

HOUSE FINANCE COMMITTEE
March 21, 2017
1:37 p.m.

RECESSED UNTIL 9:00 a.m. ON WEDNESDAY, MARCH 22, 2017

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CALL TO ORDER

Co-Chair Seaton called the House Finance Committee meeting to order at 1:37 p.m.

MEMBERS PRESENT

Representative Neal Foster, Co-Chair
Representative Paul Seaton, Co-Chair
Representative Les Gara, Vice-Chair
Representative Jason Grenn
Representative David Guttenberg
Representative Scott Kawasaki
Representative Dan Ortiz
Representative Lance Pruitt
Representative Steve Thompson
Representative Cathy Tilton
Representative Tammie Wilson

MEMBERS ABSENT

None

ALSO PRESENT

Ken Alper, Director, Tax Division, Department of Revenue;
Representative Garran Tarr.

SUMMARY

HB 111 OIL & GAS PRODUCTION TAX;PAYMENTS;CREDITS

HB 111 was HEARD and HELD in committee for further consideration.

Co-Chair Seaton reviewed the agenda returning to the presentation on HB 111 from the tax division.

#hb111

HOUSE BILL NO. 111

"An Act relating to the oil and gas production tax, tax payments, and credits; relating to interest applicable to delinquent oil and gas production tax; and providing for an effective date."

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KEN ALPER, DIRECTOR, TAX DIVISION, DEPARTMENT OF REVENUE, turned to slide 13 of the PowerPoint presentation: "Oil and Gas Production Tax and Credits: Background and Bill Analysis." The slide discussed the background on Alaska's oil and gas taxes and analysis of CSHB 111(RES).

Mr. Alper moved to slide 14. He explained that the exploration credit went back to 2003, and was intended to give a benefit against taxes of some percentage of spending on desired exploration activities. There was also the capital expenditure credit, which was part of the Petroleum Production Tax (PPT) bill. The capital credit was expanded in 2010 and created a 40 percent credit called the "well lease expenditure (WLE)." The North Slope credit was repealed with SB 21 [oil and gas tax legislation passed in 2013] in the previous legislature. House Bill 247[oil and gas tax legislation, 29th Legislature] eliminated the capital credit in two stages, to be repealed in the following year. In Middle Earth there would be a small credit remaining into the future. The main credit that what was discussed the most was the Net Operating Loss (NOL) credit, which paid for a percentage of a company's losses. That type of credit was "stackable" with exploration and capital credits. This lead to up to 85 percent state participation in company expenditures for about a two-year period.

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Representative Guttenberg wondered about stackable credits and how prevalent they were in the world.

Mr. Alper responded that the whole idea of cashable credits was quite unique to Alaska. He did not know whether they existed in other jurisdictions.

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Co-Chair Seaton acknowledged Representative Ortiz and Representative Tilton at the table.

Vice-Chair Gara asked whether Mr. Alper knew of another jurisdiction that pays for a portion of a company's losses.

Mr. Alper responded that it was not unusual for losses or pre-production spending, also considered losses, to be carried forward and captured once there was production and value. There were many ways to do this, but it was the nature of a profit system that the costs from pre-production ended up in the taxes post-production.

Vice-Chair Gara indicated that the major producers saw a 35 percent credit for NOL and a 35 percent deduction on their expenses, but did not pay a 35 percent tax rate. He asked whether it was not more common to see a deduction based on tax rate as opposed to something much larger than the effective tax rate.

Mr. Alper pointed out the difference between the nominal versus the effective tax rate. He suggested it would be easier if it were just a flat tax rate. He had a slide that provided a better NOL rate. He agreed that the system created nuances such as those mentioned.

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Mr. Alper scrolled to slide 15. He spoke about some of the different tax credits. The small producer credit went back to the beginning of PPT. It was designed to make the first amount of a company's profits effectively tax-free if it fell beneath a certain production threshold which worked out to be the first \$12 million of tax liability for the first nine years of production. In order to qualify, small producers had to have first production by May 2016. There would be a gradual phase out of small producer credits over the subsequent nine years. The per-taxable barrel credit had been the foundational credit for the SB 21 calculation. He mentioned the sliding scale for legacy oil. The new oil would receive the \$5 flat rate credit. Other credits were essentially cash, and were not really considered production tax credits, but were against the state's corporate income tax.

Mr. Alper discussed credits against corporate income taxes. In 2007, the state began to buy back the credits at face value from the companies. He explained the rationale behind the choice. The state created a tax credit fund and created certain rules for buyback. One of the rules governing this was that the company had to produce less than 50,000 barrels per day in order to be eligible for cash. The larger companies would have to carry their credits forward to the following year. Exxon, ConocoPhillips, and BP, as well as Hilcorp as of 2015, all fit this category.

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Representative Wilson asked if it made a difference whether a company wrote off the loss in its taxes or if the state paid a check to the company.

Mr. Alper answered that there was no real difference. He pointed to a big table in the Revenue Sources Book, Table 8-4, which broke out cash credits, credits subtracted against liability, North Slope/non-North Slope, with a lot of detail. The main difference was time. If the company was set to receive cash, they would receive it the following year, whereas if the credit was used against the company's own taxes, they may receive it five or seven years later.

Representative Wilson asked if those were the same credits that a company could take to a bank as collateral.

Mr. Alper responded that there had been a provision added in 2013 that enabled a company to assign the rights to its credit cash to a bank. For the state, that meant that it was paying directly to the bank, which allowed for some bankruptcy protection to the bank. Much of the lending for small oil companies was venture capital, high-risk money. What began to occur was companies would borrow an extra \$50 million in year 1. They had the same startup money from venture capitalists and would bank on that credit to pay the second lender back. The banks that were making the short-term loans were left hanging with the lack of credit cash.

Representative Wilson asked if the credit system increased oil production.

Mr. Alper responded that he did not want to speculate on increased production, but that it certainly had accelerated spending.

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Mr. Alper moved to slide 16 on the history of oil and gas production tax credits.

FY 2007 thru 2016, \$8.0 Billion in Credits

North Slope

- \$4.4 billion credits against tax liability
Major producers; mostly 20% capital credit in ACES and per-taxable-barrel credit in SB21
- \$2.3 billion repurchased credits
New producers and explorers developing new fields

Non-North Slope (Cook Inlet & Middle Earth)

- \$0.1 billion credits against tax liability
Another \$500 to \$800 million Cook Inlet tax reductions (through 2013) due to the tax cap still tied to ELF
- \$1.2 billion repurchased credits (most since 2013)

Mr. Alper elaborated that \$8 billion was offered in credits in the first 10 years of the program. About \$4.5 billion of that was not an expenditure by the state, but an offset to taxes and a reduction in revenue received. This occurred mostly in the North Slope, and almost entirely via either the per-barrel credit in SB 21 or the old 20 percent capital credit from ACES. If a major producer spent \$600 million, and earned 20 percent capital credit, they would be subtracting \$120 million from that year's taxes. The other \$3.5 billion were cash credits.

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Vice-Chair Gara asked if the state still allowed companies to sell their credits to other companies at a discount.

Mr. Alper explained that the credits could be sold to another company and that the company had to inform the state of the activity, but it was not required to specify how much it received. The private market for secondhand tax credit was an unknown, private negotiation.

Vice-Chair Gara provided an example of the state buying back credits from BP for the full amount. He asked whether it had been proposed that the state participate at the same level, buying them at a discount.

Mr. Alper responded that he did not know whether that had been proposed, but the Senate added language to HB 247 in the previous year which said that a company could get up to \$70 million in a given year. The first \$35 million had to be paid at face value. If it wanted more, the company would have to accept a 25 percent haircut. The most any company could get would be \$61.25 million to purchase \$70 million worth of credits. There had never been a discussion to buy the credits at a discount.

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Representative Pruitt spoke to the credits against tax liability. He asked whether when Mr. Alper meant the \$8, \$7, \$5 when referring the per-taxable barrel credit in SB 21..

Mr. Alper replied in the affirmative.

Representative Pruitt asked how much of the \$4.4 billion was associated with that particular credit.

Mr Alper replied that the credit became effective in January 2014, with the effective date of SB 21. In the first 18 months or so, it was around half a billion dollars. It had been a much smaller number since prices had fallen, to where most North Slope production was well under the minimum tax threshold. He noted that a later slide would show that the numbers quickly went to \$8 [slide 47] then dropped rapidly at prices under \$70 and companies bumped up against minimum tax.

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Representative Pruitt was trying to recall the discussion around SB 21. He recalled that there had been concern that the state was moving away from the progressive tax in Alaska's Clear and Equitable Share (ACES). He wondered if the state should be grouping the tax with other credits. It was an integral part of that particular tax.

Mr. Alper remarked that the answer to the representative's previous question was \$1.2 billion. He stated that it was a credit, it was called a credit in statute, it needed to get accounted for when credits were accounted for, and it was used to offset taxes. He agreed it was an integral part of the SB 21-based tax system. The change had been made for reasons of progressivity. The original bill presented by Governor Parnell had been a 25 percent flat tax, without progressivity or per-barrel credits. The problem with that was that, when layered with royalty, which was slightly regressive, it led to an overall regressive tax regime. The goal of the then legislature had been to have a relatively flat total government take curve. That changed from \$25 with no credit to \$35 with a \$5 credit, and was roughly revenue neutral at \$100 per barrel oil. It wasn't viewed as a tax increase, only an increase in the tax rate, with a credit benefit that roughly equaled each other out. Suddenly, it added \$800 million a year in credit liability to the state, even though it was revenue-neutral.

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Vice-Chair Gara reported that the 35 percent credit was called a 35 percent tax - he strongly disagreed. When the so-called credit, which was really a price-sensitive tax reduction, takes place, at \$80 per barrel the state received 15 percent profits tax. He stated it was not really a 35 percent tax.

Mr. Alper stated that the bill introduced in 2013 had a flat 25 percent tax. Had that structure survived, it would be a 25 percent tax at all prices. By throwing in the subtractive feature, nominally the state received above 25 percent at certain prices, but for the last three years those prices were quite a bit lower than that.

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Mr. Alper explained slide 17.

Providing some detail out of confidential data:
Of the nearly \$3.5 billion in state-repurchased credits through the end of FY16:

- \$1.5 billion went to eight North Slope projects that now have production
- \$0.8 billion went to 11 North Slope projects that do not yet have any production. Some of these are

abandoned, and some are in process

- \$0.9 million went to eight non-North Slope projects that have production
- \$0.3 million went to eight non-North Slope projects that do not yet have any production

Mr. Alper remarked that the data was all confidential, but that of the \$3.5 billion in state-repurchased credits, about \$1.5 billion went to 8 companies on the North Slope that were currently in production. Another roughly \$0.8 billion went to 11 North Slope projects that did not yet have production. \$0.9 million went to 8 non-North Slope projects that had production, and about \$0.3 million went to 8 non-North Slope projects that did not yet have production.

Mr. Alper continued to slide 18.

North Slope Repurchased Credits

- Between FY07-FY16 spent \$1.5 billion supporting eight producing projects
- Total production from these producers through end of 2015 is 63 million barrels
- Total credits = \$24 / barrel
 - Doesn't include payments to non-producing projects
 - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were \$6.0 billion
 - Credit support was 25% of lease expenditures

Mr. Alper elaborated on slide 18. Narrowing down to North Slope credits that went to companies in production, through the end of calendar year 2015, that came to 63 million barrels of oil produced. The state's investment was about \$24 per barrel. The total credit support for lease expenditures was 25 percent.

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Representative Wilson asked how much money the state received through royalty, oil, and other taxes up to FY 16.

Mr. Alper explained that \$61 billion was the total oil and gas revenue.

Representative Wilson surmised that the state had paid out \$3.5 billion for the \$61 billion that it received.

Mr. Alper suggested it was important to recognize that the great bulk of that revenue came from older assets that were producing long before the state began buying tax credits. He agreed that a relatively small amount had gone to tax credits in the early years. It was becoming a larger percentage as prices declined.

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Representative Wilson disagreed, stating that some of the repurchasing was owed for what had been previously received.

Mr. Alper responded that the numbers represented in the slides were paid in full. The issue of unpaid tax credits was limited to FY 17 and beyond.

Representative Wilson asked whether there was not a way to say that credits coming forward had nothing to do with projects that came online that provided benefit to the state.

Mr. Alper remarked that the slide attempted to identify projects that were specifically tied to the credits received.

Representative Wilson stated that a lot of the credits that were written off had to do with production already received, as there were not a lot of new projects going forward. She wanted to ensure that it was not the case that the state was not getting its money's worth from 2017.

Mr. Alper gave the example of a project for which a company received \$100 million in credits over time, with 5 million barrels of production in a few years. Simple division would say that the state had invested \$20 per barrel. Three years on, that company could be up to 10 million barrels, from those same wells, and not earning more credits as they were not drilling more. At that point the \$20 per barrel figure drops to a \$10 per barrel figure, as all the old credits would be divided among more barrels.

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Representative Guttenberg reiterated that the state had paid \$1.5 billion on eight producing projects, for a total of 63 million barrels. He asked how many of the barrels were in production before the credits came online. A lot of the projects were already in place pre-SB 21, which changed the economics. People applauded all of the things that happened with SB 21, but many of those were already in place. He asked Mr. Alper to extrapolate how much of the \$63 million was a result of those credits.

Mr. Alper responded that there were inevitably decisions that had to be made when putting together the data set he was presenting. The projects which were already in the pipeline before SB 21 were not included, however Economic Limit Factor (ELF) projects were included in the 63 million barrels.

Representative Guttenberg concluded that it was really difficult to understand the results of the credits outside the boardroom

Mr. Alper explained that he attempted to get as much information to the decision-makers as he could within the current laws regarding confidentiality.

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Mr. Alper spoke to slide 19. He highlighted that the slide showed the production tax received by year since FY 07. The first bar showed calculated tax, or the tax rate. The middle bar showed the amount of revenue actually received by the state. The darker red bar was the net income to the state after cash credits have been paid. The system had developed in a time in which the state was receiving \$2 billion to \$6 billion a year. Investing in the future of Alaska made a certain fiscal and long-term strategic sense. Then the price fell and the credits remained similar in scope. Suddenly, the revenue was offset by the credits. In FY 15 and FY 16, the amount of credits paid was more than the revenue coming in. All of the liability for FY 17 rolled forward and would become FY 18 liability, shown in the negative red bar in the slide. The forecast showed a small number.

Mr. Alper turned to slide 20 which showed the same data set but with unrestricted petroleum revenue. The only thing not

shown was royalties going into the Permanent Fund. High numbers get higher, but the amount of total revenue is more dramatically impacted by having a several hundred million dollar credit system.

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Vice-Chair Gara asked Mr. Alper to return to slide 19. He asked whether, with all owed credits paid, there would be a net zero in 2019.

Mr. Alper responded that he would have to examine the numbers but that to the naked eye it looked like a fairly low number.

Representative Wilson wondered why the state would not add all of the royalties into the chart, as the state still receives them.

Mr. Alper answered that the chart was made at the beginning of the process. The unrestricted royalties could be added.

Representative Wilson believed that including all royalties made the graph transparent and easier for constituents to understand.

Mr. Alper indicated that it was a robustly edited graph, with requests from committees over the last year. He would be more than happy to add another layer.

Representative Pruitt asked if Mr. Alper recalled that the throughput forecast for 2026 was around 309,000 barrels per day.

Mr. Alper agreed that it was in the 300,000 to 350,000 range. At the beginning of the chart, it was around 700,000 per day of throughput in 2007 and 2008.

Mr. Alper turned to slide 21. He spoke to the unpaid balance:

- FY2009-2015 Legislature used "open ended" appropriation language. All credit certificates presented were purchased
- FY16 Appropriation Capped at \$500 million
 - o \$498 million paid out by end of June

- o About \$211 million North Slope, \$287 million non-NS
- FY17 Governor proposes \$1 billion to clear credit liability as part of reform package and full fiscal plan
 - o Legislature appropriated \$460 million towards expected demand of \$775 million
 - o Governor vetoed all but \$30 million (formula calc.)
 - o Funds were paid first in-first out; most went to Cook Inlet capital and well lease expenditure claims

Mr. Alper expounded that the amount presented for repurchase estimated to be \$400 million was appropriated from the General Fund to the tax credit fund. He stated that the most that was ever spent in a given year was \$628 million. For FY 16, the governor struck out the open-ended language and replaced it with \$500 million. It turned out to be \$498.5 million, so the appropriation was spent. A little over 40 percent was North Slope, and the rest non-North Slope, meaning half of the credits were Middle Earth and Cook Inlet credits. He reported that Representative Geran Tarr had mentioned the governor's complete fiscal package introduced in the previous legislative session including a one-time \$1 billion appropriation to put money into the tax credit fund. This was envisioned as an overall solution that would eliminate most of the credits into the future and fix the existing problem. The package had not passed and what was eventually appropriated by the legislature was \$460 million. He did not know the origin of the amount. At the time the estimated demand had been \$775 million, so this was underfunded. The governor vetoed \$460 million down to \$30 million, based on a formula calculation. The formula was a statutory guideline.

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Mr. Alper continued to address slide 21 showing the \$30 million had been spent and most of the money had gone to Cook Inlet earlier claims. He moved to slide 22 and shared that the Tax Division had issued about \$600 million in certificates in FY 17; about \$100 million had either been paid or transferred.

- \$600 million in certificates have been issued in FY17

- Of these, about \$100 million have either been:
- o Paid (from the roughly \$30 million available funds);
 - o Transferred (to be used against another company's tax liability); or
 - o Are ineligible for repurchase
- Total remaining awaiting repurchase ~\$500 million
 - Applications in-hand about \$200 million
 - o \$50 million "023" credits (NOL and Cook Inlet drilling)
 - o \$150 million "025" credits (Exploration; have sunset)
 - So total known demand is roughly \$700 million
 - Additional ~\$400 million forecasted for FY18

Mr. Alper specified that the current amount awaiting repurchase was \$500 million. About \$200 million was in-hand applications, about \$50 million in NOL and Cook Inlet drilling, and \$150 million in the exploration credits had sunset. The division was currently working through a very large last slug of the exploration credits. The division knew about \$700 million and anticipated another \$400 million in FY 18. That meant \$1.1 billion in liability, minus appropriations and current credits changing hands, leaving a hanging balance of \$900 million.

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Representative Pruitt asked what kind of credits represented the \$400 million forecast in FY 18.

Mr. Alper answered they were mostly NOLs and Cook Inlet capital and WLE credits. All of the 2016 NOLs would come in roughly March 31 [2017].

Representative Pruitt suggested the NOLs were not cashable. He was trying to understand the partial payment. Ultimately, he wondered how much would have to be cashed out.

Mr. Alper responded that they were cashable. The current number was more like \$500 million.

Mr. Alper turned to slide 23. He explained that the greybars represented what the statutory formula would appropriate in a given year, expected to be \$50 million to \$100 million. Meanwhile credits would accrue at a faster

rate. The rate of increase was shrinking due to reforms. The graph only represented known, current projects, leading to \$1.6 billion by 2026.

Mr. Alper moved to the formula on slide 24:

Credit appropriation formula AS 43.55.028(b) and (c)

- Based on a percentage of production tax revenue before subtracting credits that are taken against liability)
 - Forecast price below \$60: 15%
 - Forecast price above \$60: 10%
- Was never used in previous years' budgets before FY17
- Earlier years would have generated large appropriations that would have exceeded the demand for credits, "endowing" the fund
- Recent years would have spent down any past surpluses; reducing the fund to zero by FY2016
- We'd be in the same place now- only there wouldn't be the expectation that we'd provide unlimited funding

Mr. Alper relayed that had the formula been followed then, the amount appropriated would have been more than the demand. It would have endowed a tax credit fund. Once lower prices occurred, the unpaid credits would still be an issue, but the difference would be that there would not be the expectation from industry that the state would provide unlimited funding.

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Mr. Alper advanced to slide 25, showing how the formula worked and how it would have worked. Open-ended language for the appropriation became more convenient and was more for the sake of simplicity rather than policy. He explained the differences between budgeted versus actual versus statutory tax credit funding formula. The graph showed credits received, actual production tax, credits against liability, revenue due to AS 43.55.011, oil price forecasts, credit caps per AS 43.55.028 (c) and end year fund balances.

Representative Wilson asked whether, because the calculation was based on ACES, when there was a change to

credits, the state should have been utilizing the formula to ensure that funding followed the formula as well. She wondered if the numbers would be different. She thought the formula should be looked at every time there was a proposed tax change.

Mr. Alper answered that had the formula been followed from the beginning, what she had described would be the case, and the formula would have been revisited. As no one was in the habit of using the formula, it had not been revisited. The moment in which that would have been important was in the era of the Cook Inlet Recovery Act. It created what led to a new liability of a couple of hundred million dollars per year. Had it been built into the system, the formula may have had to adapt.

Representative Wilson asked whether one could speculate that, had the formula been used, and the numbers were positive rather than negative, the state would be revisiting the tax structure if there was not the liability since the state had a formula that worked and that the state followed.

Mr. Alper responded that the poster child for the tax credits were the companies wanting to explore areas that were too marginal for the major producers - the 50 million to 10 to 20 thousand barrel per day fields. What happened was a handful of rather large, unexpected discoveries. If the current system applied to those projects going forward, that would mean billions of dollars in credit liabilities which the state simply did not have the resources to pay for. The system would need to be revisited anyway.

Representative Wilson explained that most of the time North Slope and Cook Inlet were thrown together, when one of them was subsidized. She wondered if Cook Inlet were taken out, leaving only North Slope, what the number would look like.

Mr. Alper stated that the department would look at the assumption that Cook Inlet had its own revenue-neutral funding source, and what the endowed fund would have looked like with only the North Slope credits.

Representative Wilson asked in the department to include interest in the data it was compiling.

Mr. Alper replied that the department would put the information together.

Co-Chair Foster recognized the presence of House Resources Co-Chair Representative Geran Tarr.

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Vice-Chair Gara asked for verification that the Cook Inlet credits disappeared in FY 19.

Mr. Alper responded that Cook Inlet credits would disappear completely in calendar year 2018. The last credits from calendar 2017 would be paid in FY 19, so they would disappear completely in FY 20.

Vice-Chair Gara asked to return to slide 19. With no new Cook Inlet credits in FY 19 and FY 20, the graph showed North Slope credits deducted from production taxes, close to zero.

Mr. Alper responded that in the 2020s, the forecast price of oil was creeping up, but still in the range of receiving the minimum tax. At very low prices, very little per-barrel credit could be used. Once oil prices reached the \$60 to \$70 range, there was still a minimum tax but all \$8 was being used. He noted that cash credits (represented by the gap between the second bar and the red bar on slide 19), were using up about half of the remaining revenue.

Vice-Chair Gara referred to the large fields as non-GVR fields. The GVR fields were new fields and post-2002 fields. The fields that received credits for the first seven years pay close to zero production tax at oil prices up to \$70 per barrel. He asked for verification that this was true.

Mr. Alper responded that the \$5 per barrel credit for new oil was not held to the minimum tax so it would pay zero.

Vice-Chair Gara reported the state was getting a zero percent production tax until oil prices reached \$70 per barrel. He asked for committee discussion on the zero revenue for no production, when some of those were projects that were already moving ahead.

Mr. Alper replied that there were many things the bill did. He remarked that the legislation was substantial. It shrunk the size of effective NOL credits, it abandoned cash payments for them, and it hardened the minimum tax. Specific provisions in the legislation addressed the issues in the status quo.

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Mr. Alper returned to slide 25. He posited what would happen to a company that had \$900 million in credits. The credits were not considered debt and did not incur interest. They were a tax offset document. They could be sold or transferred to another company. There was not much demand at present especially as even major producers have low tax liability. The companies were not paying very much, and it could only be used to offset 20 percent of tax. The exploration credits were not under that restriction, however, the last of the exploration credits would be issued later in the year. The secondary market for credits was not robust.

Mr. Alper moved to the topic of the major provisions and regional impacts of HB 247 on slide 28. The final law had been largely based on the Senate's version of HB 247.

Cook Inlet

- Complete phase-out of NOL, QCE, and WLE by 2018
- Extends "tax caps" on gas indefinitely, adds \$1/bbl oil tax
- Municipal utility pro-ration of costs

Middle Earth

- Reduces the NOL, QCE, and WLE credit rates
- Extends "Frontier Basin" exploration credit to July 2017

North Slope

- GVR "Graduation" provision after three to seven years
- GVR can't be used to increase the amount of an NOL

Statewide

- \$70 million per company per year cap (\$61 with "haircut")
- Interest rates increased for 3 years, then drops to zero

- Transparency, local hire, state obligation offsets, surety bond

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Co-Chair Seaton referred to the qualified capital expenditure (QCE) credit, which had been extended past a July 1 date in the Senate version of the bill. He asked if the particular credit could be used for Hilcorp's flow out gasline in Cook Inlet.

Mr. Alper responded that the QCE credit had been reduced from 20 percent to 10 percent for 2017. Middle Earth would continue on and Cook Inlet would go to zero. If capital work was to be carried out in 2017, the company could apply for the credit. He did not know about specific restrictions for repairs. There was specific language in statute that covered restrictions.

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Vice-Chair Gara asked Mr. Alper to explain the effective tax rate on oil produced in Cook Inlet.

Mr. Alper relayed that the Cook Inlet oil and gas paid the lowest tax under ELF. The smaller fields paid the lowest tax. He detailed that PPT locked ELF multipliers from 2005 into place for all oil and gas fields in Cook Inlet through 2022. On the gas side the average gas production was taxed at 17 cents per 1,000 cubic feet, and all oil was taxed at zero. In HB 247, the 17 cent tax was extended in perpetuity, and it would no longer sunset. On the oil side the zero was seen as unsustainable; therefore, the Senate placed the \$1 tax in HB 247. There were about 5 million barrels of oil produced in Cook Inlet, so the result was \$5 million.

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Vice-Chair Gara asked if there was a way of converting to terms of gross or profits tax that were more commonly used.

Mr. Alper said that he did not know the actual costs of producing oil in Cook Inlet. The tax cap in place made it less important for tax calculation. He reported that all of the oil produced in Cook Inlet was sold to local refineries, not to the global market, and did not have the

same shipping costs associated with it. It would be easy to describe it as a gross tax. He did not think there was enough information to convert it to a net tax.

Vice-Chair Gara stated that oil was a global commodity so the price was the same regardless. Taxing oil by a dollar would not make the cost for oil higher.

Mr. Alper agreed. For the sake of simplicity, one could assume that that oil was being sold for \$50, which was about what a barrel of oil was worth. He specified that a \$1 production tax was about 2 percent of the gross.

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Co-Chair Seaton asked Mr. Alper to provide a comparison which would help to determine an appropriate tax for Cook Inlet, considering that it did not incur the same expenses as North Slope oil.

Mr. Alper complied and suggested that if the market price was \$50, the gross tax from the North Slope was 4 percent of \$40 and the dollar tax in Cook Inlet was 2 percent of \$50, it could be determined what tax would be comparable for the Cook Inlet.

Co-Chair Seaton asked about the gross value reduction of 20 percent. He asked whether the extra 10 percent used to lower the royalties was still on the books.

Mr. Alper thought Co-Chair Seaton was referring to the late addition to SB 21, which created the gross value reduction. It was a 20 percent benefit for "new oil," and a new layer was added. If all leases on a given field are greater than 12.5 percent then the company would receive a 30 percent benefit. This was characterized as a payback for high state royalties. He underlined that this only regarded state royalties.

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Representative Pruitt asked where the oil would come from if the refineries did not purchase the Cook Inlet oil. Mr. Alper thought it would come from the North Slope or somewhere else in the world.

Representative Pruitt asked if the cost for a similar product from somewhere else would include delivery. Mr. Alper thought that all oil contracts were different, but believed that there would be a higher price due to delivery.

Representative Pruitt indicated that the market cost of \$50 for oil, for example from the Middle East, would have an added cost for delivery. Mr. Alper mentioned that the contracts were private, but that he assumed that closer oil would be attractive due to this lesser cost for delivery.

Representative Pruitt asked whether a state increase to Cook Inlet oil tax would increase the costs to customers.

Mr. Alper thought it was reasonable to assume that companies would pass those costs on. It would be another cost to the refineries. He underlined that there was no change to Cook Inlet tax in the legislation.

Mr. Alper continued with slide 29 regarding concerns over tax and credit system:

- Hybrid system with a net tax above \$75, a gross tax between \$45 and \$75, and a net tax (via the NOL credit) below \$45
- Possible multi-billion dollar future liability for large new discoveries
- Possible ability to use carried forward operating loss credits to zero out all taxes ("hardening the floor")
- Equity between major producers and new explorers if major changes made to operating loss credits
- High per barrel credit keeps us in the 4% "minimum tax" at up to nearly \$80 oil

Representative Wilson asked if the same effect occurred due to constant changes to the tax structure.

Mr. Alper was unaware of how oil companies factor in changes in Alaska oil tax. He thought that the current structure was unstable. The potential credit liability was larger than the anticipated revenue. Regardless of what action was taken, the state still would not have the means to pay \$1 billion per year in tax credits going forward.

Companies needed to know how the state would resolve that issue before they could commit to producing that oil.

[2:59:24 PM](#)

Representative Wilson remarked that Alaska was the unstable entity. The projects are long-term, and the changes to the tax system were yearly. She asked Mr. Alper whether he was confident that the proposed legislation would ensure the tax structure could stay in place for at least three years, resulting in more oil in the pipeline.

Mr. Alper replied that he could not promise anything, but noted the importance of resolving the credit issue in a stable manner. He did not think the current bill before the committee would address the issue of tax. He thought issues of oil tax would continue to come up inevitably, but the issue of oil credits needed to be addressed in the current year.

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Representative Pruitt asked which credits Mr. Alper thought should change.

Mr. Alper answered that NOLs in current law were not affordable as cash. If the policy were to be that the state would not buy credits, then it should be put into statute. He would address the sectional of the bill in later slides. The overarching change in the legislation was getting the state out of the business of paying cash for NOLs.

Representative Pruitt asked if the oil companies felt similarly about the issue and whether the state could expect a similar conversation with them.

Mr. Alper suggested that no company would gladly give up a benefit, however no one was proposing taking away the \$900 million in credits. Going forward, the state needed to know what the companies need to move ahead with projects, with the understanding that the State of Alaska was getting out of the cash business.

Representative Pruitt stated that the companies make plans years into the future. He wondered if they would come to the state to indicate that losing that benefit would affect those plans.

Mr. Alper said that the oil companies had paid 90 percent of state government in the past. When the state needed money, it would previously go to oil companies rather than a cigarette tax which would have raised \$25 million. Suddenly a substantial percentage of the GF was coming out of invested assets. In all likelihood, it would take some of the pressure off future legislatures because expectation and demand would be lowered.

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Vice-Chair Gara asked about the page 2 in Mr. Alper's response to Vice-Chair Gara dated February 6, 2017 (copy on file), regarding the effective tax rates on GVR and non-GVR oil at various prices. He asked for verification that there was an approximate tax of 4 percent from non-GVR fields (i.e. Prudhoe Bay and older fields) at prices slightly above \$70 per barrel.

Mr. Alper replied that the statement was mostly accurate, but noted things varied from producer to producer. He added that the minimum tax governed to around \$70 or so.

Vice-Chair Gara referred to new oil (i.e. Nakaitchuq, Ooguruk, Point Thomson, and other post-2003 oil). He stated that for the GVR oil the state did not receive the 4 percent tax up to oil prices at about \$70 per barrel. He stated that according to Mr. Alper's report, the average North Slope GVR field did not pay the 4 percent minimum tax and paid no taxes up to prices of about \$70 per barrel for the first seven years.

Mr. Alper replied in the affirmative related to production tax. He detailed that there was no hard floor on new oil. There tended to be zero tax at low prices.

Vice-Chair Gara stated that one of his biggest concerns was related to what he termed the "zero percent and four percent tax problem" the state would live with until oil prices exceeded the current price by 25 to 40 percent. He suggested that if the state were to have the audacity to raise those taxes, for every \$1 increase the company only paid about \$0.60.

Mr. Alper thought the net \$0.60 was fairly accurate.

Co-Chair Foster indicated that the committee would have to adjourn in about 20 minutes.

Mr. Alper stated that the next few slides would prove important as they contained graphs which illustrated the legislation.

Co-Chair Foster asked Mr. Alper to proceed with the sectional analysis.

Mr. Alper advanced to slide 31. He spoke to the impact on interest rates in Section 2:

Interest rates were amended in HB247

- DOR expressed concern when Senate Finance CS introduced the "zero interest after 3-year" provision
- Makes it very hard to settle tax disputes
- Sought to get it removed in Conference Committee
- Proposed removing it in HB 5005(July session)
- Currently, doesn't impact any actual interest calculation until 2020 so can be retroactive to 1/1/17

Concern with language: HB247 separated the Oil and Gas Production Tax interest rate from all other taxes for the first time. HB111 does not fix this. We would prefer all taxes to use the same interest.

Mr. Alper elaborated that the problem with interest going to zero after three years was that there was no incentive to settle. This bill could go through the court system while earning the time-value of money in appeal. He thought the interest rate should stay the same. He did not think there should be a zero interest rate. No one would be paying zero until 2020, so it could be made retroactive to 2017.

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Mr. Alper continued to address slide 31 and pointed out that HB 247 had separated the production tax from everything else. If the legislation was going to address interest rates, the administration requested that the

interest rate be the same for all taxes. He moved to slide 32 and addressed Sections 3 through 4 of the legislation:

Information about credits made public

- These sections were originally introduced as HB99
- Expands provision from HB247 requiring annual DOR report of who received tax credits and the amount
- Adds to the report how much in tax credit certificates is issued, as well as
 - o A description of each company's expenditures;
 - o The purpose of the expenditure; and
 - o The lease or property on which it's located

Concern with language: As this bill mostly eliminates "credits," to meet the intent of the original bill it may be necessary to redraft Sec. 4 to report "lease expenditures. Also, Sec. 22 is redundant with the other report requirement in Sec. 4

Representative Pruitt shared Mr. Alper's concern. He felt it represented a huge change. He understood the conversation about transparency, but he wondered if there were Securities Exchange Commission (SEC) violations that could occur related to lease expenditures.

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Mr. Alper replied that the point was valid and he was not necessarily suggesting that comprehensive expenditures were released. Since it was converted to a carry forward lease expenditure, if the same information was desired, the drafted sections would not obtain that goal. He noted that Rich Ruggiero [oil and gas consultant hired by the legislature in 2017] knew more about the nature of transparency and what was legally required.

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Mr. Alper continued to slide 33 related to Section 5 on executive sessions:

Provides authority for DOR to share certain confidential taxpayer information with legislators

- As written, legislators would have access to the same information as our audit employees
- Section requires developing a substantial confidentiality agreement to be signed by legislators
- Some administrative costs and possible taxpayer concerns
- Would likely engage IRS rules including background checks, chain of custody, information retention, etc.

Concern with language: Also may need to change reference from "credits" to "lease expenditures"

Mr. Alper thought this would involve creating a very robust confidentiality system. He relayed that when an employee leaves the tax division, all other employees must be informed so that no information is thereafter shared.

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Representative Wilson asked about the liability. She wondered if the liability would rest on the legislator or on the state.

Mr. Alper imagined the state could be held accountable for negligence. The IRS [Internal Revenue Service] could cut off access to certain taxpayer data if they deemed it necessary. The Tax Division was under additional scrutiny.

Representative Wilson wondered about information being taken with pictures on a smartphone. She wanted to be able to provide information to her constituents but wanted to be certain that there was no risk of liability.

[3:24:05 PM](#)

Mr. Alper moved to the subject of a minimum tax on slide 34:

The minimum tax is an "alternative" calculation

- The taxpayer calculates their net-profits tax, which is 35% of "production tax value" less the sliding scale per barrel credit

- In parallel, they calculate the "gross minimum tax", which is 4% of gross (wellhead) value when oil prices are above \$25 / bbl
- Actual tax due is the 'higher of' the two calculations
- Typical "crossover" occurs at about \$70-\$75 oil
- Amendment raises this minimum tax from 4% to 5% when the oil price is above \$50
-

Mr. Alper expounded that the amendment changing Section 6 would change the tax from 4 percent to 5 percent when the price of oil was above \$50 per barrel.

Mr. Alper referred to the graph on slide 35. He reported that revenue to the state at various price points was illustrated by blue, orange and grey lines. He pointed to the grey line indicating zero minimum tax. Starting at \$50 there would be additional revenue. The graph on slide 36 represented the change due to a 1 percent tax increase. At just over \$50 a barrel, the increase represented \$60 million, at \$70 per barrel, \$85 million. A 1 percent increase, from 4 percent to 5 percent, actually represented a 25 percent increase.

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Mr. Alper moved to the subject of hardening the floor on slide 37. He explained that the sliding scale per barrel credit was statutorily hardened to the floor. Many of the other credits could go below the floor, potentially to zero. There were six different sections due to changes in the language regarding a series of different credits.

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Mr. Alper discussed the meaning of hardening the floor. He indicated that regulations say that if the sliding scale credit was used, no other credit could go below the floor. The legislation aimed to avoid all other credits going below the floor. The near-term impact at low prices was about \$20 [million]. In the fiscal note there was an amount of \$20 million. He explained that the fiscal note contained a spreadsheet in which each line represented a different change in the bill, each with its own cost. The sum total of the fiscal note was \$20 million in short-term revenue.

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Representative Wilson asked if the four credits, because they could not go beneath the floor, could be carried forward.

Mr. Alper responded that the small producer credits and the per barrel credit could not be carried forward. He stated that in general, credits under AS 43.55.024 fell under the "use it or lose it" category; however, credits under AS 43.55.023 and 43.55.025 could be carried forward into future years (i.e. NOLs and exploration credits). Co-Chair Foster reviewed the agenda for the following day.

3:31:22 PM

AT EASE

3:32:16 PM

RECONVENED

Co-Chair Foster RECESSED the meeting until 9:00 a.m., Wednesday, March 22, 2017.

^RECESSED UNTIL 9:00 a.m. ON WEDNESDAY, MARCH 22, 2017

3:32:16 PM