

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

February 25, 2016

8:34 a.m.

MEMBERS PRESENT

Representative Benjamin Nageak, Co-Chair
Representative Mike Hawker, Vice Chair
Representative Craig Johnson
Representative Kurt Olson
Representative Paul Seaton
Representative Andy Josephson
Representative Geran Tarr

MEMBERS ABSENT

Representative David Talerico, Co-Chair
Representative Bob Herron

COMMITTEE CALENDAR

HOUSE BILL NO. 247

"An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the

limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 247

SHORT TITLE: TAX;CREDITS;INTEREST;REFUNDS;O & G

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/19/16	(H)	READ THE FIRST TIME - REFERRALS
01/19/16	(H)	RES, FIN
02/03/16	(H)	RES AT 1:00 PM BARNES 124
02/03/16	(H)	Heard & Held
02/03/16	(H)	MINUTE(RES)
02/05/16	(H)	RES AT 1:00 PM BARNES 124
02/05/16	(H)	-- MEETING CANCELED --
02/10/16	(H)	RES AT 1:00 PM BARNES 124
02/10/16	(H)	Heard & Held
02/10/16	(H)	MINUTE(RES)
02/12/16	(H)	RES AT 1:00 PM BARNES 124
02/12/16	(H)	Heard & Held
02/12/16	(H)	MINUTE(RES)
02/13/16	(H)	RES AT 1:00 PM BARNES 124
02/13/16	(H)	-- MEETING CANCELED --
02/22/16	(H)	RES AT 1:00 PM BARNES 124
02/22/16	(H)	Heard & Held
02/22/16	(H)	MINUTE(RES)
02/24/16	(H)	RES AT 1:00 PM BARNES 124
02/24/16	(H)	Heard & Held
02/24/16	(H)	MINUTE(RES)
02/25/16	(H)	RES AT 8:30 AM BARNES 124

WITNESS REGISTER

KEN ALPER, Director
Tax Division
Department of Revenue (DOR)
Juneau, Alaska

POSITION STATEMENT: On behalf of the governor, continued the PowerPoint presentation, "Oil and Gas Tax Credit Reform- HB247, Additional Modeling and Scenario Analysis - Part 1a."

CHERYL NIENHUIS, Acting Chief Economist, Commercial Analyst
Anchorage Office
Tax Division
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Answered questions related to HB 247.

ACTION NARRATIVE

[8:34:02 AM](#)

CO-CHAIR BENJAMIN NAGEAK called the House Resources Standing Committee meeting to order at 8:34 a.m. Representatives Tarr, Josephson, Hawker, Seaton, and Nageak were present at the call to order. Representatives Johnson and Olson arrived as the meeting was in progress.

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

[8:34:59 AM](#)

CO-CHAIR NAGEAK announced that the only order of business would be HOUSE BILL NO. 247, "An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits

for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

[8:35:28 AM](#)

KEN ALPER, Director, Tax Division, Department of Revenue (DOR), on behalf of the governor, continued the presentation, "Oil and Gas Tax Credit Reform- HB247, Additional Modeling and Scenario Analysis - Part 1a." He advised that the presentation delves into the deep sectional [analysis] and reviewing some of the more complicated pieces of the bill and how they work. The presentation goes into modeling of specific new field scenarios and the overall economic impact of the bill. He noted that the last slide of his previous presentation was slide 44, "Section 17(c): Strengthen the Minimum Tax," which was the end of the conversation of "strengthening minimum tax by moving per barrel credits from month-to-month or preventing that from happening."

MR. ALPER turned to slide 45, "Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit" and said the concept would prohibit a producer operating at loss who is eligible for the gross value reduction (GVR) for the new oil benefit from being used to increase the size of net operating loss. For example, he said, this scenario is akin to the current day of low oil price/low cost. In the event a producer is losing money because the prices are low, it earns an operating loss credit based upon its loss but is allowed to increase the size of that credit by taking the "so-called" gross value reduction (GVR) and subtracting it from the loss to make it appear, on paper, to be a larger loss. He offered that the result of the change would reduce the credit to 35 percent of the actual net operating loss rather than a calculated number that is somewhat higher. Within the upcoming case, he explained, was that the state's liability would be reduced by approximately 50 percent, or in the context of a \$10,000 taxable barrel per day field, of approximately 7.6 million per year.

8:37:59 AM

MR. ALPER moved to slide 46, "Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit - Current law allows GVR to increase an NOL credit." He reviewed the example depicted on the table in a world of \$40 oil, and pointed out the following: West Coast price \$10 transportation - shipping and pipeline tariffs; the well head value, which is also the gross value, \$30 a barrel; lease expenditures - the lifting cost \$36; and the loss is \$6 a barrel. He advised that the model being looked at is based on a single barrel of taxable oil, and for the purposes of this example this producer lost \$6 a barrel producing that oil. The way the GVR works, he explained, is to determine the wellhead value (\$30 gross value), and take 20 percent which equals 6, and subtract it from the net value (negative 6), and the resulting subtraction equals negative \$12. For purposes of the credit calculation, under current law, although the producer lost \$6, it appears as though it lost \$12, and the 35 percent credit (operating loss credit) applied to that \$12 results in a \$4.20 cash rebate for the operating loss credit. The \$4.20 is roughly 70 percent of the \$6 a barrel loss. The bill contemplates that although the GVR is important, for the purposes of reducing the tax burden of profitable new producers, "we don't want that reduction to be useable in the event of a loss," and by by-passing that calculation only the \$6 actual cash flow loss would be eligible for the credit, 35 percent of \$6 equals \$2.10. Therefore, the state's credit liability would be cut in half - \$2.10 per taxable barrel, or when multiplied across the year with a 10,000 barrel field, \$7.6 million a year in credits instead of \$15.3 [million].

8:40:11 AM

MR. ALPER addressed the second example on slide 48, "Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit - Current law allows GVR to increase an NOL credit." He said this example looks at a slightly different type of scenario with a higher oil price, but the company may still be losing money. He described it as a quite plausible scenario especially for a new field because typically the producer drills its first couple of wells, it begins production and has oil flowing, and the producer continues to drill major wells causing additional costs that could cause cash flow losses over the course of the first several years of production. He explained that the scenario depicts higher costs based upon field buildout and also higher prices, still generating a \$10 per barrel cash flow loss, and as the example points out the GVR could lead to very high credits.

He then explained that the scenario started with \$80 oil which is now high priced oil, and pointed out the following: there is the same expense of transportation, wellhead at GVR of \$70, lease expenditures at \$80 per barrel, and now that company lost \$10 per barrel last year. Based upon the \$10 barrel, under normal circumstances the company would receive a \$3.50 credit (35 percent of the loss) except, due to the application of the GVR, it is necessary to go back to the \$70 wellhead value, 20 percent of that \$70 equals \$14. The company would then subtract the \$14 from the negative \$10 to get the red circled number of negative \$24. For the purposes of the credit calculation and only for that purpose, the company is considered to have lost \$24 a barrel, and apply the 35 percent credit to that number, which results in an \$8.40 credit, or 84 percent of its loss is paid by the state's operating loss credit. He said that by making the change envisioned in HB 247, the actual credit paid would be limited to 35 percent of the loss, or \$3.50. In this circumstance, based on a 10,000 barrel field, the difference would be a savings to the state, or a reduction in the state's credit liability, of \$17.9 million.

[8:42:37 AM](#)

REPRESENTATIVE SEATON surmised that the state allows a calculation of net operating loss at 35 percent of the expenditure, and the purpose is to say that in the calculations the net loss is carried forward and could be no more than 35 percent of the company's loss.

MR. ALPER clarified that the loss carry forward credit of 35 percent is 35 percent of the loss itself, statutorily. He said Representative Seaton was absolutely correct because the bill is saying that the amount the state is paying isn't going to exceed a number greater than 35 percent of the loss. He posited that the application of the GVR calculation being used to increase the size of that loss was an unintended consequence of an unforeseen circumstance that was in the formula of the previous legislation that lead to very high credits. Last year and the year before, the operating loss credit was 45 percent, and he said he has seen circumstances where the state was paying credits of more than 100 percent of the loss.

[8:43:57 AM](#)

REPRESENTATIVE JOSEPHSON referred to paying more than 100 percent of the loss and asked whether a model of that is contained within the presentation.

MR. ALPER replied it isn't modeled in any of the slides because it's looking going forward with a 35 percent operating loss credit. He offered that when getting to the \$24 paper loss, the calculated loss after the application of GVR in this status quo scenario, if a person takes 45 percent of that, it would be another \$2.40 on top of the \$8.40 which would be \$10.80. In this case, he pointed out, it would be 108 percent of the \$10 cash flow loss the company actually experienced in its operation, if it was eligible for 45 percent credit if the example on slide 48 were a 2015 example instead of a future year example.

REPRESENTATIVE JOSEPHSON responded that within that scenario for purposes of production tax only, not property and equipment or royalty, the state took absolutely nothing - there's no production tax in that scenario.

MR. ALPER answered that if the company is losing money, unless it is susceptible to the minimum tax of which new oil is not, the state would generally take nothing. In this circumstance, the discussion is minimizing the size of the operating loss credit paid rather than any amount of take. Representative Josephson is correct, he stated, in this circumstance that company would not have paid any production tax.

[8:45:34 AM](#)

REPRESENTATIVE JOSEPHSON pointed out that during yesterday's meeting, Mr. Alper testified that he had reviewed the minutes on the question regarding the monthly calculation of tax and the migration issue, and that he saw only an exchange between a former deputy commissioner and Representative Seaton. Now, he pointed out, Mr. Alper is saying that relative to this "you didn't say an oversight, but that was the essence of it," and asked why that is so.

MR. ALPER reiterated that he does not believe there was much contemplation of what happens in a very low cost scenario and how losses might be treated. The GVR was specifically discussed as a means of reducing tax liability for qualified new oil, and there have been multiple hearings on the debate about what qualifies for new oil, such as new fields, how to define that, new participating areas expanding, expansions to existing, and will there be a menial requirement. The regulatory process, he pointed out, was regarding what would qualify but the actual calculation of how the new oil benefit would be treated in the

event of a loss was never contemplated. In speaking with several professionals within and outside the division, the department's attorneys, and people who closely follow the process, "I've received something like consensus that this was an unforeseen circumstance ... this is not something that we thought of ourselves." He reiterated that when a credit came before [DOR] with this type of calculation, it was stopped in its tracks and given to the lawyers to be certain this was being treated correctly because it appeared intuitively wrong. The law is the law and it was interpreted strictly, he advised, and a strict interpretation led to these calculations. Although it will take money out of the pockets of several companies, that money is greater than 100 percent or very high loss credits that [DOR] believes was outside the intent of the legislature. He said he views it as more of a technical cleanup, although there is a material value to the state to prevent this circumstance from occurring in the future.

[8:48:11 AM](#)

CHERYL NIENHUIS, Acting Chief Economist, Commercial Analyst, Anchorage Office, Tax Division, Department of Revenue (DOR), added that when "we were reviewing this bill, it did come to our attention that a ... net operating loss could be increased by the GVR, and I believe that the administration was made aware of that." Having not been part of the legislative process, she said that she does not know what was communicated.

REPRESENTATIVE JOSEPHSON asked who "we" represents, and assumed that if there is a license plate bill, the governor is advised by the license plate people whether to sign the bill.

MS. NIENHUIS stated "Yes, I'm talking about the previous administration which could explain why Director Alper may not know that we had those conversations."

[8:49:21 AM](#)

REPRESENTATIVE SEATON related that many of the current members of the House Resources Standing Committee were on the committee during the previous administration. He remarked that there was quite a bit of discussion as to whether the 45 percent net operating loss should be allowed because the number was high and it was limited to two years as "kind of a ramp-down to 35 percent net operating loss credit." He stressed there was never an indication, that the committee could be discussing the state picking up 70 percent, 80 percent, over 100 percent of a

company's net operating loss. That would have risen to a level of high concern and however the numbers are calculated here, he opined, that it was not the intent of this committee at any time to say that the net operating loss would exceed 45 percent, and that only for two years. This calculation needs correction back to the [prior] committee's intent, he emphasized.

[8:50:37 AM](#)

REPRESENTATIVE TARR concurred with Representative Seaton and noted that the materials and modeling the previous committee reviewed were well above today's price range and that it was a shortcoming on the part of the committee. She then referred to the fiscal note from Senate Bill 21, and asked what the anticipated fiscal impact of the provisions of that bill were versus the actual fiscal impact. While the comparison may not be available today, it might be a useful comparison to determine whether the committee "over-shot/under-shot" in terms of the committee's expectations.

MR. ALPER described the Senate Bill 21 fiscal note as an excellent historic document, with a table breaking down the various components of that legislation into its sub-sections, wherein the department tried to the best of its ability to calculate the fiscal impact of the specific sections. The section related to the GVR "bounced around a lot" as the definitions of GVR changed as the bill worked its way through the legislative process. At the end of the day, it was estimated in the early years to be approximately a \$25 million fiscal impact, meaning a negative revenue on the state, he said. The ability of the GVR to effect refundable credits was not contemplated within the fiscal note, which is the circumstance currently before the committee. The fiscal note was based upon the forecasted price at the time, he reiterated, which was in the low one hundreds.

[8:52:21 AM](#)

MR. ALPER drew attention to slide 49, "Sections 26-27: Credit Refund Limitations - Four New Limitations on Cash Refunds," and said that the bill discusses restrictions on the state repurchase of credits. This is different from the elimination or the disqualification for credits because it envisions circumstances where credits will be earned but the company will not be able to receive cash for those credits. Additional requirements where companies would be forced to hold those credits and either sell them to another company, or use them in

some future year when they owed taxes and had profitable production, he explained. Under current law, he pointed out, there is a restriction that only one set of companies can attach; those are the companies that produce greater than 50,000 barrel a day, the major producers. He said that "the ability to refund open-endedly might be unaffordable for Alaska in the current circumstances" and depending upon the companies that might be attracted to investing in Alaska, some may have a greater ability than others to hold credits on their own balance sheets for the future. He pointed out that with some of the companies "we do want to continue to offer money to because it helps them with their financing and their ongoing operations."

[8:53:31 AM](#)

MR. ALPER said there are four different limits that will affect different companies differently, as follows: The first restriction is that in addition to this 50,000 barrel a day (the three major producers in Alaska), the world's other major producers don't need cash for their credits. He conveyed that if a company has gross global revenues of greater than \$10 billion in the previous year and should those companies be investing in Alaska, they have the means and balance sheets to hold their credits until a future date when they have oil production, and those credits will retain their value and be used against their taxes.

MR. ALPER explained that the second restriction is separate and distinct, and is for those companies smaller than the \$10 billion threshold. For these companies "we are going to say, 'here are your credit certificates, we will cash them out up to the amount of \$25 million per company per year.'" He noted that that number was pulled from the original credit buyback language in the production profits tax (PPT) bill (2006 House Bill 3001). In 2007 it was removed and HB 247 would restore it to statute. For a company in Cook Inlet, for example, if the state is currently paying 50-60 percent of costs and the company says it is investing \$200 million this year, "that means we would be paying \$100-\$120 million of that cost through the refundable credit program." Under HB 247, he continued, "We're saying we're only going to issue \$25 million in cash, the rest of those credits would be rolled forward, used against the next year, and it would be a first-in/first-out type of calculation."

[8:55:16 AM](#)

REPRESENTATIVE JOSEPHSON offered that he is not saying that it's not a good policy, but it seems that the fallout would slow development and suppress economic interest.

MR. ALPER recognized that any change improving the state's fiscal picture by reducing the producer's fiscal picture will in some manner affect decision making. He said he comes before the committee mostly from the position of affordability, in that the state is paying hundreds of millions of dollars a year that it does not have. Therefore, in looking to conform the system to the state's abilities, to ask "what can we do ... we want to help, we want to encourage new development, we don't want anyone leaving, or we don't want to throw uncertainty in anyone's financing." He said it is important to get the limitations pinned down because it creates even more uncertainty if credits are being issued that the state can't afford to buy back, which is something that could be occurring before too many more years. There is no particular magic to \$25 million, he reiterated, as it was the number used in the PPT bill. All of the credits are transferrable and can be sold, there is a free market in credits. For example, if a company has tax liability it can go to another company that has extra credits and purchase credits, generally at a discounted rate, and the company purchasing the credits would be able to use them to offset its own tax. Although, he noted, there are certain limits and restrictions on that in existing statute but that is another certain circumstance that occurs.

[8:57:11 AM](#)

REPRESENTATIVE SEATON commented that the committee has seen the situation where the state has a large liability for a large percentage of a project which is used as a financing mechanism, and the companies without adequate balance sheets come in and then go bankrupt, thereby leaving people in the state on the hook through the bankruptcy court going back 90 days. The bankruptcy court then recovers money from the Alaskan supplier because it was within 90 days of the bankruptcy. He pointed out that the problem is being stimulated by the excessive amounts of credits available for people to finance operations when they don't have balance sheets to support the operation. Then if something happens, as has happened in Cook Inlet, all of a sudden the citizens of the State of Alaska who have been doing business are left on the hook for that. He stressed that something must be done and if the limitation of \$25 million a year assists in the situation of ascertaining that the state has

companies with reasonable balance sheets to support their activities, it would be helpful but it is not the whole answer.

[8:58:55 AM](#)

REPRESENTATIVE JOHNSON pointed out that the committee is looking at one portion of the tax. He said he appreciates the affordability aspect, but asked whether the state can afford to potentially lose the royalties and property taxes, "basically what's the total government take for lack of a better term." He further asked how, if the aforementioned is lost, that stacks up against losing this particular one segment of the tax structure. As an overall picture, what happens when a company decides it is not going to do anything, can the state afford that in terms of those other taxes the state would be missing out on? He asked that that be part of the calculation as well, including the cities and state, and the total government take, because this presentation is a small piece of a very large puzzle.

MR. ALPER agreed and said the upcoming presentation starts to drill into those issues, the total government take, how the royalty fits in, the producers' profitability, and net present value calculations reviewing cash flow, which is important because the royalties are more back-loaded and these credit obligations more front-loaded. Without question, the royalty does compensate the state, even in circumstances where the state's value from the production tax might be zero or negative. He noted there is some danger in that there is no restriction that these credits have to be used on state lands; therefore, the credits could also be going to projects that do not generate royalties to the state. He pointed out that it is not a fix contemplated in HB 247 but it is worthy of discussion.

[9:00:56 AM](#)

REPRESENTATIVE JOHNSON said it is important to keep in mind that when it is all rolled together the total take is still a net profit even though the discussion has been that the state is paying 100-110 percent of this tax. There is no scenario, he opined, where someone drills a well, with everything included, that the state loses money. The state loses it in this particular segment, but overall when someone puts a straw in the ground and starts producing oil the state does generate revenue. He asked whether there is a scenario where it wouldn't.

MR. ALPER responded that if the project is unsuccessful the state could be out the credits and then not have the revenue.

If the company is drilling on state land there may never be enough revenue just in the property or corporate income tax to compensate for the negative cash flow from the production tax. Frankly, he pointed out, some of the smaller producers, the startup companies that Representative Seaton referred to, are not necessarily "so-called C Corporations," and are not paying the state's corporate income tax, and then the state is left with the property tax. Property tax issues are different in different parts of the state. In the North Slope the state only receives 7.5 percent of the property tax and the North Slope Borough gets the rest, in Kenai it is a little closer to 50-50 percent. For the most part, he explained, if there is a successful project the state will have positive cash flow; if the cash flow is discounted over time because of the negatives up front, the state may not make money.

[9:02:34 AM](#)

REPRESENTATIVE JOHNSON said he knows that "we are a state entity but we can't discount the money that we're going to have to come up with at some point for schools and everything else, that that property tax that goes to those cities." He continued, "So, we can't discount the fact that when the cities are making a dollar, that's a dollar we don't necessarily have to deal with on a state level. So, I don't want to discount the fact that 50-50 or 17 percent, it's all part of that total government." At some point, he said, he would like to see how this fits into that and take a big picture of a realistic and hypothetical project and determine what is being jeopardized if one of the plugs is pulled. He said he wants to make it clear that the total government take is an important issue as well.

MR. ALPER answered that his current presentation jumps around in the bill and is drilling down at specific provisions because at the original presentation of the sectional there was a lot of confusion in that it is a big technically complex bill. He said it is his hope to provide the committee members an understanding of the bill's intent and vision. The next presentation has a total government take analysis, how it changes in different price scenarios with or without the bill, and how the features of the bill affect the project. The next presentation creates some theoretical field sizes, "what's a 50 million barrel field look like, and on the North Slope what's a big field if someone finds a 750 million barrel field, an Alpine plus type field ... how would these credit changes impact their development." Now that the model exists it is quite robust and can run additional scenarios per any member's desire.

9:05:07 AM

REPRESENTATIVE JOSEPHSON referred to Representative Johnson's point and said he looks forward to that presentation. He referred to Middle Earth and Doyon lands, which he noted is a different thing in that the state does not receive royalty. He opined that everyone is a cheerleader of that project because they are the underdogs who are trying to make this happen. He surmised that that would be an example of no positive income there unless things turn, and Doyon says that things might turn.

MR. ALPER replied that the royalty picture varies wildly in different areas of that state, and Representative Josephson is correct in that Alaska doesn't have a tremendous amount of private land outside of the urban areas. The various blocks of federal land have different revenue sharing formulas. For example, on the National Petroleum Reserve-Alaska (NPR-A) the state receives 50 percent of the federal government's royalty, although that royalty is currently somewhat restricted in what the money can be used for. The largest private land owners are the Native corporations and the state doesn't receive royalty.

9:06:38 AM

MR. ALPER resumed his review of the credit refund limitations on slide 49 and explained that the third restriction is the Alaska hire provision. For example, if a company is eligible for \$10 million in a refunded credit, the state looks to the company's labor statistics for the prior calendar year and if they were 80 percent Alaska hire, only 80 percent of that credit would be eligible for refund. The rest would not be lost, but would be carried forward into the next year and usable against the next year's taxes.

9:07:12 AM

REPRESENTATIVE JOHNSON opined that he had introduced a bill on oil taxes wherein this was a key portion and he was told repeatedly that it was unconstitutional. He further opined that other members introduced a stand-alone bill that did the same thing, and legal opinions were that it was unconstitutional. He asked whether Mr. Alper had a legal opinion on this.

MR. ALPER responded that it is obviously a highly controversial concept and it may not survive court challenge, and should it survive through final legislation will almost certainly be

challenged. Governor Walker brought this idea forward as it is important to convey the message that the state wants its partners in the oil industry to hire as many Alaskans as possible. In the event there is a constitutional hook, if it is a more constitutional than some other Alaska hire requirements, it's because no one is losing value. The value remains, a company would just have to carry it forward into a future year rather than be cashed out. Structurally, he explained, if the attorneys leave "a tell" behind in the bill -- all of the other restrictions on cash refunds are in Sec. 26, and this one was carved out and placed separately in Sec. 27 with the understanding that it was a little bit more challengeable.

REPRESENTATIVE JOHNSON offered that if the state is going to fight a constitutional battle, local hire is the ground he wants to be on, and he is not opposed to it.

MR. ALPER appreciated Representative Johnson's moral support and said he, too, believes it is a fight worth fighting. If HB 247 progresses with this language in it, he said, it is important to obtain written legal opinions on the record. Currently there are verbal assurances from the attorneys that it is plausible.

[9:09:57 AM](#)

MR. ALPER returned to slide 49, explaining that the fourth restriction on credit refunds is the sunset of the certificates themselves. In the event anything rolls forward a full 10 years the credits would start to expire and not be useable. He noted that within most of [DOR's] modeling scenarios it did not have a material impact and the credits started disappearing in some of the very large fields and very low priced scenarios. The idea is to not have these credits last forever and to make sure people use them. In addition to the economics of new field development, he noted, anecdotally there is a handful of older credits on DOR's books that DOR can't seem to get anyone to claim; but DOR can't make them disappear either, so DOR would to find a way to erase them.

MR. ALPER stated that Sections 26-27 have an estimated fiscal impact in the aggregate of approximately \$150 million per year. When looking at the suite of work ongoing today - how much money is being spent and how much will be refunded - [DOR] thinks that about \$150 million less will be paid out. Those \$150 million will roll forward and will be used against future years' taxes with the expectation, frankly, that there will be future years taxes, that the price of oil will recover to the level where

companies have a tax liability and could use those carried forward credits to offset their taxes. The numbers for future years will depend on the actual project. He reiterated that the fiscal note tends to decline in the out years simply because DOR's forecasting of the amount of spending of companies isn't that precise two, three, or four years down the road.

[9:11:39 AM](#)

REPRESENTATIVE JOHNSON referred to the statement that the fiscal note declines over future years because DOR just can't predict. He asked whether Mr. Alper was sure it's not declining because "we think it's going to reduce production."

MR. ALPER replied that the fiscal note for HB 247, as far as savings in the future, is really tied to the fiscal note for the future credit spend. He said, "What we're told we're going to be refunded based upon the knowledge that we have, which is itself based on our estimate of company lease expenditures that's built into our production forecast. Really, that's our core mission." [The department's] production forecast data set comes from the producers themselves, they have fairly frank conversations every fall, they tell the state what they plan to do, but they themselves don't know what they are doing more than a couple of years out and everything gets a bit more vague moving deeper into the six year fiscal note.

[9:12:48 AM](#)

MR. ALPER moved to slide 50, "Section 31: Gross Value can't go below Zero." He reminded committee members that the gross value and the tax calculation is the market value, the sales price of the oil minus the cost of getting it there, it's the so-called wellhead value. Historically, this has never been an issue but the current market price is approximately \$30 a barrel and could possibly be going lower. Under what circumstances could the state see transportation costs of more than \$30 that would lead to negative gross values at the point of production? He said there are one or two properties where that could start to approach that, if prices go lower than \$20 a barrel more properties could be affected.

MR. ALPER turned to slide 51, "Section 31: Gross Value can't go below Zero - Jan. 2016 TAPS and feeder pipeline tariffs (these are before adding the \$3.37 marine transport costs)." He explained that this information is for various properties on the North Slope. The \$6.13 number is just from the Trans-Alaska

Pipeline System (TAPS) - going from Pump Station 1 to Valdez. Additionally, the oil must get to Pump Station 1. He used Kuparuk Pipeline as the biggest example in that Kuparuk's feeder pipeline is only \$0.32 per barrel because there is a lot of oil flowing from Kuparuk, plus it's a depreciated pipeline so the cost of operating it is low enough that it only costs \$0.32 a barrel. The Endicott Pipeline coming from the Duck Island Unit costs \$2.22 simply because there is a lot less oil moving through that supply pipeline. Before the committee now is an unusual circumstance with Pt Thomson which is about to come online, in that Pt. Thomson has built a very robust pipeline designed to carry a larger amount of oil that might be produced in a full field development circumstance related to the natural gas pipeline. It as a new, very large pipeline that once it begins operating will pump a relatively small volume of oil. Pt. Thomson filed for an approximate \$19 tariff to move its oil from the Pt. Thomson production facility to the connection to the existing infrastructure at Badami. From Badami it still has to get to Pump Station 1 and then finally the TAPS pipeline, leading to a total estimated tariff of \$28.49 per barrel, should it be in production right now.

[9:15:09 AM](#)

MR. ALPER drew attention to slide 52, "Section 31: Gross Value can't go below Zero - Example of gross value potentially going below zero." Focusing on Pt. Thomson, he said that if a person presumes on top of that number the \$3.37 average of the marine transportation to get the oil from Valdez to the market, the refinery or wherever the oil is being sold, it leads to transportation costs of \$31.86 against a potential West Coast price of around \$30 today. He explained that if the \$1.86 loss on just the transportation is multiplied by the estimated 10,000 barrel a day initial production, there would be a negative gross value at the point of production of negative \$5.9 million. While not a massive amount of money by the economics of much of the North Slope, he continued, it is still material and it would typically be used to offset positive gross values from other fields, resulting in the state losing taxation from the companies who own that production at about 35 percent of the difference, which would be a loss to the state of approximately \$2 million. Going back to the Alaska's Clear and Equitable Share (ACES) bill, he said there is language inserted in the tariff language that says "in the circumstance ... where the actual tariff is not reasonable, we use a reasonable cost calculation, that reasonable language is tied to arms-length relationships and a few other factors." Colloquially, it is

being said that "to have a tariff that's more than the value of the oil itself is not reasonable, that we want to make the maximum tariff equal the value of the product itself so that the gross value can't be reduced to less than zero."

[9:16:49 AM](#)

REPRESENTATIVE HAWKER asked how solid the number of \$19.17 is for the Pt. Thomson pipeline tariff.

MR. ALPER responded that it is a filed tariff that the state has protested so it's in the process of appeals and he believes it is before the Regulatory Commission of Alaska (RCA) right now. However, he noted, this is not his area of specific expertise.

REPRESENTATIVE HAWKER advised there are protests on that from both sides and said the tariff on a cash basis is probably a lot more than that with the very limited production underway and foreseen there. He asked who mandated that the state establish that limited production of 10,000 barrels of condensate.

MR. ALPER replied that the 2012 Pt. Thomson settlement agreement requires that this initial production and reinjection be created in part as a test and in part to get to production, and also to provide the infrastructure in expectation of a full field development. He offered his belief that there is a decision point in 2019 regarding Phase Two and whether to expand full cycling, whether to commit to a major gas sale, or whether to ship more gas over to Prudhoe Bay for reinjection.

[9:18:07 AM](#)

REPRESENTATIVE HAWKER asked whether as part of retaining the Pt. Thomson lease the state has demanded and insisted that this production be created at a loss knowing the billions of dollars required to get a minuscule amount of oil into the pipeline, and now the state is going to deny the company, that the state demanded incur this loss, the benefit of that loss as part of the company's overall portfolio. He expressed his concern with the state taking that heavy handed approach with anyone. "Quite frankly," he added, "I don't like ExxonMobil any better than you do, but we have to be fair."

MR. ALPER answered he does not dislike ExxonMobil, it is one of the world's great companies and has done a lot of impressive things over the last 100-plus years. He said it's not about ExxonMobil or about any specific company, there are multiple

partners there. "I'm not quite sure 'demanded' is the exactly correct word," he said. "There was a settlement, a legal agreement, to do that; there was conditional on retaining the leases, the previous versions of the Alaska state government fought to take those leases back beginning and around 2005." He agreed that [ExxonMobil] would not be able to earn the full benefit of those losses should they happen at a loss, and once again the state is at a circumstance that was never envisioned. He pointed out that there are a lot of losses out there that were not contemplated, and minimum tax calculations that were not contemplated. The state is in new territory with all of the existing statutes that were passed and is trying to determine how to adapt the statutes to the current reality.

[9:19:43 AM](#)

REPRESENTATIVE HAWKER said that's his point exactly. He added:

We the state have got to stop changing the playing field on everybody when we're asking them to make long lead decisions and every time something comes up that you don't like, we end up sitting here completely ... very much starting over and redefining things so that the state gets what it wants, but we are creating absolutely no certainty, no ability to continue to attract people to this state. While we may have ... issues that we can tighten up here, but again, my biggest concern and this is a classic example, we incent ... we tell someone to do something in a settlement and then we literally want to pull the rug out from under them when we discover that ... the world has changed around us and now we don't have what, as you said yourself, the whole motivation behind this, the state doesn't have enough money from our oil fields to continue to operate at the levels we're looking. Frankly, I'd ask you guys at the state to start figuring out some ways we can reduce the size of government, rather than trying to chase industry out of the state.

[9:20:50 AM](#)

REPRESENTATIVE JOSEPHSON pointed to the three lines at the bottom of slide 52, which read:

This negative GVPP could be used to offset positive values from elsewhere on the North Slope, resulting in

a tax reduction of 35% of the difference (about \$2 million)

REPRESENTATIVE JOSEPHSON commented that ConocoPhillips Alaska, has an interest in Kuparuk and Greater Moose's Tooth. For purposes of the company's final tax payment, he asked whether the two are aggregated so that one can be offset by the other.

MR. ALPER responded yes, for the purposes of taxation the entire North Slope is called a segment, all of the company's profits or production tax value are combined and aggregated. The specific change here is that it's a multi-step calculation as follows: "First you get to this thing called gross value at the point of production, and then you start subtracting your lease expenditures, your operating and capital costs." The change in Section 31 would make the gross value calculation somewhat higher by not allowing, in this case, the \$5 million deduction for the loss from Pt. Thomson, and therefore the net value would be, likewise, \$5.9 million higher. The end result is yes, it's all a commingled tax for each producer across the North Slope.

[9:22:17 AM](#)

MR. ALPER moved to slide 53, "Section 37: Municipal Utility Limitation," and said it is a provision of law that [DOR] is fairly certain was also unforeseen and technical in nature. He said there is language in the section amended by Section 37 that says "a municipal utility that is a producer gets to the benefit of their credits ... to the same extent as any other producer."

MR. ALPER advised that the somewhat vague language says that the municipal utility is also eligible to receive credits. Typically if a municipal utility owns a gas production, it is for the utility's own purposes - it has turbines somewhere and wants to burn that gas and generate power for its citizens. In some cases, if the municipal utility happens in a given day or given month to produce more gas than it needs to burn in its own turbine, the municipal utility is as free as anyone else to sell that gas to a third party that might need more gas.

[9:23:23 AM](#)

REPRESENTATIVE OLSON said it appears that Pt. Thomson was singled out and asked why.

MR. ALPER responded that Pt. Thomson was not singled out. The specific economics of Pt. Thomson made this issue rise to

[DOR's] attention, but the impact would affect possibly several other developments, especially the more remote developments that might have high tariffs associated with them. There are a few pending but currently none of the state's fields have tariffs that would approach \$30, let's say, except for Pt. Thomson; so it was used for illustrative purposes and was by no means singling Pt. Thomson out.

REPRESENTATIVE OLSON asked Mr. Alper to name the other fields.

MR. ALPER said he has no idea of the economics of ConocoPhillips Alaska's "string of pearls" as they get deeper into NPR-A, but in moving to Moose's Tooth 1, 2, and all the way out to Bear Tooth, he guesses that by the time they get to the last string of that pearl the tariffs are going to get fairly high to bring that oil all the way back to Pump Station 1. Caelus Energy Alaska is investing in its Smith Bay project much further out along the coast of NPR-A, and he is certain that should Caelus find meaningful amounts of oil and try to ship it back towards Prudhoe Bay and TAPS, it's going to be a very expensive project to get that pipeline built. Offshore projects certainly will be expensive. This is something the state would need to look at as new projects come on, obviously. But the corollary for these remote projects and their tariffs is that quite probably none of them are going to happen if the price of oil stays at \$30-\$40 a barrel anyway, so it's an academic conversation.

[9:25:10 AM](#)

REPRESENTATIVE OLSON referred to the first two and commented that conceivably they will be much higher than Pt. Thomson.

MR. ALPER replied that he doesn't know, they will be built for their expected production. There is an unusual circumstance that Representative Hawker spoke correctly to, that the Pt. Thomson pipeline was overbuilt, it was built for future production that might not come for a substantial number of years, or whatever feeder lines they build in NPR-A will be sized for expected levels in the near term. He reiterated that everyone gets to deduct all of their tariffs so long as it doesn't bring them below zero, no one is going to make any investment if they expect the value to be zero. As [DOR's] modeling will show, nothing, including the status quo scenarios, work at \$40 oil, which is the current reality.

[9:26:14 AM](#)

REPRESENTATIVE OLSON asked whether that would be 42 inch or 48 inch pipe.

MR. ALPER responded he is happy to say that it is not his job.

MR. ALPER returned to slide 53, and said that these are, for the most part, small dollar items, but they do add up. He presented a model of a basic scenario as follows:

Let's say a company produces 20 million cubic feet a day ... and 18 of it goes into their own turbines. Those 18 million cubic feet a day are not taxable, that is an internal transfer that is not a sale; the Tax Division of the Department of Revenue does not interject itself into that part of the equation. However, if they sell 2 of them to somebody else, to someone else's utility, that 2 of them is taxable income and they are paying the production tax like any other producer on that 2 million cubic feet per day. So, just working that through the equation, 2 million cubic feet a day, \$8 just to pick a price, that's \$5.8 million a year in revenue subject to taxation. Now, so, here's the interesting part, let's say their lease expenditures are \$3 per thousand cubic feet. The way the current law is structured, they get to take all of their lease expenditures on the whole 20 million they've produced and offset them against ... only the 2 that they sold. So that leads to, if you work your way down the left hand column, \$21.9 million dollars' worth of lease expenditures against \$5.8 million in sales - they show on paper a \$16 million dollar operating loss and would be eligible, using the Cook Inlet figure, the 25 percent net operating loss credit in Cook Inlet, we would be paying this company a \$4 million dollar credit in this circumstance because they sold a small amount of their gas. Usually this is a somewhat unreasonable and unintended consequence of a literal interpretation of statute. The change in Section 37 is brief, but it says, colloquially, that we are pro-rating their expenses to the share of the gas that was actually sold. So, if they sell 10 percent of the gas they get to claim 10 percent of the lease expenditures, if they sell 99 percent of the gas they get to claim 99 percent of the lease expenditures. And in the example before us here where 10 percent of their gas was sold and they had \$21 million in lease expenditures, 10 percent of that is

\$2.1 million, that gets reduced from their revenue and now instead of getting a big operating loss they have a small profit that would be subject to the production tax, although the numbers are small enough that in the current circumstance, small producer credits and the like, they would not be likely to be paying any actual taxes and that's fine at this scale. The issue is that we the state don't feel that we should be paying a large operating loss credit to a company simply because they're selling a small amount of their gas ... to a third party.

[9:29:09 AM](#)

REPRESENTATIVE JOHNSON asked whether this is limited to municipalities or would include a co-op such as Chugach Electric Association. He further asked whether it means that because a municipality sells gas to Chugach Electric it is going to get this tax credit.

MR. ALPER answered it doesn't matter who the municipality sells it to. The idea is that by selling it, a transaction with money is involved, [that is a taxable] event. Regarding whether this would apply if, for example, Chugach Electric had its own gas field, production, and turbines, he said his understanding is that yes, a co-op would be treated like a municipality in this change. The co-op would be eligible for the oversize credits. To his knowledge, Chugach Electric does not currently own production, but he knows it is buying some and so this is going to be an issue. If Chugach Electric owns more production than it needs and sells some of it, [the administration] would like to prevent the circumstance where the co-op is receiving disproportionate credits.

[9:30:24 AM](#)

REPRESENTATIVE JOHNSON asked whether, if the state does this, that would make that acquisition impractical, and further asked whether it is marginal enough that this is the difference between Chugach Electric Association becoming partners which, in theory, would lower the cost for all consumers. He said he wonders if by doing this, it would take that off the table and possibly cost consumers in his hometown more money. He said that this is something to look into.

MR. ALPER responded that he cannot answer regarding the economics of a project. He said it is worth asking Chugach

Electric and the other potentially impacted players. The credits are out of scale with the sales because of the nature of the conversation. These are issues that have been appealed and have been adjudicated. "We're dealing with literal interpretation of law issues," he said. "We certainly don't want to harm the economics of your constituents to get gas, this one was perceived as somewhat excessive and ... I'd like to hear from the individual players how this might impact them."

[9:31:52 AM](#)

REPRESENTATIVE TARR surmised that this particular instance has not occurred to date, but that Mr. Alper wants to prevent this from happening.

MR. ALPER answered he cannot actually say that because he cannot talk about specific credits earned by specific companies.

[9:32:16 AM](#)

MR. ALPER resumed his presentation, advising that slides 55-58 were put together by the Department of Natural Resources (DNR). The issue was raised about Cook Inlet gas supply. Because HB 247 looks to sunset or repeal some of the capstone Cook Inlet credits and reduce the state's support of ongoing development from roughly 50-60 percent to 25 percent, the question arose as whether that is going to affect gas supply. That is one of the more important questions before the committee. He continued:

So the first question we asked is, How long can the known supplies meet the regional demand? And as ... DNR are the resource people, they understand rocks, they understand pipes, they understand things like that much better than any of us at [DOR] do. We mostly understand dollars. And so they said ... it depends on how fast the known supply can remain available and by extension how much new supply comes on. So, they looked at ... rapid response, that's them saying we gave them a couple days to please answer these questions for us. We have the known ready to pump reserves of a bit less than 1.2 trillion cubic feet ... that's what they call 2P (proven and probable), all you need to do is drill the well, you know it's there, the infrastructure is in place, all of that. And then there are two new field developments, and the two new field developments ... their names you're all familiar with - the Cosmo

development from BlueCrest and Furie's at least [indisc.-technical difficulties] Kitchen Lights Unit in the deep water in the middle of the inlet. Building those ... in round numbers without getting into anyone's confidential data they can comfortably say we have about 1.6 billion cubic feet available, numbers that can go up dramatically depending on full delineation of those fields and how much development they do, and future work that would have to.... But with known information we could say that.

[9:34:27 AM](#)

MR. ALPER continued his discussion of slides 55-58:

And then they're looking at three different demand cases. Now a good number to have in our mind is, What is the actual utility demand in Cook Inlet in an average year? That number is about 80 billion cubic feet ... per year or a little over 200 million cubic feet per day. That's the utility and field use and so on that then ... goes into the existing facilities. The high end of that would be 140 billion cubic feet, that would be what we have, and plus the limited amount of export from the Conoco export facility, plus the Donlin Gold which would require a dedicated pipeline from Cook Inlet heading out to Southwest Alaska where that gold mine is, and then a two train full development of the Agrium plant restart. That at the high end, at least with the medium terms of about 140 billion cubic feet per year. And then you say, well if we know what we have and we know what we might need, how many years do we have and recreate some lifespan scenarios.

[9:35:25 AM](#)

So, Supply Case 1 ... 1.2 trillion or 1,100 billion cubic feet in the legacy field from the Division of Oil and Gas, 1.6 with the additional ballpark estimates for Kitchen Lights and Cosmopolitan.

Demand Case 2 is sort of the middle. That was the addition of Donlin and the one-train Agrium. The second-train Agrium brought it from 116 to 140 billion cubic feet per year. And just to put the numbers in perspective too, the flow from the AK LNG Project is a

bit less than 3 billion cubic feet per day. So even at the full demand level, we're talking less than 2 months production from the North Slope should that ... proceed to construction and development.

So, how much gas do we have behind pipe? The current circumstance, we have 15 years of life span. ... And that's 15 years with high deliverability. That's an important distinction from where we were five or eight years ago when there wasn't the storage capacity, the ability to put gas in in the summer when there is less demand, pull it out in the winter when there is high demand. So they're telling us that we have about 15 years' worth of current demand. If the additional production continues on and comes on line that is under development, or about to be under development, hopefully in Kitchen Lights and Cosmo, that increases to 15 years. Knowing that, what happens if the demand increases - if Agrium restarts with a single train, Donlin Creek moves forward with what they think is 12 billion cubic feet per year - that reduces what we have to 14 years. The full development of Agrium and Donlin brings it down to 11 years. If those things are happening, we're all confident, DNR would agree I hope, that that would encourage substantial additional development of those and additional fields to make sure that the supply stays on line. But even with full development, which obviously isn't happening overnight, they're looking at 11 years of supply.

[9:37:24 AM](#)

REPRESENTATIVE HAWKER requested Mr. Alper to explain the disclosure in the box under the title of Slide 57, which read:

These supply "lifespan" estimates require significant continued investment to ensure reserves and discovered resources will be produced in time to meet demand.

MR ALPER explained that even when a producer has a gas or oil field, the company must continue drilling wells due to the nature of the geology. For example, when drinking a Slurpee and begin sucking air it is necessary to pick up the straw and move it over one-half inch to get more Slurpee. He related that the expectation is that ongoing investment happens, but that is among the least risky investment in the industry because there is a known proven reserve with a market, and the cost is known,

and it is known the gas or oil is down there because it is in between two producing wells. Continuing ongoing investment will absolutely be required because if everyone stopped drilling the decline curves are inherently more rapid.

[9:38:25 AM](#)

REPRESENTATIVE HAWKER said:

You keep saying that it's a very attractive basin, don't worry your pretty little head Mike. Well, I worry about my community. If it's such a great opportunity why ... three years ago where we were having blackout drills in my community, literally, because we were trying to train our public with what to do because they had no heat or lights on the coldest days of winter. If it's such a great attractive prospect, why were we doing that?

MR. ALPER stressed that he was by no means saying that Representative Hawker should not worry about his community as it is his job to worry about his community. Representative Hawker has done many great things for the energy security in Cook Inlet through the credits he helped work through the system several years ago. Probably the most important one was the storage credit. "That storage credit has created essential seasonal deliverability security that didn't used to exist," he said, "especially in the absence of the flexible users like the export facility, say, that isn't operating at full capacity." He offered his understanding that many of the issues behind that blackout drill were because of deliverability more than supply. Also, he continued, additional supplies have been discovered that are more easily developable and there is a very high price. There were regulatory issues in the years leading up to those blackout drills where gas supply contracts were being denied. He said he doesn't want to delve into the history and politics behind those....

REPRESENTATIVE HAWKER interjected that those were fixed in the Cook Inlet Recovery Act.

MR. ALPER agreed and acknowledged that there was language in that bill discussing the RCA having to show its work at the very least and explain its reasons. Suddenly now, gas supply contracts are coming at higher levels, higher dollar values, that support drilling. He said he has heard from others that Cook Inlet has among the most generous fiscal regimes and one of

the highest gas prices in the world. That doesn't say it's extremely attractive, just that maybe it doesn't quite need the same level of ongoing cash support that it currently enjoys, which is the state paying 50-60 percent of a company's development costs.

9:40:54 AM

REPRESENTATIVE HAWKER noted that Mr. Alper acknowledged that the economic situation created in Cook Inlet attracted sufficient investment to increase production. He posed the question of significantly taking away, as HB 247 proposes, some of the incentives in the basin and how it will affect continued investment - how much reduction in investment Cook Inlet can expect - and how that will affect these lifespan calculations.

MR. ALPER responded that the type of decision making contemplated in the question relates to new supplies in addition to the supplies stated in this slide. He explained that the supplies in this slide are, for the most part, discovered and should the price support it, "we believe will continue." If the discussion is regarding the next tranche of supply beyond this, "we will come to the committee with field analysis, with economics." It's tricky to look at field economics in Cook Inlet because a tax regime kicks in in 2022 that is very high and unstable. It has been discussed that a new Cook Inlet tax system is needed. He said he cannot say with certainty whether a new project will or won't happen, with or without the tax change envisioned in this bill.

REPRESENTATIVE HAWKER stated that Mr. Alper just said that it's going to be all these new discoveries that are going to be the things that are affected by continued investments. He asked whether it doesn't also take continued investment to maintain the level of production from the known and proven reserves.

MR. ALPER replied that it takes continued investment but that's a much less riskier investment in a proven developed field where it is known what is there. If there is a market and a sales price, he explained, that is a far less risky investment than going out and looking for new gas.

9:43:02 AM

REPRESENTATIVE HAWKER recited the adage, "The best place to find oil is in an oil field." Yet, he argued, there is the law of diminishing returns, too, where it becomes increasingly

expensive to extract those final resources, the more-difficult-to-achieve resources in the fields. He reiterated that he would like Mr. Alper to be able to stand up in front of his entire community and tell them that his proposal is not going to place them at risk of having insufficient energy to meet their needs in the foreseeable future.

MR. ALPER responded that a hearing or two ago Commissioner Hoffbeck said something along the lines of, "Is it time to declare at least partial victory?" Should the state find itself in a circumstance where supplies are becoming risky to get in Cook Inlet, he said:

We believe we have sufficient lead time to reinstitute certain benefits, certain incentives to go and find more gas. Right now there is enough gas, we believe, that given the state's fiscal situation, we cannot afford to continue to support ongoing development to the rate that we have been. We want to continue to, to the extent that we can, to the maximum benefit of the community, within what is reasonable given the state's fiscal limitations.

REPRESENTATIVE HAWKER stated that what Mr. Alper just said scares him and makes him pity the people in his community.

[9:44:25 AM](#)

MR. ALPER referred to slide 58, "Cook Inlet Undiscovered Resources (USGS resource assessment, 2011)." He explained that the map on this slide shows the extent of the Cook Inlet basin, which has an estimated nearly 600 million barrels of oil. The green line represents roughly where the oil is believed to be. The conventional gas is almost 14 trillion cubic feet and the unconventional gas is another 5.3 trillion cubic feet on top of that. In the context of the current annual use consumption in Cook Inlet, as currently fully developed with both heat and electric utilities almost entirely dependent upon gas, a trillion cubic feet will last about 12 years. If there are in fact 13 trillion feet of undiscovered technically recoverable gas, there is approximately 150 years' worth of gas in Cook Inlet currently, and "obviously that is much more speculative and will require far more additional work to bring any of that sort of gas to market, but you are living on top of a robust gas basin, or at least so the professionals in that field believe."

[9:46:10 AM](#)

REPRESENTATIVE JOHNSON referred back to his previous question regarding the utilities and said:

I want to throw Fairbanks in the mix. What does it do to Fairbanks gas deliverability because they are involved in the trucking now and ... there's challenged projects both ways north or south on that one. And right now I think the plan is to truck gas to the north. What does that do to their deliverability if these credits.... So maybe you can't answer these ... we're outside the realm of some of the state, but we're very heavily invested in that Fairbanks gas utility as a state. So ... I just want to focus on some of things that unintended consequences ... I want to make sure that we're not burying Fairbanks or Anchorage or anyone in this, and all of a sudden we've got great ideas and no gas. So, I want to make sure that we're dealing with those kind of aspects. ... I don't know where they fit in because I don't know if they're even a utility, they're not regulated, they may have to pay the full taxes. I mean there's a lot of moving pieces in that. They could end up a lot of difference ways. ... I certainly understand that if you want to beg this question for a later time, but I want to at least put it on the table.

[9:47:34 AM](#)

MR. ALPER offered to take a first crack at understanding the transactions embedded in the aforementioned scenario by Representative Johnson. He said that the Fairbanks utility is not a producer, it's a consumer, and will be buying gas from someone. He said he thinks the issue being raised by Representative Johnson is more an issue of gross values being less than zero; that whoever is selling that gas and the market price is low and the cost of trucking it up there is high, the circumstances could be that the gross value is less than zero. Although, he advised, he is not certain how trucking fits into the calculation of allowable transportation.

REPRESENTATIVE JOHNSON advised that he does not need an answer now, but wants it on the table because it is an issue that the committee has spent a lot of time on, and he would hate to see all of those investments go to the wayside for lack of at least talking about them. The committee has not talked about some

things that have come up - low oil prices, high oil prices - and he would like to get everything on the table this time.

MR. ALPER agreed and said:

We don't want to keep doing this. We want to envision all of the possible circumstances. ... I like to think we're spiraling in towards the center of something rather than zigging and zagging back and forth. But I don't have a nuanced answer to give Representative Johnson's question. It is important to contemplate how both the Section 31 and Section 37 changes might impact the Fairbanks utility, and we will look into that, absolutely.

[9:49:45 AM](#)

The committee took an at-ease from 9:49 to 9:53 a.m. and another from 9:53 to 9:54 a.m.

[9:54:19 AM](#)

CO-CHAIR NAGEAK advised that the next meetings on HB 247 will be at 1:00 p.m. today, and 10:00 [a.m.] tomorrow, 2/26/16.

[HB 247 was held over.]

[9:55:13 AM](#)

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 9:55 a.m.