

HOUSE FINANCE COMMITTEE
March 31, 2016
5:08 p.m.

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CALL TO ORDER

Co-Chair Thompson called the House Finance Committee meeting to order at 5:08 p.m.

MEMBERS PRESENT

Representative Steve Thompson, Co-Chair
Representative Dan Saddler, Vice-Chair
Representative Bryce Edgmon
Representative Les Gara
Representative Lynn Gattis
Representative David Guttenberg
Representative Scott Kawasaki
Representative Cathy Munoz
Representative Lance Pruitt
Representative Tammie Wilson

MEMBERS ABSENT

Representative Mark Neuman, Co-Chair

ALSO PRESENT

Ken Alper, Director, Tax Division, Department of Revenue;
Randall Hoffbeck, Commissioner, Department of Revenue; Dan
Stickle, Chief Economist, Department of Revenue; Paul
Decker, Petroleum Geologist, Division of Oil and Gas,
Department of Natural Resources;

PRESENT VIA TELECONFERENCE

Corri Feige, Director, Division of Oil and Gas, Department
of Natural Resources;

SUMMARY

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

HB 247 was HEARD and HELD in committee for further consideration.

Co-Chair Thompson discussed housekeeping.

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#hb247

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."

KEN ALPER, DIRECTOR, TAX DIVISION, DEPARTMENT OF REVENUE, asked if there were any questions on the fiscal note section of the presentation.

Co-Chair Thompson informed the committee that Mr. Alper would be available to visit each member's office to review the presentation slides that were discussed in the 1:30pm meeting.

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RANDALL HOFFBECK, COMMISSIONER, DEPARTMENT OF REVENUE, introduced himself.

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Mr. Alper continued his presentation from the 1:30pm meeting. He began with Slide 45:

Introduction to Scenario Analysis

- The Tax Division has developed a new model, looking at project life cycles
- Cash flow over the 30-40 year life of a project, for the state's production tax and credits, all state revenue, the producer's cash flow, and discounted (NPV)
- Scenarios Analyzed at \$40, \$60, \$80, and Fall Forecast oil price
- Status quo modeled vs. Governor's original bill
- Two full presentations on BASIS from previous committee

Mr. Alper explained that when modeling credit and tax changes in the past the tendency had been to look across the North Slope as if it were one entity, which did not capture the individuality of different projects. He highlighted that the modeling reflected the life cycles of specific projects. He said that House Resources Committee had seen several presentations on the status quo model, versus the Governor's Original bill, which were available on BASIS.

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Mr. Alper turned to Slide 46:

Introduction to Scenario Analysis

Fields Analyzed:

North Slope Scenarios:

- 50 million barrel North Slope Oil
- 750 million barrel North Slope Oil (20% GVR)

Cook Inlet Scenarios

- 50 million barrel Cook Inlet Oil (with and without tax caps)

Supplemental Scenarios

- 750 million barrel North Slope Oil (30% GVR)
- 750 million barrel North Slope Oil (50% Private Royalty)
- 670 bcf Cook Inlet Gas
- 670 bcf Middle Earth Gas

Mr. Alper explained that the 50 million barrel North Slope oil was analogous to the smaller, newer projects that had developed 10 years ago at Oooguruk, Nikaitchuq, and projects by Brooks Range Petroleum; the economics of the smaller fields that existed among the bigger, older fields in the North Slope. He relayed that the 750 million barrel North Slope Oil economics were equivalent to projects by Armstrong or Repsol. He said that for Cook Inlet, the smaller oil field economics applied, as no one expected to find large fields in that area. He highlighted that the numbers had not been based on anyone's individual economics, but on stylized projects, and the department had examined what was perceived to be the typical and expected economics of projects in those areas of the state. He explained the supplemental scenarios. He relayed that under SB 21, the GVR was a 20 percent tax reduction was standard, but if the field in question was a very high royalty field, with leases greater than 12.5 percent, the company would receive a 30 percent GVR. He noted that there were documents in committee packets that explained how royalty sharing worked in different areas of the state. He said that the state received the production tax anywhere in Alaska; the royalty that was collected was very specific to the state being the landowner. He said that the state had been fortunate that past geologists had been thoughtful enough to select the Central North Slope at statehood

securing Prudhoe Bay on state land. He said that the royalties that the state collected were specific He added that royalty sharing arrangements with the federal government varied around the different areas of the state. He revealed that the department had done a modeling run in order to forecast what would happen if the North Slope field were half state, and half private royalty. He explained that the state did not receive private royalties; for example, if there was an oil development on Native Corporation land, they did not have any obligation to share their royalties with the state. He said that the state did have a tax on the royalty, which was 5 percent of their gross royalty. He relayed that at 12.5 percent royalty the state received the equivalent of six-tenths of 1 percent of tax on the royalty. He furthered that if the royalty was 12.5 percent, whatever the royalty dollar was, the state would collect a 5 percent tax on the royalty dollar; effectively, the state's revenue would be 5 percent of the 12.5, slightly over six-tenths of 1 percent. He said that gas fields in Cook Inlet and in Middle Earth had also been modeled.

Mr. Alper turned to Slide 47, "Sample of Scenario Analysis: North Slope- 50 mmbo Status Quo, \$60/bbl." He said that the slide reflected the status quo analysis of a North Slope small oil field. He pointed to the slide on the upper left, which charted the production tax cash flow. He relayed that there had been 5 to 6 years of development of construction, and as companies spent money they were eligible for tax credits from the state. He stated that under the model the North Slope was getting a 35 percent operating loss credit; if the company was spending \$125 million per year to develop their field, they would earn a 35 percent operating loss credit. He said that years of production were represented in blue bars.

Mr. Alper spoke to the upper right hand bar graph, which charted annual state net gains and losses at 20 percent GVR at the \$60 and price. The chart on the upper right reflected the annual state net gains and losses at 20 percent GVR at the \$60 ANS price. The green bars represented the production tax, the blue bars represented the royalties, the red bars represented property tax, and the purple bars represented state corporate income tax. He said that the lower left hand graph illustrated the total producer cash flows at 20 percent GRV at the \$60 ANS price.

The box in the lower right hand corner summarized the three data sets on the slide:

<u>Life Cycle Totals</u>	<u>\$Millions</u>
Production Tax Credits Cashed	162
Production Tax Paid	183
Net Production Tax	21
Production Tax NPV 6.15%	-37
Total Annual State Losses	121
Total Annual State Gains	501
Net State Gain (Loss)	380
State NPV 6.15%	136
Total Producer Cash Out	327
Total Producer Cash In	731
Net Producer Cash Flow	404
Producer Cash NPV 6.15%	112

Mr. Alper said that scenarios had been run using \$40/bbl and that all resulted in lost money, which led the administration to believe that no one would sanction a substantial project in the state at \$40/bbl. He noted that at \$60/bbl the state would break even, and things looked more robust at \$80/bbl.

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Co-Chair Thompson queried the most efficient way that the committee could ask questions about the scenario slides.

Mr. Alper responded that the slide came in pairs: before HB 247, and after HB 247, and that now would be a good time for questions.

Vice-Chair Saddler asked about the timeline of the scenarios.

Mr. Alper responded that the timeline began when the company started spending money on the project. He said that the upper left box was unique to just the production tax system, both taxes and credits, and did not capture the lease bonus payment.

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Representative Gara spoke to the calculation of the gross revenue exclusion for the bigger fields, and the gross value reduction for the smaller fields. He asked whether a gross value reduction field was represented in the top left hand corner.

Mr. Alper answered that it was a gross reduction field. He furthered that the assumption in all of the modeling was that if it was a new field on the North Slope, where the GVR was the law of the land, it would qualify for the GVR because it was designed to benefit new fields.

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Representative Gara noted that he had a report from the department that said that for production taxes on GVR fields (post 2002) the state did not receive a production tax until approximately \$73/bbl. He wondered why the slides reflected production tax revenue at \$60/bbl.

Mr. Alper replied that he would get back to the committee with the information. He noted that the numbers were not particularly large for an entire oil field over the course of a year, but that they were positive numbers. He suggested that Mr. Stickle could further explain the numbers.

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DAN STICKLE, CHIEF ECONOMIST, DEPARTMENT OF REVENUE, explained that the analysis that had been previously provided to the committee had looked at all GVR eligible fields on the North Slope in the aggregate. He said that the fields included a mix of companies that were operating, as well as investing in capital expenditures. He stated that the slide reflected a development scenario where most of the capital expenditures took place up front, followed by a period of time of spending only operating expenditures. He relayed that the structure of the spending profile brought the break-even down from the mid-70s level.

Representative Gara remained confused.

Mr. Alper offered to rephrase the response. He explained that the field in the scenario was specific to a field where the spending was "front loaded". He said it the capital spending in the oil field was spread evenly over 30

years, there would be capital spending in 2010-13, which would be enough to offset the tax and drive it down to zero. He stated that when doing an aggregate analysis of many different fields, in different stages of their life cycle, one groups capital spending would always offset another groups taxes. The slide did not reflect any capital offsetting of the earnings for the later years, so taxes were paid at a lower oil price.

Representative Gara understood that averaging out the early spending and the later revenues would show negative returns for the state in the beginning and positive returns later, and a zero production tax over the life of the field.

Mr. Alper responded that the analysis included multiple fields at multiple stages in their life cycles. He added that some of the fields had a lot of capital spending that when taken all together would offset the taxes from those that were paying taxes.

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Mr. Alper scrolled to Slide 48. He stated that Slides 47 and 48 were the same exact field, but Slide 48 included the changes that had been in the original version of HB 247. He said that the most substantial change to the economics of the projects was the per company cap of \$25 million. He pointed to the chart in the upper left, which showed that the production tax credits cashed/payments did not go below \$25 million but they could be applied for more years. He spoke to the chart in the lower right, which offered the life cycle totals in millions:

<u>Life Cycle Totals</u>	<u>\$Millions</u>
Production Tax Credits Cashed	101
Production Tax Paid	155
Net Production Tax	54
Production Tax NPV 6.15%	-10
Total Annual State Losses	59
Total Annual State Gains	470
Net State Gain (Loss)	412
State NPV 6.15%	163
Total Producer Cash Out	362
Total Producer Cash In	746
Net Producer Cash Flow	384

Co-Chair Thompson requested that members to hold their questions until the end of the presentation.

Mr. Alper turned to Slide 49, which reflected a sample scenario of North Slope oil at 750 mmbo, under HB 247, and Co-Chair Thompson \$80/bbl. He said that the scenario on the slide was analogous with the Armstrong field, and peaked at roughly 120,000 barrels per day. He said that \$80 oil had been used because that was the price point needed to secure the investment. He shared that spending by investors on a new oil field was viewed in terms of capital expenditures per dollar, per barrel of oil that would be produced. For example, if the field was going to produce 750 million barrels, at approximately \$13 of capital expenditure per barrel; the result was \$10 billion worth of capital spending on the North Slope to produce the field. He felt that it was important that the committee understood the state's commitment to investors under the status quo law. He relayed that once spending was made in the range of \$1 billion, or more, per year, the state would be spending many hundreds of millions of dollars in refundable tax credits. He said that was simply the way things worked under the 35 percent operating loss credit. He pointed out to the committee that the red bars in the upper left hand graph reached over \$800 million in peak years of construction on the project. He indicated the slide on the upper right of the slide, and relayed that once production was underway, the state would receive over \$1 billion, per year, in revenue. He insisted that \$80/bbl oil was necessary for the state to get their \$1 billion per year, and that he held out hope that the price of oil would bounce back. He added that the slide reflected a 40 year time cycle, which meant that the time line would require patience. He spoke to the box on the lower right, which listed the life cycle totals related to the scenario on the slide:

<u>Life Cycle Totals</u>	<u>\$Millions</u>
Production Tax Credits Cashed	2,830
Production Tax Paid	8,923
Net Production Tax	6,093
Production Tax NPV 6.15%	869
Total Annual State Losses	2,553
Total Annual State Gains	16,623

Net State Gain (Loss)	14,069
State NPV 6.15%	3,527
Total Producer Cash Out	5,247
Total Producer Cash In	17,933
Net Producer Cash Flow	12,686
Producer Cash NPV 6.15%	2,216

Mr. Alper turned to Slide 51, which incorporated into the scenario the changes proposed by the legislation. He revealed that the numbers indicated that the \$25 million cap on spending would greatly reduce the state's cash outlay, and there would be a significant level of carry forward credit. He said that once production began, the built up, carry forward credits would cancel out production taxes and would eventually result in the loss of operating loss credits for companies. He highlighted that the total production tax credits cashed would drop from \$2.8 billion, to \$109 million, and the state's production tax discounted cash flow would be double what it was under the scenario on Slide 50. He pointed to the box on the lower right of the slide, which reflected life cycle totals under the scenario:

<u>Life Cycle Totals</u>	<u>\$Millions</u>
Production Tax Credits Cashed	109
Production Tax Paid	6,533
Net Production Tax	6,424
Production Tax NPV 6.15%	1,743
Total Annual State Losses	100
Total Annual State Gains	14,479
Net State Gain (Loss)	14,379
State NPV 6.15%	4,388
Total Producer Cash Out	7,832
Total Producer Cash In	20,317
Net Producer Cash Flow	12,485
Producer Cash NPV 6.15%	1,415

Mr. Alper admitted that the scenario was slightly overstated; no single company was going to come to Alaska and spend \$10 billion. He furthered that any company interested in a project of that size would seek out several partners. He said that if 4 partners were to develop the project, using the Governor's bill as the underlying system, it would result in \$100 million in credits per

year. He disclosed that the state had learned that the \$25 million cap could work for smaller fields, but it would need to be altered in order to accommodate larger fields.

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Mr. Alper continued to Slide 51, which offered a summary of the North Slope scenarios. He said that field size and tax regime numbers, the first two columns, had been modeled in the scenarios on the previous slides. He reiterated the numbers as they related to the taxes at \$40, \$60, and \$80/bbl oil, under both the status quo and HB 247, with the varying field sizes. He relayed that the House Resources Committee had heard the slide presentation in February 2016. He turned to Slide 52, which reflected the same variables using the Cook Inlet scenarios. He opined that the problem with Cook Inlet was that there would be an impending moment in 2022, when the statutory zero taxes went away, and a fork in the road was created. He said that two different options were created: option A would have the tax caps sunset and revert to the base tax of 35 percent, with no per barrel credit or GVR; the alternate was that the caps did not sunset and the future legislature chose to maintain a zero tax in Cook Inlet. He said that the answer would lie somewhere between the two scenarios. He continued to the supplemental North Slope Scenario and the Supplemental Cook Inlet and Middle Earth Scenarios on Slides 53 and 54.

Co-Chair Thompson asked that the Department of Revenue remain in the room until after the Department of Natural Resources completed their presentation.

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PAUL DECKER, PETROLEUM GEOLOGIST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, introduced the PowerPoint Presentation: "Alaska's Oil and Gas Industry; Overview & Activity Update." He turned to Slide 2, "Overview":

North Slope:

- Resources and Reserves
- Current Activity & New Developments
- Who's Working the North Slope?
- Leasing Activity

Cook Inlet:

- Resources and Reserves
- Current Activity & New Developments
- Who's Working the Cook Inlet?
- Leasing Activity

Frontier Basins:

- Resources and Reserves
- Current Activity & New Development
- Who's Working the Frontier Basins?
- Exploration Licensing & Lease Conversion

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Mr. Decker turned to Slide 3, "North Slope Resources Overview." The slide provided an overview map of the North Slope. He noted that the area shown on the map was approximately 500 miles from west to east. He said that the 3 miles into the Chukchi and Beaufort Seas were federal Outer Continental Shelf (OCS) and were managed by the Bureau of Ocean Energy Management (BOEM). He pointed out that the green areas to the south were permanently protected federal land. He furthered that the National Petroleum Reserve-Alaska (NPRA) was also federally owned and run by the Bureau of Land Management (BLM). He said that the Alaska National Wildlife Refuge (ANWR) 1002 was not permanently protected, but could be by an act of Congress.

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Representative Guttenberg pointed out that the OCS was further than 3 miles out.

Mr. Decker agreed that the shelf extended much farther than 3 miles. He clarified that the state's ownership only extended from the shoreline to 3 miles out. He returned to the map on the slide. He spoke the central North Slope state lands; the state's 3 area wide lease sales were outlined in red on the slide. He said that there was a lot of private ownership within the foothills. He stated that the main oil fields were shown in green and were strung along the shoreline of the Central North Slope. He added that there were a number or oil and gas fields along the coastline, mostly gas fields near the foothills. He spoke to the black dots, which represented all of the exploration wells that had been drilled, to date, on the slope. He

believed that the map showed a lot of room for growth in the area of exploration.

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Representative Pruitt understood that the dark green area on the map included oil accumulations that were known to exist, but had not been produced.

Mr. Decker responded that there were several non-producing fields contained within the dark green area, most notably Hammerhead and Kuvlum in the eastern Beaufort Sea.

Representative Pruitt understood that the dark green areas of the map were expected to increase.

Mr. Decker replied that if the projects became sanctioned and went into development, the dark green area would be expanded.

Representative Pruitt asked whether there were other areas that held resources that were not in dark green on the map.

Mr. Decker responded that there were very few such examples. He reiterated that the intent of the map was to show land that had been "discovered by the drill bit".

Mr. Decker turned to Slide 4: "Arctic Alaska Oil & Gas Resources." The slide offered a table of what the federal government would estimate for undiscovered, technically recoverable conventional resources in Arctic Alaska. He said that the slide was not meant to indicate that all of the volumes would be commercially recoverable, but rather, would the volumes exist in accumulations that could be recoverable given the technology in current practice. He pointed out to the committee that the slide showed 40 billion barrels of oil, and 207 billion cubic feet of gas. He furthered that the gas was equally distributed between OCS waters and onshore state lands and waters. The mean oil estimate reflected that there was more oil in the offshore than in the onshore.

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Mr. Decker continued to Slide 5, "Arctic Alaska Oil & Gas Resources":

Gas Reserves:

- Approximately 30 trillion cubic feet of associated gas is estimated to be recoverable from producing or developing North Slope fields, mostly at Prudhoe Bay & Point Thomson. Without a pipeline, most of that gas is best described as contingent resource, not reserves.
- Approximately 5.9 trillion cubic feet of proved associated gas reserves estimated in Alaska, virtually all on North Slope (Energy Information Administration(EIA),2014)

Oil Reserves:

- Approximately 2.8 BBO of proved oil reserves estimated on the North Slope (EIA, 2014)

Mr. Decker stated that tis subset of gas would be used for making natural gas liquids that could be sold to the Trans-Alaska Pipeline System (TAPS), and minor gas sales thorough local markets.

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Mr. Decker discussed Slide 6, "North Slope Current Activity and New Developments":

- **Accumulate Energy**
 - Franklin Bluffs area shale play evaluation
 - Drilled Icewine #1 well in October-December 2015
 - Seismic survey of lease area this winter
- **AEX (ASRC)**
 - Placer Unit
 - Currently drilling Placer #3 well -spud in late January 2016
- **BP**
 - Prudhoe Bay Unit
 - Completed 8 new wells, 46 new sidetracks, ~420 well workovers in Initial Participating Area (IPA), 2015
 - Completed first wells in Lisburne PA in 9 years, 2015

- Completed 3D seismic program in North Prudhoe, 2015

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Mr. Decker advanced to Slide 7, "North Slope Current Activity & New Developments":

- **Caelus Natural Resources**

- Ooguruk Unit
 - On-going development (4-5 wells/year; all long-reach & frac'd)
- Nuna
 - First production from Nuna Torok Phase 1 in late 2018(?)
 - No construction activity this winter
- Smith Bay Exploration (shallow water ice pad)
 - Second of two exploration wells nearly complete

- **Conoco Phillips**

- Colville River Unit
 - Initiated first production at CD5 in 2015
 - Plan for a total of 8 new wells in 2016
- Greater Mooses Tooth Unit (Federal/NPRA)
 - Approved funding for \$900MM GMT1 project
 - Plan to drill two Tinmiaq exploration wells in western part of unit

Mr. Decker elaborated that PA meant participating area; the subset of the leases within a unit that were actively contributing to production. He added that MI stood for miscible injection, a method used for enhanced oil recovery purposes. He said that Caelus had slowed the development of the Nuna project due to the slump in oil prices.

He went on to explain Conoco Phillips' activity on slide 8, "North Slope Current Activity and New Developments":

- **Conoco Phillips**

- Kuparuk River Unit

- First wells came online at Kuparuk DS-2S in 2015
- Significant drilling planned in 2016 for Kuparuk PA, Tarn PA and West SakPA during 2015-16
- **ExxonMobil**
 - Point Thomson Unit
 - Completion of Initial Production System in 2016
 - Completed 22 mile liquid hydrocarbon pipeline from Point Thomson to Badami Field, which connects to TAPS
 - Start-up expected by mid-May 2016 (10,000 bpd condensate)
- **Great Bear Petroleum**
 - Currently acquiring large 3D seismic dataset (~450 sq miles)
 - Planning for additional work at Alkaid #1 in 2017

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Mr. Decker discussed Slide 9, "North Slope Current Activity and New Developments":

- **Hilcorp**
 - Northstar Unit
 - Returned 2 wells to production
 - Milne Point Unit
 - Drilled 3 new wells, started new G&I plant construction in 2015
 - Plan to drill 10 new wells and complete 16 workovers in 2016
- **Repsol/Armstrong**
 - Pikka Unit (Nanushuk Project Development)
 - Drilled 3 exploration wells & sidetracked 1 in 2015 (total of 12 wells & sidetracks since 2012)
 - Commenced the project EIS under NEPA in June 2015

- Plan to drill 1 additional exploration well in 2017

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Mr. Decker turned to Slide 10, "North Slope Wells Drilled and Seismic Acquired":

- **New Exploration and Development Wells Drilled 2004-2014**
 - 110 Exploratory Wells and Well Branches
 - 1,646 Development & Service Wells and Well Branches
- **2D & 3D Seismic Data Acquired (Tax Credit Data) 2004-2014**
 - Line Miles 2D (onshore/shorezoneice)~ 870
 - Square Miles 3D (onshore/shorezoneice)~ 9,945

Mr. Decker categorized the activity on the North Slope as steady over the past decade.

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Mr. Decker advanced to Slide 11, "Who's Working North Slope?":

Large Majors (>\$40B Market Cap):

- BP Exploration, Inc.
- Chevron USA, Inc.
- ConocoPhillips Alaska
- Eni
- Exxon Mobil Corporation
- Shell Offshore, Inc.

Large Independents & Mid-Sized Companies:

- Armstrong Oil and Gas/70 & 148 LLC
- Anadarko E&P Onshore LLC
- BG Alaska E&P Inc.
- Caelus Natural Resources Alaska LLC
- Halliburton Energy Services
- Hilcorp Alaska, LLC
- Repsol

Mr. Decker relayed that there were three categories of companies working on the North Slope: large majors, large independents & mid-sized companies, and small independents.

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Mr. Alper advanced to Slide 12, which listed the small independent companies on the slope:

- **Small Independents:**
- Accumulate Energy Alaska, Inc.
- Alaska, LLC
- Alaskan Crude Corp.
- ASRC Exploration LLC
- Aubris Resources, LP
- AVCG, LLC
- Brooks Range Development Corporation
- Burgundy Xploration LLC
- Caracol Petroleum LLC
- Chap-KDL, Ltd.
- Colt Alaska LLC
- Dewline Petroleum LLC
- Donkel Oil & Gas, LLC
- Eastland Property and Minerals
- GMT Exploration Company LLC
- Great Bear Petroleum Ventures
- MEP Alaska, LLC
- Mustang Operations Center 1, LLC
- NordAq Energy Inc.
- Pacific Lighting Gas Development
- Petro-Hunt, LLC
- Pinta Real Development, LLC
- Petro-Hunt, LLC
- Pinta Real Development, LLC
- Ramshorn Investments, Inc.
- Red Technology Alliance, LLC
- Renaissance Umiat, LLC
- Royale Energy, Inc.
- Samson Offshore, LLC
- Savant Alaska, LLC
- Sunlite International Inc.
- The Eastland Oil Company

- TP North Slope Development, LLC
- Transworld Oil & Gas Ltd.
- Ultrastar Exploration LLC
- URSA Major Holdings LLC
- Woodbine Petroleum, Inc.
- Woodstone Resources, LLC

Mr. Decker explained that 7 or 8 of the companies listed on the slide were actively exploring on the slope, but most were lease holders waiting for activity to occur and were not leading in the exploration of their leases.

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Representative Gara pointed out that there were companies listed, but not listed as having any activity.

Mr. Decker replied that the activity slides were not entirely comprehensive. He admitted that the slide did not reflect Eni's continuing development at Nikaitchuq. He said that they were actively expanding in the area, doing "prudent operator" work.

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Mr. Decker turned to Slides 13, 14, and 15, "North Slope Leasing Activity Trends." Each slide contained a bar graph that illustrated the number of tracts that had received either single or multiple bids on area wide lease sales in the North Slope, Beaufort Sea, and Foothills areas. He said that the area were held open for area wide leasing and that everything that was open came up for lease every year. He referred to Slide 13, which pertained to the North Slope. He pointed out to the committee that there had been aggressive leasing activity in 2014; Caelus had put in over 100 bids for leases along the Barrow Arch, and Armstrong had purchased approximately 100 leases in the same lease sale.

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Representative Wilson whether the companies were required to act on the leases in a certain amount of time, or could they bide their time while paying a fee to retain the leases.

Mr. Decker stated that some of the leases that had been issued had been accompanied by certain work commitments. Generally, the lease hold in Alaska required an annual rental fee that escalated considerably after several years, which worked as an incentive to either develop or drop the leases in a timely manner.

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Mr. Decker moved to Slide 14. He noted that 2006 had been a big year for leasing in the area, and in 2011.

Mr. Decker spoke to Slide 15. He noted that in 2001 and 2002, there had been a burst of activity that coincided with interest in natural gas potential in the area. He noted the next burst in 2006, but felt that since then investors had decided to wait until further progress was made on the gasline. He informed the committee that the area was gas prone, and not oil prone, and that its fortunes would be linked to a gasline.

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Mr. Decker pointed to Slide 16, "Cook Inlet Resource & Reserves Overview." The slide pictured a map showing where the U.S. Geological Survey had assess the resources. He said that the federal estimates were the undiscovered, technically recoverable resource of oil and gas:

- **Undiscovered, Technically Recoverable Oil and Gas (USGS, 2011):**
 - mean conventional oil 599 MMBO
 - mean conventional gas 13.7 TCF
 - mean unconventional gas 5.3 TCF
- **Natural Gas Reserves (ADNR, 2015)**
 - 1.18 TCF (Proved and Probable)
- 1.2 TCF additional mean resource assessed in OCS waters (**BOEM, 2011**)

Mr. Decker elaborated on the unconventional gas areas.

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Representative Pruitt asked how much gas the state was expected to produce in the future in Cook Inlet. He also queried how much gas had been produced out of Cook Inlet over the past 40 years.

Mr. Decker believed that approximately 8 TCF had been produced in Cook Inlet to-date. He said that the 1.18 TCF remaining proved and probably reserve was a significant fraction of the available gas. He added that the number had not dropped, and was higher than previous estimates from 2010. He said that with activity, exploration, and aggressive development companies had been able to book additional reserves. He was encouraged that there was still a significant lifespan of resource, but that it would depend on the rate of investment in getting it out of the ground.

Mr. Decker addressed Slide 17, "Cook Inlet Current Activity & New Developments":

Apache Alaska Corporation:

- Ceasing all seismic acquisition and other exploration activity in Alaska
- Intend to hold leases until expiration

Conoco Phillips:

- Recent sale of interest in Beluga River Unit

Furie Operating Alaska

- Kitchen Lights Unit:
 - Set monopod platform in 2015;
 - Completed onshore gas facilities & pipeline in 2015
 - Commenced production in December 2015
 - Randolph Yost, 2ndjack-up rig, arrived in Homer early March, plan to drill two development wells in 2016

BlueCrest Energy, Inc.

- Cosmo Unit:
 - Planned arrival of new land-based drill rig for oil development in 2016
 - Plan 1st oil in mid-2016 (oil production will be from onshore)

- Possible offshore drilling for gas (Spartan 151 jack-up rig) in 2016

Mr. Decker stated that Apache Alaska Corporation had hoped to develop prospects to be drilled in the next few years, but were ceasing exploration activity in the state due to low oil prices. He said that a skeleton crew would remain in Anchorage offices in order to maintain their assets. He said that Conoco Phillips had been slowly exiting the basin gradually. They had sold their share of the interest in the Beluga River Unit to Chugach Electric and the Anchorage Municipal Light and Power (ML&P), increasing ML&Ps share making them the dominant owner. He furthered that Furie was currently selling gas to Homer Electric and had plans to drill more wells within the coming year.

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Representative Wilson asked whether companies were relying on tax credits when securing financing for exploration and whether the department knew when the credits switched from exploration to development credits.

Mr. Decker replied that there were different types of tax credits. He said that in Cook Inlet most of the credits that had been used had applied to both exploration and development; the 023(1) well lease expenditure credits. He added that many companies were dependent on receiving timely reimbursements from credits in order to use that money in the next phase of exploration or development.

Representative Wilson assumed that companies filed plans with DNR before beginning their process. She asked whether part of the plan covered financing, or if finance discussion were limited to DOR.

Mr. Decker answered that the main plans that were submitted to the state had to do with obtaining permits to use the land, or in a unitized area the Division of Oil and Gas would be tasked with overseeing a plan of development. He said that DOR would had additional insight into the financial aspects.

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Mr. Decker moved to Slide 18, "Cook Inlet Current Activity & New Developments":

Hilcorp Alaska, LLC:

- Cannery Loop Unit:
 - Completed 2 new wells in 2015
 - Planned 2 workovers in 2016
- Deep Creek Unit:
 - Drilled 1 new well in 2015 and 2nd is planned for 2016
- Ninilchik Unit:
 - Completed 3 new gas wells in 2015 and 7 new gas wells in 2014
- Trading Bay Unit:
 - 19 workover jobs in 2015 and 3 new wells in 2016
- Purchased XTO Energy, Inc. assets in southern Cook Inlet
- Projected ~\$120 MM investment in Cook Inlet in 2016

Mr. Decker said that Hilcorp Alaska was the dominant operator in the Cook Inlet basin. He stated that there would not be as much progress witnessed in the Cannery Loop Unit had a less assertive and ambitious producer taken over the fields when they came up for sale. He said that Hilcorp projected spend for 2016 was \$120 million.

Mr. Decker advanced to Slide 19, "Cook Inlet Wells Drilled & Seismic Acquired":

New Exploration & Development Wells Drilled 2010-2014

- 24 Exploratory Wells and Well Branches
- 65 Development & Service Wells and Well Branches

2D & 3D Seismic Data Acquired (Tax Credit Data) 2004-2014

- Line Miles 2D (onshore/offshore) ~ 725
- Square Miles 3D (onshore/offshore) ~ 660

Mr. Decker noted that the time window used on the slide had been used because that was a time when the basin had been perceived to be in crisis.

Mr. Decker scrolled to Slide 20, "Who's Working Cook Inlet":

- **Large Majors (>\$40B Market Cap):**
 - ConocoPhillips Alaska

- **Mid-Sized Independents:**
 - Hilcorp Alaska, LLC
 - Apache Alaska Corp.

- **Small Independents & LLCs:**
 - Alaska Energy Alliance Inc.
 - AIX Energy LLC
 - Alaska LLC
 - Aurora Gas LLC
 - Aurora Exploration LLC
 - BlueCrest Energy Inc.
 - CIRI Production Company
 - Cook Inlet Energy LLC
 - Cornucopia Oil & Gas Company LLC
 - Corsair Oil & Gas Company LLC
 - Furie Operating Alaska LLC
 - New Alaska Energy LLC
 - NordAq Energy LLC
 - Taylor Minerals LLC
 - Woodstone Resources LLC

Mr. Decker relayed that Hilcorp would remain active, but that Apache would not. He reiterated that some of the small independents were actively exploring, but most were holding their lease positions and waiting to see what happened with the price of oil. He turned to Slide 22, which contained a bar graph of Cook Inlet area wide lease sale results, 1999 through 2015. The slide reflected 2011 as the biggest year, since then participation had declined.

[6:24:39 PM](#)

Mr. Decker turned to Slide 23: "Frontier Basins Tax Credit Areas." He relayed that the basins were sometimes referred to as "Middle Earth". He said that the terms could be confused and were not always interchangeable. He detailed that the map showed the 5 regions in which the Frontier Basin Tax Credit [43.55.025(a)(6-7)], a form of super-credit for seismic and well drilling, could be claimed. Under current statute the credits would sunset in 2016.

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Mr. Decker turned to Slide 24, "Statewide Resource Assessments -Undiscovered, Technically recoverable resource."

Region	Mean Oil Estimate (Million Barrels)	Mean Gas Estimate (Billion Cubic Feet)
Onshore Arctic	15,908	98,960
Offshore Arctic	23,750	108,180
Interior Basins* (only partially assessed)	234	5,641
Upper Cook Inlet	599	19,037
Other Southern Alaska**	2,859	23,458
TOTAL	43 BBO	255 TCF

*Includes Yukon Flats and Kandik basins (Nenana, Kotzebue, Copper River, Holitna, & Susitna basins not assessed)

**Mainly federal OCS waters, minor AK Peninsula onshore

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Mr. Decker scrolled to Slide 25, "Exploration License Program":

- The program supplements the state's oil and gas leasing efforts & encourages exploration outside of known oil & gas provinces
- Every April, DNR accepts proposals to conduct exploratory activity outside existing leasing areas
- The DNR Commissioner may issue a notice requesting proposals to explore a designated area (encourages competition)
- The applicant has up to 90 days to submit their proposal
- Three exploration licenses have been converted to lease: Susitna II, Copper River, & Nenana

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Mr. Decker advanced to Slide 26: "Who's Working The Frontier Basins?":

Ahtna

- Copper River Basin, Tolsona Exploration License:

- Reprocessed 2D seismic data & acquired new Tolsona 2D seismic in spring 2014
- Plan to drill Tolsona #1 gas exploration well in early 2016; follow up to the Ahtna #1-19 well drilled in 2007-2009 (Rutter & Wilbanks)

Doyon

- Nenana Basin:
 - Drilled Nunivak #1 and #2 exploratory wells, 2009-2013
 - Acquired 2D and 3D seismic, gravity, magnetics, and lakebed geochemical surveys, 2005 -2014
 - Converted exploration license to leases between 2013 & 2014
 - Additional 2D seismic in progress
 - Plan to spud Toghotthele #1 this June

Mr. Decker continued to Slide 27, "Who's Working The Frontier Basins?":

Doyon

- Yukon Flats Basin:
 - Acquired 2D seismic, gravity, magnetics, and lakebed geochemical surveys

NANA

- Kotzebue Basin:
 - Evaluating and marketing prospects based on legacy industry seismic

Usibelli Coal Mine Inc.

- Healy Basin Gas-Only Exploration License:
 - Drilled one shallow exploration well in 2014

Mr. Decker stated that Doyon had not drilled any wells, but had conducted geophysical and geochemical surveys. Doyon owned much of the land, which meant that there would be no expiration license in the Yukon Flats.

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Mr. Decker moved on to Slide 28: "Frontier Basins Wells Drilled & Seismic Acquired":

New Exploration Wells Drilled 2004-2014

- 7 Exploratory Wells and Well Branches

2D & 3D Seismic Data Acquired (Tax Credit Data) 2004-2014

- Line Miles 2D (onshore)~ 1,220
- Square Miles 3D (onshore)~ 340

Mr. Decker believed that 3 of the 7 exploratory wells had been in the Nenana Basin, 3 in the Copper River Basin, and 1 in Healy.

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Mr. Decker reviewed Slide 29, "Frontier Basin Exploration Licenses", which listed the 5 locations for each license and the details of: ADL file number, acres, commitment, effective date, term, and status. He revealed that Cook Inlet Energy had relinquished their Susitna 5 license due to bankruptcy.

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CORRI FEIGE, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (via teleconference), pointed out that the slides that showed the smaller companies working in Cook Inlet and on the North Slope had business models that differed greatly from the models of the larger and major companies. She noted that on the North Slope, several small companies at a time could join together on a single project. She said that companies often bundled together in groups in order to spread the investment and raise the capital necessary to undertake the project.

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Co-Chair Thompson indicated that Mr. Alper and Commissioner Hoffbeck were available for questions.

Mr. Alper stated that the remainder of the slides had to do with implementation of the legislation. He turned to Slide 56, "Implementation: Transition":

- Original bill was written with an effective date of 7/1/16 for nearly all changes
- CS moves most changes to 1/1/17, with the full repeal of the Well Lease Expenditure credit on 1/1/18
- The bill's original fiscal note included a fund capitalization for \$926,575.0 to the .028 fund.
- This is the difference between what is in the operating budget and \$1 billion.
- This would have covered all expected credit liability before the effective date.
- With the changes made in the CS, additional appropriation will be needed

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Mr. Alper discussed Slide 57: "Implementation: Connection to Fiscal Plan":

- HB247 was introduced as one of 10 bills that comprised the governor's fiscal plan.
- All the bills taken together, with anticipated budget cuts, proposed a balanced budget by FY19
- The broader fiscal package, and the specific tax credit bill, are intended to add certainty to industry regarding what support the state can provide and how we're going to continue to pay for government
- Original bill also assumed companion "AIDEA Loan" bill to help with projects that lost funding with credit changes
- HB246 would create a new "fourth fund" at AIDEA to concentrate on oil and gas development loans, for proven reserves
- Envisioned \$200 million initial fund capitalization

Mr. Alper relayed that in the first committees of referral for the initial hearings on all of the governor's bills the administration had worked to put the bills in context of each other. HB 247 was one of 10 bills that comprised the governor's overall fiscal plan: the Permanent Fund Protection Act (SB 128), the income tax bill(SB 134/HB 250), the AIDEA loan bill(SB 129/HB 246), the three consumption tax bills - alcohol, tobacco, and motor fuel(SB 131/HB 248; SB 133/HB 248; SB 132/HB 249, and the three

business tax bills - mining, fisheries, and the cruise ship head tax(SB 137/HB 253; SB 135/HB 251; SB 136/HB 252). He solicited questions from committee members.

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Vice-Chair Saddler queried the required criteria for loans from the AIDEA development fund.

Mr. Alper responded that the loan would be for up to 50 percent of a projects value. He said that there would need to be a proven reserve and a resource evaluation obtained by AIDEA from an external consulting service that would prove the legitimacy of the project. He added that the cost of the services would be rolled into the loan and would be paid back. He deferred further explanation to an AIDEA representative.

Co-Chair Thompson understood that a proven reserve needed to exist in an effort to move toward development and production.

Mr. Alper explained that to the extent that the state was still providing credits, those credits could focus on exploration work; the state should not be lending money against a project that might not be able to pay it back.

Vice-Chair Saddler clarified that Mr. Alper had been speaking to 50 percent of the project cost.

Mr. Alper replied in the affirmative.

[6:50:14 PM](#)

Representative Guttenberg about the relevance of the AIDEA loan concept to the version of the bill that came out of House Resources Committee.

Commissioner Hoffbeck responded that it would be less relevant because of the intent that it would replace some of the cash credits with a loan program. He said that the credits were being used to leverage loans for projects. He said that the legislation would make for a more direct loan, at rates that were competitive. He stated that the state would not expect repayment on the debt until actual production began, which would be attractive to developers. He expressed the desire to see companies move toward the

loan program, versus direct credits. He relayed that initial provisions in HB 246 stipulated that if a company took the loans then they would no longer be eligible for the credits.

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Representative Guttenberg surmised that the original version of HB 247 had included the loans, but that they had been replaced by the direct credits.

Mr. Alper clarified that the original HB 247 had not directly referenced the loan program, they had been introduced as a package. He said that the original bill greatly reduced the expected credit support, which prompted the need for the new loan program.

Representative Guttenberg probed the difference between a loan package and a direct payout. He wondered how the state's fiscal situation would be affected if there was no return to the state with a direct payout, and if the loan package would become a revolving loan fund.

Commissioner Hoffbeck commented that that administration had viewed the legislation as a long-term solution to the fiscal crisis. He said that the revolving loan fund would need to be endowed to begin with, and additional appropriation would be necessary depending on the popularity of the program. He stated that the capital would return to the state eventually, and then could be re-loaned. He noted that a direct cash payout would require continual appropriations.

Co-Chair Thompson reminded the committee that HB 247 was on the meeting agenda and that HB 246 would be debated during a different committee meeting.

Representative Guttenberg rebutted that the evolution of the bills was relevant to discussion on HB 247 and direct credits. He said that he was curious about the solvency of the state with money "going out the door with no return on it."

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Representative Gara understood that the governor's intention in Cook Inlet was to allow the net operating loss

to continue for companies that had not made money in order to encourage them to explore, but to eliminate the capital expenditure and well lease expenditure credits for companies that were making a profit and were not paying production taxes. He summarized that credits would be given to companies that were not making money and no credits to companies that were making money.

Mr. Alper explained that the credits were not meant as encouragement for exploration, but more of a support to the companies while they were under development. He added that as originally proposed the net operating loss credit meant that the state would be refunding 25 percent of a company's costs up to the point of profitable production.

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Representative Gara surmised that companies that were doing work, but not making money, would be supported by a credit in Cook Inlet; companies that were producing, but were not paying production taxes in Cook Inlet, would lose the capital and well lease expenditure credits.

Mr. Alper responded in the affirmative.

Representative Gara understood that the governor had proposed limiting the annual credit payment to \$25 million per company.

Mr. Alper responded yes. He added that current statute did not contain a defined limit.

Representative Gara summarized that the other proposal from the governor was to have a hard minimum tax floor for fields that paid the minimum tax. He contended that there was currently no minimum tax for GVR fields, but that the pre-2003 fields would floor that could not be lowered using the net operating loss credit.

Mr. Alper replied that for new oil that enjoyed the gross value reduction, and could currently pay at zero, the intention was to make them pay at zero. The administration hoped to harden the floor so that an operating loss credit would not result in reducing payments to below the floor for the legacy fields that already paid at the floor.

Representative Gara continued to interpret the legislation.

Mr. Alper responded that Representative Gara seemed to understand the major provisions of the legislation.

Representative Gara asked whether there would be any ongoing costs to the state related to the AIDEA loans.

Mr. Alper did not believe that any ongoing costs would be added by passage of the legislation. He furthered that the bill would create the statutory authority for a new fund, with separate management, and a fourth parallel structure inside the governing AIDEA law. He said that the fiscal note attached to the bill would establish the initial \$200 million to begin issuing loans.

[7:00:07 PM](#)

Representative Gara spoke of what the state could expect in production taxes over the next several years if the bill did not pass. He asked, if the bill did not pass, what the state was projected to receive in production taxes after tax credits were deducted.

Mr. Alper responded that the production taxes were quite low at present, and were expected to drop further. He said that it was expected that all of the major producers would have operating losses in 2016, and the production tax would drop to zero by 2018. He said that there was \$825 million in estimated production tax cost for FY 17, updated from the spring forecast; \$450 million in FY 18; \$375 in FY 19.

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Representative Gara wondered whether tax credit payments would exceed all oil revenue if thing remained the status quo.

Mr. Alper clarified that when the governor released the spring forecast the revenue for unrestricted general fund of all oil and gas sources added up to a number that was expected to be less than the anticipated credit spend. He added that this was unique to FY 17, in FY 18 the state would again be in the black.

[7:02:42 PM](#)

Co-Chair Thompson understood that the current version of the bill had a \$200 million credit limit per company.

Mr. Alper responded in the affirmative.

Co-Chair Thompson hypothesized that 4 companies could come together to work on one project, on one pad, and could each receive the \$200 million credit, totaling \$800 million in credits.

Mr. Alper replied yes. He added that in order for that to happen the companies would have to be spending over \$2 billion.

[7:03:16 PM](#)

Representative Wilson understood that the governor's original bill would eliminate gas tax credits in Cook Inlet.

Mr. Alper responded that the governor's bill would have eliminated the 20 percent capital credit (QCE) and the 40 percent well lease expenditure credit (WLE). He said that those were the credits tied to expenditure that could be stacked with the operating loss credit. The operating loss credit was left intact at 25 percent. He explained that from the point of view of a company that was under development, the current 60 percent level of state support would be reduced to 25 percent state support. He furthered that the company that was generating profit would be receiving no credit support from the state.

Representative Wilson asked whether any of the credit expenditures had been written into SB 21.

Mr. Alper replied that SB 21 did not touch upon any of the credits outside of the North Slope.

Representative Wilson thought that now could be a good time to review the credits. She noted that there would be another review in 2022.

Mr. Alper responded that he had spoken to Senator Giessel's resource working group over the interim about the idea of, "maybe in Cook Inlet it's time to declare victory and move on." He said that there had been push back regarding the sentiment. He believed that Representative Wilson made a valid point; the issues of supply anxiety were less severe than they had been 7 years ago, and the sponsors of SB 21 had admitted that enhanced credits for Cook Inlet had been

an extreme measure, meant to sound an alarm. He thought that the mission had been partially accomplished because it had spurred conversation about ramping down the credits.

7:05:52 PM

Representative Wilson wondered how much money further ramping down of the credits would save the state.

Mr. Alper believed that the original fiscal note had reflected approximately \$150 million.

Representative Wilson requested a chart that would show the tax credits that were in SB 21 that would be affected by the legislation, versus how the credits that had not been in SB 21 would be affected.

Mr. Alper pointed out that the department had presented to the Joint Resources Committee in June, a document that had the information that Representative Wilson sought. He said he would supply the document to the committee. He believed he had sent it to the Co-Chair's office the previous evening.

7:06:59 PM

Vice-Chair Saddler referred to Slide 47. He requested that the department provide the analysis to \$20, \$30, \$110, and \$120/bbl.

Mr. Alper clarified that the information could be provided. He asked whether Vice-Chair Saddler wanted the Cook Inlet, small field scenario, or a wider range of scenarios.

Vice-Chair Saddler referred to Slide 51. He thought modeling of the same could be done using the numbers he had requested.

Mr. Alper agreed to provide the information. He added that just a \$40/bbl showed red on the chart, \$20 and \$30/bbl would reflect even less optimistic numbers.

Vice-Chair Saddler asked whether the capital expenditure of \$18/bbl was averaged over the 30 year lifespan used in the models.

Mr. Alper responded that the numbers were drawn from model fields that provided known information. He said that any new oil field would had a lot of capital spending in the first several years. He continued to say that the operating expenditures tended to be ongoing as the field was in production, and was attached to the per barrel charge, from year to year. He stated that each of the sets of scenarios had a full slide of assumptions. He clarified that what was being looked at, specific to the field on Slide 47, was a field where all of the oil produced over the entire 30 year lifespan would add up to 50 million barrels of oil. He added that 50 multiplied by \$18/bbl would be equal to \$900 million dollars, which meant that the total capital spend to get the project going was \$900 million.

Vice-Chair Saddler confirmed that the net state gain reflected on the slide included royalties, property tax, production tax, and corporate income tax.

Mr. Alper responded in the affirmative.

[7:11:03 PM](#)

Vice-Chair Saddler asked about the first bullet under "Interest Rate Reform" on Slide 34. He asked why the error was considered technical.

Mr. Alper answered that the original version of SB 21 that had been proposed by Governor Parnell intended to reduce the interest rate from 11 percent to 3 percent over the federal discount rate. He added that previous law had compound interest, and the original version of SB 21 kept the compound interest. He stated that when the bill made it to the Senate Floor, and passed with the 3 percent, over discount rate, compound interest. He relayed that the contentious legislation failed to garner an effective date vote on the Senate Floor. The bill made its way to the House Resources Committee, which crafted a committee substitute that included work around language to deal with the lack of an effective date. He summarized that drafting errors pertaining to the interest rate and compound interest would be changes to better reflect the original intent of the legislation.

[7:13:57 PM](#)

Representative Pruitt wondered whether the department had communicated with other oil resource states about how they were addressing the downturn in oil prices.

Commissioner Hoffbeck replied that tax structures in various states had been examined. He said that Alaska was unique in its net tax, other states were on a gross tax basis. He relayed that the Oil and Gas Competitiveness Review Board had not spoken to the issue to-date, and that some provision changes had occurred in other states.

Mr. Alper explained that the other states that produced oil in America were all on the gross, Alaska was the only state on the net. He added that Alaska was also the only state that offered refundable cash credits. He said that companies were losing money in Oklahoma, North Dakota, and Texas right now because that price of oil was the same there as it was in Alaska, and they were paying a gross severance tax to those state of up to 11 percent. He asserted that Alaska had a 4 percent gross tax at the current oil price, the net tax was a theoretical upside should prices recover.

[7:15:50 PM](#)

Representative Pruitt stated that effectively the state was increasing its tax by reducing the tax credit. He wondered which other states were increasing taxes during this time of low oil prices.

Commissioner Hoffbeck contended that there was a fundamental disagreement on whether the removal of a subsidy should be considered an increase of the tax. He asserted that a tax was a demand from a government entity for repayment, but in this case the state was paying money out and reducing the amount of subsidy that it paid. He did not believe it should be classified as an increased tax, rather a subsidy reduction.

Representative Pruitt argued that the bill would not only adjust the credits but would also increase to 5 percent, and harden, the floor. He asked his question again.

Commissioner Hoffbeck stated that he did not believe any other state was raising the tax. He admitted that the hardening of the floor at 5 percent could be categorized as a tax increase.

Mr. Alper continued to Slide 59: "Implementation: Administration":

- The changes anticipated in this bill still require somewhat substantial reprogramming of the Tax Revenue Management System (TRMS) and Revenue Online (ROL) which allows a taxpayer to file a return online and update the current tax return forms
- We have received a preliminary estimate from the software developer, and currently assume a one-time cost of about \$1.2 million to accomplish this
- We do not anticipate any additional costs to administer the tax program
- There will also be a need for substantial amendments to existing regulations to fully implement the changes

SB 247 was HEARD and HELD in committee for further consideration.

[7:19:58 PM](#)

Representative Gara pointed out that there was a statutory formula for what the state was required to pay on all tax credits, under current law. He requested documentation of what the state was statutorily required to pay on tax credits.

Mr. Alper agreed to provide the information to the committee.

Co-Chair Thompson discussed housekeeping

ADJOURNMENT

[7:20:56 PM](#)

The meeting was adjourned at 7:21 p.m.