challenges of, "Now you must drill to test and develop those resources." And, again, [there are] the challenges of how we, together, assure that we create an environment that encourages the most efficient and effective development of those resources.

MR. UTSLER said that from an operating standpoint, the aforementioned arctic conditions result in some of the highest-cost barrels in the world to develop and produce. Again, the question becomes what can BP and the state do together to enhance operability and increase efficiency in developing the barrels. Furthermore, operations in the North Slope are significantly disadvantaged because of the transportation infrastructure that industry requires in order to get goods, services, and materials to the North Slope. With regard to the question of BP's sentiment, he said:

> First and foremost we start with the barrels in terms of where the barrels are, and our abilities to understand the size and magnitude of the resource that's in the ground. We then look at what is the risk and the uncertainty of those barrels, in terms of our confidence that they can be developed, in order to be able to produce to the market place. The second [thing] we then look at is ... what's the technology required to actually develop those barrels - how and what do we need to do once we've determined that there is a 100 million barrels, 200 million barrels, or 10 million barrels - how hard is it to get those 10 million barrels, and what confidence do we have in terms of the ability to develop and bring them to the market place.
>
> And then thirdly we look at what is the life of [the] asset, what is going to be required in terms of facilities, how long must those facilities operate, what's the cost structure to operate those facilities,

> is it a 10-year field development, is it a 20-year, is it a [50-year, or an] ... 80-year. And each of those decisions bring with it certain risks and view of what is the full life of that asset's or that barrel's development cost, so that we don't look at just the front-end cost, but we have to look at the full field life, and we have to be able to evaluate, in the development of that barrel over the life of that field for however long it is, with confidence, what is the cost structure, the recovery, and the subsequent environment in which we operate. And ... [we then] compare those, on a global basis, from market, from basin to basin to basin where hydrocarbons exist.

9:47:57 AM

REPRESENTATIVE RAMRAS posited that the DOR will argue that one of those variables is the tax rate, whereas what members have heard, he relayed, is that the tax rate is "pretty far down your pecking order" and that it won't affect BP's investment decision - that the other variables previously specified are much more dominant in BP's determination of whether to invest. He asked about investment climate, and whether an incremental increase in taxes, after the large policy shift of a year ago, will have any impact on BP's sentiment regarding whether to go forth with a particular project.

MS. FITZPATRICK said that all of BP's investment decisions, at the economic level, are made on an after-tax basis. So, does fiscal policy come into BP's decision making? Absolutely, regardless of whether the project is in Alaska or someplace else. In terms of barriers, she remarked, there is not a fiscal term that will enable BP to develop 50 million barrels per day (mbd) of heavy oil tomorrow; rather, BP must first overcome technological challenges. However, knowing that there is a good fiscal policy in place makes it a lot easier for BP to say that it is prepared to make the investment to actually work out how to apply that technology, in this particular environment, knowing that once BP has mastered the technology, it can then work on getting the economics right to then progress the project. That decision is impacted by fiscal terms.

9:51:34 AM

MS. FITZPATRICK, in response to a question by Representative Doogan, relayed that there is an articulation of BP's strategy at the group level that is in the public domain, and offered to

provide members with that information later. In response to a further question, she said that the state has information that BP is required to share with the state, and that there is also some very detailed information available publicly - though some [is only available through] subscription services - on every single one of Alaska's fields, including information about capital, tariffs, and production profiles. She said that she would be happy to provide further information regarding how BP views Alaska's resources.

REPRESENTATIVE DOOGAN asked whether there is also information available publicly that will help member's determine whether BP has the technology to drill a particular well.

MS. FITZPATRICK said she hopes that later testimony will provide that information.

REPRESENTATIVE DOOGAN asked whether he will, at some point, be capable of predicting the effect of any particular change in the state's fiscal policy.

MS. FITZPATRICK pointed out that there is always a way to do something via mathematical models, but such models will still be wrong because they are based on assumptions and the world is not static. "When we make our investment decisions, we're assessing risk, and ... I've never seen a project that has actually delivered exactly what we thought it was going to; some are better, some are worse, and we're evaluating those risks to make that decision," she added. For better or for worse, members of the legislature are in the same position.

REPRESENTATIVE DOOGAN surmised that the term "risk" includes economic risk but not exclusively.

MS. FITZPATRICK explained that for BP, the term "risk" refers to resource risk, technology risk, economic risk, cost risk, and fiscal risk - a wide variety of risks. In response to a question, she said that although there should be sufficient information made available to help guide members, it would be impossible for someone other than the company to know what decision it would be making under any particular set of circumstances because there are many other factors that the company takes into consideration when making such decisions.

REPRESENTATIVE SAMUELS surmised that the risk tolerance of various companies is not information that would be available to the public.

MS. FITZPATRICK acknowledged that each company will have its own risk tolerance, which will vary depending on where a particular project is as well as other variables. For example, a small exploration company can take a lot more risk for its size than one might think but it's basing its decisions on what it thinks the rewards are. And the larger a company is, the more risk, financially, it can take because it can actually cope with it, whereas if a smaller company drills a $100 million dry hole, that could have a fairly devastating impact on that small company.

9:58:03 AM

MS. FITZPATRICK, referring to slide 4, said that production is a key point - more barrels means more money for the state; that the point of slide 4 is that investment leads to barrels, which in turn leads to increased revenues; and that slide 4 illustrates a range of outcomes. For example, if the goal is to stem decline down to 3 percent - as opposed to the current 6 percent rate of decline - it will require substantially more investment than there has been to date. In response to a question, she explained that according to the chart on slide 4, the industry investment is "point forward," with the 3 percent decline rate going out to about the year 2050. She added:

> We've made an assumption, here, on the revenues of the current tax structure. We've assumed 60 percent dollars, [and] we've used the state's ... cost forecast. It's merely to sort of point out two things. One is, the lower the decline, [although] it requires more investment, ... it does in fact generate a lot more revenue, both from PPT but also from the other revenues primarily driven by royalty. There's actually a range of royalty rates. The average of 12.5 that's used actually belies the range that runs from 11 to 27, depending on the field concerned. So that can actually have quite a substantial impact if it's more barrels in the pipe.

REPRESENTATIVE HOLMES asked in what year is the 15 percent decline that's indicated on slide 4.

MS. FITZPATRICK reiterated, "That's point forward," and offered to get more specific details to the committee.

10:01:36 AM

REPRESENTATIVE RAMRAS, referring to the term "opportunity cost," asked who BP competes against for limited capital dollars, and how that position is arrived at. He said he wants to know whether changing the tax policy in Alaska will affect BP's investment behavior, and how BP will "go up against" its units in other countries for capital.

MS. FITZPATRICK offered that BP's Alaska unit first looks at what its set of opportunities are and what the opportunities are, even within Alaska, that BP thinks are the right opportunities related to short-term issues - getting production, getting barrels in the pipe - and to mid- and long-term issues.

REPRESENTATIVE RAMRAS surmised that investing in operating expenses is what generates profits.

MS. FITZPATRICK relayed that BP looks at the range of opportunities, and at what activities the company can actually execute with the equipment and personnel it has, though if there is a project that can't be started right away but the company wants to be able to do so in the near future, the company makes plans that will enable it to start that project at the appropriate time. Once a group within BP decides it would like to go forward with a project, it then presents that "activity set" and accompanying "financials" to the head office in London, which in turn looks at the parameters of the project and its potential short- mid- and long-term benefits to all of BP's groups and at what is actually possible. At the group level, the company then looks at all of its branches in various parts of the world and considers the proposed project in terms of its robustness and stability. She said that each individual project is assessed on its own merits but within the context of BP's strategic and financial frameworks. The more stable she can be in Alaska, she remarked, the better her chance of saying to the board that any incremental capital at the group level ought to be spent in Alaska; thus stability is quite important.

10:12:45 AM

MR. UTSLER added that BP's first challenge is to grow the business via replacing the barrels it's produced with new barrels - "we need to find more barrels than we've produced the previous years." Therefore the upstream decision is based on the availability of oil in the world; the company's ability to discover, develop, produce, and market that oil; and the subsequent return on the oil that the company does sell.

CHAIR OLSON said he hopes that "maintenance has a voice and is asking [for] more money."

MR. UTSLER said "Absolutely." He attempted to assure the committee that BP first starts with complying with the law and with understanding exactly what its operational costs are, particularly those specific to the activity set required to continue meeting the law and industry standards. The company must then make decisions regarding what it is willing to spend based on how long the life expectancy of a particular field is. He offered that over the last five years, BP has spent four times the amount on maintenance operations than it spent the previous five years, and spent three times the amount on repair operations in the last four years than it spent the previous four years.

MS. FITZPATRICK relayed that there is no competition for required maintenance capital.

MR. UTSLER remarked that the [North Slope field] is one of the first arctic developments in the world; is the largest field discovered in North America 35 years ago; is still the largest producing field in North America; that although its original lifespan expectation was 20 years, that lifespan is now expected to be 80-plus years; that "it is a massive structure"; and that the scale and significance of its hydrocarbon accumulation is staggering on a global-scale basis. This size, however, creates huge challenges. Greater Prudhoe Bay itself is over 60 square miles in size; BP has over 11 major producing facilities necessary to handle the oil, gas, and water produced from the field's reservoirs; and BP has developed over 42 well pads allowing the company to drill through 1,500 feet of permafrost and into reservoirs that range from 3,000 feet below the earth's surface to 9,000 feet below the earth's surface.

MR. UTSLER mentioned that approximately 1,200 of the wells that BP has drilled in this field either are currently producing or are being used to inject water or gas [into the reservoir] in order to optimize resource recovery. He indicated that one of the things that needs to be understood is that although the total oil production is declining on the North Slope, the total fluid production is actually increasing. Every day the company has to handle more water being produced with every barrel, and that water has no revenue value but does have disposal cost. This increased fluid production carries with it greater risk, greater cost, and greater complexity in terms of how the company

optimizes the next barrel of oil it produces from this field. He went on to say:

> Every day we produce somewhere between 6 Bcf [billion cubic feet] in the summer to almost 9 Bcf of gas a day from the reservoirs. We have to take that gas production and re-inject it back into the ground. That does two things for us. It provides pressure - support - to the reservoir to enable us to get yet another barrel out of the ground tomorrow. It also provides an avenue of support by which we can actually produce those barrels more efficiently from the reservoir. ... At 9 Bcf, that's 40 percent of the Lower 48's household gas consumption on a daily basis that we are managing every day and putting back into the ground.
>
> Millions and millions of horsepower are required to re-inject that gas across the field into the reservoir, again, with no revenue benefit ... other than the impact that it has on our abilities to produce. So [it's] a significant set of challenges for us. As we've continued to produce the oil, over this 30-year period, the physical ability to recover, every day, more oil from that reservoir becomes more challenged - it's harder - and therefore we're looking constantly for new ways and new technologies to be able to enhance the scrubbing of the reservoir in a way that allows us to get every possible barrel of oil out that we can recover from this known resource.

REPRESENTATIVE SAMUELS asked what BP uses diesel for and how much diesel BP uses in its day-to-day operations.

10:25:04 AM

MR. UTSLER explained that BP is looking to build - jointly with ConocoPhillips - an ultra low sulfur diesel (ULSD) refining plant in the Kuparuk field. This plant will allow the companies to comply with federal law regarding the use of ULSD by January 1, 2010. The state, via legislation, has demanded that BP instead achieve this goal by January 1, 2009. Currently in greater Prudhoe Bay, BP uses approximately 3,000 gallons of diesel per day in the company's over 750 vehicles - though the amount varies greatly depending on the season - and in operating its emergency generators and backup equipment. Furthermore, BP uses diesel for a variety of other reasons such as well

stimulation. In response to questions, he relayed that the diesel that BP currently uses either comes from Flint Hills or is produced on site at BP's "crude oil topping facility"; that he couldn't speak to how much diesel the other Prudhoe Bay producers are using; and that the aforementioned refining plant will only meet industry demands on the North Slope.

MS. FITZPATRICK added that if the refining plant produces beyond what the companies needs, BP could provide a supply to North Slope villages, though doing so would not be its primary aim. Should BP and ConocoPhillips not be able to meet the state's new timeline, it will result in a significant increase in supply trucks on the road, and this in turn will have an impact on environmental and safety perspectives.

MR. UTSLER, in response to comments and a question, acknowledged that once Alaska has a gas pipeline, oil production will decline considerably, though BP is working to address the "optimized off-take of gas" since gas is an important part of the mechanism by which BP extracts and recover hydrocarbons from the reservoir; the consequences of gas production in Alaska will have to be carefully managed with regard to the volume of "off-take" and with regard to how to at least partially offset the loss of that energy in the reservoir.

REPRESENTATIVE NEUMAN surmised that the change from oil to gas will have an impact on the state's income.

MS. FITZPATRICK, in response to a question, offered that when the gas pipeline becomes operational, there will be a change in the mix of resources that are recovered, and that the issue of how to maximize the molecules - whether they be oil or gas - for the state's benefit will need to be addressed.

REPRESENTATIVE DOOGAN asked whether the aforementioned proposed ultra low-sulfur diesel refining plant will meet industry needs on the North Slope.

MR. UTSLER reiterated that it will, adding that the challenge will be to move that diesel product to where it's needed.

10:35:36 AM

REPRESENTATIVE SAMUELS said that one problem with the state giving BP a credit for the proposed refining plant is that that same credit won't be extended to the other companies that have an interest in the plant.

MR. UTSLER remarked that the North Slope is a complex environment in which to produce oil and gas, and is getting more complex every day in terms of technology needs and operating costs. Referring to BP's PowerPoint presentation, he then spoke of the volume of oil that's been produced to date from the North Slope and greater Prudhoe Bay, and noted that this production has come with tremendous challenges both technically and opportunistically. He relayed that $19 billion has been invested to develop [BP's holding] in greater Prudhoe Bay, and although more money is being invested each year to essentially produce fewer barrels, that investment continues to be an important part of the company's ability to progress. After starting with "natural production," he offered, the company quickly realized that it needed to utilize additional pressure support in order to optimize recovery, and since that time other technologies have been utilized as well. Both BP and its working interest owners have been focusing on "exploration within the known," because even a mere 1 percent improvement in recovery from greater Prudhoe Bay is equal to 250 million barrels.

REPRESENTATIVE DOOGAN asked what is meant by the term, "development investment" as it relates to the aforementioned $19 billion.

MR. UTSLER said that the figure of $19 billion reflects the total capital invested since the beginning of the field's development, and includes money spent on building facilities, drilling wells, and delivery on a year-in-year-out basis, adding that this year alone, BP will have spent upwards of $700 million in "capital spend" and almost $900 million in "operating spend." He again mentioned that developing the resources has become more difficult each year, particularly in the environment in which it is located, and so ongoing investment is necessary in order to achieve the type of long-term success that will result in another 50 years' of life for the field. He then spoke of the various support facilities located in the area, and characterized the facility 250 miles north of the Arctic Circle as the largest gas processing plant facility in the world.

REPRESENTATIVE NEUMAN asked whether BP has plans for upgrading or expanding that plant.

10:44:32 AM

MR. UTSLER said yes, BP does have such plans, particularly given that in the future, the North Slope will change its primary focus to gas production with associated liquids. Gas production - especially if it is meant to continue for the next 50 years - will require both the existing infrastructure as well as the TAPS, because without an oil pipeline, there can be no gas production since the oil and the gas and the water are produced together. Furthermore, if the gas is not developed at some point, then large value in terms of hydrocarbon resource potential will be left in the ground. The facilities of the future will not be the same as existing facilities, and folks at BP are currently researching that issue further so as to be able to optimize the North Slope infrastructure; some of the questions being considered are, what types of facilities will be needed, what levels of reinvestment will be required, and how to go about leveraging the significant potentials of heavy oil.

REPRESENTATIVE NEUMAN surmised that transition to a gas pipeline will require investment in new facilities.

MR. UTSLER offered that some existing facilities could still be used, though some of the facilities will have to be changed. One of BP's rationales for replacing the oil transit lines with an entirely new system of piping is to allow the company to deliver a 50-year future in a much more efficient and effective way. Referring to another slide in BP's PowerPoint presentation, he offered that currently there have been over 2,500 wells drilled in greater Prudhoe Bay - 1,200 of them are currently active - and described what the slide showed, adding that BP is currently drilling an average of 100 wells a year across the North Slope. Significant continued investment is planned, he reiterated, adding that infill drilling is part of new development.

MR. UTSLER, in response to questions, said that BP has several hundred gas wells that are being used to re-inject gas into the reservoir cap, and has several hundred wells that are identified from the "gas-cap standpoint."

CHAIR OLSON surmised that there is gas readily available if a company had the means to develop it.

10:53:12 AM

MR. UTSLER concurred, but pointed out that as gas is produced and is taken out of the top of the reservoir, oil migrates into that void space and is lost if gas is taken out too quickly and

unless steps are taken to manage the pressure differential in such a way so as to try to keep the oil where it was, so a balance between oil recovery and gas recovery must be maintained. In response to a question, he said that BP has been working closely with the Alaska Oil and Gas Conservation Commission (AOGCC) in a very cooperative manner to jointly understand the reservoir and the characteristics of the off-take levels.

REPRESENTATIVE SAMUELS asked how much it costs to drill an infill well.

MR. UTSLER said that it costs an average of $4 million to $5 million to drill a well in greater Prudhoe Bay. In response to another question, he indicated that reservoir by reservoir and field by field, the cost of drilling a well varies depending on where in Alaska that well is drilled.

MS. FITZPATRICK, in response to a question, said that the aggregation of the satellite fields that took place under economic limit factor (ELF) system meant that those satellite fields were treated as a single taxing unit as opposed to "differential" ones. At the time that the ELF aggregation occurred, she recalled, the forecast was that doing so would generate an extra $150 million in revenue for the state; this aggregation made a significant difference in the development of the satellite fields. In response to further questions, she said that when investment decisions were being made at that time, because the satellites were different, it was felt that "we could make a differential decision where it was optimum from an economic perspective" and that the tax consequences were [acceptable] when deciding whether to drill an otherwise uneconomic well.

MR. UTSLER referred BP's PowerPoint presentation, and said it illustrates the nature of the impact to BP's long-term recoverable resources from greater Prudhoe Bay. He indicated that members were looking at "the bottom hole pressure" of the reservoirs that BP is operating against, adding that as water, oil, and gas were produced from those reservoirs, pressure began to decline; with that decline comes a loss of energy in the reservoir and this potentially results in less recovery over the long-term. In looking at how to slow that energy loss, BP began putting water into the reservoir, but this incurred a lot of necessary operating costs, particularly since precision with regard to where to re-inject the water was required. He indicated that the slide members were looking at compared the

decline profile before water flooding commenced with the decline profile after water flooding was commenced, and characterized this increase in recovery as a significant contributor to BP's having moved from 9 billions barrels of recovery to 11.5 billion barrels. This technology will be "an important support" over the next 50 years to the next 2-3 billion barrels of additional light oils that BP expects to recover.

MR. UTSLER mentioned that currently BP is having to handle 1.2-plus million barrels of water - some of it treated seawater - in greater Prudhoe Bay everyday, though BP's goal is to eventually increase its water injection, collectively, to over 2 million barrels a day. This water, however, must then be separated from the oil so that it can again be re-injected into certain other wells to enhance their recovery. Also, from a technological standpoint, BP has been researching how to add water to the gas cap, thus compressing the gas in the reservoir and thereby maximizing the sweep of oil in the reservoir. If flattened pressure can be maintained, there will be an increase in long-term ultimate recovery, but it will result in the company having to handle more and more water and paying the extra costs associated with doing so.

11:05:17 AM

MR. UTSLER, in response to a request, explained that BP needs to achieve a balance between injection wells and producing wells, adding that injection wells are "capital to drill" but then "operating cost to operate" because they don't produce a revenue stream. He indicated that of the $700 million invested in drilling, 50 percent is capital investment for water injection wells that have no rate of return other than helping long-term oil recovery rates.

MS. FITZPATRICK, in response to a question, offered that all of the aforementioned expenses are upstream and are thus impacted by the PPT statutes or HB 2001's proposed changes. She added:

> The treatment of whether it's capital or operating, then you get the differential treatments within the tax structure, recognizing that this is all talking about Prudhoe Bay, and we then get to the issue of at what point does the floor kick in versus the 25 percent net. And I know that the administration, yesterday, said that they believe that was around $40. We've not finished doing our analysis, we wish longer time to understand what was presented over the last

two days, but our current view at the moment is that it would kick in at a rate substantially higher than $40, driven off different views on production, capital, et cetera. So these will be impacted.

MR. UTSLER, in response to a question, indicated that the chart members are looking at illustrates the original greater Prudhoe Bay field with seawater injection. Again, it reflects an increase in the seawater being used to augment oil recovery.

REPRESENTATIVE COGHILL asked what the ratio of water injection wells is to production wells.

11:11:29 AM

MR. UTSLER said he would be able provide those details later, but mentioned that BP is producing oil in many different ways. Referring to the chart, he said:

> In the portion just below the gas cap, in this area, approximately, of the field, we actually use gravity to help us produce, and so it's called, "gravity drainage." And it's actually oil producing wells that are using gravity effects of the steep dip ... of the reservoir to actually drain oil to the well bore set low in the structure and help us recover oil from that. We're actually not using water to move the oil, but we're using water, then, in the next band, basically along these areas.
>
> And that's why you can see these blue; along this area of the reservoir, below gravity drainage, we actually are using a water flood pattern where we use injection wells with a center producer, and we're pushing water, on all sides, towards that [center] producer. And so we use water flooding on the lower portions of the reservoir, gravity drainage in the center, gas re-injection in the crest, and water "injectivity" on the base to try to keep that oil moving but also contained within the boundaries of not wanting to see oil migrate into the gas cap where we would then lose resources ultimately recoverable.

REPRESENTATIVE COGHILL observed that members will need to have a concept of the capital and operating expenses necessary for enhanced production.

11:13:00 AM

MR. UTSLER offered that BP uses several technologies in an effort to increase oil recovery by the aforementioned 1 percent. One of those new technologies developed by the industry is called "Bright Water" and it has proven to be very encouraging in its early stages of application. Because water that is injected tends eventually to travel only on the path of least resistance towards the producing well, standard water injection technology ultimately leaves bypassed oils - oils that aren't being swept up by the water that's been injected - and Bright Water technology makes use of a polymer that once injected, sets and hardens and creates obstacles around which the injected water must flow, thus resulting in the formally bypassed oils being pushed by the injected water towards the producing well. This technology is costly, however; to illustrate, BP spent $1.8 million in chemicals alone on a three-well pilot program. In response to a question, he indicated that the industry has been working on the concept of this technology for the past 20-plus years, though this particular seemingly successful method - with the specific set of polymers and compounds that were used in the pilot project - has only been applied in the last 3 years.

MR. UTSLER said that while exploration is an important part of Alaska's future, 70 percent of all the hydrocarbon values that are expected to be developed in the North Slope sit in already-found fields; again, the challenge for industry involves focusing on optimizing the recovery of that oil. Referring to BP's PowerPoint presentation, he indicated that the chart members were now looking at illustrates that if the goal is to sustain field production performance, continuing investment in the technologies to drill, develop, infill, and optimize the reservoirs is imperative. For example, 50 percent of the oil today that's moving through the TAPS came from wells that were only drilled during the last four years. Referring to another chart, he said it illustrates that the investment of over $250 million which occurred in 2002 produced a lot of barrels; a similar amount of investment in 2003 and in 2004 produced fewer barrels of oil. This decrease is not a function of a decreased ability to operate, he remarked; rather it is a function of the technical challenges of finding oil on a daily basis inside a very mature field. Thus more investment is required if industry is going to significantly impact the production decline referred to earlier.

MR. UTSLER, in response to a question, acknowledged that the dip in the number of barrels that were produced as illustrated in

one of the aforementioned charts reflects the period of time during which BP's pipeline leak was discovered and BP had to partially shut down its production in Prudhoe Bay. He mentioned that dips also occur, generally during the summer months, when BP engages in major repairs and maintenance of its facilities. In response to a question, he indicated that that chart reflects production from 2002-2007. There is less oil to be developed today than there was yesterday and it's getting harder to develop that oil; industry must continue to find ways to encourage investment in existing fields.

11:26:34 AM

MR. UTSLER, referring to another set of charts, relayed that it reflects that new technologies have enabled increased development. For example, just 20 years ago the approach by industry was to just drill single a vertical well from the surface down through the reservoir and then produce the oil in that well. New technology, though costly, now allows for multiple horizontal drill routes to be established from only one downward "mother bore"; technology such as this can unlock previously unrecoverable resources.

REPRESENTATIVE SAMUELS asked what the cost is of horizontal drilling compared with the cost of vertical drilling. He observed that the charts appear to indicate that horizontal drilling is accurate to within 20-30 feet.

MR. UTSLER concurred, adding that vertical drilling can be controlled to within 1-3 feet, and that experience and technology allow BP to have a relatively accurate picture of the reservoir's makeup. Two of the advantages with a horizontal well, he explained, are that the cross sectional area is significantly enlarged and the pressure drop is significantly reduced, both of which result in enhanced oil recovery (EOR). He mentioned that the cost of drilling horizontally after first having drilled a vertical well increases the cost by about another 60 percent.

REPRESENTATIVE SAMUELS surmised that the credits for drilling a well apply to both vertical wells and horizontal wells.

MS. FITZPATRICK concurred, but acknowledged that there could be a legislative change made to that credit.

REPRESENTATIVE RAMRAS asked who [within the administration] sees the information about BP's innovations related to lengthening the life of the oil field.

11:35:55 AM

MR. UTSLER said that from a Department of Natural Resources (DNR) standpoint, BP updates its plans of development every three years, and that BP also works with the AOGCC with regard to the reservoir and hydrocarbon stewardship. Furthermore, the wells must be permitted, and so BP has to provide various state agencies with information regarding proposed well designs.

REPRESENTATIVE RAMRAS asked whether the DOR is provided with this information as well.

MS. FITZPATRICK said that BP has given presentations to the DNR regarding certain aspects of the industry, and mentioned that most of the information requested by the DNR has been either financial data or production data, both historical and projected.

MR. UTSLER, in response to questions, said that BP generally attempts to use its existing vertical well bores to start its horizontal drilling operations, though sometimes new well bores are drilled specifically with the intention of then using them for horizontal drilling operations; that such operations don't qualify for exploration credits; and that both operating funds and capital funds are used for such wells, depending on the actual procedure BP engages in.

REPRESENTATIVE DOOGAN asked whether proposed wells compete for approval.

MS. FITZPATRICK relayed that generally wells are looked at on a program basis, though sometimes, depending on the actual nature of a proposed well, it will be considered separately.

MR. UTSLER added that the complexity of a horizontal well is much greater than a vertical well, so the decision regarding whether to drill a vertical well - or a multi-lateral well - is considered in terms of the risk and reward of the potential hydrocarbons to be developed and how to best develop them with the capital deployed.

REPRESENTATIVE DOOGAN asked whether a proposed horizontal well's potential return has to be proven before it is approved.

11:43:35 AM

MR. UTSLER said yes, adding that one of the questions that must be answered is whether a horizontal well will recover at least the same amount of reserves as a vertical well will. In response to a comment, he indicated that the operating costs for a horizontal well are somewhat higher than for a vertical well.

MR. UTSLER, in response to a question, indicated that when operators develop a program, each well being recommended for drilling must be presented to the working interest owners in the form of an authorization for expenditure.

MS. FITZPATRICK added that if the information on individual wells within the program of wells changes over time, these changes are also discussed with the working interest owners, though such changes won't necessarily have to be relayed to company headquarters.

MR. UTSLER relayed that when BP develops an Alaskan plan, it is presented internally to BP's president and the other working interest owners in Alaska; this plan then faces competition from BP's other operations around the world.

REPRESENTATIVE SAMUELS asked what happens if the other working interest owners don't agree with the proposed Alaska plan.

MR. UTSLER said a compromise is then sought, though the working interest owners with less interest are given less say.

MS. FITZPATRICK, in response to a question, said that within Alaska, there is a fairly continuous cycle of business planning, though data is submitted to BP's main office during specific timeframes.

MR. UTSLER relayed that BP submits its yearly proposal to its working interest owners in September of each year.

MS. FITZPATRICK, in response to questions, relayed that BP does annual plans, 3-year plans, 5-year plans, 10-year plans, and 20-year plans; and that BP is currently planning for calendar year 2008 and beyond.

REPRESENTATIVE DOOGAN surmised that there must have been a plan of development under the ELF after the satellite fields were aggregated, and under the PPT. He asked whether BP has a

similar prospective plan under the proposed Alaska's Clear and Equitable Share (ACES) legislation - HB 2001.

11:56:35 AM

MS. FITZPATRICK said that BP is not working on a plan of development or a long-term plan under the proposed ACES legislation; such plans are only created based on current law, not pending legislation. She mentioned that BP's past plans under the ELF and under the PPT are not comparable and would not be helpful to look at because production profiles have since changed, different technologies have been engaged, and there are now very different cost structures and price environments.

MR. UTSLER mentioned that there is now technology that allows BP to control the amount of water used in the injection wells. Referring to BP's PowerPoint presentation, he indicated that the slide members were now looking at is intended to demonstrate that there are other reservoirs to be developed in greater Prudhoe Bay; that there are four new reservoirs that have been developed since the year 2000; and that there is a project [underway] that will develop viscous - or heavier - oil inside the west flank of the field. He relayed that BP has already spent over $80 million in the early engineering design, development, and testing of "these" reservoirs, which are now producing viscous and heavier oils at a rate of about 25,000 barrels per day.

MR. UTSLER offered that BP is also looking to propose a development project that would represent nearly $2.1 billion-plus in expenditures for wells, facilities, and necessary infrastructure to develop what could represent 250 million barrels of additional oil recovery from greater Prudhoe Bay and between 40,000 and 60,000 barrels of incremental production per day. However, this will be very different from the existing production stream; it will have to be managed within the construct of the existing field development, and therefore does require specific infrastructure such as the gas partial processing plant, which would need to be built as part of the field's development, and other equipment specific to producing heavier oil. This will require the employment of a significant number of people as these facilities are constructed. He indicated that this project will be extremely sensitive to economics because of its investment scale and complex nature.

MR. UTSLER then remarked that the third significant resource development at Alaska's disposal on the North Slope is heavy

oil, which lies, largely, over Kuparuk, Milne Point, and a portion of the western side of greater Prudhoe Bay. He mentioned that the main reservoirs of greater Prudhoe Bay have approximately 25 billion barrels of oil in place as well as approximately 50 trillion cubic feet (Tcf) of gas. The shallowest oil - heavy oil - is estimated to amount to between 20 billion and 25 billion [barrels] in place. He emphasized that although heavy oil represents a significant opportunity for the state and participating operators, it is also significantly challenged with regard to technology, the ability to develop the heavy oil, and the necessity of having to have a robust light oil with which to produce the heavy oil.

12:07:21 PM

MR. UTSLER, in response to a question, relayed that although some heavy oil is currently being produced on a limited basis, it is not the heaviest of the heavy oils, which makes up the lion's share of Alaska's heavy oil and which is being developed only on a trial basis.

MS. FITZPATRICK, in response to a question, relayed that BP does produce some heavy oil in Venezuela, and that there are different types of technology suitable to the task.

MR. UTSLER explained that the portion of BP's PowerPoint presentation that members were now viewing illustrated the challenges associated with producing heavy oil, which, in general, is physically difficult to handle because it is so thick and tar-like, particularly under arctic conditions. Heavy oil is also of lower quality and hence lower value because it is more expensive to refine into product that the public can use; a barrel of heavy oil can be discounted as much as $10-$12 compared to a barrel of light oil. Heavy oil is currently being produced in California, Canada, and other parts of the world via the use of steam, which is an expensive process, and, with varying rates of success, via the use of other types of technology. He mentioned that in Alaska, at Milne Point, the test process being used is Cold Heavy Oil Production with Sand (CHOPS), and briefly described how the CHOPS process is supposed to work. If this process is to prove successful, it could require the drilling of thousands of wells. He offered that for Alaska's oil resources, the more light oil that's available and the longer that light oil is available, the more heavy oil can be produced; the faster light oil reserves decline, the less heavy oil will ever be developed.

12:16:29 PM

MR. UTSLER, in response to questions, relayed that in speaking about the heavier oils that have been produced thus far in Alaska, he is referring to viscous oil, not specifically heavy oil, and that BP is examining some of the heavy oil technologies being employed in the oil sands in Alberta, Canada. In response to a further question, he offered that BP is hoping to develop - over the long-term - a significant [heavy oil] resource base that could produce 50,000-plus barrels per day, and that currently only about 2,000 gallons of diesel a day are produced; therefore, if diesel were to be used as a diluent to produce Alaska's heavy oil resource, the state's capacity to generate diesel must be massively increased. In other words, in Alaska, diesel is not an economically viable diluent mechanism under current technologies. He remarked that although heavy oil is a huge resource for the state and participating operators, bringing that resource to market will require massive technology and massive investment.

MR. UTSLER offered that Alaska has a unique resource and hydrocarbon basin; it is massive in terms of opportunity, but because of its location, the cost of developing those hydrocarbons is disadvantaged to most of the global market place. On average, the costs of acquiring seismic and geotechnical data are much higher, it is more costly to drill and develop the wells, and the scale of infrastructure necessary to produce Alaska's fields results in still further cost disadvantages. In fact, the state's own data, in its 2007 spring forecast, indicates that per barrel, the cost of operations, transport, and taxes averages $16 as compared to only $10 for oil produced elsewhere in the United States.

MR. UTSLER, in response to a question, offered his understanding that according to the state's information, each barrel of Alaska oil costs $6.04 to transport, is subject to a production tax of $2.77, and has forward operating costs of about $7.75.

REPRESENTATIVE KAWASAKI surmised that transportation costs are a significant component of that $16 average.

MR. UTSLER concurred.

REPRESENTATIVE KAWASAKI noted that despite the higher costs of developing Alaska oil, BP still reported a significant profit. He asked how much of that profit could be attributed to Alaska's resource.

MS. FITZPATRICK said she would be able provide that information later on in the presentation. In response to comments, she indicated that the average $16 per barrel figure provided by the DOR excludes the capital costs of producing that barrel, and that those figures might need to be crosschecked with other data.

12:28:51 PM

MS. FITZPATRICK, on the issue of profits, relayed that for 2006, according to BP's U.S. Securities and Exchange Commission (SEC) reports, for its holdings in the U.S., including Alaska, BP showed a profit of $6.2 billion. She mentioned that copies of another of BP's SEC reports are forthcoming and will be distributed to members as soon as they arrive.

MR. UTSLER, in conclusion, offered that from an operations perspective, the legacy fields - greater Prudhoe Bay and Kuparuk - are critical resources for the state and have many, many challenges if industry is to optimize their remaining lifespans, which BP believes to consist of at least another 50 years. That future, for greater Prudhoe Bay, can only be "unlocked" with continued strengthening of investment, a focus on developing new technologies, and continued application of existing technologies. Over the next 50 years, it will be critical for BP to redevelop the infrastructure and begin focusing more on gas production with associated liquids.

MS. FITZPATRICK offered that although working on the North Slope is becoming more challenging and more expensive, that does not mean that the work to date has been easy. Referring to BP's PowerPoint presentation, she noted that the 15 billion barrels of oil that have already been produced is 20 percent more than was originally anticipated. Additionally, the resources in the existing mature fields represent only 70 percent of the North Slope's future resource potential. She too indicated that the sustained development of Alaska's light oil is paramount in developing Alaska's heavy oil.

MS. FITZPATRICK, referring to BP's PowerPoint presentation, relayed that it is extremely difficult to break down statistics in terms of molecules; that substantially more investment is required than has occurred to date; and that at least 50 percent of the additional investment in new developments is coming from heavy oil, with the remaining 50 percent coming from the use of technology and new discoveries within existing fields and

beyond. With regard to new developments, she pointed out that they take years in terms of design and permitting before actually achieving first production. She remarked that 70 percent of production for the next 20 years will come from Prudhoe Bay and Kuparuk; therefore, a key point is to ensure that the right investment activity takes place in those locations.

12:38:56 PM

MS. FITZPATRICK, referring to BP's PowerPoint presentation, relayed that what members were now viewing illustrates the percentage increases in costs, which have increased overall, adding that this "cost movement with price" is one of the reasons why BP supports a net tax - everyone is aligned with what's actually happening and the dynamics of the market. She added:

> Another factor just to be aware of ... is that for companies like us, we often enter into long-term contracts. So the timing of when cost inflation hits through will also be dependant on when our contracts happen to run out. And they'll then be renegotiated based on market prices at that time.

MS. FITZPATRICK offered that [investment] activity has gone up significantly on the North Slope in terms of people working, rig counts, seismic activity, and various other activities. When thinking about costs in the context of tax, she observed, although costs are often thought of as being bad, she tends to think of costs as being good in a broader economic sense; if money is being spent on the North Slope, for example, it means that contractors are being engaged and they in turn employ people who are then spending their wages and in this way helping the economy. She offered her understanding that a 2001 study indicated that 1 percent of employees in Alaska are directly employed by the oil industry, that 12 percent of the jobs in the private sector are attached through the multiplier effect to the oil industry; and that 20 percent of salary and wages in the private sector are linked to the oil industry.

MS. FITZPATRICK, in response to a question, relayed that some of [BP's employee] growth in recent years is due to technological advances, contract costs, and various other factors; in other words, a change in the tax structure cannot be pointed to specifically as the reason for this growth. Furthermore, BP's business isn't annual - some of the investment decisions that

were made a couple of years ago have simply taken time to take effect with regard to employee growth.

REPRESENTATIVE RAMRAS asked how many people BP employs globally.

MS. FITZPATRICK said 100,000-plus employees, but noted that that figure includes "downstream" employees.

12:44:49 PM

MR. UTSLER indicated that almost 10 percent of "upstream" BP employees are located in Alaska.

REPRESENTATIVE RAMRAS said that that is also indicative of the human resource component and its accompanying capital that [Alaska's branch of] BP competes for.

MS. FITZPATRICK concurred. In response to questions regarding BP's increased labor costs, she indicated that for all positions at all levels, accessing, recruiting, and retaining skilled experienced people now costs more, and offered to provide specific information on that point. On the issue of taxes as they relate to economics, she said:

> The question ... was asked earlier ..., "How do I know, if I move one percent or two percent of tax, what's it going to do." Sadly, I don't have a magic answer. ... It's complex, there's a lot things that go into it. All we can say is that when we look at our economics, on the very simplest level, increasing tax will decrease the value of my post-tax investment, therefore my economics have [gotten] worse. What I'm interested in then is, ... "Where does that then sit?" There's a number of projects which I know were already marginal but were on the right side of marginal when I take into account all of the risks. They will all get looked at again, [though] I can't say, definitively, where they will be.
>
> The other thing to note is, when we look at a project and ... at first light ... it doesn't look economic, we don't throw our hands up and say that's it; the first thing that ... [Mr. Utsler] and his team do is ... [consider the question], "What do we need to do to make it economic?" We work very hard at that. We're also aware that there is a huge amount of investment that we do, that we will continue to do, under the

terms of our lease, to prudently develop the resource. So this is around what's beyond that. [Because] 70 percent of the resource is in existing fields, 70 percent of the production for the next 20 years will come from those fields, that's the area that we're obviously particularly focused on - how do we maximize those investment opportunities.

Changing the policy doesn't help; changing the policy to meet a forecast doesn't feel like good policy, and it will impact behaviors, not only of incumbents, but also of people looking to enter Alaska. The other thing that we've put up there [on the presentation] is not only the 70 percent of future investments within [Prudhoe Bay] and Kuparuk, [but] the floor - the 10 percent gross - when that kicks in, will also have a significant impact on the investment decisions within those legacy fields - remembering they're covering heavy oil, viscous oil.

Getting the decline to 6 percent to start with before you even start building on it, ... that infrastructure needs to be there, not only for the base production, it needs to be there for the new stuff, it needs to be there for heavy [oil]. There's a whole activity set around that that's beyond just what's actually producing barrels but which is needed in order to make the barrels the most efficient and effective that they can be, for us and for everyone else who will hopefully be on the [North Slope] in the future. ...

Hopefully our key points are fairly self-apparent. This is about investment, to stem decline. The barrels are getting harder; technology is needed, more investment is needed. Economics will get worse if tax increases. The question for me should be not so much how do we stem decline per se but what would it take to get a million barrels in the pipe from the current sort of 700. The last point I've put up there is, the current bill ... does create uncertainty; this would be the third tax change in three years which I don't need any consultant to tell me creates concerns over fiscal stability.

REPRESENTATIVE SAMUELS asked whether BP buys credits.

MS. FITZPATRICK said it is not corporate policy to buy tax credits. In response to a question regarding transportation costs, she said that when BP is looking at its projects, it's looking at them purely from an upstream perspective. There is a requirement, under the Federal Energy Regulatory Commission (FERC) regulations, to have [firewalls]. So there is a lot of information regarding BP's business and its interests in the TAPS that certain employees will know about but that other employees won't know about; for example, there is a requirement that shippers and producers are not privy to the same information.

12:54:46 PM

MS. FITZPATRICK, in response to another question, reiterated that of the resource base that is yet to be developed, 70 percent is in the known fields, and that when viewing where production is coming from for the next 20 years, according to the DNR's forecast, 70 percent of that appears to be coming from Prudhoe Bay and Kuparuk.

REPRESENTATIVE RAMRAS asked who is ultimately making the decisions regarding Alaska. He said he is interested in how minor tax-policy changes affect the behavior of those who are ultimately making the decision to go forward with a particular project.

MS. FITZPATRICK said such decisions are made at various levels. For example, with regard to a proposed project in Alaska, after the planning process is complete and the parameters of the project are given, the decisions can be made within Alaska by a collective leadership team. So while the president of the company ultimately makes the final decision, he/she looks to the Alaska team to see what its members collectively think about the proposed project in terms of whether it will be good for BP Alaska.

REPRESENTATIVE RAMRAS asked whether BP finances projects from earnings, and how does Alaska compete for those earnings that could then be re-circulated into Alaska's oil fields and economy.

12:59:55 PM

MS. FITZPATRICK explained that the BP group sets its financial framework based on its strategic objectives. This financial framework will include how much [the BP group] believes it's

appropriate to be reinvesting capital globally across its entire business. It's not a definitive number to the dollar - it's usually a range. Within that, the group then looks to see how it wants to allocate [resources] in terms of global risk - whether with regard to refining and marketing or with regard to exploration and production - and where it wants its geographic risk spread. For the Alaska project, the group is looking at very different strategic objectives than it would be for a new project elsewhere in the world. With regard to the exploration/production segment, BP still operates within a financial framework. She added: "When we go forward with our annual plans and our five-year plans, it's within the context of, what [is] the exploration/production division looking to achieve, and how does that fit with the group strategy."

MS. FITZPATRICK said that BP has a financial strategy of a certain band of debt that it will have as debt-to-equity ratio, and that will move up and down depending on what happens with [the company's] cash-flow generation. Some of [the company's] cash is used for repurchasing shares, though the decision regarding how many shares are repurchased and when is done as part of a global and group policy; it's not done on the basis of individual earnings from any particular location, it's done in the aggregate. Getting funding for the Alaska project is dependant upon the [Alaska team's] being able to put together a compelling business plan which illustrates that the project would constitute a good investment for BP on both a short-term basis and a long-term basis. She added:

> We have put together what we believe is a good 50-year future strategic view. And certainly, as I've said earlier, my ability to go back and defend that will be impacted by my ability to say, "This is what we said is going to happen, and this is what will happen."

REPRESENTATIVE DOOGAN asked how, if taxes are increased, the legislature will know whether doing so was a mistake in terms of BP's investment strategy.

MS. FITZPATRICK said that such cannot be known until after the event; for example, in five years time, the legislature could come to realize that investment was not generated as anticipated. "We believe it's too soon to look at this," she remarked, particularly given that BP has not had an audit yet. So although investment has increased, the ultimate goal is to keep investment going as opposed to making a change that could cause things to go the other way. Noting that BP does have

contractual obligations, she indicated that she is not saying BP won't invest, but there will be issues "at the margin" that will have to be considered very carefully.

1:05:04 PM

MS. FITZPATRICK, in response to comments, suggested that the best way [for members] to evaluate the situation is to look at what they are trying to achieve - for example, more investment - and consider whether the proposed changes will achieve that goal. Members could also look at the production forecast put together by the DNR, for example, as well as at some external factors. "The fundamentals for me on the economics are, increasing taxes will decrease the economics; therefore, by default, some of the projects are going to become more marginal," she added.

REPRESENTATIVE NEUMAN asked whether BP has an estimate of how many barrels of oil will be going down the TAPS in 10 years, and what conversations is BP having with the administration with regard to oil, gas, and the future of Alaska.

MR. UTSLER offered that if there is a 6 percent rate of decline over the next 8-10 years, that would result in approximately 350,000 barrels [per year] going through the TAPS; this amount constitutes a critical threshold for the TAPS, thus risking a shutdown. He surmised, though, that "the TAPS' ownership" would have been working to address options before any shutdown actually occurred. He mentioned that BP is willing to talk to [the administration] about the facts as BP understands them, and has been speaking with the AOGCC and the DNR about its plans of development.

MS. FITZPATRICK added that BP is not currently having any conversations with the administration regarding a gas pipeline, and that BP was very open and transparent, at the time of the Alaska Gasline Inducement Act (AGIA), when it said it would not be able to make a conforming bid.

MR. UTSLER, in response to comments, acknowledged that if, internally, the decision is made to not advance a particular project - whether it be because of Alaska's proposed tax changes or some other reason - the reasons for not doing so may not ever be made known to the public.

MS. FITZPATRICK, in response to further comments, offered that the only answer that might become available would be in the form

of an economic model, which would be known to be wrong. She added, "Yes, you're absolutely right, you'll never know definitively; what you can know (indisc.) it's a risk you're taking and it's around pace and scale." Generally speaking, projects don't just disappear; rather, they simply get revisited if they are not initially gone forward with.

1:14:38 PM

MR. UTSLER spoke of some of the projects that Alaska's projects will be competing against, adding that more than twice as much investment is occurring in the Lower 48 and Alberta - and more than five times as much in the Gulf of Mexico - than is occurring in Alaska. There are many factors responsible for these differences in investment amounts, though one is the disadvantaged price of Alaska's barrels of oil and another is Alaska's already existing "significantly higher tax structure."

MS. FITZPATRICK offered that based on upstream numbers, the total capital spending "on EMP" for 2006 for the U.S. was $4.5 billion.

REPRESENTATIVE SAMUELS noted that the economic consequences of being wrong with regard to the proposed tax increases will affect his constituents, and yet the legislature won't actually know what those consequences are, or whether the taxes imposed are too high or too low.

CHAIR OLSON offered his understanding that BP has global development projections going out at least 50 years.

MS. FITZPATRICK offered that BP has a variety of views going out over a very long period of time and they are [being considered] at the strategic level. In response to a question, she said BP's view on Alaska covers the next 50 years.

The committee took an at-ease from 1:19 p.m. to [2:37] p.m.

2:37:29 PM

KEVIN MITCHELL, Vice President, Finance & Administration, ConocoPhillips Alaska, Inc., referring to a PowerPoint presentation, first relayed that ConocoPhillips Alaska, Inc. ("ConocoPhillips") is the largest oil producer, the largest gas producer, and the largest holder of exploration acreage in Alaska, adding that the company is also a very sizable tax and royalty payor in Alaska; has a major position in all major

sectors of the oil and gas industry in Alaska - ConocoPhillips is heavily involved in the Prudhoe Bay area, is an operator with a significant ownership interest in the Kuparuk area, operates the western North Slope with sizable ownership interest in the various satellites to the Alpine field, is in the Cook Inlet, and is active in exploration; has been in the state for approximately 50 years; and will continue to maintain its presence in the state because Alaska is very important to ConocoPhillips.

MR. MITCHELL offered his belief that ConocoPhillips and the state are both seeking to nurture the growth of the industry and progress its future because, as history has shown, when industry is successful, so too is the state, and when industry struggles, so too does the state. He said it is ConocoPhillips' view that it is too early to change the PPT legislation - there are a lot of unanswered questions regarding its performance - and that a review of that legislation should be held only after sufficient time has passed and there is then adequate data from which to draw some conclusions. The uncertainty created by changing tax legislation on a frequent basis cannot be [overstated], and although investment decisions are not made entirely on the basis of the tax structure, this uncertainty becomes a risk factor during the investment evaluation process. The potential impact of the proposed bill on investment is the most significant point to consider, particularly with regard to the legacy fields.

MR. MITCHELL, referring to a chart in his PowerPoint presentation, indicated that it illustrates three different revenue projections for 2007. The first one, by the DOR, represents the revenue the state would have received had the ELF still been in place - around $.5 billion; the second one represents what the PPT's fiscal note projected the state would receive - a little bit under $2 billion; and the third one represents the DOR's projection of revenue under the PPT legislation - a little bit over $2 billion. He explained that the differences between the actual revenue received under the PPT legislation and the projected revenue were due to increased costs as well as many other variables, and surmised that in any given case, the actual revenue will never equal the forecasted revenue, because such forecasts are based on inputs regarding price, production, operating costs, and capital costs, and these inputs generally end up being inaccurate. In the case of the PPT legislation forecast, for example, it showed the effects of changing prices, but did not reflect any changes to the other aforementioned components.

2:46:46 PM

MR. MITCHELL relayed that in general, ConocoPhillips supports the additional transparency provided for in HB 2001, and understands the need for the DOR and the DNR to be able to share information. There are some concerns with the bill, however. In the context of exploration, the bill allows the DOR to share all information with the DNR without exception, and so there is some degree of confidentiality concern with regard to non-state lands. The DOR has information on all lands - private corporation lands and federal lands - and the DNR is responsible for managing state lands and, to some degree, is in competition with those federal and private corporation lands; thus there is a potential conflict of interest with regard to sharing data to the extent outlined in the bill.

MR. MITCHELL, with regard to the process pertaining to exploration credits, relayed that the DNR is able to make a determination of a well's geological success before granting the credit, but the appropriate data must be provided prior to the granting of that credit - and thus prior to the final auditing. So a company gives up information before it knows for sure that it will be receiving the credit, and this feels a bit one-sided, he remarked. Furthermore, the exploration credit application waives confidentiality rights, and hence there is some concern that a company would choose not to apply for a credit because it would prefer to keep certain information confidential; therefore, this waiver could be viewed as an added impediment to exploration activity.

MR. MITCHELL offered, therefore, that HB 2001 does have some provisions that make it slightly less attractive to explorers than the PPT legislation was.

MR. MITCHELL in response to a question, offered his understanding that HB 2001 contains language allowing the administration to request whatever "other information" it deems necessary to accomplish its goals. A concern with this language is that the bill also contains a penalty, on the order of $1,000 per day, for every day the requested "other information" is not provided. In response to another question, he indicated that the concern centers on the fact that that "other information" - whether it be confidential information or not - might not be easily gathered within the set time limit before the $1,000 per day penalty starts applying.

MR. MITCHELL, on the issue of forecast data, said:

> As an industry, we typically are very nervous whenever we get into any discussions around providing our projections and forecasts anywhere other than within our own corporate entities, and what we would plead is that ... those requests are limited to that same information that is provided to partners in our unit - unit operations. That is information that is shared anyway, and I don't believe ... any other participant in the industry here in Alaska would have too much concern over sharing that same information. And we would like to see those specifics contained [in the bill] ..., and stay away from other corporate-type projections and information.

2:55:55 PM

MR. MITCHELL, in response to comments and a question, opined that the bill's language allowing the administration to request "other information" is written very broadly. He then noted that the bill also extends the statute of limitations "for audit" from three years to six years. If the department were to utilize this proposed new statute of limitations to its full extent, "by 2011, when that review is scheduled to be complete, they, in theory, might not be through one audit in that time," he offered; this proposed change could mean that the results of a first audit might not be available until 2012. On the issue of cost deductibility, he said that the PPT was set up on a net profit approach, and this follows the federal code in determining what expenses are allowable as deductions - the terminology that's used is something along the lines of, "ordinary and necessary expenses" in the operation of the business. Adoption of those federal standards has simplified the lives of the producers because they already follow the federal code when preparing their financial statements and tax returns.

MR. MITCHELL said that a deviation from those standards could add another layer of complexity to what is currently being done, and this impacts ConocoPhillips as an industry and the DOR as it goes through the audit process. House Bill 2001, in contrast, is proposing that the regulatory agency - the DOR - define what deductions are allowable; this will create a lot of uncertainty, he opined. In addition, the bill contains a provision allowing the DOR to issue nonbinding advisory bulletins regarding its interpretation of AS 43.55; this takes away any assurance regarding how the information provided in such a bulletin will

be treated by the auditor. This has also engendered discussion regarding whether the producers would simply claim the maximum amount of expenditures possible and then battle out the details during the audit process; however, while currently there is no penalty for doing such, the interest accrued on over-claimed expenditures is a minimum of 11 percent per year, and this accrued interest and any subsequent penalties would constitute a significant additional financial burden, particularly given the bill's proposed six-year statute of limitations.

3:02:10 PM

MR. MITCHELL referred to "exclusions for cost deductibility," one of which is the exclusion of maintenance that is unscheduled and that results in an interruption of production. Any exclusion, he opined, adds complexity to the legislation, and this particular exclusion could potentially create an auditing nightmare and does not reflect the reality of producing oil on the North Slope. This exclusion is for maintenance that ultimately brings production back online, and therefore is the very type of expenditure that should be the most incentivized. All the exclusions [from cost deductions], he surmised, penalize the very maintenance and repair activities that are necessary to bring production back on line as quickly as possible. In addition, the bill contains a retroactive provision stipulating that the cost of any such maintenance occurring as far back as April 1, 2006, can not be used as a deduction; he said he is not sure how practical or possible such a provision will be to implement.

MR. MITCHELL noted that there is an exclusion for dismantlement costs. Dismantlement costs are those expenditures that are necessary at the end of an asset's life; they are meant to return the site to the condition it was in prior to any of the [oil and gas] activity having occurred there. This a legitimate cost, the companies are required to undertake this activity, and this cost was listed as an allowable deduction under the PPT legislation. To first allow such costs to be deducted and to then preclude such costs is another "item" of instability, he remarked.

MR. MITCHELL, in response to a comment and question, remarked that under the PPT legislation, the "abandonment allowance" could be accrued on an ongoing basis from the present to the end of the field's life, and that everything that ConocoPhillips would deduct as a lease operating cost are those costs that are

incurred as operator of the Kuparuk area, and all those costs are shared among the various unit owners.

3:08:24 PM

REPRESENTATIVE SAMUELS questioned whether the state, in accessing that shared cost information via one of the owners, then has access to that information as it pertains to the other owners.

MR. MITCHELL indicated that it did. Referring again to his PowerPoint presentation, to the issue of cost deductibility, and to the crude oil topping plant at Kuparuk, he explained that currently there is a significant amount of diesel being used on the North Slope, and noted that both Prudhoe Bay and Kuparuk have their own topping plants and manufacture their own diesel. Both state and the Environmental Protection Agency (EPA) regulations will require the use of ultra low sulfur diesel (ULSD), and ConocoPhillips has evaluated various options that would allow it to meet those requirements. The company has concluded that the most effective way of meeting the needs for ULSD on the North Slope is to upgrade the plant at Kuparuk with a Hydrotreater so as to be able to meet the low sulfur specifications. That project [will cost] approximately $300 million, and, at its construction peak, could employ approximately 300 people. The alternative to building this plant is to transport/import the necessary fuel to the North Slope either from somewhere else in Alaska or from the Lower 48; he surmised that this alternative would not be the most cost-effective option to pursue.

MR. MITCHELL, in response to comments and a question, offered his understanding that if the company were to use fuel it manufactured on site, it would not be allowed to deduct the purchase price of the fuel, but if the company purchased fuel from another source, the cost of that purchase is deductible as an expense. The company's concern, he indicated, is whether the cost of [building the Hydrotreater and] upgrading the current facility so as to produce ULSD would be considered an allowable expense and thereby be eligible for a credit. In response to another question, he said that if that credit isn't available, then ConocoPhillips will simply resort to importing fuel and deducting the cost of its purchase.

3:15:14 PM

JIM TAYLOR, Vice President, Commercial Assets, ConocoPhillips Alaska, Inc., added that ConocoPhillips has worked carefully with refiners so as to be able meet the EPA's standards. The proposed plant is designed to meet industry requirements and those of any existing local market. If, through the building of the Hydrotreater, the company has the ability to produce what it needs locally while also complying with the spirit of law, which is to reduce emissions, then to not build the Hydrotreater will increase the demand for the product and the amount of importation traffic, thus causing emissions to increase as well as risk. Building the Hydrotreater is not intended to allow industry to set prices.

REPRESENTATIVE SAMUELS asked whether there are any federal credits available for that project.

MR. MITCHELL said he is not aware of any.

MR. TAYLOR, in response to a question, offered his understanding that the future demand for ULSD will be about 700 barrels per day at Kuparuk, and about 1,000 barrels per day at Prudhoe Bay. He also offered to provide further details on that point.

MR. MITCHELL added that those numbers translate into roughly 100,000 gallons of ULSD per day. In response to a question, he offered that ConocoPhillips's assumptions are that the local market is competitive without the tax break, and that this is slightly preferable from an economic standpoint.

CHAIR OLSON noted that Tesoro Alaska Company ("Tesoro") just completed a similar facility for approximately $200 million "with no tax break, and they seem to be making money."

MR. MITCHELL indicated that building something in Kenai is very different, in terms of construction costs, from building something on the North Slope.

CHAIR OLSON surmised that ConocoPhillips is seeking a similar cost advantage by adding to an already existing facility.

MR. MITCHELL concurred. In response to a question, he indicated that if ConocoPhillips didn't build a Hydrotreater on the North Slope, the ULSD that it would need would have to originally come from the Tesoro facility and would then have to be trucked in from Fairbanks.

REPRESENTATIVE DOOGAN surmised that Tesoro would have to expand its present facility - without receiving any state tax credits - in order to meet future demands on the North Slope should ConocoPhillips and BP not build the aforementioned Hydrotreater.

MR. TAYLOR concurred.

3:23:35 PM

MR. MITCHELL, referring to his PowerPoint presentation, noted that the PPT provided for transitional investment expenditures (TIE) credits, which recognize investments made under a prior tax structure, and are meant to provide equity and stability with regard to the treatment of expenditures. Removal of these TIE credits, as HB 2001 proposes to do, will hurt those very companies that have been actively investing in Alaska. One example of where this change will have an effect is the "Fiord development," which is an "Alpine satellite." He explained that on the chart members are now viewing, "the blue bars" represent capital investment, and "the red line" represents production. Most of the capital investment in the Fiord development was made prior to the enactment of the PPT legislation, when taxes were calculated under the ELF, but when production comes on line, the company will be paying tax under the higher PPT rate.

MR. TAYLOR offered that the "10 percent gross floor" can and will impact investors' views and risk tolerance for the future, will affect companies' planning processes, and can come into play in both high- and low-price environments. Preservation of an investment climate in the legacy fields is an important attribute of keeping oil in the pipeline. He explained that the chart members are now viewing uses information from the DOR's spring revenue forecast, and said that it will take significant capital to curb a 15 percent rate of decline in production.

MR. TAYLOR pointed out that resource developers inventory their opportunities on a regular basis as a part of their ongoing planning process, and offered that a "company hurdle rate" is a function of the risk associated with an investment and can vary from company to company. This rate is something investors also consider when deciding what order to make their investments in. A tax change, particularly if such changes are made frequently, will cause investors to take a different view of their risk tolerance, and marginal projects could be delayed.

MR. MITCHELL, in response to a question, offered his understanding that "Pioneer" obtained royalty incentives from

the state that allowed it to move forward with a particular project.

MR. TAYLOR, in response to comments, acknowledged that different investors have different risk tolerances, and will therefore make different decisions regarding which projects to go forward with; there are many factors that go into a company's analysis of whether to go forward with a project.

3:38:46 PM

REPRESENTATIVE SAMUELS asked whether a larger company needs "larger finds."

MR. TAYLOR reiterated that there are a variety of factors that can motivate an investor to pursue a particular project.

MR. MITCHELL clarified that ConocoPhillips still has an interest in smaller, incremental projects.

MR. TAYLOR, referring to a chart in the PowerPoint presentation, offered that it illustrates that the "10 percent gross floor" can impact investment in six specific marginal projects, and said that it could put at risk between $3.5 billion and $4 billion in investments.

MR. MITCHELL, in response to comments and questions, said that two things could trip the 10 percent floor - lower prices or higher costs; both have the effect of reducing the taxable margin.

MR. TAYLOR, in response to comments, made references to a chart members had looked at on a different day, and said his conclusion is that none of the projects listed on that chart are economic at $40 per barrel. He went on to say:

> Costs are higher. The reserves are more challenged to get because they're not the conventional, traditional light oil developments of the past; they're heavy oil, they require steam in many cases, and they're far more complex to recover [and they] require a lot of directional, horizontal wells. ... The [costs] to develop those projects are much higher. And so anything that is going to add more risk or more taxation is going to erode and make those projects riskier. So what I showed you here in a color code was something that probably more resembles the $50 to

> $60 oil price. It shows that there are some projects that can be done. But there are projects, though, that should the attributes of the bill that's currently being evaluated be passed, could render those uneconomic at this time.

MR. TAYLOR, in response to a question, said that when capital is pulled out of the system fairly rapidly, production also declines fairly rapidly. He offered that the PowerPoint presentation illustrates that the largest potential that remains on the North Slope under current projects exists inside the legacy fields. Preserving that investment environment is very important, not only for investors but also for the state. He said that ConocoPhillips believes that it is too early to make changes to the PPT legislation, particularly given that the uncertainty of frequent tax changes does alter investors' risk tolerance. Increased taxation erodes after-tax cash flow, which in turn impedes a company's ability to reinvest, and the "10 percent legacy floor" is a disincentive to investment in both a low-price environment and in an opportunistic high investment environment, he concluded.

MR. MITCHELL, in response to a question, said that ConocoPhillips does purchase credits.

3:58:16 PM

MR. TAYLOR, in response to a further question, offered his belief that there is good resource potential on the North Slope, though there are challenges with regard to the pursuit of technology, the addressing of the heavy oil reserves, and the continuation of a healthy price forecast. The rate of production over the next 10 years will depends on the amount that investors are willing to risk and pursue, and with a healthy investment environment and a returning of investments in the legacy assets, there is a lot of potential.

REPRESENTATIVE NEUMAN asked whether ConocoPhillips has had discussions with the administration regarding the future of oil and gas in Alaska.

MR. TAYLOR said that ConocoPhillips is very open to such discussions, but is not currently involved in any specific negotiations.

The committee took an at-ease from 4:00 p.m. to 4:20 p.m.

4:20:18 PM

KEN THOMPSON, Managing Director, Alaska Venture Capital Group (AVCG) LLC, paraphrased from his written testimony, which read in part [original punctuation provided along with some formatting changes]:

> I am the Managing Director for Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company formed with a sole focus on the North Slope of Alaska. AVCG is a privately held member LLC comprised of private equity investors made up of 15 independent oil and gas companies and individuals from Kansas and me as an owner/member partner from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices and staff in Anchorage. In Alaska and on the North Slope, we operate under the name Brooks Range Petroleum.
>
> AVCG has lease holdings and explores currently only in Alaska...and nowhere else. AVCG/Brooks Range Petroleum likes to think of our company as "Alaska's Independent Oil and Gas Company."
>
> AVCG LLC has been very active in the past seven North Slope areawide lease sales and active in acquiring acreage held by other companies where we see potential. We and our partners currently hold over 300,000 acres of exploration leases in five exploration prospect areas on the Slope. Our exploration strategy is to explore in the central part of the North Slope for fields in the 10-100+ million barrels range, fields that may be too small for the giant producers but satisfy as niche fields that can be "company makers" for a small independent. We believe there are hundreds of millions if not billions of barrels of oil left on the central North Slope in smaller fields of this size for small independents like ours that want to take this type of exploration risk.
>
> Last year, AVCG LLC announced joint venture agreements with two Canadian independents, TG World Energy and Bow Valley Energy, and with a private exploration company from Houston, Ramshorn Exploration. Together, as working interest co-owners we are exploring the central part of the North Slope.

In the winter of 2006, AVCG participated with an ownership interest in the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. Unfortunately, that well was a dry hole.

This past winter for the first time, our operations subsidiary, Brooks Range Petroleum operated the drilling of two exploration wells for our working interest partners in the Gwydyr Bay area of the North Slope, just northwest of Prudhoe Bay. One well, the Sak River #1, was a dry hole, but we were excited to announce earlier this year that our Northshore #1 well northwest of the Prudhoe Bay Field did strike oil. We plan to complete and test this well this winter. In addition, we ran a 130-square mile 3D seismic survey over our acreage and surrounding area in the Gwydyr Bay area on the North Slope. In total this past drilling season, our JV Group invested over $44 million on land, seismic and drilling activities.

This winter our Joint Venture Group will be among the most active of explorers as we plan to shoot over 200 square miles of new seismic data on the extreme western and eastern sides of the Central North Slope and to drill up to four exploration wells. We plan to test the Northshore #1 well and also drill one or two other exploration wells nearby to see if we can discover a sufficient volume of oil to warrant a commercial development at Gywdyr Bay. We will drill our Tofkat #1 well south of the Alpine Field and also drill a fourth exploration well on a prospect to be named. In total, our group will spend over $40 million in seismic and exploratory drilling in winter 2008. If our Northshore oil completion test is as suspected and one of the wells strikes oil close by, we may proceed with Northshore development with more substantial capital investment in the second half of 2008.

My comments today represent the perspectives of a small, independent exploration company that is actively exploring on the North Slope with a good level of activity, generally on prospects that because of smaller size no longer interests the major companies. At the end of next drilling season, AVCG

since 1999 and our partners since last year will have jointly invested over $100 million in Alaska even though none in our group have generated any revenues yet from Alaska oil, so we sincerely appreciate being listened to. We think in the long run we can bring substantial, incremental value to the State of Alaska. Please wish us good luck.

Many of you also know me as the past President of ARCO Alaska, Inc. from 1994-1998. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in 10 U.S. states and in over 20 countries throughout the world, so I'll also share my perspective in how I see the ACES bill in the context of competitiveness in the United States and in the world.

General Comments On ACES Legislation

At this point, I would like to address various key points in the ACES legislation.

First, our company prefers that the PPT be allowed to run its course in the next few years, and that ACES not be approved with its current provisions. I agree with Dr. Pedro van Meurs that in the light of declining oil production in the state of Alaska and prospectivity trending to smaller field sizes, the State should not once again increase its taxes after having done so last year. I will tell you that when recruiting companies to join in our Alaska ventures in 2005 and 2006, many were concerned about the threat of tax increases in Alaska. PPT proved tax increases were not a threat but a reality. Adding yet another tax increase via the ACES bill this year shows instability in Alaska's tax policy which results in uncertainty and risk when making investment decisions.

I heard that consultant Daniel Johnston differed strongly from Dr. van Meurs and urged the oil industry to understand the "cloud of corruption" over the existing Petroleum Profits Tax, or PPT, and that this alone provides a good reason to change PPT. I challenge Daniel Johnston that the bushel should not be thrown out because of a few bad apples.

In fact, last year during the PPT debates, I recall those who are guilty of paying bribes and some who are accused of taking bribes actually supported a 20% base tax rate, not the 22.5% base rate that was finally adopted. In fact, I'd like to think that the almost all in the Legislature and in Industry were honest, that they could be trusted in their deliberations last year, and that the final answer of PPT was a good answer and an honorable answer.

It is also very important to keep in mind that the progressivity tax was added at high oil prices to drive the real tax rate to even higher levels than 22.5%, with a range exceeding 30% now possible at certain prices. And let's not forget to tack on the royalty, the corporate tax, the ad valorem property tax, and environmental and permitting fees. It appeared to me that the checks and balances in the system worked in the Legislature last year, and I applaud the honesty of the legislators who in the end made a positive difference.

But I sit here feeling as if the honest and trustworthy investors in this industry are being punished alongside the guilty. I personally think this will have negative consequences for Alaska in the long haul in relationships and even in sustainable increased value.

But I am politically astute enough to know that the ACES train is moving fast down the track, so I can stand out of the way or jump on board and try to make the ACES bill better before we reach derailment in the long-term relationships between this industry I love and this State I love.

So, I have some suggestions of things not to change and things to change in the ACES proposal.

Five Things *Not* To Change In ACES

1) Keep the exploration and development investment tax credits. For a small explorer startup company like AVCG LLC, the exploration economics with the exploration tax credits ranging from 20-40% as provided by PPT and with ACES are more favorable with an improvement in the investor's rate of return as

compared with Alaska's old severance tax system. Near-term cash flow because of the investment tax credits is higher which improves the return on investment. Plus refund of cash to companies like AVCG and our working interest partners via the credits mean that we can apply that cash to our capital budget the next year to run adequate seismic and do additional drilling that increases the chance of more oil production and reserves for us and for the State.

Likewise, the credits for losses for a startup company like ours while we establish production and also the development investment credit can take substantial risk out of development of smaller fields that our company is focusing on. May of these smaller fields can add up over time and provide significant incremental revenue to the State.

2) Keep the "standard tax deduction/exemption" for smaller companies. The "Small Producer Tax Credit" that exempts up to the first $12,000,000 in production taxes for smaller companies can allow us to return a larger share of our annual cash flow for exploration and investment while we build the company to a critical mass of reserves and production necessary to expand staffing and have a routine level of major capital spending each year.

3) Keep the new ACES tax credit allowance for qualified delineation wells. A new proposal in the ACES bill that was not in the PPT law is the possible tax credit allowance for the investment in up to two delineation wells following a discovery. This would be very helpful to small explorers as well as for large companies on the North Slope where often one well is not enough to determine if field size is large enough to warrant development.

A real case in point is that should we have a discovery this coming winter at our Tofkat exploration well on the western side of the Slope, we will have to drill one or two delineation wells to confirm if field size is sufficient to develop the resource at this remote location. Often, due to the nature of these complex stratigraphic traps where sands unpredictably come and go, the delineation wells can be almost as risky as the initial exploration well. Having a

credit where the State, in a real sense, is sharing in the risk will - I think - expedite delineation of new fields and advance development for revenues.

4) Keep the revised progressivity tax rate at 0.2% per dollar increase in oil price. The PPT tax law had an incremental tax rate of 0.25% per each dollar increase in oil price above a trigger price while the new ACES reduces this incremental tax rate to 0.2% per dollar increase in oil price at a trigger price. While we can debate all day long the competitiveness of Alaska's tax rate with other countries' fiscal systems, giving some reduction in this surcharge keeps the government take at more reasonable levels. However, as I'll outline below, I would change the ACES trigger price back to $40 per barrel net and not the proposed $30 per barrel net if Alaska wants to better balance revenues with industry capital investment at low prices as I'll more fully discuss.

5) Do establish the Oil and Gas Tax Credit Fund for the purposes of purchasing certain tax credits from explorers and producers. This ACES provision would establish a procedure and standard for appropriation into this fund and management of this fund. Having a clear and transparent way for small explorers to receive their credits at full value is extremely important for AVCG to then be able to plow those credits back into seismic and exploration on the North Slope.

MR. THOMPSON, in response to a question, said that under the current PPT legislation, an exploration well, for example, can get a tax credit of up to 20 percent; however, if that well is more than 25 miles away from an exiting unit, it could get a tax credit as high as 40 percent. Those credits can be refunded by the state, or they can be sold to producers. For a company like AVCG, that is very important. Also under PPT, as well as under ACES, there is a 40 percent tax credit for "new seismic" that qualifies. Such credits allow the state to share in some of the exploration risk, and allow companies such as his to perhaps drill [an] extra exploration well per year, and this improves the chance of exploratory discovery.

4:38:13 PM

REPRESENTATIVE NEUMAN surmised that Mr. Thompson is in favor of keeping progressivity at .2 percent and start at $40, and keep the PPT rate at 22.5 percent.

MR. THOMPSON concurred, and opined that the state's consultants didn't show enough with regard to the competitive position of Alaska relative to other states and other countries. He also opined that the government's percentage may need to be adjusted if the goal is for Alaska to remain competitive with the Gulf of Mexico or a few other states.

CHAIR OLSON mentioned that the administration has been asked to provide the committee with the tax information and tax structure of four of the states that Mr. Thompson's written testimony refers to.

MR. THOMPSON said that a DOR update will be helpful, and mentioned that most of the AVCG's investors only invest in projects in the U.S.

4:40:38 PM

MR. THOMPSON continued paraphrasing from his written testimony, which read in part [original punctuation provided along with some formatting changes]:

> **Four Things To Change In ACES**
>
> **1) Change the recovery of tax credits from two years as proposed in ACES back to the recovery of credits in one year currently provided for in the PPT law.** In the PPT law, a company could file for the various credits, and if approved, would receive those full capital credits not to exceed credits of $25 million per company. In the new ACES law, while the cap has been removed which is very positive, the credits are refunded over two years instead of over one year, e.g., 50% of qualified credits can be applied for in the first year once a well is completed or abandoned and 50% in the following year.
>
> For a small company like ours, this will definitely affect our capital spending in a given winter as we plow all the credit refunds back into seismic or exploration drilling. As a very real example, AVCG and our working interest owners are projecting to spend $41 million in seismic and exploration drilling

this coming winter and likely around the same in 2009. We calculate that we could receive $16 million cash in qualified credits in mid-year 2008. So essentially, our working interest owners are planning to provide cash out of pocket of $25 million for the 2009 drilling season; this is a fixed number based on cash availability in these small companies to spend toward the Alaska portfolio. If the State refunds only one-half of this credit in the first year, or only $8 million instead of $16 million, AVCG and our partners will still provide $25 million out of our pockets as now planned and budgeted...meaning our overall spending in 2009 will be $33 million, not $41 million, i.e. $25 million from our available funds and only $8MM from the State. This would mean one less well that will be drilled by our group in 2009. And one less chance for another discovery that eventually could provide revenues to us all. With small companies, this is just the way our cash flow situation works. And for some of our AVCG investors like me, when I say "out of pocket," I mean "out of pocket."

So, we hope the full credit can be applied for and refunded in a given year. We hope this happens for all of industry. As an innovative compromise, however, the Legislature may consider a "Small Company Refund" provision that allows for companies that meet the no production or low production measures in the "Small Company Tax Credit" provision of the PPT law - that remains in ACES - to receive tax credit refunds that are fully refunded in the first year for qualified costs. Once a company grows in production beyond this "small company" measure with more substantial cash flow, perhaps refunds of 50% each year would apply as outlined in ACES.

MR. THOMPSON, in response to a comment, said that refunding credits in the first year would allow a smaller business to reinvest those funds that much sooner.

REPRESENTATIVE RAMRAS noted, however, that if the state spread the refunding of those credits over two years, the state would then have that much more money with which to provide state services.

MR. THOMPSON argued that refunding credits over a two-year period of time could defer the exploration of, and thus the development of, resources that could help fund state services in the future.

REPRESENTATIVE RAMRAS acknowledged that point.

4:47:36 PM

MR. THOMPSON continued paraphrasing from his written testimony, which read in part [original punctuation provided along with some formatting changes]:

> **2) Change the base tax rate in ACES from 25% back to the PPT tax rate of 22.5%, and re-review again in 2011 after some time has passed as allowed for in current law.** As I mentioned in my introduction, I felt the 22.5% base tax rate was reasonable. And the real tax rate is much higher with the tax progressivity factor. But what is fair, and how exactly is "fair" determined?
>
> I saw a copy of a presentation entitled "Guiding Principles For A New Production Tax System" by the Department of Revenue urging the changes in ACES, arguing that the average government take in various international countries averaged 67% for all types of fiscal regimes internationally, averaged 74% for production sharing agreements, but only 55% for tax and royalty regimes internationally. Somehow, the Department of Revenue representatives concluded an average of 68% as provided for in ACES would be close to the average of 67% for all types of regimes internationally.
>
> First, the average recommended to Alaska is the average of all regimes, i.e. the averaging of government take from tax and royalty regimes with the government take from production sharing agreement (PSA) regimes. In some countries that I worked in that had production sharing regimes, the risk profile for capital development was often much different that in regimes that use a tax and royalty regime such as Alaska. In PSA countries, it was not unusual for a producer on capital projects to have a very low initial tax burden until the capital investment was fully recovered plus a negotiated rate-of-return was

> achieved. Then and only then was the government take increased substantially...thus giving the average take for such countries as 74%. But the risk profile was often much better than Alaska, i.e. there was up front recovery of capital and a preferred investor rate-of-return. That is not the risk profile of Alaska when a company first has production...the ACES high tax rate and the added progressivity tax will start immediately along with royalties, corporate taxes, property tax and other charges rather than allowing for recovery of capital and a contractual rate-of-return.

REPRESENTATIVE NEUMAN asked how most countries in the world, with safe, but difficult environments, compare with regard to the percentage of "government take."

MR. THOMPSON offered his understanding that the average government take in countries where the fiscal system is most like Alaska's is around 55 percent. Currently, in Alaska, under the PPT legislation, the government take is approximately 60 percent. He reiterated that in countries with a PSA system, the average government take is 74 percent, and suggested that the legislature should spend more time looking at other regimes.

4:54:33 PM

MR. THOMPSON continued paraphrasing from his written testimony, which read in part [original punctuation provided along with some formatting changes]:

> As another distinction, most of the individual people and company investors specifically in AVCG, LLC, do not consider international regimes as areas to consider as competition for our investment dollars with Alaska. Rather, the main competition for most AVCG Owners' cash is in other states in the U.S. I found it astounding and concerning that the average of 67% for all international regimes did not consider weight-averaging in the major American producing states. As examples, the current government takes in the Gulf of Mexico offshore - one of the main competing areas for Alaska investment dollars - averages 45%. This is under consideration by the U.S. government for increase, but it is highly doubtful with the boom going on in deep water exploration and development that the U.S. government would increase the government take from 45% to 68%.

> In other producing states that compete for investment by our AVCG investors, the state and federal combined government takes in 2006 were as follows and averaged 45-57%:
>
> U.S. Gulf of Mexico 45%
> Colorado 51%
> Wyoming 52%
> Kansas 53%
> Texas 53%
> New Mexico 53%
> Oklahoma 53%
> California 53%
> Louisiana 57%
>
> To my knowledge, these states do not have the added progressivity surcharge tax which further separates Alaska in government take from these competing states. I would argue that Alaska should have a government take of 55% if we were to maintain long-term competitiveness with these other states for investment dollars. Having said that, some of these states do not have the prospectivity of Alaska, so Alaska could command some premium in take, but certainly not as high as being proposed in ACES.

REPRESENTATIVE DOOGAN asked whether Alaska's government take includes royalty payments.

MR. THOMPSON said it does.

4:58:00 PM

REPRESENTATIVE DOOGAN surmised that if one were to compare tax rates between Alaska and Texas, one would have to subtract royalty payments.

MR. THOMPSON concurred, and then continued paraphrasing from his written testimony, which read in part [original punctuation provided along with some formatting changes]:

> If Alaska set a government take at 60% to the government and 40% to the investor, the ACES legislation should be amended to allow for a base tax rate of 22.5% not 25%, should be amended to allow for a trigger price of $40 per barrel and not $30 per

barrel, and the incremental progressivity tax rate increase should be 0.2% per dollar.

3) Change the trigger price to $40 per barrel net and not $30 per barrel. If the government take is to be the fair and equitable 60% and not the unfair 68%, the trigger price should stay the same as in the PPT law, i.e. $40 per barrel net. If Alaska is to share in high prices with the progressivity surcharge tax, then Alaska should share in the pain of low prices. To amend the trigger price lower when and if prices collapse will be a false economy measure for the State of Alaska. When prices fall and a company's cash flow is sharply reduced, capital spending will fall. A "double whammy" to be taxed more with a progressivity tax at lower prices further reduces the amount of capital for reinvestment.

4) Consider some type of "Transitional Investment Expenditure (TIE)" tax credit. This provision allowed for in PPT was repealed in ACES. While this provision does not greatly benefit our company, AVCG, because we did not have large seismic or exploration drilling costs between March 31, 2001, and April 1, 2006, it is important to other major investors in Alaska.

As an example, the largest explorer and developer in Alaska, ConocoPhillips, now with the ARCO heritage assets was hardest hit in tax exposure with the change from the old severance tax law to the PPT and now to ACES. I simply think allowing a good steward who is the largest explorer in Alaska some transition allowance to ease the pain of greatly increased taxes is the right thing to do and can only build better, more trusting relationships. Again, this provision does not greatly benefit our company, however.

Concluding Remarks

This concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. My ultimate wish would be for the State to leave PPT alone and re-review it under the law as planned in 2011 or perhaps even in 2010. But if the ACES train has left the station and cannot be stopped, I urge you to at least consider the five

things our company would not change in this bill and the four things we would change.

The above comments are offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices for the substantial risk they have taken in the remote and harsh environment of the North Slope. In the end, I hope both sides get a fair and equitable share at all price levels.

And my comments are offered with the highest sincerity that the State and Industry can someday restore a mutual trust at all levels.

REPRESENTATIVE NEUMAN asked Mr. Thompson how he feels about sharing seismic data.

5:04:07 PM

MR. THOMPSON said that he would love to acquire older seismic data more readily at more reasonable prices, but acknowledged that some things ought to be considered proprietary for awhile because disclosure of such information might hurt a company's competitive position. He relayed that he wishes there were a "more reasonable" timeframe in which to share proprietary data, whether it be 5 years or 10 years, because that could help exploratory companies like his. He spoke of equipment and technology that [such companies] use, and explained that this use is possible because of "the seismic tax credits of 40 percent" that the state offers.

REPRESENTATIVE NEUMAN noted that the legislation contains the phrase "on request, furnish records, files, and other information ...", and asked Mr. Thompson to comment.

MR. THOMPSON opined that there are certain types of data that really should be held confidential; there are some types of data on federal acreage, for example, where the state is actually competing in lease sales and although it would certainly be appropriate for the DOR to see that data to ensure that the provisions of statute are being complied with, making that same data available to the DNR could affect competitiveness between state and federal leases. He said that the AVCG is willing to provide the necessary data, and that he agrees with earlier

comments that on all types of data, there are definitions of certain things that have been worked out over the years, and so his hope is that the state could adopt all those standard definitions and accompanying procedures.

MR. THOMPSON said he does have a concern regarding agencies being able to redefine things, because it just means one more set of things to try to calculate. "I think what's revealed to all investors in financial statements and to the [SEC] is the right and fair way to go in providing different types of data," he remarked. With regard to the issue of providing forecasts, such as cost forecasts, he said he doesn't mind providing forecasts, but noted that Mother Nature doesn't always cooperate.

REPRESENTATIVE RAMRAS asked Mr. Thompson whether the bill, if passed as currently written, will improve the investment climate in Alaska.

5:11:06 PM

MR. THOMPSON said he thinks it will diminish the investment climate for his type of company. For example, if the AVCG does not get its tax credits back next year for this winter's activity, the company won't have as much capital for the following winter, and this could result in one less well being drilled then. He then reiterated some of his written comments to illustrate another example.

MR. THOMPSON, in response to another question, said he thinks that passage of the bill as currently written will help the state realize a lot more income, at least in the beginning, but it could have a different effect as time passes because there will be a faster decline rate with regard to production on the North Slope. He offered his belief that his suggested changes to the bill will help the state and the industry find a better balance, create more capital investment, lessen the decline rate, and create more wealth for all parties. In response to a question, he added, "I think the ... decline in the production rates from ... all of Alaska will be less under ACES in the three to four or five years than it would be under PPT.

[HB 2001 was held over.]

ADJOURNMENT

There being no further business before the committee, the House Special Committee on Oil and Gas meeting was adjourned at 5:16 p.m.