HOUSE FINANCE COMMITTEE
March 3, 2021
1:34 p.m.

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CALL TO ORDER

Co-Chair Foster called the House Finance Committee meeting to order at 1:34 p.m.

MEMBERS PRESENT

Representative Neal Foster, Co-Chair
Representative Kelly Merrick, Co-Chair
Representative Dan Ortiz, Vice-Chair
Representative Ben Carpenter
Representative Bryce Edgmon
Representative DeLena Johnson
Representative Andy Josephson
Representative Bart LeBon
Representative Sara Rasmussen (via teleconference)
Representative Steve Thompson
Representative Adam Wool

MEMBERS ABSENT

None

PRESENT VIA TELECONFERENCE

Dan Stickel, Chief Economist, Economic Research Group, Tax Division, Department of Revenue; Colleen Glover, Director, Tax Division, Department of Revenue.

SUMMARY

PRESENTATION: ORDER OF OPERATIONS BY THE DEPARTMENT OF REVENUE

Co-Chair Foster reviewed the meeting agenda. He remarked that the presentation was not meant to spur an oil tax policy debate.

^PRESENTATION: ORDER OF OPERATIONS BY THE DEPARTMENT OF REVENUE

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DAN STICKEL, CHIEF ECONOMIST, ECONOMIC RESEARCH GROUP, TAX DIVISION, DEPARTMENT OF REVENUE (via teleconference), provided a PowerPoint presentation titled "Order of Operations Presentation: House Finance Committee," dated March 3, 2021 (copy on file).

Co-Chair Foster observed that the PowerPoint was complex, and the committee would take questions throughout the presentation. He asked committee members to be cognizant of the time.

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Mr. Stickel shared that the purpose of the presentation was to present a high-level overview of how Alaska's oil and gas production tax worked for the North Slope. He noted that the discussion was likely a refresher for some committee members, but the hope was to help viewers less familiar with oil taxes to better understand the current system. He moved to slide 2 showing a list of acronyms pertaining to the oil and gas industry. He shared that the industry and tax system tended to have a lot of jargon and he would try to minimize them as much as possible. The slide acted as a reference of terms.

Mr. Stickel turned to slide 3 and reviewed the presentation agenda. He noted that the presentation was not intended to talk about policy, but to make sure there was a solid understanding of how the existing tax system worked for North Slope oil. He would begin by reviewing all of the sources for oil and gas revenue to the state, followed by a detailed explanation of each step of the production tax calculation. The presentation would look at FY 22 per the fall 2020 forecast. The end of the presentation included a five-year overview from FY 19 to FY 23.

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Mr. Stickel turned to a disclaimer on slide 4. He shared that the analysis was attempting to break a complex tax system down into understandable pieces. He elaborated that the analysis was based on aggregated data and the

Department of Revenue (DOR) fall forecast estimates of various items in the tax calculation. He clarified that he was an economist, not an auditor; therefore, anything he said was not an official tax interpretation. The presentation was a review of the revenue forecast to illustrate the tax calculation.

Mr. Stickel advanced to slide 5 titled "Oil and Gas Revenue Sources." He highlighted that Alaska received oil and gas revenue from four primary sources [state royalty, corporate income tax, property tax, and production tax]. State royalty was received for any production from state land. Alaska also received a share of royalty from production on federal land. Corporate income tax was based on worldwide income apportioned to Alaska, which applied to many, but not all of the companies operating in the state. Property tax applied to all property anywhere in the state and within the state's three-mile limit. Production tax was the severance tax on Alaska's oil and gas. He noted that production tax also applied to all production anywhere within the state and within the state's three-mile limit offshore.

Mr. Stickel added that with a couple of the revenue sources, royalty in particular, not all oil was the same. He relayed there was a slide at the end of the presentation focused on how production from different categories of land was treated for revenue purposes.

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Mr. Stickel moved to a table on slide 6 showing a five-year comparison of state revenue from oil and gas revenue sources from FY 19 to FY 23. He noted that the property tax reflected on the slide represented the state's share only (an additional amount of property tax went to municipalities including the North Slope Borough). The corporate income tax applied only to C corporations under federal tax law. There were some temporary impacts to the corporate income tax in FY 20 through FY 22 that had to do with the federal tax law changes in the federal Coronavirus Aid, Relief, and Economic Security (CARES) Act discussed in the DOR fall forecast presentation several weeks earlier.

Representative Wool referenced corporate income tax and C corporations. He remarked that BP had been sold as a C corporation to Hilcorp, which was an S corporation. He

asked if Hilcorp was the only notable S corporation in the oil production world. He asked if there were other small corporations that were not at the forefront like Hilcorp.

Mr. Stickel answered that the department could not speak to whether any specific company was a taxpayer or what their corporate status was due to taxpayer confidentiality rules. He relayed that there were multiple producers in the state that were not C corporations and would be passthrough entities. Those producers represented about 30 percent of the total oil and gas production in Alaska.

Representative Wool asked for verification that all of the S corporations accounted for 30 percent of the oil production on the North Slope. He believed that Mr. Stickel's statements meant there was more than one S corporation. He understood that Mr. Stickel would not disclose confidential information. He noted that some of the companies were common knowledge.

Mr. Stickel clarified that the 30 percent represented production from companies that were not subject to the corporate income tax. The group encompassed various passthrough entities including S corporations and partnerships.

Mr. Stickel continued to review a table showing a five-year comparison of state revenue on slide 6. The third line showed production tax, which was the focus of most of the presentation. The fourth line showed state royalties, which included royalty revenue in addition to related bonuses, rents, and interest. The table reflected total royalties to the state, which included the share of royalties going to the Permanent Fund and school fund [Public School Trust Fund]. The fifth line showed Constitutional Budget Reserve (CBR) Fund settlements, based on assessments or disputes regarding any prior year production tax royalty or other oil and gas taxes; the funds were deposited to the CBR per the state constitution. The last oil and gas revenue source was shared revenue from the Natural Petroleum Reserve-Alaska (NPRA). He detailed that 50 percent of any of the federal royalties and related revenues from NPRA were shared back to the state. He noted there were special provisions outlining how the funds could be spent by the state. He added that revenue from the NPRA was relatively small currently; however, as new developments came online,

it was expected to become a larger revenue source in future years.

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Mr. Stickel addressed the fiscal system order of operations on slide 7 as follows: royalties, property tax, production tax, state corporate income tax, and federal corporate income tax. Royalties were first and were based on the ownership of the land. He detailed that landowners received their share of the resource off the top before any taxes were applied. Property tax came second - state and local property taxes were considered lease expenditures that could be applied against production tax. Production tax came after royalties were subtracted and it allowed property tax as a deduction. State corporate income tax used worldwide income as part of the tax base. He noted that property tax and production taxes were excluded from the state income tax base. Last was federal corporate income tax, which allowed all state taxes including the state corporate income tax, to be deducted when calculating the federal corporate income tax.

Representative Johnson asked if there would be a separate overview on royalties and deductions that were taken from the state's royalty share.

Co-Chair Foster asked Mr. Stickel if the information was included in the presentation.

Mr. Stickel answered that the focus of the current presentation was on production tax. The purpose of slide 7 was to put production tax in context. He believed in prior years the Department of Natural Resources (DNR) had provided a similar overview presentation on royalties. He deferred to DNR on the royalty calculation.

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Mr. Stickel moved to a table showing the production tax order of operations for FY 22 on slide 8. Due to the abundance of information in the table, there were a handful of slides on the topic [slides 8 through 13]. He relayed the table was based on the income statement in Appendix E of the DOR Revenue Sources Book. He began with the fall forecast average oil price of $48 per barrel and the forecasted daily production of 439,600 barrels to calculate

the annual barrels and the dollar value of production. He reported that the focus for the next several slides would be on the total annual value of $7.7 billion and how it was split and taxed. He pointed out that the information was an aggregation of the tax calculation for the North Slope only. He noted that the North Slope accounted for the largest portion of the production tax revenue.

Mr. Stickel reviewed the income statement on slide 9. The first step was calculating taxable barrels. He detailed that any royalty barrels were subtracted regardless of the ownership of the barrels. Typical royalty rates were one-eighth (12.5 percent) or one-sixth (16.67 percent). He noted that rates varied by field. Federal and private land royalty was subtracted in addition to state royalty. The adjustment also subtracted any production not subject to tax located in federal waters, which included a small portion of North Star production and fields like Liberty. The department was estimating 141 million taxable barrels for a total taxable value of $6.8 billion.

Representative Wool looked at the total annual production value highlighted on slide 9. He stated his understanding that royalty value had been deducted. He did not know whether the slide showed a deduction of one-eighth or other. He surmised that royalty was deducted because a certain percentage of the oil produced belonged to the state and was calculated in barrels. He asked for verification that the barrels were converted to dollars and the value of the oil was deducted from the $48 per barrel price to arrive at a price of $38. He thought the calculation reverse engineered the price based on the deduction of barrels paid in royalty.

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Mr. Stickel reiterated that the calculation of taxable barrels began with the total annual production estimated at 160 million barrels; of the total, DOR estimated 19 million barrels would be royalty [and federal] barrels, which were not subject to production tax. The resulting taxable barrels came out to 141 million. Given an estimated oil price of $48 per barrel, the total value was estimated at $6.8 billion. He noted that the calculation was limited to determining the tax base for the production tax.

Mr. Stickel turned to slide 10 and reviewed the calculation for the gross value at point of production (GVPP). He shared that the term was used widely in production tax and royalty and was also know as the wellhead value. To get to the GVPP, transportation costs (also known as netback costs) were subtracted. He began with the sales price at market of $48 per barrel and subtracted the transportation cost to determine the wellhead value. The $48 per barrel price was at the West Coast at major destinations of Long Beach, CA and Anacortes, WA. He explained that marine tanker costs, Trans-Alaska Pipeline System (TAPS) tariff, any feeder pipeline tariffs, and other [inaudible] adjustments were subtracted from the per barrel price. In FY 22, transportation costs of just under $10 [per barrel] resulted in an average GVPP of $38.09 per barrel. The total worked out to $5.4 billion GVPP.

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Mr. Stickel turned to slide 11, which began the process of getting to the production tax value. The production tax was essentially a modified net profits tax. He explained that companies were able to deduct capital and operating expenditures when calculating their tax base. The department used Internal Revenue Service (IRS) guidelines to define what constituted a capital expense. Companies were not required to use any depreciation for production tax; companies received an immediate deduction of all capital costs in the year incurred. Operating expenditures were any allowable expenditures other than the capital expenditures. Generally, operating costs included the ongoing costs of operations and labor.

Mr. Stickel highlighted the terms allowable and deductible lease expenditures. Allowable lease expenditures included any cost of a unit directly associated with producing oil. He noted that not everything was allowable, such as financing costs, lease acquisition costs, litigation costs, dismantlement, removal, restoration, and other. Deductible lease expenditure was a term of art developed by DOR for presentation purposes. He noted that the term was not part of any statute or regulation. Deductible lease expenditures were the portion of allowable lease expenditures that were applied in the tax calculation in the year incurred, up to the gross value. He clarified that nondeductible lease expenditures included any allowable expenditures beyond a company's gross value, which could be turned into

carryforwards that could be potentially used to offset production taxes in future years.

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Representative Josephson looked at slide 11. He recalled that in HB 111 several years back, the legislature effectively said that if a company had operating and capital expenditures and no production, it could deduct the expenditures against future production for a period of seven to ten years. He remarked that a company would need to be fairly confident that it would begin production relatively soon or it may be stuck with the costs. He asked if his statements were accurate.

Mr. Stickel replied in the affirmative. He explained that the situation described by Representative Josephson was a nuance of the carryforward lease expenditures. He elaborated that if a company earned the carryforward lease expenditures, the expenditures began to decrease in value beginning in the eighth or eleventh year after being earned.

Representative Josephson stated that one of the impacts of the reform was that companies needed to have confidence in their production plan and have good geologists.

Mr. Stickel responded that before HB 111, a company had been able to get a credit for lease expenditures that were not applicable against a tax liability. He explained that the credit could in some ways be cashed out by the state. The current system gave companies the ability to carryforward lease expenditures. Depending on whether a company had a future tax liability, it may or may not be able to receive the full value of the carryforward. He stated that the system impacted decision making and the economics of making investments.

Vice-Chair Ortiz looked at the downstream transportation costs category on slide 11. He asked if the amount varied. He believed the number reflected a percentage of the per barrel value. He wondered if any other factors caused the transportation figure to change.

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Mr. Stickel replied that there were several important variables impacting transportation costs over time. One variable was the overall level of production. Specific to TAPS, more production going through the pipeline meant that fixed operations costs were distributed over a greater number of barrels, which resulted in lower per barrel costs. He relayed there was a transportation cost variance between the different fields. He expounded that some fields had feeder pipelines and tariffs were paid on those lines, whereas Prudhoe Bay did not have a feeder pipeline and oil went directly into TAPS.

Representative Wool looked at the deductible operating expenditures of $2.3 billion and deductible capital expenditures of $2 billion under the value column on slide 11. He surmised that the calculation included dividing by the number of barrels to get the per barrel expenditures. He asked for verification that no one calculated their expenditures per barrel initially.

Mr. Stickel replied in the affirmative.

Representative Wool referenced Vice-Chair Ortiz's question on transportation [costs]. He remarked that transportation costs depended on production because the more oil produced, the cheaper it was to move per barrel. He wondered if the value of the pipeline was used as a production cost, whether the cost diminished over time because the pipeline had been paid for "a few times over." He wondered if it was cheaper to move oil through the pipeline over time, aside from maintenance costs.

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Mr. Stickel deferred the question to a colleague. He stated the department could follow up.

COLLEEN GLOVER, DIRECTOR, TAX DIVISION, DEPARTMENT OF REVENUE (via teleconference), replied that common carrier pipelines were regulated by federal and state governments. There were specific provisions on what the pipelines could charge. She explained that a cost of service model was used to recoup cost and return on investment. The return amount varied over time. She stated that it was a function of the cost it took to run a pipeline and the [oil] volume traveling through.

Representative Thompson recalled that several years back there had been a conversation about the deduction of capital or operating expenses. He believed there may have been a move for worldwide companies to try out new drilling methods or ways to extract more oil from sands in Alaska because they could deduct all of the costs from taxes and production. He asked if he was remembering the situation accurately.

Mr. Stickel answered that Alaska had been through several oil tax debates and there had been discussion in previous debates about the motivations behind some of the spending that took place. He communicated that he would prefer not to rehash the debate during the current meeting if it could be avoided.

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Mr. Stickel addressed the production tax value (PTV), which was the tax base for the production tax (slide 12). He detailed that the PTV is calculated by subtracting deductible lease expenditures from the GVPP. He explained that PTV reflected the net profit on the North Slope. He informed the committee that each company calculated its PTV based on all of its North Slope activity, including all fields and any new developments the company was undertaking.

Mr. Steininger advanced to slide 13 and explained there were two parallel calculations done and the final tax ended up being the higher of the two. In addition to the PTV, there was a tax calculation of a minimum tax floor. The minimum floor was 4 percent of GVPP when oil prices were greater than $25 per barrel for the year. He relayed that if oil prices averaged less than $25 per barrel for one year, the minimum tax rate would decrease below 4 percent. For FY 22, the department was forecasting a minimum tax rate of 4 percent applied to the GVPP of $5.4 billion, for a total minimum tax floor of about $215.5 million.

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Representative Wool asked about the $74.5 [million] deduction in the net tax.

Mr. Stickel answered that he would provide further information in the upcoming slides. He explained that slide

13 focused on the two side-by-side calculations of the minimum tax floor and the net profits tax. He would review both calculations.

Mr. Stickel turned to slide 14 titled "Gross Value Reduction." He explained that the gross value reduction (GVR) was an incentive for new development that was enacted as part of the SB 21 (oil and gas production tax legislation passed in 2013). The GVR was a temporary benefit used to refer to oil from qualifying new fields. He detailed that the GVR expired after seven years of production or any three years where oil prices exceeded $70 per barrel. The GVR allowed a company to exclude 20 or 30 percent of the gross value from the qualifying fields when calculating its production tax value, which reduced the net tax calculation for the fields. The 20 percent was for new fields and the 30 percent applied if a field was comprised exclusively of state issued leases with greater than 12.5 percent royalty.

Mr. Stickel continued to review the GVR on slide 14. He stated that another wrinkle related to the GVR was that eligible production received a flat $5 per barrel of taxable production credit that could be used to reduce tax below the minimum tax for any companies that did not take a sliding scale credit. He would address the distinction between the per barrel credits in several slides.

Vice-Chair Ortiz referred to slide 13 and the minimum tax calculation of $215.5 million, reflecting the floor tax of 4 percent. He looked at the bottom of the "Value" column and observed that $163 million was actually paid. He asked what enabled a company to go below the minimum floor in actual taxes paid.

Mr. Stickel answered that he had been planning to address the question later in the presentation, but he would address it at present. He explained that the minimum tax floor on slide 13 reflected an aggregate calculation. He clarified that in reality, each company calculated its own minimum tax. He elaborated that if a company chose not to take any sliding scale per taxable barrel credits, it may use other credits to take its tax liability below the minimum tax. The minimum tax was a hard floor for companies that chose to take the sliding scale per taxable barrel credits; however, if a company opted to forgo the sliding scale credits, it could use other credits to go below the

minimum tax. He reported that DOR's official revenue forecast assumed that at $40 per barrel oil, some companies would elect not to use the sliding scale credits in order to pay below the minimum tax.

Mr. Stickel reviewed the calculation of the net tax, including the GVR, on slide 15. He highlighted that the headline net tax rate was 35 percent of PTV. The slide showed the impact of the GVR, which applied to companies with a positive production tax value that were able to reduce it with the GVR provision. The 35 percent tax rate applied to the PTV after GVR yielded a net tax of $367 million for FY 22.

Mr. Stickel moved on to review tax credits against liability on slide 16. The major credits were the per taxable barrel credits, which were actually two separate credits in statute. The first was the $5 per barrel credit for GVR eligible oil and the other was a sliding scale credit for non-GVR oil. The vast majority was the non-GVR credits, but it could change with major new fields coming online in the future. There was an $8 sliding scale credit for non-GVR production fields at wellhead values of $80 and below. The credit gradually stepped down to zero at wellhead values greater than $150 per barrel of taxable production. He reiterated his earlier statement that the non-GVR sliding scale credits could not be used to reduce the tax below the minimum tax. Additionally, any companies claiming the credit could not use other credits to pay below the minimum tax.

Mr. Stickel stated that the GVR eligible production credit could be used to reduce tax below the minimum floor if companies did not take any sliding scale credits. He reported that the per taxable barrel credits were "use it or lose it" and could not be carried forward or refunded. In FY 22, DOR was estimating that $186 million in per taxable barrel credits would be deducted in calculating the tax liability even though $1.1 billion in per taxable barrel credits would be generated. He reiterated his previous statements that a company could only use credits to get down to the minimum tax for the sliding scale and in some instances to go below the minimum floor with non-sliding scale credits. Other tax credits against liability included small producer credits.

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Mr. Stickel moved to slide 17 and reviewed other items and adjustments in the production tax calculation. The slide showed a reconciliation of the simple calculation with DOR's official revenue forecast for FY 22. The adjustments number included any prior year tax payments or refunds, private landowner royalty interest, hazardous release surcharge or "nickel per barrel tax", any taxes on gas on the North Slope, any net tax liability from Cook Inlet oil and gas, and any additional company specific details in the tax calculation. For FY 22, the $163.3 million represented the fall forecast of total cash into the General Fund from the production tax. The department was also estimating an additional $563 million of nondeductible lease expenditures were expected to be carried forward and would potentially be available to apply against future year tax liabilities.

Mr. Stickel referenced an earlier question asked by Vice-Chair Ortiz and reiterated his earlier answer. He stated that some people would look at the $163.3 million of total production tax and ask why it was lower than the minimum tax of $215.5 million. He explained it was because the minimum tax was applied on a company-by-company basis. He elaborated that companies could not go below the minimum tax if they used any sliding scale per taxable barrel credits, but DOR was forecasting that at $48 per barrel oil prices, some companies would choose to forgo the sliding scale credits and use other credits to reduce their payments below the minimum tax. Consequently, when all of the companies were added together, the net tax calculations collections were below the aggregate minimum tax calculation in the forecast.

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Representative LeBon asked if there was an example of what qualified as other credits a company could use against liability.

Mr. Stickel answered that the small producer credit was an example of other credits against liability. He elaborated that it was a credit of up to $12 million per company. A sunset had been on the small producer credit several years back but some companies still had eligibility for the credit. Another example was the net operating loss credit earned prior to 2018 that companies still had on the books.

Representative Wool observed that after taking away royalties and transportation, GVPP was $5.38 billion, and the total paid to the state was $163 million. He could see why people were scratching their heads related to the specific portion. He asked if the royalty of $912 million went to the state in its entirety. He believed it would bring the state take up to about $1 billion.

Mr. Stickel answered that the majority of the royalty went to the state. He referred back to slide 6 and reported that DOR was estimating that the state royalty was $797 million plus an additional $12 million of shared royalty from the NPRA. The $912.9 million included state royalties, the value of federal royalties retained by the federal government, and the value of private landowner royalties. The adjustment included any production in federal waters beyond the state's three-mile limit, which represented a small share of production from the North Star field.

Representative Wool stated his understanding that the state received $163 million plus royalties. He looked at new net lease expenditures earned and carried forward at a total of $562 million. He asked if carryforwards from the year before had been or would be applied towards the $163 million.

Mr. Stickel answered there would potentially be carryforwards earned in prior years. The department was not estimating that any prior year carryforwards would be applied in FY 22. He relayed that any carryforwards were applied at the lease expenditure stage. The idea was that $562 million became a potential addition to lease expenditures in a future tax year.

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Representative LeBon looked at the top of slide 17 that showed royalty and federal barrels value at approximately $913 million. He remarked that a portion of the value was deposited into the Alaska Permanent Fund. He understood the amount depended on the field and which formula was used. He asked approximately how much of the $913 million would flow to the Permanent Fund.

Mr. Stickel confirmed that a portion of the state royalty flowed to the Permanent Fund. He explained that the number was between 25 and 50 percent depending on when the lease

was issued. He reported that the average Permanent Fund share was about 30 percent of state royalties. He referenced page 38 of the DOR Fall Revenue Sources book and highlighted the department's forecast that $199.2 million of oil and gas royalties and related revenue would go to the Permanent Fund in FY 22.

Representative Josephson referenced language "net new lease expenditures" at the bottom of slide 17. He asked for verification that the new lease expenditures would appear under North Slope lease expenditures in a future year.

Mr. Stickel replied, "That's correct, potentially."

Representative Josephson asked if the total tax paid would be less than $163 million in FY 22. Alternatively, he asked if it was hard to predict because there would be new production/revenue in addition to the expenditures.

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Mr. Stickel responded that a company could opt to carry forward lease expenditures. Generally, companies applied carried forward lease expenditures only if they would expect to be paying above the minimum tax in a future year. A company would have to have sufficient future year revenue to be able to benefit from the lease expenditures. Additionally, in terms of production, there was a provision that in order to use a carry forward lease expenditure, a company had to have production from the field where the lease expenditure was earned.

Representative Josephson recalled that when discussing state revenue 10 years back, people talked about tax, but royalty was an afterthought. He remarked that the state had brought in $6 billion to $7 billion in peak years and currently it was looking at $163 million. He asked about the accuracy of his statements.

Mr. Stickel replied that it was true that production tax represented a significantly larger share of the state's oil and gas revenue in prior years. He reported that production tax generated $6.1 billion in FY 12 out of slightly under $10 billion in total oil revenue that year.

Representative Josephson stated that no one disputed that the [oil] price was lower [at the present day]; however,

people disputed whether the economy at large in the form of jobs in the private sector, benefitted from SB 21 and whether the state was encouraging more production that would not be there "versus the change in tax." He understood that Mr. Stickel did not want to revisit the topic during the current meeting.

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Representative Wool surmised that the transportation costs changed over time based on the tanker charge. He believed the pipeline cost was fairly fixed. He referenced a time in the past when production had been 1 million barrels per day. He used 2012 as an example and asked how high production impacted transportation cost.

Mr. Stickel answered that it would be necessary to go back to the early 2000s to reach production of 1 million barrels per day. He referenced a 10-year history on page 105 of the DOR Revenue Sources Book. He reported that in 2011 the total transportation charge had been $6.67 per barrel. He stated that the transportation charge had been somewhat lower at that point.

Representative Wool asked for the production and the price of oil at the time.

Mr. Stickel replied that the price of oil had been $94.49 per barrel [in 2011] and North Slope production had been about 600,000 barrels per day. He explained that there were several costs that impacted transportation costs over time. He elaborated that for some elements like TAPS, the total production level was a very important factor. Other elements moved with price and inflation. For example, one of the important factors influencing tanker cost was the price of the fuel. Historically, the general trend was that transportation cost had increased over time, while production had decreased. There had been a stabilization of the transportation cost over the past several years, which had been concurrent with a stabilization of production on the North Slope.

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Representative Wool observed that price of fuel would impact tanker cost. He expected the tanker cost to be higher at $94 per barrel oil. He remarked that 600,000

barrels per day was higher than the current daily production of 500,000 barrels. He found the cost of transportation interesting and stated that on a $48 barrel, $10 went to transportation. He noted it was not lost that the people who owned the oil and the pipeline likely owned the tankers as well. He commented that it was not a bad thing that the owners could get a good transport fee for their oil.

Representative Thompson stated that in the past when there had been much more oil running through the pipeline, the oil friction would heat it up. He understood that at production of 500,000 barrels per day the oil had to be heated during periods of cold weather in order to keep it flowing. He asked if there was a fixed cost per year for heating oil.

Mr. Stickel replied in the affirmative. He stated his understanding that TAPS had added additional heating capacity and the costs worked their way through the tariff calculation and were eventually passed on to the shippers.

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Representative LeBon considered the price of oil and where it had fallen since 2014. He asked if aside from employment on the North Slope and the volume of oil running through the pipeline, whether the state was better off with production tax revenue under SB 21 than under Alaska's Clear and Equitable Share (ACES) when considering the price of oil over the past six years.

Mr. Stickel responded that it was the $1 million question. He was not prepared to opine on an answer to the question. His goal for the presentation was to provide an understanding of how the current tax calculations worked.

Representative LeBon remarked that the topic had been brought up and he had wondered if Mr. Stickel had some insight into whether the state benefitted from SB 21 versus ACES at an average lower price of oil over the past six years.

Vice-Chair Ortiz stated he was not a tax accountant. He asked if it was safe to say that under Alaska's oil tax system, the effective tax rate was different for each company.

Mr. Stickel replied in the affirmative. He expounded that each company had a separate tax calculation based on the different fields and developments it was involved in. He confirmed that the effective tax rate varied between companies.

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Vice-Chair Ortiz asked about the range of the effective tax rates paid by companies across the state.

Mr. Stickel responded that he did not have the analysis in front of him and he would follow up with the information.

Mr. Stickel moved to slide 18 showing a five-year overview from FY 19 to FY 23. He detailed that production tax value had declined annually from $5.1 billion in FY 19 to the forecasted $1.1 billion in FY 22 and less than $1 billion in FY 23. He reported that FY 21 through 23 were forecasted as minimum tax years under the fall forecast. He elaborated that it meant that generally companies were able to use credits to bring production tax down to the minimum level. At the forecasted oil prices, DOR estimated that some companies would choose to forego the sliding scale credits and use other credits to pay below the minimum tax. He added that the phenomenon was seen in all three of the years where the estimated production tax to the state was below the calculated minimum tax floor.

Representative Josephson noted that in the past, the tax floor had been hardened by either HB 111 or HB 247. He asked for verification there was nothing that prohibited the legislature from hardening the floor further. He asked for confirmation there was no contract doctrine or common law doctrine that would prevent the legislature from specifying that a 4 percent floor meant a 4 percent floor.

Mr. Stickel replied affirmatively.

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Mr. Stickel relayed that he had concluded the main body of the presentation. There were several additional slides that had been requested when the presentation had been provided to the other body. He turned to slide 19 showing how revenue would be impacted by different levels of the

sliding scale per taxable barrel credit. Currently the sliding scale credit went up to $8 per taxable barrel. The table on slide 19 showed what the FY 22 tax calculation would look like assuming a maximum value of $5, $4, or $3 per taxable barrel. He explained that not all of the per taxable barrel credit was used due to the tax floor and in some cases, companies could use other credits to make up for a reduction in the per barrel credits. He reported that an impact on production taxes from a credit change of $1 was less than $1 multiplied by the number of barrels. He detailed that changing maximum per taxable barrel sliding scale credit from $8 to $5 would increase estimated production tax revenue from $163 million to $180 million for FY 22. Production tax revenue would be $207 million under a $4 maximum credit and $234 million under a $3 maximum credit.

Mr. Stickel clarified that DOR was not making a policy suggestion, the department was showing information that had been requested by the other body [Senate] in the past. He remarked that any changes in the credit would have impacts on investment and the economics.

Mr. Stickel moved to slide 20 titled "Illustration Assuming a Single North Slope Taxpayer: FY 2022." He remarked that the information on the slide related to an earlier question asked by Vice-Chair Ortiz. He stated that currently some companies paid at or above the minimum tax, while others chose to forgo the sliding scale credits to reduce payments below the minimum tax. Consequently, the FY 22 production tax forecast was less than the aggregate minimum tax calculation. Whereas slide 20 reflected that if there were only one taxpayer, the department expected the company would use sliding scale credits to reduce its tax liability down to the minimum tax (meaning it could not go below the minimum tax). Under the illustration, the total production tax to the Treasury would be $229 million in FY 22 compared to the $163 million in the official forecast. The slide highlighted the impact of individual company economics on the tax. He noted that each company had a different portfolio of operations and investments.

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Mr. Stickel concluded on slide 21 titled "State Petroleum Revenue by Land Type." The slide showed how state petroleum revenues varied by land type. He noted that the basic

concept was not all oil was the same. He detailed that production, corporate, and property taxes applied everywhere in the state except for federal waters beyond three miles offshore, regardless of the ownership of the land. Whereas the royalty varied depending on the ownership of the land. He elaborated that there were different royalty provisions depending on whether the land was state, private, or federal.

Mr. Stickel noted there had been a question the previous day about oil prices that he would like to address. He shared that the question had pertained to oil prices and why Alaska's oil prices had diverged from Brent crude prices in 2020. He explained that Alaska North Slope (ANS) was not a widely traded crude; therefore, DOR liked to compare its price to a global benchmark. The department used Brent crude as the closest comparison, which was a similar quality, and both had access to world markets by tanker (also known as "waterborne"). Typically, ANS and Brent crude were priced very similarly with only slight differences in value. He noted that ANS may trade for a dollar or two higher or lower than Brent at any given time.

Mr. Stickel elaborated that at the end of March 2020, ANS and Brent had been near parity; however, beginning in April the estimated value of ANS dropped below Brent and the discount got as large as $28.25 per barrel on April 20. He reported that it had been the day ANS prices were estimated at a negative value, the lowest price on record, while Brent prices had remained over $25. The divergence had lasted through April and the first part of May and by May 20, ANS prices had been back to trading in tandem with Brent.

Mr. Stickel addressed the reason for the divergence between ANS and Brent prices. He explained there had been significant turmoil in the oil market in the spring of 2020. There had been an unprecedented demand drop as COVID-19 had started to unfold and oil storage had filled rapidly, tremendous uncertainty in the oil markets had occurred. The department believed the ANS/Brent divergence reflected West Coast and Pacific specific market dynamics. The West Coast and Pacific had seen some of the largest drops in demand and at the same time storage in the market had been filling rapidly. He elaborated that at one point there had been dozens of oil tankers parked offshore California looking for a place to put their oil. For a

period of time, when they were trying to sell ANS it had been selling into an extremely oversaturated market. Eventually, the markets worked through the supply/demand and ANS prices had returned to their historical relationship with Brent. Unfortunately, part of that supply/demand balance had involved temporary curtailments in Alaska production, which was one example of how the markets came back into balance.

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Representative LeBon stated that most of the oil from Alaska went to the West Coast. He asked what percentage went east. Additionally, he wondered what factors determined whether oil was shipped to West Coast refineries or international markets.

Mr. Stickel answered that historically most ANS oil went to the West Coast, which was still the case. There were some examples of oil being shipped overseas to Asia markets. The department had spoken with several industry experts about the phenomenon and there were a couple of potential factors. One was the changing mix of oil and gas producers in Alaska. He elaborated that the state was moving from a situation where companies had largely been fully integrated where they owned the oil fields, production, refineries, and distribution. He reported that some companies were moving away from the model and were opting to limit their operations to producing and selling product to the market. Another impact was taking advantage of pricing trends in the U.S. versus Asia. He explained that if a company was selling into a market and did not necessarily own the refinery, it would look to where it could get the best price; sometimes the best price was the West Coast and other times it was in Asia.

Representative LeBon stated that Alaska did not have a say in where the oil went, whether it was the West Coast or the Far East. He asked if Alaska was disadvantaged if the oil went to an international destination versus the West Coast.

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Mr. Stickel answered that the one place the state had a say was in state royalty oil, some of which was taken by the Department of Natural Resources and sold to the instate refineries. From a tax perspective, DOR assumed a company

would act in its best interest to get the best value for its oil. He noted that the state benefitted when a company received the best possible value for its oil.

Representative Wool thanked Mr. Stickel for the presentation. He referenced a comment by Representative Josephson earlier related to incentives and tax credits. He found it concerning that the production curve did not appear to be going in the right direction, regardless of incentives. He observed that the bottom line of $163 million with $5.8 billion after royalties seemed like a pittance. He reasoned the price was low and he thought it was the driver of much of the production "stuff." He was interested in the transportation aspects, including pipeline and tanker costs, and hoped to go more into depth on the issue at another time. He speculated that because much of the transportation was owned by the same corporations, perhaps there was not a lot of incentive to lower the price. He thought there was an incentive in Alaska. He thanked Mr. Stickel for his presentation.

2:50:21 PM

Vice-Chair Ortiz thanked Mr. Stickel for his presentation. He asked if Mr. Stickel had always worked with DOR. He wondered if he had worked with the Department of Natural Resources (DNR) in the past.

Mr. Stickel answered that he had been with DOR for his entire state career beginning in 2004. He had started as a non-petroleum economist and had subsequently worked as a petroleum economist. He reported that he had shifted into a management role about 10 years back.

Vice-Chair Ortiz asked if the Mr. Stickel's duties included production forecasting.

Mr. Stickel answered that he was involved in the process. He explained that DOR worked collaboratively with DNR on the production forecast, but DNR was the lead.

Vice-Chair Ortiz stated that the production forecasts looked like they would stay at about 500,000 barrels per day for the coming 10 years. He recalled that in 2012/2013 when SB 21 had been debated and eventually passed, there had been talk about increasing production to 1 million barrels per day. He asked what had changed in the world

situation or Alaska's situation that had caused production to be much lower, likely around 500,000 barrels per day for the next ten years.

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Mr. Stickel replied that it was a topic that could warrant its own presentation. He believed that the production goal of 1 million barrels per day had been aspirational in nature. Over the past decade, oil prices had fallen significantly from where they had been in 2013. There had been some potential sources of new production that had not come to fruition, such as the Outer Continental Shelf. He reported there were many different factors that had contributed to not reaching the goal.

Vice-Chair Ortiz surmised the production was not likely to get to that amount in the near future.

Mr. Stickel answered that as Vice-Chair Ortiz had observed, the production forecast anticipated fairly stable production over the next ten years.

Representative Thompson recalled that the state had been losing about 6 percent throughput per year. He stated that when SB 21 had passed, there had been projections that without the passage of the bill, production would be down to 300,000 barrels per day. He remembered being told the pipeline would likely have to be shut down if production declined to that level. He highlighted that SB 21 had passed [the legislature]. Subsequently, the 6 percent decline had ceased, and production had increased. He asked if he was remembering the situation accurately.

Mr. Stickel answered that his goal was not to rehash any past oil tax debates during the presentation. He confirmed there was a correlation, and oil production had roughly stabilized over the past eight or so years.

2:55:18 PM

Representative Wool referenced a time when the price of oil had dropped into the negative for a given amount of time. He remarked that there had been a glut of oil and the pipeline had been throttled down in response. He reasoned that if the pipeline were to stop functioning, it would not be for mechanical or physical reasons, but due to fiscal

reasons. He asked what would happen if the price of oil was $18 per barrel for a prolonged period and transportation costs were $10 per barrel. He considered whether there would be any money remaining after transportation costs. He surmised that if companies were losing money, at some point the companies would turn off production regardless of the mechanical capabilities of the pipeline. He thought an oil price of $24 per barrel was a decent number in the early days of the pipeline. He wondered if the problem could occur if, for example, there was a glut of oil or people started driving their electric cars.

Mr. Stickel replied that it was a risk. He stated that transportation costs came off the top before a company deducted any cost of production. He used the example of a pie for illustrative purposes and explained that the greater the transportation cost, the less pie remained. He highlighted a situation earlier in the spring where the major companies had elected to curtail production as a result of the low price environment.

Representative Wool considered the numbers and data provided by DOR. He contemplated a scenario where the oil price was $28 per barrel instead of $48 per barrel. He wondered what the breakeven number was for oil companies.

Mr. Stickel answered that the breakeven price would vary by company. He elaborated that in the aggregate, DOR estimated the breakeven price to be somewhere between $40 and $50 per barrel. The fall forecast was just above that point.

Representative Wool highlighted various factors that could influence oil price including a geopolitical event, General Motors' announcement to go to all electric cars in a certain timeframe, or if there was a glut or low demand. He surmised that depending on the circumstances, oil prices could be below $40 for a prolonged period in the near future. He thought some of the fiscal decisions should factor in the possibility. He wondered whether the department thought about the scenario.

Mr. Stickel answered there was always a risk on oil prices. He brought attention to a table in the Revenue Sources Book that included a low and high case. He thought it was good advice to consider how to address the low case scenario. He added that the state had been fortunate that oil prices had increased. He concluded that oil prices had been around the

$60 per barrel range recently; however, there was no guarantee prices would remain at that level.

Co-Chair Foster thanked the presenters. He reviewed the schedule for the following day.

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ADJOURNMENT

3:00:46 PM

The meeting was adjourned at 3:00 p.m.