

HOUSE FINANCE COMMITTEE  
January 21, 2026  
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 Elexie Moore  
Representative Will Stapp  
Representative Frank Tomaszewski

MEMBERS ABSENT

Representative Nellie Unangiq Jimmie

ALSO PRESENT

Derek Nottingham, Director, Division of Oil and Gas, Department of Natural Resources; Travis Peltier, Petroleum Reservoir Engineer, Division of Oil and Gas; Representative Jubilee Underwood.

SUMMARY

PRESENTATION: PRODUCTION FORECAST BY THE DEPARTMENT OF NATURAL RESOURCES

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Co-Chair Josephson reviewed the meeting agenda.

^PRESENTATION: PRODUCTION FORECAST BY THE DEPARTMENT OF NATURAL RESOURCES

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DEREK NOTTINGHAM, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, noted that Acting Commissioner John Crowther could not attend the meeting due to a prior commitment. He stated that he wanted to begin by providing a high-level overview of the production forecast before turning to his colleague to discuss the details. He stated that 2026 was a significant year because new production was expected to come online from the Pikka project.

Mr. Nottingham stated that substantial progress had occurred over the previous year on the Pikka project, including construction activity, facility installation, and the drilling of multiple wells. He characterized the progress as significant. He added that notable progress had occurred on the Willow project and other major North Slope developments. The forecast also included information on ongoing activity at existing fields, including the Milne Point Unit (MPU). He stated that the production forecast reflected several positive developments. Over the next ten years, production was projected to increase from current levels to more than 600,000 barrels per day by the end of the forecast period.

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TRAVIS PELTIER, PETROLEUM RESERVOIR ENGINEER, DIVISION OF OIL AND GAS, shared that he was a petroleum reservoir engineer for the Division of Oil and Gas (DOG) within the Department of Natural Resources (DNR). He graduated from the University of Alaska Fairbanks (UAF) in 2006 with a Master of Science degree in Mechanical Engineering. He spent the previous 19 years working in Alaska's oil industry, primarily on the North Slope, as a petroleum engineer with BP. During his 14 years with the company, he worked across all BP-operated fields, ranging from the Kuparuk River Unit (KRU) to the Point Thomson Unit (PTU). He joined DNR in 2021 and was asked to lead development of the state's oil production forecast in 2022. He continued to lead the effort and the team responsible for producing the forecast on a biannual basis.

Mr. Peltier introduced the PowerPoint presentation, "Fall 2025 Oil Production Forecast" dated January 21, 2026 (copy

on file) and relayed that the presentation focused on Alaska's oil production forecast for the upcoming decade. He explained that DNR had conducted the analysis since 2016. He stated that the goal of the presentation was to share production forecast results for FY 25 as well as the ten-year forecast, including an overview of the methodology and background used to generate the forecast.

Co-Chair Josephson recognized Representative Jubilee Underwood in the audience.

Mr. Peltier continued to slide 2 which included a list of acronyms for reference. He stated that the acronym "BOPD" referred to barrels of oil per day and appeared frequently throughout the presentation. He stated that additional acronyms used on individual slides were listed at the bottom of those slides for reference. He continued to slide 3 and outlined the structure of the presentation. He would first review a preview of the forecast, followed by a review of FY 25 production. The presentation would then cover DNR's fall 2025 production forecasting approach and the methodology used to generate the ten-year forecast.

Mr. Peltier advanced to slide 4 which included a chart that displayed the fall 2025 North Slope annualized production forecast. He explained that the left axis reflected fiscal year annualized average daily oil production. For FY 26, the internal forecast was approximately 460,000 BOPD. The vertical axis ranged from zero to 1 million BOPD and each data point represented a single fiscal year along the horizontal axis. The chart incorporated information from the Department of Revenue's (DOR) Revenue Sources Book, including low, official, and high forecasts. He stated that the chart also overlaid operator forecasts for currently producing fields, which were provided confidentially and were aggregated for use in the production forecast. He noted that the operator forecasts were represented by a dashed line. He relayed that there were differences between DNR's forecast and the operator forecast. For FY 26, the operator forecast was higher, but it decreased beginning in FY 27. He emphasized that operator forecasts reflected only currently producing fields and did not include future developments such as the Pikka project, which was included in the department's forecast.

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Mr. Peltier continued to slide 6 and explained that the next portion of the presentation reviewed actual field production rather than forecast data. He stated that FY 25 production was reviewed to assess forecast accuracy. He relayed that DNR aimed for forecast uncertainty within plus or minus five percent for the upcoming fiscal year. For FY 25, actual production exceeded the prior year's forecast by 0.3 percent. He drew attention to the chart displayed on the right side of the slide. He stated that the vertical axis ranged from zero to 600,000 BOPD. The high-end DNR forecast for FY 25 was approximately 510,000 BOPD and the low end of the forecast range was 424,000 BOPD. He clarified that the mean forecast presented to the committee the prior year was slightly above 466,000 BOPD, while actual production concluded at just under 468,000 BOPD. He noted that the result fell within the targeted plus or minus 5 percent range.

Representative Hannan observed that the DNR forecast appeared accurate, but operator projections were more optimistic. She asked whether DNR conducted follow-up inquiries to determine where the anticipated 20,000 BOPD estimate had not materialized, or whether the discrepancy resulted from aggregated data across multiple operators rather than a specific development that failed to occur.

Mr. Peltier responded that DNR reviewed the data internally at the field level but did not request explanations from individual operators regarding overperformance or underperformance relative to their forecasts. He explained that operator projections were used solely as a comparator and were not relied upon in developing the DNR forecast. He explained that the operator forecast shown on the far right of the chart reflected a combined total of just under 487,000 BOPD for FY 25.

Mr. Peltier continued reviewing slide 6 and described several factors that were considered when shaping the annual forecast. He explained that DNR often received similar feedback from various operators working on the North Slope and in Cook Inlet. He relayed that feedback often highlighted continued industry interest in the Brookian topset prospects on both state and federal land. He noted that exploration results were recently released from the Sockeye 2A well during the prior winter season and demonstrated continued interest.

Mr. Peltier added that exploration activity on federal leases had increased under the current federal administration, with four wells proposed for exploration in the National Petroleum Reserve-Alaska (NPR-A) during the current year. He also noted that moderate oil prices and capital discipline across the industry continued to present challenges for development decisions. Additionally, inflation, elevated interest rates, and insurance-related challenges affected North Slope exploration costs and operations.

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Representative Galvin asked for clarification regarding inflation impacts. She noted that inflation had declined over the previous year and had decreased from 5 percent in January of 2025 to 3.7 percent in December of 2025. She asked whether operators had identified an ideal interest rate and she expressed uncertainty as to why inflation continued to pose a significant challenge.

Mr. Peltier responded that oil field inflation differed from consumer price index (CPI) inflation. He explained that cost increases specific to oil field operations often exceeded CPI trends. For example, between 2010 and 2014, CPI increased by approximately 2 percent annually while oil field inflation rose closer to 10 percent. He explained that sustained cost escalation of that magnitude constrained development activity. He noted that oil field inflation continued to outpace CPI.

Representative Galvin asked if oil field inflation included labor, subcontracting, and related operational costs.

Mr. Peltier responded in the affirmative.

Representative Stapp asked about the third and fourth bullet points on slide 6 concerning oil prices and capital discipline. He observed that the industry had made significant capital investments in both existing infrastructure and exploration wells during the current and prior year and noted that the investment occurred despite inflationary pressures and declining prices. He asked how Alaska compared to other areas of the country. He remarked that Alaska continued to attract interest in high-risk plays, including Sockeye 2A, and appeared to remain a competitive investment environment.

Mr. Peltier responded that he could not provide a direct comparison of inflationary pressures between Alaska and the rest of the country. Based on qualitative observations, operating costs in Alaska were generally significantly higher than in other areas of the country. He noted that wells drilled in other states could cost several million dollars, while comparable wells in Alaska were often more expensive.

Representative Stapp asked what actions the legislature could take that would most negatively affect continued capital investment.

Mr. Nottingham responded that he could not identify a specific legislative action that would be the worst course. He emphasized that maintaining a competitive business environment for Alaska, regardless of price conditions, remained critical. The oil and gas industry was highly competitive and companies had multiple alternatives for capital deployment. He encouraged the legislature to consider policies that preserved Alaska's competitive advantages.

Co-Chair Josephson asked for clarification on the location of Sockeye 2A. He understood that the Brookian topset was west of Point Thomson. He asked if the Canning River was also west of Point Thomson. He had visited Point Thomson and he understood there were some disputed lands in the area. He asked whether the prospective location was within contested or uncontested areas.

Mr. Peltier responded that the Canning River was located east of Point Thomson. He explained that the disputed boundary involved the border between state lands and NPR-A. He confirmed that the Sockeye 2A prospect was located west of Point Thomson and was not near the disputed lands associated with the river.

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Representative Galvin clarified that her earlier comments referred to interest rates rather than inflation. She noted that interest rates had declined and asked why operators continued to identify high interest rates as a challenge. She asked whether an ideal interest rate existed.

Mr. Peltier responded that the concern related primarily to private financing rates rather than federal benchmark rates. While Federal Reserve rates were publicly available, private sector borrowing for development projects typically carried significantly higher interest rates. He stated that he did not have access to specific figures and noted that such information was often confidential. He offered to follow up if additional information could be obtained.

Representative Galvin asked for confirmation that Mr. Peltier was referring to private lending rates above federal benchmarks.

Mr. Peltier responded in the affirmative.

Representative Galvin noted the answer was sufficient and she did not need a follow up.

Mr. Peltier continued to slide 7 and explained that the chart displayed information similar to the prior slide. He relayed that DNR had introduced the chart format during the previous year. He noted that the chart presented a 12-month forecast broken out by month. The left-hand axis reflected oil production rates in BOPD, ranging from 0 to 600,000. He stated that the orange curve with high-frequency fluctuations represented daily production rates. The purple line and the blue forecast line represented the monthly forecast compared against the average of daily run-ticket volumes. He explained that DNR generated monthly internal forecasts and used the chart to compare those forecasts against aggregated daily production.

Mr. Peltier explained that the right-hand axis reflected cumulative production measured in millions of stock tank barrels, ranging from 0 to 300 million barrels. He described the straight orange line and the dashed blue line as cumulative actual production and cumulative forecast production, respectively. The total forecast for 2025 was approximately 170 million barrels and actual production finished slightly above the forecasted level. He emphasized that the variance was minor and that the chart was intended to show how daily production translated into monthly and cumulative results. He added that an 18-month view would be presented later to illustrate the anticipated impact of the Pikka development scheduled to come online later in the year.

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Representative Hannan understood that the chart began at zero simply because it marked the first day of the fiscal year. She asked if the most relevant information was the cumulative total on the far right side of the chart.

Mr. Peltier responded that Representative Hannan's interpretation was correct. He explained that the cumulative forecast line was difficult to see because it was largely overlaid by the actual cumulative line. He noted that any meaningful forecasting error would appear as a visible gap between the two cumulative lines. He explained that if production underperformed in a given month, a divergence would emerge over time. He pointed to May 2025 and June 2025 as the point where daily actual production slightly exceeded the forecast, resulting in cumulative actual production marginally surpassing the forecast. He emphasized that the difference was small.

Representative Hannan noted that on the prior slide, Mr. Peltier had indicated that actual production exceeded the forecast by 0.3 percent. She asked whether the cumulative forecast remained within the acceptable margin, which she understood to be within plus or minus 5 percent.

Mr. Peltier responded that the cumulative forecast remained within the plus or minus 5 percent range that DNR targeted on an annual basis.

Mr. Peltier advanced to slide 8. He explained that the slide continued the review of actual field performance for FY 25 and did not present new forecast information. He reminded members that legacy North Slope fields, including the Prudhoe Bay Unit (PBU) and KRU, were mature fields that typically experienced year-over-year production declines despite ongoing reinvestment by operators. Contrary to typical expectations, total North Slope production increased in FY 25 compared to FY 24. He reported that basin-wide production rose by approximately 7,000 BOPD. He characterized the increase as a positive outcome and attributed it to sustained investment and reinvestment in legacy fields.

Mr. Peltier directed attention to the charts on the right side of the slide. He explained that the top chart showed fiscal year annual average daily oil production for the

entire North Slope from FY 19 through FY 25. He noted that production averaged approximately 495,000 BOPD in FY 19, experienced fluctuations during FY 20 and FY 21 related to the COVID-19 pandemic, and then generally declined through FY 25, where average production was approximately 468,000 BOPD. The bottom chart showed the change in production between FY 24 and FY 25, broken out by field. He noted that the bullet points on the left corresponded to the chart.

Mr. Peltier relayed that there were production declines at the Colville River Unit (CRU), the Greater Moose's Tooth Unit (GMTU), and PBU. He explained that the declines primarily reflected natural reservoir decline, partially offset by development drilling. There were also declines at the Endicott Unit and the North Star Unit (NSU) and no development drilling or new wells occurred during the fiscal year. He explained that the resulting volume losses reflected natural reservoir decline. He relayed that PBU produced more than 200,000 BOPD and a decline rate of less than 2 percent for a field of its size was notable. He emphasized that PBU formed the backbone of throughput into the Trans-Alaska Pipeline System (TAPS) and he credited the operator with effectively mitigating reservoir decline.

Co-Chair Josephson remarked that he was struck by the performance of KRU and asked whether it was fair to characterize it as performing strongly despite its status as a legacy field.

Mr. Peltier responded that KRU production increased in FY 25. He explained that the operator, ConocoPhillips, demonstrated strong base performance and undertook significant new drilling. Recent projects such as the Coyote Project had come online successfully and contributed to increased production. He also noted that there were positive results from viscous oil drilling in the Schrader Bluff reservoir, which further supported KRU production. He added that the Badami Unit also experienced an increase in production. He reported that the new well B-133A came online and had produced more oil than the remainder of the field combined.

Mr. Peltier stated that MPU continued to show sustained production increases driven by its ongoing infill drilling program. He reported that production at MPU increased by more than 4,000 BOPD in FY 25. He indicated that additional discussion of MPU activities would be provided on a later

slide. He added that the Nikaitchuq, Oooguruk, and PTU also recorded production increases during FY 25. The increase at PTU largely reflected recovery from a pipeline shutdown during the prior fiscal year, when a freeze during a production upset halted operations for several months. He noted that production resumed during the summer of FY 24, resulting in higher production levels during FY 25.

Mr. Peltier reported that the Southern Miluveach Unit (SMU) appeared on the chart for the first time. He relayed that production volumes were modest due to the timing of initial production, but early results had been positive. He indicated that additional information on the field would be available in future forecasts.

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Co-Chair Josephson asked whether production from PTU consisted of gas and condensate.

Mr. Peltier responded in the affirmative and explained that condensate volumes were reported as oil production and expressed in BOPD. He clarified that condensate was sold under a separate quality bank with its own quality meter. He explained that although PTU condensate carried a distinct grade, it was included under oil production totals for reporting purposes.

Representative Hannan asked whether the apparent increase in PTU production reflected a restoration following the aforementioned shutdown of another pipeline. She asked how current production compared to levels the year prior to the pipeline incident.

Mr. Peltier responded that detailed field-level production charts were publicly available and allowed users to review production data by well across North Slope fields. The last bullet point on slide 8 was a link to the field charts. He explained that PTU production had declined from FY 23 to FY 24 due to well performance issues in addition to the shutdown. He noted that the field had only one producing well and that the well experienced a loss in productivity. He explained that while production increased in FY 25, it had not yet returned to prior levels. He stated that the current operator was conducting ongoing remediation efforts to restore production and refill the facility.

Mr. Peltier continued to slide 9, which detailed the history and performance of MPU under both the prior operator, BP, and the current operator, Hilcorp. He explained that the chart displayed oil plus natural gas liquids on the left axis and water production on the right axis. He noted that oil production was expressed in thousands of BOPD and that water production ranged up to 200,000 barrels of water per day (BWPD). The chart reflected calendar-year monthly data from 1995 through November of 2025. He stated that under BP's operatorship, MPU functioned primarily as a "Kuparuk light" oil field and reached peak production in July of 1998 at just under 59,000 BOPD. He explained that production declined over time and reached approximately 18,779 BOPD day in November of 2014, when BP sold the asset to Hilcorp.

Mr. Peltier explained that Hilcorp assumed operatorship in November of 2014 and initially focused on stabilizing production. He explained that the operator later invested in SBU and implemented new drilling and polymer flooding, which resulted in year-over-year increases in production. He reported that the most recent monthly production level shown on the chart was 50,906 BOPD.

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Mr. Nottingham remarked that he had nearly 30 years of industry experience and it was rare to see a revitalization of a mature oil field that nearly duplicated its prior peak production. He explained that while some mature fields experienced later revitalization phases, production rarely returned to previous peak levels. The most notable aspect of the MPU revitalization was that production increasingly came from the Schrader Bluff reservoir, which produced more viscous and heavier oil than the Kuparuk reservoir. He explained that the original facilities were not designed to handle the heavier oil and the operator had successfully adjusted drilling practices and modified facilities to accommodate the oil.

Co-Chair Josephson remarked that Hilcorp was known as an operator that excelled at redeveloping mature fields.

Mr. Peltier advanced to slide 10, which provided a status update on five North Slope projects. He explained that Pikka Phase 1, Pikka Phase 2, and Willow were new projects associated with new fields. He relayed that CRU CD8 project

and Project Taiga under PBU were new pads within existing fields. He explained that new fields carried greater risk and cost than new pads in existing fields. During the prior year, the Pikka Phase 1 operator, Santos, conducted construction and drilling activities and anticipated first oil in the second quarter of 2026. As of 2026, the project was more than 95 percent complete and commissioning activities were underway. He reported that first oil was anticipated by the end of the first quarter of 2026. He added that peak production was estimated at 80,000 BOPD and that production would ramp over time.

Co-Chair Josephson asked whether there were plans for expansion into adjoining fields.

Mr. Peltier responded in the affirmative and explained that the expansion was classified as Pikka Phase 2. During the prior year, Pikka Phase 2 was in the conceptual engineering and cost estimation stage, with publicly stated plans to advance to front-end engineering design in 2025 and a final investment decision in 2027. As of January of 2026, Santos prioritized completion of Pikka Phase 1 before proceeding with Phase 2. He explained that Phase 2 included a new pad and additional production capacity and was expected to add approximately 80,000 BOPD. He explained that combined peak production from Pikka Phase 1 and Phase 2 was estimated at 160,000 BOPD.

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Representative Hannan asked whether Santos had sold or transferred ownership of the project.

Mr. Peltier responded that Santos acquired Oil Search, both of which were Australian companies. He explained that Oil Search Alaska (OSA) remained the Alaska subsidiary and held a 51 percent ownership interest in Pikka Phase 1 and Phase 2. He explained that Repsol held the remaining 49 percent interest. The current ownership structure was a 51-49 split between Santos and Repsol.

Co-Chair Josephson understood that the other name for Pikka Phase 1 was Horseshoe. He asked what the names for the other phases were.

Mr. Peltier responded that Horseshoe and Qilak were distinctly different projects from Pikka. He emphasized

that those projects were wholly separate units on the North Slope and were not part of the Pikka development.

Co-Chair Josephson asked whether the projects were also separate from Pikka Phase 2.

Mr. Peltier responded in the affirmative.

Mr. Peltier continued on slide 10 to discuss the Willow project, which was a ConocoPhillips development. He explained that first oil remained on track for 2029 and that the project was now more than 50 percent complete. The Willow Central Facility was currently under construction in Texas and was planned for transit to the North Slope in 2027. The Willow project was expected to reach a peak production rate of 180,000 BOPD. He relayed that the project was primarily located on federal land, unlike Pikka Phase 1 and Pikka Phase 2, which involved a mix of state and Alaska Native lands.

Mr. Peltier continued on the slide to discuss projects involving new pads within existing fields. He relayed that ConocoPhillips began permitting the CRU CD8 project in early 2025. He explained that the United States Army Corps of Engineers (USACE) served as the lead agency and that a notice of intent was issued on September 9, 2025. Engagement with stakeholders was ongoing and a draft environmental impact statement comment period was underway and scheduled to continue through the fall of 2026. He explained that a record of decision was anticipated in early 2027 and first oil was expected in 2030. He stated that no public production estimate had been released yet, therefore DNR was therefore sharing its internal mid-case estimate of approximately 20,000 BOPD.

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Representative Tomaszewski asked whether the production estimates for the projects discussed, including 80,000, 160,000, and 180,000 BOPD, explained the high North Slope forecast shown on slide 4, which approached approximately 975,000 BOPD. He asked if there were any factors that could derail the projects and if the high forecast was likely to be realized.

Mr. Peltier responded that the official forecast relied on mid-case assumptions rather than the high or low scenarios.

He explained that the official forecast summed to just under 700,000 BOPD and was a more representative estimate. He relayed that DNR assumed approximately plus or minus 5 percent uncertainty in the first year of the forecast and that uncertainty increased in later years. He explained that some projects might not come online as anticipated, which was reflected in the low-case forecast, while stronger-than-expected performance was reflected in the high-case forecast. Both scenarios were intended to show the range of potential outcomes.

Representative Stapp remarked that the chart reflected approximately 400,000 BOPD of additional production. He asked when the department had last been able to present projects of such a scale to the legislature. He noted that several other projects, including Sockeye 2A, were not shown on the slide and asked how the high level of new production compared to the state's historical experience.

Mr. Nottingham responded that he had been in his role for four years and that the department had often discussed the projects. He explained that the projects had progressed through multiple stages and faced numerous challenges, but what distinguished the current year was that construction activity was underway, facilities were being installed, and significant capital was being spent. He explained that Pikka had reached a point where production would soon come online and that Willow was well into development. He explained that the projects had moved beyond the conceptual stage and were now becoming reality.

Representative Stapp expressed that he viewed the situation as a historic moment in the state's recent history. He noted that Alaska had long discussed declining production. He was 38 years old and for the first time in his life, the state would experience a substantial increase in oil production. He thought that the increase reflected years of difficulty, significant capital investment by industry, and extended timelines. He noted that prior tax structure discussions had anticipated production growth and the results were materializing. He asked how the department determined which projects were included on the slide and which were excluded.

Mr. Peltier responded that the slide focused on large projects that were either nearing production or were materially significant to the long-term production

forecast. He explained that a later map would display all projects included in the North Slope production forecast, as well as one Cook Inlet project included in the aggregate forecast. The department reviewed its projects annually. He explained that inclusion of a project depended on whether a development plan existed, whether a known resource had been identified, and whether the operator intended to develop the project within the next 10 years. Any projects that no longer met the criteria were removed from the list, citing the Liberty project as an example. He explained that Liberty was no longer included because it was not expected to come online within the 10-year forecast window.

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Representative Stapp remarked that he was glad Liberty was mentioned. He was interested in projects like Liberty and asked how often companies invested significant capital in Alaska projects that ultimately did not succeed, resulting in financial losses for the operator.

Mr. Peltier responded that outcomes varied significantly across projects. He explained that PBU had exceeded expectations as it was initially projected to produce approximately 9.6 billion barrels of oil and had since produced billions of barrels beyond the estimate. Other projects did not meet expectations, such as Badami. He explained that the peak production rate for Badami was projected to be approximately 35,000 BOPD, but actual production never reached that level. He explained that peak daily production occurred early in the field's life and remained well below projections, with monthly average production significantly lower and long-term production declining to approximately 1,000 BOPD until the recent drilling of the B133A well. Overall, the Badami project had not met its original expectations.

Co-Chair Josephson commented that Shell's efforts in the Beaufort Sea were "notorious." He understood that there were efforts to develop Smith Bay as well.

Mr. Nottingham responded that Shell's efforts to explore the Beaufort Sea were extremely expensive and difficult to execute. The efforts ultimately resulted in significant costs and were abandoned. He explained that Alaska contained substantial resource potential but also presented extreme logistical challenges, particularly in remote

locations where specialized equipment was required and operational conditions had to align precisely for exploration and development to succeed. Additionally, resources were identified in Smith Bay, but the location was remote, situated on state land in state waters, and access required transit through NPRA. He relayed that federal access constraints created challenges for exploration, even on state lands, and that Alaska's development history reflected ongoing logistical and regulatory complexities.

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Representative Moore asked for an update on Pikka road access. She understood that there were jurisdictional challenges related to federal lands, state lands, and NPRA and there were additional challenges related to accessing the road in the winter.

Mr. Nottingham responded that the Pikka road access issues had largely been resolved. He explained that ConocoPhillips and Santos had entered into a mutually agreed-upon use agreement. He noted that prior legal action had occurred and that a ruling had been issued in superior court. While the state pursued further legal review, the companies resolved the matter through a commercial agreement. As a result, the supreme court determined the issue to be moot and vacated the superior court ruling. He suggested that he could ask the Department of Law (DOL) to follow up with more details.

Representative Moore asked for confirmation that road access issues would not prevent Pikka from coming online.

Mr. Nottingham confirmed that there were no anticipated delays for Pikka related to road access.

Mr. Peltier introduced the last project on slide 10, which was a brand-new project in PDU that had not been included in the project list presented the prior year. He stated that Hilcorp was proposing to move forward with two new pads referred to collectively as Project Taiga. He reported that first oil from the first pad was expected in 2028, and first oil from the second pad was anticipated between 2028 and 2030, depending on the final investment decision. He noted that the peak production rate for both pads could reach as high as 40,000 BOPD.

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Mr. Peltier moved to slide 11 and provided highlights for the Cook Inlet Basin and compared FY 24 and FY 25. He reported that production in the basin declined approximately 8 percent, reflecting the region's status as the most mature basin among Alaska's oil assets. He noted that many fields had been producing for over seven decades. He emphasized that the Cook Inlet supply remained critical for in-state refineries.

Mr. Peltier explained that most fields in the Cook Inlet were not experiencing significant new well drilling, which contributed to the production decline. He noted that well work performed by Hilcorp could sometimes offset natural decline. For example, maintenance and well work at the Redoubt Shoal Field resulted in a net positive production change for the year. He clarified that all other fields were still experiencing net declines despite operator efforts to manage the assets.

Representative Bynum asked whether the anticipated focus on gas production in the region might shift toward oil production if a gas line were developed.

Mr. Peltier responded that he could not provide a definitive answer. He stated that his assumption was that operators would aim to maximize the value of their existing fields regardless of the presence of a natural gas pipeline.

Mr. Peltier advanced to slide 12 to discuss the production forecasting methodology. He noted that there had been no changes in methods used since the DNR's fall 2022 and spring 2023 forecasts.

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Representative Galvin commented that she had a question related to forecasts but not directly to the material on the slides. She referenced a prior audit regarding whether oil companies had made the appropriate write-offs and whether the state was receiving the appropriate amount due. She had heard from various sources that the amount being negotiated had changed significantly, from hundreds of

millions to nearly zero, and asked for clarification on the current status.

Mr. Nottingham responded that he could not speak to the issue and apologized for not being able to provide an update.

Mr. Peltier proceeded to slide 13 and detailed the production forecasting methodology. He explained that the bulk of the production forecast was developed using decline curve analysis for all producing pools on the North Slope and the Cook Inlet. Each individual pool on the North Slope was treated separately, while the Cook Inlet pools were aggregated as a single unit, reflected in the DOR's Revenue Sources book. He reported that as of June 30, 2025, there were approximately 41 producing pools on the North Slope and additional pools in the Cook Inlet. The department also conducted interviews, both in person and in writing, with operators in both regions and reviewed internal plans of development.

Mr. Peltier continued that based on the assessments, 13 projects were identified as worthy of consideration under the "under development" and "under evaluation" categories. The projects relied on confidential operator information and were not typically reported individually unless the information was already public. He explained that production from these projects was risked and adjusted for scope, probability of occurrence, and anticipated start date. He relayed that 12 of the projects were located on the North Slope and one was in the Cook Inlet. He would provide a map on a later slide.

Mr. Peltier advanced to slide 14 and explained that the production forecast was broken out into various categories of ongoing and future production. The current production (CP) category referred to existing fields, which included the 41 North Slope pools discussed previously. He noted that forecasts took into account well and facility uptime, operator spending to maintain base production, and changes in reservoir management. The under development (UD) category included production that required new investment, such as drilling new wells or installing new production facilities. He explained that the contribution of new wells carried uncertainty, particularly in legacy fields. The scope was also included in the evaluation such as the number of new wells and facility capacity.

Mr. Peltier added that the under evaluation (UE) category accounted for timing risks associated with new projects. He indicated that for projects nearing completion, such as Pikka Phase 1, timing uncertainty had decreased, while for other projects like Willow and Pikka Phase 2, timing uncertainty remained. He clarified that commercial risks were incorporated into all forecasts, such as oil price fluctuations and breakeven costs.

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Representative Bynum remarked that legislators received many inquiries regarding global volatility in oil markets. He noted that volatility in the northern hemisphere directly affected oil prices. He asked whether any global climate conditions could impact Alaska production to the point that production would be curtailed.

Mr. Peltier asked for clarification on what Representative Bynum meant by climate conditions.

Representative Bynum responded that he was referring to volatility in global oil markets, including developments in Venezuela and the Middle East. He wanted to know whether such conditions could directly impact oil production in Alaska.

Mr. Peltier responded that he did not anticipate legacy field production in Alaska being affected in the near term by changes in Venezuelan or Middle Eastern supply, including potential redirection of oil to refineries in the contiguous U.S. He noted that from 2014 to 2016, Middle Eastern producers increased output, oil prices declined significantly, and future projects were deferred. He explained that such conditions affected future production but not near-term legacy production. In April of 2020 during the COVID-19 pandemic, oil prices fell sharply, but Alaska's legacy fields continued producing. He offered reassurance that while oil prices could fluctuate significantly, production generally continued, as operators typically maximized volume except in extreme pricing conditions.

Co-Chair Schrage asked whether capital requirements for investments in other markets, including Venezuela, could

affect development in Alaska and the state's ability to bring projected production online.

Mr. Peltier responded that the question was one the department regularly raised with operators during confidential discussions. He relayed that he could not identify any current impacts. He explained that maintaining Alaska's competitiveness remained important given its large resource base. He had no information to share regarding whether capital was being diverted from Alaska projects to other states or overseas markets.

Co-Chair Schrage understood that it was conceivable that capital needs elsewhere could impact Alaska, even if not reflected in the forecast. He asked how much exposure existed and whether companies included in the forecast were also considering investments in Venezuela. He noted that there were reports that Hilcorp might be pursuing investment in Venezuela and asked if other companies were also interested in investment.

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Mr. Peltier responded that he did not have a specific number. He noted that he had seen the news indicating that several companies with operations in Alaska were represented at a recent White House meeting. He stated that one company expressed hesitation regarding Venezuela, while others were more optimistic. He could not speak to whether companies were already diverting capital and noted that such considerations were outside the scope of the department's forecast.

Representative Stapp asked about the implications of potential capital related to Venezuela. He asked whether increasing taxes on companies while potentially moving capital elsewhere would guarantee that capital left Alaska projects.

Mr. Peltier responded that it was an interesting question, but he did not have an answer.

Representative Stapp commented that if the concern was competition from projects in other regions, it would seem counterproductive to make doing business in Alaska more expensive.

Mr. Peltier advanced to slide 15, showing the major projects under evaluation that were considered for the fall 2025 North Slope forecast. He stated that the projects were not online as of June of 2025 and therefore remained classified as projects. Although Pikka was planned to come online, it was still considered a project because it was not yet producing. He stated that the projects carried higher risk than currently producing fields but were known discoveries with identifiable operators that required major investment.

Mr. Peltier highlighted that the slide included a map of North Slope projects in development. He identified the Willow development located on federal land. He stated that the Horseshoe project was located south of Willow and consisted of a mix of state and federal acreage. The CRU CD8 project was located in the southern area of the CRU. He identified the Pikka unit east of CD8 and stated that Pikka Phase 2 and Phase 3 were aligned along a north south trend within nonproducing state leases. He highlighted that the Quokka Unit's Mitquq well was east of Pikka. He stated that KRU did not include any major projects under development for the forecast and the existing projects had moved into currently producing pools. He identified the Pantheon Great Bear projects south of Prudhoe Bay, including Theta West, Talitha, and Alkaid. He stated that no major projects east of Prudhoe Bay were included in the forecast.

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Mr. Peltier moved to slide 17 which included an annualized forecast chart for the North Slope. He noted that he would focus on the summary points due to time constraints. He stated that the DNR forecast for FY 26 showed an annualized statewide production average of 464,500 BOPD, with North Slope production at 457,000 BOPD. He stated that the low case was 418,400 BOPD and the high case was 495,300 BOPD. The operator forecast for FY 26 was 476,000 BOPD. He explained that the operator's long term forecast did not include new fields and therefore diverged from DNR's forecast later in the projection period. He stated that the operator's forecast remained within the low and high case range. The differences between the low case, official case, and high case resulted from uncertainty analysis related to project timing, project success, and production rates. He relayed that uncertainty increased over time and that the forecast assumed operator plans remained static. He noted

that an updated forecast on how the assumptions had changed was expected to be released in mid-March of 2026.

Representative Tomaszewski asked about the production increases shown on the slide. He noted that the increase between 2026 and 2027 appeared to reflect Pikka Phase 1 coming online in March, with an estimated year-end rate of approximately 80,000 BOPD. He observed that the increase between 2029 and 2031 appeared to correspond to Willow, with increases of roughly 160,000 to 180,000 BOPD. The increase between 2031 and 2035 of approximately 100,000 BOPD appeared to reflect Pikka Phase 2. He asked whether there was an estimate for Pikka Phase 3 production.

Mr. Peltier responded that Pikka Phase 3 was not viewed as having an additional production capacity at the facility. Instead, it was considered a new pad that would come online as production from Pikka Phases 1 and 2 declined over time. He explained that Phase 3 was intended to fill the available capacity created by that decline by adding new wells, thereby maintaining the overall peak production rate of the Pikka facility rather than increasing it.

Mr. Peltier continued on slide 18. He explained that DNR decided to present an 18-month forecast rather than a 12-month forecast to better address questions regarding the timing and ramp-up of Pikka production. He noted that the chart included actual production data through January 14, 2026, allowing a comparison between actuals and the forecast, which was finalized in late November. He stated that North Slope production was running slightly higher than the forecast but remained generally on trend, with no significant divergence. He added that the cumulative production line also showed close alignment between forecasted and actual cumulative volumes over the 18-month period.

Mr. Peltier explained that Pikka Phase 1 was expected to come online toward the end of the first quarter of 2026, but it was not anticipated to immediately reach a production rate of 80,000 BOPD. He stated that the forecast reflected a modest increase beginning in April of 2026, followed by a decline through the summer months. He explained that the seasonal pattern reflected constraints in legacy North Slope fields, which produced significant volumes of gas and experienced reduced oil production during warmer months. Additionally, there were planned

summer maintenance and turnaround activities that typically occurred in June, July, and August. The forecast showed a larger production increase in August of 2026, reflecting both the continued ramp-up of Pikka Phase 1 and the completion of summer turnaround activities across the North Slope. He added that production was then projected to increase further as colder winter conditions return.

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Mr. Peltier advanced to slide 19 and explained that the charts presented Alaska statewide annualized average daily oil production by production category. He stated that both charts used the same scale, from zero to 700,000 BOPD, to illustrate the relative contributions of existing production, new projects, and new drilling. He noted that the chart on the left included an overlay of the spring 2025 forecast to show how projections had changed.

Mr. Peltier explained that the forecasts showed a high degree of stability overall. He observed that while the spring 2025 forecast was slightly higher, the current forecast reflected a modest reduction compared to prior projections. He emphasized that production from existing fields continued to decline over time and that a significant portion of new production from projects offset the declines rather than representing net growth. The orange curve represented new drilling, which reflected the next 12 months of drilling in existing fields. He noted that although it was the smallest component, it demonstrated a material impact on the production forecast and showed the continued value of the drilling moving forward. He explained that the remaining drilling was represented in gray and covered months 13 through 120 of the forecast.

Mr. Peltier directed attention to the chart on the right which overlaid future projects against one another. He indicated that the spring forecast and the current forecast showed slight differences. He had not corrected the spring forecast to reflect the Torok projects or the ConocoPhillips projects that were being executed at the time, as he wanted to leave them visible to illustrate the relative contribution of projects such as Pikka coming online in the near term. He indicated that Pikka was expected to be a significant project with substantial near-term impact.

Mr. Peltier noted that there was a gap that developed in the 2028, 2029, and 2030 time frame. He explained that the gap resulted from uncertainty surrounding certain projects previously discussed, including Pikka Phase 2. He noted that the timing of the projects was uncertain relative to expectations from the prior year, which contributed to differences between last year's expectations and the current forecast.

Representative Bynum asked whether the projections reflected only currently known information. He asked if potential changes in the federal administration, the opening of the NPRA, challenges to Willow, and changes to pad development were considered. He also asked whether such factors might be incorporated at a later time.

Mr. Peltier responded that the question was one the department debated internally. He explained that the forecast did not take into account any actions by a new federal administration with respect to Willow. He noted that while new exploration activity in the Willow and GMTU area had been publicly reported, the exploration wells had not resulted in the discovery of oil. He explained that because of uncertainty, no barrels associated with that exploration activity were included in the production forecast, despite interest in how the activity might ultimately affect future production.

Mr. Peltier advanced to slide 20 and relayed that the production forecast relied on the best available information from DNR and DOR. He stated that the forecast was intended to be as accurate as possible in both the near future and long term. He explained that the forecast represented a static view of production and that as business plans changed, underlying assumptions could become outdated and were updated when possible. He noted that DNR's outlook for fall of 2025 showed mean annual production beginning at approximately 465,000 BOPD and increasing to 685,000 BOPD by the end of the outlook period. He moved to slide 21 and thanked the committee for its time.

Co-Chair Josephson thanked the presenters. He remarked that the forecast included positive information, particularly for future legislatures.

Co-Chair Josephson reviewed the agenda for the following day's meeting.

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ADJOURNMENT

2:56:07 PM

The meeting was adjourned at 2:56 p.m.