

**ALASKA STATE LEGISLATURE  
HOUSE RESOURCES STANDING COMMITTEE**

October 31, 2007

9:05 a.m.

**MEMBERS PRESENT**

Representative Carl Gatto, Co-Chair  
Representative Craig Johnson, Co-Chair  
Representative Anna Fairclough  
Representative Bob Roses  
Representative Paul Seaton  
Representative Peggy Wilson  
Representative Bryce Edgmon  
Representative David Guttenberg

**MEMBERS ABSENT**

Representative Scott Kawasaki

**OTHER LEGISLATORS PRESENT**

Representative John Coghill  
Representative Les Gara

**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: HB2001

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)
10/22/07	(H)	O&G AT 9:00 AM HOUSE FINANCE 519
10/22/07	(H)	Heard & Held
10/22/07	(H)	MINUTE(O&G)
10/23/07	(H)	O&G AT 9:00 AM HOUSE FINANCE 519
10/23/07	(H)	Heard & Held
10/23/07	(H)	MINUTE(O&G)
10/24/07	(H)	O&G AT 9:00 AM HOUSE FINANCE 519
10/24/07	(H)	Heard & Held
10/24/07	(H)	MINUTE(O&G)
10/25/07	(H)	O&G AT 10:00 AM HOUSE FINANCE 519
10/25/07	(H)	Heard & Held
10/25/07	(H)	MINUTE(O&G)
10/26/07	(H)	O&G AT 10:00 AM HOUSE FINANCE 519
10/26/07	(H)	Heard & Held
10/26/07	(H)	MINUTE(O&G)
10/27/07	(H)	O&G AT 2:00 PM HOUSE FINANCE 519
10/27/07	(H)	Heard & Held
10/27/07	(H)	MINUTE(O&G)
10/28/07	(H)	O&G AT 2:00 PM HOUSE FINANCE 519
10/28/07	(H)	Moved CSHB2001(O&G) Out of Committee
10/28/07	(H)	MINUTE(O&G)
10/29/07	(H)	O&G RPT CS(O&G) NT 4DP 1NR 2AM
10/29/07	(H)	DP: SAMUELS, NEUMAN, RAMRAS, OLSON
10/29/07	(H)	NR: DOOGAN
10/29/07	(H)	AM: KAWASAKI, DAHLSTROM
10/29/07	(H)	RES AT 1:00 PM HOUSE FINANCE 519
10/29/07	(H)	Heard & Held
10/29/07	(H)	MINUTE(RES)
10/30/07	(H)	RES AT 9:00 AM HOUSE FINANCE 519
10/30/07	(H)	Heard & Held
10/30/07	(H)	MINUTE(RES)
10/30/07	(H)	RES AT 6:30 PM HOUSE FINANCE 519
10/30/07	(H)	Heard & Held

10/30/07 (H) MINUTE(RES)  
10/31/07 (H) RES AT 9:00 AM HOUSE FINANCE 519

**WITNESS REGISTER**

CLAIRE FITZPATRICK, Commercial Senior Vice President  
BP Exploration (Alaska) Inc.  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, provided a presentation.

BERNARD HAJNY, Manager  
Production Tax & Royalty  
BP Exploration (Alaska) Inc.  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, answered questions.

JOHN IVERSEN, Director  
Tax Division  
Department of Revenue  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, provided comments and answered questions.

KEVIN MITCHELL, Vice President  
of Finance and Administration  
ConocoPhillips  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, provided a presentation.

JIM TAYLOR, Manager  
Production Tax & Royalty  
ConocoPhillips  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, discussed future resource development on the North Slope and how the tax structure will impact that development.

KURT GIBSON, Acting Deputy Director  
Division of Oil & Gas  
Department of Natural Resources  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, discussed the exploration incentive credits in AS 43.55.025, enacted in 2003.

JULIE HOULE  
Resource Evaluation Section  
Division of Oil & Gas  
Department of Natural Resources  
Anchorage, Alaska

**POSITION STATEMENT:** During the hearing of HB 2001, answered questions.

#### **ACTION NARRATIVE**

**CO-CHAIR CARL GATTO** called the House Resources Standing Committee meeting to order at [9:05:42 AM](#). Representatives Johnson, Guttenberg, Edgmon, Fairclough, Wilson, Seaton, and Roses were present at the call to order. Also in attendance were Representatives Coghill and Gara.

#### HB2001-OIL & GAS TAX AMENDMENTS

[9:06:21 AM](#)

CO-CHAIR GATTO announced that the first 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." [Before the committee was CSHB 2001(O&G).]

CO-CHAIR GATTO informed members the presentations today would be given by the stakeholders. He introduced Claire Fitzpatrick and Bernard Hanjy.

[9:07:02 AM](#)

CLAIRE FITZPATRICK, Commercial Senior Vice President, BP Exploration (Alaska) Inc., provided the following presentation:

Thank you, Mr. Chairman, members of the committee. First off, I'd like to thank you for the opportunity for BP to come and present its perspective and its concerns and views over the proposed bill. Before we start, I'd like to introduce myself. My name is Claire Fitzpatrick. I'm the commercial senior vice president for BP here in Alaska. With me I have Bernard Hanjy, who is our tax manager responsible for production taxes and royalty.

What we're proposing to do this morning is to focus the discussion around Alaska. We've elected not to bring in various other independent and expert views, recognizing that you have heard from many already and we felt it might be more appropriate to focus on what's Alaska's resource, Alaska's cost structure. What are the things that we think are appropriate and important for you to be taking into consideration as you're considering what is the right fiscal policy for Alaska? From our perspective, this is about Alaska's economic future.

I know that many of you have had various presentations, both through the last debate and many of you, I believe, were kind enough to sit through some of our presentations last week where we went through a number of operational matters. We are not proposing to go through the same degree of operational and technical material this time but rather allow the conversation to move on a bit more through some of the specifics around the bill. However, I would like, at the outset, to make the offer that if there are more technical things that you would like to have presented to you, we're very happy to arrange for the most appropriate people to come down and present them to you. I may be able to answer some questions but I'm not an operating expert, therefore my answers may not be sufficiently detailed to actually meet your particular requests and requirements.

We'd also like to say that we support the net tax basis, which is what is currently in petroleum production profits tax (PPT) and we believe the policy behind that was around promoting investment. When we make our investment decisions, we're looking with a view to both the medium and the long term and sometimes that can take a little bit of time before

you would actually see what the outcome of those investments are. But we'll go through that a little bit more.

The other thing I'd like to say at the outset is our starting point is not about there will be no investment if changes are made. We have been in Alaska for nearly 50 years and we believe that there will be good business opportunities for us here for the next 50 years. Changes in fiscal policy do change investment decisions. They do impact them. It's not the sole impact but it is one of them. So, for us, changes in fiscal policy will impact the scale and pace of investment. We will still continue to do the investment that we need to do in order to meet our contractual obligations, which is to prudently develop the resource. What we're looking to do is to talk about what ways and things you need to consider when you're looking at how do you maximize the investment, attract the investment, both from the likes of BP who is currently here, but also for companies who are not yet here that you would like to encourage to come and invest here.

I think we might have a small technology problem so we're going to do the more old fashioned way of going back and forward. Sometimes paper and pen can be easier ....

We'd like to just start with our key messages and then we'll go through in a little bit more detail. I think through the presentations that you've already listened to, you'll hopefully - and I do believe that you appreciate that accelerating the decline will outweigh any benefit that would come through a change in the tax rate. Increasing the barrels in the pipeline will increase the opportunity for the state, in terms of its revenue generating.

[9:12:20 AM](#)

CO-CHAIR GATTO asked whether there is a way to increase the volume of production, or is the task to lessen the decrease in volume.

[9:12:38 AM](#)

MS. FITZPATRICK answered, "Yes to both." She said she will address how to mitigate the decline and what the opportunities are within the existing fields. Some of her comments will go beyond the existing decline and through some of the more challenged projects. She will also address how to tap into Alaska's resource base in the existing fields and beyond through incumbent companies and new explorers. DNR's decline forecast shows a 1 percent decline, down from the current 6 percent decline. She asserted it is possible to get below a 1 percent decline.

MS. FITZPATRICK continued her presentation, as follows:

The key thing for us - I think we have a common goal of getting more barrels in the pipe, whether that's through a combination of stemming decline but also getting more barrels beyond just stemming the decline. Investment is the key and that's investment both in technology, that's investment in the infrastructure. One of the things that is also key to remember is the North Slope was an amazing engineering feat. It was built with a view of 25 to 30 years. If we're now thinking, as at BP, we talk about the next 50 years, we also need to think about what's the infrastructure - what's the right infrastructure for the next 50 years. We have to bear that in mind when we're also thinking about the production because there's a huge efficiency aspect to take into consideration around what's the best way to access the next 50 years.

When the bill initially came out, what's now known as HB or SB 2001 - I know we're now on to committee substitutes, one of the concerns we raised was around the fiscal stability and that was around - if there's another change made this year, this will be the third change in tax structure in three years. I know there have been some questions raised about is it the third or the second. I'm aware that the ELF aggregation was not done through the legislative body but, for investors, it was an increase in tax. So this would be the third change in tax in three years and that does have a bearing when we're thinking about what is the fiscal risk around investments that are made. And, for companies who are not yet in Alaska, they're watching and they're aware of that as well.

[9:15:12 AM](#)

CO-CHAIR GATTO asked how many changes are acceptable to BP within a specific timeframe.

[9:15:23 AM](#)

MS. FITZPATRICK responded that BP does not have a definitive number, unless the parties are under complete contractual terms and even those can change. She opined that keeping a fiscal policy in place for ten years sounds reasonable. She noted one must recognize that the environment changes so it comes down to establishing a policy of goals and objectives that is designed to be flexible enough to respond to changes in the market while meeting the goals and objectives.

[9:16:00 AM](#)

REPRESENTATIVE GUTTENBERG asked Ms. Fitzpatrick to expand on the definition of stability and whether that refers to the number of times a tax policy changes or whether those changes are in BP's favor. He noted that oil companies may come back to the Legislature after a number of years and say a particular policy is not working and is preventing development. He questioned whether tax changes made in such a case would be counted as [destabilizing] changes. He pointed out that changes in the social, political and economic climate, and geologic structure and activity, also precipitate tax changes.

[9:16:54 AM](#)

MS. FITZPATRICK relayed that BP bases its investment decisions on a number of factors: geology, political risk and economic risk. She said BP does not view North America as politically unstable but it does view some other countries that way. When looking at economic risk, BP views price risk, cost risk, inflation, supply and demand, and fiscal risk. She opined that instability is meaningful in terms of the number of changes and the reasons behind them. If BP requested the Legislature to make changes in royalty relief, she would not consider that to be a fiscal change because that would remain within the existing fiscal policy and would address how both parties ensure that investment useful to both of them progresses. She said regarding whether the changes are to the producers' advantage, she is aware of examples around the world in which taxes were lowered. She suspected taxes have increased in more countries than decreased. She would count that as a change to fiscal policy.

MS. FITZPATRICK then continued her presentation:

One of the things which we also raised earlier, and we're still in a similar place and that is that raising taxes deteriorates the economics. There isn't a definitive point at which I can say that's when it moves from one side of the line to the other, but it will deteriorate economics and, because fiscal terms are part of the economics that we take into consideration, it will have an impact.

Where we are, in terms of BP, we don't explore in the true sense of the word, what we do is - this is what we use in our language, is we explore for the known through technology and that is, there's a large known resource base and what we would like to do is focus our efforts on actually developing that rather than focusing our efforts on finding stuff that isn't yet out there. I'm hopeful there are many other companies that are more interested in doing that because I think both are important for Alaska. The key is basically around increasing investment.

This is a slide which we've shown before and it's also one that the state has shown. You'll notice throughout our presentation where possible we're not introducing new numbers, new graphs. We might show them in slightly different ways but that's because the principles are the same and introducing new numbers then tends to confuse the issue into where the numbers are coming from as opposed to the principle that we're trying to talk about.

This is the decline that is currently projected.

And, getting back to Representative Gatto - Chairman's question of is this around just stemming decline or actually moving in the other direction. You'll see the answer is a little bit of both over a period of time, depending on which years you're looking at. We've elected not to show all of the history and historically the decline has been around 6 percent. It has been lower in certain years. You'll notice on the chart the sort of 2001, 2002 times actually is considerably flatter before it starts to decline again. That's reflecting the investments that were

made in Alpine and Northstar so that flattening is actually those two fields coming on-line. That was the result of increased investment that happened a few years prior to that as it takes time for these investments to actually come through as volumes.

What we've actually got on the chart, it's not terribly clear in the colors up on the screen so I apologize for that. I hope it's a little clearer on the slide in front of you. There are basically four key elements to this. There's the solid green with the sort of steep decline curve. That's what we refer to as the underlying production. That's the production that would come from the existing wells, provided we do normal and expected maintenance for that.

There isn't a hard line and that's deliberate between that, what I'll refer to as a wedge, and the next one up which is a slightly more dotted one, which again is more clear on the slide in front of you. That's reflective of the additional well work, i.e. maintenance, bringing the wells back to the most effective production and new wells that we drill. We've drilled in the last 10 years about 800 wells in Prudhoe Bay. We drilled - or we've invested, rather, in 100 new wells across the North Slope last year and we predict we'll be investing in about 100 this year. That's across the Slope in our interests, our fields, in the ones we have investments in.

[9:22:54 AM](#)

CO-CHAIR JOHNSON asked for clarification of the total number of new wells.

[9:23:34 AM](#)

MS. FITZPATRICK clarified that 800 new wells have been drilled in Prudhoe Bay over 10 years. BP, as an interest owner in that field, is investing in them, as are the other working interest owners. When she said BP has invested in 100 wells across the [North] Slope, she was referring to Prudhoe Bay, Kuparuk, and some of its other fields. She elaborated:

In terms of the 100 wells that we invested in, what percentage does that reflect of the total wells. I

can see it on a bit of paper and I'm hesitant to give you the definitive number and, again, add more confusion. So, if you're okay, I know I have it back in the office. I will definitely get it for you.

[9:24:29 AM](#)

CO-CHAIR JOHNSON expressed interest in knowing what portion of the drilling is not being done by BP to determine the total number of new wells, regardless of the investor.

[9:25:09 AM](#)

MS. FITZPATRICK said the number she has refers to the percentage of total wells BP invests in. She said [BP invests in] more than half and she will provide that information [at a later date].

[9:25:20 AM](#)

CO-CHAIR GATTO asked how many wells are in the Prudhoe Bay Unit.

MS. FITZPATRICK estimated 2,500.

[9:25:42 AM](#)

BERNARD HAJNY, Manager, Production Tax & Royalty, BP Exploration (Alaska) Inc., affirmed that a previous BP testifier said 2,500 wells have been drilled in Prudhoe Bay.

CO-CHAIR GATTO questioned whether a limit on the number of wells to be drilled exists and how the industry will determine whether the pace of drilling will continue at its current rate.

[9:26:30 AM](#)

MS. FITZPATRICK informed the committee that the pace of drilling must increase to sustain the current production decline level. She explained that existing wells lose efficiency as they age and production declines rapidly. In those cases, BP does "well work" to improve efficiency. In addition, in terms of the new wells that get drilled, there is capacity to drill more wells but BP has a footprint constraint for environmental reasons. That is where new technology is applied to drill multi-lateral wells within the same footprint of the existing unit.

[9:27:32 AM](#)

CO-CHAIR GATTO questioned whether a vertical well counts as one or three wells.

[9:27:42 AM](#)

MS. FITZPATRICK explained that it is counted as both. There is one [vertical] bore, but each lateral is counted individually so, for example, the count would be 1a, 1b, and 1c.

[9:27:48 AM](#)

REPRESENTATIVE SEATON pointed out that 100 wells were drilled in 2006 prior to the passage of PPT and 100 wells are being drilled in 2007 under the PPT. He said the committee must determine the effect of the change in Alaska's tax regime regarding net profit, deductibility, and credits on the oil industry's investments. He asked whether the amount of drilling and well work has increased since the enactment of PPT.

[9:28:47 AM](#)

MS. FITZPATRICK replied that a direct correlation is difficult to make on an annual basis because BP makes short term and long term investment decisions. Long term investments will not show results for maybe five or ten years so no instant impact can be seen. She said BP is investing to get the barrels in the third layer up, which will take time. Whether BP would have drilled more or less wells under a different scenario is hard to say because her business models and plans are not based on what might have been in place. BP wants to drill more wells but is limited by capacity and infrastructure. However, if BP is confident that the environment it is working in is stable, it would plan the logistics and support to move forward.

[9:30:49 AM](#)

REPRESENTATIVE SEATON recalled testimony given last year by Mr. Van Tile (ph) of BP during which he said BP had sanctioned all of the projects that were economic [on the North Slope] and was proceeding as fast as possible. He asked whether the situation has changed.

[9:31:12 AM](#)

MS. FITZPATRICK replied that the situation is always changing for a variety of reasons. One reason is that BP might progress

down a path but events change due to a greater understanding of technical risks. She said much work is done prior to the time BP will formally sanction projects and commit funds. She explained that BP's process of sanctioning a project consists of the group committing funds to progress a project with the expectation of developing a specific resource. The group does a lot of work on projects in Alaska before it goes forward to get a formal commitment from its organization. She noted a lot of activity is taking place, for example, on the western region development in Prudhoe Bay. That project will probably cost more than \$2 billion. It has not been formally approved by BP's board, yet two years of preparation and testing have been done. The activities so far range from drilling wells to building new facilities for gas handling, to getting a handle on the technical, economic and financial risk.

[9:33:40 AM](#)

REPRESENTATIVE SEATON asked, "I am wondering whether BP has economically viable projects that they determined are economically viable now that they are not investing in, or are they investing in all of the projects that they determined are economically viable?"

[9:34:24 AM](#)

MS. FITZPATRICK replied that when BP identifies an economically viable project, it begins to work on how to go about accomplishing it.

[9:34:27 AM](#)

CO-CHAIR GATTO asked if, within BP, teams of employees that represent viable projects in different parts of the world compete with each other.

[9:35:12 AM](#)

MS. FITZPATRICK said BP makes investment decisions at different levels of study. Group level decisions are global and strategic in nature and concern market exposures for various countries, such as what kind of market exposure does it want in Southeast Asia versus what kind of country exposure it wants in North America. If the group makes a strategic decision to enter a new country, that would not be at the expense of taking funds from Alaska, for example. That is done under a different set of principles that guides the group's management of its financial

position. However, project decisions are made under a different set of principles and criteria; the most important being how risk will be managed and mitigated. Not all projects get to the same stage of maturity and have the same robustness at the same time. She cautioned that even projects that look very, very good economically may not be approved because the technology risk is huge. She said regarding whether projects compete globally, some of that has to do with the desired portfolio balance. Alaska projects are most likely competing against other projects in North America.

[9:37:24 AM](#)

CO-CHAIR GATTO observed that the success of a project comes down to the net present value and the likelihood of success.

[9:37:45 AM](#)

REPRESENTATIVE WILSON compared this conversation to planning for retirement and investing accordingly. Younger people make a variety of riskier investments but, as they get closer to retirement age, they realize they cannot take those risks. She said many experts have testified that the major oil fields have been discovered already. She asked whether BP has stopped exploring and is instead zeroing in on using new technology to find the remaining oil in the known fields. She assumes BP looks at many angles of development.

[9:40:28 AM](#)

MS. FITZPATRICK agreed with Representative Wilson's analogy of risk profiling at different stages and felt it applies from a global perspective because BP takes different risks in different places. However, in Alaska, BP feels that exploration opportunities for other companies exist. BP is focused on extracting the harder barrels from existing fields. She said it is likely that the majority of the larger oil fields have been discovered but BP is always surprised by what geology has to offer. She noted that global warming may be a mixed blessing in that the ice caps may change and will provide opportunities for research. Those areas have not been surveyed to the same extent as other places. She continued her presentation:

So going back to the chart here in terms of what are the various things that we need to work on, we've touched on the drilling, the in-field drilling. I started to say that I haven't got a hard line between

the first two slices that are up there and that's because it's very easy to draw it. I've just about mastered the PowerPoint skills to draw that myself, but not quite.

In reality, being able to separate them out and be able to work out partly how the molecules - which comes from which - what's cause and what's effect if you drill a pressure injection. That causes benefits for several wells. How would you attribute it to each of those particular areas and allocating costs and things like that? I know it's an area that has come up in discussion and just wanted to share with you that the IRS, the federal tax authority attempted to do one of these sorts of splits in the past with a windfall profit tax and reverse that decision because it was impossible for them to actually manage it. It resulted in a long period of litigation, which was in nobody's best interest. Both Norway and the UK have on many an occasion had conversations on how could they do this. They've never managed to come up with a way, which is actually workable, without creating a huge bureaucratic process, which, from the government's perspective, they didn't want to do. From the industry perspective, we didn't particularly want to have to double our staff to manage it either. So just so you're aware that I can make it look nice and simple in a graph but unfortunately life doesn't quite work like that.

Weaving on, then, to the next layer of sort of those large projects, technology, I'll come along and touch a bit about what some of those things are. It's critical, in terms of getting the kind of production profile that's shown here. Do we believe it's possible? It is but it will require significant investment well in excess of what's been seen in the last 20 years.

Is it worth going for? I think it is but that's because I believe the right answer for the future of the economic position here is getting more barrels in the pipe.

New fields and exploration - we have Oooguruk coming on, hopefully early next year. I'm sure Pioneer will be talking to you. They've already done great

testimony and that's great. That's a wonderful sign to see - someone else on the North Slope developing one of those smaller fields where they were able to sort of see value and decided to go for it. That's great to see and I'd like to see more of that.

You'll also see a little bit of a bump further out around the 2011-12. I think that's probably Liberty coming on, which is a field BP is in the process of starting to develop. That will involve having the world's largest rig up on the North Slope and drilling a lateral well, which will be nine miles to actually bring that across, and we'll be bringing that across the Endicott facilities. That's a federal lease but it's still barrels going into the pipeline, which is still a benefit to Alaska and it's a benefit also in terms of getting better positions for new entrants coming in. Although the federal leases don't give you production taxes, it's still good for Alaska to have those barrels going through the pipe.

[9:46:21 AM](#)

CO-CHAIR GATTO asked for confirmation that states bordering the Gulf of Mexico get a percentage of the federal revenue from oil production because of impacts that activity has on those states.

[9:46:50 AM](#)

MR. HAJNY expressed his belief that when a company can show that projects are not meeting requirements through economic or technology challenges, the federal government will negotiate to see what can be done to bring those barrels on stream.

[9:47:25 AM](#)

CO-CHAIR GATTO re-stated his question, "Does Louisiana or Texas benefit from offshore drilling even though it's on federal waters or do they simply say we're stuck, it's going to come across our land and enter into our pipelines and finally get to a refinery? Do they make nothing or something?"

[9:47:52 AM](#)

MR. HAJNY said he believes the rules are similar to those that apply to Alaska, that being that waters within three miles of the coastline are state waters. The waters between 3 and 6

miles are shared, somewhat. He said BP pays federal royalties on the Liberty lease, and believes the state will get a portion of the federal royalties. He was unsure of what law applies beyond six miles from the coastline.

[9:48:38 AM](#)

MS. FITZPATRICK encouraged the committee to also consider the ancillary benefits of oil production, such as support service jobs and additional business activity. She pointed out that although the Liberty project is in federal water, a lot of money will be spent on that project, which means an economic benefit to Alaska in terms of jobs for Alaskan contractors and other benefits.

[9:49:35 AM](#)

CO-CHAIR GATTO agreed that more oil in the pipeline makes each barrel less expensive to move so Alaska and BP have a common objective. He said the state has no income tax or sales tax. He pointed out that jobs do not necessarily put revenue in Alaska's treasury.

[9:50:29 AM](#)

MR. HAJNY pointed out that at the Liberty project, the majority of facilities will be onshore within the Endicott field. Those facilities would be subject to the same property taxes that apply to other facilities.

[9:50:55 AM](#)

REPRESENTATIVE FAIRCLOUGH asked Ms. Fitzpatrick to speak to the issue of access to the pipeline by producers other than the three companies that hold ownership interests.

[9:51:40 AM](#)

MS. FITZPATRICK stated that there is capacity in the pipeline for more oil so any producer has the ability to put its oil in the pipeline.

[9:51:46 AM](#)

REPRESENTATIVE FAIRCLOUGH asked what the transportation cost would be.

[9:51:51 AM](#)

MS. FITZPATRICK said she believes there are agreed processes and procedures to establish that but she is not familiar with the details.

[9:52:02 AM](#)

REPRESENTATIVE FAIRCLOUGH said she appreciates that acknowledgement for the record. When she attended a meeting held by the Governor in Anchorage, a constituent expressed concern that the big three oil companies are "siloing" oil on the North Slope by not allowing access to the pipeline for other wildcat drillers. She asked for assurance that the pipeline owners allow access at a fair transportation charge to all producers.

MS. FITZPATRICK said she believes the pipeline is regulated.

[9:52:41 AM](#)

MR. HAJNY affirmed that the pipeline is a common carrier pipeline and the weighted average tariff is published on the Department of Revenue (DOR) web site.

[9:52:47 AM](#)

REPRESENTATIVE FAIRCLOUGH assumed that the hurdle for a wildcat or small driller is the transportation cost negotiated in that agreement.

[9:53:13 AM](#)

MS. FITZPATRICK said she is unsure about how the rate regulations are set. She pointed out Alaska is an expensive place to do business because of its geographic location. She said many of the costs of Trans-Alaska Pipeline System (TAPS) are high level fixed costs that are reduced by the number of units.

[9:53:33 AM](#)

CO-CHAIR GATTO inquired whether BP actively encourages other independent producers to use the TAPS.

[9:53:47 AM](#)

MS. FITZPATRICK said BP does not discourage use of or "hog" the pipeline but she is not sure that it is BP's position to encourage new companies to invest in Alaska. She asserted:

It's a case of making the investment environment competitive so as other companies want to come in and invest in the state. And then if they're finding the right opportunities, we're certainly not blocking them of any access to the pipe because it's in our best interest to have more people in the pipe because that lowers the cost for everyone.

[9:54:36 AM](#)

CO-CHAIR GATTO observed that the owners can assess a surcharge, or rent feeder lines to the pipeline. He said legislators have heard the statement that producers make it more expensive for new companies to operate. When they refer to producers, they are referring to BP.

[9:55:06 AM](#)

MS. FITZPATRICK explained that any facility sharing agreement is a commercial agreement that is negotiated between the parties. Those agreements can be complicated, particularly by capacity constraints. For example, a company might want capacity for 1200 barrels while the available capacity is only 1,000 barrels. She stressed that more participation is still in BP's best interest. The agreements are a normal commercial process but they are complicated.

[9:56:06 AM](#)

CO-CHAIR GATTO acknowledged the complications and said he just wanted a statement from her that BP does not deliberately oppose, discourage, or interfere with new producers.

[9:56:38 AM](#)

REPRESENTATIVE FAIRCLOUGH recalled watching BP ads that state that the pipeline is two-thirds empty and that time is running out. They also say Alaska has helped to stimulate continued production by the existing producers who have been loyal and done things above and beyond the capacity of other organizations and that Alaska has benefited from the large oil companies through employment opportunities and financial contributions to communities. She noted she does believe there is a barrier

within the FERC and its cost calculations that prevent the entry of smaller producers on to the pipeline. She said she is aware of the role that rolled-up rates, the calculation of transportation costs, and depreciation play in this agreement, but noted that if BP is interested in putting more oil in the pipeline it should work with its partners to remove the obstacle to smaller producers that is part of the FERC ruling on transportation costs.

[9:59:23 AM](#)

MS. FITZPATRICK continued with her presentation, as follows:

The final point I want ... to make on this is around the interdependence of some of these factors. I touched on earlier about the infrastructure and the fact that it was built for 25 or 30 years. That's also a key thing when we look at the outer years here and that is, knowing and seeing progress on some of the larger projects, the technology, focusing on what the future life might be for the oil on the North Slope. That's one of the things that we're taking into consideration when we're starting to think about what should we be doing around the infrastructure. What are the investments for the future that aren't generating barrels themselves but will make it a lot easier for the barrels to actually flow and to make them more efficient, not only for ourselves, but for other players on the North Slope. These projections here are not just dependent on the existing producers. They are dependent on new players as well, or on the existing producers finding new oil through existing fields and new technology or through new exploration.

Again, sort of listening to the various ... committees, I am well aware that - and you've reiterated common goal barrels in the pipeline. I also think you're all familiar and understand that more barrels in the pipeline ends up with a better state revenue position from the royalties as well as from the PPT.

What this was intending to show is a representative set of scenarios. That's basically - in order to get the investment - the decline rate lower requires significant investment. These numbers were calculated based on me saying, well, if I want to get to 7.5

billion produced barrels, that's 3 percent. Chances are from the existing, that's going to be a mixture of light, a mixture of heavy, and a mixture of new. I took some of the state's numbers - very simple arithmetic there - no huge signs behind it, as merely indicative.

Do I actually think it will cost more? Yes I do and that's because I think the costs are increasingly - the activity is increasingly harder and therefore the costs are going to become increasingly higher.

[10:01:51 AM](#)

CO-CHAIR GATTO said all [Alaskans] have been subjected to a substantial amount of advertising in the form of mail, radio, television, and newspaper ads that talk about what needs to be done to increase state revenue. He noted Ms. Fitzpatrick stated, in regard to investment, "...not only for us, but also for Alaska." He pointed out that is the first time he has heard a major oil company representative refer to "us." He stated when state revenue increases, the oil companies' revenue increases as well, probably more than the state revenue. However, the advertising always implies the state is the "bad guy." He guessed that BP could drill several more wells with the same amount of money it spends on advertising.

[10:04:36 AM](#)

MS. FITZPATRICK said she would do her best to make sure BP advertising reflects the mutual benefits and repeated that BP is in a partnership with Alaska that has lasted for 50 years and continues today.

[10:05:13 AM](#)

CO-CHAIR JOHNSON opined that money spent on advertising is not enough to pay for a well.

MS. FITZPATRICK said her thought was if BP is spending enough on advertising to pay the costs of drilling a well, she would like to see the invoices.

[10:05:39 AM](#)

CO-CHAIR GATTO asked whether \$5 million is enough to drill a well.

[10:05:51 AM](#)

MS. FITZPATRICK answered the costs of drilling vary under different circumstances. She acknowledged that a previous testifier used that number last week but that number referred to "the mother bore," which occurs before the multilaterals or injector wells are drilled that enable the well to produce.

[10:06:20 AM](#)

REPRESENTATIVE SEATON spoke of a previous analysis of Slide 4 by advisors from Gaffney, Cline and Associates, Inc. regarding the net present value and dollars per barrel. Their testimony pointed out that BP is reporting essentially the same cost per barrel in each scenario. He asked whether the estimates of production decline, shown on Slide 4, are BP's numbers or the Department of Revenue's (DOR's) numbers.

[10:07:10 AM](#)

MS. FITZPATRICK reminded the committee of her testimony last week, in which she said all of the estimates are based on DOR forecasts, so that is what she has said all along. She noted, for example, the 3 percent decline estimate requires a substantial amount of heavy oil development, which BP does not have viable economics to forecast. She is unable at this time to give estimates on the development cost per barrel because she does not have one yet. She repeated that the numbers she is using are indicative and are not representative of what BP's estimated project costs.

[10:08:15 AM](#)

REPRESENTATIVE SEATON asked Ms. Fitzpatrick to provide cost production estimates at a later date.

[10:08:43 AM](#)

MS. FITZPATRICK assured the committee that she will provide further information about the estimates and continued her presentation, as follows:

I suspect the point of this slide is well understood so we will move on from this.

What I've done here is - the slide which had shown the decline curves in terms of what was from new investments, etc. - all we've done is to switch that around into a different format so, as you can see, this is our estimate based on those numbers of what would come from Prudhoe and Kuparuk versus other existing fields and new developments. 70 percent of the state's forecast production for the next 20 years will come from Prudhoe and Kuparuk. A good amount of that will be from the longer term investments and the ongoing drilling and well work, both for the light oil as well as the increasingly heavier ends of the oil.

We touched earlier on how we make investments in terms of around sort of our global portfolio, strategic and the fact that we take into account technology risk, economic risk, etc. What I'd like to do is touch on a little bit of ...

[10:10:10 AM](#)

REPRESENTATIVE WILSON interrupted to ask whether the numbers provided in the remainder of her presentation are from BP or state forecasts.

[10:10:37 AM](#)

MS. FITZPATRICK remarked:

These numbers are how we believe that profile breaks down and have I been able to verify that? No, but that we've kind of, on the information that is available publicly, we can make a reasonable basis of how we think that would then pull down.

MS. FITZPATRICK explained that the remainder of the presentation contains numbers from third party agencies and the state. The following slides about BP contain BP forecasts and individual contractors have provided their own headcounts.

[10:11:10 AM](#)

REPRESENTATIVE WILSON asked if the numbers on Slide 5, regarding state revenue per billion, refer to the existing 13 wells or \$13 billion.

[10:11:30 AM](#)

MS. FITZPATRICK explained that the forecast shown on Slide 5 indicates that existing wells will provide \$13 billion in state revenue from 2008 to 2026, based on existing PPT terms and a \$60 per barrel Alaska North Slope (ANS) price. She pointed out the longer term investments are providing a lot of revenue to both BP and the state. She said BP recognizes that 70 percent of the next 20 years' production will be coming from the large, existing fields and is looking at different aspects associated with that.

MS. FITZPATRICK called the committee's attention to Slide 6, titled: Developing and Deploying Technology. As previously discussed, 70 percent of future oil production in the next 20 years will come from existing oil fields; therefore, BP will enhance production from existing wells by using new technology. She described the following enhanced recovery procedures: Bright Water; Multi-Lateral Wells; Cold Heavy Oil Production with Sand (CHOPS); and Gas Partial Processing. She informed members that a one percent increase in recovery is equal to about 250 million barrels of oil. She noted new technology is being tested to enhance recovery to extract every possible drop and find new oil. She said BP is now able to drill multilateral wells within a few feet of where it wants them. Ten years ago, that wasn't even dreamt about.

MS. FITZPATRICK said BP is also thinking about western region development, which will require new processing facilities and significant investment. She noted Alaska has a lot of heavy oil that is challenged but also has an advantage in that it has light oil. To make the heavy oil flow down the pipe, BP needs the light oil to thin it. A variety of technologies can be used to extract the oil such as Cold Heavy Oil Production with Sand, thermal, and in-situ combustion.

MS. FITZPATRICK informed the committee that Alaska has heavy oil in Prudhoe Bay, the Kuparuk River Unit and the Milne Point Unit. BP has a pilot well ready for testing in Milne Point, and the right fiscal environment would be conducive to the sanctioning of this project. In addition to requiring new technologies for production, heavy oil garners a discounted price on the market due to its chemical and physical properties. She pointed out the refineries will have to change their operations to be able to cope with the heavy oils.

[10:17:30 AM](#)

REPRESENTATIVE ROSES surmised that pilot wells test for the success of the technology and the economics. He asked if the fiscal climate is determined by the results and cost of production weighed against the fiscal climate.

[10:18:22 AM](#)

MS. FITZPATRICK agreed that the pilot well tests for quality, flow rate, and the success of the technology. However, one pilot well will not determine the economics of the field. After further testing, a stable fiscal environment will be one of the factors considered when the final decision is made.

[10:19:48 AM](#)

REPRESENTATIVE ROSES re-stated his point that the pilot well will test for oil and the economics of the costs of production.

[10:20:12 AM](#)

MS. FITZPATRICK agreed that is a huge contributor.

[10:20:17 AM](#)

CO-CHAIR GATTO asked for a comparison of the volume of heavy oil on the North Slope to that of light oil before it was developed.

[10:20:33 AM](#)

MS. FITZPATRICK answered the volume is the same but a couple of numbers have been used. One is referred to as oil in place, which is 20 to 30 billion barrels of oil. Of that, about 10 percent is technically recoverable; however the former BP estimate was zero to three percent, zero recognizing that BP could drill a lot of pilots and discover the flow rate and technology have a long way to go. BP is looking at up to 3 billion barrels of recoverable oil. The effect of new technology on the estimate of what is now recoverable is unknown. She told members the following:

In terms of there are - sort of some of the technical risks that we have, when we're making investment decisions, technical risk is clearly part of it but then so are the economic risks. This is just recognizing that Alaska's challenged in many ways, as well as having many opportunities. We've got light oil here; we've got heavy oil here. Having the two

together means we are increasing the - hopefully the likelihood of being able to get that heavy oil to flow. But we do have to recognize that there's 800 miles of pipe, 2,000 miles of shipping to get to the West Coast refineries. It is an Arctic environment. Those things alone mean that it's a higher cost than average U.S. Alaska is not average and I suspect 99 percent of Alaskans would be horrified if they were described as average. It's not the way of thinking here.

So, recognizing that that is the environment, then the cost structure is different. Now the cost structure is different because of where Alaska geographically is and the Arctic temperatures. Costs have also changed dramatically over the last few years as a result of global prices and as a result of global prices there's then been a change in industry activity, which, in turn, has a driver on costs.

CO-CHAIR GATTO asked if the number on the lower right hand corner - Alaska \$16 average, for the U.S. \$10, so that the differential is \$6 per barrel.

MS. FITZPATRICK replied:

Mr. Chairman, there's a variety of data points you could take. Again, what we've done there is to merely show the indication of Alaska is a lot higher cost. The U.S. average is taken from a published document from J. Herold and Son, and the \$16 is actually based on us pulling together information from states' information. That doesn't include any capital costs. It's just the operating, transportation and production tax.

CO-CHAIR GATTO said he heard the question as recent as yesterday about whether that number could be \$20. He was glad to see the statement relative to the U.S. as being an absolute \$16 and not \$20.

MS. FITZPATRICK said the \$10 is absolutely U.S. and [the additional \$6] is a relative position of Alaska being more expensive. The operating costs included in that \$16 consist of the \$7.75, which is from the August PPT report for FY 2008. She explained that estimate is a blended number from industry's FY 2008 reports to DOR and that her numbers are a subset of the

state's portfolio. She said her actual operating costs are higher but she is assuming the state has 7 months of BP's numbers and its forecast for the remainder of 2007, so she is confident DOR has blended them to come up with this number.

[10:24:58 AM](#)

REPRESENTATIVE EDGMON observed that annual reports from the oil industry specify that 36 percent of the industry's profits in 2006 came from production in Alaska and 27 percent came from the continental U.S.

[10:26:04 AM](#)

MS. FITZPATRICK responded that she prepared a letter on the same subject for Senator Wielechowski that contained some information from BP Alaska Incorporated's "20F" filing, and compares its profit to that of the "BP Group." The BP Group includes retail activities in Europe and solar and renewable energy. She stressed when profit comparisons are made, profits from Alaska must be compared to other BP exploration and production activities. A regional analysis of BP Alaska's exploration and production activities included in that same document, which was prepared for the U.S. Accounting and Reporting Standard No. 69, and through agreements required by the Securities and Exchange Commission (SEC). When these are compared, a number of other regions are more profitable. She said BP Alaska Inc. is a legal entity that exists to hold investments. It owns investments in some of BP's Australian downstream activities so it pertains to areas other than Alaska. However, even with Australia included, Alaska is not BP's most profitable operation.

[10:27:48 AM](#)

REPRESENTATIVE EDGMON asked Ms. Fitzpatrick to compare Alaska to similar states or sovereign nations in terms of cost structure and profit structure and its 800 mile pipeline and 2,000 miles of shipping.

[10:28:46 AM](#)

MS. FITZPATRICK advised the committee she would have to first look at the geology of a region and then at the economic environment and whether it is more or less costly, and the fiscal terms. She concluded that Alaska is unique and too complicated to choose one comparison when making policy decisions. She said it is important to consider whether policy

changes will increase or decrease the likelihood of achieving the chosen objective.

[10:29:46 AM](#)

CO-CHAIR GATTO agreed that BP, like the Legislature, must consider its shareholders.

[10:29:56 AM](#)

CO-CHAIR JOHNSON asked whether the estimated U.S. average operating, transportation, and production tax cost of \$10 per barrel of oil includes Alaska.

[10:30:18 AM](#)

MS. FITZPATRICK assumed that it did but offered to check and report back.

[10:30:28 AM](#)

CO-CHAIR JOHNSON emphasized that the inclusion of Alaska's costs of \$16 would bring the U.S. average up considerably, since Alaska produces a large portion of U.S. oil. He suspected the average would be about \$6.00 to \$8.00 if Alaska's costs are not included. He asked Ms. Fitzpatrick to provide the U.S. average cost if Alaska's oil is excluded.

[10:31:25 AM](#)

MS. FITZPATRICK said she would investigate those numbers further. Continuing to discuss economic data, she said although Alaska is not average, the economic drivers are similar for Alaska and the rest of the U.S. She told members the actual inflation impact has lagged a bit in Alaska. BP's global cost structure underwent dramatic changes beginning in 2005; that change did not begin in Alaska until 2006. She told members that could be due to the fact that Alaska has longer term contracts because of limited supplies and intense competition for equipment. She added that when the prices increase on a sustained basis, costs eventually follow, usually in one year's time, and a decrease in oil prices will be followed by a decrease in costs after two years. She opined that, if the \$90 per barrel oil price continues, BP will continue to experience increasingly high production costs. She reminded members that a net tax structure self-regulates as those numbers increase and decrease.

10:34:53 AM

MS. FITZPATRICK presented Slide 10, which displays BP's recent investment activity. Since 2004, BP Exploration Alaska has increased its number of employees and contractors and is building infrastructure to sustain the increased activity level on the North Slope. The cost of investment activity, although usually considered a negative, is good for the total economic position of BP and the state as long as the scale and pace of the activity is ramped up to a sustained level with due consideration of the limits to production on the horizon. One of the drivers that can sustain this higher level of activity and be controlled is tax policy.

10:36:21 AM

REPRESENTATIVE EDGMON referred to Slide 10 and asked whether the increase in North Slope contractor jobs are jobs held by Alaskans.

MS. FITZPATRICK replied the 7,000 total contractor jobs are comprised of Alaskans and non-Alaskans; BP desires to hire all Alaskans and tries to encourage that.

REPRESENTATIVE EDGMON asked for the percentage of Alaskans holding the contractor jobs.

MS. FITZPATRICK guessed that 30 percent to 40 percent do not live in Alaska and offered to check.

10:37:55 AM

CO-CHAIR GATTO acknowledged that Alaska does not have the population to completely provide the necessary labor for a major construction project. However, Alaskan schools are now concentrating more on vocational education in anticipation of increased investment on the North Slope and the construction of a gas pipeline.

MS. FITZPATRICK stated that BP is also doing a lot to access talent at various stages, beginning at the high school level, to encourage opportunities for future employment for Alaskans. BP is involved at the university level to encourage offering courses that develop the needed skills for work in its industry, especially in the engineering and technical arenas.

10:40:42 AM

MS. FITZPATRICK discussed Slide 11, which shows BP's initial view of the proposed legislation. She asked members to consider unintended consequences caused by the new legislation. The first item pertained to information reporting; she relayed an incident regarding a request for data from DOR. Alaska's previous tax policy required one set of data. However, because the tax process changed 14 months ago, both parties need to find solutions for the new process of data sharing. Her experience is that fiscal change takes a bit of time; the industry and the state are now recognizing the key elements of information that need to be shared under the new process. She informed the committee that members have been provided with a summary of the information BP has disclosed to the state. The two parties now need to decide what information will be most useful, ranging from production forecasts to capital costs and a review of DNR's models. She alluded to confusion in the past about the state's requirements.

10:44:11 AM

MR. HAJNY told the committee that he was surprised by the criticism about the lack of information provided by the industry to the Administration. Each month BP provides cost, expense, and revenue forecasts for the year. Estimated monthly payments for the upcoming year are determined in January, based on a summary of the best data provided. Additionally, BP is required to provide, along with its unitary tax return form 1065, partnership returns for each unit. For Prudhoe Bay, under state income tax return requirements, BP must submit copies of its partnership joint venture billing returns. Those returns provide the total annual costs, broken down between capital and expense. That data provides the state with an idea of trends developing within a current period.

MS. FITZPATRICK recognized that more work needs to be done with state officials on this issue, especially with forecasts.

10:46:25 AM

CO-CHAIR GATTO reflected that annual reports provide specific data that may be collected for different times and purposes, such as for shareholders or a board meeting. He suggested that the industry should anticipate what data would be most helpful to the committee prior to a presentation, and thus avoid a lot of unanswered questions and assumptions not based on facts.

[10:49:45 AM](#)

REPRESENTATIVE GUTTENBERG spoke of information shared by the industry in partnership reports that is unavailable to state auditors. Without detailed information from those reports, auditors don't have a basis for understanding the decisions made, especially when decisions are based on information from international holdings. He noted that the details needed by the auditors are often withheld by the industry as confidential information.

MS. FITZPATRICK asked whether Representative Guttenberg was referring to a situation where costs are being charged to Alaska that are not sourced in Alaska.

REPRESENTATIVE GUTTENBERG restated his concern is that the state's auditors do not have the ability to look beyond the state's borders when auditing a taxpayer with international holdings.

MS. FITZPATRICK stated that the only costs that BP charges to Alaska operations are directly attributable to BP's operations in Alaska.

MR. HAJNY expressed his belief that Representative Guttenberg is referring to joint venture billings and said his point is well taken. He pointed out that Prudhoe Bay is a partnership field that is operated by BP and its partners, ConocoPhillips Alaska, Inc., ExxonMobil Corporation, and ChevronTexaco. He said that all parties are audited for those billings. He believes the concern of auditors is unfounded in that scenario because unacceptable costs would be revealed by other parties to the agreement.

REPRESENTATIVE GUTTENBERG clarified that he was not making accusations regarding billings; however, his concern is that circumstances at an international level may impact decisions made by the industry in Alaska.

The committee took an at-ease from [10:55:13 AM](#) to [11:19:37 AM](#).

CO-CHAIR GATTO reconvened the meeting.

[11:19:49 AM](#)

REPRESENTATIVE FAIRCLOUGH observed that international definitions of terms related to the oil industry may be different in Alaska than in Norway or Venezuela. She referred to the accounting definitions of the joint agreements and asked whether the chart of accounts is agreed to, along with the definitions of contributing costs. She asked, "Are [these] the same in each of those entities? So, that's question number one, on the accounting side."

MS. FITZPATRICK answered yes and asked Mr. Hajny to elaborate.

MR. HAJNY further explained that each joint venture partnership does have a specific chart of accounts that is used for billings; that was one advantage of using those as a starting point for audit purposes for each of the interest owners. After the joint interest billings are categorized and sent back to the partners, each of the interest owners will use those numbers in its own chart of accounts for booking and financial purposes. For the purposes of PPT, each company would have the same type of category or explanation for expenses. The same would be used for the joint partnership returns and for federal income tax purposes. The PPT allows companies to piggyback regarding whether an item is an expense or a capital cost. That procedure eliminates the question of whether the item should be an expense or a capital [cost]. He opined that, in general, a company or entity is looking to claim any of those expenditures as an expense on the federal income tax return. In addition, within Alaska, a taxpayer can receive a credit for a capital expense.

MR. HAJNY assured the committee that the partners have agreed to a very specific chart and accounting procedure to be used in the Prudhoe Bay Operating Unit.

[11:23:16 AM](#)

REPRESENTATIVE FAIRCLOUGH remarked:

...those charts of accounts feed into your corporate structure of chart accounts that might be different then?

MS. FITZPATRICK stated that the joint venture billing is set up to feed into what the tax requirements are; they differ around the world. For example, a particular expenditure, according to a joint operating agreement in Alaska, may be viewed as an expense or cost item. The same expense in another location may be viewed as a capital item under a contract. When these

differences must be grouped and reported in financial accounts, BP will revert to following international accounting standards and reconciliation will be made under the complete set of rules and procedures for expense versus capital under both sets of accounting regimes. Both accounting regimes are very similar and all reconciliations are made public.

[11:24:35 AM](#)

REPRESENTATIVE FAIRCLOUGH asked whether the state has requested a chart of accounts from BP and, if so, do the auditors have sufficient information in their possession in order to appropriately understand the costs reported under PPT.

MR. HAJNY answered:

... yes, we... sat down with them at the end of our filing for 2006 and explained how our 2006 PPT filing was developed and walked them through a mapping of how that tied to our federal income tax partnership returns, our tax trial balances and how each one of those specific categories of cost mapped into that.

He confirmed that the state auditors have been provided with copies of BP's joint operating agreements and accounting procedures.

REPRESENTATIVE FAIRCLOUGH acknowledged that all parties are in the first stages of an exchange of information under PPT. She expressed her understanding that all of the accounts and information inside of the agreements would be used for the audits, and said that she would ask the Administration her question.

MR. HAJNY stated that he and Representative Fairclough may just be using a little different terminology. The term "chart of accounts" may not be referred to within the partnership agreements; another term may be used.

[11:26:47 AM](#)

REPRESENTATIVE FAIRCLOUGH responded:

[I'm] just looking for the road map that guides us in capital expenditures and understanding that in different countries ... different categories of expenses could be classified differently and I want to

make sure that the state has the information that we're seeking.

Mr. Chairman, the final question is in regards to the replacement of reserve barrels that is shown on Alaskan assets. Ms. Fitzpatrick and I have discussed this a little bit so if I'm not clear to my questions for committee members or to those who might be listening, the idea is that companies have to disclose replacement barrels and in that disclosure, that helps to keep them healthy as far as those who invest in the organizations may look on as the Security Exchange [Commission] goes forward with different regulations. I'm fairly correct to that point?

MS. FITZPATRICK said she would come back to that point after Representative Fairclough finished her question.

REPRESENTATIVE FAIRCLOUGH continued:

My question to Pedro [Van Meurs] in that Legislative Budget and Audit hearing was, is there a reason why Alaskans' resources may be held in the ground because they can book so many more barrels of recoverable oil and are those standards and practices globally - the accounting standards and practices - recognized in the same way or is there advantage in the U.S. market that would make our barrels less attractive to move forward on to market because they can reserve them and hold them on their balance sheets in a different way as far as the market goes. I want to know if we have something somewhere that is advantageous for producers to hold the reserve barrels on their books instead of actually producing them. That's the bottom line and so I want to know how globally the U.S. accounting practices fit into those globals and if there's an advantage or disadvantage from BP's perspective.

[11:28:33 AM](#)

MS. FITZPATRICK replied in terms of whether reserves and a replacement ratio are metric and are an indicator of market interest, the answer is yes. The replacement ratio is based off proved reserves, which is defined by the SEC. The investment community is interested in proved reserves but is interested in other factors as well. The SEC has defined proved reserves very narrowly and a lot of debate has taken place with the SEC about

whether SEC definitions need to be updated. The SEC regulations were taken from the Society of Petroleum Engineers' (SPE) definitions in 1972. Technology has evolved since then so the SEC is looking into evolving its definitions as well. BP does not book certain things as proved reserves under the SEC rules because those rules do not allow that. However BP believes that some of those reserves are recoverable.

She explained that investors are interested in a few things. The first is the reserve replacement ratio and how fast those reserves are being developed and are becoming certain relative to the amount produced. That is an indicator of the progression to production. The investment community is interested in how much of a resource is present. BP believes the heavy oil is present but needs to figure out how to extract it with technology and how to extract it economically. She noted:

If I think \$100 oil is here forever, maybe I might think it's economic. Is that a risk I'm willing to take - entirely different question. So the industry is interested in - the investment community is interested in well, what are your resources. There isn't really a definitive published set of numbers that would meet resources. There's a lot of stuff around [indisc.] the Society of Petroleum Engineers. There's been some stuff around the United Nations framework, in terms of trying to get some international standards and, if you are interested, not in this committee, I'm very happy to arrange for someone to take you through the United Nations framework on how it maps to the SPE. There are various layers of complexity and definition behind that because ultimately what an investment bank is interested in is what is the cash flow generation likely to be and hence, what is also the gross capital - capital gross - in terms of share price.

Back to Representative Wilson's thought about assessing your risk profile for your own sort of retirement. That's what the investor is ultimately looking for - is what's my capital gross and what's my return [indisc.] to the dividends. The investment banks are then working out well what is the flow of resources around the pinning there and what is the risk attached to that. They model that quite extensively so the resource reserve replacement ratio

and the SEC definitions is a subset of what an investment bank is actually interested in.

[11:32:39 AM](#)

REPRESENTATIVE FAIRCLOUGH surmised then that the U.S. markets take a more conservative approach to the reserve barrels that BP is holding on U.S. records, because U.S. definitions are lagging behind world definitions.

MS. FITZPATRICK said that is correct but added that a significant portion of public oil companies are U.S. companies or foreign filers; all are required to follow the same SEC rules. BP's primary reporting is governed by international accounting standards. The board has not yet set its definitive rules on reserves disclosure so the SEC rules are used as the default.

MR. HAJNY added that it's appropriate to view what kind of reserves Alaska is looking at. He pointed out that DOR's forecast for production includes more than proven reserves. Many of the barrels forecasted, particularly in the long term, are not actually proven reserves.

[11:34:15 AM](#)

CO-CHAIR GATTO recalled Dr. Van Meur's testimony about "bookable" reserves, which no company can declare unless a reasonable certainty that reserves are likely to be developed exists. He asked if BP was predicting its "bookable" reserves based on a 3 percent decline and then shifted to a 6 percent decline, those "bookable" reserves would have to be removed from BP's inventory.

MS. FITZPATRICK explained the SEC definitions of proved or "bookable" reserves include the requirement that BP must evaluate whether those reserves are economic based on the Dec. 31 price each year. Therefore, a company can have a huge shift in its "bookable" reserves purely dependent on changes to the oil price in the world market on December 31. That price impact causes significant swings for many companies. When BP looks at its decline curve, it looks at what it can reasonably produce, its projects, and investment evaluations. That differs from a snapshot of reserves based on a single day's price.

[11:36:13 AM](#)

CO-CHAIR GATTO noted the committees have focused a lot of the discussion on investment and attaching that to reserves. He recalled a statement made earlier that if the costs are too high in Alaska, the [oil companies] would go elsewhere. He pointed out that would prevent oil companies from being able to declare those reserves. He stated:

So the feeling has been that if you have \$1 to invest in Alaska and it's going to get you \$1.50 in return, even if there's \$1.75 across the street, you'll actually do both. Isn't that likely? I mean you're not going to just move your investments somewhere else based on what kind of a tax deal you get.

MS. FITZPATRICK replied it comes back to a phrase she used earlier: scale and pace. When BP discusses booked reserves, the issue is which projects become marginal, in which case BP would wait for another advance in technology to make that project more economical. BP's discussion centers on making incremental projects more valuable. BP does not run its business on bookable or proved reserves; it is interested in the total resource base and how to pool that base through to production.

[11:38:33 AM](#)

REPRESENTATIVE ROSES surmised that the effect of taxation change will be long range since the [oil companies] have planned ahead for 2 to 8 years. An immediate impact could occur if the economics of a project changes and the "bookable" reserves could immediately change because that number is calculated annually.

MS. FITZPATRICK said the price at the end of the year can cause dramatic changes. She continued:

In terms of what impact would a change of fiscal policy have, I'm not thinking about that actually purely in the terms of my bookable reserves. It will have an impact because the point at which - if it's higher tax costs - the point at which I become not economic and, by the way, the definition of "not economic" for the SEC means that you no longer make 1 cent, just to be very clear. It is not around what is our profit margin. The definition of economic is you make 1 cent. If I'm down to making those investment decisions, I'm in a very different place.

So, the choice then around what's happening with the economic decisions and when would you see an impact? It will depend on what the impact on that investment decision is. Are there investments that I have already started? Yes. Might I change the pace of them? I might but please don't take that as a threat. The answer is I don't know yet but would I be revisiting to look and see what is the right pace? Do I want to slow it down? Do I want to absolutely keep exactly with what I'm doing? What about the next phase of investments? How economic are they looking? Do I have the next phase of sanctionable projects coming through?

MR. HAJNY added that as part of a tax organization, he is asked to look at all of the projects that come through and asked to provide assurance that the tax assumptions are accurate. While he can only make assumptions based on the current fiscal regime in place, he will be asked about the likelihood of that regime staying in place. Management will want to know whether many tax policy changes have occurred in the recent past to determine any additional risk that needs to be placed on a particular project.

[11:41:34 AM](#)

CO-CHAIR GATTO said Alaska had no [tax policy] changes for 10 years while oil prices increased substantially. He questioned whether Mr. Hajny would consider an environment with no tax changes over a 10 year period to be riskier than an environment that deliberated and made tax changes over two years.

MR. HAJNY said Co-Chair Gatto's point is well taken. He explained that prior to two years ago, the assurances he provided were reviewed [by management] with much less scrutiny than they are today and he is asked many more questions today than in the past.

CO-CHAIR GATTO asked if Alberta is keying off of Alaska. He suspected Mr. Hajny has his hands full when trying to determine where the tax structure will be stable over the next five years.

[11:43:35 AM](#)

REPRESENTATIVE FAIRCLOUGH said one of the reasons she brought up "bookable" reserves in Alaska is because of current production rates. She asked why, if oil is at \$90 a barrel, production hasn't been increased to monetize that resource at a higher

value. She questioned why more oil can't be put into a pipeline that advertisements say is two-thirds empty.

MS. FITZPATRICK said other things need to be taken into consideration. First, the reservoir must be managed appropriately so that if production is maximized now, the reservoir could be damaged and the supply won't be available later. Second, access to rigs to drill more wells to increase production might be limited and some rigs may have to be modified. Whether the costs are economic at \$90 per barrel, and how long that price is likely to last are also factors that are considered, among others. She noted even if the rigs and employees are available, the employees may have nowhere to sleep.

REPRESENTATIVE FAIRCLOUGH noted Ms. Fitzpatrick said costs lag by about a year.

MS. FITZPATRICK said they do but state whether rigs are available or will need to be built must be considered.

[11:46:47 AM](#)

MR. HAJNY made the following comments about substantive provisions within the legislation. He said:

[Slide 11] ...The bill changes the statute of limitations from three years to six years to audit taxpayers. Our concern is that an additional three years to audit the taxpayer would potentially subject us to another three years of interest calculated at the statutory rate of 11 percent on the findings, regardless of intent of the taxpayers. BP has traditionally been very accommodating to the audit staff and granted extensions to allow time for all of the audits to be performed and clear up any misunderstandings on the audit issues as they arise. One of the concerns is that with the potential for this increase, these audits could extend on for seven, eight, nine years, potentially if we granted these extensions.

The question, I guess, I would ask from a policy standpoint is might producers be less inclined to grant these extensions if we continually are subjected to the 11 percent interest rate because, from our standpoint of view, that is a significant hindrance

wanting to continue and stretch out audits and include costs that should not be deductible there.

Moving on to the issue around sharing of confidential  
....

[11:48:22 AM](#)

REPRESENTATIVE SEATON interjected that a concern about the statute of limitations was expressed earlier, that being that overdue reports would be fined on a daily basis so that extending the timeframe to six years is too long a duration for that type of fine. He asked if BP would feel more comfortable if the bill specifies that after a certain time period, perhaps 60 days, the \$1,000 fine would kick in so that a company would have 60 days to comply without being fined.

MR. HAJNY replied the \$1,000 daily penalty is related to a provision to provide information. He felt Representative Seaton's idea is a good suggestion; however, he still believes the \$1,000 a day penalty is excessive. One of BP's concerns is that an auditor could come in years down the line and say BP did not provide information that was requested six or seven years earlier, therefore a retroactive penalty of \$1,000 per day from that time period could be imposed.

REPRESENTATIVE SEATON surmised that changing that provision so that imposing a fine for failure to report would come after notice was given and adequate time for a response was provided.

MR. HAJNY said that would help but he is still concerned that six years later, if BP didn't provide requested information because it submitted 19 of 20 requested items and felt the 20<sup>th</sup> item was answered by previously submitted information, the auditor could determine that information was inadequate. He said a legitimate oversight could also occur.

[11:52:07 AM](#)

CO-CHAIR GATTO noted when collecting taxes, legitimate oversights and intent are rarely important. The most important factor is how much is owed. He said when an audit shows that an item was misreported and more tax is owed when the correct number is inserted, the penalty is 11 percent annually. He said if a company is getting an annual return of 35 percent, accruing a penalty would be economically advantageous. He said 11 percent does not seem outlandish because if the penalty was 2

percent, a company would more likely pick the more advantageous number. He felt it is the state's desire to encourage accurate numbers so that penalties do not have to be imposed. He repeated he does not believe 11 percent is too high and mentioned the IRS imposes a penalty plus interest.

CO-CHAIR GATTO said regarding the example Mr. Hajny described with a company responding to 19 of 20 items, the company would enclose a document describing where the data that responds to item 20 can be found. Absent a response from the state, the company would have a case against it if the state wanted to impose the \$1,000 fine six years later. He said that kind of a fine is not unreasonable when a company decides it is unwilling to reveal certain data but does not communicate its decision. He asked Mr. Hajny if he disagrees with charging interest as a penalty.

MR. HAJNY said through the period of audits, legitimate issues have come up. They are usually differences in the interpretation of a law or regulation. They are legitimate in that they are areas that need further clarification. In the end, the parties might resolve how to file in the future. If BP agrees that it owes tax on that particular item, it will pay a minimum of 11 percent. As BP goes through the audit process several years down the road, that interest has the potential to cost more than the original item. His management would scrutinize that situation thoroughly, which would be significant incentive to file to the best of his ability and to "be on the button" about the amount owed.

CO-CHAIR GATTO asked Mr. Hajny if he would like Mr. Iversen to address the committee.

MR. HAJNY said that would be fine.

[11:58:05 AM](#)

JOHN IVERSEN, Director, Tax Division, Department of Revenue, Juneau, Alaska, provided the following comments:

First off, in regard to the statute of limitations issue, this is - you know we can come at this in a couple of different ways. We are dealing with, from an administrative standpoint, a whole other batch of costs that we haven't been dealing with in the past. We've been looking at downstream costs. Historically now we're looking at upstream costs as well. In

addition, we're also now going to be taking advantage of looking at joint interest billings and joint interest audits between the working interest owners in a unit and the operator. The working interest owners would do an audit on the operator's billings to them. Those take time - years. And then, after that there are going to be some audit issues that are contested that may remain unresolved for years. Meanwhile the clock is ticking on our statute of limitations. If it takes three years for an audit to be completed and then we've got remaining issues that were contested, hanging out there, we're bumping up against that six year deadline even at that potentially - at least the three year deadline.

CO-CHAIR GATTO asked if the clock stops the moment a challenge is made or if it continues until the six years is up.

MR. IVERSEN said the clock starts when a return is filed and resets when an amended return is filed. He gave an example of a clock starting for 2006 returns when filed in late March or early April. If that return is amended due to a federal partnership return, that would be filed in the fall [October]. If the company had to file an amended return [with the state], the clock would start over. That clock would run until the taxpayer waived time for logistical reasons. That does happen often in a cooperative arrangement between the parties because the state is trying to get the information it needs to finish the audit. It is to the taxpayer's advantage to submit the information so that the auditor does not have to guess. If DOR runs out of time and no waiver is granted, the state has two choices: to do no assessment or do a jeopardy assessment. The six year statute of limitations would prevent unnecessary disagreement and push back on timing. The clock ticks until DOR makes its assessment so that it has three years from the time the return is filed to make the assessment, which is the written statement from DOR of the tax due. He pointed out DOR is up to speed on its audits. It has not started any comprehensive audits of 2006 returns under PPT but historically there has not been a big time lag.

[12:03:11 PM](#)

MS. FITZPATRICK said BP doesn't oppose the six-year extension per se. BP is concerned that an adequate process be designed so that misunderstandings don't occur. BP is also concerned that when an audit is finished, if regulations are written during

that time, it does not want to incur a penalty for a good faith filing for a regulation written subsequently.

[12:04:28 PM](#)

CO-CHAIR GATTO asked if a penalty is imposed for failure to report or for reporting inaccurately or whether only interest is charged.

[12:04:33 PM](#)

MR. IVERSEN said [the bill] contains an additional penalty portion. There is an important distinction between the penalties under ACES and the penalties currently in statute. The penalties under ACES are up to \$1,000 per day. The penalties under current law are based on a percentage of a deficiency so if the information is not provided but there is no deficiency or an underpayment or failure to file a return, there is no penalty. That leaves the information request without an explicit penalty so if a company does not willingly supply the requested information, DOR needs to get a subpoena to get it. Under current law, penalties are based on an underpayment or failure to file. Those penalties start at 5 percent per 30 day period or a fraction of that up to 25 percent. A negligence penalty of an additional 5 percent can also be assessed if the failure to pay is due to negligence. A fraud penalty of the greater of \$500 or 50 percent of the unpaid amount can be imposed on top of the others.

[12:06:11 PM](#)

CO-CHAIR JOHNSON suggested modifying the bill to say "from the time of request." The clock would start ticking if that information is not provided within 30 days of the request.

MR. HAJNY told members that tax filers need a sufficient amount of time to gather information and 30 or 60 days may not be enough time. He acknowledged the devil is in the details; the bill needs sufficient language to ensure the taxpayer is notified of the exact information requested and the penalty date and amount.

[12:09:06 PM](#)

CO-CHAIR JOHNSON asked if the deadline was 120 days after the request was made, the fine should be higher and, if it was six months, even higher so that the hammer falls harder with more

time. The details need to enable DOR to get the information and provide a hammer to impose that penalty.

MR. HAJNY said ultimately, DOR already has a hammer through subpoena powers so BP believes DOR has the ability to get the information it needs now.

[12:11:40 PM](#)

CO-CHAIR JOHNSON said as a legislator, he has tried to commit to not introducing legislation based on snapshots or legislation that will end up in court. He said if he was to amend the bill using a subpoena as the hammer, he would be ignoring his fiduciary responsibilities to the citizens of Alaska. He thought the Legislature should create clear lines and try to stay away from subpoenas or legislation that will require a judge to determine the outcome. He said he is leaning toward a longer time period and a heavier fine.

MR. HAJNY said he doesn't expect to ever encounter that provision in the bill but it may be necessary to address issues that are unforeseeable at this time. BP will provide any requested information to the best of its ability within certain boundaries surrounding its legal entities and partnerships.

[12:13:32 PM](#)

CO-CHAIR GATTO asked Mr. Iversen if the timely response issue could be addressed in regulation.

MR. IVERSEN told members he thought the details would have to be fleshed out in regulations. He clarified that the penalty can be up to \$1,000 per day. If DOR is excessive and unreasonable, taxpayers can use a three tiered appeal process. If DOR is found to be unreasonable, the penalties will be abated. He said he believes that because the subpoena power is a ticket to a court battle, it is rarely used.

[12:15:28 PM](#)

REPRESENTATIVE GUTTENBERG asked how aggressive the industry as a whole has been in standing up against DOR and how often a case goes to court.

MR. IVERSEN said that boils down to the respective responsibilities of both parties. The oil companies' responsibility is to their shareholders. DOR's responsibility

is to the citizens of Alaska. That relationship often results in audit disagreements. Generally an audit will turn up miscalculations or claims that fall in a grey area. Those disputes are often resolved through the informal conference process and the additional tax is either paid or DOR backs off. Many cases go to the Office of Administrative Hearings where they are decided by an administrative law judge. Some cases go to superior court but not often. The cost for these cases increases dramatically with each step so returns diminish the farther a case proceeds. Once a decision is reached at the Office of Administrative Hearings, the result becomes public. Taxpayers are uncomfortable divulging certain information to the public and there are incentives to settle along the way. Any settlement must be approved by the Department of Law, as well as DOR, by statute.

[12:18:42 PM](#)

REPRESENTATIVE EDGMON asked if this discussion is directed toward the added complexities caused by the enactment of the PPT so is forward looking.

CO-CHAIR GATTO said the discussion started with the extension from 3 to 6 years and then moved to penalties so the committee is discussing new provisions in the bill.

REPRESENTATIVE EDGMON asked if the backdrop is the new tax regime.

[12:19:26 PM](#)

MR. IVERSEN said he was framing his comments by contrasting the ACES \$1,000 per day fine with the current penalties. The litigation and conflicts refer equally to past and anticipated cases.

[12:20:08 PM](#)

CO-CHAIR GATTO asked if ACES will require more auditors because of increased reporting and auditing.

MR. IVERSEN replied affirmatively.

[12:20:36 PM](#)

REPRESENTATIVE GUTTENBERG stated part of the dialog has revolved around a net and gross tax. A net tax would require more

auditors because of the need to look at operational and capital costs. He asked Mr. Iversen if he has done an analysis on the tax division's different needs under a gross versus net tax.

MR. IVERSEN replied the distinction, from an audit perspective of gross versus net, must be framed in terms of what kind of gross tax is imposed. Incentives to any gross tax add incremental layers of complexity.

[12:22:22 PM](#)

MR. HAJNY commented he fully understands the need for DOR to acquire information and is willing to engage in discussions about how to provide that information. However, it is important to be very careful about forward looking statements, legal procedures that must be followed and disclaimers in respect to them. BP believes certain precautions should be established statutorily to control and limit access to forward looking information. BP appreciates that DNR and DOR need to be fully aware of the legal necessity of appropriate access controls so that allowing access to confidential and sensitive information by DNR staff who are directly involved in taking state royalty in-kind and know to whom it is to be sold and the price would not be a regular occurrence.

[12:23:38 PM](#)

CO-CHAIR JOHNSON said he is very concerned about confidentiality and understands the state will be a competitor at some point. He said he was assured by the Administration that its standards and measures will be adequate. He asked if BP agrees.

MS. FITZPATRICK said she is not sure she can answer that question because she does not know what the access controls are. She said if the need for access controls is recognized, she may have to go forward in good faith. Access controls are not unusual; BP has them and she has worked for other organizations that have them as well. She believes access controls are entirely manageable.

CO-CHAIR JOHNSON commented he believes DOR has said that confidentiality access controls are already in place and that everyone in the department has signed a confidentiality agreement. He asked whether any breaches of confidentiality have occurred.

MR. HAJNY said BP's view is that its confidential taxpayer information has been breached on more than one occasion. Whether intentional or not, that demonstrates BP's concern with providing confidential taxpayer information and who it is shared with. Creating certain guidelines to ensure that does not occur in the future is very important to BP.

[12:26:17 PM](#)

CO-CHAIR JOHNSON said it is equally important to him and that it is incumbent upon the state to protect confidential information it is given so that companies do not have to decide whether or not to hand over certain information because of the fear of a breach of confidentiality.

[12:27:12 PM](#)

REPRESENTATIVE SEATON said he shares the same concern but the problem of confidentiality of tax information can't be cured in this legislation for one industry; access to all confidential tax information for all industries needs to be addressed.

[12:28:08 PM](#)

CO-CHAIR JOHNSON agreed, but said the Legislature has to start somewhere.

[12:28:20 PM](#)

REPRESENTATIVE ROSES asked what remedies exist for companies when they feel a breach of confidentiality has occurred.

MR. HAJNY replied the reality is that the processes in place would make it difficult to acknowledge the specific breach. The first problem is that BP would be acknowledging specific information put in the public domain. In addition, BP would have to pinpoint where the breach occurred and whether it was intentional. He said the remedies for that problem have not been adequate in the past to sufficiently protect BP's confidential taxpayer information.

[12:29:44 PM](#)

REPRESENTATIVE ROSES said this legislation has been touted for its fairness; therefore a company and the state should be equally penalized for breaches of confidentiality. He said he

will look into placing tougher sanctions on the state for breaches.

[12:30:49 PM](#)

CO-CHAIR GATTO asked when BP has discovered a breach, has it been able to verify the breach didn't occur within BP or whether a finger is automatically pointed at the [state employee] who might have breached the information.

MS. FITZPATRICK said BP would first assume the problem occurred within the company. A review of internal processes and controls would take place. She did not want to discuss specifics, but said BP has had concerns [about state confidentiality] and believes the issue is important and that access and confidentiality can be managed.

[12:32:21 PM](#)

REPRESENTATIVE GUTTENBERG maintained that both sides have legitimate concerns. He said whistle blowing on the job is often encouraged in the industry for the sake of safety. He felt having a whistle blowing process in place and providing an avenue of protection should be considered and addressed. He pointed out that up until this point, the discussion has centered on leaking trade secrets but inappropriate activities are occurring in all industries.

[12:35:25 PM](#)

REPRESENTATIVE WILSON commented that whether intentional or not, a breach of confidentiality should never occur so severe consequences should be created to act as a deterrent.

[12:36:13 PM](#)

MR. HAJNY continued his presentation:

[Slide 12] Speaking a little bit about the lease expenditure aspect of PPT and HB 2001 - from a tax policy perspective, the determination of whether a tax is performing we think should be judged on its merits and facts. Allow the process to work. Perform some audits and report a complete set of facts and findings. The tax policy should be based on facts. If, after doing some audits of the returns, there is a compliance problem, it should be reported to you for consideration and correction.

The proposed bill asks you to set tax policy without a full finding of these facts. This appears premature to me.

We've clearly stated and are committed to cooperating with the DOR to explain and provide the information to help them understand our joint venture accounting processes and these JV processes are an excellent standard for qualified lease expenditures for PPT deductions. There's a lot of work that's gone between the industry and the Legislature and the Administration to design this system of how taxpayers will comply with the PPT. But we are very troubled that the current bill would repeal DOR's explicit statutory authority under [AS]43.55.165(c) and (d) to require or authorize the use of operators' joint venture billings as the starting point for determining deductible lease expenditures...

CO-CHAIR GATTO asked for the title of the referenced statute.

MR. HANJY answered the section is named Deductible Lease Expenditures. He continued his testimony, as follows:

...for that unit or field. Why would the Administration take away the authority to use these billings unless they intend to disallow them in future regulations? It's a little puzzling to us there.

CO-CHAIR GATTO asked if Mr. Hanjy is saying that section is in ACES.

MR. HANJY clarified that AS 43.55.165(c) and (d) have been removed, which allows DOR to use the joint venture billings as the starting point.

CO-CHAIR GATTO asked whether that deletion was made in ACES or by the previous committee.

MR. HANJY told members that section was deleted in SB 2001 and HB 2001 but it is currently in both versions of the committee substitutes.

CO-CHAIR GATTO asked Mr. Hanjy if BP wants that section deleted.

MR. HANJY said BP wants those provisions put back in the bill. He noted the current provisions within PPT are sufficient.

12:39:42 PM

REPRESENTATIVE ROSES asked Mr. Hanjy to discuss advisory bulletins noticed on the previous page.

MR. HAJNY said he used the categories originally used by the Administration as the specific provisions within the bill. From an administrative standpoint, BP is fully supportive of posting advisory bulletins. He understands the purpose of posting the bulletins is to potentially prevent future conflicts.

REPRESENTATIVE ROSES asked Mr. Hanjy if he thinks the advisory bulletins could be used to trigger the beginning of a limitation or look-back in terms of penalties.

MR. HAJNY said he wouldn't know how DOR could use those bulletins to calculate interest. It would be a concern, but BP has been more concerned about being able to obtain affirmative decisions on specific questions asked about the interpretation of a current bill. Any information that provides clarity is a positive step.

12:41:48 PM

CO-CHAIR GATTO asked Mr. Iversen to comment on that topic the next time he addresses the committee.

MS. FITZPATRICK informed members that other agencies post bulletins. The SEC posts bulletins when asked how [a rule] actually applies to let people know. She requested that DOR post the bulletins in a place that is easy to find.

12:42:45 PM

MR. HAJNY said BP believes it has filed a compliant 2006 PPT return and followed the laws and regulations when making its 2007 estimated payments. Specific areas need to be addressed under the regulations; BP encourages the Administration to complete Phase 2 of those regulations. BP understands the principles behind PPT and the joint venture billings to define lease expenditures. He said expenditures such as advertising, lobbying, tax planning and charitable contributions have not been included in BP's current filings. The PPT requires deductible lease expenditures to be direct and ordinary and necessary costs of oil and gas for exploration, development, production. The IRS defines the words "ordinary and necessary"

in the same way. He noted the PPT relies upon the federal definition of "capital" and "expense." BP believes that is an asset to the PPT.

[12:44:00 PM](#)

REPRESENTATIVE ROSES asked Mr. Hanjy to repeat the list of items that are not deductible.

[12:44:12 PM](#)

MR. HAJNY said he cited the following examples: advertising, lobbying, tax planning and charitable contributions.

[12:44:28 PM](#)

MS. FITZPATRICK clarified those items were given as examples and do not represent the exhaustive list.

[12:44:36 PM](#)

REPRESENTATIVE SEATON noted a provision in PPT says if the joint venture partners reject a bill that would be reason for the state to reject the deduction as a lease expenditure. He questioned whether that section will be changed by ACES or the committee substitute.

[12:45:18 PM](#)

MR. HAJNY affirmed that is a concern of BP's because if joint venture billings are used as a basis for allowable costs, they should also be the basis in the other directions - which costs are allowed and which are disallowed. BP has filed with the understanding that as Phase 2 of the regulations are implemented, the joint venture billings would be used as a basis for first looking at what the partners allowed or disallowed. That would provide a first cut at whether or not to include those costs. Within that, 18 items are specifically excluded so that just because a partner paid its share of an excluded item, that item could not be included in the filing.

[12:46:35 PM](#)

REPRESENTATIVE SEATON referred to the recent leak on the North Slope and the need to replace pipe, and asked if that billing has gone to the partners in the joint venture and whether the billing was accepted or rejected by them.

12:47:02 PM

MS. FITZPATRICK replied BP has not yet included any deductions in its PPT filings.

12:47:15 PM

REPRESENTATIVE WILSON asked what is to prevent the partners from getting together and planning what to deduct.

12:48:02 PM

MS. FITZPATRICK replied that would not happen for several reasons: legal requirements, such as the controls required under the Sarbanes-Oxley Act; BP's code of conduct on how employees conduct business - avoiding an appropriate tax rule would not be condoned; and partners are very tough on each other and none of them want to pay the other.

12:49:17 PM

MR. HAJNY informed members the bill goes to the extreme by allowing lease expenditures to be determined by regulation. Taxpayers will not know whether they are filing a compliant return because regulations can change with the stroke of a pen. The taxpayer will have no stability under this approach and the Legislature could only react to changes after regulations had been promulgated.

12:50:05 PM

MR. HAJNY commented on the costs for unscheduled interruptions:

The exclusion of costs for unscheduled interruptions of production feature is not a provision that is, in our opinion, able to be administered. It will create uncertainty and an area of constant debate and dispute in the future. It was thoroughly discussed last year and in the spring, and verified this year by Dr. Van Meurs and Dan Dickinson that the 30 cents a barrel exclusion was put in place to simplify and cover the costs associated with costs that the state did not want to be deducted due to maintenance costs.

12:50:50 PM

CO-CHAIR GATTO asked if the Legislature should increase that amount to 50 cents to take care of some of the unscheduled costs.

12:51:00 PM

MS. FITZPATRICK jested she can only answer that one way - no. She elaborated the difficulty of working out what an "unscheduled interruption" is. She said some unscheduled interruptions are assumed to occur in a large facility because of the amount of machinery involved. Sometimes the interruption can be an extension of a planned event. She told members:

...You go in and you're doing some planned work and you're like well, I could sort this now or I can come back and do it another time. It might be better to say actually no, let's extend this and plan for the future and do something now as a good investment for the future rather than saying no, I won't do it now, I'll come back and do it later. That's what we're meaning by unintended consequences. I think it would be very, very difficult to administer. As Bernard said, the conversation last time, I believe, went round this and it was the 30 cents - I have no idea if it's the right or the wrong number but that was viewed as a manageable way to do it.

12:52:57 PM

CO-CHAIR GATTO said the words "unanticipated interruption" literally jumped off the page at him. He stated:

If I said gee, if I were at the oil company and I had an unanticipated shutdown...[or] interruption, then I would say rather than have an unscheduled interruption tomorrow at 2:00, I think I'll just schedule one today for tomorrow at 2:00 and now it's a scheduled interruption and we've done away with the difficulty.

The other term was "unanticipated" to substitute for "unscheduled." I said I wonder if that's the intent of the person who put this in the bill really meant. Either way, I was tending to think like you did. It's complex and, for instance, Alaska Airlines tickets I was looking at this morning, it said on-time rate - 40 percent outbound, 50 percent inbound. I said that's pretty terrible. Are those scheduled? Apparently, at

least they're telling us that's their record. So, is there a better way? Rather than striking the terms, is there a better substitute because I think you know the intent of saying when we lose revenue as a basis of somebody's unscheduled something that happened anyway and we think you are smart enough to have known this would have happened, should we take the loss or should we say we're going to disallow that as an expense? That's where we're going on that one.

[12:54:43 PM](#)

MR. HAJNY said Dr. Van Meurs came up with the 30 cents per barrel solution because he recognized that getting language around that would be very difficult. He believed the 30 cents would cover the state in those areas for a period of time. He submitted that over a period of time, there will be many times when no unanticipated events occur but the 30 cents will still be excluded from costs.

[12:55:32 PM](#)

REPRESENTATIVE SEATON said this issue revolves around the subject of the [recent] spill and the replacement of the line on the North Slope, as well as trying to prevent that future conduct. BP has pleaded to criminal negligence in that situation. He referred to Section 6 of the bill before members and said language was added to Section 6 that says, violation of law or failure to comply with obligations under the lease, permit or license.

The Legislature wrestled with SB 80 and the definition of "improper maintenance" and how that could have a huge effect on the industry. Now the Legislature is wrestling with the term "unscheduled interruption," which could also have a huge ripple effect. Obviously the Legislature is dealing with the subject and the bill is moving forward. Members are trying to figure out how to work this into the bill so that it has the least amount of detrimental effect on future operations. He said so far three suggestions have been made: increase the 30 cent deduction and clarify Section 6 and Section 19. He asked if BP has any suggestions on how to cover this issue with the fewest ripple effects and unintended consequences.

[12:58:17 PM](#)

MS. FITZPATRICK said she does not have a suggestion. BP has said it will follow the tax law when it files its PPT returns. Whenever BP files a tax return, it consults with its legal advisors about compliance with the law.

[12:58:58 PM](#)

REPRESENTATIVE SEATON asked:

If, on Section 6 - that's on page 26 of L version, we would have violation of law, criminal negligence, or failure to follow lease and then that would cover the events on the North Slope last year that was that interrupted service and all. If we would do that, do you see any necessity or benefit for having Section 19 and its uninterrupted consequences and duties to ... the standard of care and those kinds of things. Do you see any benefit to having Section 19 in there if we would include criminal negligence under Section 6?

[1:00:00 PM](#)

MR. HAJNY responded if the intent of that language is to prevent those types of costs, he would see no need for Section 19. In addition, he would see no need for the 30 cents per barrel exclusion that also covers the costs the state does not want to share in.

[1:00:36 PM](#)

REPRESENTATIVE GUTTENBERG said from his perspective, this issue is one of stability. Legislators are trying to determine the best position and course of action to take. The state's and industry's planned development on the North Slope is to increase, or at least maintain, production. He said it is important that the Legislature and public know the oil companies are doing the [maintenance] that needs to be done or, if they have made an economic decision to cut maintenance costs and that backfires, damages will be paid. He repeated this issue is very important to the public and they are putting pressure on legislators to address it.

[1:03:50 PM](#)

CO-CHAIR GATTO asked Mr. Hajny to conclude his presentation.

[1:04:12 PM](#)

MR. HAJNY told members:

The issue around the topping plant or diesel plant exclusion on the North Slope - the exclusion of the costs for building or operating the crude oil topping plant that provides diesel for field operations is a peculiar tax policy call in our opinion. It would disallow costs for building and operating plants that would provide ultra-low sulfur diesel fuel to the North Slope operations and potentially villages. While "incentivizing" operators to import diesel at a much higher cost of supply while having 50 to 80 trucks on the Haul Road - and that's according to the Conoco testimony that they provided - every day, the potential safety and environmental hazards, hazardous concerns of this policy are troublesome to us.

[1:05:06 PM](#)

CO-CHAIR GATTO pointed out that Representative Seaton has looked into ways to provide economic advantages.

[1:05:21 PM](#)

REPRESENTATIVE SEATON said the existing diesel topping plant was built [on the North Slope] without tax deductions or credits, so nothing would prevent another ultra-low sulfur diesel plant from being built. The question is whether the Legislature is going to allow a tax subsidy for that in opposition to other refineries in the state. If the state does allow the subsidy under PPT or ACES, it will not only be giving a capex deduction and opex, it will also forego any royalty paid on whatever is used in the plant. He explained if it is in an existing or other constructed off a leasehold site, the state will receive the royalty on the oil. The Legislature is looking at this issue from a subsidy standpoint rather than from the standpoint of preventing a plant from being built on the North Slope. He asked if BP has the same perspective on that issue.

[1:06:59 PM](#)

MS. FITZPATRICK said BP would consider whether the project is economic versus other projects. An unintended consequence from an environmental and safety perspective is the number of trucks traveling the Haul Road with diesel and the associated risks.

[1:07:52 PM](#)

MR. HAJNY told members the last new exclusion in the current version of the bill applies to DR&R costs. That exclusion creates a significant amount of issues in the future. He gave the following illustration. An operator decides to shut down two gathering facilities in the future to build a more efficient, centrally located facility but that facility will not directly replace one of the original structures. Under the current bill, the cost of dismantling and removing the existing facilities would not be deductible. He asked members to consider that policy call.

[1:08:52 PM](#)

REPRESENTATIVE GUTTENBERG said he thought BP had been taking DR&R deductions for a long time. Monies for DR&R have been put aside for just that purpose. He asked if BP is asking for additional credits to dismantle a facility.

CO-CHAIR GATTO added the state has collected 5 cents per barrel for TAPS DR&R. He was unsure whether any money had ever been collected for the gathering lines.

REPRESENTATIVE GUTTENBERG said the 5 cent per barrel charge is for a different fund, not the DR&R fund.

[1:09:45 PM](#)

MS. FITZPATRICK said when differentiating TAPS from the North Slope, she was not sure what BP has collected regarding DR&R, but BP is looking at, when assessing projects, the current and future infrastructure. In the aforementioned scenario, BP could choose to maintain two power plants but they are using 30 year old technology. BP could also dismantle them and build a new plant using new technology. The new plant would be more efficient and would benefit BP, as well as other new entrants. The economics of that decision will be dependent on whether the DR&R provision remains excluded.

[1:10:55 PM](#)

REPRESENTATIVE ROSES asked if under the current PPT bill, BP would get an exclusion for the DR&R, and capital credits and deductions for building the new plant.

[1:11:12 PM](#)

MR. HAJNY clarified that under the current version of PPT, certain calculations apply to deductions for any dismantlement, replacement and removal of items put into service prior to April 1, 2006, depending on how much was invested before and after that date. He verified BP would get a portion of that and a deduction and potential credit if putting in the new item is a capital cost.

[1:12:10 PM](#)

REPRESENTATIVE ROSES asked if BP would expect operating costs to decrease with one plant, rather than two; therefore operating costs would be lower, deductions would be lower and state revenue would be higher.

[1:12:22 PM](#)

MS. FITZPATRICK said that would be the objective. When assessing a project, she would look at cost efficiencies. She said, in regard to the power plant, if the cost is lower, the deduction would be lower. The lower cost would also benefit others accessing that power.

[1:13:02 PM](#)

REPRESENTATIVE ROSES said he would like more information on that topping plant, specifically at what level of deduction the gallons of diesel fuel would be deducted as an expense. If the state is subsidizing the plant, it should not be giving a full deduction for the full dollar value of each gallon because the price would be lower if no royalties or taxes are paid.

[1:14:02 PM](#)

MS. FITZPATRICK agreed to provide the specifics. She said her initial understanding is that it wouldn't be both.

[1:14:16 PM](#)

MR. HAJNY continued:

Many of you remember there was a considerable amount of debate surrounding the transitional investment expenditures, or TIE credits, during the previous debate on PPT. After much consideration, the Legislature modified the tax credits by requiring a

TIE and tying the credit to our future spend. A producer must spend \$2 in the future to receive a credit of \$1 spent in the prior years. Keep in mind that there's a fixed amount of credits available for each company under the current TIE credits. It's just a matter of how fast a company is eligible to take them and whether they invest the money over the first seven years of the PPT to be able to take the eligible credit. Remember that these particular credits would expire in 2013. The Administration has stated that the amount of TIE credits that were taken last year in the filings was approximately \$114 million by the industry. They were surprised by that level of credit. The question that I had is isn't this exactly what the credits were intended to do?

1:15:25 PM

In the same line around credits, the current version of HB 2001 and SB 2001 changes the 20 percent capital credit and spreads it over a two-year period, causing additional administrative burdens and complexity for both the taxpayer and the Department of Revenue that is not needed. As Mr. Van Meurs noted, it reduces the incentive targeted by the credit but still costs the state the same amount of money in the end, with the exception of what we would consider a tax increase in the very first year because there's no period of time to capture that credit in the first year of the implementation. So, in our opinion, it just reduces the overall economic impact to any project that will be considered in the future.

1:16:30 PM

MS. FITZPATRICK summarized by telling members 70 percent of the next 20 years' production is currently forecast from Prudhoe and Kuparuk. Tax increases will create an economic change, as well as the current committee substitute, which changes gross progressivity. That will not provide flexibility for future changes, whereas a net tax would be self adjusting. She cautioned:

By that I mean we're in an unprecedented world at the moment of \$90. If that stays, and costs then catch up, there may well be opportunities that today I wouldn't be thinking were robust price tags to look

at, which could well be in the higher ends there. But if costs are caught up with that and I'm in a gross progressivity, which is kicking in a lower rate, that might, in fact, have the counterintuitive impact of impacting investment decisions at a time when you would think I should be actually encouraged to do more. So that is something that I would encourage you to think about in terms of is going to a gross progressivity in these environments actually going to give you the flexibility to encourage the investment at the higher ends if that's in fact where we end up **re-equilibrating** at.

Key messages - I'm not going to read the slide to you. You're all perfectly able to read the slide. It's about what's the policy you want to put in place. It's about investment. Ladies and gentlemen of the committee, you all understand that and I appreciate your balance is trying to decide how to get the right answer for Alaska's economic future. I'd like to thank you for your time and your questions. I have a list of about 4 or 5 things which I've taken, which were specific requests that we will do our best to get back to you as soon as possible and, hopefully if you have follow-ups, we're very happy to take them.

[1:18:32 PM](#)

CO-CHAIR GATTO said it is interesting to see the word "uncertainty" bolded. He said certainty and predictability are terms given to the Legislature by the previous Administration. He ascertained the state wants the same things.

[1:19:00 PM](#)

MS. FITZPATRICK said all one can do is try to manage uncertainty; eliminating uncertainty is unlikely. When making investment decisions, she tries to balance many uncertainties.

CO-CHAIR GATTO thanked Ms. Fitzpatrick and Mr. Hajny for discussing BP's concerns with the committee. He pointed out the word "partnership" is very valuable to legislators; they want to have a partnership with BP, not a confrontational relationship. Both parties have done a fair amount of work to create a partnership and trading information has helped that partnership.

[1:20:27 PM](#)

CO-CHAIR GATTO announced that the committee would recess until 2:00 p.m.

2:17:37 PM

CO-CHAIR GATTO reconvened the House Resources Standing Committee meeting and asked Mr. Mitchell and Mr. Taylor of ConocoPhillips to present to the committee.

2:17:53 PM

KEVIN MITCHELL, Vice President of Finance and Administration for ConocoPhillips Alaska, Inc., began his presentation, as follows:

... With me today is Jim Taylor, who is Vice President of Commercial assets for ConocoPhillips here in Alaska. What we'd like to do today is take you through a little bit of ConocoPhillips' overview. We'll touch on that a little bit to set the stage and give some comments on our perspectives on PPT and how we see PPT performing.

We'll then go on to talk a little bit about what we see the future resource potential being and being on the North Slope of Alaska for our industry and transition that into how we see the tax structure as being integral to how the North Slope development will play out in the coming years. And then we'll get specific on certain areas of the bill that we want to comment on. So with that, what I'd like to do to start with is just give you a little bit of overview of ConocoPhillips in Alaska.

2:19:08 PM

Pretty much by whatever way you look at ConocoPhillips in this state, we come out as the number one - in the number one position whether it's on a production means - we're responsible for some 35 to 40 percent of the state's oil production. We're not too far behind that percentage on a gas basis with our Cook Inlet operations. We're the largest lease holder in the state with an interest in some 2.6 million undeveloped acres outside of the existing developed acreage. We've been actively involved in exploration over the years. As you look at all of the key components of

the industry here in Alaska, whether that's the original Legacy fields of Prudhoe Bay and Kuparuk, the development in the western North Slope, that's Alpine and the satellites there, the Cook Inlet developments and the exploration, we've been actively involved in all of those sectors of the business here in Alaska.

Alaska has been very important to us. We've been here for some 50 years or so. It will continue to be very important to us and we look forward to a long and continuing relationship with the state as we look ahead.

[2:20:44 PM](#)

MR. MITCHELL continued:

So, as we move on - just to give some summary comments. First point here is we really believe there needs to be alignment between the industry and the state. What is good for the industry is good for the state. When the industry is having hard times, the state is in hard times as well. There's been a lot of talk over the last several days about the economics of projects and when a project is economic or what makes it not economic. The reality is we want economic projects because that delivers a return to us and to our shareholders, but the same applies to the state because an economic project by definition means it's a project that's going to be generating tax and royalty revenues that go back to the state. So, in that regard, there really is a common alignment as we look at that.

We do think that with the PPT legislation just being enacted last year, it's very soon to do any kind of fundamental change to that legislation. It's unsettling from an investor perspective to have that degree of tax changes on such a frequent basis and we'll talk a little bit about that.

Generally speaking, tax changes will have an impact on the investment climate and we'll spend some time, as I said, talking about the future resource potential and how the fiscal structure can have an impact there.

[2:23:08 PM](#)

MR. MITCHELL continued:

We can't get away from the fact that when the tax take increases, the investment climate looks less attractive and then the frequency of tax changes also adds a kind of stability question mark around that.

And then the last comment is that there are several - I'll call them administrative provisions in this bill and we just want to make sure that they all get the appropriate thought and consideration that they deserve before any of that becomes law, not to say that we don't necessarily agree with the intent of what's behind a lot of those but want to make sure to get the right consideration as we go through this process.

Just to go through a little bit of background, what this - the chart on this slide [Slide 4] represents the production tax revenue forecast. The first bar, the short bar that goes up to almost the \$500 million mark represents the Department of Revenue's spring forecast back in the spring of 2006 forecast for FY 2007. That forecast was done under the ELF regime and that showed that \$500 million projection.

The next two bars represent the forecasts for that same fiscal year - the first one - what was contained in the PPT fiscal note. The second slightly taller bar, slightly above the \$2 billion mark is what was in the Department of Revenue spring 2007 forecast, again for FY 2007. There's been a lot of discussion around how the actual results came in compared to the expected results. There are three major components, as you know, with a PPT type calculation. There's the price piece, there's the volume piece, and there's the cost piece. Every one of those will have an impact on the actual end result. The reality is every one of those came in the actual - or as close to the actual as we can determine - came in quite different to what the original fiscal note projected. However, when you roll it all up together, it comes in really not too far apart and to look at - if I knew the price was at this level, then I should have gotten a different number. It kind of ignores some of the reality of

it's not a static environment where one item will move and the other components will stay static.

I've been involved in the finance business of the industry for many years and I've spent a lot of my career explaining to senior management why actual results didn't come in line with forecasts or budgets or projections. All the time the explanations are a combination of price, volumes and costs. That's the nature of the business that we're in.

[2:25:33 PM](#)

MR. MITCHELL continued:

So I have sympathy for the situation the Administration's been in. This was a significant change, this move to a net structure and it's not easy. But I do believe that as we progress over time, that will somewhat rectify itself as they have more experience with that system. We have more experience of the Administration trying to work with that system and helping - providing them with the kind of information that they need as they move forward. So, I think just to round that out, it just to me emphasizes that is it really the right time - is this - the reasons for going back in and making a significant change to the tax structure?

[2:26:20 PM](#)

MR. MITCHELL said Mr. Taylor would talk more about future resource development on the North Slope and then revisit how the tax structure will impact that development.

CO-CHAIR GATTO welcomed Representative Johansen to the committee.

[2:26:40 PM](#)

JIM TAYLOR, Vice President of Commercial Assets for ConocoPhillips, said he would try to describe what ConocoPhillips sees as the future potential of North Slope oil and gas resources, ConocoPhillips' participation in those resources and describe those in enough detail so that Mr. Mitchell can follow-up with the taxation aspect.

[2:27:28 PM](#)

MR. TAYLOR told committee members:

The way I'd like to start is to address this same curve and I think our partners before testified to this curve. It looked a little bit different but what this is the Department of Revenue's future forecast and I've just captured a time frame by which I will state a few statistics to try to emphasize our view of what this represents.

The first thing I'd like to say is that ConocoPhillips is proud to report to the state that we participate in all levels of these projects - all the way from wildcat exploration all the way through final Legacy field production and all the developments that ensue in between.

[2:28:10 PM](#)

CO-CHAIR GATTO asked if, by saying ConocoPhillips participates, he is saying it supplies all of the documents the state has requested and more.

[2:28:20 PM](#)

MR. TAYLOR clarified the context of his statement is that ConocoPhillips invests and participates in a project from wildcat exploration through to production.

[2:28:39 PM](#)

MR. TAYLOR continued:

So what is set up in this slide are four layers of future production as forecasted by the Department of Revenue, the top layer being new fields that are brought on line; the yellow layer being those other areas outside of the anchor fields or the Legacy fields as they've been referred to. It represents production from Alpine, Fjord, Northstar, Nanook and others.

The large red wedge is a wedge that I'll further describe later as being those oil and gas resources associated with Kuparuk and the greater Prudhoe Bay

area and the blue being a representation of an estimation of what Kuparuk and Prudhoe Bay would look like without the investment that would be required to fight the natural production decline that occurs in oil and gas assets.

What we've imposed on there is a 15 percent decline and I think what you have on the top of the red is about a 2 percent decline. I'm not here to advocate the precise nature of each of those, but what I'd like to do is describe what's contained in those and what we see as an investor is necessary in order to bring those to light on behalf of our investors as well as the state.

What I'll point out is the way I look at this is over the next eight years, in 2016, to visualize what needs to happen in order to sustain this level of production. I've kind of broken down what percentage of each of these layers is in 2016. The top layer represents about 15 percent of the total production that is forecasted by the DOR in this particular forecast coming from new fields. 15 percent will then also come from those fields outside of Kuparuk and Prudhoe Bay, such as Alpine, Northstar and others, but the single largest pieces are those that come from Kuparuk and the greater Prudhoe Bay area. That represents about 42 percent of the production and it will require, I think as testified earlier, require significant investment to bring that to light. And, of course, without the investment you can see that the production in those two large fields will decline to represent as little as 30 percent of the total production potential during that period.

What is contained inside the red wedge? The red wedge consists of projects such as infield drilling, wells that are added - you heard described earlier this morning - that bring on new production. As we produce fields, we learn about the complexity that the reservoir has in it.

[2:30:59 PM](#)

MR. TAYLOR continued:

We modify where we drill wells. We move bottom hole locations to help exploit and bring to light the production that we learn is represented in different ways. So there is a lot of side track and infield drilling potential that goes into a field throughout its life.

There are other projects that are referred to as improved recoveries. Prudhoe Bay, as an example, is one of the most complex reservoirs in North America, if not the world. It has a combination of recovery mechanisms that all interact with each other. It's a very large field that has primary depletion, natural depletion that goes on. There's water injection. There's **miscible** gas injection and then there's gas cap depletion that goes on. Let me assure you, it's one of the most complex that I've encountered in my 28 year career.

So with that comes a lot of opportunities to optimize along the way the things that we learn about the field, such as how do we handle the ever increasing amounts of water that come with production. That adds cost. It adds complexity. It adds changes in how you maintain the assets because the composition of the fluids is changing. You start to have higher gas production rates, which require more reinjection, additional costs, and greater complexity as well. So, the improved recovery projects are contained inside of that and will require continued reinvestment in order to bring those reserves to light.

And then one that I'll spend a lot more time on in the coming slides are those that I think you've heard described briefly before and those are the reserve potentials contained in the viscous oil reservoirs, as well as the heavy oil reservoirs. What I'll show you is that that is a significant reserve potential that I think you heard testified earlier as being something that we want to work very hard at learning how to unlock and bring to light.

[2:32:46 PM](#)

So, the key message from this slide is that the investments of the past that have been focused primarily on the conventional oil and gas that was

contained in those large fields is starting to transition, is starting to transform. The North Slope is moving from just a conventional oil and gas basin to one that is now going to have an ever increasing amount of viscous and heavy oil and someday when a gas pipeline comes to light, we'll also be transforming from an oil producing region to a gas producing region in that regard.

So there is a transformation that's occurring and it's important that we work together to preserve the investment climate so that we can optimize the realization of the potential of the North Slope.

[2:33:35 PM](#)

MR. TAYLOR continued:

I'll spend just a little bit of time on this slide [Slide 6]. It is not intended to confuse but this is a pictorial of the North Slope. It shows in these areas the outline of the greater Kuparuk unit and the greater Prudhoe Bay area and then the various colors represent leasehold acreage by [us], as well as others. So, what it tries to represent is that there has been a fairly substantial amount of exploration occurring in the North Slope over the past. We've participated in over 60 or those exploration wells with varying degrees of cost and complexity. Those that you drill close to your existing producing fields can cost as little as \$8 million. Those when you start to move away from those existing fields where you have to start building ice roads and you get off the pre-existing pads can grow to \$12 million or more. And those in those very remote locations where miles of ice roads and a tremendous amount of logistical planning has to go into it, the cost of those wells can exceed \$36 million.

So ConocoPhillips has participated in many of those prospects throughout the years and have brought some of those satellite fields to light.

[2:34:44 PM](#)

MR. TAYLOR continued:

Another point that I'd like to make on this slide is basically a statement of the evolution of a lease. I've heard the question asked: What is being done to encourage other investors? Are we encouraging the independents to come to Alaska and work? I would answer that question as yes we are and I would describe it this way as that when the company comes in and participates in a lease round, they see a prospect, they see potential. As they evaluate that, they drill wells; they learn things that may change their view of that lease. Well when, say, someone like ConocoPhillips says well I've done all that I wanted to do to try to understand what I thought was there, there may be others that see other things. There may be others and a secondary market that says well I'm willing to take some risks. I see things differently. So, in that regard, those leases are made available to other companies. We farm leases out to the independents. We have partnered with independents. Anadarko is a partner of ours in the [National Petroleum Reserve-Alaska] NPR-A and also in the Alpine field.

So we not only partner with smaller companies ... and large companies, but we also create a market by which they can enter the market, whether it's by lease sales or by amendments to existing leases. So there is a value chain that I would advocate that we do participate in that does encourage other investors. We share rigs. We share in the cost of construction of ice roads. So there's a lot of cooperation that goes on that I think enables that and hopefully encourages others.

[2:36:03 PM](#)

Another point that I'd like to make here as I describe the progressive increase in costs as you move away from existing facilities, it would go without saying that Prudhoe Bay being the single largest producing field in North America, and the largest oil field found in North America, would also probably represent the largest field that was going to be discovered on the North Slope.

What happens in hydrocarbon basins you go through a creaming curve where typically the larger fields are

found and that what happens over time, there are smaller fields. So those are conducive to other types of investors but what I want to show you is that it's also conducive to the opportunities that lay inside of the large fields. And hopefully I'll describe that we're in pursuit of those as well.

2:36:49 PM

MR. TAYLOR continued:

Just a couple of quick points here is that this is another slide [Slide 7] that represents the Alpine field and some of the early exploration that has gone on in that area. This is a remote area. This is one of those areas that is difficult for those to enter that haven't been there before and, as I described to you, I think we're doing a lot of cooperative measures that makes it possible for others to participate as well.

But, I think there [are] a couple of points to make here. Because of the remote nature and the high regard we have for the sensitivity of the environment and the footprint that we are impacting, these two slides show that the exploration in these areas does leave a minimal footprint and that the amount of time, cost and effort that goes into building ice roads, placing in this case a 3 million pound drilling rig with 160 foot derrick on 12 inches of ice is not a cheap investment. It's something that has to be well thought through, done very carefully. And then, when we're done, hopefully there will be a small production pad in this area but in this case you'll see that this exploration well was left inside of a house for future assessment. There may other drilling or they may come back and plug and abandon that well and hopefully you will not eventually notice that that well ever existed.

So there is a high degree of scrutiny applied to this environmentally sensitive area but I think the industry is doing a good job of trying to manage that along with the interests of the state.

The other point that I'd make in a picture that could follow up to this is, well what does the development

look like in this area and how does that impose the cost of what remains on the North Slope. Typically you'll move from a well pad of this size to a production pad that is trying to be managed in terms of its size.

[2:38:21 PM](#)

MR. TAYLOR continued:

So the design and the threshold of costs that these smaller fields can endure in order to create an economic project are challenged in their own right because you're trying to compress everything into a smaller area so you can address a lower reserve size potential to create an economic venture.

[2:39:02 PM](#)

I'll jump ahead a slide here [Slide 9] because I want to briefly describe some of the large remaining potential that we see on the North Slope and I think BP described this briefly in their last testimony and in great detail in previous testimonies.

The way I'll characterize is - I guess first of all describe the degree of difficulty and complexity and we've done that by showing two different densities and viscosities of crude oil that exist in the various formations up there. On the left you see that there's an easier form of flow, and I would describe the 19 API crude as more like maple syrup that goes on our pancakes. When it's warm it can flow fairly well but obviously not near as well as the conventional oil and gas whereas the 10 degree API crude on the right flows like molasses. So, if we put these types of crude inside of rocks and bury them 3 to 4,000 feet at depth and put them at 45 to 50 degrees temperature, they're going to be challenged at getting them out. So these are some of the challenges that we're trying to unearth and crack in bringing this large, large resource to light.

[2:40:08 PM](#)

The other take away from this is the graph on the left tries to show that many of the geoscientists and

engineers estimate that the resource size, the original oil in place, is as large as the conventional oil and gas that was discovered 30 plus years ago.

[2:40:23 PM](#)

CO-CHAIR GATTO said he always thought 40 to 90 sounded warm. He asked whether permafrost exists below and above it because he had heard the heavy oil was in the permafrost.

[2:40:41 PM](#)

MR. TAYLOR said it is his understanding the zones he described exist below the permafrost.

CO-CHAIR GATTO noted that people have suggested using an open pit mine concept as is done in Alberta, but the oil is too deep for that.

MR. TAYLOR said that is his understanding too.

[2:41:10 PM](#)

MR. TAYLOR continued:

Alberta obviously has the oil sands that crop out of the surface and then they vary at depth as you travel south. They do encounter deposits like this so the technologies that they are employing are those that we would be looking to try to test and create commercial projects in Alaska as well. So I can assure you there are some very exciting things going on, not only in Canada, but in some of the South American heavy oil basins, as well as Alaska. So there are some ground breaking technologies that are being developed and employed. I'll show you a couple of them that we're pretty proud of participating in Alaska.

[2:41:42 PM](#)

CO-CHAIR GATTO said that is absolutely crucial to this state and any successes will benefit both parties. He asked if Alaska's resource is the most difficult [to develop].

[2:42:09 PM](#)

MR. TAYLOR said that is a good question. ConocoPhillips deals with challenges in many basins. It finds similarities and differences. Typically the heavy oil deposits exist at shallower depths. ConocoPhillips, in basins with known deposits, has drilled through them to look for other deposits at greater depths. Those deposits were not easy to exploit and went into inventory because ConocoPhillips didn't know how to develop them at the time. However, as prices rise and technologies advance, they become more interesting and worth pursuing. They challenge economic models. ConocoPhillips is looking for ways to reduce costs and increase recovery so that it can pursue those resources.

[2:43:17 PM](#)

MR. TAYLOR continued:

Large target, challenged asset results in high costs. So what I'm going to talk about briefly here is where they exist and the relationship they have with the conventional oil that exists on the North Slope. What I've done here is show, once again, the outline of the greater Prudhoe Bay area and the Kuparuk River unit along with the Alpine area.

As you'll see, the green represents the light oil production in the larger areas. The brown represents the viscous oil, which we see today as being on the cusp of commerciality and I'll describe one of those projects here in a minute. And then the darker heavy oil is that that is really challenged by cost and future potential.

The point that I would like to make here is that the co-location of the potentials, the reservoirs, lay on top of each other.

[2:44:25 PM](#)

So the conventional means of producing the light oil has typically been through the vertical well.

CO-CHAIR GATTO asked if the reservoirs are in contact or separated.

MR. TAYLOR replied they are usually separated by a few thousand feet. A typical conventional oil well will be anywhere from

8,000 to 10,000 feet, depending on the deviation or inclination of the well. The heavy oil deposits exist between 3,000 and 4,500 feet. They probably had the same source basin of hydrocarbons but became trapped.

[2:45:20 PM](#)

CO-CHAIR GATTO asked whether they have different BTU values.

[2:45:26 PM](#)

MR. TAYLOR said the quality differs. Typically, the heavier viscous oil has a discounted price compared to that of light conventional crude. Most refineries have been built with a certain product in mind. As those product slates change, the refineries must change. He noted many of the refinery expansions associated with the Alberta oil sands have needed increased coking capacity. Those investments must be recovered, which typically comes with a discounted price on the feed stock.

[2:46:12 PM](#)

MR. TAYLOR continued his presentation:

Back to the points that I was trying to make here that the resource potential is very large. The reservoirs overlay each other. They will utilize some of the existing well pads. The wells will sit next to each other because they are drilling a similar area but they are stopping in different places so they will co-exist next to each other. So there is some leveraging that's trying to go on between the heavier oil and the conventional oil and they're going to try to use the same existing facilities. But because they are different products, they do require incremental investments, not only in the well technology but also the process technology.

So the underscoring point here - high target resulting in higher cost and lower recoveries with a longer production profile, so that challenges the economics. All of those attributes go into what we use to calculate an economic project.

[2:47:08 PM](#)

MR. TAYLOR continued:

What I'd like to go over here is just a description of some of the technology that's being employed and distinguish this and the cost and complexity from the conventional oil. The West Sak example that I've used here is a trilateral, horizontal well. As you can see, it's been completed and utilized some new technologies to where it's accessing three different sandstones from the same well bore. That requires a lot of directional drilling. As you can see, to put this in perspective, this horizontal section can reach up to a mile and a half away from the well bore itself. So it's reaching a long ways. It's utilizing new technologies and it's overcoming production problems that we previously had not figured out to do very well but this technology is advancing.

Once again, a well like this, as compared to a conventional well, can run up to 12 or more million dollars so there are higher costs.

The table - I won't go in any great depth but the point that I'd like to make here is there are other technologies outside of just drilling that have advanced in recent years that's starting to bring this to life. But they do come at a price. They do come at high complexity. So, the largest potential that will exist in those deposits I showed you will be challenged by some of the costs that are occurring.

So anything that could happen to the tax regime or the fiscal take or anything that will impact the cost, the price or those things that would detract from the economics, push these things back and forth on and off the bubble of their economic viability. And so that's the point that I was trying to raise here.

[2:48:45 PM](#)

CO-CHAIR GATTO noted Mr. Taylor's title is the Vice President of Commercial Assets and asked if commercial assets mean only commercially valuable assets or all assets.

[2:49:02 PM](#)

MR. TAYLOR said his responsibilities include ConocoPhillips' interests in the Prudhoe Bay area. He is also a representative

of the owners' committee of TAPS and manages ConocoPhillips' gas operations in northern Cook Inlet. He has a counterpart who is responsible for ConocoPhillips' operated assets, which are Kuparuk and Alpine.

[2:49:44 PM](#)

REPRESENTATIVE ROSES said each producer has talked about the increase in costs. He referred to the mud system on Mr. Taylor's chart and said that system was water based in 1998 but is now oil based, which increases the cost. Also, the chart refers to water flood as a recovery mechanism and viscosity reduction. He asked if those are the technologies that will rapidly increase the costs.

[2:50:22 PM](#)

MR. TAYLOR said that is absolutely correct; this table shows that money is being invested to advance technology and that comes at a cost.

[2:50:42 PM](#)

REPRESENTATIVE ROSES said the fact that the mud system is now oil based means that oil cannot be sold.

[2:50:49 PM](#)

MR. TAYLOR said oil based mud systems can range from crude systems to mineral based oils but they are not necessarily sourced at the field level. They are brought by service and other partner companies. They are usually mineral based oil systems that attempt to preserve the productivity of the wells. The sands and wells sometimes react unfavorably to certain fluids. The oil based mud system increases penetration and helps deliverability but it is more costly.

[2:51:38 PM](#)

MR. TAYLOR continued his presentation:

Zooming through the points here - what we've done here is taken - displayed an aerial photograph of the Kuparuk CPF 1 production facility. Some of the points that I'd like to make here and I'll clear this site fairly quickly is that - once again, the large production target associated with viscous and heavy

oils is large but it does need to coexist because it does lay in the same areas as where our conventional oil does. So what we're working hard to do is make sure we are leveraging the investments we've already made but yet we have to enhance those facilities in order to accommodate this new development that's going on.

The other point that I'd like to make is because they are so interrelated, and you can tell by just looking at the complexity of these ingoing and out coming lines that represent production flow lines, injection flow lines, fuel gas lines and gas lift lines, that there's a high degree of complexity if we were to consider trying to separate these two. It would be - I guess I would call it a nightmare. It would be very hard and actually would add a lot of investment costs that we had to try to figure out how we could exploit the heavy oil and separate it from the light oil.

The second point is a technical point - it is that they do need each other. The heavy oil will have flow assurance problems as it enters pipelines. The temperature drops. It needs a way to mix itself with another component and the conventional oil serves a very good purpose in creating flow assurance in the existing pipeline technology.

[2:53:15 PM](#)

CO-CHAIR GATTO asked if heavy oil has a different paraffin content than light oil.

MR. TAYLOR said typically they do but not always.

CO-CHAIR GATTO asked if it is more or less.

MR. TAYLOR answered:

More. Their pour point is at a much lower temperature - or at a much higher temperature they start to thicken up and have a hard time with their flow characteristics so, in the earlier days, say 10-15 years ago in Alberta, they were using a lot of natural gas liquids to mix with the heavy oils in a lot of the pipelines to keep them thin enough so that they would flow.

2:53:44 PM

MR. TAYLOR continued his presentation:

Now that the NGLs are a fairly scarce commodity, they are moving to synthetic oils that are actually manufactured for this sole purpose mixed with the oil to keep them flowing. In this case, we think that there's a tremendous synergy that the health and wealth of conventional oil is something that can be mixed with the heavy oil and help with that flow assurance. It's estimated - it could be a requirement of 1 to 1 - one barrel of heavy viscous to one barrel of conventional that would continue the flow assurance in the existing technology. But when that starts to change, it will challenge us technically on how to continue to exploit the heavier oil in the absence of those types of [indisc.].

2:54:35 PM

CO-CHAIR GATTO said some people like to burn number 1 diesel in their trucks and use an additive to prevent gelling. He asked if gelling is caused by the paraffin.

2:54:42 PM

MR. TAYLOR said they are similar events in that gelling prevents the flow of a liquid. Paraffin does create a higher viscosity and inhibits flow at various temperatures. It is not the same phenomenon but similar.

2:54:58 PM

CO-CHAIR GATTO pointed some of those additives make things that aren't supposed to flow, flow.

MR. TAYLOR said that is accurate. Those products are very expensive and cause those resources to come at a higher cost.

2:55:28 PM

CO-CHAIR GATTO asked, "Can you recover them at the other end, where it warms up when they load them aboard a ship and the ship is heading to warmer waters or are they just gone forever?"

[2:55:38 PM](#)

MR. TAYLOR replied they typically can be and are recovered in the refinery process. He explained in the case of Alberta and the North Slope, those crude oils are marketed at various refinery locations. The degree of added complexity to the products requires consideration of how the refineries can accept those products. If the refineries need to buy and the processing of crude slate costs an additional dollar that crude will sell for a discounted price. Therefore, it not only comes at a higher cost, it typically has a discounted value at the wellhead.

[2:56:31 PM](#)

REPRESENTATIVE WILSON asked Mr. Taylor to go through the ConocoPhillips' thinking process when planning for future mixing of heavy oil with light oil.

[2:57:21 PM](#)

MR. TAYLOR told members a tremendous amount of planning is necessary. As an investor, ConocoPhillips prioritizes its existing producing assets. He assured members it is not part of the thought process to inventory producible crude oil or natural gas, although ConocoPhillips does require responsible reservoir management. It is not advantageous to take gas from a reservoir at the expense of the oil. As assets like heavy or viscous oil start to come to light, the impact to flow lines, pumps and the composition of the crude in TAPS must be considered. All of those challenges require ConocoPhillips to anticipate various thresholds of complexity and investment that must be tackled before those products arrive. ConocoPhillips believes the capacity of the current system has room for substantial growth with current technology. However, if volumes decline, the cold temperatures associated with the flow lines will create different pour points and challenge the flow of the crude oil. Those factors will require more technical analysis and solutions, which typically come at a higher price. He repeated he is not saying the viscous or heavy oil is not "doable," but it is challenged. He described some of the challenges ConocoPhillips is facing at West Sak and said this higher price environment is encouraging new methods. He noted ConocoPhillips plans well in advance, so repeated changes to tax policy raise the risk of taking steps to make a project economic that might take several years.

3:00:45 PM

REPRESENTATIVE WILSON asked if ConocoPhillips is using the bright water technique mentioned by BP.

3:00:57 PM

MR. TAYLOR told members ConocoPhillips participates in the Prudhoe Bay field. He said as an engineer who has worked in a lot of older oil fields, the pursuit of altering water channeling is something ConocoPhillips has pursued for many, many years. He said he shares BP's excitement that they may have found a very good application in a particular reservoir. ConocoPhillips would like to think it will have applications in other places too.

3:01:50 PM

CO-CHAIR JOHNSON referred to a previous slide about dilution with Kuparuk production and asked if the Kuparuk oil is injected into the well for recovery and whether 100 percent of the injected oil is recovered.

3:02:28 PM

MR. TAYLOR said that oil is not injected. He explained the intent of that table is represented by Slide 11. He stated the dilution occurs above ground and it all goes into the same production facility. He said while ConocoPhillips is challenged with costs, it is doing everything possible to leverage its current investments. He said it would be virtually impossible to separate the two.

CO-CHAIR JOHNSON said he wanted to be sure oil was not being reinjected.

3:03:48 PM

MR. TAYLOR continued his presentation:

Okay, carrying on, I bring this slide up [Slide 12] only to revisit some of the testimony ConocoPhillips had made previously and also in an attempt to try to be more specific. I know when we come in here we talk about information; we talk about generalizations and concepts. It can be frustrating that we're not talking about real numbers. What we've tried to do is

bring some real numbers in a generic way that makes it easier to talk about something that reflects our viewpoint.

What this slide is the column on the left represents the state's consultants' characterization that I think you may have seen in previous testimony of some of the field simulations they've done on various fiscal regimes and the calculations that went into it. What we have done is we laid some real projects that we have in our current decision making process. These are real projects I'm discussing with my boss and others as to how and when and if we'll sanction these projects.

Some of the attributes that I'd like to point out - first of all is the reserves side. If you go down and look at the - about the middle column that starts at 80 and works its way across and totals to 250 million barrels, the average reserve size is not large but yet they are somewhat significant. I would venture to say that they are maybe below some of the threshold of new field economics but they are projects we are in hot pursuit of. They are those that we want to do. A majority of these are viscous or heavy oil type projects.

The other thing I'll draw your attention to is the capital per barrel is higher and you can see that there's upwards of \$4 billion or something that resembles a \$16 to \$20 per barrel investment as opposed to \$11 per barrel that was illustrated in simulation.

The other thing I'd point out is it comes at a higher operating cost and you can see that the conventional - or the simulation was done at \$7 a barrel and let's say the weighted average here without doing the calculation, it's going to be higher than that. But, much of what I described in the previous slides are trying to be represented in this slide is, there are higher upfront costs and there are higher ongoing operating costs associated with much of the potential remains.

But in the aggregate, there are significant reserves.

They need to be addressed and brought to light and that's what we're trying to accomplish here.

[3:06:18 PM](#)

CO-CHAIR GATTO asked, assuming a 15 percent recovery for heavy oil, whether the 258 million barrels he referred to represents the 15 percent recoverable oil.

[3:06:31 PM](#)

MR. TAYLOR said that is correct. He explained:

I think the previous testimony, as well as numbers that I would use here, you know, a 10 percent to 15 percent recovery with the total resource potential we saw as being 26 billion, could be 3 billion plus or minus barrels that will be recovered at a much higher cost over a longer period of time but still represents a significant target. It's 50 percent more than some of the conventional oil reserves that exist in Prudhoe Bay today.

[3:07:08 PM](#)

CO-CHAIR JOHNSON asked Mr. Taylor to clarify the hypothetical projects versus the actual projects.

[3:07:38 PM](#)

MR. TAYLOR said the numbers are from clearly defined projects that ConocoPhillips is trying to make investment decisions on. Project 1 is a conventional oil project that could be characterized as an improved recovery project - how to handle the ever growing volumes of water. In the combined Kuparuk and Alpine area, ConocoPhillips is producing 280,000 barrels per day, which comes with more than 650,000 barrels of water every day. Overall, for the 280,000 barrels of oil produced, 1 million barrels of water are handled everyday.

[3:08:41 PM](#)

CO-CHAIR JOHNSON asked if the expenses on the chart include taxes.

[3:09:06 PM](#)

MR. TAYLOR said those are the lease operating costs only. The total combined state take that could result from the six projects on an undiscounted basis could be as high as \$6 billion, as stated in previous testimony. Significant taxes and royalties come with projects like this. ConocoPhillips believes in the net system as the state is also an investor and that is the correct alignment. With that comes the royalty, which can happen immediately after a project is enabled.

[3:09:49 PM](#)

REPRESENTATIVE SEATON said committee members have continually been told that those [projects] that are on the bubble might be changed or might not go forward at this time. The economists have told the Legislature that adding state participation of 2.5 percent on capital costs and adding 2.5 percent on operating costs can aid a marginally profitable project. He ascertained that Mr. Taylor said do not allow us more capital deductions and questioned why that would not improve the margin for sanctioning a project.

[3:10:55 PM](#)

MR. TAYLOR told members ConocoPhillips is in favor of a net tax system: the deductibility of lease operating and capital costs. That would help project economics. Without that, the projects that ConocoPhillips is trying to find ways to reduce costs on and increase recovery from would be further challenged by tax changes. ConocoPhillips does favor deductible costs. Tax changes affect planning because with an inventory of projects; those "on the bubble" go back and forth, depending on whether they are impaired by technology, taxes, or costs.

[3:11:56 PM](#)

REPRESENTATIVE SEATON inquired:

So, other than, let's say, the gross floor, which has pretty much fallen off the table in the bill that we have before us now I mean on project 4 there, by us adding another \$500 million into your capital deduction, in other words the state picking up that and adding 2.5 percent of the expense - I didn't calculate that one out but that's about one third of that. How does that not enhance your ability to sanction that project?

[3:12:39 PM](#)

MR. TAYLOR said those attributes do enhance those projects. He said he has prepared some comments related to the proposed legislation and this segues into a discussion about the gross progressivity.

[3:12:56 PM](#)

REPRESENTATIVE SEATON replied:

Rather than get on that I'd like to drill down into this first because the difference between 22.5 percent net tax and 25 percent net tax is 2.5 percent that we allow you to deduct - or we increase our participation in your costs of capital and we increase our participation by almost 10 percent in the deductibility of the expenses. All the economists that we've talked to, whether Pedro Van Meurs or others, they cautioned about what percentages because the state's risk goes up because we participate more in these very expensive projects that if on the margins are not very profitable, you don't tax much but our increase in liability for additional cost sharing goes up significantly. So, I'm constantly having this problem of industry coming in and saying that this is a detriment when \$500 million for projects for capital costs - and I guess that's about \$1.5 billion more in the expense column there - according to the economists that are testifying to us, it actually makes those projects - it goes from either non-economic to marginal or marginal to viable. So if you can explain that to me I'd appreciate it.

[3:14:28 PM](#)

MR. MITCHELL explained that it amounts to the timing of the cash flows and how much upfront investment is subject to that deduction and credit and, once a project is operational, how much of a margin is subject to the higher tax level. He said with some projects the upfront investment benefit could exceed the value of the additional tax once the project is producing. He said that will not apply to every project but Representative Seaton's point is valid because some projects will benefit more from the upfront deduction.

[3:15:44 PM](#)

REPRESENTATIVE SEATON said the disconnect he is hearing is that the oil companies say marginal projects will fall off when, in reality, marginal projects will be aided and made less marginal by the increase. He pointed out the tax rate is applied across the entire company's profit but the tax rate applied to marginal projects enhances their viability.

[3:16:52 PM](#)

MR. TAYLOR said the net tax system will encourage some investments. Once the PPT passed, the industry stabilized and looked at their projects, reloaded and moved forward. The difference between a 22.5 versus 25 percent tax rate will not destroy every single project. It will have an "erosional effect" on some of the marginal projects at 22.5 percent. They would be less productive at 25 percent.

[3:17:47 PM](#)

REPRESENTATIVE SEATON asked Mr. Taylor to pencil it out for him later.

[3:19:01 PM](#)

MR. TAYLOR reemphasized that in 2016, 42 percent of the production shown by DOR will come from existing fields. Those are incremental investments. As ConocoPhillips starts to make those investment decisions, factors that alter the economics associated with those choices will have a direct impact on ConocoPhillips' ability to fight that decline. It will not eliminate all of the projects but will take away from the economic viability of some of them that could fight the decline. He continued:

It's not about the overall tax of existing assets. It may be a mathematical exercise - is 25 percent of this amount of production going to generate more state revenues than 22.5 percent, let's say, of this wedge, which is really part of the analogy that's trying to be brought to light here. Industry is saying that altering costs and altering risk alter our decisions about the incremental project - the new project. And what we're trying to advocate here is upwards of 40 percent of the future in as little as 8 years from now will come from those new investments.

[3:20:40 PM](#)

REPRESENTATIVE SEATON said he can understand that on a company-wide profitability basis but industry says marginal projects will lose. He said Mr. Taylor is saying high profit projects without the large proportional costs will be impacted the most but marginal projects with lower profitability and higher costs will be aided and made less marginal by the 2.5 percent. He asked Mr. Taylor to prepare a flowchart that shows the influence of the 2.5 percent tax difference on a marginal project for committee members.

[3:21:59 PM](#)

MR. TAYLOR offered to provide feedback on that but clarified that it is the high cost, high investment project that will be on the bubble of marginal economics and will be impacted.

[3:22:30 PM](#)

REPRESENTATIVE ROSES echoed Representative Seaton's concerns. He commented in terms of the credits, he planned to build three car washes and gas stations over three years but decided to build all three in one year when the federal government offered investment credits on equipment. The credits allowed him to capture 10 percent of all of the equipment costs and he could escalate the depreciation. His investment decision was changed because of tax structures. He felt Representative Seaton was trying to convey that some of the incentives offered by the state will make some of the marginal projects less expensive in terms of the oil companies' capitalization because the state will be taking a proportional share of it.

[3:24:15 PM](#)

REPRESENTATIVE GUTTENBERG indicated that members are talking about increasing credits for capital investment and the difference of 2.5 percent. The price of oil has jumped from \$70 to \$100 per barrel. It could jump to \$130. At that point, he cannot see that difference be anywhere near as significant as the change in cost. He felt the price increase would have a much higher influence [on investment decisions] than a 2.5 percent tax increase when the state is increasing its involvement.

[3:25:13 PM](#)

MR. TAYLOR replied the elements of progressivity and tax were introduced in PPT. But now the talk is about doing something in addition to that. He is saying anything that is done in addition can have erosional effects on some of those decisions that ConocoPhillips has contemplated. He believes some of the expectations set out in terms of changing the tax that resulted in PPT have been met. The revenues have increased. The question now is whether that was the intent or should it again be changed. He repeated that taking additional steps will always erode the economics of what is on ConocoPhillips' slate. He emphasized that each step the state takes has an additional erosional effect. He said the concepts behind the net tax system are helpful in ConocoPhillips' planning process. He continued:

Of course, the question in front of us here today, and what's being discussed - do we need to take additional steps beyond what PPT had established. I think what we're trying to say is that if you do raise tax beyond what's in the current law that will have an erosional effect. Is it totally destructional? No. Does it start to push other projects further out or those that were marginal with PPT at a higher tax rate - will they become marginal? Yes. That line goes up and down as we change the impacts of costs. That was the intention.

[3:27:36 PM](#)

MR. TAYLOR turned the presentation over to Kevin Mitchell.

[3:27:52 PM](#)

MR. MITCHELL told members his comments would be specific to the contents of the committee substitute bill, which contains the 22.5 percent PPT rate but replaces the progressivity from PPT to a gross base progressivity.

[3:28:45 PM](#)

MR. MITCHELL began his presentation:

In the draft bill that we have in front of us today, the progressivity, which in PPT was a net based progressivity - just as a reminder that progressivity kicked in at a \$40 per barrel net margin, if you like,

and escalated at a rate of .25 percent per increase over that \$40 threshold.

In this bill, that progressivity has been removed. The base rate is still the same as PPT at 22.5 percent but that net progressivity has been removed and has been replaced by a gross progressivity, which triggers at a \$50 per barrel net back price and then escalates at a .225 percent increase above that.

What we find as we look at the impact of really any tax on the gross, what that does is give the ... it puts the biggest challenges on the projects that are the most challenged in the first place, and we see a lot of those out there in terms of where the future development potential is. Those are the very projects that suffer the most from that. The reason for that is the fact that they are the most challenged is saying they are the highest cost projects and so the margin that's left to play with is squeezed more for those projects than any of the more attractive projects. By taking a slice out of the gross, what that's doing is reducing the revenue that would otherwise be available to cover those higher costs. And then, specifically with a gross progressivity that has a trigger point with no indexation in it, and the reality is the costs will rise over time, eventually you could get to a point where there's a progressive tax coming out of a revenue stream that really is - all it's doing is covering costs. We can see that could happen over time.

[3:30:46 PM](#)

With the net system that we have today, it really works in all situations because the most profitable areas get hit with a very sizeable tax percentage. So in the current environment, for example, where we are dealing with high prices, and yet we've made a lot of statements that costs follow prices, which over time there's a lot of evidence to say that does happen but we fully accept that costs haven't risen over the last three months to the same extent that the prices have risen, so there has been a significant expansion of that margin that's available.

But with the PPT progressivity that we have, at current prices that's probably something like a 28 to 29 percent tax rate that's being applied to that marginal [indisc.] so in many ways it behaves like a high rate gross system and yet, at the same time, the more challenged projects are adjusted because that calculation is based on the net. And so, it really works. The PPT type net structure - it fits all sizes a lot better than whenever you introduce a gross component, there are certain areas that will get really disadvantaged by that. Actually I think the Administration has been a very strong advocate of retaining the tax structure on a net basis.

3:32:35 PM

REPRESENTATIVE ROSES agreed the Administration has supported the net progressivity but it has also pushed for a 10 percent floor on the lower end. The Administration has also approached removing some of the credits that this bill put back in. One reason the progressivity was included was to offset some of the other changes. As the price escalates, the higher expenses can be deducted at the initial base tax rate of 22.5 percent. He surmised the question becomes where does the progressivity on the gross offset what a company would get on the base.

3:33:33 PM

MR. MITCHELL replied the difficulty he has with the floor is that the 10 percent floor hurts at the very time you don't want to hurt investment. That could occur in a low price environment where a fixed percentage is taken from the gross. That becomes a very progressive feature from a tax perspective. However, in those environments with opportunity for significant investment, the floor can be triggered by high investment levels because the calculation is based on the higher of the PPT net or the floor. He explained:

And if you're progressing some of these projects, a significant amount of investment activity going on, that can be enough in itself - it triggers the floor, which thereby removes the investment incentives, the deductions and the credits and turns you back to projects that no longer look as attractive. And so that's the difficulty we have with the floor is that it hurts you both in a low price environment but also when you've got potential significant investments

ahead of you, which is why we come back to really the net works in all environments. It does mean if you stick with a purely net system, there's no doubt there are situations where it means the state has more downside risk. The floor reduces the downside risk for the state but it doesn't get impacted by the investment potential.

[3:35:32 PM](#)

CO-CHAIR GATTO asserted, "That floor will so change the State of Alaska we'll be worrying about a lot more than did we lose our 10 percent at these low oil prices."

[3:35:40 PM](#)

REPRESENTATIVE WILSON said she hears Mr. Mitchell saying the net tax will go up and down with any and all projects. However, with a gross tax and oil company would have to pay more so the state could lose out because the oil company might decide not to do a project that is right on the line.

[3:36:33 PM](#)

MR. MITCHELL said that is correct. Some projects might not happen because of the existence of the 10 percent gross tax. The net tax reflects both the revenues and costs of development so it becomes self adjusting and reduces the likelihood that this topic will need to be revisited again in the near future. Generally net tax structures are more sustainable than gross structures.

[3:37:18 PM](#)

REPRESENTATIVE WILSON asked how legislators can assure their constituents that the state is getting its fair share with a net tax.

[3:37:49 PM](#)

MR. MITCHELL expressed his belief that it comes down to the alignment between industry and the state. The net tax will provide more incentive to move forward with some of the more challenged projects. That is good for both parties because economic projects generate taxes and royalties. He reminded members the 12.5 percent royalty comes off the top anyway.

[3:38:41 PM](#)

MR. TAYLOR added another consideration is that investment fosters secondary and tertiary benefits to the local economies, whether that is in the form of employment or goods and services.

[3:39:52 PM](#)

REPRESENTATIVE SEATON questioned whether the problem is not the progressivity tax itself but rather the gross trigger under the current bill because projects with different cost structures would be taxed equally. If the trigger is adjustable on the net profit or the margin of a field that would be the actual factor that makes the previous tax work better, rather than the structure of the tax itself.

[3:41:05 PM](#)

MR. MITCHELL said yes. What ConocoPhillips likes about the PPT structure with its progressivity is that the trigger point is on a net basis so there must be a profit component before any progressivity is applied. The progressivity calculation is then based on the expansion of that margin, not just the expansion of revenue. Under the proposal in the committee substitute, all of the progressivity is on a gross basis.

[3:41:54 PM](#)

REPRESENTATIVE SEATON surmised that Mr. Mitchell is concerned that one of the components of the current bill's "gross tax" section is keyed strictly to price and not to the economics of the field. ConocoPhillips is less concerned about the deductibility of the tax itself than it is about it being keyed to the margin of the field so it takes place when the economics of a field reaches that point.

MR. MITCHELL concurred, adding that in such a scenario it is a mutual benefit that "we're not paying that tax when we're not making ... a margin."

REPRESENTATIVE SEATON remarked the Legislature is worried about revenue and about the financial risk to the state. The problem is that a net tax on a "net trigger" means that a high rate of tax also becomes deductible. Therefore, if the progressivity caps out at 25 percent under any of the scenarios, if left as a net tax, the state would be contributing another 25 percent to the capital and operating expenses of the projects. He said he

would be willing to "key" the tax to the margin and have that float with the net tax but asserted, "I am definitely thinking that we've provided enough in 22.5 or 25 percent tax deductibility plus credits, without making the progressivity also a deductible item." Making it "key to the margin," Representative Seaton posited, would cure Mr. Mitchell's main objection to the progressivity.

MR. MITCHELL concurred.

[3:44:50 PM](#)

MR. MITCHELL continued his presentation:

So we've probably actually beaten this subject to death. We did have another slide in here that talks about the impact of progressivity on the gross. We probably have really covered all of these points that these examples - and these are just generic examples that say when you have a low cost project, depending on what price assumption you have out there, the tax paid is going to be split between the base net share and then the amount that is driven by the progressivity. In a higher cost project, you could envision a scenario where assuming a reasonable price environment and not a complete blow-out in prices, you could imagine a scenario where there really is no net margin and, in fact, there's a tax coming out of the gross, which is making the overall project look uneconomic. I think we really covered all of these points in the last few minutes of discussion.

CO-CHAIR GATTO asked Mr. Mitchell if he is about to transition his presentation into TIE credits.

MR. MITCHELL said he is.

CO-CHAIR GATTO announced the committee would take a 10-minute break.

CO-CHAIR GATTO gaveled the meeting back to order at 4:10 p.m.

MR. MITCHELL continued with his presentation:

What I'd like to do now is talk a little bit about the transitional investment expenditure (TIE) credits, which we recognize that in this version of the bill,

they were - some form of TIE credits was added back compared to what was in the original bill that the Administration had produced. However, they weren't added back to the full extent of how they were included under PPT.

The key point on the transitional, or the TIE credits, is that the companies that are impacted by removing those TIE credits are those companies who one, were investing in the past and two, were investing in the future. It requires that historic investment and future investment in order to capture any value associated with the TIE credits and so - and ConocoPhillips has been a consistent investor in Alaska and we plan to continue - we are continuing our investment and when you look at some of the examples that actually you could draw a scenario that says we might have been better off having not advanced those projects when we did but delaying them, which really isn't ultimately in anyone's - it's not what any of us want ... to look at that. But it's those investors, historic and future, that stand to lose by the removal of the TIE credits, which - that's the very reason they were put into the PPT in the first place.

The TIE credits do serve to soften the impact of tax changes and it does have a finite - that provision has a finite life on it. It's not an ongoing component of the tax legislation but it does come to end - by 2013 is the limit by which you can use up those available TIE credits.

[4:12:55 PM](#)

MR. MITCHELL continued:

Moving on, I did want to talk a little bit about some of the exclusions and deductions from allowable expenditures that are included - that are part of this bill. The topping plant has had some discussion previously and my main point on the topping plant is whichever way you look at it, that plant is an integral part of our operations to generate diesel fuel for use in lease operations and to take that one asset and isolate it and say we're actually going to treat that asset different for tax purposes. To me it goes against good sound tax practice and it adds

complexity. With any kind of a net system, the system will operate best with a straightforward, if it's a cost of operations then it's an allowable - if it's a leasehold operating cost then it's an allowable deduction and by taking a particular piece of that plant and saying we're going to treat that differently just kind of adds some complexity and confusion to the overall structure. I recognize there are concerns around the project, which is that the [ultra-low sulfur diesel] ULSD project on that - and understand those concerns around that but nonetheless, just the exclusion of a particular piece of the operation just doesn't feel quite right in the context of what is a net tax structure.

[4:14:41 PM](#)

CO-CHAIR GATTO questioned how it adds to the complexity and the confusion.

[4:14:51 PM](#)

MR. MITCHELL explained the ongoing costs of operating that particular plant are not allowable deductions while the ongoing costs of operating everything else are allowable. That requires segregating out the costs of the plant. A formula allows for that but the fact that one piece must be segregated out and not included creates complexity.

[4:15:42 PM](#)

CO-CHAIR GATTO said he thought that system would be less complex because those particular costs would be ignored.

[4:15:58 PM](#)

MR. MITCHELL said his view is that unit is integral to ConocoPhillips' operations. Some of the costs associated with its operations are potentially shared with other areas. It is more difficult to segregate those costs out than to add them in because those costs are already included in the total.

[4:16:33 PM](#)

REPRESENTATIVE WILSON asked Mr. Mitchell if ConocoPhillips wants to treat the topping plant like the rest, whether the

Legislature should charge royalties and the PPT so that everything is charged the same.

[4:17:20 PM](#)

MR. MITCHELL told members the costs of the existing topping plant are included in the PPT as an operating expense. Therefore, to exclude that now and replace it with another formula adds complexity. The crude oil used at that topping plant to manufacture diesel, assuming that diesel is consumed in lease operations, would not be subject to royalty or tax payments. However, on the flip side, if ConocoPhillips does not provide its own product and purchases it instead, then the value of the purchased product becomes a deduction against tax.

[4:18:26 PM](#)

REPRESENTATIVE WILSON asked how much production will increase.

[4:18:56 PM](#)

MR. MITCHELL clarified that Prudhoe Bay has its own diesel making plant, as does Kuparuk. The proposed project would be one plant that would serve both Prudhoe Bay and Kuparuk. The combined facility would not create an incremental volume [increase]. He stated, "For the plant at Kuparuk it's additional, but that's to be able to provide the use for Prudhoe Bay as well.

[4:19:36 PM](#)

REPRESENTATIVE WILSON said she assumed, from previous testimony, that ConocoPhillips would be able to sell diesel to some of the explorers and other companies.

[4:19:51 PM](#)

MR. MITCHELL said that is correct; it will be able to provide ultra low sulfur diesel for Slope-wide use. To the extent it isn't used in ConocoPhillips own operations, it would be subject to royalty and tax.

[4:20:12 PM](#)

REPRESENTATIVE WILSON acknowledged the project is relatively small now but could mushroom into something big. She expressed concern about the amount the state would lose if that happened.

4:20:23 PM

MR. MITCHELL said it should not mushroom into anything beyond the sum of what is available today. The Kuparuk facility would be larger but it would replace some of the diesel production taking place at Prudhoe today.

4:20:52 PM

MR. TAYLOR added:

If you think of the logistical complexity of what we would have to do if it was not manufactured on site - on site it would be a construction project that would be for the beneficial use of the lease. It's designed to meet the EPA [Environmental Protection Agency] and ADEC [Department of Environmental Conservation] requirements for road applications. So there is current diesel that's being manufactured now and it's being manufactured on the lease for the benefit of the lease in the local area.

If we were not to build a plant of ULSD on the Slope, then the logistics that would be behind it is that crude oil would be produced down the pipeline, be picked up by a boat, be taken to a refinery somewhere, then remanufactured into ULSD and then have to be transported back up to the Slope to be used on the Slope. So all that seems to add additional costs and inefficiencies when it's our opinion it would be more efficient to be done locally and that it is a beneficial use of the lease and it is a lease cost associated with it. So, that's the thinking that we're applying to it.

Some of the added risks I think were alluded to this morning were that depending on what that transportation would look like, whether it's rail up to Fairbanks and then trucked on the Haul Road up to the Slope that that starts to add some risk associated with derailment or roll over or some potential risk associated with the environment. So that's another added attribute of consideration.

It's not the sole determining factor but those are some of the complications that go through our minds

when we think about doing something locally, something for the benefit of the lease to meet those environmental requirements as opposed to going through the tortuous process of taking it from the Slope, taking it to a refinery and then bringing it back.

[4:22:46 PM](#)

CO-CHAIR GATTO asked if ConocoPhillips currently produces all of the diesel needed and more or whether the amount it is producing does not satisfy the requirement.

[4:23:07 PM](#)

MR. TAYLOR answered he does not know whether any surplus is produced, but he noted the ULSD project is designed with local use in mind. Its design capacity is 2800 barrels of diesel per day, which is broken down into 1,000 barrels per day for use in the greater Prudhoe Bay area and 700 barrels per day for Kuparuk. The remainder would be used for rigs and contractor support. To the extent available, it could be supplied to local communities for heating fuel.

[4:23:58 PM](#)

CO-CHAIR GATTO said he is curious about whether independents and others would have equal access or whether diesel would be rationed until the three major producers' demand is satisfied.

[4:24:18 PM](#)

MR. TAYLOR responded his project engineers and economists have informed him the 1,000 barrels a day is designed for Prudhoe Bay demand and 700 for the Kuparuk area and the balance is for the independents, contractors, and to support lease operations, and could be made available to others at the local market price.

[4:24:50 PM](#)

CO-CHAIR GATTO asked if a competitor would suffer an economic penalty when buying that diesel.

[4:25:24 PM](#)

MR. TAYLOR said ConocoPhillips' intent is to design a plant for the beneficial use of the lease and provide a competitive local

market price, not to create a situation that would gauge anyone inequitably.

CO-CHAIR GATTO asked if a competitive local price means it would be competing with a Fairbanks manufacturer who is trucking it to a facility.

MR. TAYLOR believed local market determination would involve factors like that as well as associated manufacturing costs.

[4:26:08 PM](#)

CO-CHAIR GATTO asked if ConocoPhillips pays federal or state fuel taxes on the diesel it produces and consumes.

[4:26:17 PM](#)

MR. MITCHELL said he would need to look into that.

[4:26:26 PM](#)

REPRESENTATIVE SEATON said he doesn't believe anyone opposes building a plant; the question is whether the state should subsidize it with credits. He asked at what point ConocoPhillips is taking capital credits and deductions on refinery module expenses and when they reflect on PPT.

[4:27:46 PM](#)

MR. MITCHELL said ConocoPhillips would recognize those charges as they are incurred. That is the case for all expenses - operating and capital.

[4:28:18 PM](#)

REPRESENTATIVE SEATON recalled that the committee previously discussed this issue to ensure that the state is not financing [refinery modules] built in Korea, Japan or Alabama and then having those capital credits and expenses deducted "when the units reached Alaska." He expressed concern that Mr. Mitchell has testified that if the tax structure changes and the capital credits are not issued, the plant might not be built. He asked at what point, since the capital credits have already been taken, ConocoPhillips might say it no longer plans to build the plant or decides to delay its construction for many years.

MR. MITCHELL responded:

We recognize the credits, the expenditure, when we are incurring it. Now, if there's ... rules that limit the timing of when you can do that - if the PPT or tax legislation defines specific rules around when you can do that - then we will do it in accordance with those rules.

By having incurred the expenditure, he remarked, by definition, the company is proceeding with the project.

REPRESENTATIVE SEATON relayed that legislators have heard that if the state doesn't "give the tax credits," ConocoPhillips may not build that plant even though the capital credits and deductions have already been taken. Nothing in the current bill, he surmised, stipulates when a company must make a decision regarding whether to proceed with a project. At what point, he asked, would ConocoPhillips Alaska, Inc., say it's not going to build a plant and thus require a tax credit refund. He stated the citizens of Alaska are worried about "getting gamed" on the net system. Therefore, he pondered, wouldn't the state be better off by ensuring that the Capex doesn't get deducted until it reaches Alaska.

MR. MITCHELL indicated that concern ought to be alleviated by the fact that ConocoPhillips Alaska, Inc., has neither committed to incurring, nor has incurred, the expenditure for the "hydro-treater," which would remove the sulfur. He acknowledged, though, that other expenditures have been incurred to scope and work the project. He added, "We typically would not be in a situation where we're spending those dollars, claiming it on a PPT return, and then deciding we're not going to go ahead with it. At that point we're well sunk, if you like, into that project."

REPRESENTATIVE SEATON reiterated that Alaskans are simply concerned about the possibility that companies will game the system, and that's why the Legislature may need to tighten the statute in that regard.

[4:34:51 PM](#)

REPRESENTATIVE ROSES asked whether state and federal taxes are paid on the diesel being produced and whether EPA is requiring low sulfur diesel be used for industrial applications only or for all purposes, including home heating.

[4:35:37 PM](#)

MR. TAYLOR said his understanding is that EPA regulations are focused on road use.

[4:35:52 PM](#)

REPRESENTATIVE ROSES asked whether the two plants that cannot produce low sulfur diesel will be dismantled or whether they could be used to produce excess [diesel] for local communities.

[4:36:20 PM](#)

MR. TAYLOR thought ConocoPhillips would continue to operate those plants to the extent that normal diesel can be used and has a beneficial use on the lease. He pointed out taxes would be paid on any sales transactions.

[4:37:09 PM](#)

REPRESENTATIVE ROSES said he would hate to see the existing plants be abandoned when they could be used for an alternative purpose.

[4:37:25 PM](#)

MR. TAYLOR said ConocoPhillips would maximize the use of its preexisting investments to the extent possible.

[4:37:38 PM](#)

REPRESENTATIVE ROSES asked whether the plant has a remaining life expectancy.

[4:37:56 PM](#)

MR. TAYLOR said he does not know how many years of use are left on the existing plants but, to the extent they are economically viable and there is beneficial use on the lease or to the local market, that should be addressed on an ongoing basis.

[4:38:23 PM](#)

CO-CHAIR GATTO acknowledged at some point the plants will have to be replaced and replacing them sooner provides the advantage of producing low sulfur diesel. However, it would be advantageous to know the remaining life span.

[4:39:26 PM](#)

MR. TAYLOR said, for the record, this project is in a state of sanctioning for ConocoPhillips Alaska, Inc. and its partners. ConocoPhillips is on hold with logistical plans to continue to meet EPA and ADEC requirements for ULSD use. The project is in a design phase to where it could go forward for sanctioning but it has not invested substantial dollars so that it could claim any credits. The sanction decision must be made before the state chooses whether deductions can be taken.

[4:40:30 PM](#)

CO-CHAIR GATTO asked if the incurred charges have been charged as operating expenses.

[4:40:37 PM](#)

MR. TAYLOR said most of those charges have entailed ongoing engineering and design costs, which is the normal practice for all operating expenses on any project for technical staff.

[4:40:56 PM](#)

REPRESENTATIVE SEATON said he has heard shipping companies say 60 or 200 trucks are loaded and waiting to come up from Seattle [with supplies for] this plant but were put on hold. He asked if that is true.

[4:41:47 PM](#)

MR. TAYLOR said he was not aware of that. ConocoPhillips has not expended substantial capital outlays on the project. He said it is possible that a procurement process or sourcing of materials may have occurred.

[4:42:16 PM](#)

MR. MITCHELL continued with his presentation:

The other item we wanted to touch on in the context of exclusions or expenditures to be excluded as allowable costs is the language that's in this draft bill on unscheduled maintenance or maintenance that causes unscheduled production interruptions and the way that language is worded. Let me just back up and say we

understand the event that triggered the dialog around that and we understand there's something that needs to be addressed through this but the way that language is laid out, it is very broad and all encompassing and, in reality, would be very difficult to actually administer and audit, even with the additional audit resources that the Department of Revenue is trying to secure through this process. I still think that particular area will be very difficult for all of us to ensure this full compliance with. It's a combination - it's not just an accounting. This is not just a financial audit type of matter. It gets to the heart of the nature of production operations and all the various things that go on that can have an impact on our day-to-day operations, which can follow all of the normal, sound operating practices, the recommended maintenance activity and yet still there will be things that happen that weren't planned. It will be very difficult to not only identify those specific events, but at the same time keep track of what's the specific cost of that event so that we exclude it from the PPT computation. It kind of - to me it's the sledge hammer to crack a nut solution and if we go on to the next page, we potentially can see what we're dealing with here.

[4:44:34 PM](#)

What this chart represents is daily production for the Kuparuk area from December 2006 through to pretty much current. And there's nothing smooth whatsoever about that line and if you trend it out and actually do a monthly average and draw that line on a monthly average, it probably would look reasonably smooth with a couple of specific spikes or dips for specific events. When you look at that it then becomes on a daily basis it is very difficult to step back and identify specifically which of those events that were a function of unscheduled down time and what were the costs associated with that specific event.

I think when the PPT legislation was put into place, there was the 30 cent per barrel reduction, if you like, was factored in for some of this. It's never been entirely clear to me exactly what the intention was of that but there is that reduction in the deduction, if you like. And at the same time, in this

latest version of the bill, I think it's subsection (6) of this relevant section talks about disallowing costs associated with violation of law, failure to comply and so on, so there already is a compliance type standard elsewhere in the bill and the piece that we're talking about, which is subsection (19) I think, then becomes very broad and difficult to administer and so I think our comment around that is it's just something that we need to be very careful how we put that into law because the way it's worded it just appears to be fraught with difficulties in making sure that we're compliant and the state is capable of ensuring that we're complying through the audit process.

4:46:42 PM

REPRESENTATIVE SEATON asked if Mr. Mitchell would be amenable to deleting [proposed AS 43.55.165(e)(19)] and changing [proposed AS 43.55.165(e)(6)] to ensure that expenses related to a recovery from criminal negligence were not allowed as a lease expense.

MR. MITCHELL indicated that solution would be preferable to what is currently in the bill.

4:48:04 PM

MR. MITCHELL continued his presentation:

[Slide 19] I think we just have a couple of other points that are really not that significant but just wanted to mention. In terms of information sharing, there's a sort of catch-all phrase that provides the Administration with the ability to request any other information it considers necessary and I just feel it's very broad to have that broad brush any other and there's always going to be some element of concern where we're subject to that very broad requirement. We understand ultimately where the Department of Revenue - what they're trying to accomplish in terms of having the right data to do what they need to do and we're supportive of that. This catch-all gives us a little bit of concern because of the breadth of it.

4:49:01 PM

REPRESENTATIVE SEATON asked for suggested wording to narrow that down and still allow DOR to get the information it needs for a net tax system.

[4:49:30 PM](#)

MR. MITCHELL said he was sure ConocoPhillips could come up with language that would address its concerns and provide DOR with the level of comfort it needs.

[4:49:46 PM](#)

REPRESENTATIVE SEATON requested that ConocoPhillips Alaska, Inc. forward its suggested language to the committee for consideration.

CO-CHAIR GATTO added in a timely manner.

MR. MITCHELL agreed to do so.

[4:50:14 PM](#)

MR. MITCHELL continued:

The statute of limitations [Slide 20] got some discussion this morning as well and, again, it's not necessarily a huge item but I think it's in all of our interests that the audit activity gets conducted timely and extending that statute from 3 years to 6 years just gives the potential. It doesn't mean to say it will happen. It just gives the potential that this audit work can drag on over a longer time period than it might need to significantly. If you take that to its literal extreme, by 2011, the year when the PPT legislation requires that review with a 6-year statute of limitations, in theory that first audit might not even be complete. So, our preference is to be able to get this work done as quickly as possible.

Of course, from a - I have to acknowledge from an industry perspective, we're always going to say we prefer a shorter time on a statute so - but six years feels like a long time to have that hanging out there.

[4:51:32 PM](#)

MR. MITCHELL continued:

So that really just leaves us with our kind of wrap up, which actually is a repeat of how we introduce this in terms of our key points with regard to this bill. We do believe that there needs to be the alignment between the state and the industry as we've said. When industry is doing well, the state is doing well. Projects that are economic for us are projects that generate revenues for the state and so we really have that common interest there. We do believe that it's too early to change PPT in the context of significantly changing what that tax structure looks like. It's very early and it's unsettling having that continual - the frequency of tax changes. In this presentation, in terms of tax take, we really focused our discussion around what impact the progressivity on a pure gross basis can have and we really want to emphasize the message that when there's any form of a tax - production tax that comes straight out of the gross - then it has the potential to have a detrimental impact. The PPT, the way it's structured with both the base rate and the progressivity on the net, it does work. It's self adjusting. The more challenged projects get the right kind of deduction and relief and yet, the more profitable areas with the progressivity still end up paying a higher percentage, especially as you look in the current price environment we see that percentage increase significantly. You almost get the behavior like - on the marginal dollar - like a high gross rate.

And then lastly, we just talked on some of the administrative provisions. We just want to make sure that we don't put anything into law that, with the benefit of hindsight, we find really that wasn't what we intended or that became somewhat unworkable so we just encourage that the right amount of thought and consideration go into that.

[4:53:38 PM](#)

CO-CHAIR GATTO said as partners, the state and industry both want money. He would prefer the word "quest" be used, rather than "aligned," which he feels is too formal.

[4:54:38 PM](#)

CO-CHAIR GATTO thanked Mr. Taylor and Mr. Mitchell for their presentations and asked Mr. Gibson and Ms. Houle to give their presentation to the committee.

[4:58:55 PM](#)

KURT GIBSON, Acting Deputy Director, Division of Oil & Gas, Department of Natural Resources, introduced Julie Houle, Section Chief for the Resource Evaluation Section in the Division of Oil and Gas and told members they would discuss the exploration incentive credits in AS 43.55.025, enacted in 2003. He continued:

It preceded PPT. There were some changes to that particular statute that were a part of the Governor's original legislation. Those changes to the existing statute were dropped between the bill moving from the ... House Oil and Gas Committee to House Resources and so we just wanted to chat about why those were appropriate in the original piece of legislation and how we might be able to create some language that is suitable to reinsert into the piece of existing legislation.

We're going to talk, really kind of in broad terms, conceptually why the language was drafted the way it was, why the changes were made. Essentially it was housekeeping. As I said, the statute already existed for exploration incentive credits for explorers. There were some, as with any rules, over the course of time it becomes evident that there are some shortcomings and so we just wanted to kind of sure up that stuff and make sure that the state was receiving proper value for the credits that it was distributing.

MS. HOULE informed members the sections were numbered 36 through 44 in the original bill as introduced.

[5:01:08 PM](#)

MR. GIBSON continued:

So, the original language intended to do the following. It intended to broaden the existing program to create greater credit incentive for explorers within certain proximity and for wells drilled within a particular timeframe. It also was

intended to provide additional predictability and consistency for explorers in terms of whether or not their exploration activity would qualify for these credits. And then finally, it was intended to sure up certain data requirements that the original statute was not entirely effective in ensuring that the state receive certain seismic and well data and core data that the original legislation - to make sure that the state received that for a number of purposes and Julie will talk about that some as we kind of get to that point.

[5:01:57 PM](#)

MS. HOULE told members DOR and the Division of Oil & Gas get involved by assessing what technical data needs to be submitted to approve an application. However, DOR approves or disapproves the expenditures.

[5:02:18 PM](#)

MR. GIBSON continued:

So the language in the original ACES bill was intended to broaden the existing program so that certain exploration activity that occurred within three miles of existing wells would receive a 30 percent tax credit if they were drilled within a certain particular timeframe and the original language addressed an 18 month timeframe, as long as they were no more recent - or rather if they were within an 18 month timeframe they would qualify for this tax credit.

It also broadened the existing program by allowing for five percent deduction for - or tax credit for old seismic data that certain existing producers in Cook Inlet and the North Slope both may have, kind of, on their books or in the vault as Julie says, creates a value for the state by ... attaching a tax credit to ... the cost of that activity. That data then becomes public and it creates the ability then for new explorers to access that data and determine whether or not certain areas are prospective and whether or not they want to engage in exploration activity in those areas.

[5:03:37 PM](#)

MS. HOULE said the last bullet would extend the allotted time to drill wells from 150 to 540 days. This would occur when a company plans to drill several exploration wells in one season. The wells might be less than three miles apart but are drilled within a short time period while a rig is onsite.

[5:03:57 PM](#)

MR. GIBSON continued:

[Slide 3] So the original statute, I think, had the unintended consequence of requiring wells to be drilled within five months of one another, or rather I guess it could be logically determined that the intent was then to make it during a single drilling season whereas an exploration may extend beyond a single drilling season and those exploration wells may be within three miles of one another. The intent of the legislation is to allow those exploration wells in the exploration program to all qualify for the exploration incentive credit.

[5:04:31 PM](#)

REPRESENTATIVE GUTTENBERG said he worked on a seismic crew in the early 1970s. He asked if that kind of information is translatable to today's standards.

[5:04:51 PM](#)

MS. HOULE replied some data from that time period is still good with reprocessing; particularly the 2-D seismic drilled for the deeper objectives. Whether it is useable depends on the quality and whether it can be digitized.

MR. GIBSON added the commissioner of DNR can determine whether making that data eligible for credits is in the best interest of the state.

[5:05:24 PM](#)

MS. HOULE clarified the seismic data could not be from an existing unit.

[5:05:34 PM](#)

REPRESENTATIVE SEATON referred to the 20 to 30 percent expansion and asked if that means 30 percent in addition to the 20 percent for PPT.

[5:05:44 PM](#)

MS. HOULE told members the AS 43.55.025 exploration incentive credit (EIC) credit was originally written to apply 20 percent to a well drilled more than three miles [from an existing unit] and to apply an additional 20 percent for wells drilled 25 miles away from an existing unit. She added the credit would also apply to seismic activity outside an existing unit.

[5:06:13 PM](#)

REPRESENTATIVE SEATON asked if the current EIC now at 30 percent would be in addition to the PPT credit of 20 percent and in addition to the deductibility against PPT of 25 percent under ACES.

[5:06:36 PM](#)

MR. GIBSON said he was not sure how the mechanics of the two pieces work but he did not believe the intent is to stack the deductions so that the state is a 70 percent participant in the investment. The intention of the EIC is to draw distinction to strictly exploration activity.

[5:07:07 PM](#)

REPRESENTATIVE SEATON said he believes it previously amounted to an additional 20 percent over the 20 percent PPT credit for a total 40 percent tax credit, and the expense was deductible. He asked Mr. Gibson to run the figures and report back to the committee to ensure the legislation is not providing a 30 percent EIC plus 20 percent PPT, plus 25 percent deductibility, plus a 9.4 percent deduction against the corporate income tax, and then federal income tax deductions.

[5:08:08 PM](#)

MR. GIBSON said he will prepare a stylistic example of how these credits and deductions would work for a qualified explorer.

[5:08:45 PM](#)

REPRESENTATIVE ROSES referred to the 5 percent credit on seismic surveys and asked if the commissioner is the only person who would determine whether the acquisition is in the best interest of the state or whether a procedure is followed prior to the commissioner's determination.

[5:09:04 PM](#)

MS. HOULE said most likely the Resource Evaluation Section group would review the data and determine whether it is in the state's best interest to acquire that data. The problem with older seismic data is that under the current system, an applicant would request a permit to shoot seismic under the multi-land use permit from the permits group. The Division of Oil & Gas gets the confidential data so that data never becomes public. Newer data becomes public after 10 years under the EIC to make older data available to companies interested in a specific area.

[5:10:16 PM](#)

REPRESENTATIVE ROSES said his concern is that the state would be giving a 5 percent credit against taxes that would become managed by a political appointee, not by someone in the best position to determine what is in the best interest of the state. A very pro-oil development commissioner is more likely to grant the five percent credit whenever requested.

[5:11:17 PM](#)

MS. HOULE clarified that her group makes the recommendation to the commissioner based strictly on a technical point of view; it has no political ambitions.

REPRESENTATIVE ROSES said he just wanted to clarify his position.

[5:11:44 PM](#)

REPRESENTATIVE GUTTENBERG asked how long seismic data remains confidential.

[5:11:55 PM](#)

MS. HOULE explained under the current statutes, seismic data shot under the multi-land use permit is kept confidential by the Division of Oil & Gas forever. The division can use the data in its assessments but it cannot be released to the public. She

noted the data would have to be obtained directly from the owner but that can be difficult because often several companies are involved and one may not want the data to be disclosed.

[5:12:43 PM](#)

MR. GIBSON continued with his presentation:

[Slide 4] So the first purpose of the EIC language as we discussed was to broaden the program. The second objective is to enhance predictability for explorers. Currently the way the EIC program works under existing statute, explorers conduct certain ... exploration activities oftentimes at great expense and then come back to the state and ask whether or not what they've done qualifies for a credit under the EIC program.

The intent of the language in the Governor's bill was to allow additional predictability for explorers so that by coming in for pre-approval, by coming to the Department of Natural Resources, for example, and laying out the exploration plan and allowing it to be scrutinized by people like the Resource Evaluation group, the commercial section and others, we could make a determination as to whether or not it was truly an exploration program, whether it qualified under the existing EIC language, and then an explorer could go more forward with the knowledge that the activity expenditures that he was undertaking were going to be eligible for the credit, rather than have this uncertainty associated with this existing language that requires them to kind of come hat in hand after having done their work and ask whether or not the work they've done qualifies for a credit.

So the intent is to make it more fair, more predictable for investors on a going forward basis.

[5:14:18 PM](#)

MS. HOULE added that would verify the well was being drilled for a legitimate reason.

[5:14:25 PM](#)

CO-CHAIR JOHNSON asked how long it would take to get pre-approved.

5:14:39 PM

MS. HOULE answered that depends on how cooperative a company is with the division. Some companies have an ongoing dialog with the division's geophysicist and engineer and the information flow is good. In those cases, pre-approval could be granted within a few weeks to a month, depending on the division's workload.

5:15:27 PM

CO-CHAIR JOHNSON asked about new entrants that have not established dialogs.

5:16:08 PM

MS. HOULE noted most new entrants have been pretty forthcoming. She estimated that given the right data, the division could probably give them an answer within a few weeks.

5:16:28 PM

MR. GIBSON explained that a tax credit is associated with the activity undertaken by an explorer. An explorer can undertake an exploration program absent credits with no delay. An explorer could proceed under current statute and the point in time for determining whether the activity is qualified for credit wouldn't change. This merely makes a shift from a back end to a front end determination and should have no bearing on how quickly an explorer can proceed.

5:17:18 PM

CO-CHAIR JOHNSON asked if an explorer filed an application for a credit a month ago that was approved, what kind of liability the state would be looking at if the legislature changes rules that nullify the approval.

5:18:03 PM

MR. GIBSON said he could not put a number on the liability. He said legislation has frequently changed but only so much certainty can be provided to industry.

5:18:38 PM

REPRESENTATIVE SEATON questioned whether this program change requires an applicant to use the pre-approval process to get tax credits or whether this encourages applicants to explore and make application later.

[5:19:29 PM](#)

MR. GIBSON said his understanding is that this is a wholesale change to Section (c) of AS 43.55.025, which lays out the process for filing for and receiving a credit. Under current statute, that process takes place after expenditure. This new language repeals and reenacts that section so that the process would take place on the front end. He believes this change would no longer allow the post-approval process to take place.

[5:20:20 PM](#)

REPRESENTATIVE SEATON questioned whether it is advantageous to make a total change rather than to allow both processes to be in place.

[5:20:52 PM](#)

MS. HOULE said if the process was an either/or, explorers would run the risk of not getting their credits.

[5:21:02 PM](#)

MR. GIBSON added:

Representative Seaton, I would ... just add to that, as Julie mentioned, if it was set up so that it was an either/or situation, for example if an explorer was uncomfortable with the speed with which the state was able to conduct its analysis, if there were a mechanism in place that would allow them to forego pre-approval and instead opt for approval after the fact, I'm not sure that that would necessarily be a major problem but I do think that it's probably important to make a decision as to whether or not an explorer should be allowed two bites at the apple. Either their exploration program is consistent with the statute and qualifies or it does not.

[5:21:53 PM](#)

REPRESENTATIVE GUTTENBERG said he recognizes that legislative changes could alter the division's relationship with the industry. He referred to the third bullet on Slide 4, "Prudent Practice"; and asked if the division has an internal mechanism in place to determine what that is.

[5:22:56 PM](#)

MS. HOULE said the staff in the Resource Evaluation Section have enough petroleum industry background that they sometimes know the data better than industry staff and are very capable of determining what is in the best interest of the state.

[5:23:20 PM](#)

REPRESENTATIVE GUTTENBERG asked whether the division ever tells an applicant to change something because it is wrong.

[5:23:37 PM](#)

MS. HOULE said if a company came in with a request to drill within three miles of an existing well, the division would say its target objective must be three miles from the existing well, but division staff would not advise that a prospect is no good.

[5:24:29 PM](#)

REPRESENTATIVE GUTTENBERG asked if the division would inform an applicant of a capped well within 2.5 miles.

[5:24:39 PM](#)

MS. HOULE said the division would inform that company.

[5:24:54 PM](#)

REPRESENTATIVE GUTTENBERG asked whether the information about the capped well is subject to confidentiality.

[5:24:58 PM](#)

MS. HOULE said if the capped well is public record, the division could disclose that information. However, even if a well is drilled within the 24 month confidentiality period, the well's location would be public knowledge.

[5:25:16 PM](#)

CO-CHAIR JOHNSON asked why a company that applied for a permit to drill within 2.5 miles of another well, and after being informed of its proximity to another well moved the location a half mile away, wouldn't then be eligible for the credit. He also asked why the division wouldn't advise an explorer that it would be drilling a dry hole if the division had that information.

[5:25:59 PM](#)

MS. HOULE said usually eight of ten wells drilled are dry holes.

[5:26:21 PM](#)

CO-CHAIR JOHNSON said she commented that the division would not tell an applicant if it was applying to drill a well in a bad location.

[5:26:37 PM](#)

REPRESENTATIVE GUTTENBERG asserted, "Sometimes you want to define the area or you have to drill there, I mean 2.5 miles instead of 3 miles, you don't think it's there and giving them the information might determine whether or not they are going to proceed at all."

[5:26:53 PM](#)

MS. HOULE responded that if an explorer was going to drill a well 2.5 miles within another, it would not qualify for the credit but the explorer would know that up front.

[5:27:09 PM](#)

MR. GIBSON said, in response to Co-Chair Johnson's first question about allowing a company to come back retroactively, the division would like companies to make decisions on a forward-looking basis and deal with applications one time. While Ms. Houle's staff is extraordinarily talented, it is not a "deep bench." The division would prefer to agree to a process and adhere to it.

[5:28:25 PM](#)

CO-CHAIR JOHNSON asserted it is refreshing to hear Mr. Gibson and Ms. Houle say they have adequate staff to do the job.

5:29:02 PM

REPRESENTATIVE SEATON commented:

... I appreciate your clarification of us pre-approving these as a working interest partner in this because that clarified it for me that yes, it makes much sense to do these things upfront instead of coming at the end because if we're talking about the 30 plus the 20, we are a majority partner in this and so the idea that somebody might go out and do these for, you know, tax credits and all, because of some other tax consequences for other fields that they have or something, is a possibility. So I do appreciate that idea and I think I've changed my opinion so your comments are well taken.

5:30:20 PM

MS. HOULE noted the division needs another reservoir engineer; currently it has one reservoir engineer who covers the entire state.

CO-CHAIR JOHNSON asked whether that is a vacant position or new position.

MS. HOULE clarified the division has a vacant position.

5:30:51 PM

MR. GIBSON continued his presentation:

[Slide 5] We've talked about kind of two of the intended goals of the language in the Governor's bill, the first being the - or the second being the predictability and the other being, kind of enhancing or expanding the EIC program, but the data sharing component of this is perhaps the most important. I think Julie is undoubtedly the most qualified to speak to this but, again, it comes down to a determination of whether or not we've struck a reasonable deal with the existing EIC statutory language. The language is intended to provide exploration incentive credits to explorers in exchange for a number of things and among those things are obviously increased production is good for the state in terms of royalty and production

tax take but at least as importantly, in terms of being able to promote or represent what the prospectivity of various areas is, we've got to have information. Information is kind of the stock and trade of Julie's Resource Evaluation group. I think the best thing to do is to hand it over to the expert and let her talk to you a little bit.

[5:32:22 PM](#)

MS. HOULE told members:

One thing I'd like to reiterate is that this 43.55.025 program is the Department of Revenue's and the Division of Oil & Gas provides technical guidance to collect the data and make sure that the state is getting the data that it needs. As we've been administering - or helping DOR with the program, we found a few glitches that we'd like to change in the program and one of them has to do with seismic data.

Currently there are a couple of aspects that are troublesome. One is a company can apply for an EIC now and only the portion over state lands gets credit so then they only give us the data for that portion that's on state lands. If you have a checker board situation where you have private landowners, then we don't get that data so the problem is you kind of have an incomplete picture. You have a puzzle with a lot of pieces missing. Also when you shoot seismic, you can say well I shot 100 miles and so it was \$100,000 so, if I do the math right, I guess \$10,000 per mile but it may not be that each mile is equivalent. You might have had ... trouble shooting that one line. You know, it's not really an even split so what we added in there in the language was that if you apply for an EIC, you have to provide the entire data set.

[5:33:53 PM](#)

REPRESENTATIVE WILSON asked what an EIC is.

[5:34:07 PM](#)

MS. HOULE explained an EIC is an exploration incentive credit. She added another problem that has arisen with seismic data is that sometimes the seismic shoot is over an existing unit or

outside a unit but it gets sliced at the unit boundary. The Division of Oil & Gas gets the data, for ten years the only data released to the public is the data outside of the unit. The division is thinking ahead about investing in the future when new explorers want to come in and need a good data set.

[5:34:43 PM](#)

MS. HOULE said regarding well data, the division would like to comport with the AOGCC regulations, which require that well data be kept confidential for two years. Currently, an explorer can apply for extended confidentiality if the activity is near unleased acreage. If an explorer wants a well credit, the information must be available to the public in two years. The AOGCC does not collect any fluid or core data. Core data is collected in Alberta and made available to the public. The division would like to be able to retain core data and fluid data for future explorers. She summarized her comments are intended to sure up some of the glitches in the existing program.

[5:35:59 PM](#)

CO-CHAIR JOHNSON asked if core data means the actual core.

MS. HOULE said that is correct.

CO-CHAIR JOHNSON asked if the actual cores will be stockpiled or if images of them will be digitized.

[5:36:22 PM](#)

MS. HOULE answered that during the two-year confidentiality period the company could keep the data confidential but would have to allow the state access to it. After two years, the core material could be moved to the Geologic Materials Center in Eagle River.

[5:36:53 PM](#)

CO-CHAIR JOHNSON asked whether a fiscal note to build a new building in which to keep the cores will accompany the bill.

[5:37:02 PM](#)

MS. HOULE acknowledged the existing facility needs to be rebuilt. She noted the core facility in Alberta is supposed to

be world class and there is no reason Alaska cannot have a similar building.

[5:37:24 PM](#)

CO-CHAIR GATTO asked the diameter of the cores.

MS. HOULE said in general, the diameter is 4 inches. The cores are cut in half lengthwise. Sometimes a two-third, one-third slab is cut so that one-third can be viewed.

[5:37:45 PM](#)

CO-CHAIR GATTO asked if the diameter is 4 inches because when the core is removed, the hole becomes a well.

[5:38:01 PM](#)

MS. HOULE said the size has to do with the ability to get porosity and permeability data.

[5:38:55 PM](#)

REPRESENTATIVE GUTTENBERG questioned whether she is talking about exploratory wells and not wells that go into production.

MS. HOULE answered the current AOGCC regulations are being changed so that development well data immediately becomes public one month after it is drilled. She said she was referring to exploration wells that fall under the two-year confidentiality period.

[5:39:17 PM](#)

REPRESENTATIVE ROSES asked when the two-year time clock starts ticking.

[5:39:30 PM](#)

MS. HOULE replied it begins when they finish drilling the well.

[5:39:45 PM](#)

REPRESENTATIVE WILSON noted that in previous testimony, oil company representatives expressed concerned about providing certain data. She asked if that concern was directed at the

data requested by the Department of Revenue or whether it also applies to the data to which Ms. Houle is speaking.

[5:40:19 PM](#)

MS. HOULE said that is a good point and that one company is particularly concerned about having to provide core data. She believes the division can assure confidentiality. She pointed out that is common practice in Alberta and other countries.

[5:40:52 PM](#)

MR. GIBSON reiterated the state is paying for this information so it is appropriate to ask for certain data.

[5:41:05 PM](#)

MS. HOULE added the state is giving a credit and investing in explorers today and will be making data available later on to new explorers that will have new technology.

[5:41:26 PM](#)

MR. GIBSON told committee members their presentation was concluded.

[5:41:41 PM](#)

CO-CHAIR GATTO announced that all of the documents that have been presented to the House Resources Committee are available online at: [HouseMajority.org](http://HouseMajority.org), under a caption entitled "What's Inside," under House Resources Committee/ACES/PPT.

[HB 2001 was held over.]

[5:42:30 PM](#)

#### **ADJOURNMENT**

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at [5:43:15 PM](#).