ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
February 24, 2016
1:02 p.m.

DRAFT

MEMBERS PRESENT

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

MEMBERS ABSENT

All members present

COMMITTEE CALENDAR

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

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

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 247
SHORT TITLE: TAX;CREDITS;INTEREST;REFUNDS;O & G
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

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

WITNESS REGISTER

CORRI FEIGE, Director
Central Office
Division of Oil & Gas
Department of Natural Resources (DNR)
Anchorage, Alaska

POSITION STATEMENT: On behalf of the governor, sponsor of HB 247, co-provided a PowerPoint presentation entitled, "Alaska's Oil & Gas Industry Overview & Activity Update."

PAUL DECKER, Petroleum Geologist
Central Office
Division of Oil & Gas
Department of Natural Resources (DNR)
Anchorage, Alaska
POSITION STATEMENT: On behalf of the governor, sponsor of HB 247, co-provided a PowerPoint presentation entitled, "Alaska's Oil & Gas Industry Overview & Activity Update."

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

ACTION NARRATIVE

1:02:53 PM

CO-CHAIR BENJAMIN NAGEAK called the House Resources Standing Committee meeting to order at 1:02 p.m. Representatives Olson, Josephson, Seaton, Hawker, Talerico, and Nageak were present at the call to order. Representatives Tarr, Johnson, and Herron arrived as the meeting was in progress.

CO-CHAIR NAGEAK and the committee wished Co-Chair Talerico happy birthday.

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

1:04:31 PM

CO-CHAIR NAGEAK announced that the only order of business is HOUSE BILL NO. 247, "An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

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CORRI FEIGE, Director, Central Office, Division of Oil & Gas, Department of Natural Resources (DNR), introduced herself.

PAUL DECKER, Petroleum Geologist, Central Office, Division of Oil & Gas, Department of Natural Resources (DNR), said he is currently the manager of the resource evaluation team.

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MS. FEIGE, on behalf of the governor, sponsor of HB 247, began a PowerPoint presentation entitled, "Alaska's Oil & Gas Industry Overview & Activity Update." She turned to slide 2, "Overview," and advised that due to time constraints the presentation has been broken into North Slope, Cook Inlet, and Frontier Basins.

MR. DECKER drew attention to slide 3, "North Slope Resources Overview," and explained that it shows the land management areas on the North Slope. The National Park Service administers the

Noatak National [Preserve] and Gates of the Arctic National Park & Preserve. The U.S. Fish & Wildlife Service administers the Arctic National Wildlife Refuge (ANWR). The coastal plain [1002 area] of the refuge is shown in a different color because it's not yet permanently protected and permanently off limits to oil and gas; he offered his hope that it will not come to that. The other federal land making up a big chunk of the North Slope is the National Petroleum Reserve-Alaska (NPR-A), which is about the same size as the State of Indiana. He then pointed out the state lands on the North Slope:

> So, the state lands are those encompassed by the red lines where we have our annual areawide lease sales. So starting along the shoreline from zero to three miles off shore we have the Beaufort Sea areawide sale, in the Central North Slope onshore we have the North Slope areawide sale, and then to the south the Foothills sale. And you'll also notice important acreage within the Foothills sale and also on the extreme western North Slope that is [Arctic Slope Regional Corporation (ASRC)] surface and subsurface estate, so yet another owner there. The coastal plain areas that are in north of the dashed blue line, and you can see that the black dots show a greater exploration well density north of that blue line, so that the coastal plain has been somewhat better explored. The Foothills area to the south is a lot lower exploration well density, less exploration there, and what you'll also notice is two trends of oil and gas accumulations, the oil in green and the gas accumulations in red. The main producing trend, of course, is near the shoreline within say 30 or 40 kilometers of the shoreline. And that's because that's underlain by a huge feature known as the Barrow Arch, which is really, really good petroleum habitat, in essence. There is also a Foothills trend, mostly gas accumulations discovered to date, Umiak being the contrarian there, the exception. So, these are the areas and most of these areas have been assessed independently by the U.S. Geological Survey [(USGS)] for their resource potential.

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MR. DECKER explained that slide 4, "Arctic Alaska Oil & Gas Resources," rolls up all of those federal resource estimates from USGS onshore and the Bureau of Ocean Energy Management

(BOEM) offshore for Arctic Alaska. The numbers on the bottom line of the chart are correct: the 40 billion barrels of oil is the mean estimate when combining the onshore and offshore oil, and 207 or so trillion cubic feet (TCF) of undiscovered gas. He reiterated that these numbers are the mean estimates of a probabilistic distribution accounting for a large degree of uncertainty about how much exactly remains in this category, which is undiscovered, technically recoverable. These mean estimates are not reserves and they are not necessarily economically recoverable. He pointed out a typographical error within the blue block entitled, "Mean Oil Estimate," and said it should read millions of barrels, not billions, thus the number is read as 15,908 million or 15.9 billion barrels of oil. It is relatively evenly split between onshore and offshore. On the oil side, the Chukchi and Beaufort seas appear to have more undiscovered oil than the onshore acreage. Onshore is dominated by about 10 billion barrels in ANWR, about 4.5 billion barrels undiscovered in the central North Slope state lands, and less than 1 billion in NPR-A.

REPRESENTATIVE HERRON asked whether the offshore estimates are within 200 miles.

MR. DECKER replied yes.

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MR. DECKER stated that slide 5, "Arctic Alaska Oil & Gas Resources," drills down to more along the lines of reserves as opposed to just undiscovered resource. There are approximately 30 trillion cubic feet of associated gas that is estimated to be recoverable in the existing producing fields, and primarily that's Prudhoe Bay with Pt. Thomson lumped in, which is about a 3:1 ratio. Since there is not yet an Alaska Liquefied Natural Gas (AK LNG) line, a gas transportation system is not in place and it is best to consider those numbers as contingent resource, he advised, and not as reserves per se.

CO-CHAIR NAGEAK requested an explanation of contingent resource.

MR. DECKER explained that contingent resource is the resource that has been discovered but not yet approved for commercial development, not yet sanctioned, not yet brought into development. So, it's discovered and it may become reserves in the future with a demonstration that those volumes are economic to produce.

CO-CHAIR NAGEAK asked what has to be done to make it so.

MR. DECKER said that typically the threshold would be a sanction decision, a final investment decision (FID) in the case of AK LNG.

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MR. DECKER referred to the second bullet on slide 5, and said it drills down within the actual currently producing fields and how much is in the proved gas reserve category. He said that according to the Energy Information Administration (EIA) there is about 6.4 trillion cubic feet of proved associated gas reserves, of which a little bit [about 0.5 percent] is Cook Inlet gas and the bulk of which is North Slope gas in places like Prudhoe Bay. He advised that the 6.4 trillion cubic feet of reserves would be the portion of the gas in the existing fields that actually has some sort of a market, and that's really mostly a local market used on lease or in adjacent fields. With regard to the oil reserves, he explained that the EIA's latest report as of year-end 2013 gives the North Slope approximately 2.8 billion barrels of oil reserves in the proved category, which is not too different from what the Division of Oil and Gas estimated in recent history from its own decline analysis.

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REPRESENTATIVE HAWKER asked whether the division's definition of "proved" resource requires being economically recoverable or is simply the known proved existent resources.

MR. DECKER responded that proved reserves are specifically in that economically recoverable, expected to be recovered, tranche of volumes. When the division says proved reserves, it connotes a 90 percent certainty that at least that much gas will be produced.

REPRESENTATIVE HAWKER inquired about the division's standard for economically viable recoverable resources.

MR. DECKER replied that the economic hurdle is considered to be met when, for example, a project is sanctioned, the gold standard is when a project is sanctioned to go into development.

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REPRESENTATIVE HAWKER concluded then that the entire 6.4 trillion cubic feet of associated gas reserves is a sanctioned project that is behind pipe.

MR. DECKER replied no, that is a bit of an exception and is one of the things about the North Slope that's a little odd. The North Slope has its own local market where gas is sold back and forth between the producers and used on site - things like miscible gas injectant or fuel use. He said he will have to ask the EIA why it describes that as proved gas reserves, but his understanding is that it's because it is part of a local market that is functioning on the North Slope.

REPRESENTATIVE HAWKER surmised that the 2.8 billion barrels of oil reserves are currently in the process of being recovered through a sanctioned project.

MR. DECKER replied "through all the sanctioned fields ... that's correct."

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REPRESENTATIVE HERRON understood that the definition of a proven reserve is 90 percent confidence in it.

MR. DECKER responded correct, 90 percent certainty that at least that volume will be produced.

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REPRESENTATIVE TARR surmised that the oil reserves in the sanctioned projects are over the life of that field. She asked for specifics that break down [the number of 2.8 billion barrels of oil (BBO)].

MR. DECKER answered he does not have that number today, but said the division could work it out in an approximate fashion. He noted that the largest part of that will be Prudhoe Bay, then Kuparuk and Colville River Unit, and so forth.

REPRESENTATIVE TARR said she would appreciate understanding the breakdown better.

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MS. FEIGE turned to slides 6-9, "North Slope Current Activity & New Developments," to outline the current and new activities of various companies. She explained that Accumulate Energy Alaska, Inc. (AEA), is a newcomer to the state and is partnered with 88 Energy and Burgundy Xploration. They came into the state with Burgundy Xploration acquiring a sizable lease position in 2014 in the central North Slope area, and are predominantly looking at shale potential. They drilled the Icewine #1 exploration well on the Franklin Bluff's pad, which is a pre-existing gravel pad located along the Dalton Highway about 65 miles south of Deadhorse. Based upon the results of the Icewine #1, Accumulate is now getting ready to commence a seismic survey across its leasehold in central North Slope, and it also participated in the November 2015 lease sale and the partnership took about 130 additional tracts in that sale.

MS. FEIGE noted that ASRC Exploration, LLC (AEX), a wholly owned subsidiary of the Arctic Slope Regional Corporation (ASRC), is currently drilling an exploration well in the Placer Unit. The Placer Unit is located immediately south of the Oooguruk Unit which is held by Caelus Natural Resources.

MS. FEIGE said [BP Exploration (Alaska) Inc.] is one of the long time foundation producers on the North Slope and continues to be very aggressive at expanding and maintaining development and production out of the Prudhoe Bay Unit. She pointed out that BP has completed 8 wells, 46 new sidetracks, and well over 420 workovers just in the Initial Participating Area (IPA) in 2015. The company completed additional wells in the Lisburne Participating Areas (PA) and also some in-unit seismic in the North Prudhoe Bay in 2015.

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MS. FEIGE reported that Caelus Natural Resources [Caelus Energy Alaska, LLC] (slide 7) entered the state in 2013, acquiring Pioneer Natural Resources position in the Oooguruk Unit. Caelus continues with ongoing development and production at Oooguruk with four to five long-reach wells drilled each year that are stimulated through large multi-stage fracks. Caelus has performed work recently optimizing that frack to optimize and increase recovery in those wells. She said Caelus Natural Resources is also undertaking the Nuna Development, a new project development. The surface facilities sit within the Kuparuk Unit immediately outside of the Oooguruk Unit, although the accumulation is within the Oooguruk Unit itself on the southeastern flank of that unit. Caelus's first production is on track for late 2017. Caelus installed a gravel road and pad last winter but is not performing construction work at Nuna this winter. Instead, Caelus, with its partner NordAq Energy Inc., is in Smith Bay drilling the second of two exploration wells. Those wells are being drilled from a grounded ice pad in shallow water just off shore. Smith Bay is located approximately 80 miles southeast of Barrow.

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MS. FEIGE stated that ConocoPhillips Alaska, Inc. (slide 7), a very active company on the North Slope, is working in the Colville River Unit and initiated production at CD5 in October 2015, with that production rapidly exceeding its expectations. Conoco plans to drill eight new wells in 2016 on the CD5 development. In late 2015, Conoco sanctioned the Greater Mooses Tooth Unit (GMT1), which will be a new development located inside the NPR-A. Conoco also continues work at the Kuparuk River Unit with the first wells at drill site 2S coming online in late 2015 and with significant drilling planned for 2016 throughout the unit.

MS. FEIGE reported the exciting news that ExxonMobil Corporation will commence production of natural gas liquids (NGLs) in the Pt. Thomson unit by mid-May 2016. Construction of the Initial Production System (IPS) has been completed, as has construction of the pipeline that connects Pt. Thomson into the Badami Field. The Badami pipeline then connects to the Trans-Alaska Pipeline System (TAPS) and the sail line.

MS. FEIGE advised that Great Bear Petroleum is currently acquiring a very large three dimensional (3D) seismic survey. Great Bear is another shale player located to the north of Accumulate in the central North Slope region. Great Bear plans to re-enter its Alkaid #1, drilled in 2014, and perform additional well work after the completion of its seismic this year and the Alkaid will come next year.

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REPRESENTATIVE HAWKER recalled that Great Bear was moving ahead rapidly with this development with the support of Alaska Industrial Development Authority funds, but its third-party financing withdrew after the veto of the state tax credits last year. He asked whether that has compromised the project, or the division's assessment of its future viability.

MS. FEIGE replied she can't speak to whether it has compromised the future viability, but that Great Bear did tell the division that it has impacted the schedule under which it is taking future work. The Alkaid #1 work was originally scheduled for 2016, and now has been pushed back to 2017. The division is aware that Great Bear is in the process of bringing other partners into its program on the North Slope.

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MS. FEIGE noted that Hilcorp Alaska LLC (slide 9), a large actor in Cook Inlet, has moved onto the North Slope with the acquisition of the North Star Unit where it promptly returned two wells to production. Hilcorp acquired a portion of the Milne Point Unit where it is now operator and in partnership with BP has drilled three wells and undertaken some new facility construction there. Hilcorp has plans to drill 10 new wells and complete a slew of workovers in 2016.

MS. FEIGE said Repsol and Armstrong Oil and Gas (slide 9) are working on the Nanushuk Project development, which the division refers to as the Pikka Unit. Repsol and Armstrong formed the Pikka Unit in June 2015 and to date, from 2012 to current, they have drilled a total of 12 exploration wells and sidetracks on that acreage, which led to the unit application. They have now commenced the environmental impact study and the National Environmental Policy Act of 1969 (NEPA) review for the overall project development. The division expects that if there are no hiccups, production will come online in five to seven years, although they may try to fast-track that.

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MS. FEIGE turned to slide 10, "North Slope Wells Drilled & Seismic Acquired," to provide a 10-year summary for the years from 2004 to 2014. During this time period on the North Slope, 110 exploratory wells and well branches were drilled, along with [1,646] development and service wells and well branches. She noted that two dimensional (2D) and three dimensional (3D) data is acquired through tax credit data under the rules of the tax credit programs. During 2004 and 2014, about 870 line miles of 2D data was acquired and just shy of 10,000 square miles of 3D data acquired. This is both onshore and near shore ground and ice acquisition.

REPRESENTATIVE HAWKER recalled that in prior years the committee would receive a colorful bar graph depicting, by year, the rig count for exploration and development wells drilled. He further recalled that there was one winter where no exploratory wells were drilled. He asked whether Ms. Feige could obtain the rig and well count data from the division's archives and prepare an updated graph for the committee.

MS. FEIGE agreed to provide a by-year breakdown. She explained that for purposes of summary and time for today's presentation, the division rolled the numbers up into totals.

REPRESENTATIVE HAWKER recalled it may have been the Alaska Oil and Gas Conservation Commission (AOGCC) that prepared the graphs he is thinking of, but surmised Ms. Feige knows what graphs he is requesting.

MS. FEIGE confirmed she knows which graphs are being requested.

1:28:54 PM

MS. FEIGE drew attention to slides 11-12, "Who's Working North Slope?" to review which companies are investing and working in the North Slope and what this shows about the evolution of the basin or region. She described Alaska as having a very healthy and robust cross-section of companies working on the North Slope, and fundamentally that says the industry still views the resource endowment and the environment of investing in Alaska as being a good place to be. In terms of large companies, these are predominantly the state's foundation producers, big legacy producers, and for the purposes of breakout here the division has classified these as companies with greater than a $40 billion market capitalization. These large companies include BP, Chevron, Conoco, Eni, Exxon, and Shell. Behind the majors are the large independents and mid-sized companies, such as Armstrong and its subsidiary 70 & 148, Anadarko, Caelus, Repsol [and BG Alaska, Halliburton, Hilcorp]. She advised that the listing of Apache is an error and should be taken off this list because it only operates in Cook Inlet.

REPRESENTATIVE HERRON inquired whether ExxonMobil Corporation wouldn't now be called an "ultra-major" rather than a large-major.

MS. FEIGE agreed that ExxonMobil Corporation and Shell with the acquisition of BG Group could be called ultra-majors as they are clearly greater than $40 billion market capitalization.

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MS. FEIGE continued her review of who is working on the North Slope (slide 12). She explained that a cadre of small independents have moved into Alaska as the exploration cycles and production have begun to mature in the regions. She explained that that many of the companies listed on slide 12 will partner together in developments. For example, Accumulate Energy Alaska is a partnership of Burgundy Xploration and 88 Energy. She noted that Burgundy Xploration also holds leases independently of the partnership. Brooks Range Development Corporation is undertaking the Mustang Development and its partners are Caracol Petroleum, Ramshorn Investments, and a number of others. She explained that the nature of the smaller companies is that they will be very fluid and their numbers will grow when commodity prices are high and their numbers will shrink a bit as commodity prices fall because they partner up and sell their assets between themselves. For some companies it becomes too high a cost environment, so they sell or partner with others to manage those economic realities. Overall, the state has a broad and healthy cross-section of players still working on the North Slope.

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REPRESENTATIVE HAWKER referred to slide 12, and said that there are issues in Cook Inlet where people come in, incented to be there, but really were not able to perform, were not able to provide the state the proper assurance for their ability to remediate any financial and environmental damage that they might cause. He requested assurance as to what the state is doing to be certain the folks on the North Slope are economically capable and certainly have the ability to provide the due diligence the state would want to have of someone undertaking these sort of activities.

MS. FEIGE replied that the Division of Oil & Gas administers the dismantlement, removal, and restoration (DR&R) program, which is the end of economic life closure period for fields that are in production. She said DR&R includes removal and remediation of facilities, infrastructure, roads, pads, and so forth. Under the leases, the lessees, and in this case the unit operators and their partners, are required to work with the state at the end of life in DR&R planning. The state works with them to determine which assets the state deems valuable that it may want to keep and carry forward, or which of the assets should be removed and the area remediated. That final plan is put together with a DR&R estimate that is maintained throughout the life of the field. As leases are transferred and new parties come in, or there is a shuffling of the interest, the parties work with the division to establish a Financial Assurances Agreement, a DR&R agreement that looks to the end of that field's life. The parties either provide a bond or pay into a Sinking Fund as production develops, so there is a pool of money available to undertake that DR&R activity at the end of the field life and the state does not find itself in a position where a company may falter or fail and end up going under or going away before the DR&R's work is finished. Thus, there is a kitty or fund available for undertaking that work should that circumstance occur.

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REPRESENTATIVE HAWKER asked about the current activities with regard to the smaller entities where safety practices have been compromised and the challenges that can come from an inability to financially complete their work up front let alone the backside of life. He further asked whether the division is focused on the front end of field life.

MS. FEIGE confirmed that the division is doing this. She said that in unit activities as well as lease hold activities, the division has authority to request performance bonds to ensure that not only is the activity undertaken but that the activity is then remediated on the backside. The Alaska Oil and Gas Conservation Commission (AOGCC) for anything downhole has a bonding requirement as well that would cover the plugging and abandonment of wells if the company can't perform, and the division has and utilizes that same authority for the ongoing early stage activities.

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MS. FEIGE turned to slide 13, "North Slope Leasing Activity Trends, North Slope Foothills Areawide Lease Sale Results," to show the generalized activity levels and interest in taking leases since the beginning of the areawide leasing program. She explained that the North Slope Foothills region is predominantly a gas prone area just north of the Brooks Range. Its areawide leasing began in 2001 with a flurry of activity with lease taking in that area in the first couple years. She said these would have been leases with the primary term of 10 years, but over the life of leasing within the North Slope Foothills there has not been much activity. She offered the division's belief that this is due to the remoteness, no infrastructure, and very high cost operating. She opined that until there is an AK LNG or some sort of means to get that gas resource to a market the state will see subdued activity.

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MS. FEIGE moved to slide 14, "North Slope Leasing Activity Trends, Beaufort Sea Areawide Lease Sale Results," and advised that this area is zero to three miles out. The Beaufort Sea areawide leasing began in 2000 with a fairly robust and consistent level of leasing. These were 10-year primary terms on the leases. So, for example, if it was leased in 2000 and wasn't developed and was allowed to come back into the lease sale, it would not have been available again until 2011, and that spike is seen on the graph. She opined that leasing for the Beaufort Sea is somewhat hampered by the fact that beyond three miles the federal government is not consistent in how frequently it is willing to lease that acreage. Therefore, there is a bit of an artificial boundary at three miles. So, a discovery near that margin that extends past the three-mile mark would be into federal territory, and without a lease to continue it is too risky because the explorer doesn't own the resource. Clearly, that has an impact on leasing in the Beaufort Sea.

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MS. FEIGE discussed slide 15, "North Slope Leasing Activity Trends, North Slope Areawide Lease Sale Results." She said that this areawide leasing program commenced in 1998 with 10-year primary terms on the leases. These track oil prices pretty consistently knowing that companies are making those leasing decisions and setting those finances aside, designating those funds, at least one to two years in advance. She reiterated that there is a robust ready sort of crew that is coming to participate in the North Slope, and the graph indicates that the interest and belief in the endowment of the resource remains.

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REPRESENTATIVE HAWKER referenced Ms. Feige's statement that the trend lines were largely tracking oil prices, and asked whether that is really what explains this very significant profound growth from 2007-2011, the fall-off in 2012, but then that incredible spike in 2014. He said that the 2014 spike seems contrary to a claim of that kind of a proportionate increase in oil prices.

MR. DECKER pointed out that beginning in 2010 the state had its first shale play bidding wherein the state received approximately 100 bids of that 117. That was a wakeup call to the division and to the industry globally that Alaska may have a shale play. Due to that flurry of activity in 2010, by 2011 the division adopted a strategy whereby the division took its former nine-square-mile tracts in the area deemed geologically appropriate to the shale play, and cut its existing lease tracts into four smaller tracts. He described it as a very deliberate decision to protect the state's interest in order that large areas would not be held without actually producing or being penetrated by successful wells. In other words, he said, a well would be needed on each lease to hold it forever and by making smaller tracts they would have to drill more wells to hold the same acreage, which is appropriate to the shale reservoir behavior because one well does not drain nine square miles. From that point on, the division has had the smaller tract scheme in place and in 2011, 140 tracts were sold and part of that is because to lease the same number of acreage they had to bid four tracts and not just one. He said that in 2014, the 212 tracts offered were to parties like AD8 Energy, Accumulate Energy, and Repsol bidding in some other areas. So partitioning of lease tracts into smaller blocks means the selling of a larger number of tracts.

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REPRESENTATIVE JOSEPHSON asked whether the aforementioned was done administratively, and further asked for background on the policy to create four units out of what had been one.

MR. DECKER clarified it was not four units, but rather four lease tracts out of a single tract. The reason for that is that with shale wells a horizontal well is drilled and fracked, but one well can only drain a very limited area in the immediate vicinity of that well. There is no way in shale play that one well could adequately drain a nine-square-mile lease tract, so the division carefully thought through the decision with the commissioner's blessing that for the sales beginning in 2011 that would be part of the terms and conditions.

REPRESENTATIVE JOSEPHSON said it begs the question then that that would have been true 50 years ago, so why the policy change now. He asked whether someone was being dilatory.

MR. DECKER answered that the reason for the change is that now the division was looking at shale plays as opposed to conventional plays. Great Bear came in and then Royale Energy and AD8 Energy came in and have forthrightly stated that they are there to develop the shale plays, so that by itself requires a different way of looking at the reservoirs and potential reservoirs.

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REPRESENTATIVE HAWKER commended the division's foresight and said the change was a "really wise decision" given the great difference between shale development and the rest of the North Slope. Since the restructuring was done in 2010-2011, he continued, it cannot account for the incredible spike in 2014. He asked what accounts for the spike in 201, and whether there is a graph for 2015.

MS. FEIGE replied that once the division finishes issuing all of those leases and has fully adjudicated numbers, it will update the graph for 2015 for the committee. Speaking to the spike in 2014, she said it is a complex relationship and a complex thought process that goes into making the investment decision to take lease assets. Looking toward the future and planning for that exploration work and more importantly the funding of that exploration work. She asked the committee to bear in mind that decisions would have been made a year or better in advance with regard to taking a significant acreage position, and the division believes that prior to that precipitous crash that started in late 2014 with oil prices, the planning would have been done and they would have pulled the trigger. Clearly, she pointed out, there was a tax change within that time period, the implementation of Senate Bill 21, the More Alaska Production Act (MAPA), that became effective January 2014. She opined that the conversation leading up to MAPA would have been factored into decisions by companies as well, and she encouraged the committee members to speak to the companies and lessees directly about some of those decisions that are made.

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MR. DECKER moved to slide 16, "Cook Inlet Resource & Reserves Overview," noting that the map comes out of the U.S. Geological Survey's 2011 resource assessment for undiscovered, technically recoverable oil and gas, which is not reserves and is not necessarily commercial but just what is the undiscovered resource out there that could be extracted with today's technology. The USGS came back with a fairly robust estimate on Cook Inlet in both oil and gas, he reported. The USGS believes the basin has approximately 600 million barrels of oil to be discovered and approximately 19 trillion cubic feet of gas to be discovered. That is broken out by between about 14 trillion cubic feet of conventional gas split between the Tertiary and Mesozoic reservoirs, and about 5 trillion cubic feet of unconventional gas split between Mesozoic sandstones and the coalbed methane play that has never quite gotten off the ground in Cook Inlet, but is still there with resource potential.

MR. DECKER then pointed to information released by the division in late September 2015 regarding the current natural gas reserves in the basin, which is gas in the legacy fields for which there is a 50 percent or better likelihood of producing. He explained that these are called "2P" or "proven and probable" reserves and that estimate is 1.18 trillion cubic feet. So that's not too different than the number that the division came up with about five years ago, and is even a little bit higher. While there's some plus or minus in the estimates, that says that "we're holding relatively steady on our reserve space with the investment that's going on in the basin; in fact, probably increasing our reserve base slightly even though we've been producing gas at the same time." So it's a good trend. The division doesn't know how long exactly the reserve's growth can continue to be the case, but it's certainly a good trend. Mr. Decker drew attention to the southern portion of the map beyond the limits of the areawide sale or the state lands where the words "Cook Inlet" are written. He advised that that is outer continental shelf and is assessed by the BOEM and BOEM gives that area a mean undiscovered resource potential of about 1.2 trillion cubic feet, as well as some oil but mostly gas.

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MS. FEIGE drew attention to slide 17, "Cook Inlet Current Activity & New Developments," and advised that Apache Alaska Corporation came into Cook Inlet in 2011 with a very aggressive acreage taking in the Cook Inlet lease sale. Apache continues its extensive seismic acquisition program, both onshore and offshore, and is in the process of permitting for a new well which could be drilled in late 2016. ConocoPhillips recently announced the sale of its interest in the Beluga River Unit to the Municipality of Anchorage, Anchorage Municipal Light and Power (ML&P), and Chugach Electric Association. Furie Operating Alaska is the newest producer in Cook Inlet at the Kitchen Lights Unit. In summer 2015, Furie set the offshore monopod platform, completed all of its onshore facilities and pipelines, and commenced first gas production from the Kitchen Light Unit in December 2015. A second larger jack-up rig is scheduled to reach Cook Inlet in mid-May [2016]. Furie needed that larger piece of equipment for drilling of the development wells off the monopod in that it is necessary for it to cantilever over the top and anchor very securely. The smaller Spartan 151 rig would be floating somewhat on the tide and anchored only by barges, which would leave them with only 1 or 1.5 feet of clearance over the monopod, which is a very dangerous situation. So Furie decided to contract the second larger jack-up rig, and Furie will utilize that rig over the next couple of years to drill out the full field development and undertake some additional exploration within the unit area.

MS. FEIGE pointed out that BlueCrest Energy has the Cosmopolitan (Cosmo) Unit and will be bringing a large ground-based drill rig for extended-reach wells into Cook Inlet in April 2015, and will produce oil from the Cosmo Unit from onshore facilities rather than offshore. BlueCrest would like to undertake gas development and if BlueCrest does choose to undertake the investment for development of the gas cap it could potentially use the smaller Spartan 151 jack-up rig from offshore. However, should BlueCrest choose not to proceed in the near term with the gas development the Spartan 151 will leave Cook Inlet.

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REPRESENTATIVE SEATON asked where the jack-up rig originated from and whether it had been active or inactive before coming to Alaska.

MS. FEIGE replied that Furie Operating Alaska reported to the division that the rig is coming out of Singapore and has been actively drilling on deep water prospects there. It had not been torn down and stacked out in storage as the Endeavor had been. It is currently on a vessel coming from Singapore.

REPRESENTATIVE SEATON related that when the Endeavor came to Alaska it had been out of the water for a month or so, but there were encrusted mollusks and other things on the jack-up rig when it arrived in Kachemak Bay. He asked whether the rig from Singapore has been inspected for invasive species.

MS. FEIGE responded that she does not know the answer to the question of inspection for invasive species but she does know that AOGCC has a robust rig inspection and rig certification program for new ground-based and offshore rigs coming into Alaska, and AOGCC will be responsible for performing the initial sign-off prior to operations. She said the division will inquire about whether invasive species will now be part of that inspection process, given the history with the Endeavor.

REPRESENTATIVE SEATON offered his appreciation because there is nothing worse than getting held up by court filings, and currently Alaska does not have a statutory requirement.

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REPRESENTATIVE HAWKER noted that slide 18, "Cook Inlet Current Activity & New Developments," shows the significant amount of work that Hilcorp is doing in Cook Inlet. He inquired about the current and anticipated proportion of production coming out of Cook Inlet today that is allocable to each of the participants, and requested a guideline as to how much of that proportion is oil and how much is gas.

MS. FEIGE responded that the division will drill down on that, but said notionally from today's activity update: Apache Alaska is not producing, Conoco is producing gas, Furie is gas only, BlueCrest Energy will be oil but nothing on production currently, and Hilcorp Alaska is clearly in production. At present, Cook Inlet oil is nearly 18,000 barrels a day, which is the highest level it has been at since 2005 with a steady increase since 2009. She said that the increase in production can be attributed to Hilcorp's activities.

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REPRESENTATIVE SEATON asked whether West Eagle plans to perform seismic workovers with regard to Buccaneer's previous attempt out there.

MS. FEIGE offered her belief that West Eagle was acquired by AIX Energy, which is on the division's list of operating companies. Although, the division has no active applications at the present time so if AIX is planning work it has not brought it to the division's attention at this point in time.

REPRESENTATIVE SEATON inquired whether AIX would have to come to the division before it does seismic work.

MS. FEIGE answered yes, the company would be required to have either a miscellaneous land use permit or, if it is on an oil & gas lease, the requirement is a lease plan of operations approval from the division.

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MS. FEIGE returned to slide 18, "Cook Inlet Current Activity & New Developments," and said Hilcorp has been working diligently throughout the basin bringing both gas and oil production on line. Notably in late 2015, Hilcorp acquired the middle ground shoal assets from XTO Energy, which is offshore in southern Cook Inlet and included onshore facilities and one platform. Hilcorp reports it has a projection of spending approximately $120 million in the Cook Inlet region in 2016.

MS. FEIGE moved to slide 19, "Cook Inlet Wells Drilled & Seismic Acquired," to summarize the exploration and development wells in the 2010-2014 period. She noted that 2010 would have been just before the Cook Inlet Recovery Act came into play. During the period of 2010-2014, 24 exploration wells and 65 development service wells and well branches were drilled. She reiterated that the seismic data acquired in Cook Inlet comes into the division via the tax credit programs, and 2004-2014 takes in the entire time period where the division would have been receiving credit-related data. Approximately 725 line miles of 2D data and roughly 660 square miles of 3D data was acquired for both onshore and offshore.

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MS. FEIGE reviewed slide 20, "Who's Working Cook Inlet?" She advised that ConocoPhillips is the one large major left in Cook Inlet. Conoco has announced the sale of the Beluga River Unit, and its North Cook Inlet Unit assets are still for sale. Mid-sized independents that are still operating include Hilcorp and Apache Alaska. Hilcorp has done a fine job of driving its operating costs in the inlet down. Because Hilcorp owns such a suite of properties it is able to aggregate its activities into areas around the basin or into type of activity - so rather than drilling one or two wells, which is the highest cost program, it aggregates those and drills 10 wells, or does 15-20 workovers at a time. This enables Hilcorp to obtain volume pricing from the local service sector and if Hilcorp is not pleased with the local pricing, it has been able to successfully bring additional service companies into Cook Inlet thereby growing competition in that service sector in the inlet. She said it has been a very successful model for Hilcorp and the division fully anticipates Hilcorp employing the same practices on the North Slope. Ms. Feige noted that the small independents and LLCs in Cook Inlet are partnered in developments around the inlet, and include AIX

Energy from West Eagle, NordAq Energy, Furie Operating Alaska and BlueCrest. She pointed out that Furie's partners in the inlet are Corsair Oil & Gas Company LLC and Cornucopia Oil & Gas Company LLC.

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MS. FEIGE discussed the graph on slide 22, "Cook Inlet Leasing Activity Trends," depicting the trends since the commencement of areawide leasing in Cook Inlet between 1999 and 2015. Notably, the big spike in the graph indicates when Apache came into Cook Inlet in 2011. It can be seen that a robust presence and level of activity continues across Cook Inlet. Interestingly, leases in Cook Inlet have a primary term of seven years as opposed to ten years because the exploration to development cycle within Cook Inlet is shorter than on the North Slope because the inlet is closer to infrastructure and there is less of a seasonal control on access in the Cook Inlet than on the North Slope.

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REPRESENTATIVE HAWKER observed that the graph on slide 22 shows a precipitous decline of activity between 2004 and 2009 and then the jump in 2010-2011 with Apache coming in and then a fairly robust activity continuing in the inlet. He asked whether DNR has a sense of how efficacious the financial incentives awarded under the Cook Inlet Recovery Act were in turning around the 2004-2009 decline and sustaining the level of investment currently and whether DNR believes those incentives are still needed and still working. Given that DNR does the forecasting and the Department of Revenue (DOR) is no longer part of the forecasting, he further asked how the passage of HB 247 would affect DNR's forecasting for Cook Inlet.

MS. FEIGE responded:

> I think first of all, we can see in Cook Inlet when Cook Inlet actually stopped being over-supplied and started actually behaving like a supply and demand driven market. And you see that really start to take hold in about 2002, and there was a ... fairly massive ... robust entrance of companies into Cook Inlet because now you could actually sell your gas and there was a market for the gas. Clearly, over time and in Cook Inlet and it is a unique market, it is not attached to the Lower 48.... Henry Hub today I think is $1.87, or something like that, and we're about

$6.56 or something ... in Cook Inlet. So we're very separate, but our market tends to become constrained fairly rapidly because the majority of our demand comes from those utilities. And we have, over time, had large industrial anchors like Agrium and looking forward we could again see Agrium ... and in a few years we could hopefully see a Donlin Creek Mine also needing to source gas out of the Inlet. So, absolutely I think that those market dynamics have played a role over time in Cook Inlet. And we were clearly, as was part of the discussion in the Cook Inlet Recovery Act, we were behind the power curve in terms of investment and drilling to make sure that we had enough ready supply of gas to meet our base utility needs and that then precipitated the Cook Inlet recovery. And we saw, I think, an upswing in activity associated with that. I think we're seeing a couple of things leading into the downturn in 2015. Again a little bit of market constraint going on, we're beginning to see our utilities out to ... some five year contracts. Utilities really like, as you all know, to have contracts out at 10 years as a minimum and ... in the last few years the best they've been able to do is 18 months, maybe 2 years, and then very recently we've seen a few 5 year contracts trickle out. So I think we're seeing the effects of a bit of market constraint here....

2:05:39 PM

MR. DECKER also responded to Representative Hawker's questions. Regarding the first question he said there is no doubt that the credits were efficacious and helped stimulate some of the drilling activity and reserve replacement activity. Also, the price has been a leveraging factor. The Hilcorp takeover is another pretty obvious point in that it is a single company that can manage the basin as almost a portfolio. Another factor is gas storage. Expansion of gas storage at the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility helps provide a little more incentive for companies to drill a well - they may not be able to sell the gas directly to the utilities year-round but they can sell it into storage. Regarding the forecasting going forward, Mr. Decker said his section of the Division of Oil & Gas, the reservoir engineers, will be working with the commercial section, as well as with some of the people in DOR's Tax Division. He said DOR's contribution is still important in that it has the rapport and history of going to the companies to speak off the record about confidential issues for projects that are under development or under evaluation. The goal is to prepare a more probabilistic forecast that recognizes the uncertainty at every level, whether the currently producing, the underdevelopment, or the undervaluation.

2:07:39 PM

REPRESENTATIVE HAWKER offered his appreciation for DNR working with probabilistic models. He asked when something like that might be available to assist the committee in judging the true impacts and consequences on production volumes of the tax proposal that is currently before the committee.

MR. DECKER estimated that the change is intended to take place in time for the fall revenue forecast.

REPRESENTATIVE HAWKER understood Mr. Decker to be saying that DNR is the forecasting entity for the State of Alaska, with a tiny amount of forecasting done by DOR, and that the legislature will not have forecast information on the consequences of HB 247 until the fall revenue forecast.

MR. DECKER replied that this is his understanding, unless it is contained in the spring DOR Source Book update.

MS. FEIGE added correct.

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REPRESENTATIVE OLSON, regarding Ms. Feige's mention of market constraints, inquired whether she was referring to the Regulatory Commission of Alaska (RCA) cutting back on the length of the gas sales to Japan.

MS. FEIGE responded she thinks that certainly had an impact at the time; it was clear that when the RCA lifted that restriction more fluidity and flow in the development of the local utility contracts was seen. After confirming that Representative Olson was specifically referring to the export to Japan through the Nikiski facility, she said she does not have an answer and will have to look into that. However, she continued, once the RCA, in general, lifted some of the constraints that were broadly seen across Cook Inlet, there was more activity in that it was one less barrier to development and sale of the product.

REPRESENTATIVE OLSON noted there was less demand as well.

MS. FEIGE agreed.

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REPRESENTATIVE SEATON noted he is trying to figure out the five-year contract period. He surmised as follows:

> Means that people bringing gas on right now unless they have some other sales are sitting there with gas not ready to sell if there's a five year filling of the market, unless Donlin Creek or something else comes on line. So, first of all, is that a correct analysis of that with if the market is fully subscribed and with a five-year contract, people that bring gas on right now, unless it would go ... through ConocoPhillips' Nikiski plant, there's really not a sale for that gas.

MS. FEIGE answered that the five-year contract she referred to, that DNR has seen, was for one of the Southcentral utilities and it doesn't actually start until 2018, so it was forward looking past the expiration of another contract. She said she thinks Representative Seaton's assessment is correct in that DNR has heard from Furie that it will need to scale the pace at which it does its development based upon the company's ability to sell its gas, which makes perfect financial sense that that is the driver. In the event Furie can't sell the gas and recoup its cost on drilling the wells and doing the development activity, it does become a hindrance to that development work and the timely fashion in which that development gets done.

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REPRESENTATIVE SEATON asked about the impact of credits versus n credits and HB 247 on that modeling. He further asked whether modeling by the Division of Oil & Gas incorporates those elements and how that would influence actual wells drilled.

MR. DECKER replied that the question of how HB 247 will impact the forecast has not come up in the division's technical discussions with DOR about how the division intends to pursue forecasting.

MS. FEIGE added that in the modeling the Division of Oil & Gas undertakes, the assessment of the impacts of the tax credits and the costing is outside the scope of what the division's commercial section normally does. She explained that DNR does not have access to the cost data that DOR has access to. However, DNR notionally keeps a working inventory or sense of how healthy production is at the various units around the state. Therefore, DNR knows that in a low price stress environment like today, some production might be taken off line or there might be a shortening of the economic life of a field. She said the kind of analysis the committee has asked for is what Director Alper and his team at DOR have been working on and are planning to present over the next couple of days. This type of analysis on bill impacts would not be something DNR would normally take up in the scope of its activities because DNR does not have access to that costing information.

REPRESENTATIVE SEATON said he wants to be sure the committee does not have expectations that the report it will receive is "on something other than their modeling."

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REPRESENTATIVE HAWKER pointed out that Ms. Feige and Mr. Decker are the experts tasked with doing the production projections. He asked whether there is concern that these projections are being done in a vacuum by not having access to the information "that would seem really relevant to these production levels." For example, DNR's charts depict very distinct changes in leasing and resultant production as a result of policy calls made in major tax increases and decreases in the state over recent years. He asked whether Ms. Feige and Mr. Decker have comfort in their ability to prepare accurate modeling without better information as to the consequences of these policy decisions.

MS. FEIGE stated that Representative Hawker makes an absolutely valid point in that access to good information is needed and to work with DOR in making those projections. She said the division tries to drive its information and its look at how industry is doing by talking directly with industry. She noted that industry is forthcoming on its perceived impacts to what industry has planned. She said, "We are in a bit of a box because of the information and ... I think that's where I'd have to leave it."

2:16:04 PM

REPRESENTATIVE HAWKER asked whether DNR has any position or counsel for committee members on HB 247.

MS. FEIGE responded:

> From DNR's standpoint and the division's standpoint, I would just stress that balance is the key. We have to keep a balance moving forward between exploration and ongoing production. The exploration wells of today and the exploration successes of today, and the next 5 years or so become the production 10, 15, 20 years down the road. So, where we really want to focus in and be very, you know, on the spot and somewhat myopic, I think we have to be cautious not to take that tact because we have to keep our eye on what's going to be our production 5, 10, 15,... 20 years ... down the road. I think that we can absolutely say that incentive credit programs work. We saw it work in Cook Inlet, but again it comes back to balance. It's a balance of what can the state afford to sustain going forward and I think that we have to keep talking to our companies, hearing from them because that's going to be the response to us all as we work through this and try to make that decision of what can the state afford to do going forward. Trying to keep our eye on what is our production source going to be ... 10, 15, 20 years down the road.

REPRESENTATIVE HAWKER noted he heard Ms. Feige say to "keep your eye on the ball."

MS. FEIGE replied absolutely.

2:18:01 PM

REPRESENTATIVE TARR addressed the statement about making sure the state is holding lease sales so there is always that ongoing activity. Regarding maintaining a balance in the current low price environment, she asked how the department plans to keep things moving forward from the lease sale side of things.

MS. FEIGE answered that the division undertakes a review of its terms and conditions within about six months prior to each lease sale, be it North Slope or Cook Inlet. The team looks at Cook Inlet, for example, from the standpoint of the resource and reserve and what the division understands about it. It looks at the commercial side of things and what's the price projection, how supplied is the Cook Inlet basin, and all of those complex factors that can come to bear on the behavior of companies and their participation in the lease sales. The division then sets the terms and conditions for each lease sale and the commissioner has the authority to raise or lower minimum entry bids to reflect what the division believes may be stress points on the industry. For example, she said, there shouldn't be a minimum entry bid that is too high in a price stressed market when companies do not have a lot of surplus cash sitting around. It is in the state's interest for companies to take that acreage and be able to hang onto it and perform their exploration planning through the period of downturn and then be positioned to really ride the wave as prices begin to come back up again. Those are all factors the division considers and works through in making its recommendation to the commissioner to engender and establish a robust level of leasing activity across the state. She pointed out that it is important that conversations like this certainly come into play in those assessments of those terms and conditions.

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REPRESENTATIVE HERRON inquired whether Ms. Feige believes her division was able to get its opinion across to the administration about how HB 247 will impact the industry. He further inquired whether Ms. Feige could share any of the concerns that industry has expressed to DNR about the bill.

MS. FEIGE replied that she and Director Alper spoke several times during the development of the legislation; he would call and ask questions about existing credits on the books, how long they've been used, and did DNR perceive that there would be an impact to industry if certain older credits were repealed. The Department of Revenue would ask DNR's opinion as to how industry may react if a credit program went away. She advised that she and her division were not intimately involved in the development of the bill that is before the committee, but DNR did add input as it was asked of it from DOR and Director Alper's team. With respect to the second question, she said the division has heard from industry that taxes generally are lumped into the bucket of cost for the overall project development or working in a specific area. In the event costs go up companies need to be able to compensate, and at a time when prices are very low that sets off some alarm bells and the division has certainly heard that from industry. The concern is over making big changes to tax policy at a time that prices are very low, and at a time when prices are not expected to come back into the $100 realm anytime soon. Ms. Feige said the division has also heard from companies that are halfway way through a development drilling program in which they have factored the tax credit programs into their expenditure equation, and if the credits go away their world changes at that point. She said it's coming back to the constant theme of stability, what can the companies expect? They need to be able to plan more than six months out, they need to plan one or two years out in order to line up their funding and ensure that they can undertake those activities without interruption.

REPRESENTATIVE HERRON commented that there has been discussion about if there is a change "where do we stop it but not impact the ones that are in play?" That is an important part of factoring in amendments to the proposed legislation.

2:24:30 PM

REPRESENTATIVE SEATON remarked that there are two different conversations, one on gas and especially Cook Inlet gas, and the rest on oil. He noted there is gas at about $1.87 Henry Hub, and worldwide LNG long-term contracts less than $5.00 spot. He asked whether there is any place in the United States or worldwide that has a better profit margin for producing gas than Cook Inlet, which is selling at $6.85, with winter prices higher than that.

MS. FEIGE responded that the answer clearly is no. The Cook Inlet is at $6.50, the Lower 48 is $1.87, and currently Japan is less than one-half of what it was two or three years ago in terms of LNG import. Cook Inlet is a good place to be for being in the gas business. "Our problem is that we lack those industrial anchors," she said. Those large consumers, just like in the power sector, shoulder the development of a big power plant. An industrial anchor allows power generation at a steady rate and then others can come into the power stream once the plant is up and going. That same model applies to gas in Cook Inlet. Cook Inlet has great resource and has a lot of companies doing a lot of good work, but at the present time it runs out of offtakes.

REPRESENTATIVE SEATON surmised that "the market is the determiner of what is happening in Cook Inlet, but that ... people drill, and if they have a market for it, is probably about the best in the world."

MS. FEIGE agreed.

2:26:58 PM

REPRESENTATIVE TARR surmised that if the Agrium [fertilizer facility] came back on line it would be large enough to be considered an anchor.

MS. FEIGE replied yes. She noted that Agrium has two trains at its facility and each train takes 24-25 billion cubic feet per year, so if the full facility came on that would be 50 billion cubic feet [per year]. Right now, the utility, field gas, and refinery-based demand in Southcentral is 80 billion cubic feet a year. Donlin Creek Mine would add another 12 billion cubic feet a year. So, those large anchor potentials are out there.

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REPRESENTATIVE HAWKER referred to Ms. Feige's response to Representative Seaton that the gross sales price for the extracted resource in Cook Inlet is higher than Henry Hub prices. He asked whether Ms. Feige would come to the same conclusion when looking at the net income of a company performing in Cook Inlet and when the cost structures are considered. If a company develops gas in Cook Inlet and wants to sell it to Japan, there is a large ocean in between. He asked whether Ms. Feige was addressing the net profitability of a company coming into Cook Inlet and operating, or was it more in the context of a high gross price and at the end of the day the company's gross doesn't matter, the net matters.

MS. FEIGE confirmed Representative Hawker is correct and said costs have to be a consideration in any business decisions, and both Cook Inlet and the North Slope are higher cost operating environments in that labor costs more, services cost more, and transportation costs from an export standpoint will certainly come into play. If companies look for an area where they can make a good return on the gas, their internal rates of return will drive that. She said she still thinks that with a robust market, Cook Inlet and Alaska are good places to be. She stressed that Representative Hawker's point is very well taken in that the net and the end-of-the-day margin matter and that is driven by cost.

REPRESENTATIVE HAWKER identified himself as the sponsor of the Cook Inlet Recovery Act and said it truly was the intent to make the basin competitive, attractive, and attract the level of production that has been seen.

The committee took an at-ease from 2:30 p.m. to 2:33 p.m.

2:33:10 PM

KEN ALPER, Director, Tax Division, Department of Revenue (DOR), on behalf of the governor, sponsor of HB 247, continued his PowerPoint presentation entitled, "Oil and Gas Tax Credit Reform- HB247, Additional Modeling and Scenario Analysis - Part 1a." Before beginning his presentation, he advised that Commissioner Randall Hoffbeck is in transit from New York, and DOR's senior economists are currently putting the finishing touches on a presentation that will be given to the committee tomorrow morning. He spoke to the evolution of DOR's forecasting process as follows:

> The Department of Revenue is charged with forecasting oil production primarily for the purpose of forecasting revenue. That's our job, is to produce the Revenue Sources Book and determine how much revenue the State of Alaska can expect. Most of the source data for that is tied to our own outreach from industry. We don't make this up, we talk to people from industry, multiple companies every year. They tell us their drilling plans, their expectations, and then we build that into a drilling forecast and then we have, for many years, used the services of an outside consulting engineer, a petroleum engineer who would help us convert that data into decline curves and expected volumes. And then to that, in more recent years, we would layer on some risk factors and delay principles, expectations for the new oil, the under development and under evaluation. What we faced in the last year or so, frankly, is because of budget short falls, we re-looked at how we paid for these services. That we thought rather than going to outside consulting services that cost the state substantial amounts of money, that much of that expertise and professional knowledge in petroleum engineering existed within the state's own system in the Department of Natural Resources. So, we looked to them to help us through it beginning this year. We are the client and they are, in many ways, our consultant. And they are going to be taking the same data set, the information on what wells are going to be drilled and helping us to turn it into the forecast that we brought before this committee ... in the fall Revenue Sources Book. If there are changes in behavior, whether tied to market forces or any changes

in legislation, those will be reflected in the fall forecast; we begin that outreach generally in the months of August and September.

2:36:14 PM

REPRESENTATIVE HAWKER understood that Commissioner Hoffbeck was back East discussing state fiscal prospects with the state's rating agencies and securities analysts. He inquired as to what the rating agency's responses were to the Alaska State Legislature considering HB 247 and imposing a major tax increase on its only sustaining industry at a time when that industry is facing severe economic losses.

MR. ALPER replied he has not spoken to Commissioner Hoffbeck on his experiences in New York, although he returns tonight and he will speak with him tomorrow. He said that the rating agency is concerned about the state's budget shortfall, and Alaska's ability to prove that it can continue to balance its budget. He said the Department of Revenue presents to them as it presents to the legislature this bill as part of a package of reducing that budget deficit.

2:37:16 PM

MR. ALPER drew attention to slide 2, "What We'll Be Discussing," to explain that the slide is from the Table of Contents of the presentation he began on 2/22/16. He reminded members that he had ended that presentation about half-way through the fourth bullet which deals with the details of how the pieces work: some of the historic cost information, overview of the oil and gas economy, DOR's thoughts as to what has worked and what hasn't, what is scheduled for sunset, what is expected to continue, what is being repealed in this bill, and summarizing the suite of credits in Alaska's portfolio. He noted that appended at the end of this presentation are DNR's slides addressing issues of gas supply in Cook Inlet, and that the bullet shown in grey on slide 2 will be presented to the committee tomorrow.

2:38:18 PM

MR. ALPER noted that the last subject he discussed was what is involved in strengthening the minimum tax by preventing certain credits from being able to be used to reduce payments below the so-called floor, the 4 percent minimum tax. He said he previously reviewed the Gross Value Reduction (GVR) eligible fields and the issues there and how DOR proposes to make the so-called new oil pay at the 4 percent minimum, as well as the issue of major producers who may have a Net Operating Loss (NOL) Credit due to losing money in one calendar year from being able to use that Net Operating Loss Credit in the next calendar to offset their minimum productions taxes and pay something like zero. He noted that slides 35-36, "Section 17(b): Strengthen the Minimum Tax, How net operating loss (NOL) credits are earned and used - page 1, page 2," are very complex but are more or less monthly cash flow slides to show that with a second year of low taxes what could happen by offsetting the minimum tax with the Net Operating Loss Credit, and then yet more Net Operating Loss Credits stack up into the future.

2:39:31 PM

MR. ALPER turned to slide 38, "Section 17(c): Strengthen the Minimum Tax, Preventing per-taxable barrel credits from being used in another month other than the month earned," and said current law allows those monthly earned taxes to be used anywhere in the year. This is only relevant with a lot of volatility specifically with certain months of the year impacted by the minimum tax and certain months of the year not impacted by the minimum tax. In the months with the minimum tax, typically the entire $8 cannot be used, the companies will start to use that $8 per barrel credit, bump up against the minimum tax, and then lose the rest of it. In the event there are other months of the year, those lost credits have been able to be applied to reduce earlier months' taxes down toward the minimum tax level. He advised that he will provide graphs later in this presentation that will show more clearly what he is discussing. He said Alaska's Clear and Equitable Share (ACES) bill was a true monthly tax, the progressivity, the entirety of the tax rate, was monthly. That regime was eliminated three years ago and the bill before the committee is more of a true annual tax where one small component of the tax would be locked into the month in which it was earned so as to prevent some upside risk to the state. [The administration's] contention is that when there are several months of high oil prices, the state should be able to earn all of the taxes earned in those high months and not have those high month revenues eroded by a possible credit earned in low months later on in the year.

2:41:22 PM

MR. ALPER addressed slide 39, "Section 17(c): Strengthen the Minimum Tax, Credits 'lost' to the minimum tax before annual true-up," and explained that the graph is a model of the actual conditions of what happened in calendar year 2014. He said:

> The top of the yellow bar is the entirety of the production tax based on 35 percent of production tax value, the statutory calculation of what the tax would be given the information provided by our producing taxpayers. The top of the green line, or after subtracting the yellow, is the actual tax paid after application of the Per-Taxable Barrel Credit. So, you could see ... in the early months of the year when prices were higher, the grey line across the top ... looks like it just might be a stray line. That's actually a line tied to the axis on the right-hand side, which is the price of oil. And you could see a price of oil that was over $100, dipped under $100 for the last time in the month of August and was down around $50 by December. So in those earlier months of the year the Per-Taxable Barrel Credit was either $5 or $6 per month. That number ... increases as the price decreases to hit a peak of $8 at below a price of oil of between $80 or $90. So that's why the yellow bar got thicker in September and October, and then into November and December what happened is there is no more green bar. What the red bar is, is 4 percent of gross tax. The 4 percent of the gross is what must be paid based upon the minimum tax calculation and the dotted lines in the November and December, those show those Per-Taxable Barrel Credits that were effectively lost to the producers; they were not able to use them because there wasn't enough delta between the top of the yellow bar and the top of the red bar.

2:43:14 PM

MR. ALPER moved to the graph on slide 40, "Section 17(c): Strengthen the Minimum Tax, 'Lost' credits recovered at annual true-up." He continued:

> You could see what happened here ... you could see the same dotted lines in November and December. What the companies were able to do is migrate those credits to effectively offset the great bulk of January's production tax above the level of the floor. And what that meant was at the time of our annual true-up in April of 2015, we refunded companies $112 million.

> That was the amount of lost credits that we were able to migrate in to ... prior months' tax liability. So that's the phenomenon that actually did occur. We've created a second scenario that would show a more extreme example of what I've just presented. In a year of greater price volatility the credit recovery, or the ability to migrate credits, could take up an even greater share and could push a large portion of the state's production tax even in high cost high price months down to the minimum tax level. And this occurs because ... the minimum tax calculation is an annual tax so the credits that cannot be used within the year ... could be recovered at the year's end.

2:44:27 PM

MR. ALPER explained that the graph on slide 43, "Section 17(c): Strengthen the Minimum Tax, 'Lost' credits recovered at annual true-up," is a more hypothetical and dramatic drop that occurs earlier in the year. He said:

> So here we have a scenario where in January of year X, the price of price of oil is $90, by December it's down to $50. And you'll recognize the structure of this chart, the yellow bar is the production tax based on the statutory 35 percent calculation. The green bar is that tax after the application of the sliding scale credit, which for most of these months would be $8 per barrel. And then beginning in June and getting larger in the later months, you see a growing dotted line which is Per-Taxable Barrel Credits that are lost, that are foregone because of the inability to use them because of the minimum tax; the companies are forced to pay at the red minimum tax level during those months. [Returning to slide 42], you could see the relative thickness of the green bars in January and February in slide 42. [On slide 43], those bars are completely wiped out by the migration of all of those unused credits from June through December and offset against February. And the total in this calculation, which was something of a snapshot created by our staff, leads to $233 million in lost credits, or about a third of the total production tax revenue for this theoretical year is lost at true-up. So, what the bill before you is doing ... and the language in it is somewhat complicated, but what it does is it locks in the Per-Taxable Barrel Credit to the month in

> which it was earned and doesn't allow it to migrate from month-to-month within the calendar year.

2:46:05 PM

REPRESENTATIVE JOSEPHSON asked whether there was any discussion in either body or in any committee about this phenomenon. He noted that it is the law and arguably it doesn't matter if there was a discussion, but he would like to know whether this came up in any presentation that Mr. Alper is aware of.

MR. ALPER replied that he specifically reviewed the committee record on this issue for the House Resources Standing Committee at the time. The gentleman who did the bulk of carrying the bill on behalf of the previous administration was DOR Deputy Commissioner [Michael] Pawlowski. Mr. Alper related that when asked a similar line of questioning by Representative Seaton, Mr. Pawlowski's understanding was that this was a monthly credit, a monthly calculation, and that it was intended to be taken within the month it was earned. Mr. Alper continued:

> To be fair, the committee record, nor the thinking at the time, did not contemplate the minimum tax. Did not contemplate that there would be years in which we would be at the floor. That this phenomena which is before you would be relevant. And I don't believe it was addressed. In the context of a normal year in which there is no minimum tax, Mr. Pawlowski was absolutely correct - this is a monthly calculation. The credit rate itself does change from month-to-month as the price of oil might change from month-to-month, but the ability to recapture it at true-up did not become relevant until roughly 18 months ago ... when the price of oil dropped to a level where for the first time in our history of having a net profits tax, we fell into the realm of minimum tax, of paying at the floor.

2:47:48 PM

MR. ALPER turned to slide 44, "Section 17(c): Strengthen the Minimum Tax," to summarize his previous comments. He said that this particular issue of strengthening the minimum tax is only an issue in years of relatively high oil price volatility where some, but not all, of the months trigger the minimum tax. He pointed out that the examples on the previous two slides showing moderate to high oil volatility reduce the state's tax payments by close to 30 percent, and an effective tax rate on net profits would reduce that from about 14.5 percent to 10.5 percent as an effective tax rate. This phenomenon causes the state to forego some fraction of the upside in years where the monthly oil prices might be very high, and otherwise would generate high revenues; the state loses some of that revenue due to the offset from the months in which prices are low. "Another phenomenon," he continued, "in the future as tariff rates begin to increase, you'll start seeing wellhead values decreasing and that might mean, for example, the Per-Taxable Barrel Credit itself will start to trend toward the larger numbers, the $7-$8 range rather than the $5 and $6 range that was envisioned in some of the committee discussions during the last major fiscal change."

2:49:11 PM

REPRESENTATIVE JOSEPHSON, regarding when Mr. Alper talks about an increase in tariff rates, asked whether that anticipation is due to moving to more unconventional oil or some other reason.

MR. ALPER responded that the most prominent factor in increasing tariff rates are declining production, when the cost of operating the transportation system is relatively fixed and as fewer barrels go through, each one has to pay a higher share of the freight.

2:49:36 PM

REPRESENTATIVE TARR understood that everything in Section 17 is retroactive to January 1. She surmised this is because at true-up at the end of calendar year 2016, DOR wants to avoid this problem for 2016. She inquired as to how difficult it would be for the companies at true-up if, for example, it was started on the fiscal year.

2:50:37 PM

MR. ALPER answered that the intent of the retroactivity is to have this phenomenon be eliminated for the current calendar year. If the bill doesn't pass until the end of the legislative session there would have to be some sort of make-up payment or a way to account for that come the first monthly payment after the passage of the bill. He offered the following:

> The concept of a split year for many of these provisions that affect the calendar year tax are very problematic; they have caused complex situations

inside the audit staff in the past. The ACES bill, for example, took effect on July 1, 2007 ... but it's a calendar year tax, it lead to a situation where in many ways they had to split 2007 into two separate tax returns and do a full analysis of the first six months separate and distinct from a full analysis of the second six months. So, to the extent features that impact the underlying tax calculation for the tax-paying producers, changes in the middle of the year, it will lead to some inevitable complexities in the administering of that tax.

2:51:58 PM

REPRESENTATIVE TARR asked which of the two fiscal notes shows this element.

MR. ALPER replied:

The one fiscal note that shows the fund capitalization element also shows the negative numbers in spending, and all of the provisions of the bill that reduce credit payments or eliminate certain credits are encompassed in that negative number. All of the minimum tax changing provisions are in the other fiscal note that shows the positive revenue numbers. So, what you see in the early couple of years is $100 million revenue estimate declining to a $50 million revenue estimate in the out years. The $50 million, in every year, is the rough estimate for the annual additional revenue from an increase in the minimum tax from 4 percent to 5 percent. Now, previous slides and this slide deck before you that we went through Monday, show that there is some variability in that and depending on the price of oil that could be a number between roughly $30 and $70 million. And with the next generation of this fiscal note, we will incorporate some of that more nuanced modeling to that element of the calculation. The second $50 million that's in the early years is the impact specifically of not being able to use Operating Loss Credits to offset minimum tax payments from the major producers. But based on our forecast, this is a phenomenon that's only in place for the current and next year so it's about a two-year problem, then it will go away of its own accord if our forecasted prices hold because at that point we don't expect any of our producers to be

> losing money; therefore won't be earning an operating loss credit. This specific provision in 17(c) that I've been discussing thus far today, is not forecasted at any value simply because our price forecasts do not consider volatility. That we have a fixed number for the year and this is a phenomena that's only relevant in a year where there's a lot of up and down and we're looking at annual average numbers and therefore can't project the value of up and down.

2:54:03 PM

REPRESENTATIVE HAWKER stated that for the last two meetings Mr. Alper has dialogued using one circumstance - the year 2014 - to discuss and illustrate the inner play of truly major components of the overall tax construct. This tax construct has evolved since the end of the Economic Limit Factor (ELF). He asked whether Mr. Alper has any support or evidence from his research of past legislative sessions that would show the legislature intended the state's major tax constructs to be anything other than an annualized tax cycle to annualize activity that can be volatile on both the taxpayer and the state as the tax administrator. Representative Hawker said Mr. Alper is clearly looking to have this parsed into a more granular tax cycle of literally an isolated monthly cycle.

2:55:29 PM

MR. ALPER responded that the specific provision addressed in Section 17(c) of HB 247 relates to the application of the Per-Taxable Barrel Credit. That is a new credit that did not take effect until January 2014 with the passage of Senate Bill 21. Senate Bill 21 describes that credit as a monthly credit and a monthly calculation that very explicitly varies from month-to-month depending upon the average price of oil in that calendar month. If it's below $90 gross value it is $8, between $90 and $100 it is $7, and so on. So, the value of the credit was quite explicitly monthly. As for the ability to use it from month-to-month it was neither addressed nor not addressed. To the extent it was discussed, Deputy Commissioner [Pawlowski] described it as a monthly calculation. He continued:

> That one specific provision of the new law was said to be a monthly calculation. All other provisions of the calculation are absolutely an annual calculation. And by the elimination of progressivity, which was the most extreme monthly calculation in the prior tax

regime, in many, many ways Alaska's oil and gas system was converted from a monthly to an annual based system. But, the remnant of a monthly system that was retained with the passage of Senate Bill 21 was this specific calculation of the Per-Taxable Barrel Credit.

REPRESENTATIVE HAWKER respectfully disagreed with Mr. Alper's characterization that the changes made moved the state from a monthly to an annual calculation as the progressivity was eliminated, and added that he and Mr. Alper are never going to agree on this.

2:57:11 PM

REPRESENTATIVE SEATON asked whether this hypothetical scenario on slide 43 only goes back and calculates what the tax would have been by applying it to past months, or also moves the other way and has a carry forward that would diminish forward months as well.

MR. ALPER replied yes, this model was built with a declining oil price much as the earlier set of 2014 actuals was a declining price, but the phenomenon works the same exact way in reverse. For example, if there are unused credits in January, but there is adequate credit value in November and December because the price of oil recovered, they could just as well be carried forward. The one essential limitation is that this is a calendar year tax and any such adjustment or migration must occur within a calendar year.

2:58:24 PM

REPRESENTATIVE SEATON asked whether, in this situation and making it retroactive to January 1, there would be any green bars to take advantage of, or to apply it to, at this point in time. He further asked whether the state would have to go back and capture any payments because going forward there wouldn't be any to apply.

MR. ALPER responded that to the best of the division's knowledge, and it won't know for sure until the annual tax true-ups are seen at the end of March, every single month of calendar year 2015 was a minimum tax month. Therefore, whatever Per-Taxable Barrel Credits were foregone, are foregone and not recoverable. In calendar year 2016 and being only two months in, everyone is hoping for a substantial price recovery, in which case this will come into play at the end of the year in April 2017 when those taxes are trued-up.

2:59:29 PM

REPRESENTATIVE SEATON questioned whether there would be any going back and having a tax calculation that was paid previously in January or February or March. He surmised that because they were all at minimum tax an adjustment would not be made.

MR. ALPER answered correct. Pointing to the graph [on slide 43], he said that October and November look like what every month in 2015 looked like. There is a minimum tax payment, there's a certain amount of Per-Taxable Barrel Credit that was used, it varied, it got smaller and smaller as the prices went down later in the year, and then there was a certain amount of those Per-Taxable Barrel Credits that was foregone. So, there would literally be no green bar against which to apply anything in all of calendar year 2015.

3:00:22 PM

REPRESENTATIVE HERRON asked why Mr. Alper continues to use the word "phenomenon," and whether it is being used because Mr. Alper questions the fact or the situation.

MR. ALPER apologized if the word seems inappropriate. He said it was an unexpected occurrence based upon the division's intuitive understanding of how the tax was supposed to work and then in practice it was different. He offered that he doesn't know what the appropriate word is to describe that, and it is by no means magical. Everything the division has seen is a literal interpretation of the statutes as they are written.

REPRESENTATIVE HERRON said he is trying to understand because normally it means that it's a fact or a situation that is happening or occurring, "but you're also at the same time, you're questioning it, and I just want to make sure I understand why you use the word so much."

[HB 247 was held over.]

3:02:15 PM

ADJOURNMENT

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