HOUSE FINANCE COMMITTEE
January 23, 2020
1:33 p.m.

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CALL TO ORDER

Co-Chair Foster called the House Finance Committee meeting to order at 1:33 p.m.

MEMBERS PRESENT

Representative Neal Foster, Co-Chair
Representative Jennifer Johnston, Co-Chair
Representative Dan Ortiz, Vice-Chair
Representative Andy Josephson
Representative Gary Knopp
Representative Bart LeBon
Representative Kelly Merrick
Representative Colleen Sullivan-Leonard
Representative Cathy Tilton
Representative Adam Wool

MEMBERS ABSENT

None

ALSO PRESENT

Sara Longan, Deputy Commissioner, Department of Natural Resources; Pascal Umekwe, Petroleum Reservoir Engineer, Division of Oil and Gas, Department of Natural Resources; Mike Barnhill, Acting Commissioner, Department of Revenue; Dan Stickel, Chief Economist, Department of Revenue; Colleen Glover, Director, Tax Division, Department of Revenue; Representative Sarah Hannan.

PRESENT VIA TELECONFERENCE

Representative Ben Carpenter

SUMMARY

FALL 2019 PRODUCTION FORECAST BY THE DEPARTMENT OF NATURAL RESOURCES

FALL 2019 REVENUE FORECAST BY THE DEPARTMENT OF REVENUE

Co-Chair Foster reviewed the agenda for the day. He indicated Representative Hannan was in the audience. He asked people to hold their questions until the end of the presentation and invited testifiers from the Department of Natural Resources to the table.

^FALL 2019 PRODUCTION FORECAST BY THE DEPARTMENT OF NATURAL RESOURCES

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SARA LONGAN, DEPUTY COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, was joined by her colleague Dr. Umekwe. They would be walking through the PowerPoint Presentation: "Fall 2019 Production Forecast." She recognized and respected that they had a significant amount of information to cover. Mr. Stokes was also present as the new director of the Division of Oil and Gas and the team responsible for preparing the forecast each year.

Co-Chair Foster queried if Mr. Stokes would be joining Ms. Longan at the table. Ms. Longan responded that Mr. Stokes would be available if needed.

Co-Chair Foster indicated Representative Ben Carpenter was online.

Ms. Longan reviewed the presentation outline on slide 2. Dr. Umekwe would walk through an overview and highlights on production including focusing on some North Slope projects that were currently under production and would be reviewing their timelines. In the production forecast the department would review the objectives, provide an overview of methodology, and share near-term and longer-term results.

Ms. Longan turned to slide 3: "State of Alaska: Oil and Gas Resource Potential." She would not spend much time on the slide because members were already familiar with the information. Alaska was a large state and land ownership was important. It could drive royalty shares from various producing leases.

Ms. Logan turned to slide 4 containing a map with greater detail focusing on the North Slope. She pointed out that

the state's royalty share differs across lands of the state. She pointed to the left side of the slide that showed the National Petroleum Reserve Alaska (NPRA) which was managed by the Bureau of Land Management. Royalty rates in NPRA were 12.5 or 16.66 percent. The state received half of the royalties which were distributed through the NPRA Impact Mitigation Grant Fund. The program was managed through the Department of Commerce, Community, and Economic Development (DCCED). Oil production revenues from NPRA were used to fund planning, construction, or maintenance projects to help offset the impacts of NPRA development to the affected communities. If any revenues were left over after all of the projects were financed, 25 percent of the remaining funds could be put towards the Permanent Fund, and other remaining balances could go to the Public-School Trust Fund or the Power Cost Equalization Fund.

Ms. Logan highlighted the middle of the slide which showed the state lands (shown in blue) where the major oil fields existed including Prudhoe Bay and Kuparuk. The royalty rate was 12.5 or 16.66 percent. The state's share was 83 percent to 100 percent. The right-hand side of the map represented the coastal plain of the Arctic National Wildlife Refuge (ANWAR). The royalty rate in ANWAR was 16.66 percent. She furthered that when there was a lease sale, the state's royalty share was 50 percent. She noted the importance of offshore projects. She explained that the state received 100 percent of royalties for any producing acres from zero to 3 nautical miles offshore. Alaska's royalty share was 27 percent for any producing acres 3 to 6 miles offshore. The state did not receive royalties for anything produced beyond 6 miles offshore. The royalty rate for all of the federal leases was 16.66 percent.

Representative Merrick asked how much production was conducted offshore. Ms. Longan responded, "In short, not much."

Representative Wool clarified that the state percentage was a percent of the royalty percentage of 12 or 16 percent. Ms. Longan responded in the affirmative.

Ms. Longan transitioned to the next portion of the presentation which Dr. Umekwe would be presenting. He would be walking through the production forecast and production highlights.

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PASCAL UMEKWE, PETROLEUM RESERVOIR ENGINEER, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, reported that the forecast was the result of an interdepartmental effort between the Department of Natural Resources (DNR) and the Department of Revenue (DOR). There was a team within DNR that worked on the forecast consisting of engineers, geologists, and commercial analysts. The first part of his presentation would cover a comparison between the forecast and actual production as well as highlights on some of the key projects that supported the production seen on the North Slope and in the Cook Inlet.

Dr. Umekwe turned to slide 6: "Fall 2019 Production Forecast: FY 2020 Outlook." The slide compared actual with forecasted production. He pointed to the left side of the slide showing actual production. He indicated that for the previous 5 months of the current fiscal year actual production had been around 490,000 barrels of oil per day which fell in the range of the production forecast. He explained that DNR provided DOR with a range of production because of the level of uncertainties in all of the fields that made up production. The department looked at the reliability of the forecast in terms of the range. The chart demonstrated that actual production had landed within the range the department provided. It was about 2 percent different from the expected mean rate.

Dr. Umekwe moved to slide 7 which showed an overall perspective of the North Slope. He pointed to the top right-hand side of the chart which showed production for the previous 5 years. Production had been somewhat flat in the first 2 or 3 years. For the prior 2 years, FY 18 and FY 19, there was a slight drop in production. The drop averaged to about 2 percent. There had been a 2 percent decline over FY 18 through FY 19. The drop of 2 percent compared well with historical decline rates seen on the North Slope. The data showed a decline of about 4 to 5 percent on the North Slope. However, for the prior 2 years it had remained at 2 percent. He suggested it spoke to the amount of work that producers had done to keep production at its current levels.

Dr. Umekwe indicated that the left side of the slide highlighted some of the fields that supported production.

He noted modest production decline in Prudhoe Bay, about 2 percent in the prior year. He mentioned other fields that had also experienced a modest decline of 2 percent in the previous fiscal year including Kuparuk, Colville River, and Nikaitchuq. There was growth in some of the other units including NorthStar, Milne Point, and Point Thompson over the same period. Some of the fields were shown on the bottom right of the slide. All the bars above zero represented fields that had experienced growth. The bars below zero represented fields that had seen decline.

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Dr. Umekwe advanced to slide 8 showing a status update on a few of the projects mentioned in the department's last presentation. He pointed to the second expansion of the CD5 pad within the Colville River Unit. Next on the list was the GMT Unit within the federally managed Moose's Tooth Unit. Other projects included Pikka, Willow, and Liberty. He pointed to the right column listing rates tied to the projects. The department obtained most of the rates from public sources. The first rate was an internal estimate based on the number of wells that the producer intended to drill. The other rates were based on announced peak rates.

Dr. Umekwe highlighted that often times the estimates changed based on new information from the operators. More details on the specifics of any of the rates seen on the slide could be addressed directly with the operators. He also noted the public numbers. He specified the number for GMT2 was about $1.4 billion; Pikka was about $5 billion; and Willow was between $4 billion to $6 billion. Overall, about $20 billion in spending was needed to bring the projects online. The projects were part of the companies' plans. However, all of the plans could be reviewed based on several factors including oil prices, the fiscal system, costs, and other factors. He noted that the projects competed for capital in the portfolio of each operator. Depending on how the projects competed, capital could be moved.

Dr. Umekwe pointed to some changes in dates from the column, "January 2019" to the column, "January 2020." He explained that often times a project might be scheduled to come online in 2020 or 2021, but because of many factors a project might go dormant. The information contributed to the department's approach in developing a forecast. Instead

of the dates being fixed, the department considered the dates as flexible and reflected the flexibility in the forecast.

Dr. Umekwe continued to slide 9 showing the long-term production outlook for the North Slope. The slide reflected the mean estimate with a high case and a low case. He pointed to the currently producing (CP) fields [represented in blue] such as Prudhoe Bay, Kuparuk, Alpine, and other popular fields. The red portion of the chart showed production expected to come from projects that would be done in the next 12 months (within the fiscal year). The brown/tan color denoted projects that were further out, between 2 years to 10 years. Looking at the rates, it was difficult to sum up the peak rates (the rates companies announced). The slide showed the peak rates combined with risks and uncertainties tied to the projects. He also pointed out that current production declined overtime. It was a natural progression. New projects were an addition to a declining base production. Adding the new project rates to the current production rate of 500,000 barrels per day to reach 700,000 would not happen quickly, as the projects would come in at different times. The impact of all the projects was more tamed.

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Dr. Umekwe indicated he would be addressing the second portion of the presentation which spoke to the method or approach the department used to generate the forecast.

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Dr. Umekwe reviewed the Fall 2019 forecast objectives on slide 11. His team's main objective was to produce a production forecast that could be used by DOR for generating the state's revenue forecast. The department also tried to apply methods that looked at both the short term and the long term. The department tried to provide a forecast that was reliable in the short-term helping legislators plan for the current fiscal year and the following year while also providing a forecast that yielded a realistic picture of future production.

Dr. Umekwe defined the three production categories on slide 12 used to generate the production forecast. Current Production (CP) was the first category and included

production from fields like Prudhoe Bay, Kuparuk, and some of the other fields online. The second category was Under Development (UD) – projects expected to come online in the current fiscal year. The third category was Under Evaluation (UE) – projects that were further out such as Willow, Pikka, and GMT2.

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Dr. Umekwe continued to slide 13 which focused on the level of uncertainty his team observed in the three different buckets of production. Most of the currently producing fields had been online for a long time, and their outlooks were easier to estimate. The outlook for currently producing fields could not be taken for granted. The production depended on spending levels the producer incurred in fixing wells and ensuring they continued to deliver. There were many other factors including the performance of a reservoir itself. As a result, there was still uncertainty around production already online. The remaining two buckets had to do with future production: under development and under evaluation. The commonality of the two buckets was that the projects were not online. There might be a level of certainty as to whether a project would happen at a specific time. Overall, if a well was not drilled, there was still uncertainty irrespective of how much confidence there was in its data. Ultimately, the goal was to see a project produce and to evaluate whether it compared closely to the expected production. He continued that projects under development would be wells he expected to be drilled in the current fiscal year, FY 20. Projects under evaluation were projects he expected to yield production beyond FY 20.

Dr. Umekwe explained that the last bucket, projects under evaluation, were very important because there were so many categories of uncertainty that applied. There were subsurface uncertainties such as brining up a field that did not produce as much as expected or exceeded expectations. He spoke of CD5 and the first phase of the project exceeding the operator's forecast. He indicated that the GMT1 project had not met the operator's expected rate. One thing was certain, actual production did not exactly equal expected production.

Dr. Umekwe spoke of the importance of continued focus on short and long-term planning on slide 14. The department

tried to provide one product that served the purpose of guiding short-term planning as well as long-term planning.

Dr. Umekwe continued to slide 15: "Forecast Accuracy: Near-Term." He noted that the most important take-away from the slide was that in the near-term maintenance work and some of the operational changes that operators made in trying to get fields to produce became important to forecasting. For instance, if there was a change in scheduling activity like an operator planned major maintenance in a given month and was shifted across several months, it would affect the accuracy of DNR's forecast in the short-term. He reported that DNR engaged with operators with the help of DOR to understand some of their processes and their planned changes and to incorporate them into the forecast.

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Dr. Umekwe discussed the accuracy of the statewide forecast in the near-term on slide 16. The Department of Natural Resources generated the forecast in November [2019] using data as up to date as June [2019] from the Alaska Oil and Gas Conservation Commission (AOGCC). He indicated the graph showed how the forecast performed. There was 5 months of history to test the forecast the department generated. He highlighted the black dots that represented actual production. The bowed lines represented the mean or expected production and the broken lines represented the range. The department's goal was to ensure that actual production came within the range provided. He noted that in the last 5 months of the current fiscal year production had aligned well within the DNR range and followed closely with DNR's mean.

Dr. Umekwe moved to slide 17, "Realistic Long-Term Projection." He would be discussing the long-term forecast. He mentioned earlier that one of DNR's objectives was to develop a product that served in the short-term and in the long-term. In the long-term the department looked at the behavior of fields, the long-term development plans. It also applied engineering judgement in terms of the outlook for fields. The department was also looking closely at the project characteristics announced by the operators for the fields that were yet to produce. All of the information was considered to provide the state a robust medium-term to long-term outlook for all of the fields.

Dr. Umekwe continued to slide 18, "Comparing Long-term Projections". He explained that one way to test the outlook DNR had in the long-term was to see an aggregated view of the operators' numbers. The chart showed DNR's mean forecast represented in red. The blue bar represented an aggregation of submissions from operators. He noted that DNR's confidence in its forecast was based on whether the operators' outlook fell within the range DNR provided. The chart confirmed that the operators' outlook fell within DNR's forecasted range. The operators' forecast fell within the high case forecast, shown in brown, and the low case forecast, shown in hashed brown.

Dr. Umekwe indicated that DNR's goal was not to replicate what the operators provided because there were some inconsistencies in the way each operator might decide to present an outlook. In order to generate a production forecast product, the department used the information that was provided publicly and applied a consistent methodology across all projects. It took into consideration the risks and uncertainties around each project including performance risks, start times, and commercial risks.

Dr. Umekwe moved to slide 19: "Increasing Uncertainty as New Fields/Projects Come Online" which showed DNR's outlook and noted that the range of uncertainty was included at each time in the outlook period. He highlighted that less was known in the out years. In the distant future there were more projects coming online. Some of them had conceptual plans that could potentially change, and others were still in the permitting process. He suggested that when incorporating all of the possible risks, like a project not starting on time or being rescoped, the outlook showed uncertainty father out.

Dr. Umekwe turned to slide 20 related to projects under evaluation in the medium to long-term. He pointed to the left of the map which showed federally-owned lands. On the right was ANWR, also federally managed (lands in which the federal government owned mineral interests). The pink sections of the chart showed Native land, and the blue sections of the map showed state managed lands. All of the projects reflected in the forecast numbers were shown on the map. Some projects spanned the entire map. He concluded the presentation and was glad to take questions.

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Co-Chair Foster recognized that Representative Tilton had joined the meeting earlier. He commented that the committee was building the budget and needed to know what the revenue would be. A good portion of the revenue would be determined by the price and production of oil. He referenced slide 7 and suggested that DNR's forecast for the first 5 months of FY 21 was 506,000 barrels per day, slightly down from the prior year of 520,000. He asked if he was correct.

Dr. Umekwe answered that slide 7 showed actual production as observed in FY 19, the most recent fiscal year, compared to the more distant past. Production for the first 5 months of the current fiscal year was shown on slide 6. He relayed that the forecasted average production for FY 20 was 506,000 barrels of oil per day. The department predicted that production would stay relatively flat from what it was in FY 19.

Co-Chair Foster confirmed that slide 6 showed the forecast of 506,000 barrels per day for the first 5 months of FY 21. Dr. Umekwe relayed that the forecast was 500,000 barrels per day for the first 5 months.

Representative Josephson addressed a question to Ms. Longan pertaining to slide 4. She had noted the royalties belonged to the federal government except for a federal law that provided for direct impact aid. She discussed how, for example, if the borough could not represent that it needed all of the royalty monies, some of it would make its way to Juneau. However, there was no history to report. He asked if he was accurate. Ms. Longan replied that he was accurate. She reported that from FY 87 through FY 19 the royalty amount that went through the impact grant fund was $209 million.

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Representative Josephson asked what Dr. Umekwe could tell the committee about production at Port Thompson. He queried if it had reached 10,000 barrels. Dr. Umekwe responded that there had been months where production had reached nearly 10,000 barrels. However, on an analyzed basis it had not reached 10,000 barrels.

Representative Josephson thought that falling production would be reflected in the later slides. He concluded that

although there was some good news, in the out years production would decline. He suggested it would be lucky if production stayed in the 500,000 to 600,000 barrel range.

Dr. Umekwe thought Representative Josephson had made a fair statement based on the risks and uncertainties around the projects as seen presently. He elaborated that because the numbers DNR provided had incorporated risk, when the actual projects came online, the numbers would be different. In most cases, the numbers would exceed what was shown.

Representative Wool mentioned the previous day's presentation from the Legislative Finance Division (LFD) which showed the projection for 10 years out. Oil production appeared flat with a slight decline. He wondered how close the predictions made 10 years prior were to current production.

Dr. Umekwe responded that DNR could provide information on how accurate a specific year's forecast was compared to present day numbers. In the past, there was a systematic bias in the forecasts. In most cases, forecasts were higher than actual production. However, there was a change in activity levels across time. Currently, it was one of the busiest periods in the state. The difficulties of forecasting production changed across time based on the number of projects in play and the level of advanced planning. He concluded that in comparing most of the forecasts in the past, the majority shot above actual production numbers.

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Vice-Chair Ortiz asked, that when DNR was forecasting production into the future beyond 5 years or 6 years, he wondered how much was factored in when considering changes in conditions in the Lower 48, production costs around the world, or worldwide demand. He wondered how they influenced the likelihood of projects coming online. He asked if things like lowering costs of production in the Basin were factors.

Dr. Umekwe responded that the price mechanism was the clearest way the market saw the interplay between demand and supply which drove the overall portfolio of production. Costs became important when considering things such as technology and its impact on reducing costs. There was a

correlation that many people could agree on which was that when prices were low, they affected the costs operators were willing to spend to bring projects online.

Dr. Umekwe spoke to the relationship between the numbers DNR provided and potential changes that could occur. The relationship was captured in price. The price numbers received from DOR reflected the market's best understanding of potential future prices. He continued that to the extent that future prices affected the economic viability of a given project on the North Slope, the projects were reflected in the forecast. Projects that were significantly challenged, such as projects in the far-flung areas of the North Slope where the costs of bringing them online could be around $100 to $150 per barrel, would reflect poorly on the numbers DNR presented.

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Representative Sullivan-Leonard mentioned Pikka, Willow, and Liberty fields. The peak rate had a potential total of 340,000 barrels. She thought it was a promising prosect when the number was added to the current average of about 500,000 barrels. She asked if there was a reliable amount of certainty regarding the development and success of the projects anticipated to come online.

Dr. Umekwe indicated that projects such as Pikka and Willow were bright spots on the horizon. The department continued to monitor their progress. However, projects and timelines could change. If prices fell drastically, it would be a guess as to how fast the projects would progress. He indicated that DNR steered away from including the rates expected from future production projects into the current production rate. The present day's production was declining. He suggested that by the time the projects came online, production might be less than the current rate. He reiterated that there was significant uncertainty.

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Ms. Longan agreed that uncertainty always had to be considered. She shared some level of excitement about the three projects Representative Sullivan-Leonard mentioned along with others. For example, the operators of Pikka, Willow, and Liberty had contributed a tremendous amount of capital expenditures to-date. The other part of the

responsibility of DNR was working on regulatory authorizations. For each of the 3 aforementioned projects, they had made huge milestones. She confirmed there were projects that were bright spots in future development.

Representative Knopp asked about the Liberty project. He queried if the prospect was in federal waters and whether it was tied up in litigation. Ms. Longan indicated Representative Knopp was correct that the Liberty Project was in litigation and did not have significant certainty concerning the timeline. As proposed, there was an artificial gravel island planned 6 miles offshore. There was a sub-c connection onshore and onshore facilities that would bring state and local revenue taxes. There were opportunities with the project.

Representative Knopp asked if she was referring to production taxes bringing in revenue resulting from the Liberty Project. Ms. Longan responded, "Yes, through taxes." She elaborated that because the production, as proposed, was 6 miles offshore, the state would not be receiving royalties.

Co-Chair Foster thanked the presenters and indicated the committee would move to the topic of the Fall 2019 Revenue Forecast.

^FALL 2019 REVENUE FORECAST BY THE DEPARTMENT OF REVENUE

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MIKE BARNHILL, ACTING COMMISSIONER, DEPARTMENT OF REVENUE, was joined at the table with Dan Stickle and Collen Glover. The majority of the presentation would be presented by Mr. Stickel and Ms. Glover. He was available to answer any questions that might arise regarding tax, revenue, and administration policy.

DAN STICKEL, CHIEF ECONOMIST, DEPARTMENT OF REVENUE, reported the goal of the presentation was to provide a high-level overview of the current state revenue forecast which underlaid the governor's budget proposal. He would touch on the major drivers of the oil revenue forecast in particular because it was one of the key revenue sources. He noted there were two elements to the Department of Revenue's (DOR) presentation: the core presentation and eleven addendum slides prepared in response to requests

from the other body. If there was time, he would be happy to delve into them. He wanted to make sure the committee had all of the information provided to the other body. Otherwise, he could leave the slides with the committee and answer questions later if they arose.

Mr. Stickel began with the chart on slide 3 which showed total revenue for FY 19 and the forecast for FY 20 and FY 21. In terms of total state revenue, the department expected it to be relatively stable at around $11 billion per year. The department presented revenue in the presentation and in the Revenue Sources Book in four broad categories consistent with the budget definitions.

Mr. Stickel elaborated that the primary category of focus was unrestricted general fund (UGF) revenue available for appropriation for any purpose. In FY 19 UGF revenue totaled $5.4 billion. The Department of Revenue was forecasting about $5 billion per year in FY 20 and FY 21. He reported three other categories of revenue in the forecast. The first was designated general fund (DGF) revenue which was technically available for appropriation but customarily appropriated for specific purposes. An example was a portion of the alcohol tax revenue which went to the alcohol and drug abuse treatment and prevention fund by a customary appropriation. The second category was other restricted revenue which was significantly more restrictive in how it could be used. There were usually debt covenants, constitutional prohibitions, or other solid restrictions on how revenue could be appropriated. The third category was federal revenue which brought in a little over $3 billion in the previous fiscal year. All federal revenues came with provisions on how they could be used.

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Mr. Stickel indicated that slide showed a visual depiction of how the $11 billion total state revenue was broken out. The largest sources were investment earnings, federal earnings, and petroleum revenue. Investment earnings, primarily with the Permanent Fund (PF), were currently the state's largest single source of revenue. He continued that beginning with FY 19, DOR was considering a portion of the PF earnings stream to be UGF revenue. Federal revenue made up about one third of total revenue and was entirely restricted in how it could be used. Finally, oil and gas made up about one quarter of state revenue. He suggested

that while other industries and revenue sources were important to the constituents they impacted in terms of employment and jobs, they only accounted for 10 percent of state revenue.

Mr. Stickel moved to slide 5 which focused on unrestricted petroleum revenue. The total amount of unrestricted petroleum revenue was $2 billion in FY 19 and was expected to be $1.6 billion in FY 20 and $1,4 billion in FY 21. The primary components of revenue included: the state's share of property tax which contributed about $120 million in the most recent year; corporate income tax which contributed a little over $200 million; and oil and gas production tax which contributed $595 million in FY 19. He noted that the production tax revenues would decline to the $300 million to $400 million range. The reason for the decline was a slightly lower price forecast, a slightly lower production forecast, and higher spending by the oil companies. A combination of the factors placed the production tax regime into the minimum tax regime. He would touch on what it entailed further into the presentation.

Mr. Stickel continued that all of the taxes were dwarfed by the revenues that royalties brought in. State royalties generated $1.1 billion in FY 19. The amount was projected to decrease in FY 20 and FY 21 due to three factors. First was the lower price in production - the state would receive a royalty on a lower value of oil. The second was a growing share of incoming production coming from non-state land. For example, the state was not receiving the unrestricted royalty on NPRA development. The third factor had to do with a provision around PF sharing. In FY 19, 25 percent of royalties were deposited into the PF which was required by the constitution. In FY 20, a higher amount averaging 50 percent for certain leases, but 30 percent of total royalties, was deposited to the PF. It had to do with a statutory provision that allowed for a higher deposit into the PF of royalties for certain leases. The forecast assumed the higher statutory deposit in FY 21 and beyond.

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Mr. Stickel turned to slide 6 which highlighted some of the key changes to the unrestricted revenue forecast compared to the spring forecast released the previous March. He indicated that for FY 19 the Alaska North Slope (ANS) oil prices came in $.56 per barrel above the department's

spring forecast. However, unrestricted revenue was about $50 million below the spring revenue forecast. The primary reason for the shortfall had to do with production tax which came in $140 million below DOR's forecast. There were higher than expected refunds for the 2018 tax year that the state paid out as well as attributing some production tax payments for the constitutional budget reserve (CBR) fund at the end of the year reducing the general fund portion of the production tax.

Mr. Stickel reported that for FY 20 and FY 21 the department reduced the price forecast for both years by $2.46 for FY 20 and by $7.00 for FY 21. The department was currently forecasting $59 per barrel in FY 21. The reduction in price forecast was the primary reason for the reduction in the revenue forecast for both years.

Mr. Stickel advanced to slide 7: "Total Percent of Market Value (POMV) Transfer Forecast." He included the slide since the PF was the largest source of unrestricted revenue. He highlighted the FY 19 transfer to the general fund of about $2.7 billion as well as the 10-year forecast reaching $3.8 billion by FY 29. The amount of the transfer was available for dividends and/or general government spending as the legislature saw fit. The transfer forecast was based on the POMV of the fund. He reported that for FY 19 through FY 21 the transfer was 5.25 percent of the average market value of the first 5 of the last 6 fiscal years. He indicated that for FY 22 and beyond the transfer was 5 percent of the market value. The forecast for the POMV was dependent on investment returns and oil production. The forecast assumed a 7 percent annual average return on the fund as well as ongoing mineral deposits that brought hundreds of millions of dollars into the fund per year.

Representative Ortiz referred to the 7 percent rate of return. He thought the Alaska Permanent Fund Corporation (APFC) had reported the average return rate to be 6.5 percent.

Mr. Stickel responded that the 6.55 percent was the expected rate of return when DOR prepared the spring forecast. However, 7 percent was the new rate of return from APFC and was reflected in the fall forecast.

Mr. Stickel advanced to slide 9 and the department's price forecast. He relayed that the department made a change to the price forecast methodology. He explained that previously the oil price forecast was based on a survey approach where DOR brought a group of state employees and experts together for a day-long session in the month of October. The group studied oil market trends and ultimately came up with the oil price forecast. There were various issues with the survey-based approach. It was very time intensive, not exceedingly transparent to the public, and by the time the forecast was released in December the information was stale. Frequently, the department ended up adjusting the forecast at the last minute not using the results of the day-long meeting.

Mr. Stickel conveyed that in the current year the department developed a methodology that used price forecasts from the futures market for the following 2 years. The department was able to compile the price forecast on Monday, December 2, 2019, and release the entire revenue forecast on the following Friday, December 6, 2019. The result was a timely price forecast. The forecast relied on the Brent futures prices as of Monday, December 2nd and was fully documented. Therefore, anyone could replicate how the department determined its price forecast. One issue that arose in preparing the forecast was that historically, Alaska North Slope (ANS) crude oil and Brent crude oil traded very closely (trading in parody). However, currently ANS crude oil was trading at a $2 premium to Brent crude oil for a variety of reasons. The department acknowledged the information in the forecast. He furthered that the $2 premium was incorporated currently and assumed that it would phase out throughout FY 20 returning to parody by FY 21.

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Mr. Stickel drew attention to the chart on slide 10 which showed 4 years of historical oil prices and 4 years of projections from various forecast sources. The prices were for Brent crude oil and were in real terms, so they excluded the impacts of inflation. He highlighted the department's Fall 2019 forecast remained fairly in line with the futures market over the near term. It was actually slightly higher than the futures market over the long term due to DOR's decision to hold prices constant beyond the budget year in real terms. The department's price forecast

was slightly below what the average oil market analyst was saying and several dollars per barrel below what the Federal Energy Information Agency was projecting. The take-away from the slide was there was a range of forecasts from the mid $50 to the mid $60 per barrel. The department's forecast looked to be within the range, possible slightly more conservative. However, DOR knew its price forecast would be inaccurate.

Mr. Stickel advanced to slide 11 which provided a sensitivity analysis showing how revenue would change based on certain oil prices. He highlighted that for FY 21 the official forecast was $59 per barrel which generated just under $2 billion of UGF revenue excluding the POMV transfer from the PF. Around current prices each $1 change in the ANS price would result in a change of about $30 million to $35 million UGF revenue.

Mr. Stickel indicated there were a couple of slides that touched on the production forecast which the committee just heard about from DNR. Slide 13 was a reminder of some key provisions. The Department of Revenue worked closely with DNR to produce the production forecast and represented a most likely value within a range of potential outcomes.

Mr. Stickel turned to slide 14 that showed the official production forecast for the following 10 years as well as high-case and low-case sideboards. He mentioned that there was a slight difference in DOR's production numbers and the numbers presented by DNR. The difference had to do with how DOR treated natural gas liquids used in enhanced oil recovery - barrels produced at Prudhoe Bay, shipped to Kuparuk, and reinjected into the Kuparuk reservoir to support enhanced oil recovery there. The department excluded an assumption of 10,000 barrels per day of natural gas liquid shipments from the production numbers that DOR reported in the Revenue Sources Book. The reason for the exclusion was because the numbers did not go into the Trans Alaska Pipeline (TAPS) and were not considered produced for tax purposes. However, DNR considered the barrels for royalty purposes.

Mr. Stickel moved to the cost forecast on slide 16. He reported that the cost of production was tracked closely for 2 reasons. First, the cost of production was a barometer of company investment in the state which ultimately led to future production and supported current

production. Secondly, production costs were an integral part of the production tax calculation. Companies were allowed to deduct most costs of production in calculating their production tax liability which included ongoing operational costs and capital expenditures with no depreciation requirement.

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Mr. Stickel relayed that slide 17 showed a 10-year history and forecast of allowable lease expenditures for the North Slope. The department used several different sources to develop its forecast. The most valuable source was information obtained directly from the operators every 6 months. They provided a detailed expectation for spending for each unit in the state. The department also looked at a variety of public information about ongoing developments and future developments as well as historical spending companies reported in their tax returns. The department applied a risk factor to costs expected for any new units that were in accordance with the risk factors used on the production side. There was some agreement between the lease expenditure forecast and the production forecast.

Mr. Stickel continued that in looking at the chart both operating and capital expenditures peaked in FY 15 and declined for several years as oil prices fell. In FY 19 allowable operating expenditures were $2.9 billion. The department expected them to decline slightly to $2.7 billion in FY 21 before climbing to $3 billion by FY 24 and remaining level. He indicated that the information was based on declining production over the near-term and new fields coming online later in the decade.

Mr. Stickel thought capital expenditures told a more interesting story. In FY 19 capital expenditures were $2.2 billion which was the first increase after 3 consecutive years of declines in capital spending on the North Slope. The Department of Revenue was expecting the increase to continue with $3.6 billion of North Slope capital spending in FY 22. The information was based on spending for large new developments like Pikka and Willow. The department had a forecast of capital spending tapering off later in the decade. However, as additional new developments became identified or more likely, there was a potential upside to the forecast.

Mr. Stickel moved to slide 18 which looked at transportation costs with a 10-year history and forecast. They were costs associated with pipelines including TAPS as well as marine transportation costs for getting the oil from the North Slope to market on the West Coast. The costs were important because they were deducted against the gross value calculation for both tax and royalty purposes. In general, what the department observed was as volume went down, transportation costs on a per barrel basis went up. Additional production in the pipeline had the potential to reduce transportation costs. He also noted there was a decline in costs in FY 19, as there was a change in how TAPS tariffs were calculated which contributed to the decline. He turned the presentation over to Ms. Glover.

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COLLEEN GLOVER, DIRECTOR, TAX DIVISION, DEPARTMENT OF REVENUE, would discuss a subset of the tax credits - only those available for purchase by the state. She turned to the graph on slide 20, a representation of the balance of those outstanding credits at the time that the Revenue Sources Book (RSB) was generated. The balance was estimated to be approximately $740 million which was represented by the blue bar in the 2020 column. The gray bars showed the amount the department estimated that the state would purchase according to the formula in statute. The graph showed when the purchases would occur. There was the potential for the tax credit bonding program to proceed and the gray bars would be used in the calculation for the discount values if it occurred.

Ms. Glover turned to slide 21: "Tax Credit Bonding Update." She reported that there was legislation passed in 2018 to allow the state to issue bonds to pay off the outstanding tax credits. The legislation was tied up in litigation with the Alaska Supreme Court. Until a decision was made, the state would hold off on issuing any bonding packages.

Ms. Glover continued to slide 23 which provided an annual update regarding oil and gas production tax audits. On the positive side, the division was working aggressively to reduce the backlog of production tax audits. All of the 2013 audits were completed in the prior year. Currently, the division was working on the 2014 audits and incorporating efficiencies and streamlining the audit process. The division intended to complete the backlog and

move to a 3-year cycle. The production tax was the only tax that had a statute of limitations of 6 years for audits, all the others were 3 years. She spoke to the advantages of a 3-year audit cycle and getting current.

Ms. Glover continued that another positive improvement was that currently the division was fully leveraging the tax revenue management system which was paying large dividends. She explained that tax returns, starting with 2014, were filed in the system making data available in the system to be explored and used for audit papers instead of having to generate the papers by hand. The team spent a significant time planning for the change and testing the system to ensure that the exported data would be accurate. Another positive improvement in the process was having a documented audit plan with each taxpayer being audited which identified communication protocols, scheduled communications, scope, and deliverables on both sides. The division met with each taxpayer and agreed to protocols. The division had received positive feedback about the engagement meetings. She concluded the presentation.

Co-Chair Foster referred to the addendum section of the presentation. He wondered if any of them were of particular interest.

Mr. Stickel pointed out slide 29 which showed a brief history of North Slope oil employment. He highlighted that, according to preliminary data from the Department of Labor and Workforce Development, North Slope oil employment increased in 2019 for the first year following several years of declines. He noted that it lined up very closely with the capital expenditures information which also showed the first year of increase following several declining years. The department was forecasting significant increases in capital expenditures. If the trend held, there was reason to be optimistic about potential oil employment over the following several years.

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Mr. Stickel touched on slide 32 briefly. The department was asked to address the potential impacts of the International Maritime Organization (IMO) 2020. He explained that IMO 2020 was a new requirement, effective January 1, 2020 to use lower sulfur marine fuel in marine transportation across the world. Refineries had been scrambling to meet

the demand for the new lower sulfur oil. He explained that while Alaska North Slope crude was not a low sulfur oil, it was on the lower side of the sulfur content and was easily blended by refiners to create the low sulfur marine fuels. The department had seen a premium compared to other benchmarks such as Brent and the global market. The provisions related to the IMO 2020 were part of the reason for the premium. Other reasons for the premium included a supply crunch on the West Coast market where there had been lower production for ANS as well as competing crudes from Iran and Venezuela. He acknowledged that IMO 2020 had had significant impacts in the refining industry and on ANS prices - the department saw it as a temporary impact.

Mr. Stickel reported that slide 33 had to do with the crossover point between gross and net tax under the production tax. He explained that it was the point at which the 35 percent net tax less per barrel credits began to exceed the 4 percent gross tax floor. In the spring forecast DOR estimated a crossover point in the mid $60 based on the spring forecast, production, and spending for FY 20. In the fall forecast the department was currently estimating a crossover point near $80 per barrel which was based on slightly lower production as well as significantly higher spending for FY 21. The department was expecting to be in the minimum tax regime given DOR's price forecast over the time horizon over the following decade. He indicated that it was a result of a combination of a slightly lower production forecast and the expected increase in company spending into the future.

Mr. Stickel reported that slide 36 demonstrated that not all oil was the same. The chart showed various categories of land in Alaska and how royalties and taxes applied for each of the categories of land. He stated that for the tax pieces, the state's taxes applied to all land in the state within 3 miles offshore regardless of ownership. Royalties varied depending on the land ownership. He was available for questions.

Vice-Chair Ortiz referred to slide 11. He asked if there was a certain price where the state crossed over from gross tax to net tax. Mr. Stickel responded the crossover point was different for each taxpayer. On aggregate under the fall forecast the crossover was around $80 per barrel. Acting Commissioner Barnhill directed attention to page 33.

2:47:56 PM

Vice-Chair Ortiz referred to slide 16 about the net taxable revenues being less than 4 percent. He wondered if the per barrel credit had been factored. Mr. Stickel responded that he was correct. He explained that 35 percent of net minus the taxable per barrel credit had to be compared to the 4 percent gross tax floor.

Representative Ortiz clarified that there should have been a reference to the per barrel credit on the slide. Acting Commissioner Barnhill responded that it was encompassed in the word, "net."

Co-Chair Johnston asked if the Tax Revenue Management System (TRMS) was online and running presently. Ms. Glover responded in the affirmative. Co-Chair Johnston wondered if the documented audit plans were online. Ms. Glover responded that the audit plans were not public documents.

Co-Chair Johnston clarified that she was wondering if both were being done within the system. She thought it was a hopeful improvement. Ms. Glover replied that the system had made it more efficient for the division to complete audits more expediently with better access to data. The division was confident about returning to a 3-year audit cycle in the near future.

2:50:02 PM

Representative Josephson referred to slide 6. He wondered about the administration's policy about moving additional royalty monies beyond the 25 percent to the constitutional budget reserve (CBR) versus the general fund. He thought it was the previous administration that changed the policy. He asked for an explanation of the change and what was in dispute. He suggested there was a difference of opinion.

Acting Commissioner Barnhill responded that under the constitution 25 percent of royalties were dedicated to the PF. The question was related to the PF rather than the CBR. The constitutional phrase started with the words "At least" 25 percent of royalties were dedicated to the PF. He continued that by statute, the legislature added another 25 percent to the established 25 percent dedication for new leases issued on or after 1980. Historically, the statutory increase for new leases had been viewed as an additional

dedication - instead of 25 percent it was 50 percent. The court dispute had to do with whether the phrase "at least" composed a constitutional dedication. The question was whether the additional 25 percent bypassed legislative appropriation. He reported that the Department of Law did not view the additional 25 percent for new leases as a constitutional dedication. Rather, it required appropriation. There were other opinions that it was a constitutional dedication not requiring legislative appropriation.

Acting Commissioner Barnhill continued that for 2 years the Walker Administration did not submit the additional 25 percent to the legislature for appropriation, and they were not appropriated. The additional 25 percent was in the budget for FY 20 and FY 21. He believed the Division of Legislative Audit subscribed to the view that the money was dedicated and should be placed in the principle of the PF. In the previous year, they proposed a mechanism to do so which was not embraced. Therefore, the issue and dispute still existed around not moving the extra 25 percent into the principle of the fund for 2 years.

Representative Josephson reported there were vetoes of some efforts to move royalty monies under the statute under HB 39 [Legislation that passed in 2019 regarding the State Operating Budget] or HB 2001 [Legislation passed in 2019 regarding appropriations, the Earnings Reserve Account, operating, funds, and other]. Acting Commissioner Barnhill did not remember the mechanism by which the money did not move. He did not recall it being a veto. He could get back to the committee on the details of how it came to be.

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Representative Josephson asked about the carry forward lease expenditures. They had to be used within a decade or they would be lost. He wondered if it had influenced the speed at which explorers worked. He thought it was one of the main reforms from SB 111 [Legislation introduced in 2019 - Short Title: OIL/GAS LEASE:DNR MODIFY NET PRO]. He wondered if there had been concern over potentially loosing capital expenditure dollars.

Mr. Stickel thought the representative made a good point. He responded that there was a provision regarding carry forward lease expenditures since the net operating loss

credits had been phased out on the North Slope that if a company incurred a net operating loss, they could carry forward the excess lease expenditures in offsetting future years of tax liability. The value of the lease expenditures began to degrade following the eighth or eleventh year after the lease expenditures were earned. He expected that companies would factor the information into their economics and their plans. A good question for companies to consider was whether it was enough to change development and production decisions.

Representative Josephson asked about another reform in SB 111 regarding an increase in the interest charge for failure to timely pay what the department thought was owed. The amount was reduced in SB 111, but there was an increase overall since SB 21 [Legislation passed in 2013 regarding oil and gas production tax]. He was concerned whether better returns had been produced in a timelier fashion.

Ms. Glover replied that the interest really played more into the audits and the timing of their completion with the interest clock ticking. She elaborated that the taxpayer filed monthly returns and annual returns. It was a factor in the audit timeline and the fact that interest was occurring until an audit was assessed and even after it was resolved or paid.

Representative Josephson assumed if the interest rate was increased, companies would be extra careful, possibly overpaying to avoid interest penalties. He asked if the state had seen anything similar.

Ms. Glover replied, "Not typically." She indicated it would be a concern for the companies regarding the state's timing of issuing an audit. She had not seen taxpayers overpay to circumvent additional interest accruing. At the time they paid their return they did not know the amount of the audit assessment. She was unaware of additional payments being made presently.

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Acting Commissioner Barnhill readdressed Representative Josephson's question regarding the veto. He indicated the proposed solution by the Division of Legislative Audit to pull money from the ERA and put it into the principle to

pay the 2 years-worth of the addition 25 percent on the new leases was what had been vetoed by the governor.

Representative Wool referred to slide 3. He queried about the $563.5 million of petroleum revenue under other restricted revenue. Mr. Stickel replied that it was the portion of oil and gas royalties that went to the PF as well as any settlements from tax and royalty disputes that went to the CBR fund.

Representative Wool asked for the CBR amount. He was aware money had to be repaid to the CBR but was unsure who enforced it. Mr. Stickel responded there were two issues. First, there was a requirement to pay back money that was used out of the CBR in the budget process. However, what was really being discussed on the slide was that any revenue resulting from tax or royalty disputes with producers was deposited into the CBR, as stipulated in the constitution. He reported that for FY 19 the deposits amounted to $181 million in petroleum revenue. The department was forecasting $200 million for FY 20 and $75 million for FY 21.

3:01:33 PM

Representative Wool noted the decline from $2 billion in FY 19 to $1.5 billion then down to $1.4 billion. He remarked about the significance of the reduction over the following couple of years. He wondered if the cut was based solely on price because the production forecast was within a slight margin of error. He wondered if the cut was based on price and the prediction of price. He thought the cut was drastic.

Mr. Stickel replied that one thing to keep in mind when looking at slide 5 was that it represented only the unrestricted portion of petroleum revenues. The state was also receiving between $400 million and $600 million of restricted petroleum revenues. Looking at the unrestricted petroleum revenues, the price was expected to be lower than it was in FY 19. Production was expected to be slightly lower and company spending was expected to be significantly higher. Slightly lower production and higher company spending moved the state into a regime where companies were paying at the gross tax floor instead of the higher net tax impacting the tax side. The combination of the additional deposits going to the PF reducing the unrestricted general

fund share of royalties as well as a lower value for oil affected royalty revenues. As a greater share of oil production was generated from NPRA and other non-state lands, the state would end up getting less royalty revenue overall.

Representative Wool referred to slide 29 that showed employment which tracked with capital investment. He asked how closely it tracked with the price of oil.

Mr. Stickel responded that there was a correlation between all three. The decrease in spending correlated with the lower oil price which also correlated with a reduction in employment. Companies were trying to figure out how to maintain viability of the operations given the lower oil prices. As prices had recovered, capital spending and employment started to recover in FY 19.

3:05:24 PM

Representative Wool noted production followed price. He relayed that the department was predicting lower pricing over time. He asked if the department had done a 10-year prediction. He wondered about the previous 10-year prediction. He asked about biases in previous predictions.

Mr. Stickel responded that one thing the department noticed in the oil price forecasts was they tended to anchor heavily to the current price. He suggested that when oil prices were above $100 per barrel, the department was forecasting prices above $100 per barrel for a long time. Depending on which forecast someone looked at, the department likely missed the mark. He thought there was one forecast about a decade earlier that forecasted prices around $59 per barrel to $60 per barrel presently. The department changed the forecast methodology because it was putting a significant effort into a fine point on the oil price forecast which turned out to be inaccurate. After some analysis, the department found that using the futures market to generate a forecast was just as accurate with much less effort.

Acting Commissioner Barnhill added that if the chart was pushed back a year, the prices were up over $100 per barrel. Oil prices were extremely volatile and had been for a long time. He mentioned that the department had observed over the prior year that volatility seemed to have

decreased. There had been a number of substantial geopolitical events over the previous few months. In the past, oil would spike then drop. He suggested that 10 years prior the markets were fairly reactive to such events but were less so currently.

Co-Chair Johnston was pleased with how the revenue forecasts were being done based on the futures market. She spoke of the price hitting $85 per barrel for one day in the prior year.

3:09:15 PM

Co-Chair Foster surmised that, looking at UGF revenue, the state could anticipate fairly flat revenue overall. Unrestricted general fund revenue was up about $10 million. Petroleum revenue was down by about $150 million but offset by non-petroleum revenue as well as the POMV which was up by about $160 million. He reiterated that revenue was fairly flat. He asked if the presenters had anything to add.

Acting Commissioner Barnhill responded that Co-Chair Foster's observations were correct. For the previous several years the state had been in the midst of a fundamental paradigm shift in terms of where the state revenues came from. The change had led to protractive discussions within the legislature and across the state.

Co-Chair Foster thanked the presenters and reviewed the agenda for the following day.

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ADJOURNMENT

3:11:05 PM

The meeting was adjourned at 3:11 p.m.