HOUSE FINANCE COMMITTEE
January 22, 2025
1:32 p.m.

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CALL TO ORDER

Co-Chair Josephson called the House Finance Committee meeting to order at 1:32 p.m.

MEMBERS PRESENT

Representative Neal Foster, Co-Chair
Representative Andy Josephson, Co-Chair
Representative Calvin Schrage, Co-Chair
Representative Jamie Allard
Representative Jeremy Bynum
Representative Alyse Galvin
Representative Sara Hannan
Representative Nellie Unangiq Jimmie
Representative DeLena Johnson
Representative Will Stapp
Representative Frank Tomaszewski

MEMBERS ABSENT

None

ALSO PRESENT

John Crowther, Deputy Commissioner, Department of Natural Resources; Travis Peltier, Petroleum Reservoir Engineer, Resource Evaluation Section, Division of Oil and Gas, Department of Natural Resources; Derek Nottingham, Director, Division of Oil and Gas, Department of Natural Resources; Representative Elexie Moore.

SUMMARY

PRESENTATION: PRODUCTION FORECAST BY DEPARTMENT OF NATURAL RESOURCES

Co-Chair Josephson recognized House Finance Committee nonpartisan staff and LIO staff. He relayed that the first order of business and the legislature's constitutional

responsibility was to pass a budget. He stated that the committee would focus on the operating, mental health, and capital budgets. He relayed that Co-Chair Schrage was in charge of the capital budget and Co-Chair Foster was responsible for legislation. The committee would hear a presentation from the Department of Natural Resources (DNR).

^PRESENTATION: PRODUCTION FORECAST BY DEPARTMENT OF NATURAL RESOURCES

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Representative Josephson invited committee members to ask questions along the way.

JOHN CROWTHER, DEPUTY COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, introduced himself. He relayed that the department had a significant amount of positive information to share.

TRAVIS PELTIER, PETROLEUM RESERVOIR ENGINEER, RESOURCE EVALUATION SECTION, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, provided a PowerPoint presentation titled "Fall 2024 Oil Production Forecast," dated January 22, 2025 (copy on file). He shared that he joined the department three years ago and had been working on the oil production forecast since that time. He detailed that the presentation would address Alaska's oil production forecast for the next decade in addition to how the forecast did in the fall of 2023 with respect to 2024.

Mr. Peltier began on slide 2 showing a reference list of acronyms. He noted the appendix included two additional slides including a table showing royalty by different property types and a map of units across federal, state, and joint properties showing the difference in royalties. He did not intend to cover the appendix slides during the presentation.

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Mr. Peltier reviewed the agenda on slide 3. The presentation would include an introduction and forecast preview, the FY 24 review with a focus on the North Slope and Cook Inlet basin, the DNR fall 2024 production

forecasting approach, and the fall 2024 forecast results and summary.

Mr. Peltier turned to a graph on slide 4 titled "Fall 2024 Forecast: North Slope." The y axis of the chart showed the fiscal year annual average daily production of barrels of oil ranging from zero to 1 million barrels per day. He noted the graph showed annualized average numbers with just ten data points. The x axis showed fiscal years 2025 through 2034. The middle blue line on the graph reflected the fall 2024 Department of Revenue (DOR) official forecast in the Revenue Sources Book. He noted the DNR production forecast was incorporated into the Revenue Sources Book by DOR. The graph also included a high and low forecast. There was always uncertainty in the forecasting and the department never knew for certain how things would work out. He detailed that the high and low forecasts for FY 25 started out at about plus and minus 5 percent respectively. Uncertainty grew over time, which resulted in a broadening spread in future years.

Mr. Peltier explained that DNR had confidential conversations with operators to compile information. For the purposes of the North Slope forecast, DNR aggregated all of the operator forecasts for currently producing fields and used the information as a comparison with the department's expectations. The operator forecast [shown as a dotted line] was the summation of all the producing units on the North Slope going into the future. He noted that the DNR forecast included future projects, but the operator forecast did not. He explained that future projects such as Pikka were not included in the operator forecast because the department did not request the information.

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Mr. Peltier moved to slide 6 titled "FY2024 as Forecasted by DNR in Fall 2023: How Did We Do?" He began with a chart showing FY 24 North Slope forecast on the right side of the slide. The chart showed the fiscal year annual average daily oil production for 2024 going from zero to 600,000 barrels of oil per day. The high and low scenarios shown on slide 4 were reflected in the bar chart as approximately 519,000 barrels and 422,000 barrels respectively. The official forecast was approximately 470,000 barrels. Actual production during FY 24 was 461,000. He noted that DNR forecasted roughly 2 percent more than the actual

production. He explained that the actual production was within DNR's range of acceptability of plus or minus 5 percent, but DNR's forecast was high. He added that the operator forecast was very close to DNR's at around 468,000 barrels, which was also high compared to actuals.

Representative Stapp believed it was the third consecutive forecast where the actuals were lower than DNR's forecast. He understood there was margin of error in the forecasting, but he was curious why the state's forecast had exceeded actuals several years in a row.

Mr. Peltier answered that the department worked annually to determine whether there was a bias in its forecast and whether it was doing something wrong in its calculations. He relayed that the department had identified a calculation bias the previous year. He pointed to the second bullet point on slide 6 that reported DNR's forecast was approximately 2 percent higher than actual FY 24 production. He clarified that 1 percent of the 2 percent difference was a result of the calculation bias, which had been addressed and fixed for the current year. The other couple of major unforeseen components that occurred the previous year related to oil field operations. He explained that the Point Thomson sales line froze in mid-January and did not resume operations until late May. Additionally, the total well count expected by the department had not been met. He would provide further detail on a future slide.

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Mr. Peltier continued to review slide 6 pertaining to forecast factors currently on the horizon. He highlighted that there was continued industry interest in the Brookian Age plays (i.e., Nanushuk) on the North Slope. There was substantial activity and exploration drilling in the east and development plays (i.e., Pikka and Willow) on the western part of the North Slope. He relayed that recent federal regulatory and leasing restrictions had presented challenges, which may change materially with the new administration. He noted that with Pikka and Willow ramping up their construction activities there had been equipment constraints on the North Slope. Overall, the operations costs had been impacted by resources being used by construction activities.

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Mr. Peltier turned to slide 7 titled "FY2024 as Forecasted by DNR in Fall 2023: Monthly Forecast with Daily Actuals." The chart showed oil production daily rates from zero to 600,000 barrels of oil per day. The chart showed monthly forecasted data reflected by a solid line overlaid with the actual Trans-Alaska Pipeline System (TAPS) North Slope production on a daily frequency. The chart included a dotted line reflecting cumulative production going from zero to 300 million barrels on the right. He highlighted that actual production varied substantially; it was impossible for DNR to forecast daily variations, but the forecast was relatively close. He pointed out a separation occurring beginning in January reflecting the Point Thomson sales line freeze along with the cumulative affect of the number of wells drilled on the North Slope and some variations on the forecast for various fields.

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Co-Chair Schrage asked about the impetus behind the slide and the month by month forecast.

Mr. Crowther referenced the earlier question by Representative Stapp about historical accuracy looking back. The department thought that adding more information and more historical detail would help explain the small variances and give more credibility and information to the legislature and public. He noted that the committee would see the same format later in the presentation as well.

Representative Hannan asked if the department went back and adjusted the 1 percent in FY 24. Alternatively, she wondered if the calculation bias had only been addressed in future forecasts.

Mr. Peltier answered that DNR did not fix the calculation bias for prior years. The presentation included the calculation bias. The change would only appear in future forecasts.

Representative Hannan asked if the future was FY 25 or FY 26.

Mr. Peltier answered FY 25.

Representative Galvin observed there was a slip in production in May through August. She thought it was fairly normal to see a slip during that time. She asked if there was anything outstanding that occurred to result in the decline.

Mr. Peltier answered that the summer months were exceedingly hard to forecast. He explained that major facility turnarounds occurred during that timeframe. He believed the downturn shown on the slide was indicative of the turnaround season on the North Slope in the major facilities. He shared that DNR had not gone back to take a look at which facility was down at the time for the forecast specifically. He noted that there was a recovery in very early July.

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Mr. Peltier turned to slide 8 showing a summary of North Slope production comparing FY 24 with FY 23. He relayed that all fields were expected to decline year-on-year. He noted that a decline may not happen every year, but generally over a two-year period a decline in production was expected in existing oil fields. The top chart on the right of the slide reflected [North Slope] annual average daily oil production from zero to 600,000 barrels. In FY 18, production was at roughly 518,000 barrels per day. Production had declined to just under 461,000 barrels per day in FY 24. He noted that the decline was not atypical in a place like Alaska's North Slope. The change from FY 23 to FY 24 was about 4 percent or a decline of about 18,700 barrels per day.

Mr. Peltier addressed a chart on the lower right of slide 8 showing production changes across North Slope assets from FY 23 to FY 24. The chart listed decreases first, which resulted in the 18,700 barrels per day. He noted that increases were shown at the end of the chart. The Colville River, Endicott and Kuparuk River units were all experiencing natural decline offset with development drilling. He stated it was good to see continued reinvestment in the fields but it was not atypical to see decline. He explained that Nikaitchuq, Northstar, and Oooguruk fields were all experiencing natural decline and did not reflect anything atypical. He noted there had not been any new drilling to offset the decline and it was what was expected from a mature field being water flooded. He

relayed that Prudhoe Bay was the largest oilfield on the North Slope, producing well over 200,000 barrels of oil per day. He detailed that the decline number looked high, but it had to do with the fact it was such a large producing field. Additionally, there had been a relatively deep turnaround in Prudhoe Bay in August 2023 that impacted FY 24. The last decrease shown on the chart pertained to the frozen sales pipeline at the Point Thomson field in the first half of 2024.

Mr. Peltier addressed increases on the North Slope in FY 24 on slide 8. The first increase was at the Badami field where well work brought one of the field's biggest wells towards the end of FY 24. The Greater Mooses Tooth Unit had a new pad called GMT2, which the operator had continued to develop, resulting in production growth. The last increase was on the Milne Point field. He elaborated that the field had continued to see year-over-year production increases due to the operator's activity.

Co-Chair Josephson recognized Representative Justin Ruffridge in the room.

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Representative Stapp asked for a summary showing the fields in aggregate in terms of the ownership and operator. He stated it would be easier for him to parse through with the declines and increases if he could see the field, land (i.e., state, federal, Native land). He explained that it would help him get a bigger picture of the overall revenue pertaining to production.

Co-Chair Josephson asked the department to route the information through his office.

Representative Johnson asked if the policy of the department was to encourage as much development as possible at all times.

Mr. Crowther answered that it was DNR's policy and statutory obligation to ensure there was full development occurring on all legacy and new fields. He relayed that the presentation would cover some of the new activities occurring. He referenced the decline shown for legacy fields on slide 8 and explained that in many cases the fields had been operating for decades and there was

significant investment going on. There were also many new, exciting projects taking place on the North Slope that the department thought would bring increased production in the future for new fields or reinvigorated activity in existing fields. He noted there had been a couple of significant transactions on the North Slope changing operatorship and ownership of legacy fields. He highlighted there had been new pad development on the Milne Point field that resulted in an impressive production turnaround, rivaling production levels from the field 20 years back. The turnaround started about 10 years back when Hilcorp became the operator and had started work on a new pad and work on recovery methodologies. He pointed out that Nikaitchuq and Oooguruk had previously been operated by ENI, but the assets had been sold to Hilcorp. In light of the geologic similarities, DNR believed some of the applications that occurred on the Milne Point field could occur for the Nikaitchuq and Oooguruk fields in the future.

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Representative Galvin asked when Prudhoe Bay would reach a typical hyperbolic curve and would level off instead of seeing the decrease.

Mr. Crowther deferred to a colleague with past private sector expertise managing the field.

DEREK NOTTINGHAM, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, replied that DNR believed the Prudhoe Bay field was already in a hyperbolic decline. He explained that a 3 to 4 percent decline per year was an expected base level decline. He elaborated that 10,000 barrels per year was close to that amount, with some additional production losses due to a longer turnaround time. He relayed that there was significant capital investment and drilling that went into maintaining the 3 to 4 percent decline. He detailed Hilcorp and its partners were active in the field with well work, drilling, and facility projects.

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Mr. Peltier continued to review slide 8. He pointed to a website link at the bottom of the slide and explained that the Division of Oil and Gas worked with the Alaska Oil and Gas Conservation Commission (AOGCC) the past year to

publish its oil production data in a chart form at the field, pad, and well level. He turned to slide 9 titled "Status Update: Milne Point Unit." The slide showed daily production rates at Milne Point beginning when BP took operatorship in early 1995 through the last month of November 2024. The left side of the chart showed the average daily oil production rate per month and the right side of the chart showed the water daily production rates. He focused on the oil production which ranged from zero to 60,000 barrels per day on the chart. He detailed that when BP was the operator it achieved a maximum rate of just under 59,000 barrels per day in 1998. The field had declined to just under 19,000 barrels per day in November 2014. Hilcorp assumed operatorship of the field in November 2014 and had started a drilling program, developed two new pads, and implemented some enhanced oil recovery projects. As a result, the average daily production in November 2024 was 47,465 barrels per day. The production was the highest it had ever been under Hilcorp operatorship and DNR had high confidence the field would continue to see production growth and exceed 50,000 barrels of oil per day due to all of the effort.

Mr. Crowther noted it was extremely unusual to see the shape like the one shown on slide 9 for the production life history for fields.

Co-Chair Josephson thought that would be true and remarked that it was good to see.

Mr. Peltier referenced the two new Milne Point pads he had mentioned on slide 9. He detailed that one of the most recent pads discussed on the North Slope was called Raven Pad (R-Pad) and had been on the department's key future project list the previous year. The pad had been developed a full fiscal year faster than DNR had expected. Slide 10 showed a status update of six key future projects on the North Slope. The projects were listed in chronological order based on when the department expected them to come online. The KRU Nuna-Torok project was a new pad within the Kuparuk River Unit (KRU), the Mustang Unit was a new single pad development to the west of KPU, and the Colville River Unit (CRU) Minke project size was to be determined. Additionally, the slide showed the large North Slope projects including Pikka Phase 1, Pikka Phase 2 (new unit and processing facilities), and Willow.

Mr. Peltier provided a status update of each of the six fields listed on slide 10. He began with KRU Nuna-Torok and relayed that in 2024 funding had been approved for the project and it had been under construction with anticipated first oil in 2025. He reported that production began in December 2024 under the operator ConocoPhillips. The department had an internal expectation for a peak rate of around 20,000 barrels per day for the project. He moved to the Mustang Unit and relayed that Finnex had taken over operatorship from the Alaska Industrial Development and Export Authority (AIDEA) in October 2023. Since that time, Finnex had worked hard to expand the pad, conduct pipeline tie-in activities, and other restart activities, in addition to drilling two development wells in 2024. Production had started on the work in the past month and the department expected peak production of about 4,000 barrels per day.

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Representative Bynum referenced slide 9 showing an abnormal curve where production had declined, the operator had changed, and production had increased. He asked if there was specific information available on the result of the increased production. If so, he wondered if a policy would be put forward to ensure the mistakes resulting in reduced production would not be made in the future.

Mr. Peltier replied that Hilcorp had chosen to invest substantial time drilling new wells at Milne Point, while the previous operator BP did not drill as many wells. Additionally, the well architecture had changed. He detailed that Hilcorp had elected to drill simpler wells that were easier to manage compared to what BP had been drilling in the past. He believed the shift [indicated on slide 9] was the result of the continued change of new drilling. He added that the Schrader Bluff reservoir was leading the change. He elaborated that the large production wedge shown for BP in the past was from the Kuparuk River formation, which had declined and continued to decline. There was Schrader Bluff drilling at that time as well; however, BP was challenged with the cost of doing the work. When Hilcorp implemented its drilling, it was mostly focused on the Schrader Bluff resources; there was a large volume of resource potential in the Schrader Bluff that was untapped when Hilcorp took over operatorship.

Representative Hannan looked at the Mustang project on slide 10. She asked how long AIDEA had been the unit operator prior to Finnex taking over and whether there were any other units AIDEA was operating.

Mr. Peltier would follow up on the question.

Mr. Crowther would confirm the period of operatorship. He relayed that AIDEA acquired the assets as a result of a series of complex financial and bankruptcy transactions. He did not believe AIDEA had a primary intent to retain and develop the field. He elaborated that AIDEA had worked to bring in partners and transfer the field to an operating company, which it had successfully done. Subsequently, the company had succeeded in bringing the field back into active production.

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Representative Hannan asked if the Mustang field sat idle with AIDEA for multiple years or a period of months. She knew there were some legal issues that led to the result. She asked if there were any other units where AIDEA was the operator even if the field was not currently operating.

Mr. Crowther replied that the department would follow up with the information. He stated that AIDEA was not presently the operator of any other North Slope units.

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Mr. Peltier resumed his explanation of the fields on slide 10 beginning with the CRU Minke field. He noted that the project had not been included in the department's key future projects list the previous year. He explained that in the past year ConocoPhillips drilled an exploration well CD5-32X. Based on the results of the exploration well, Conoco planned a producer-injector well-pair to be drilled in the current winter. He noted that future production would depend on the performance of the producer-injector pair.

Mr. Peltier addressed large projects being installed on the North Slope. Pikka phase 1 had been under construction the previous year when DNR presented to the committee, and it was still under construction. First oil was initially expected in Q1 of 2026 and it was now expected in Q2 of

2026. He added that Santos had indicated in its investor presentation it was targeting trying to get the field online in December of 2025. The peak rate for the project was 80,000 barrels per day. Pikka phase 2 was expected to follow phase 1. The department expected the project to move to the FEED [Front End Engineering and Design] stage in 2025 with a final investment decision (FID) in 2027. There was potential for an additional 80,000 of production capacity from phase 2. The department was looking forward to seeing Pikka phase 1 come online in the next 12 to 18 months.

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Mr. Peltier addressed the ConocoPhillips Willow project at the bottom of slide 10. He relayed that a Bureau of Land Management (BLM) record of decision on the supplemental environmental impact statement (SEIS) was issued in 2023, which enabled construction to begin in April of 2023. Conoco announced FID in December of 2023. He detailed that first oil was expected in 2029 and the peak production rate was expected to be 180,000 barrels per day.

Co-Chair Josephson looked at the chart on slide 4 and thought it appeared the department was being hopeful that the Pikka project would produce the full 160,000 barrels. He asked if his understanding was correct.

Mr. Peltier replied that he would address the question on a slide later in the presentation.

Mr. Crowther highlighted that the legislature passed a unanimous resolution in support of the Willow project, which had positive results for the project. He thanked the legislature for the resolution. He remarked that the projects were getting closer to startup and the volume of new production was unseen in modern Alaska. He stated the projects reflected a turnaround and growth that rivaled the startup of the Kuparuk River field. He added that the argument could be made that it rivaled Prudhoe Bay in terms of new activity and volume of production. From the department's perspective, it was a major change in the paradigm on the North Slope. He stated it was very exciting.

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Mr. Peltier turned to slide 11 titled "FY2024 Summary: Cook Inlet." He pointed to a chart on the top right of the slide showing Cook Inlet daily production. He relayed that Cook Inlet had been in production for over seven decades. The field had a large production number in the past; however, there had been seven decades of decline. The chart showed a daily production range of zero to 20,000 barrels [from FY 17 to FY 24]. The chart reflected a production peak of just over 15,000 barrels of oil per day in FY 18, declining to around 8,500 barrels per day in FY 24. There was a production decrease of 450 barrels per day (5 percent) between FY 23 and FY 24. He highlighted that the oil from Cook Inlet was critical to the supply of instate refineries; the oil was used to create aviation fuels for use in the Southcentral Railbelt region.

Mr. Peltier addressed a chart on the lower right of slide 11 reflecting production decline by field. He relayed that Beaver Creek, Granite Point, Hansen, McArthur River, and Swanson River units were all experiencing natural decline. The fields were all mature and the operator was doing as much as possible to produce as much oil as possible, but there had been no real drilling for oil in the Cook Inlet for some time. The Redoubt Shoal had natural decline; however, rate-adding well work had restored some oil production and cut into the natural decline. The Kenai Loop and Middle Ground Shoal fields were effectively offline. They were reflected on the chart because they were existing units, but both were producing at a zero rate. He noted that Swanson River was experiencing natural decline. Trading Bay and West McArthur River fields were producing more oil in FY 24 than the prior year because well work offset the fields' natural decline.

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Representative Galvin recognized slide 11 pertained to Cook Inlet oil forecasting. She asked if the gas production rates for the fields were similar.

Mr. Peltier answered that it depended on the field. He explained that some fields had natural gas reinjection. He elaborated that those fields produced a fair amount of gas, but it was put back into the field to augment oil production. He relayed that natural gas should be declining with the oil production rate if managed pressure was being used. He noted that the oil fields did produce natural gas

used in the Southcentral Railbelt; however, they were not as key as the gas producing fields.

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Representative Hannan asked about a scenario where oil was reinjected in the Kenai Loop or Middle Ground fields that were effectively no longer producing oil. She asked if the gas was still there and could be extracted.

Mr. Nottingham responded that if gas was injected into a field for enhanced oil recovery some of the gas came back out of the ground with the oil as the oil was matured. Some of the gas would get trapped in the pore space, but a lot of the gas did get produced along with the oil. He relayed that if it was economical, there where techniques that operators could use to recover the remaining gas.

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Co-Chair Schrage asked why the presentation did not include a list of key projects for Cook Inlet. He asked if there were not the volume of projects and activity in Cook Inlet compared to the North Slope.

Mr. Peltier answered that there was one key project for Cook Inlet. He added that the Cosmopolitan project was included on a later slide.

Co-Chair Josephson referenced the use of gas for reinjection and enhanced oil recovery on the Cook Inlet. He asked if it would be more meaningful for home heating fuel because the amount of oil production was de minimis relative to the North Slope. He noted that rather than burning the gas, it was being used for enhanced oil recoveries.

Mr. Crowther replied that the oil produced in Cook Inlet was entirely consumed by instate refiners, which led to instate fuel and commodities - there were some exports of heavy and residual ends of the crude - for things like gasoline, aviation fuel, asphalt used in Southcentral. He explained that the tradeoff would result in a fuel supply problem of another kind. He noted there was already a fuel supply problem in Cook Inlet as production declined. He stated that the oil itself was very important. He relayed that as operators came to DNR with development plans for

different projects, the department looked at what the projects targeted and how the priority fit with other things in the operator's portfolio. He noted that oil continued to be important because of the need for fuel supply and the operators' ability to make their own development decisions. He added that the Cosmopolitan project was a potential oil project. The department had much more information about potential gas production from existing fields and potential new resources that could be presented to the committee at another time. He stated it was related to some of the same dynamics impacting oil production, but there were some unique factors DNR was looking closely at.

Mr. Nottingham added there were no ongoing gas injection projects for oil in the Cook Inlet. He believed the last one may have been at Swanson River and the gas injection for enhanced recovery was shut in several years back. He would follow up with detail.

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Mr. Peltier transitioned to how DNR created the production forecast. He relayed that there had been no change in methodology in the past three years with the exception of fixing the calculation error. He moved to slide 13 titled "DNR Forecast Process: Projects/Pools Included in Forecast." He explained that the department's production forecast started with a decline curve analysis for all existing production for all producing pools across the North Slope and Cook Inlet. The forecast currently included 40 pools across the North Slope and Cook Inlet, which had to be online and producing by June 30, 2024 or earlier to be included in the decline curve analysis portion of the forecast. Additionally, DNR worked with the Department of Revenue (DOR) to have confidential in-person and in-writing interviews with all of the operators. The operators provided the departments with a fair amount of information it could use to help gage the uncertainty on current production and future projects.

Mr. Peltier relayed that at the end of the discussions with operators the past fall, there were 16 large projects that DNR considered to be under development or evaluation to further include in its portfolio of large projects. He reminded the committee that the information was confidential; therefore, DNR could not talk about specific

projects other than to communicate that 15 were located on the North Slope and one was located in the Cook Inlet. He clarified that the production forecasting only included oil.

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Mr. Peltier addressed slide 14 titled "Categories of Production: Ongoing/Current vs Future Production." He noted that the department broke production up in a number of ways. He explained that existing fields were referred to as current production (CP). He clarified that the category pertained to ongoing production from existing fields with the expectation that the fields had to be online before June 30, 2024. He noted that the Nuna-Torok project from the Kuparuk River Unit and the Mustang project were included in the presentation as future projects because they were not online on June 30, 2024. He reviewed features and considerations pertaining to current production including well and facility uptime, operator spending to maintain base production, and major changes to reservoir management.

Mr. Peltier continued to review slide 14. He relayed that DNR had made a slight change to its definition for projects under development. He explained that under development (UD) pertained to investment and infield drilling on existing fields. He highlighted that DNR was leaving all of the large projects in the under evaluation (UE) category for a risking perspective. He detailed that DNR never changed how it risked the 16 large projects; therefore, it decided it should not be changing UD or UE until they came online. He noted that the categories had never been treated differently. He relayed that UD and UE projects required new investment to come online. He elaborated that there was always uncertainty in future well performance and project scope. Historical well performance data was used to gage the uncertainty of the performance of new wells drilled in existing fields; however, there was a lot more uncertainty for new projects in terms of scope and timing. He explained that economic and commercial risk associated with variations in oil prices could impact when a project came online. He noted that DNR did not include the risk components for infield drilling projects.

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Mr. Peltier turned to a map showing the North Slope on slide 15 related to major projects under evaluation considered in the fall 2024 forecast. He reviewed the general characteristics of major UE projects:

- Projects that were not online by end of FY2024 (data cut-off date of 6/2024)
- Higher risk factors than currently producing fields
- Known discoveries with identifiable operators
- Require major investments

Mr. Peltier pointed to a map on slide 15 showing North Slope major projects. The Willow development was located in the west on federal property. The Colville River Unit Narwhal CD8 and Minke projects were located on a mix of state, federal, and private lands. Various Santos projects were located a bit farther east and included Horseshoe Stirrup, Pikka Unit Development, Pikka Phase 2, Pikka Phase 3, and Quokka/Mitquq. Next was the Mustang unit. Farther to the southeast were the Theta West, Talitha, and Alkaid projects operated by Pantheon Great Bear. He noted that publicly the company called the Alkaid and Talitha fields Ahpun and Kodiak. He noted that DNR had left the names as Alkaid and Talitha to reflect the current unit names. He relayed that it may change in the future and DNR would change accordingly. Farther to the east was the Point Thomson unit operated by Jade Energy, which included an expansion project to increase production rate and the Sourdough project, an unrelated oil prospect located in the southern part of the Point Thomson unit.

Co-Chair Josephson asked if Point Thomson was still owned by Exxon.

Mr. Peltier answered that the ownership was a combination of Exxon and Hilcorp. He noted there were some other owners as well. He relayed that Exxon was the majority owner and Hilcorp was the operator.

Mr. Peltier reviewed the Fall 2024 North Slope annualized forecast on slide 17. The chart showed the fiscal year annual average daily oil production rate from 2025 through 2034 ranging from zero to 1 million barrels. The data came from the DOR Revenue Sources Book. The department expected average daily statewide production to be about 474,000 barrels of oil in 2025, with the North Slope accounting for 466,000 barrels per day. The range of uncertainty was

roughly 5 percent, ranging from 424,000 barrels of oil per day to 510,000 barrels per day. The department expected production to increase in the long-term as production projects came online. He noted that the production forecast was built on assumptions from the operators. He stated that business plans could change; therefore, the slide showed a static snapshot in time from the fall of 2024. The department provided an updated forecast twice a year in the spring and fall. He highlighted that the data on the slide included information up to November [2024] and did not reflect any changes since that time.

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Mr. Peltier asked to be reminded of Co-Chair Josephson's earlier question pertaining to Willow.

Co-Chair Josephson looked at slides 10 and 17 and observed that DNR appeared to be hopeful that Pikka phase 2 would occur even though FEED had not yet been completed.

Mr. Peltier replied that part of DNR's process involved bringing in 24 experts on various aspects for oil field development to get a sense of their thoughts on the risks of each of the projects and to learn whether they believe the projects would happen and what year they would come online. He relayed that Pikka phase 2 had been part of the department's project portfolio for years. He stated that with the continued development of Pikka phase 1, the confidence that Pikka phase 2 would come online had increased, but DNR did not consider it to be a foregone conclusion. The chance of its occurrence had increased from the previous year, but it was not guaranteed. He noted that the production bump indicated on the chart in the 2030 timeframe was more of a direct effect of Willow production.

Co-Chair Josephson recognized Representative Elexie Moore in the audience.

Representative Bynum asked if the information from operators took into consideration the improvement in technology resulting in better production from fields in the future. Alternatively, he wondered if it was based on operating plans in place at the time of development.

Mr. Peltier answered it was a combination of both. He stated that sometimes there was talk about brand new

technologies. He liked to use the wait and see approach at times. He referenced Milne Point as an example and explained that using existing technology in a new way had been extremely beneficial. He relayed that DNR took it into account.

2:37:40 PM

Co-Chair Schrage observed that a final investment decision for Pikka phase 2 was expected around 2027. He asked when the project was expected to meet peak production.

Mr. Peltier answered that first oil was expected about three to four years after FID. He added there was a range of uncertainty around the timeline.

Mr. Peltier advanced to slide 18 titled "FY2025 as Forecasted by DNR in Fall 2024: Monthly Forecast with Daily Actuals." He shared that it had been seven weeks since the department published its fall 2024 forecast. A chart on the slide showed oil production rate on the left and cumulative oil production on the right. The forecasting monthly data for FY 25 shown in blue reflected the department's forecast. He noted that the data on the slide was not something DOR published, DNR published it specifically for the presentation. The chart showed the Alaska North Slope (ANS) daily production for FY 25. He pointed to the cumulative forecast over time (the orange segment of the line reflected actuals and the dotted portion reflected the forecast) and relayed that prior to submitting the presentation, DNR had data through January 15, 2025. He remarked that DNR's forecast and actuals were right on. He noted that seasonal turnaround time came into the forecast around the end of August/early September, but by the time they averaged out, DNR had about matched actuals, which was a good start for the forecast cycle.

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Mr. Peltier turned to slide 19 titled "Fall 2024: AK Statewide Annualized Forecast (Expected Case with Production Categories)." The slide showed changes from the spring 2024 forecast to the fall 2024 forecast. The chart on the left showed annual average daily oil production ranging from zero to 700,000 barrels per day. The blue wedge showed current production and the orange reflected the next 12 months of expected infield drilling on the

North Slope. He explained that due to the definition change, all future projects and future infield drilling from years two through ten were included in the gray wedge. He highlighted that the current forecast was slightly less than the forecast for the previous year; it took into account how fields had performed over the past year, minor modifications had been made, and it was a slightly smaller forecast for FY 25. He noted that DNR anticipated that factoring in projects such as Willow and Pikka phase 2 would exceed the forecast from 2024 in the next seven to ten-year timeframe.

Co-Chair Josephson looked at the last bullet point on slide 19 and remarked that the Pikka and Willow projects were in between under development and under evaluation. He asked if it was appropriate to say the two projects were under evaluation.

Mr. Peltier answered that Pikka and Willow would remain in the under evaluation category until they began producing. He elaborated that the tools used to calculate the risk of projects coming forward would not change by simply moving the projects to the under development category.

2:42:22 PM

Mr. Crowther remarked that the department was struggling a bit to clearly present such a significant new greenfield project because there had been significant new pads or well programs within existing units, but there had not been a 50,000 to 100,000 barrel new greenfield project go into the currently producing wedge for some time. He stated it was a good problem to have in terms of how to communicate it.

Mr. Peltier highlighted the chart on the right side of slide 19. The chart showed production bumps expected from future projects that would come online within the next three years. Additionally, the chart reflected another tranche that would come online in years six through ten. Overlaid with that was the spring 2024 forecast. He pointed out the difference indicating the increased confidence pertaining to projects in the outyears.

Representative Galvin observed that as the forecasts got closer the level of certainty increased. She wondered if forecasts made ten years ago projecting the present day

production would have relied on the majority of production coming from projects under evaluation at the time.

Mr. Crowther responded that there had always been under evaluation projects. He elaborated that ten years ago, the under evaluation contribution was highly speculative and much smaller and there was a forecast that trended into a production level of 300,000 [barrels] or less. He stated that very fortunately current production was approximately 460,000 to 470,000, dramatically beating the forecast from ten years ago. He explained it was due to numerous factors including infield work, small projects, and rate maintenance. They were moving to a scenario where there were large "mega projects" in the Alaska sense, potentially coming online and changing DNR's ten-year trajectory. From his perspective, it was a two-point win for the state and the people of Alaska because they were dramatically beating the forecast from ten years ago and the forecast for ten years in the future was potentially better than the present.

2:46:00 PM

Representative Galvin stated her understanding that DNR did not believe the ten-year production projections would be as far under as the projections ten years ago.

Mr. Crowther answered that there was a tranche of things contributing to the positive forecast and outlook. He detailed that the continued investment in legacy fields had maintained in many cases rather than seeing a dramatic decline (where instead of a 3 to 4 percent decline there was an 8 to 12 percent decline, which was cumulatively dramatic over a 10-year period). Additionally, the under evaluation projects that were in construction and nearing startup were viewed as a major new tranche. He stated that exploration was a very exciting component. He explained that it was speculative and not confirmed, but the exploration activity was occurring in a variety of areas. He stated it led him to have confidence that the 16 projects in the UE wedge may or may not proceed and may contribute significantly ten years out. He expounded that there were units with committed exploration programs and current drilling. He explained that if one or more of the programs turned into potential discoveries, it would increase the UE category. It was very encouraging to see

that in every category and range of measurement, there were things that could be added.

Representative Tomaszewski remarked that there was a 180 from the previous federal administration to the new Trump administration with a number of executive orders targeting Alaska and its industry. He asked if there were steps the state should take to capitalize on the new administration and how it would push for oil and gas production from Alaska.

2:49:02 PM

Mr. Crowther responded that the potential for expanded activity and exploration, which went to future activity that may lead to discoveries and projects. He highlighted exciting areas beginning with the coastal plain 1002 area. He relayed that the department could present in more detail the history and specific changes DNR was seeing with the new [federal] administration. He explained it was an area where if seismic data could be gathered and exploration activity that could occur, it could be a major contribution in the longer term to the state and national production. The same dynamic was playing out in the NPRA to the west. The Willow project in the area was a huge new discovery that had moved into construction. There was significant reason to believe there were geologic prospects that the new federal administration was committed to supporting in its executive order. He noted that the governor was focused on working with the Trump administration to have coordination and move forward in the opportunities. He relayed that the department was prepared to jump on the opportunities.

Co-Chair Josephson recalled the discussion on Willow that had been agreed on in the legislature. He remembered looking at the previous Trump administration plan for the NPRA and its predecessor Obama plan. He remarked that even though there was a four-year term, the work did not happen overnight. He asked for verification that the only development thus far was in the far northeast corner of the NPRA.

Mr. Crowther responded that the Greater Mooses Tooth Unit and the Bears Tooth Unit or Willow project that were both under production or active development and were located in the northeast corner [of the NPRA].

Co-Chair Josephson remarked on what he viewed as a seesaw back and forth between administrations on whether there should be a two-thirds versus one-third or three-quarters versus one-quarter available acreage for potential development. He stated there was certainly hope for more and an argument that it was needed. He asked for verification that "these things take time."

Mr. Crowther agreed. He stated that when there was the federal policy layer it included time, potential litigation, and dispute over how to effectuate a development imperative articulated by the new administration. The department anticipated needing time and substantial work to allow exploration and potential additional leasing to occur. The department was very engaged in participating and supporting that and the governor had directed DNR to work expeditiously with the new administration.

2:52:12 PM

Representative Stapp asked if there were any updates on a situation involving Kuparuk [River Unit], a road, Santos, and ConocoPhillips. He asked if the situation had been figured out or if it was still a mess.

Mr. Crowther answered that DNR issued a permit to provide for access and there was a legal challenge. There was a superior court decision directing the permit to be vacated, but the state had appealed the ruling to the state supreme court. The appeal was proceeding, and the state was evaluating with the parties how to move forward with the litigation. The department maintained it was critical for operators to work together to ensure the state's interests were not impacted. Fortunately, the construction activities had proceeded and there had not been disputes in real time. The Pikka project had been able to proceed timely and the situation had remained a legal, commercial, and corporate dispute. The issue remained active for the state as the department analyzed how to protect the state's interest in the development and opportunities in the future such as leasing of state or federal lands located on the other side of existing road networks. There was more work to be done.

2:54:10 PM

Representative Johnson asked for verification that the situation was not slowing down the Pikka development.

Mr. Crowther replied that he could not speak for the operators or companies, but DNR had not yet seen a delay, which was important. He remarked that the past construction season had been very busy and there had been cooperation in field activity operations for the development to proceed. If the department saw something that was slowing it down, it would be an immediate concern for the state and it would do everything it could to prevent it from happening.

Representative Hannan believed the court ruling directing the state to vacate the permit was in December. She asked when the supreme court would decide whether to take the case.

Mr. Crowther answered that the different administrative stages had stretched on for several years. The superior court final decision took place several months back and the state promptly filed an appeal with the supreme court. The appeal was proceeding and had not yet been briefed to the supreme court. The state sought an emergency stay, which the supreme court did not grant; however, it noted in its order that the state had leave to seek a stay again if there was any indication of actual challenges to the access on the ground. The litigation would proceed with briefing, subject to continued work to resolve the issue between the companies themselves and also with the litigation with the state.

Co-Chair Josephson asked if the trial judge was judge [Andrew] Guidi.

Mr. Crowther replied that judge Guidi was the superior court judge.

Co-Chair Josephson offered to provide a copy of the court document to committee members. He discussed the schedule for the following day. He noted that the oil price and production were somewhat down from where the state hoped to be, meaning there would be some patching to do in the budget.

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ADJOURNMENT

2:58:04 PM

The meeting was adjourned at 2:58 p.m.