ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
February 22, 2016
1:22 p.m.

DRAFT

MEMBERS PRESENT

Representative Benjamin Nageak, Co-Chair
Representative David Talerico, Co-Chair
Representative Bob Herron
Representative Kurt Olson
Representative Paul Seaton
Representative Andy Josephson
Representative Geran Tarr

MEMBERS ABSENT

Representative Mike Hawker, Vice Chair
Representative Craig Johnson

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

WITNESS REGISTER

KEN ALPER, Director
Tax Division
Department of Revenue (DOR)
Anchorage, Alaska
POSITION STATEMENT: On behalf of the governor, sponsor of HB 247, provided a PowerPoint presentation entitled, "Oil and Gas Tax Credit Reform-HB247, Additional Modeling and Scenario Analysis - Part 1."

ACTION NARRATIVE

1:22:30 PM

CO-CHAIR BENJAMIN NAGEAK called the House Resources Standing Committee meeting to order at 1:22 p.m. Representatives Tarr, Josephson, Seaton, Talerico, and Nageak were present at the call to order. Representatives Olson and Herron arrived as the meeting was in progress.

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

1:23:25 PM

CO-CHAIR NAGEAK announced that the only order of business is 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."

1:24:18 PM

KEN ALPER, Director, Tax Division, Department of Revenue (DOR), on behalf of the governor, sponsor of HB 247, first drew attention to two letters to Representative Seaton from the Tax Division, dated February 2, 2016, and February 19, 2016. He explained that these letters are the latest iterations and updates to modeling efforts for the North Slope and the Cook Inlet that were prepared over the last interim in response to Representative Seaton's request for analysis of field lifecycle costs and benefits to the State of Alaska of various new field developments and what the state's cash flow is going to look like from new development. The letters are provided as background documents for the committee as well as a precursor to some of the modeling that DOR will be providing in its next presentation to the committee. That modeling looks at the current situation, which is what is in the aforementioned letters, as well as looks at the impact on that of the changes envisioned in HB 247.

MR. ALPER began a PowerPoint presentation entitled, "Oil and Gas Tax Credit Reform-HB247, Additional Modeling and Scenario Analysis - Part 1." He turned to slide 2, "What We Will Be Discussing," and outlined the topics that he planned to cover today and on 2/24/16: overview of revenue and production; what credits worked and what didn't; credit cost in perspective; bill details and how the pieces work; scenario analysis and economics of changes; and gas supply issues in Cook Inlet.

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MR. ALPER moved to the graph on slide 4, "Overview of Revenue and Production," to discuss what the state's revenues have looked like over the last 10 years [fiscal years 2006-2015]. He pointed out that the production tax (depicted in dark blue) is the most reactive to the changes in the price of oil. This is followed by the state's other petroleum revenues such as the corporate income tax and property tax (depicted in orange), unrestricted royalties (depicted in gold), restricted royalties (depicted in grey), and non-petroleum revenues (depicted in lighter blue). Thus, the graph shows the state's undesignated general fund (UGF) plus the permanent fund royalties. The graph puts into perspective how much impact that changes in the price of oil have on things, especially on the production tax side.

MR. ALPER displayed the pie chart on slide 5, "Overview of Revenue and Production," and reported that 17 billion barrels of crude oil have been produced on the North Slope since the Trans-Alaska Pipeline System (TAPS) began [in 1977]. The great bulk of that oil, over 90 percent, came from two fields - Prudhoe Bay (depicted in red) and Kuparuk (depicted in dark green). Various other fields are depicted by the other colors on the chart.

MR. ALPER brought attention to the graph on slide 6, "Overview of Revenue and Production," to review the declining curve in oil production between the years 1977 and 2025. He explained that things ramped up after the commencement of commercial operations and have been gradually declining since then. An expectation of a flattening in the decline can be seen on the graph, but a decline still continues from today's number of about 500,000 barrels a day to about 300,000-400,000 barrels a day in 8-10 years from now.

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MR. ALPER showed slide 7, "Overview of Revenue and Production," and noted that the graphic is from the U.S. Energy Information Administration. He said the graph depicts the scale of Alaska's oil fields and shows production aggregate [from 1990 to date]. The central North Slope has produced about 8 billion barrels of oil [shown in black] and still has a lot of oil yet to be produced (shown in light blue). A substantial chunk of that oil is proven, especially in the offshore. There is also a very large amount of unproved technically recoverable oil, oil that has not explicitly been discovered but which the professionals say is there. The two bars at the bottom of the graph depict the largest shale developments in the Lower 48, the Bakken and the Eagle Ford, which in terms of total production are much smaller than Alaska has had, but they have very large volumes of potential or technically recoverable oil.

MR. ALPER turned to the pie charge on slide 8, "Overview of Revenue and Production," to point out that the great bulk of Alaska's oil production comes from the three "majors," which are BP, ConocoPhillips, and ExxonMobil. Alaska also has five other substantial producers: Chevron, Hilcorp, ENI, Anadarko, and Caelus. Some of these five companies operate smaller fields of their own and some have smaller partnerships in the major oil fields of Prudhoe Bay and Kuparuk; many of the proposed changes in HB 247 would impact these companies. The proposed changes in the bill would also impact the explorers, such as the Brooks Range/Mustang field, the Repsol/Armstrong project, Great Bear, Furie, BlueCrest, and several others.

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MR. ALPER moved to slide 10, "Credits: What Worked, What Didn't?" He noted that a number of credits have been put into law over the years that have never been used. These include the New Areas Credit [AS 43.55.024(a) and also known as the Middle Earth Credit], a credit of up to $6 million that was provided in

House Bill 3001, the production profits tax (PPT) bill that was passed in 2006 [Twenty-Fourth Alaska State Legislature]. This credit was structured very similarly to the Small Producer Credit: a company that began producing in the frontier areas in the Interior would get a $6 million offset to its taxes. That has not been used because there has not yet been any commercial production from the Interior portions of the state. Another unused credit is the Jack-Up Rig Credit, which was part of the various reform measures passed in 2010 [AS 43.55.025(m) Senate Bill 309, Twenty-Sixth Alaska State Legislature]. Also unused is the 80 percent Frontier Basin Drilling Credit that was part of the Frontier Basin Act of 2012 [AS 43.55.025(n), Senate Bill 23, Twenty-Seventh Alaska State Legislature]. While some of those activities have occurred, the companies have found it advantageous to use....

CO-CHAIR NAGEAK requested a definition of the term "stacking."

MR. ALPER used the Cook Inlet Jack-Up Rig Credit as a means to define stacking. Under that credit, he explained, the state will pay 100 percent of the cost of drilling a well that meets certain criteria. But tied up with that 100 percent credit are various conditions, including some data requirements and a requirement to pay back half the money if commercial production is brought in from that. In Cook Inlet, companies have found it more advantageous to instead use the general purpose 40 percent Well Lease Expenditure Credit and to stack it, combine it, with a 25 percent Net Operating Loss Credit. In that circumstance the state pays roughly 65 percent of a company's costs without some of the contingencies and requirements to pay it back in the future.

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MR. ALPER resumed his discussion of slide 10 and reiterated that the New Areas Credit, Jack-Up Rig Credit, and Frontier Basin Drilling Credit are in current law but scheduled to sunset [in 2016]. To qualify for any of these benefits a company would have to do some activity by sometime in 2016. He said [the Tax Division] doesn't anticipate making any payments on those, although there is certainly a possibility of it.

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MR. ALPER drew attention to slide 11, "Credits: What Worked, What Didn't?" and discussed credits that have been used but are scheduled to sunset and be phased out regardless of what the committee does. Regarding North Slope exploration credits, he said the Exploration Incentive Credit that came into statute in 2003 is scheduled to sunset on July 1, 2016, meaning the work must be done by that date. While DOR cannot provide specific numbers due to confidentiality, he can say that the state has paid between $125 million and $200 million on those exploration credits. Another $150-$200 million was used against liability, meaning the companies that explored had a tax liability, most of those companies being the state's major producers, and they used that credit to reduce their tax payments. The great bulk of credits used against liability occurred before fiscal year 2011, while the refunded credits have been more used in recent years. In round numbers, the North Slope exploration credits have resulted in between $275 million and $400 million of state past expense, direct or indirect. Regarding non-North Slope exploration credits, primarily Cook Inlet Exploration Credits, the range of refunded credits is roughly between $25 million and $75 million. Not a material amount of credits was used against liability because there is not a lot of tax liability due to the Cook Inlet tax caps that are in statute. He further noted that as part of Senate Bill 21 [passed in 2013, Twenty-Eighth Alaska State Legislature], the Net Operating Loss (NOL) Credit was increased to 45 percent starting January 2014. When that happened the Exploration Credit of 40 percent could be stacked with an operating loss and there was a time period where the state was paying up to [85] percent of companies' costs on the North Slope. That was a two-year increment that went away at the end of 2015. Meanwhile, with the addition of the 40 percent Well Credit in 2010, the Exploration Credit became somewhat redundant. Many of the expenditures that were qualified for the Exploration Credit were also qualified for the Well Credit with certain exceptions like in seismic work. These exploration credits are going to be going away under current law.

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MR. ALPER turned to slide 12, "Credits: What Worked, What Didn't?" and discussed two more credits that are scheduled to sunset and be phased out. He explained that the Small Producer Credit is a nonrefundable, non-carry forward credit that can only be used to reduce a small producer's tax by up to $12 million. This credit has been well used on the North Slope: between $250 million and $400 million was used through fiscal year 2015 and another $257 million is projected to be used before this credit goes away. He explained that even though this credit is going away, the sunset is for applying for the credit and that is why another [$257] million is projected. Once a company starts producing as a new producer, the company can get this credit for up to nine consecutive years. Although those companies that might have been receiving it since 2007 or 2008 are phasing out, any new companies coming into it now will be able to receive this credit until approximately 2025, so the state will be making some payments on this credit until then.

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REPRESENTATIVE JOSEPHSON said that sounds like, in effect, the companies control the key to the statute of limitations because they set the clock ticking.

MR. ALPER replied that the clock begins ticking when a company first claims that credit, which is generally when it first came into production. It is not like companies are in production and choosing not to use the credit, it is that there are companies that are just starting up and they will begin using the credit.

REPRESENTATIVE JOSEPHSON, using the North Slope exploration credits on slide 11 as an example, surmised that someone within DOR or DNR knows which of the credits bore fruit as a general proposition for the people of Alaska, but cannot fully disclose that because it would violate current law.

MR. ALPER responded that [the Tax Division] cannot discuss on a case-by-case basis. For example, [the division] cannot say the state gave $20 million to Company X and Company X ended up not producing anything, or that Company Y was given $10 million and subsequently found an oil field that is producing 10,000 barrels a day. [The Tax Division] is unable to share at a level of detail, but it can aggregate these things. For example, last week the committee was shown a slide that talked about total dollars on projects that have borne fruit, are in production right now, and then dollars spent on credits that have not yet borne fruit. He said he believes that for the North Slope about $650 million in credits has gone to companies or projects that are not yet in production and about $1.45 billion in refunded credits has gone to projects that are now in production.

REPRESENTATIVE JOSEPHSON asked whether as a general proposition there should be a statute that at least lets [legislators] meet in executive session so that they can do their jobs fully and not miss this critical fact.

MR. ALPER answered he is not an attorney and is not certain how that would work. He pointed out that Section 8 of HB 247 does allow for a confidentiality waiver so these things could be discussed going forward. To be able to have an executive session to discuss what credits the state has spent over the last 10 years so legislators and policymakers could understand the scope of what is before them is an idea that he thinks is excellent. However, he qualified, he does not know the legal nuance of that.

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MR. ALPER returned to his discussion of slide 12. He reiterated that the Small Producer Credits will sunset slowly. A smaller amount of the Small Producer Credits was used in Cook Inlet because the volumes are smaller in the inlet: $50-$100 million has been used against liability and about another $15 million is projected before that credit goes away fully.

MR. ALPER noted that the credit which subsidized the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility in Kenai was part of the Cook Inlet Recovery Act of 2010 [AS 43.20.046, House Bill 280, Twenty-Sixth Alaska State Legislature]. That credit was specifically written to only allow a single credit for a specific project and has been used. That statute could therefore be repealed without any plus or minus to the system, but [the administration] didn't contemplate doing that when writing the bill. That statute has a specific confidentiality waiver, he said, so he is able to tell the committee that the state gave $15 million to CINGSA to build its facility.

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REPRESENTATIVE SEATON inquired as to why the CINGSA credit was not eliminated from the statute given it is a credit targeted specifically to corporate income tax rather than production tax.

MR. ALPER confirmed that this credit is in AS 43.20, which is the corporate income tax statute and so was intended to be used against that tax. He said he does not recall whether CINGSA is a corporate taxpayer, but that the company earning this credit would have the ability to transfer or sell that credit to a company that might owe corporate income taxes in Alaska. That occurred and was paid out in fiscal year 2014. According to the historic record of credits provided for this meeting, it can be seen that credits under AS 43.20 are $15 million in fiscal year 2014, which is a specific reference to this credit that has been paid. He reiterated that there is no reason why this statute could not be repealed as part of this or any other legislation.

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REPRESENTATIVE SEATON advocated for repealing this credit because, to his knowledge, it is the only place where the state is giving an oil and gas production tax credit against corporate income tax. He said he thinks this is a model that the committee would want to remove from statute.

CO-CHAIR NAGEAK inquired whether Representative Seaton plans to move his suggestion at a later time.

REPRESENTATIVE SEATON replied that he will be doing so, but added that he is just making members aware of the probability.

MR. ALPER pointed out that there are two other credits in the oil and gas statutes that go against corporate income tax, CINGSA being AS 43.20.046. He explained that AS 43.20.047 is a similar credit that would build storage tanks; for example, liquefied natural gas (LNG) storage tanks are envisioned for the Interior gas utility. He offered his belief that there is intention to use that credit, which remains on the books and is useable against corporate income tax. Likewise, he continued, the "Refinery Tax Credit" in AS 43.20.053 [qualified in-state oil refinery infrastructure expenditures tax credit] can be used against the corporate income tax, and at least one Alaska refinery is publicly talking about an asphalt plant project that it envisions earning that tax credit against.

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MR. ALPER brought attention to slide 13, "Credits: What Worked, What Didn't?" to discuss which credits would be repealed in HB 247. He noted that the bill would change many of the rules but would not repeal that many credits. He allowed that the two credits that would be repealed, the 20 percent Qualified Capital Expenditure (QCE) Credit and the 40 percent Well Lease Expenditure (WLE) Credit, are very large credits. The Qualified Capital Expenditure Credit existed on the North Slope until 2013, but the Well Lease Expenditure Credit never existed on the North Slope. [The Tax Division] cannot discuss exact totals, he noted, but he can say that a total of between $500 million and $800 million in Cook Inlet and some in the Interior has been credited, cashed out, for these line items. Over 85 percent of it occurred after fiscal year 2013, largely because of the greater activity that was incentivized by the passage of the 40 percent Well Lease Expenditure Credit in 2010. So, the state is spending $150 million to $200 million a year. If these credits were repealed, the state's credit liability going forward would go down commensurately by about $150 million per year. Mr. Alper noted that these credits were created, in part, due to supply anxiety and the fear that gas was going to run out in the Cook Inlet. That problem has now been somewhat fixed. He urged members to keep in mind that these credits could also be spent on oil drilling and oil well workovers and activities that increase oil production, which are good for the economy and great for having oil in the refineries, but not necessarily the same sort of life and death issue....

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CO-CHAIR NAGEAK requested Mr. Alper to expand on well workovers.

MR. ALPER explained that a workover is when an existing oil well is cleaned out and new equipment added, a second-generation activity to make an old oil well newer again and produce better. It fits under the definition of well lease expenditures, so generally that sort of activity would get the higher level, 40 percent, credit. Cook Inlet has a lot of old oil wells. In the 1960s production was over 200,000 barrels a day. New players have come in and worked over some of the old wells and Cook Inlet oil production has more than doubled in the last few years. A lot of that activity would have been eligible for the state's credits at the higher level because that activity met the definition.

CO-CHAIR NAGEAK asked whether this is currently being used "up north" by the companies that have taken over production from the bigger companies and are doing well workovers.

MR. ALPER replied yes, "Cook Inlet north" is most definitely earning these credits.

CO-CHAIR NAGEAK clarified he is meaning the North Slope.

MR. ALPER responded that on the North Slope these well drilling credits are not available so the companies are unable to claim the credits. However, the companies are working over old wells and trying to get increased production from mature fields in the North Slope.

REPRESENTATIVE NAGEAK recounted that he visited one of those wells last year and was told that smaller companies have taken over fields from BP and others and these companies have a system for doing this to the wells. He said he thinks this will occur more and more as the wells age.

MR. ALPER answered it is important to note that, yes, this is happening on the North Slope and companies are not getting drilling credits for it, although the state is offering drilling credits in Cook Inlet for similar work. He surmised that the companies will provide greater detail in this regard when they testify before the committee.

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REPRESENTATIVE SEATON inquired whether splitting out the amount that was given for oil and for gas can be done without breaking confidentiality.

MR. ALPER replied he will talk with staff to determine whether that would be possible. He asked whether Representative Seaton is meaning to try to break the oil-related from the gas-related expenditures for Cook Inlet or non-North Slope credits in this category.

REPRESENTATIVE SEATON responded yes and added that he would like the information for the years since 2013.

MR. ALPER agreed to do his best to get that to the committee.

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MR. ALPER concluded his discussion of slide 13. He said he will make the case later in the presentation that the Cook Inlet gas supply issues are less problematic than they were in 2010 when Southcentral Alaska was planning and practicing brownout drills.

MR. ALPER moved to slide 14, "Credits: What Worked, What Didn't?" to outline the credits that would remain on the books should HB 247 pass as presented. He said the Carried-Forward Annual Loss Credit, also called the Net Operating Loss (NOL) Credit, is the primary credit envisioned by [the administration] as being part of the state's system going forward. This credit is 25 percent in Cook Inlet and the Interior, and 35 percent on the North Slope. It can be cashed out, with the exception that large producers must carry it forward and use it against liability. Regarding the exploration credits that he earlier spoke to as being about to sunset, he explained that the exception to that is the Middle Earth Exploration Credits, which are outside of the North Slope and the Cook Inlet. These credits are 30-40 percent of qualified expenditures depending on the location of the well and the activity, and will sunset in 5.5 years on January 1, 2022. Regarding the Cook Inlet Tax Caps, he noted that they are not strictly speaking a credit but a statutory maximum on the amount of taxes the producers can pay if they are producing in Cook Inlet. He said this cap is roughly 17 cents per thousand cubic feet (MCF) of gas and the oil tax is zero. These tax caps are tied to the old economic limit factor (ELF) formulas that were in place in 2005 and are currently scheduled to sunset on January 1, 2022.

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REPRESENTATIVE SEATON drew attention to the Net Operating Loss Credit that is 35 percent on the North Slope and 25 percent in the Cook Inlet. He requested Mr. Alper to explain why 25 percent is working well in Cook Inlet while it is 10 percent more on the North Slope.

MR. ALPER answered that the Net Operating Loss Credit has historically been tied to the base rate of the Net Profits Production Tax. The 2007 bill, Alaska's Clear and Equitable Share (ACES), had a 25 percent tax rate with a sliding scale, or progressive factor, that went higher based on that, so the decision was made to pay losses at the base level of that 25 percent and that was both Cook Inlet and North Slope. On the North Slope, the passage of Senate Bill 21 raised the tax rate itself. The rate of 35 percent is more of a maximum tax than a minimum tax and it tends to slide down because of the sliding-scale credit. The way the legislature addressed that in 2013 was by raising the size of the Net Operating Loss Credit on the North Slope to 35 percent, tying it to the tax rate. The 25 percent operating loss rate in Cook Inlet is a remnant of the 2007 ACES statute. In some ways the North Slope Net Operating Loss Credit is called a playing field leveler: a producing company who owes taxes spends more money and reduces its tax liability, so this creates a parallel benefit to the newcomer. In Cook Inlet where there isn't much tax liability, it is arguable that the 25 percent Net Operating Loss Credit itself isn't needed to level the playing field, but it is very much of an incentive and encourages ongoing work and enables people to get an advantage to investing money in Cook Inlet.

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REPRESENTATIVE SEATON noted that there is the increased base of 35 percent on the North Slope as well as a "per-barrel well credit" that is not figured in or subtracted from the 35. He asked whether the way to make these things equivalent would be to somehow calculate in the [Per-Taxable-Barrel] Credit against the 35 percent base tax.

MR. ALPER replied that Representative Seaton is really talking about a calculation of the effective tax rate after [Per-Taxable-Barrel] Credits and somehow scaling back the Net Operating Loss Credit to an effective tax rate. He advised that there might be some technical complexities in doing that because the effective tax rate varies from field to field and producer to producer, but if it was the will of the committee to reduce that Net Operating Loss Credit to some sort of metric that used an effective tax rate for the North Slope, [the administration] could help the committee produce an amendment or different language. He added that Representative Seaton is correct that as a playing field leveler the state is probably giving more than equal benefit. When looking at it from the marginal dollar level - and other committees have looked at marginal costs and marginal tax rates over the years - when a major producer spends one incremental dollar it gets an incremental 35 cent tax benefit at the margin because the producer has reduced its taxable base, its production tax value, by $1, and then 35 percent off of that is 35 cents. However, the [Per-Taxable-Barrel] Credit itself is not impacted by that marginal additional dollar of spend and therefore this is designed to be a marginal benefit - the 35 percent Net Operating Loss Credit equals not so much the effective tax but the tax benefit that the company receives from its last dollar spent.

CO-CHAIR NAGEAK added that the cost of doing business is much higher in the North Slope than it is in the south because of the transportation cost.

MR. ALPER agreed that without question the logistical costs, the mobilization costs, in the North Slope are very different than anything else in Alaska.

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MR. ALPER concluded his discussion of slide 14. He reiterated that the credits that would remain after passage of HB 247 would be the Carried-Forward Annual Loss Credit, the Middle Earth Exploration Credits, and the Cook Inlet Tax Caps.

MR. ALPER turned to slide 15 to continue his review of the credits that would remain if HB 247 passes. These credits are less known, he noted, because there has not yet been production in Middle Earth. The first of these is the Middle Earth Tax Cap at 4 percent of the gross value for the first seven years of production so long as that production begins before 2027. That is a provision of the "Frontier Basins Credit" bill of 2012 [Senate Bill 23, Twenty-Seventh Alaska State Legislature]. Any production that begins in, say, Nenana or similar areas in the state, will pay a 4 percent gross tax regardless of the price of oil for the first seven years of production. The other two remaining credits are the corporate income tax credits mentioned earlier. The LNG Storage Facility Credit and the "Refinery Infrastructure Credit" [qualified in-state oil refinery infrastructure expenditures tax credit, AS 43.20.053] would remain on the books, although the Refinery Infrastructure Credit is scheduled to go away in 2020.

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MR. ALPER drew attention to slide 17, "Credit Cost in Perspective," to discuss how much the state has spent and what it has received related to North Slope refundable credits [between fiscal years 2007 and 2015]. He reiterated that the state spent $1.45 billion supporting six projects that are now in production. Production from those six projects equaled 38.5 million barrels of oil in total aggregate. This means the state spent $37.30 for every barrel of production from these new fields that have come on in the North Slope. That dollar number will decline over time because, for the most part, the money is spent and the oil is going to keep flowing for years to come and every new barrel from that is going to dilute/reduce the per-barrel cost. Meanwhile, the lease expenditures for all of those projects through the end of fiscal year 2015 was just less than $5 billion for the companies involved. So, the state's $1.45 billion in credits represents roughly 29 percent of the companies' total lease expenditures; this is the share of the project that the state has put money into on the North Slope over the last 8-10 years.

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REPRESENTATIVE SEATON understood that the per-barrel dollar amount is anticipated to go down, but noted that the state is continuing to pay lease expenditures at 29 percent of the costs. He asked how rapidly that is expected to go down.

MR. ALPER expected that that number will go down because the incremental lease expenditures, the operating expenditures to keep the existing fields going, is less than the start-up costs. Likewise, this analysis is only looking at refunded credits. So, the answer to the question is also largely contingent on the price of oil - are these companies going to be profitable or not? If they are profitable and they are taxpayers, they are not going to be getting cash credits. If they are running operating losses during production, the state will be continuing to pay them refundable credits on their operating losses and that will bring up the spend numbers. Therefore, a couple of different variables are in play here. He said he would expect this lease expenditure credit to drop, but not as rapidly as the per-barrel number.

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REPRESENTATIVE JOSEPHSON understood from slide 17 that the North Slope refundable credits for six projects have aided in the production of nearly 39 million barrels.

MR. ALPER answered that "aided" is a subjective term. He repeated that the state has given $1.45 billion to the companies that were involved in six projects that are now in production.

To date, those projects have produced 39 million barrels of oil. He allowed it is fair to say that the state has "aided" them.

REPRESENTATIVE JOSEPHSON posited that if this were 1988 it would be the equivalent of 19 days of Alaska North Slope (ANS) production at 2 million barrels a day.

MR. ALPER replied yes and said 1988/1989 production was about 2 million barrels a day.

REPRESENTATIVE JOSEPHSON, regarding the $37.30 per barrel, offered his understanding that if the net value was $74 during the period in question, the tax rate would be applied against half that because the credit is half the $74.

MR. ALPER responded that the great bulk of these credits were refunded before there was substantial amounts of production. So these were under construction - the companies had their capital credits at the time and then their operating loss credits. It is therefore hard to answer that question without getting into project specifics because once a company is in production the company's spending is far less.

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REPRESENTATIVE SEATON observed from slide 17 that previously the state spent $1.45 billion on these six projects and that lease expenditures for these projects were $5 billion. He asked whether the credit support of 29 percent of $5 billion of lease expenditures was in addition to the $1.45 billion.

MR. ALPER answered that the 29 percent is the $1.45 billion: the companies spent $5 billion and the state paid them back nearly $1.5 billion through the state's credit programs.

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MR. ALPER turned to slide 18, "Credit Cost in Perspective," to discuss how much the state has spent and what it has received related to Cook Inlet Refundable Credits [between fiscal years 2007 and 2015]. He reiterated that the state spent about $450 million on credits that went to six producing projects. Those projects have produced about 56 million barrel of oil equivalent (BOE), with the great bulk of that being gas. State spending comes to $7.80 per BOE or about $1.30 per MCF of gas, with this number decreasing over time if additional production comes on from those same fields. The lease expenditures over that time period for those companies involved in those six projects was a little less than $1.1 billion. Although the per-barrel state cost in Cook Inlet is less, the percentage of the cost is higher, with the state supporting these projects by about 40 percent of the lease expenditures.

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MR. ALPER drew attention to slide 19, "Credit Cost in Perspective," to discuss the benefit of the Cook Inlet tax caps. He said it is important to remember that there is a delta between the statutory tax rate and the capped tax rate that is tied to ELF. The Tax Division's analysis of that will be available at the next committee hearing, he advised, but the division estimates that the value of the tax cap to industry is between $550 million and $850 million over the years 2007-2013. This amount is the tax savings from not having to pay at the statutory rate from Cook Inlet and instead paying at the capped rate. Cook Inlet produces about 250 MCF of gas per day, so over that seven-year period that is the equivalent of 640 billion cubic feet (BCF) of gas or 106 million BOE. Cook Inlet also produces about 10,000 barrels of oil a day (it was lower at the beginning of the period and a little higher towards the end), which over that seven-year period comes to 26 million BOE. The total production of 132 BOE and the $700 million in taxes that were not paid (using the midpoint of the division's estimate) equals a tax savings of roughly $5.30 per barrel or $0.88 per MCF. Adding together the credit support of $1.30 per MCF and $0.88 per MCF equals $2.18 per MCF in benefit that the state has given to incremental gas production in Cook Inlet.

MR. ALPER next began addressing the specific sections of HB 247, saying that he will be providing additional modeling and explanation as per the committee's request and that this is not a comprehensive sectional. Moving to slides 21-22, "Section 7:

Interest Rate Compounding," he started reviewing the evolution of the interest rate language in Senate Bill 21.

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REPRESENTATIVE TARR returned to the previous slides to compare the per-barrel equivalent of $37 for the North Slope credits and the per-barrel equivalent of about $13 for the Cook Inlet credits. She asked Mr. Alper whether those numbers surprised him or seemed about right in terms of relative favorability for the North Slope versus Cook Inlet.

MR. ALPER replied that it was a little surprising to him. However, he explained, there are oddities in the data that are hard to parse out. For example, what is really being talked about here is by company. There are companies in Cook Inlet that are producing a lot of oil and gas and all of their production might not have benefitted from credits, but all of it fits into the total production that was worked into this division factor. So, that might lead to some smaller apparent numbers in Cook Inlet than the reality of what was actually impacted by the state's contribution. It is hard to separate a specific company into its component parts in different projects.

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REPRESENTATIVE TARR, regarding Alaska's overall competitiveness relative to other jurisdictions, pointed out that the focus is often on Alaska's base tax rate rather than the aforementioned perspective. In terms of comparing Alaska's favorability to other jurisdictions as a place to invest, she asked whether any other jurisdiction provides credits of almost $40 per barrel equivalent or, as in the Cook Inlet, in the range of $13 to $15 per barrel equivalent.

MR. ALPER responded that comparative fiscal systems is a very complicated art. He said DOR participated in, and drafted, the document for the Competitiveness Review Board. The most recent version of the board's report came out in February. It is very hard apples to apples because every system is different, he explained. Some jurisdictions count sales taxes and property taxes differently than does Alaska. Other jurisdictions have production sharing agreements. In general, it is hard to say. Alaska's realm of refundable credits tied to expenditure is relatively unique in the world. There are not a lot, if any, other jurisdictions that do this to the degree that Alaska has.

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REPRESENTATIVE SEATON commented that he is trying to determine a relative-value chain looking at the Cook Inlet tax caps. He related that according to the radio recently, the Henry Hub was less than $2 per MCF, yet Alaska is providing credits of $2.18 per MCF and the sales price [in Southcentral Alaska] is about $7 per MCF. He inquired as to where the $2.18 per MCF would compare to the development and operational costs of producing that gas as far as comparing the relative value of gas.

MR. ALPER answered:

> We don't know the extent to which our credit regime impacts the price of gas in Homer or Anchorage, without question. We can't tell you if these credits were to change how that might impact the market price of gas. But, if these numbers are relatively accurate ... as the companies go through their own internal economics and say, "we're spending this much money and we're selling this much gas and we have a sales contract," they are more or less able to build in the assumption ... that they're going to be getting $1.30 in refunded credits on the average unit of gas and that they're avoiding taxation of 88 cents on the average unit of gas. So, if they're comparing that to ... an opportunity they have elsewhere in the country that should be built into their equations. But I can't say how any individual company might build that into their internal modeling.

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REPRESENTATIVE SEATON said his reason for trying to figure this out is because at a hearing in Kenai this last interim, Hilcorp testified that it has been able to reduce its [Alaska] exploration and drilling costs to the same costs it has in the Lower 48. He stated he is therefore struggling with why these tax and credit supports are necessary with the price differential that is being seen in sedimentary basins and retail sales in Alaska versus the same comparisons in the Lower 48.

CO-CHAIR NAGEAK commented that maybe Representative Seaton will come up with something in thinking about it.

MR. ALPER added that Representative Seaton is right that Cook Inlet does have among the most general fiscal regimes in the world as far as how the state treats production and also has a substantially higher price than other areas in the U.S.

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MR. ALPER returned to slides 21-22 and resumed his discussion of the evolution of the interest rate language in Senate Bill 21. He addressed why Alaska does not have compound interest in its tax right now and noted that this is not just oil taxes but all of Alaska's taxes. The general tax statute is where the interest rates are, he explained, so someone with delinquent cigarette taxes would be working from the same statutory formulas. When Senate Bill 21 was in the other body, the idea was to reduce the rate from 11 [percent] to a much smaller number. When it passed the other body, Senate Bill 21 failed to pass an effective date vote. This meant that all of the things that changed a number on a date certain were not applicable and it couldn't be said that on January 1 the interest rate would be changed. For purposes of administration one wants to have an even breakdown on when something begins and when something ends. Consequently, when Senate Bill 21 came to the House Resources Standing Committee in the 2013 session, multiple parts of the bill received what is called applicability language, meaning production before January 1, 2014, falls under "this" criteria and after 2014 falls under "that" criteria. It was something of a work-around to the inability to get a two-thirds vote in the other body. When that happened, one of the sections to which that was done was the interest rate section. Meanwhile the compound language remained. There was a technical error in the language that came out of the House Resources Standing Committee that put back some of this 11 percent language that had existed in prior statute, but the compounded language was there. He noted that for every major bill, especially in the finance committee, there is always a cleanup amendment with the chair's name on it that fixes about a dozen things and that passes unanimously. In this case, the cleanup amendment from the House Finance Committee that intended to delete the 11 percent language also deleted the compounding language, which [the administration] believes was inadvertent. The sentence from that amendment stated to delete from page 2, lines 23-25: "**, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter**". The phrase, "**compounded quarterly**", means that the state is only charging simple interest on all delinquent taxes across the board starting January 1, 2014; that there is no more interest compounding from that date forward. Restoration of compounding is one of the things that would be fixed with HB 247.

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REPRESENTATIVE JOSEPHSON asked why Mr. Alper thinks this was inadvertent.

MR. ALPER replied that every version of Senate Bill 21 had compounding language, there was much debate and discussion about reducing the interest rate and charging a much less onerous rate. There was consensus, at least among those who supported the bill, to do that. There was never any discussion of eliminating compounding, it was never brought up in any committee debate. It just showed up in the last amendment in the last committee as a technical amendment that happened to do that while it was also doing something else. He said he therefore believes it was inadvertent because he found no committee record to show that doing it on purpose was discussed.

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MR. ALPER continued his presentation. He moved to slide 23, "Section 7: Interest Rate Increase," and stated that increasing the interest rate is much more substantive. He explained that the current interest rate of 4 percent is a rate that is 3 percent above the federal discount rate. The federal discount rate changes quarterly and right now that rate is 1 percent. A 4 percent rate, he noted, could actually create incentives to delay and contest tax payments. When the rate was 11 percent and the Tax Division informed a company that it owed the state $100 million, even if the company didn't want to, it would typically pay it because if the appeals process went another two years the company would owe 11 percent interest on that $100 million and the company didn't want to have pay the interest. So the company would pay the money and then if at the end of the appeals process the company won, the state would pay the company back the difference plus the interest, so the company got the 11 percent back from the state. At 4 percent, the incentive structure is flipped on its head a little bit and companies are more likely to not pay contested taxes. The appeals process is gone through with the money in the company's bank instead of the state's because the company is generally able to earn more than 4 percent on its money; if the company loses at the end, it has actually made money over the time. So, [the administration] believes that somewhere in between 4 percent and 11 percent is the right number. Importantly, in a low price environment where the state is spending its savings to operate the state every day, every dollar of tax that is not paid is one more dollar that the state is taking out of its savings. Therefore, when that tax is eventually paid, it should compensate the state for what it would have earned had it remained in savings. The number from the permanent fund's financial advising company, Callan & Associates, is about 7 percent.

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CO-CHAIR NAGEAK requested Mr. Alper to provide correspondence to tell the committee if it is actually happening the way he is explaining it.

MR. ALPER responded that the permanent fund publishes an estimate of returns and also publishes its actual returns as time goes by. The permanent fund's most recent publication shows an expected earnings rate for the next 10 years or so as averaging about 7 percent per [year]. He said he will be happy to keep the committee up to date as those numbers change going forward. He clarified that the bill isn't tied to this number; rather, the bill has a fixed number of 7 percent above prime, which currently works out to 8 percent. That is an error on [the administration's] part, it probably should say 6 percent over the discount rate, which would be 7 percent. A formula could be built that is somehow tied to the permanent fund's estimated earnings or its actual earnings and have it change every quarter. There would be a way to make an adjustable rate within statute, it's just one step more complex. When putting the bill together, [the administration] chose to go with a simpler formula tied to currently expected earnings. But, he advised, that might not fully compensate if there are broad swings in expected earnings in years to come.

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REPRESENTATIVE JOSEPHSON understood Mr. Alper to be saying that the intent was really to achieve 7 percent so the bill should properly say 6 percent. He remarked that this seems like a multi-million dollar question and inquired whether it is the administration's preference that the committee adopt 6 percent.

MR. ALPER answered that his understanding is yes, the administration's preference is to have a number tied to the permanent fund's estimate, which is 7 percent. The bill, as written, really says 8 percent, so the administration would prefer 7 percent in that that is tied more closely to the permanent fund's estimate.

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REPRESENTATIVE OLSON recalled that the last audit completed [by the Tax Division] on the production tax was 2008. He requested Mr. Alper to provide a breakdown of the audit amount due on the interest for 2008.

MR. ALPER replied that the complete set of audits for all the producers that paid taxes claimed - not all has been paid and some is being contested - the division assessed $265 million, of which about $110 million, or almost half, was interest. That was based on the 11 percent compounded interest for the years 2008 to January 1, 2014. The interest rate did not change until the effective date of Senate Bill 21. For the last year of it the interest was a much smaller number.

REPRESENTATIVE OLSON understood it took six years to complete the audit or to get to the point that the division is at now.

MR. ALPER confirmed that the 2008 audit was completed six years after the taxes were received. He clarified that the division was not working on that audit for six years; it was doing lots of other things during that time, including the 2007, 2006, and 2005 audits. The division used all of the statute of limitations available to it last year.

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REPRESENTATIVE TARR understood that Section 7 would change the interest rate from 3 percent to 7 percent above [the federal discount rate], so with the 1 percent that would make the rate 8 percent. She asked whether instead of the cap at 7 percent, [the administration] would want it to be an either/or scenario, so the language would give a cap of whichever is greater - 7 percent or....

MR. ALPER responded that this gets a bit beyond his expertise, but explained that the 1 percent discount rate has some tie to inflation. If there was a spike in inflation it would be expected to have a spike in that rate and therefore a spike in the interest that the state would be charging. Also, the permanent fund would start seeing higher returns as well. Even though the real returns might remain the same, the interest embedded in all of its portfolio would be going up along with inflation. That 7 percent number assumes about 4.5-4.75 percent real returns offset by 2.5-2.25 percent expected inflation.

REPRESENTATIVE TARR remarked that it sounds like this is the scenario that [the administration] would want to avoid if there was a change in inflation because that would end up getting the state close to the current scenario of 11 percent, which is what [the administration] is saying is too high. She said it seems that maybe the alternative would be to put this plus 1 or 7 percent, whichever is greater.

MR. ALPER responded that the language prior to the passage of Senate Bill 21 was the higher of 11 percent or of 5 percent over discount, which would be 6 percent in today's world. So, the higher of calculation was eliminated and the 5 was replaced with a 3. Representative Tarr is suggesting a minimum rate of 7 so that if the state was going 6 above discount, and the discount rate was below 1 percent for several years, which was an historical anomaly. If it gets down below that, he said he is personally not terribly worried about the difference between 6.5 and 7 in the returns. Rather, he is more curious about what happens if the discount rate gets a lot higher and an 8 or 9 percent interest is starting to be seen; but, on the other hand, there is a lot more underlying inflation and then the permanent fund would be growing faster. Ideally they should be balancing each other. He suggested that if trying to tie this to the permanent fund, it might wise to find a more explicit way to tie it to fund performance inside the state's assets.

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MR. ALPER resumed his presentation and brought attention to the chart on slide 24, "Section 7: Interest Rate Increase." He explained that the chart compares an interest rate calculation on a standard $1 million assessment under current law and under HB 247. He said the chart uses a smaller number because these are general tax statutes, not oil and gas language, and for many of Alaska's smaller taxes the assessments are much smaller. As well, most of the general fund money that is going to come in as a result of this change is going to be in these smaller numbers. For the major oil and gas settlements and assessments that come in, almost all go to the Constitutional Budget Reserve and not to the general fund. If there is a $1 million assessment at the end of the 2015 tax year it would be the end of second quarter 2017 by the time the Tax Division assesses it, so the company would owe a year and a half's worth of interest. At simple interest on $1 million, the total interest would be $60,000 at 1 percent per quarter or 4 percent per year. If an interest rate of 8 percent is begun on the proposed effective date in HB 247 of July 1, 2016, and if from that date forward that interest was subject to compounding, the net effect of status quo and changes by the bill is $42,000 in additional interest to the state. If instead of $1 million the assessment is $100 million, that $40,000 becomes $4 million.

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REPRESENTATIVE OLSON inquired whether it is delinquent if the division waits six years to do the audit.

MR. ALPER allowed it is not ideal business practices. He noted that there have been a few extenuating circumstances, including multiple tax changes and the implementation of a major software rewrite that took everyone off task for a long time. The Tax Division is doing everything in its power to catch up and move off of that statute of limitations, which was something that he inherited when he took the job. He said he is extremely proud of the division's staff in the Audit Group and he believes that in a year from now there will be substantial catchup.

REPRESENTATIVE OLSON recalled that a few minutes ago Mr. Alper stated that the division used the statute of limitations fully.

MR. ALPER replied he is unsure what he just said that contradicted that. He said the division did go up against the statute of limitations, meaning it took all of the time allotted to it to get the 2008 audits out. The 2009 audits are due at the end of March. The audits were expected a month or two ago, but the division was given a snafu in a court ruling that affected some tariff rates from 2009; they need to get reworked through the system and this threw a lot things back into the work pool for a little while. He reiterated that 2010 and 2011 are going to be completed simultaneously and by a year from now the division should be at least one full year off the statute of limitations and by three years from now the division would like to be three years off the statute of limitations.

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REPRESENTATIVE TARR understood that Mr. Alper is projecting that a year from now the division will be more within the three-year range of the statute of limitation. She understood there is likely some expected period of delay and that once the division is caught up a two-year to three-year delay is reasonable.

MR. ALPER responded three years, possibly four, is probably reasonable. The old statute before the passage of ACES was four years. It was extended two years because of the understanding that the system got a whole lot more complex with the switch to a net profits tax. The division's work plan right now is to be five years off the statute one year from now, four years off the statute two years from now, and three years off the statute three years from now. The division is going to be doing two years in one for the next two or three years. He said his hope is that the division's resources hold out and that no strong wrinkles get thrown at the division, but the division believes that it will be able to do that. The new software in 2011 is making an order of magnitude difference in DOR's ability to handle data, as well as in DOR's ability to handle data for every other tax type.

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MR. ALPER returned to his presentation and concluded discussion of Section 7 by moving to slide 25, "Section 7: Interest Rate Increase." He explained that while he created an example with $42,000, it is difficult to quantify future revenue impact because the division cannot know what is going to be assessed and cannot know what is going to be delinquent because these things are different every year in every tax type. The near-term impact would be very small because the difference does not start accruing until July 1, 2016, but increasing delta would be seen between that point and years afterwards. In the production tax, most of the impact is going to be in the Constitutional Budget Reserve.

MR. ALPER moved to the graph on slide 26, "Section 12: Increase Minimum Tax." He said Section 12 of the bill increases the [gross] minimum tax from 4 percent to 5 percent. The grey line on the graph, he explained, depicts the underlying Senate Bill

21 net tax of 35 percent after credits without any minimum tax. Currently, that tax would go to zero at an oil price of around $70 and fortunately the state benefits from the 4 percent minimum tax depicted by the blue line. Current revenue looks like the blue line until it crosses the grey line and the grey line is to the right of the mark for roughly $80 a barrel. A 5 percent minimum tax is depicted by the orange line that is seen above the blue line and which then crosses over with the grey line. The delta of revenue is the wedge between the blue line and the orange line.

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REPRESENTATIVE OLSON asked whether any models have been done for prices up to $135 or $140 a barrel, given that the mistake a few years ago was stopping at $95 a barrel.

MR. ALPER answered that [the division's] standard modeling is now using $20 to $130 a barrel. There is now a giant table of royalty production tax, unrestricted royalty, and restricted royalty at all oil prices from $20 to $130 for the next 10 years. He said he will provide this table to the committee.

MR. ALPER returned to his review of slide 26 and noted that while the grey line will continue to go up and larger numbers in revenue would be seen at an oil price of $130, slide 26 is illustrating the impact of the minimum tax and the minimum tax is irrelevant at those prices. Slide 26 looks at the crossover point between the minimum tax and the net profits tax, which currently occurs at an oil price of around $80. If that minimum tax were to be raised to 5 percent, the crossover would move to a price of somewhere between $80 and $85. If the legislature were to desire a very large minimum tax of 10 or 15 percent, a much higher parallel line would be seen on the graph and the crossover of the grey line might not happen until an oil price of $100 or higher. The higher the minimum tax, the more a gross tax paradigm is being introduced over the net tax system that Alaska has.

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MR. ALPER drew attention to the illustrative model on slide 27, "Section 12: Increase Minimum Tax." He said the model shows how much money is being talked about if all of the oil were at the same price and none of the oil was eligible for the Gross Value Reduction (GVR). The model simplifies the whole system at a range of prices between $20 and $100, and looks at the net value (fifth row down) after a per-barrel cost of roughly $46, which is the cost estimate for the current year in the Revenue Sources Books. The calculated net value cannot be below zero. The tax rate is 35 percent of that, and then there is a sliding-scale credit. Bringing attention to the two lines for "Tax After Credits" and "Minimum Tax", he explained that these are calculated in parallel and the companies pay the higher of. Where the Wellhead Gross Value is $10, the state is getting $0.40; where the Wellhead Gross Value is $20, the state is getting $0.80. When the Wellhead Gross Value is $60, the state is getting $2.40 and the calculated tax after credits is only $0.40. But, at an oil price of $80, the minimum tax is $2.80 and the calculated tax jumps up to $3.90 because that is where the crossover is. The revenue from a 5 percent minimum tax would increase by $16 [at an oil price of $20] on up to $96 million at an oil price of $70. At an oil price of $80 it [drops to no increase]. That roughly parallels the graph seen on slide 26. The number in the fiscal note is $50 million, a number that roughly lines up with DOR's forecasted revenue.

MR. ALPER turned to the bar graph on slide 28, "Section 12: Increase Minimum Tax," depicting the revenue impact of raising the minimum tax from 4 percent to 5 percent. He explained that while slide 27 was a more illustrated and calculated model, the graph on slide 28 is closer to the actual revenue. This is because the graph lines up with the state's forecasted price of oil, the forecasted production, and how the specific circumstances of the state's individual producers interact. If the price of oil remained at $30 for all of fiscal year 2017, the proposed 5 percent tax would only get the state $20 million. But if the price of oil were to rise to $50, the 5 percent tax would get the state $50 million. [At a price of $75, the 5 percent tax] would peak at about $80 million and then drop off.

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MR. ALPER moved to slide 29, "Section 17(b): Strengthen the Minimum Tax," to review which credits can break through the floor under current law. He explained that the slide depicts the 4 percent tax floor and underneath that floor is the "basement" of zero tax. He discussed what is and is not limited by the floor. Limited by the floor is the sliding-scale per-barrel credit specifically on non-GVR-eligible oil, meaning legacy oil, and this old oil is limited by the floor. All other credits under current law can go below the floor and include: the Net Operating Loss Credits, Per-Barrel Credits on GVR-eligible oil (new oil), the Exploration Credit that is scheduled to sunset, and the Small Producer Credit. All of these credits are being used to reduce tax payments below the minimum tax, he pointed out, and in many circumstances are being used to reduce tax payments to zero.

CO-CHAIR NAGEAK requested Mr. Alper to further explain that.

MR. ALPER replied that each one of these is a slightly different situation. He posed a scenario of a small producer producing less than 50,000 barrels a day that is a junior partner in a major oil field that pays at the legacy rate. In other words, a company that owns a smaller percentage of Prudhoe Bay. This company's profits would be subject to the 4 percent floor just as this company's larger partners would be paying at the 4 percent floor. However, this small producer would earn a credit of up to $12 million that could be subtracted off the top of its taxes. If this company's minimum tax was less than $12 million, this company would pay the state zero tax. Mr. Alper posed another scenario of a small producer operating a newer field on the North Slope. This company would pay a tax on its production tax value and would be eligible for the GVR, which tends to reduce the company's liability, but if the oil price is high enough the company will have a tax liability. However, the company's $5-Per-Barrel Credit can offset the company's taxes all the way down to zero and, if it doesn't, the company could also be eligible for the Small Producer Credit. So, at a wide range of prices it is reasonable to say that the smaller producers with the smaller fields can generally offset their taxes all the way to zero between the $5-Per-Barrel Credit and the Small Producer Credit.

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REPRESENTATIVE JOSEPHSON noted that industry got a legislature to pass Senate Bill 21, which then went to a referendum and industry prevailed in the referendum. He surmised that this may not have gotten much attention in the debate that occurred in August 2014 because it is complicated. He inquired as to whether the "basement" issue was vetted by the legislature in committee in 2013.

MR. ALPER responded that this condition is not a by-product of Senate Bill 21, but rather a pre-existing condition going back to Alaska's Clear and Equitable Share (ACES) and the production profits tax (PPT) that came before ACES. Senate Bill 21 created the limited hardening of the floor: the legacy producers with the sliding-scale credit cannot use that credit to go below the floor. The comparable large credit earned by the legacy producers before 2013 was the 20 percent Capital Credit and that could be used, and was used, to go down below the floor. The other reality is that until 18 months ago the minimum tax was an academic conversation. The price of oil had not gone into the territory in modern history where the minimum tax came into play in any material way, modern history being since Alaska has had a net profits. The minimum tax is now suddenly relevant and is being discussed in greater detail because that is where the state is getting its revenue from, whereas during the referendum debate it was not part of the conversation in any material way.

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REPRESENTATIVE OLSON said the other major variable that is still not being talked about is the lack of production over the years. When he was first sworn into office 12 years ago the price of oil was $30, but a major difference from now is that a million barrels a day was going through the pipeline.

MR. ALPER offered his belief that Representative Olson is right that production has dropped by half during the last 12 years.

He further stated that $30 then is different than $30 now and that the cost of producing those barrels and the tariff for moving them down the pipeline are also higher than they were. A lot of things are working against the state in addition to reduced production. Many of these incentives were put in place to do what they could to reverse or at least slow that decline. The decline has continued. There is geology in place that he cannot speak to, but there are other people who can.

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REPRESENTATIVE TARR recalled that the goal when Senate Bill 21 was passed was to see 100,000 new barrels of production. She asked what the current Revenue Sources Book forecasts for production increase.

MR. ALPER replied he doesn't know the numbers off the top of his head, but said that a number of fields are under development and under evaluation. He explained that DOR considers the oil that is currently being produced and adds the oil that DOR believes to be happening. The department applies probabilities and risk factors to the oil that is under development and under evaluation. The Mustang, Nuna, and Point Thomson projects, he reported, are presumed to be happening within the period studied in DOR's forecast. He offered to provide the committee with a comprehensive list of the fields and projects that are in DOR's forecast.

REPRESENTATIVE TARR said she would like to receive that list.

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MR. ALPER brought attention to slide 30, "Section 17(b): Strengthen the Minimum Tax," and specified that current law allows all credits to go below the floor with the exception of the sliding-scale per-barrel credit. [The administration] is seeking to change the law under HB 247 so that four distinct different credits also cannot reduce taxes below the floor. The bill would make it so that: small producers would have to pay the minimum tax level; new GVR-eligible fields would pay at the minimum tax level; the Net Operating Loss Credits that are carried forward could not be used to reduce payments below the minimum tax; and Exploration Credits, if used against liability, could not be used to go below the minimum tax.

MR. ALPER turned to slide 31, "Section 17(b): Strengthen the Minimum Tax." He advised that three very different policy questions are before the committee and allowed that members might have a different opinion and a different desired result on each one. Several things are being done with the minimum tax, he explained. First, regarding the Small Producer Credit, the question being asked is whether everyone, not just the major producers, should pay at the minimum tax level. Under current law, only the large producers pay that floor. Second, regarding the Per-Taxable-Barrel Credits for "new" oil, the question being asked is whether the tax on production from new fields should be allowed to go to zero. The third question is whether a major producer that carries a loss forward into the next year should be able to use that Net Operating Loss Credit to reduce its payments below the floor or should the company be forced to pay at the minimum tax level and then continue to carry that credit forward into a future year when it has more tax liability. And, if it is made so that the net operating loss cannot be used against minimum tax payments, the question is whether that should be made retroactive to January 1, 2016, as proposed in HB 247. Mr. Alper reported that at least one major producer showed a loss for 2015 and will be offsetting minimum tax payments beginning this month to the level of zero by using its Net Operating Loss Credit from calendar year 2015 to offset minimum tax payments from 2016.

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MR. ALPER drew attention to the table on slide 32, "Section 17(b): Strengthen the Minimum Tax," to illustrate how the GVR-eligible per-barrel credits [can reduce taxes below the minimum tax] at a West Coast oil price of $80. He explained that the table includes two parallel calculations of how the minimum tax treatment applies under current law to legacy oil and to GVR-eligible new oil. At a price of $80 and a transportation cost of [$10], the wellhead value (also called the gross value at the point of production) is $70. The minimum tax is tied to the gross calculation, not to the market price. The lease expenditure cost of $36 is subtracted from the wellhead value, arriving at a net value of $34. If that oil is subject to the 20 percent Gross Value Reduction (GVR), then 20 percent of the $70 gross is $14; this $14 is then further subtracted from the net value of $34, arriving at a net value after GVR of $20. This is where the disparity is seen: the net value after GVR is $34 for legacy oil and is $20 for GVR-eligible oil. The tax is then calculated by taking 35 percent of the net value after GVR; so the tax before credits is $11.90 on the legacy oil and is $7 on GVR-eligible oil. For legacy oil the Per-Taxable-Barrel Credit is a sliding-scale credit; at a price of $80 this credit reaches its maximum of $8, which reduces the base production tax after credits on the legacy oil to $3.90. For the GVR-eligible oil, the Per-Taxable-Barrel Credit is $5, which reduces the base production tax after credits to $2.00. At a price of $80, the minimum tax calculation is $2.80. The tax of $3.90 paid on each taxable barrel of legacy oil is above the minimum tax. However, the tax of $2.00 paid on the GVR-eligible oil is below the minimum tax; this is because under current law the minimum tax does not count for the GVR-eligible oil. Under HB 247, a producer in that circumstance would be forced to pay at the level of $2.80.

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REPRESENTATIVE JOSEPHSON surmised that bringing GVR-eligible oil up to the legacy rate is the parity Mr. Alper was talking about.

MR. ALPER responded correct. He pointed out that because the taxes are higher, the legacy oil is not impacted by the floor at $80, but the GVR-eligible oil is. If the floor were in place, the GVR-eligible oil would be paying $2.80, whereas under the current statutory rate the tax on that oil is $2.00.

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MR. ALPER moved to slide 33, "Section 17(b): Strengthen the Minimum Tax," to do the same calculations at a price of $60. At this price, he noted, the taxable net value goes down to $14. At a tax rate of 35 percent the base production tax before credits is $4.90 for legacy oil. The full value of the $8 per barrel credit is partially lost when applied because the tax goes to zero. The minimum tax then comes into play: at 4 percent of the wellhead value, which is $50, the minimum tax is $2.00. So, under current law at a price of $60, the tax on legacy oil is $2.00 per barrel. For GVR-eligible oil, the net value of $14 is reduced by the 20 percent Gross Value Reduction, reducing the net value to $4.00. At a 35 percent tax rate the tax before credits is $1.40. The $5-per-barrel credit reduces that tax to zero. So, under current law, GVR-eligible oil is paying a tax of zero. Under HB 247, GVR-eligible oil would pay [a minimum tax] at the same rate as the legacy oil - 4 percent of the gross or $2.00 a barrel.

MR. ALPER brought attention to slide 34, "Section 17(b): Strengthen the Minimum Tax," to discuss the portion of Section 17(b) that is related to the Net Operating Loss (NOL) Credit and would affect the major producers. This provision would prevent companies from applying a Net Operating Loss Credit against the minimum tax. The statutory definition of a loss is when a producer's total lease expenditures for the year exceed the gross value [at the point of production]. In plain English, this is when a producer has negative net income based on Alaska law. He pointed out that this is for a calendar year, not a fiscal year. At around $50 and below, some Alaska producers start experiencing operating losses.

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MR. ALPER turned to the tables on slides 35-36, "Section 17(b): Strengthen the Minimum Tax," to review how Net Operating Loss (NOL) Credits are earned and used. He explained that the table on slide 35 is a stylized reality for the aggregate of all of Alaska's producers for calendar year 2015. The table depicts each month of the year and how the production tax value, meaning after all expenses, is calculated. The negative numbers are shown in grey. Those numbers cannot really be below zero when calculating them, he explained, but they are calculated when dealing with Net Operating Loss Credits. This leads to negative taxation or tax calculations that would be negative if these operating losses were calculated into the tax. What actually happens is that the minimum tax is charged and from the minimum tax comes certain credits. The State of Alaska's actual tax payments for calendar year 2015 roughly equals the bottom line on slide 35 - about $187 million. Adding up all of the negative numbers on the production tax value line will show that the companies lost $183 million in Alaska last year. So, at the 2015 Net Operating Loss Credit rate of 45 percent, this $183 million loss translates into a Carried-Forward Annual Loss Credit of $82 million.

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MR. ALPER moved to slide 36 to explain what happens to the Carried-Forward Annual Loss Credit in 2016 if the price of oil goes to $40 and stays there through December. He noted that the second to last line on the table is the application of the carried-forward credits. The third to last line should be the companies' minimum tax payment. However, the companies are subtracting the carried-forward credits from the minimum tax payment and paying zero tax all the way through until September. By September the companies have used up all their Operating Loss Credits and are then left with only paying the amount that is in the last row of the table for the months of October, November, and December - a total of about $27 million. So, the state only gets the minimum tax for the last three months out of the year. More importantly, if these trends continue, and these are well below the state's forecast, the companies would show a $1.2 billion loss in 2016, which at the credit rate in play at the time would result in over $400 million in Carried-Forward Annual Loss Credits. If these low prices continue for another couple years, that's another two years of zero tax revenue because the companies would be able to completely offset any minimum tax payments for two years into the future until they have run through the $400 million in credits and possibly earning additional credits along the way. Essentially, the state would not start seeing any revenue until there is substantial cost recovery. It is being proposed under HB 247 that this credit cannot reduce the minimum tax payments. Even if the companies are losing money, [the administration] wants them to pay the 4 percent gross tax because the state should be getting at least something. Those credits would then be carried forward and used in a future year once there was adequate recovery in the price of oil and adequate tax liability that the companies would be able to offset it with their credits.

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REPRESENTATIVE OLSON inquired whether the companies are doing anything illegal or unethical in their calculations.

MR. ALPER answered that, to his knowledge, they are not. The companies are following the law and paying and filing their taxes the way Alaska's rules and regulations instruct them to.

REPRESENTATIVE OLSON remarked that the companies are paying approximately 90 percent already and now the state is going to go after the other 10 percent.

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MR. ALPER stated that slide 37, "Section 17(b): Strengthen the Minimum Tax," talks about the previous two slides. He said the information on slides 35-36 shows how those operating losses would be used to carry forward. He reiterated that the net operating loss for calendar year 2015 is $183 million, this loss would generate a credit of $82 million, and this loss credit would start offsetting 2016 minimum taxes beginning in January. If oil prices were to rise to $40 and stay at that level through all of calendar year 2016, [the North Slope producers] would see a loss of over $1 billion. That loss would stack up yet another $400 million loss credit that would be applied beginning in January 2017. The changes proposed by HB 247 would not take the credits away from anyone, he stressed. An Operating Loss Credit is something that has value and is wanted to be carried forward. He advised that there are other changes to Operating Loss Credit payback elsewhere in the bill. He said [the administration's] expectation is that these would be deferred, kicked forward, to some future year when the state had more money and higher tax revenue coming in from production tax. Those Operating Loss Credits would be used then to reduce tax payments and take money from the state in the future when it has money instead of in the present when the state doesn't have money.

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REPRESENTATIVE TARR recalled that the negative scenario depicted on slide 36 was not contemplated during consideration of Senate Bill 21. She noted she was on the committee at that time and feels that if this very low price environment and the consequences had been contemplated the committee may have done something differently. She asked whether there are other calendar years that mimic what is being shown on slide 36.

MR. ALPER replied that he can provide other calendar years to show stylized how it worked. In none of those years was there an issue of minimum tax. He recalled that there was a price collapse in the early months of 2009 and therefore that might be a year to provide the committee. The ACES regime was in effect at that time. He stated that these issues are not unique to Senate Bill 21 and said this is not the appropriate time to cast dispersions at the current tax regime. These are issues that have been embedded in Alaska statute since switching over to a net profits regime. They happened to have come to the forefront now, not because of Senate Bill 21, but because oil prices have collapsed to such a degree that operating losses are starting to be seen in the industry.

REPRESENTATIVE TARR requested Mr. Alper to provide the committee with [the 2009] calendar year for comparison purposes.

MR. ALPER agreed to do so, and added that he would continue his presentation when he was next before the committee [on 2/24/16].

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[HB 247 was held over.]

3:02:37 PM

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 3:02 p.m.