HOUSE FINANCE COMMITTEE
February 27, 2019
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 Tammie Wilson, Co-Chair
Representative Jennifer Johnston, Vice-Chair
Representative Dan Ortiz, Vice-Chair
Representative Ben Carpenter
Representative Andy Josephson
Representative Gary Knopp
Representative Bart LeBon
Representative Kelly Merrick
Representative Colleen Sullivan-Leonard
Representative Cathy Tilton

MEMBERS ABSENT

None

ALSO PRESENT

Maduabuchi Pascal Umekwe, Ph.D. and Commercial Analyst, Division of Oil and Gas, Department of Natural Resources; Sara Longan, Deputy Commissioner, Department of Natural Resources.

SUMMARY

PRESENTATION: FALL 2018 PRODUCTION FORECAST

PRESENTATION: PERMITTING ISSUES, & STATUS OF DEVELOPMENT ON NORTH SLOPE

Co-Chair Foster reviewed the meeting agenda.

^PRESENTATION: FALL 2018 PRODUCTION FORECAST

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MADUABUCHI PASCAL UMEKWE, PH.D. AND COMMERCIAL ANALYST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (DNR), introduced himself. He shared that he was trained as a petroleum engineer and economist. He intended to talk about the fall 2018 production forecast. He provided a PowerPoint presentation titled "Fall 2018 Production Forecast" dated February 27, 2019 (copy on file). He relayed that the Division of Oil and Gas had been conducting a production forecast for the state since the fall of 2016. The primary objective was to support the revenue projection work done by the Department of Revenue (DOR). He noted that the information in the presentation was a result of work done by a team of engineers with support from the commissioner.

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Mr. Umekwe turned to slide 2 and addressed a presentation outline. The first part of the presentation included a high level overview touching on North Slope projects that had impacted production in the past several fiscal years. The section showed a comparison between actual production and the division's forecast for the fall of 2018. He noted it was a long-term 20-year outlook for production in Alaska. The second part of the presentation addressed the approach the division had taken to generate the forecast, including some of the efforts taken to improve the near-term and long-term results included in the presentation.

Mr. Umekwe moved to slide 3 and addressed a comparison between actual production the fall 2018 production forecast. Actual production was represented by the blue bar and the forecast was represented by the red bar. He pointed out that the information was from the month of July through November. He noted that data outside those months would be a slightly different comparison. He highlighted that the forecast and actual numbers for the period shown were very close. He highlighted that the period shown included summer months that typically had lower production because the operators did a lot of work in the summer and there were inefficiencies in gas compression capabilities in the different fields. The variance between the forecast versus actual was about 15,000 barrels.

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Mr. Umekwe advanced to slide 4 and discussed the overall perspective for the North Slope including some of the projects that had impacted production in the past four fiscal years. He pointed to a graph on the top right showing that production had been flat for the past four fiscal years. He pointed to a more detailed view showing change across some fields during the past four years. In FY 15 through FY 17 there were two years of production growth, primarily intensive work carried out by operators on the different fields. Prudhoe Bay was the largest and had numerous efficiency gains during the period. Additionally, operators had conducted rig work and other work to keep production healthy in the Prudhoe Bay field.

Mr. Umekwe highlighted the Kuparuk unit and detailed that ConocoPhillips' work on the Sharks Tooth development and 1H-NEWS development was instrumental in maintaining steady production growth. He reported that the CD5 development had been beneficial for the Colville River and ConocoPhillips was looking into doing a second expansion of the development. He moved west to the Greater Mooses Tooth unit (GMT1) and detailed that much work had gone into the development that had its first production in the fall of 2018.

Mr. Umekwe discussed future projects (at the bottom of slide 4) including the CD5 expansion, GMT2, and Hilcorp's Milne Point Moose Pad. Farther out in the future, projects that would impact the state's overall production would be exciting discoveries like Pikka and Willow. He highlighted that old discoveries like Liberty were now moving forward.

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Mr. Umekwe addressed the 20-year production outlook on slide 5. The blue section of the graph represented legacy production from Prudhoe Bay, Kuparuk, and some of the other fields currently producing; the red portion represented production expected to be online within FY 19; and the brown portion showed production expected to be online after FY 19. The chart showed that legacy production continued to be the backbone of overall state production, especially in the near-term. He noted that five to six years in the

future, projects expected to come online beyond FY 19 would play an increasingly important role (e.g. Pikka, Willow, and GMT2).

Vice-Chair Ortiz looked at slide 5 and surmised that even with the future projects, the long-term future for production was a gradual decline. He asked if all of the potentially feasible future projects were reflected in the tan area of the graph.

Mr. Umekwe replied that all of the projects that DNR considered as discoveries where companies were moving forward were included in the tan area of the graph. He noted that the tan area represented the mean case and not the best case scenario. There were outcomes where production could be higher. He pointed out that subsequent slides showed a range around the number. He confirmed that the potentially feasible future projects were reflected in the tan area of the graph. He explained that legacy fields were still very important and as those naturally continued to decline, the new production would be added on top. He detailed that if production from legacy fields was 300,000 barrels, the new production would bring total production to about 500,000 barrels (as shown on the graph).

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Vice-Chair Ortiz referenced Mr. Umekwe's earlier statement that production was typically less in the summer months. He noted that it was not possible to use ice roads as much along with other factors. He wondered whether climate change would mean there would be less and less productive time periods for Prudhoe Bay due to the gradual increase in temperature.

Mr. Umekwe answered that the reason production declined in the summer was for two key reasons. First, at the time it was most convenient and safest to work. He detailed that if work that may have been done in the winter was scheduled for the summer to increase safety, production took a hit. For some of the wells that were aging and needed artificial methods to continue production - one of the main methods used on the North Slope was gas lift. He elaborated that the ability to compress gas to move gas to the fields declined in the summer period. As a result, the production from the wells was reduced.

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Mr. Umekwe advanced to slide 7 and spoke to fall 2018 forecast objectives. The primary objective for every forecast was to support the work DOR did to generate state revenue projections. The goal was to improve the long-term accuracy of the forecast. For every field, the division aimed to ensure its assumptions were tuned based on the best available information it could get from the operators. Also, the division was working to improve its forecast for the near-term to ensure the state was working off of the best possible information.

Co-Chair Wilson asked about the distinction between near-term and long-term.

Mr. Umekwe answered that the near-term represented the current fiscal year (FY 19). Key drivers for variation within that period would be changes in the way the operators worked with or handled a field and the schedule and work a company intended within that fiscal year. The division tried to ensure it captured the production impacts that some of the activities would have.

Mr. Umekwe moved to slide 8 and highlighted the three production categories that enabled the division to handle the timing aspect and risks involved in projects. The first category was currently producing/legacy fields. The second category was fields expected to yield production within the current fiscal year. The third category was fields expected to generate production beyond the current fiscal year.

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Mr. Umekwe advanced to slide 9 titled "Production Categories: Addressing Uncertainty." He discussed that most legacy fields had long production histories (some had been producing for decades); therefore, engineers within the Division of Oil and Gas had a good understanding of how the fields had behaved in the past. The division stayed abreast on whatever was happening in a field as part of its day-to-day work managing production from the fields. The knowledge was used to generate forecasts for the fields. He reported that what the legacy fields would generate in the future was still slightly uncertain; the division tried to hone its certainty in generating the outlook for a field like Prudhoe or Kuparuk.

Mr. Umekwe addressed the projects under development category, which included projects that were expected to be done within the current fiscal year (FY 19). There was more uncertainty with the category because it pertained to wells that had not yet been drilled; there were times the wells underperformed or overperformed operators' expectations. The third production category included projects expected to yield production beyond the current fiscal year (e.g. Pikka, Willow, GMT2). There was much more uncertainty when generating a forecast for projects under evaluation.

Mr. Umekwe highlighted the financial risk and economic thresholds the projects would have to meet in order to be sanctioned. Other uncertainties included the chance of the project occurring in the 10-year forecast window. For example, the Liberty project had been known about for the past decade or so, but for one reason or another the project had not been moved forward in the past. He explained that those were the kinds of things the division considered when looking at any new project discovered throughout the state. Additionally, there was uncertainty around timing - the start of sustained production. He noted that producers often moved the start date for a project based on logistical, seasonal, or other reasons. He added that there were times where projects had come online sooner than anticipated. There was also uncertainty around project performance - a well could overperform or underperform expectations. The division considered the three areas of risk for a project.

Mr. Umekwe explained that in most cases the division discounted the peak rates provided by operators because it was trying to ensure that the state planned its short and long-term future based on the best information available.

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Mr. Umekwe turned to slide 10 and discussed continued focus on both sort-term and long-term forecast accuracy. He stated that a secondary goal the division aimed to achieve with the forecast was to give the state the clearest near-term and long-term production outlook. The idea was to ensure the forecast continued to serve multiple purposes including state budgeting and revenue projections.

Mr. Umekwe discussed near-term focus on slide 11. The division tried to be mindful of the schedule of work the operators had planned for the near-term. For example, perhaps the operators were planning work in the summer that would have a major impact on production.

Mr. Umekwe moved to a chart titled "Near-Term Focus: North Slope" on slide 12. The dots on the chart represented actual production and the dashed lines represented the high and low side of future production outcomes. The black line represented the mean case. He detailed that based on the division's work in the spring of 2018, its forecast aligned well with actual production. He pointed out that the black line and two broken lines represented the division's forecast for the fall of 2018; some of the points were right on target and in some cases actual production came in a bit higher or lower than the projection.

Co-Chair Wilson referenced Mr. Umekwe's earlier example about summer maintenance impacting production. She asked if more shutdowns for maintenance were anticipated in the coming year.

Mr. Umekwe replied that the data the division had received from operators did not show a significantly different scale of maintenance or shutdowns in the coming season than had occurred in the past. He highlighted that the preceding year the Colville River unit had major maintenance that happened every five years; the unit was expected to run at full capacity for the coming year.

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Mr. Umekwe moved to slide 13 and spoke about a realistic long-term projection. He explained that instead of taking a blanket assumption on every field, the division got the best idea of what operators expected for production for the different fields. The division applied industry techniques including the decline curve analysis to project production for the various fields. Instead of generating one production outcome for a given field, the division tried to acknowledge the production uncertainties that could impact even legacy fields. The technique was applied to generate several possible outcomes for every field; the outcomes were combined to come up with the best estimate for a field. The purpose of the method was to ensure the division

generated a long-term projection that considered the best available information operators could provide.

Mr. Umekwe turned to a chart slide 14 that compared the long-term projections of the operators with long-term projections generated by the Division of Oil and Gas (2020 through 2028). The high side of DNR's forecast was shown in red and the low side was shown in tan. The blue bars showed an aggregate of the operators' outlook. The chart showed that overall, the operators' outlook fell within the range DNR provided to DOR for its revenue projections.

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Mr. Umekwe advanced to slide 15 and addressed the level of uncertainty for the three production categories. Once the information was combined, the division came up with a forecast that had the potential to be significantly different from the mean projection. The slide included a chart showing the production forecast range from 2014 to 2028. The black line showed historical production and the blue line going into the future represented the mean case. He drew attention to the bars indicating that production could be anywhere within the range shown [the chart indicated an increasing uncertainty (wider range) in the longer-term forecast]. He explained that if everything aligned well, there could be a situation where production significantly exceeded the mean line up to 700,000 barrels per day.

Mr. Umekwe showed a map of projects under evaluation (medium and long-term) that DNR had considered in its forecast (slide 16). He pointed out that most of the projects were located within the central area of the North Slope (some were located to the far west such as Liberty and some were south). The yellow section of the map showed federal government interest lands. The blue section showed mostly state land and the pink reflected Native land. He highlighted that GMT1, GMT2, and Willow fell within the federal section on the map. He noted that most of the other fields he had discussed, including Pikka, fell within the state-owned land.

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Mr. Umekwe showed a "North Slope Oil Production" chart on slide 17. The chart depicted a portfolio-scale rollup of

all of the risks DNR applied to the projects. He pointed out that at the peak, the projects could yield 200,000 barrels of oil per day. He noted that as time went on, DNR would continue to update the information as it received more information from operators about changes in scope and start times. He reiterated his earlier remarks that the new production would all be layered on top of a declining base of legacy production. For that reason, the 200,000 barrels were not being added to the current 500,000-plus barrels.

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Vice-Chair Johnston asked for verification that forecasting had been brought in-house three years back. Mr. Umekwe replied it had been in the fall of 2016.

Vice-Chair Johnston asked for verification that the forecast work currently done by the Division of Oil and Gas had been contracted out as well.

Mr. Umekwe replied affirmatively.

Vice-Chair Johnston asked if there was a comparison between the in-house projections and the contractor projections.

Mr. Umekwe answered that DNR had the information and had done some analysis in the past. He offered to update the information and make it available.

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Vice-Chair Ortiz asked how much price variability impacted a company's willingness or unwillingness to increase production.

Mr. Umekwe answered that the impact of price on production depended on numerous factors. For example, normally companies evaluated projects based on an update in their price outlook. While the state's oil price forecast may serve as a good medium for companies to talk to each other, the companies had internal price outlooks. He explained that in most cases the state new when changes occurred, based on activities and other factors in the news; however, companies may have a different timeline - perhaps they needed to see oil prices significantly down for a long period of time prior to updating the outlook on different projects. He explained that it depended on the company. He

furthered that some companies may hedge a series of production. Once the price of crude was hedged, based on the contract the company had with a buyer, it made momentary changes in oil pricing material to the specific company. He summarized that it depended on the company and their own internal assessments, but overall if oil prices were projected to be low or high, companies updated the outlook for their projects.

Vice-Chair Ortiz returned to the production range chart on slide 15. He considered the best case scenario showing 700,000 barrels of oil per day in 2028. He asked how much price would play in contributing to the best case outcome shown on the slide.

Mr. Umekwe answered that he did not have an exact number. He explained that the forecast generated by DNR was based the price projection for the state provided by DOR. The price projection had a range around it and DNR's projection was directly tied to the range in the state's outlook for oil prices.

^PRESENTATION: PERMITTING ISSUES, & STATUS OF DEVELOPMENT ON NORTH SLOPE

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SARA LONGAN, DEPUTY COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, provided a PowerPoint presentation titled "Alaska Department of Natural Resources: Oil and Gas Outlook and Permitting" dated February 27, 2019 (copy on file). She intended to provide additional information on an oil and gas outlook and share updates on the status of the department's oil and gas permitting programs. She began on slide 2 and addressed the state's land base and ownership:

Land Base

- 586,412 sq. miles—more than twice the size of Texas
- Larger than all but 18 sovereign nations
- More coastline than all other 49 states combined
- More than 3 million lakes; half of world's glaciers
- Approximately 40% of the nation's freshwater supply

Land Ownership

- Federal Land: more than 200 million acres
- State Land: Approx. 100 million acres of uplands, 60 million acres of tidelands, shore lands, and submerged lands, and 40,000 miles of coastline
- Native Corporation Land: 44 million acres

Ms. Longan advanced to slide 3 and provided a basic, high-level overview of the business conducted by DNR:

- Secure lands and access from federal government
- Identify minerals and oil and gas prospectivity via interest findings
- Lease lands for exploration and development
- Permit programs to ensure conservation of resources and protection of state's lands and interests
- Manage production units and mines to protect state's royalty interests
- Approve and monitor reclamation and closure operation

Ms. Longan noted that the department's business was continuous and often cyclical. She highlighted that in addition to Alaska's large size, it had world class resources. She shared that IHS Markit recently classified Alaska's North Slope basin as a super-basin. She discussed oil and gas resource potential on slide 4:

North Slope

- More undiscovered, potentially recoverable oil than any other Arctic nation
  - OIL: Est. 40 billion barrels of conventional oil
  - GAS: Est. over 200 trillion cubic feet of conventional natural gas
- Untapped unconventional resource potential, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates

Cook Inlet

- Significant undiscovered resources remain
  - 19 trillion cubic feet of natural gas

- 600 million barrels of oil
- 46 million barrels of natural gas liquids

Compared to most basins, Alaska is relatively underexplored, with 500 exploration wells on the North Slope, compared to Wyoming's 19,000.

Ms. Longan advanced to the oil and gas outlook on slide 5. She reported that the 2018 fall lease sale brought the 3rd highest number of winning bids since 1998. A map on the slide showed the North Slope and leases purchased (in green) in the 2018 sale. The sale included over $29 million in total bonus bids, the highest bid per acre was $586, and over 243 acres were leased. The blue portion of the map displayed the state acreage already under lease on the North Slope.

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Ms. Longan discussed royalty rates on a state map on slide 7. She began with state lands in the middle of the map where the royalty rates were 12.5 percent or 16.67 percent and the state received 83 to 100 percent of the royalties. The Natural Petroleum Reserve-Alaska (NPRA) on the left of the map had royalty rates of 12.5 percent or 16.67 percent. The state received 50 percent of those royalties, which were managed by the Department of Commerce, Community and Economic Development (DCCED) and made available to the communities within the NPR-A through DCCED's impact mitigation grant fund. She noted an error on the slide and reiterated that 50 percent of the state royalties went through the state mitigation fund.

Ms. Longan reviewed the Alaska National Wildlife Refuge (ANWR) coastal plain on the right of the map where the royalty rate was 16.67 percent and the state received 50 percent of the royalties. She finished with offshore developments and reported that from zero to three nautical miles the state received 100 percent of the royalties at a rate of 16.67 percent. At a distance of three to six miles, the state received a royalty rate of 20 percent.

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Representative Knopp referenced the information on slide 4 specifying that Alaska had 500 exploration wells compared to Wyoming's 19,000. He asked if the data pertained to

initial discovery wells. He remarked there were many more wells as far as production injection.

Ms. Longan replied that she would follow up with the information.

Mr. Umekwe answered that the 500 wells were designated as exploration wells and drilled for the purpose of finding the resource. In some cases, the well would be repurposed as a development well.

Mr. Umekwe advanced to slide 8 and explained a graph reflecting a 20-year production outlook for the North Slope. Legacy fields were represented in blue and production anticipated to come online in FY 19 or later was shown in orange. The graph broke out the Pikka and Willow projects separately in gray and yellow respectively.

Mr. Umekwe advanced to a map on slide 9 that Willow and Pikka developments. He shared that the next couple of slides showed the different revenue outcomes as a result of the different project locations.

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Mr. Umekwe turned to slide 10 and addressed the Willow development (representing a success case). The slide addressed revenue the state was anticipating from the Willow development. He detailed that generally the state experts on production taxes were housed within DOR, but he would speak briefly to the issue. The first chart on the top right represented the revenues the project would generate for the state at a flat price of $60 per barrel. He noted that the figures would be slightly different with inflation. He detailed there was a slight impact on the state in terms of reduced corporate income taxes as the company spent money to get the project online.

Mr. Umekwe moved to the chart on the lower right of slide 10 showing revenues the project would generate for the state at a flat price of $75 per barrel. He explained that in the initial years as a company spent money to get the project online, because taxes were estimated at the total North Slope level all costs and revenues generated from assets or developments for the entire North Slope were part of the assessment conducted by companies. In the absence of a project like Willow, the initial spending incurred by a

company would be part of the overall spending it was assessed on. He explained it was the reason there was more spending with the project and consequently, the company paid slightly lower taxes. However, going into the future, the development yielded more revenues for the state.

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Mr. Umekwe moved to slide 11 and addressed the Pikka development (representing a success case). The slide gave an example of a project carried out by a company without existing tax liability. He drew attention to two bar charts on the right side of the slide and noted that the blue portion of the bars representing royalties to the state had not been present in the previous slide for Willow. He explained that the project was located on state lands, the operator would pay royalties to the state as well as production taxes.

Mr. Umekwe elaborated that the first chart on the top right [of slide 11] represented the revenues the project would generate for the state at a flat price of $60 per barrel. He detailed that while the company was spending to get the project online, the expenditure was not shown because the company was experiencing a loss at the time (there was spending, but no production). Once production began in 2024, some of the losses the company accumulated would help the company reduce its production tax liability for the initial years; after those ran out, the company would start paying more production taxes. He noted that at the flat $60 price, the company was a minimum taxpayer.

Mr. Umekwe explained that three things could happen for a company developing resources on the North Slope: 1) if assets were in production, there could be a situation where the company was producing oil, but it was spending much more than it was producing; 2) if the company was slightly profitable, it would be a minimum taxpayer because the state's tax system allowed the state to get some revenue if the gross tax was higher than the net tax; 3) in a situation where the net tax was higher than the minimum tax and the companies would pay the net tax.

Mr. Umekwe moved to the chart on the lower right of slide 11 showing revenues the project would generate for the state at a flat price of $75 per barrel. He noted that revenue take for the state was much higher under the

scenario. He highlighted that it was still the case that in initial years the company was spending without production, which would allow the company to use some of its losses to reduce the production tax liability in the future. Overall, the project would yield between $8 billion and $13 billion for the state (he noted a typo on the slide in the revenue figures listed on the slide).

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Mr. Umekwe turned to slide 12 and reviewed a royalty analysis broken out by different areas of the state. He pointed to the royalty rate of 16.67 percent in the first row of the first column related to a project in the NPR-A. He explained that nothing went to the state's General Fund; whatever the state received from resources on federal land, 50 percent went to the impact mitigation fund and whatever was spent on grants and projects would be available to the state. The green portion of the table showed production from state land. He reported that the state received 100 percent of the royalties generated from that production. The state received a share of the royalties generated on lands that were jointly owned by the state and Native lands. He noted that the state received 83 percent of two-thirds of the production from Pikka. Offshore, the state received 100 percent of the royalty between zero to three nautical miles; the state royalty was 27 percent from three to six nautical miles. In ANWR the state received 50 percent of the royalties.

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Representative Josephson asked why some royalty rates were 12.5 percent and others were 16.67 percent.

Mr. Umekwe replied that when lease sales were organized, terms and conditions were set and included things like royalty rates, minimum bids, and net profit shares in some cases as had been done in the past. When the leases were issued, 12.5 percent and 16.67 percent had been rates set by the state. He believed there was a statutory minimum of 12.5 percent.

Representative Josephson thought it had to do with challenged fields, but he was trying to understand why they were seeing more fields with a royalty rate of 16.67 percent.

Mr. Umekwe answered that one of the internal analyses the Division of Oil and Gas had done in the past was to look at the general area of the North Slope. He agreed there were areas that DNR considered to be more prospective, where the general rule of thumb was to set the royalty rate at 16.67 percent. He explained that areas that were far from infrastructure and had no evidence of successful commercial development would be offered at the lower royalty rate.

Representative Josephson believed there had been a 12.5 percent used in 1968 or 1969 when oil development began in Alaska. He believed those rates were binding unless revisited through mutual agreement of both parties. He asked if the state's royalty rate was competitive with rates in other states (setting aside the difficulty of exploring in Alaska).

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Mr. Umekwe answered that he knew of areas in the Lower 48 such as Texas, where royalty rates were 20 percent or more. He pointed out that all of those areas were privately owned so it was possible for a private landowner to negotiate whatever royalty rates they could. Additionally, the scope, scale, and spending of those projects were different. All of those items were considered in a transaction before operators had access to acreage.

Representative LeBon pointed to the Willow project on NPR-A land [slide 12] with an Alaska Native royalty of zero percent and a federal royalty of 50 percent. He asked what the mitigation impact fund royalty is and who received it.

Mr. Umekwe deferred the question to Ms. Longan.

Ms. Longan replied that the program was administered by DCCED. She shared that 50 percent of the NPR-A royalties were received by the state and were administered by through DCCED's impact grant program. There was legislation that dictated how the funds were utilized. The first use of the royalties went to communities within the NPR-A who could apply through the DCCED grant program for qualified projects to help offset the impacts of development. She elaborated that if those funds were not used, the remaining funds went to the school trust and elsewhere. She offered

to provide general information from DCCED on the mitigation program.

Representative LeBon asked if the money remained within the state. Ms. Longan replied in the affirmative.

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Ms. Longan advanced to slide 14 and addressed the status of development:

- 2019 is expected to be the highest year in the last 20 years for exploration and production rig activity.
- Pikka, Mustang, and Placer finds demonstrate great potential.
- New data suggests enormous potential in Nanushuk and Torok formations.
- Legacy fields including Prudhoe and Kuparuk have exceeded internal expectations through infield work.
- Smaller companies, like Caelus, BlueCrest & Armstrong, are engaging in exploration plans that will help maximize TAPS throughput into the future.
- New players, like Oil Search, indicate industry acknowledgment of large, viable fields that were unknown.
- Continuous work with North Slope communities, presidential administration, and Congressional delegation on Arctic energy policy and decision making that support responsible development (ANWR Coastal Plain, OCS, NPR-A)

Ms. Longan elaborated on the second to last point and noted that new players, like Oil Search, indicated industry acknowledgement of large, viable fields that were previously unknown or were not totally understood.

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Representative Sullivan-Leonard considered the great potential with Pikka, Mustang, and other North Slope fields. She found it very encouraging. She asked how much oil they were expecting from new exploration. She referenced the graphs showing a gradual decline in production.

Ms. Longan answered that the production outlook ranges provided by Mr. Umekwe had been determined by the department and showed what types of production would be going into the Trans-Alaska Pipeline System (TAPS).

Representative Sullivan-Leonard spoke to the decline. She stated the decline was not with the new companies coming onboard and putting oil into TAPS. She asked the decline pertained to the other companies.

Ms. Longan answered that the projects the division used to analyze what the production outlook may be based on its assumptions and taking multiple factors into consideration, there was always the opportunity for new companies to acquire leases. She agreed, that once new companies entered into exploration to understand resource potential, DNR did not know what the future held. When new players came to Alaska to lease lands and perform exploration activities where there were discoveries and resource potential elsewhere, it would help increase the TAPS throughput and would slightly change the production outlook presented by Mr. Umekwe.

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Ms. Longan moved to a map on slide 15 showing the status of development. She noted the busy nature of the map and stated it was indicative of the significant activity taking place across the North Slope by multiple applicants and companies. She detailed that the information was routinely updated by the Division of Oil and Gas and was available on the department's website. She briefly highlighted two maps on slide 16 that were routinely updated by the department.

Ms. Longan addressed updates on the permitting process and status and how DNR was engaged in oil and gas permitting activities. She began with a description of the basic anatomy of a large-scale development project on slide 18. She noted that DNR's priority continued to be to manage its permit programs as efficiently as possible to shorten the time necessary from appraisal to development. She reviewed slide 18:

- Statewide or regional impact - infrastructure development, economic growth opportunities

- Generally [companies] require long term leases or dedicated legal access such as easements in order to obtain project financing
- Lease/Unit Plan of Operations or Plan of Development
- Shorter term land use permits are necessary for construction
- Material sales for development
- Water Authorizations for development and operations

Ms. Longan shared that there were other departments with jurisdiction over the permitting of oil and gas projects. She planned to describe how DNR was interacting in the processes, supporting other departments as they processed permits for oil and gas activities.

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Ms. Longan shared an example of a success story on slide 19. She detailed that over the past few years the Division of Oil and Gas had been working to increase permit efficiencies. She pointed to a bar chart and highlighted that in 2013 it had taken an average of 180 days for the division to process permits. Over time, gains had been made and in 2018 it took approximately 30 days to process the permits. The division had achieved the accomplishment by automating and modernizing its systems (e.g. electronic applications). The division maintained a continuous feedback loop with applicants to understand where things were going well and identify future efficiencies. The department recognized that incomplete applications could cause delays; therefore, the division was proactively working with applicants to ensure they understood permit requirements. Additionally, updated guidance documents were available online. There was currently no permit backlog.

Ms. Longan reported there had been some structural changes at the department with the goal of maximizing the use of its time and gaining efficiencies. The department had moved the previously autonomous State Pipeline Coordinator's Section underneath the Division of Oil and Gas. The change had been made to increase efficiencies and made sharing knowledge and working towards similar goals and timelines more cohesive between the groups.

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Ms. Longan advanced to slide 20 and reported that DNR had learned the importance of doing business efficiently in order to handle the routine and daily workload. Additionally, it was important to be flexible, nimble, and ready for an uptick in activity. Over the past two years, there had been more federal activities across the North Slope than in the past. She reviewed reasons for the change on slide 20:

Tax Act – Coastal Plain Activity

- BLM to administer an oil and gas leasing program in the Coastal Plain of ANWR
- Section 200001 PL 115-97 requires at least 2 lease sales to be held by 2024
- Each sale must offer 400,000 acres of highest hydrocarbon potential, up to 2,000 surfaces acres of Federal land to support production and support facilities
- SOA Royalty 50%

NPR-A Activity

- Oil and Gas Leasing
- CPAI continued progress
- CD-5 production
- GMT-1 began production October 2018
- GMT-2 & Willow Development
- SOA Royalty 50% through NPR-A Impact Mitigation Grant Program

SOA authorizes water withdrawal, fish habitat permits for activities on federal lands SOA consultation, shares expertise on tundra travel, air quality, reclamation, etc.

Ms. Longan elaborated that under NPR-A there had not been as much of an uptick in activity over the past two years; it was more of a progression of accomplishments and activities over the last several years. She reported that ConocoPhillips continued to have great success and had reached significant milestones including production from the CD5 project. She added that production from the GMT1 project was the first production from a federal lease within the NPR-A. She shared that the state had authorities that were triggered on the activities taking place on federally managed leases. For example, DNR was authorizing water withdrawals; the Department of Fish and Game was

processing and approving fish habitat permits; and the Department of Environmental Conservation maintained authorities over air quality, water quality, and solid waste management. She informed the committee that as the federal agencies were busier responding to an uptick in activity, the state was busier managing the workload.

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Representative Josephson had always been curious about the rejection of a permit application. He wondered if the reason the legislature did not hear much about it was because in order to proceed there would have to be some mitigation or adjustment. For example, he assumed that if someone did not obtain a fish habitat permit, they would not merely stop because it meant the project would die. He thought perhaps someone would come to DNR to do a workaround of some sort. He asked for an explanation of something that had been rejected and then accepted.

Ms. Longan replied that the scenario described by Representative Josephson was fairly common throughout the state's permitting process. She believed the reason people did not commonly hear about permits being rejected was because the process was iterative. She used Representative Josephson's example of a fish habitat permit and detailed that often times permit applications may not be suitable or fish biologists and experts may have an alternative project configuration or plan to help and support the project applicant to make adjustments, which may have less impacts on anadromous fish. There were numerous examples and most often, permit applications as received were optimized and improved over time, which was the reason there was such a high success rate in permit approvals.

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Ms. Longan turned to slide 21 and described the complex federal processes including the length of time it took to obtain an oil and gas permit. She hoped to adequately explain the reason the length of time to obtain an oil and gas permit depended. She relayed that the timeline for state permit agencies was almost always driven by a major federal authorization and action. The left arrow on the slide described the various stages of the National Environmental Policy Act (NEPA), which was required for almost all proposed oil and gas activities. The longer

process could require an environmental impact statement (EIS) and there was a different process called an environmental assessment (EA).

Ms. Longan continued that over the past year NEPA had been working well in Alaska - oil and gas permits were typically going through a three-year NEPA timeline. There were other examples where things where things were delayed for various reasons and NEPA's process took five or more years. She reported that federal leadership was requiring federal agencies to conduct EIS, the NEPA review, in a one-month timeframe, while maintaining robust public and stakeholder outreach. Federal agencies were requiring and had issued four major projects including a Donlin [mine] project and GMT2 in a joint record of decision (JROD). She detailed it involved multiple federal decisions for a single project, which were combined and issued within a joint record of decision. She stated it was very important; it should and probably had translated into minimized risk to the project applicant (lessening the chance of conflicting federal agency decisions).

Ms. Longan moved to the second arrow from the left on slide 21 showing examples of a major federal authorities and required review processes that typically happened concurrently throughout the NEPA process. She noted there were dozens of examples that were not included. She highlighted the Army Corps of Engineers 404 wetlands permit required under the Clean Water Act anytime fill was placed in U.S. waters. She shared that the state was known for its robust, multi-layered permitting system.

Ms. Longan intended to highlight the DNR permit process and the process in several other state agencies. Some permits (e.g. the 404 permit) were associated with requiring longer lead times. For example, the State Historical Preservation Office (SHPO) was responsible for conduction the Section 106 review for proposed projects, which was important to understand and minimize risk or any impact to cultural and historical resources. She explained it was a good example of where a state had authority to administer the Section 106 process, but it also had to comply with federal statutes and regulatory guidelines. She elucidated that when a state permitting program had the federal compliance piece, it increased the level of complexity and in some cases required more time for departments to collaborate and coordinate with their federal counterparts.

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Ms. Longan continued addressing slide 21. She shared that because DNR recognized that Section 106 was so important to the overall timeline for large projects, it had made another structural change for the specific review for large projects. The department had moved the work into an office to ensure the SHPO review process was close to leadership to provide support throughout the operation. She underscored that DNR were not experts at what other state departments were doing for oil and gas permits. She shared that DEC's air quality permit could be associated with longer lead times. She explained that DEC had authority to administer its air quality permit program and authorizations thereunder, but they were also required to comply with federal statute and regulatory guidelines under the Clean Air Act. She relayed that data was essential to inform DEC of how to issue air permits; data collection could typically take one year or longer.

Ms. Longan shared that permit agencies recognized where review processes may be complex; therefore, they were working hard from a leadership and staff level to communicate consistently between DNR, DEC, and DFG to proactively troubleshoot any problems.

Ms. Longan relayed that while NEPA and federal and state authorizations were concurrently moving forward, the project applicant had to work with the local borough and municipalities to secure borough, city, and tribal village plans.

Representative Josephson shared that his office had learned that the draft EIS for the Donlin Mine had a comment period of about seven months. The Army Corps of Engineers was offering a 90-day public comment period for the proposed Pebble Mine project. He highlighted that the state's delegation including Senator Lisa Murkowski and Senator Dan Sullivan had stated that the 90-day period was too short. He noted that Bristol Bay Native Association, Bristol Bay Native Corporation, and Bristol Bay Economic Development Corporation had asked for a longer comment period. He asked why the Army Corp had limited the comment period to 90 days and why it had denied requests to lengthen the timeline. He wondered why the agency gave seven months for Donlin and only three months for Pebble.

Ms. Longan did not know the answer but wanted to try to help. She reminded the committee that federal government (Army Corps of Engineers) had decided on the length of the public comment period for the proposed Pebble project. She noted that federal agencies typically made determinations based on how robust and successful the stakeholder engagement process was throughout the review period from the point where land was released and when exploration took place in advance of a project approval for oil and gas and mining projects. She explained that if the lead federal agency deemed there was sufficient information and the process had been robust enough, it was factored into the decision to extend or not.

Representative Josephson stated that one of the major mines that most Alaskans had heard less about was the Donlin project. He shared that earlier in the day he had met with four residents of the Lower Kuskokwim district who claimed the current administration was not being cooperative in terms of government to government relations. He noted the reference to tribal village plan on slide 21. He relayed that the Lower Kuskokwim residents wanted some assurance their concerns about subsistence issues and related matters were heard.

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Ms. Longan addressed the reference to a tribal village plan on slide 21 and explained that securing the plan was the responsibility of the project applicant. She noted that she was not an expert in the terminology referenced by Representative Josephson because there was no requirement for the State of Alaska to offer the formal government to government consultation required by federal law; however, DNR and the state maintained a broader public comment opportunity and stakeholder outreach and engagement. She noted it was an important responsibility of the department's and the process was iterative. Often members of the public or people living in rural communities throughout Alaska and perhaps those impacted by the proposed Donlin project, learned more about a project over time due to its complexity. She would share an example of how the department tried to break the process down to make sure the affected stakeholders and public were keeping track and able to voice their concerns to DNR. She stated that the process was ongoing.

Co-Chair Wilson asked if there was any point in the process where the state was more stringent than the federal government.

Ms. Longan answered in the affirmative. She detailed there was a lot of discretionary approval in many of the state authorizations where the state followed very prescriptive regulation. Alternatively, she used the fish habitat example and relayed that if there was something in a proposed action or project that needed to be modified, the state could be more prescriptive by catching that and wanting to work towards solutions. She did not know the specific regulations where the state was more prescriptive than the federal government. The state routinely examined the issue and made changes to its regulatory programs to make them more or less restrictive. The state also worked for consistencies - if the state regulations required one thing and the federal government required something completely different, it was an iterative process where the state tried to be as consistent as possible.

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Co-Chair Wilson asked whether it added more time to get permits through.

Ms. Longan replied in the negative. She detailed that changes to a regulation could not and should not impact a project application that had already been submitted. She had not witnessed a time where a change had added a permit delay.

Co-Chair Wilson thanked the department for its increased efficiency and recalled that in the past the permit process had been far behind. She was thankful that the items were not all happening separately.

Representative LeBon believed the EIS likely touched almost every permit. He wondered if it was usually the lead for the project. He asked if many permits waited for the final EIS before getting into their process. He noted that slide 21 gave the impression that everything was taking place concurrently, but he did not believe that to be the case.

Ms. Longan agreed. She emphasized that the state could not issue permits until the EIS process was complete. She explained that the process configuration changed through

the EIS process. The configuration would be optimized and modified to reduce environmental impacts. The state was educating itself and working with the public and project applicant to understand what the NEPA looked like. She would describe the specific actions momentarily. She stated it was imperative, because if the department waited for the EIS to go on for a year without knowing much about it, it started virtually from scratch when it worked to review the state permits. The state was coordinating to make the process as concurrent as possible, but the state would typically not issue its major permits until the completion of NEPA and the EIS.

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Representative Carpenter lauded the department for eliminating the permit backlog. He wondered where the department recommended that a new company hoping to invest in Alaska begin in the process.

Ms. Longan replied that the question pertained to her next slide. She had some success stories to share and a well-executed process in Alaska. She turned to slide 22 and shared that it was important for DNR to operate efficiently, but it was also important to understand the need to strike a healthy balance - that no matter how efficient DNR was operating, it was still working to issue science informed decisions that took public and stakeholder input into consideration, ultimately to enable DNR to issue defensible permit decisions. One of the greatest tools DNR had seen utilized by the public and private sector for over 20 years was the Office of Project Management and Permitting (OPMP). She detailed that OPMP was established in the 1990s with the advent of the Fort Knox Mine. They had recognized there was major federal jurisdiction, that there would be numerous state permits required, and it would make sense to have a structure in place for the federal, state, and local governments to be able to coordinate and operate things as concurrent as possible.

Ms. Longan detailed that OPMP was located in the DNR commissioner's office, which was unique nationwide. She believed the state was well ahead of the times. She explained that it had been a voluntary coordination services - the office was run almost exclusively off of reimbursable services. She shared that OPMP was offering industry a one-stop permit coordination approach to

minimize the regulatory risk of things not running concurrently or off the tracks. The office was working daily to ensure the process was fair, predictable, and on time.

Representative Carpenter clarified that his previous question was based on comments and discussions in the legislature and his past experience in the military dealing with governments and tribal governments outside of Alaska. He observed that the Tribal Village Plan was one of many items in the process [slide 21]. He stated that because all emergencies were local, all development was also local. He asked if the state was recommending that companies start at the local level to gain buy in from the local community before starting the federal or state process.

Ms. Longan replied in the affirmative. The local governments had to wait for NEPA to finish in order to issue permits. The companies with sights on doing business in Alaska were sophisticated and knew the process; if they did not know, they were reminded by DNR and most likely legislators of the importance of getting boots on the ground and working with local governments and stakeholders to understand how they wanted to be incorporated into the process. She was proud of DNR's leadership over many years. She explained that in order for the state to help aid communication, the project applicant needed to communicate with local residents and the boroughs, and the state needed to maintain effective communication as well.

Ms. Longan continued that due to high activity on the North Slope and elsewhere in the state, DNR had a longstanding memorandum of understanding (MOU) with the mayor of the North Slope Borough. She was pleased to report that new DNR leadership was working on updating the MOU. The work required teams to work at the commissioner to mayor level, there were quarterly leadership meetings, and staff spoke monthly or on an as needed basis to ensure they were sharing what they were hearing from applicants. The department was also encouraging the private sector to maintain good communication at the local and state level.

Vice-Chair Johnston referenced Ms. Longan's discussion of changes made in Section 106. She asked if Section 106 had been brought into "this" [OPMP] office.

Ms. Longan replied in the affirmative.

3:04:18 PM

Ms. Longan relayed that the next several slides [slides 23 through 25] to highlight the complexity of the process. The slides also addressed where to start. She explained that OPMP maintained coordination protocol that allowed DNR to communicate with all branches of government so the private sector and public could understand who they need to contact. Slide 23 included a list of the various state departments that were often involved with reviewing oil and gas permits. She noted there were numerous departments with multiple divisions underneath; the same was true for federal counterparts [slide 24].

Ms. Longan turned to a state agency coordination bubble chart on slide 25. The slide was intended show that OPMP was a first line of contact to direct people to the appropriate agency. The office also communicated with counterparts throughout federal, state, and local government. She stressed that the coordination effort provided by OPMP was a value added tool that made the complex permitting framework a bit easier to understand. She concluded the presentation on slide 26 with a list of department staff who had contributed to the presentation. She thanked the committee for its time.

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

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ADJOURNMENT

3:06:58 PM

The meeting was adjourned at 3:06 p.m.