

HOUSE FINANCE COMMITTEE
April 15, 2021
9:03 a.m.

[9:03:23 AM](#)

CALL TO ORDER

Co-Chair Merrick called the House Finance Committee meeting to order at 9:03 a.m.

MEMBERS PRESENT

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

MEMBERS ABSENT

Representative Bryce Edgmon

PRESENT VIA TELECONFERENCE

Ryan Fitzpatrick, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources; Jhonny Meza, Commercial Manager, Division of Oil and Gas, Department of Natural Resources.

SUMMARY

HB 81 OIL/GAS LEASE: DNR MODIFY NET PROFIT SHARE

HB 81 was HEARD and HELD in committee for further consideration.

Co-Chair Merrick reviewed the agenda for the meeting.

#hb81

HOUSE BILL NO. 81

"An Act authorizing the commissioner of natural resources to modify a net profit share lease."

9:04:04 AM

RYAN FITZPATRICK, COMMERCIAL ANALYST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (via teleconference), introduced himself. He thanked members for the opportunity to present HB 81 which allowed for the modification of net profit shares on net profit share leases by the Department of Natural Resources (DNR). He introduced the PowerPoint presentation: "HB 81 - Net Profit Share and Royalty Modifications on Oil and Gas Leases," (Copy on file).

Mr. Fitzpatrick turned to slide 2. He provided an outline of the presentation which was broken into different sections. He would describe net profit share leases and move into the reasons why DNR believed allowing for the modification of net profit shares in certain circumstances was justified. He would also provide the committee with an overview of the modification process and a preview of the changes the bill proposed. The same modification process for royalty modifications currently in statute would be used for net profit shares. He would walk through the royalty modification process and explain how that would transfer to the modification of net profit shares. The presentation would be an overview of both the current royalty modification process and how it would apply to net profit shares if the bill were to advance. Finally, he would provide the committee with an overview of the changes that were made in the current committee substitute. He noted the appendix at the end of the presentation.

Mr. Fitzpatrick advanced to slide 3 showing the first section on the overview of net profit share leases. He advanced to slide 4 to discuss the royalty and net profit share. He explained that a net profit share lease (NPSL) was an oil and gas lease issued by the State of Alaska that included a net profit share revenue component. He wanted to distinguish the traditional royalty revenue component with the net profit share component, because the net profit share leases were a rather uncommon type of lease in Alaska. He explained that a royalty component in an oil and gas lease provided the state with a share of the gross production from the lease. The state took its share of royalty without having to consider the field costs. The

lessee was allowed to deduct certain transportation costs to get oil from the lease to market. However, the actual field costs for the development and operation of the lease were not deducted against royalty. All of the oil and gas leases offered by the state had a royalty component and included NPSLs.

Mr. Fitzpatrick continued by explaining that a NPSL had a royalty component but also had a separate revenue component called a net profit share. A net profit share was a percentage of the profits derived from the lease. In order to calculate how the net profits were generated from the lease, the net profit share accounted for all of the development expenses incurred to encourage bringing the lease into production. They were accounted for in a development account. From the moment the development expenses were incurred, the account was credited with interest at the prime rate plus some additional percentage.

9:09:28 AM

Representative Johnson clarified that when there was a lease sale a royalty was set and the net profit share was also set. She wondered what mechanism would trigger going beyond the original provision of the lease contract and changing to a net profit share. She asked Mr. Fitzpatrick for further clarification.

Mr. Fitzpatrick suggested starting at the beginning when a lease was first issued. He explained that there were two circumstances in which a lease could be issued with a net profit share component. Leases that were currently offered by the State of Alaska were traditionally offered with a fixed royalty. When the lease was put out for bid, the bid variable was a bonus bid, a cash bid that a company paid upfront in order to secure the lease. A net profit share lease could be issued in two ways. The first way involved a lease containing a fixed royalty component, a fixed net profit share component, and a bonus bid. The bonus bid would be the bid variable.

Mr. Fitzpatrick continued that when a lease was put out to bid the royalty percentage and the net profit share percentage were specified. Companies would bid based on the bonus bid to secure the lease at auction. The second way a NPSL could be issued was with a fixed royalty component and a variable net profit share component in which the net

profit share variable was the bid variable. It would have a fixed royalty, and companies would bid the highest net profit share rate in order to secure the lease at auction. In looking at the NPSLs issued by the state, some had 30 percent fixed net profit shares, 40 percent net profit shares, and some were more exact. In one instance, the percentage was 92.3 percent - a result of companies bidding based on the net profit share bid variable.

Mr. Fitzpatrick relayed that once a lease went into production, the royalty component began payment immediately. The state took a percentage of production from the lease without any regard for the costs of development or the costs of operating the lease. The costs of transportation to get the oil or gas to market was simply deducted from the royalty payment. If the state took the royalty in-kind, alternative transportation arrangements were made. The royalty payment continued throughout the production life of the lease.

Mr. Fitzpatrick continued that in the case of the net profit share component, the payment would not begin until later into the life of the lease. The development costs for the lease were credited to a development account which earned interest while the lease was being developed. Once the lease went into production, the revenues generated from the sales of non-royalty oil and gas (the oil and gas credited to the lessee) were determined and the costs of operation of the lease were deducted from the amount. Whatever was left over from that amount (the profits from the operation) got deducted against the accrued development costs for the lease (the costs incurred before the lease entered production).

Mr. Fitzpatrick indicated that once the development account reached zero, the lease was considered to be in payout. In other words, all of the development costs had been recouped by the lessee in addition to the interest that had accrued during that time. At that point, the net profits generated from the lease would be shared with the state based on the net profit share percentage. From the time net profit share payments began, the state had two revenue streams from the lease. The royalty component continued - the state always received its royalty share from the production based on gross production without regard to the expenses. Once the lease reached payout, the state also received the net profit share payment from the same lease.

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Representative Johnson stated it was her understanding that the royalty and net profit shares were set at the lease sale and did not change. She asked for a brief look-back at the original lease sales versus present lease sales. She asked if the state was heavy on the royalty side for early lease sales. She wondered if there were any trends in what the state required from its lease sales.

Mr. Fitzpatrick responded that historically the state initially offered oil and gas leases with a fixed royalty rate. The net profit leases were not offered by the state until later. The initial oil and gas leases issued by the state were predominately issued at a 12.5 percent royalty rate. All of the net profit leases currently in existence were issued in the late 1970s or early 1980s. During that period, the net profit shares that were issued had fixed royalty rates of either 12.5 percent or 20 percent. He had a slide containing the information later in the presentation.

Mr. Fitzpatrick continued that the net profit share component ranged from 30 percent to 93.7 percent. After some experience with net profit share leases, the state experienced some difficulties in accounting and in development. He would discuss the North Star development later in the presentation. It was determined that it was in the state's best interest to revert to issuing leases with fixed royalty rates plus bonus bids. It had been the state's practice since the early 1980s. Since then, the state increased the royalty rates for oil and gas leases in certain circumstances. Whereas the state had initially offered oil and gas leases at a 12.5 percent royalty rate, in certain circumstances and for currently offered leases on the North Slope, the fixed royalty rate was 16.3 percent.

Representative Wool summarized the comments provided by Mr. Fitzpatrick. He suggested that the net profit share lease component was added but predominantly discontinued at present. He asked if he was accurate.

Mr. Fitzpatrick responded that Representative Wool was mostly accurate. He clarified that the royalty component of the NPSLs was usually at the same rate or a higher rate

than what had previously been offered. The lowest royalty rate on a NPSL was 12.5 percent. Some of them ranged to higher fixed royalty rates in addition to the net profit share component.

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Representative Wool suggested that originally there was a fixed royalty, then for a while, a royalty plus a net profit was added creating an additional income stream for the state. He assumed the royalty would have decreased when adding a net profit share. The royalty went up along with a net profit share and was later discontinued. If there was no profit, the net profit component would be zero. Mr. Fitzpatrick had stated that the royalty went higher. He assumed that the state had been in a different negotiating position at the time.

Mr. Fitzpatrick responded that looking back at the history of oil and gas production on the North Slope, Prudhoe Bay came online in the late 1970s and early 1980s. When the state was issuing oil and gas leases for prospects, there was an expectation or hope that the prospects would be similarly large finds. In subsequent developments it was discovered that some of those finds were nowhere near as respective as hoped. The North Star prospect was the example he had illuded to earlier. In the late 1970s there was an expectation or hope that the prospects would be large fields able to bare the higher royalty and net profit share component. Experience showed that it was not the best way for the state to go about issuing oil and gas leases. It was discontinued after several years.

Representative Josephson asked if any of the net profit share leases had a 16.6 percent royalty. Mr. Fitzpatrick responded that any of the currently issued net profit share leases had royalties at 12.5 percent or at 20 percent. He did not believe there were any at 16.6 percent. He had a slide later that listed all of the net profit share leases and their percentages.

Representative Josephson referred to slide 3. The last bullet point said the sharing of net profits occurred once exploration development costs allocated to lease were recovered through revenues. He wondered why the state would discount the net profit lease once the costs were paid off.

He suggested the bill would discount the net profit share leases.

Mr. Fitzpatrick replied that the purpose of the bill was to allow the department to reduce the net profit share in certain defined circumstance. One circumstance was a modification that would allow a field or pool that was not currently in production because of it being uneconomical without a modification to go into production. A net profit share modification might also be allowed towards the end of the life of a field. It might also be allowed if the field had been shut in and a modification would extend the years of its production. Otherwise, the field would be shut down due to it being uneconomical. In such a case the state could choose to grant a modification with the hopes of keeping the field in production for a few additional years. If the state chose not to grant the modification, the field would potentially shut down and the state would not receive either the royalty or the reduced net profit share lease revenues.

Representative Josephson wanted the department to show how everybody would win.

[9:25:16 AM](#)

Representative Wool asked about production taxes in relation to a net profit share and royalties. Mr. Fitzpatrick responded that he had a slide that might address his question.

Mr. Fitzpatrick turned to the spreadsheet on slide 5 that showed the difference between royalty and net profit share. It also allowed for a description of the difference between the components and the production tax. He reiterated that the royalty component was assessed at the lease level. The beginning of payments started with commercial production. The payment did not consider the costs of operation or developments. The net profit share was also assessed at the lease level based on the net profits. The beginning of those payments only started when the net profit lease reached a payout stage. The net profit share leases considered field costs. Royalty and net profit shares were calculated differently than production taxes. Production tax was calculated at the tax payer level and involved payments that began at the start of production. Payments were based mostly on estimates. Similar to a net profit

share, production tax took costs of development and operation into consideration. It did so in a different way than net profit share leases. There were similarities and differences between all three of these revenue components. The profit to the lessee was calculated on the cash flow from the lease after all of the other payments were considered.

Mr. Fitzpatrick continued to slide 6 which provided an example of a net profit share lease. It showed some of the operative language that was included in this particular lease. The lease was issued to Amerada Hess Corporation in 1979. The second box on the slide indicated that the lease was issued where the net profit share component was the bid variable. The net profit share rate was issued at 93.2 percent. It was one of the leases issued in what was presently the North Star Unit. It also had a 20 percent royalty component. As he alluded to before some of the net profit share leases had the net profit share components and the royalty rates that were higher than those previously issued by the state.

[9:28:55 AM](#)

Mr. Fitzpatrick advanced to the graphic on slide 7 showing net profit sharing. The slide would help to explain how production tax fit into all of the payments and revenue streams. The slide presented a breakdown of the costs and revenues from the production of a barrel of oil under two scenarios. The first scenario was a traditional oil and gas lease that only included a royalty component. The second scenario was from a lease that also included a net profit share component. For simplicity, he noted that he was not representing oil and gas property tax or corporate income tax in the diagram because they were assessed at the property level or the tax payer level. The revenue streams on the slide went more towards the actual production of the oil itself. Between the two diagrams, the bottom three components - the development costs, the capital expenditures to bring the lease into production, the operating expenditures, and the transportation costs - all stayed constant between the two examples. They were costs that were borne for the production of the barrel of oil.

Mr. Fitzpatrick continued that the next component up was the royalty component. The royalty component stayed the same between the two leases assuming that the royalty rate

itself was constant between them. There were examples of fixed royalty rate leases and net profit share leases where the royalty rate was 12.5 percent. The next item up was production tax which was paid after royalty. However, he pointed out that production tax in the second diagram was slightly smaller than production tax in the first diagram. The second diagram included the additional net profit share payment. For the purposes of production tax calculation, the payment of net profit share was considered a deduction for the purposes of production tax. The additional payment reduced the revenue that a tax payer would pay production tax. In the second diagram the state received the royalty and a smaller production tax payment. The state also received the net profit share payment. He pointed out that the state received a larger share in the second diagram than in the first diagram.

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Representative Wool commented that Mr. Fitzpatrick was presenting hypothetical scenarios in which random numbers were used that did not necessarily reflect reality. He noted that on the previous slide the lease from 1979 had the highest percentage of 93.2 percent. He suggested that in the diagram on slide 7 the royalty was the same and the production tax was less because the net profit share could be deducted. If the net profit was zero, he wondered if the production tax would be the same. He thought the diagram was misleading because the illustration on the right looked lower than the one on the left. It was slightly shifted down even though Mr. Fitzpatrick reported that everything was equal to royalty until the royalty line. If net profit was zero, he wondered if the net tax would be the same because it would not be deductible.

Mr. Fitzpatrick responded in the affirmative. He elaborated that if talking about a net profit share lease where the lease was not in payout and there was not a net profit share payment being made, then production tax, all else equal, should be the same between the two. He explained that there would not be a profit share payment that would be deducted in the second diagram. He apologized he had not noticed the different height of the two barrels. It might be that the second one was slightly smaller in comparison. He would look at it after the presentation. His intent was to show an apples-to-apples comparison. He noted he had not attempted to quantify the diagrams based on particular

dollar values. All of the rations would change depending on the ultimate price of the barrel of oil. He used percentages as an example for the slide. It was not intended to represent any particular dollar value.

Mr. Fitzpatrick moved to slide 8 which showed a map of currently active leases on the North Slope of Alaska. He noted that the next slide was the list of NOSLs with additional details. He highlighted that the NPSLs that had been issued on the North Slope were included in several different units. All of the units containing NPSLs were currently in production. However, not all NPSLs were production. There were some units where there was production from the unit but the production was not credited to the NPSL because of the area that the production horizon which was actually producing within the unit. It did not reach the leases that had the profit share term. Reading from left to right Colville River, Kuparuk River, Ooguruk, Nikaitchuq, all had NPSLs.

Representative Wool noted there were 26 active NPSLs. He asked how many leases were non-NPSLs. Mr. Fitzpatrick did not have the exact number of non-NPSLs on the North Slope. He thought the number was in excess of 1000. He could get back to the committee with the number. Representative Wool thanked Mr. Fitzpatrick and indicated the scale was fine.

Representative Johnson asked how many of the 26 NPSLs were non-producing. Mr. Fitzpatrick wanted to continue to the next slide that contained the answer to Representative Johnson's question.

[9:37:08 AM](#)

Mr. Fitzpatrick indicated that slide 9 contained information on all of the active NPSLs in the state. He noted that the righthand column contained information on whether there was production. It showed the payments that were generated from the net profit share component. He directed attention to the third set of leases. Point Thomson was the unit that had NPSLs that currently were not in production. There was production from the Point Thomson unit, but the NPSLs in Point Thomson were not associated with that production. There were two other sets of leases in Kuparuk River and in Nikaitchuq where the NPSLs were in production but had not reached payout

to-date. Therefore, they had not generated any net profit share payments.

Mr. Fitzpatrick pointed to the issuance year on the left side of the slide showing when the NPSLs were issued. He noted that there were a couple of NPSLs with an issuance date in the 2000s. They were NPSLs were created due to a subdivision of a prior lease. A portion of the NPSL was created in the 2000s, but the original lease that was subdivided was issued during the late 1970s to early 1980s. He pointed to the column showing the net profit share rate for each lease. Most of them were issued at a 30 percent or 40 percent rate. In Duck Island and in Point Thompson there were leases that were issued with higher percentages. They were a result of lease options where the net profit share rate was the bid variable. The royalty rates could also be seen on the slide. Most of the leases were issued at a 12.5 percent royalty rate with the exception of the Duck Island lease and the single Point Thompson lease which were issued at a 20 percent royalty rate. At the time none of the leases had a royalty percentage rate of 16.67 percent. He believed it was after the state stopped issuing NPSLs that the 16.67 percent royalty term became common for state issuance.

Representative Josephson asked why Duck Island was treated differently. He wondered why there was no gradation in the bill. Mr. Fitzpatrick responded that the bill did not contain the gradation. However, because the bill inserted the modification of net profit shares into the currently existing royalty modification structure, the existing structure for royalty modification allowed for gradation. The current structure required the Department of Natural Resources to make a determination that new production or continuing production would not be economic as part of a modification. It would be in the case of new production or for continuing production near the end of field life. He believed the requirement that the department determined that the production would not be economic without the modification allowed the department to make the gradation.

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Vice-Chair Ortiz asked Mr. Fitzpatrick to define the term, "non-economic." Mr. Fitzpatrick replied that within the context of the royalty modification statute that existed presently, the concept of non-economic or uneconomic

development was a development, either new or continuing, that was not economic enough for the producer to make the initial investment or to continue production from an existing field. From the producer or the lessee's point of view, the decision not to make the investment or to shut down production from the existing unit. It looked at the question of economics from the point of view of the lessee. He qualified that the royalty modification, the statute incorporated the notion of a reasonable lessee. The department would not necessarily look at it from the profitability standpoint of the particular lessee that was applying for the royalty modification. However, from a hypothetical general reasonable lessee or producer.

Vice-Chair Ortiz asked if it was accurate to say that non-economic had to do with price.

Mr. Fitzpatrick responded that price was a variable that could heavily influence whether a project was economic. Economic would also include costs of development, projected operating expenditures, the capital structure in place at the time whether interest rates were low or high for financing a development. The ultimate production would influence whether a project was economical. If a development had higher-than-expected or lower-than-expected production could drive the economics. The intention of the bill was not to change the modification process for royalties. He noted that one of aspects of the existing royalty modification statute was that in crafting any sort of modification there was a sliding scale mechanism as part of any modification. If oil prices rose in the future higher than was expected at the time a modification was granted, production came online at a higher rate, or costs were less than anticipated, the royalty modification would either phase out at higher process or phase out over time. The statute as currently enacted considered the potential for those changes after the modification was granted.

Representative Carpenter asked how the production got associated with a particular lease. Mr. Fitzpatrick replied that as a field or pool entered into production there was a process of determining where the bottom hole of the wells that were drilled ended up and production was associated with those well locations. It was not necessarily based on where the wells were drilled, but where the well bores existed in the subsurface. Estimates were made of the drainage radius around the well bore. Once those

determinations were made, the drain pattern as compared to the surface leases and allocated on a percentage basis to those different leases. He invited his colleague, Johny Meza, to provide additional comments.

9:47:40 AM

JHONNY MEZA, COMMERCIAL MANAGER, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (via teleconference), responded that the explanation Mr. Fitzpatrick provided was correct. He indicated the division generated percentages based on the drainage production from each well and provided the allocation percentage to each of the leases including NPSLs.

Mr. Fitzpatrick reviewed the modification of the Northstar Unit NPSLs through legislative action in 1996 on slide 10. The slide provided some background on one of the issues he had alluded to earlier regarding the modification of certain NPSLs for the Northstar Unit. He noted he should have mentioned when he was looking at the map and the list of NPSLS a few slides back that neither the map nor the list of current NPSLs included any leases in the Northstar Unit. He further explained that while some of the leases in the Northstar Unit were originally issued as NPSLs, in 1996 the legislature modified those leases through the enactment of specific legislation to change those leases from NPSLs to leases with a fixed and a variable royalty rate.

Mr. Fitzpatrick continued that the slide presented information on the 4 NPSLs that were originally what made up the Northstar Unit. They were issued in 1980. They were leases that were issued with the net profit share as a bid variable. He highlighted that the net profit share rates ranged from a low of about 85 percent up to 93.2 percent. It was the lease that he looked at as a specific example earlier. He reported when the leases were originally issued the expectation was that the Northstar Unit was going to be a much larger discovery than it turned out to be. At the time the leases were issued there was a bidding frenzy over getting the leases and bidding high net profit share rates. Once additional exploration was conducted it was found that the discovery was not as large as expected which led to issues getting the unit into development for several years.

Mr. Fitzpatrick reported that ultimately, BP approached DNR and proposed development of the Northstar Unit including

the leases listed on the slide if something could be done to modify the net profit share rates. At the time, the legislature was enacting the royalty modification statute that existed. However, the statute did not include the authority to modify net profit share rates. Therefore, the department initially declined to modify net profit share rates for the particular leases. After continued discussions, a modification package was negotiated with the understanding that that package would be submitted to the legislature for the legislature's consideration.

Mr. Fitzpatrick reported that in 1996, the Department of Natural Resources and BP presented the legislation to the legislature which modified the 4 specific leases listed on the slide. The legislature considered and signed the legislation into law. In the end, the leases retained their 20 percent fixed royalty rate. In exchange for the net profit share rate, an additional sliding scale royalty component was added to the leases based on the price of oil. The sliding scale royalty could range up to an additional 7.5 percent. The royalty component on the leases ranged from a low of 20 percent to a high of 27.5 percent based on the price of oil at any particular time. He believed that a present, all of the leases were operating at the highest rate, 27.5 percent, based on oil prices.

Mr. Fitzpatrick continued that after the legislation was passed, it was challenged in the courts. The Alaska Supreme Court upheld the modification by the legislature. Thereafter, the Northstar Unit went into production, and since entering into production the cumulative royalty revenue to the state (listed in the far-right column on the slide) had been \$1.73 billion.

Representative Josephson asked who initiated the lawsuit. Mr. Fitzpatrick could not remember the parties. He had a reference later in the slide packet. He would follow up with the committee with more information.

[9:53:55 AM](#)

Representative Josephson wondered why slide 6 was included in the slide deck. He expressed astonishment that someone would allow a bidding frenzy. He thought Mr. Fitzpatrick had reported that the legislature essentially negotiated an agreement to seriously modify the net profit share due to the bidding frenzy. He suggested that the example that Mr.

Fitzpatrick used that was most egregious was never realized. He asked if he was correct.

Mr. Fitzpatrick responded, "That's correct." He elaborated that the lease that was issued on slide 6 with the 93.2 percent net profit share rate was one of the Northstar leases that was modified by the legislature. He included the example specifically to demonstrate that in particular circumstances the modification of the net profit share rate could lead to production that might not otherwise have occurred. At the time the leases were issued in the Northstar Unit, the expectation was that would be much larger than it was which was the reason the net profit share rates were bid so high. He thought the example demonstrated potential issue with issuing NPSLs in that a very high net profit share rate could insert circumstances that were an impediment to the development of an oil and gas unit that otherwise would provide royalty payments to the state. Thereafter, it was determined that the use of bonus bids in circumstances where there was a high expectation, received state money on the front end, and on the back end did not create the same potential for development problems with the leases. It was one of the reasons the state went from issuing NPSLs to more traditional royalty leases with the bonus bid.

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Representative Wool thought the slide was showing 4 leases issued in 1980 and undeveloped for 16 years. In 1996, the lease holder communicated that they would not develop the leases unless the state eliminated the net profit share that ranged from 85 percent to 95 percent. He suggested the percentage should have been reduced to 40 percent rather than zero. He wondered why the decision was made to no longer issue NPSLs.

Mr. Fitzpatrick had not delved into the history of the state's decision to stop issuing such leases. He thought encouraging development played a role. He had seen some administrative challenges of administering the leases and the net profit share component. They were certainly more complex to administer. The state decided to stop issuing the NPSLs in the early to mid-1980s. Thereafter, the state had only issued oil and gas leases with the fixed royalty percentage and the bonus bid.

Representative Wool did not believe the \$1.73 billion included production tax. He asked about production tax which he assumed would be grater under a non-NPSL because they could not deduct it. He wondered about further analysis of the \$1.73 billion with and without net profit share including production tax. He thought the state would have yielded more money cumulatively with royalty, production, and net profit share. He asked if he was accurate.

Mr. Fitzpatrick answered that it was difficult for him to produce production tax numbers because of confidentiality around tax records and the fact that several of the leases did not have multiple tax payers with which the information could be combined for confidentiality purposes. He did not think he would be able to provide information around production taxes specific to particular leases. He suggested that production taxes levied at the tax payer level across the Northslope with some variations for individual units when there were accrued access lease expenditures. It was difficult to present an apple-to-apple comparison.

Mr. Fitzpatrick responded to the question of whether there had not been a modification. If the Northstar unit had entered production and the leases had included the original net profit share rate, he would have expected to see a larger revenue stream. He had not done the analysis specifically. In the case of the Northstar Unit, the modification was to reduce the net profit share rate down to zero. It also added the sliding scale additional royalty. The royalties received were larger than would have otherwise been the case without the modification. He added that the royalty payments began the moment Northstar entered production. Whereas the net profit share payments would have only begun after the initial development expenses had been paid for. Without running the numbers, he could not say which of the scenarios would have resulted in a higher payment to the state. He could look at the information, try to come up with something, and provide it afterwards.

[10:01:59 AM](#)

Representative Wool thought it would be good information to have. Mr. Fitzpatrick could try to come up with the information. The question was whether Northstar would have

gone into production without the modification. At the time, BP indicated they would not invest in Northstar in the absence of the modification. He could look at the current numbers for production and to come up with a hypothetical payment stream with the net profit share rates. However, he would not be able to do the analysis of whether the investment would have been made without the modification.

10:03:50 AM

Mr. Fitzpatrick moved to the second section on the description of why the department believed allowing modification of net profit share could potentially add value to the state.

Mr. Fitzpatrick moved to slide 12: "Increase Production from Otherwise Stranded Resources." The intent of the bill was to allow DNR to modify net profit shares. If production did not occur the state would not receive royalty payments or any net profit share payments. The state would not receive production tax payments from the production that did not occur. The goal of the legislation was to allow or encourage production that otherwise would not occur so that the state could receive some value for the resources. In thinking about the potential for resources to become stranded, there were two potential scenarios where resources could become stranded.

Mr. Fitzpatrick conveyed that the first scenario was if a new production, a production from a new field or pool, was not economic and the producer elected not to move forward with an investment in it. The state would not see any production from the field which would result in a lack of royalties, net profit share payments, or a production tax. The state would receive no value for the resources other than the bonus bid that was originally received for the lease.

Mr. Fitzpatrick moved to the second scenario: when a field or pool was nearing the end of its life and became a stranded resource. He elaborated that when a field was approaching the end of its life, production declined causing revenues from the field to drop and operating expenditures to potentially trend down with production, although not likely at the same rate. The per-barrel costs of production would increase. At some point, the per-barrel costs might exceed the potential profit for a producer

prompting a shutdown. No additional production would be received from the field or unit and no payments would be made to the state. The goal of the bill was to allow modifications when the department could determine that a modification would result in production from a new field or pool that would not be brought online otherwise. The department could also find that a modification could extend the life of a field or pool near the end of its field life. It might result in the state receiving additional payments from additional production. It could potentially lead to lower royalty or net profit share rates, but the state could receive payments for an additional number of years where the field or pool would otherwise shutdown.

[10:07:15 AM](#)

Representative Johnson thought there were 26 active NPSLs on the North Slope - 17 leases were producing and 9 were not producing according to the chart on slide 9. She asked if DNR would only be making changes to the 9 leases currently not producing under the plan in the bill.

Mr. Fitzpatrick responded that, for the existing royalty modification statute and for the proposed net profit share modification process, the process required a producer or lessee to approach the department with a proposal for a modification. The department did not have the authority under existing statute or in the bill to modify the royalty rate or the net profit share rate without an application from the lessee. The lessee had to first determine that the field or pool was uneconomic either to bring into production or to continue production and then propose modification to the department. As part of the review process the department looked at all of the records of the lessee including financial records, resource evaluation information, and subsurface data.

Mr. Fitzpatrick continued that the department also looked at the current state of the market and potential forecasts for changes in oil prices making its own determination whether the production would otherwise be uneconomic. If the department determined it to be uneconomic, only those leases included in the application could be modified. The department's goal, with reference to a sliding scale royalty, was to only allow modification sufficient to change the investment decision of the lessee. In other words, the goal was to only allow enough modification to

either induce the lessee to make an initial investment to bring a field into production or to invest enough in the field or pool to continue production for a set number of years.

10:10:03 AM

Representative Josephson thought that most of the fields would have already invested heavily. He wondered why the lease holders would not continue to invest. He asked how the state measured the trustworthiness of lease holders.

Mr. Fitzpatrick thought Representative Josephson's question got to the heart of when the department should be authorized to allow for modifications. He reiterated that the department did extensive analysis when a modification application was received under the existing royalty modification statute. There were a number of provisions in place about how the analysis was done and included internal guidelines within the department. He relayed that one part of the statute allowed the department to seek a third party to provide analysis and the cost would go to the applicant.

Mr. Fitzpatrick continued that one of the important features of the current modification process was that the legislature had set a higher bar of proof for modifications than was typical for most applications. In the case of a typical permit application, the burden of proof around the application would be preponderance of the evidence (a 50 percent plus one burden of proof). If it was simply more likely than not, then a fact was established and the permit could be issued based on the fact.

Mr. Fitzpatrick explained that under the current royalty modifications or net profit shares operated on a much higher burden of proof. The lessee had to show clear and convincing evidence that they had met the requirements of the statute in order to be eligible for royalty modification - a standard the department took very seriously. The applicant was required to produce voluminous data on finances and sub surface data. The department evaluated the information with a skepticism. There had been 8 royalty modification applications in the 26 years that the statute had been on the books. He reported that of the 8 applications, the department had only approved 3 of them. He detailed that 2 of the applications were denied and 3 were withdrawn by the applicant after a partial evaluation

by the department. The applicant opted to no longer proceed with their modification application. Less than 50 percent of the modification applications received by the department had been granted. The bill intended to preserve the requirement that the department treated modification applications with a high degree of skepticism - a component of the review process.

10:14:23 AM

Representative Rasmussen asked if Mr. Fitzpatrick had any graphs or charts that provided a timeline and additional details of the 8 requested modifications. She thought some background information at the time of the requests would be helpful. Mr. Fitzpatrick replied that the information was provided on slide 18. It listed all of the royalty modification applications that the department had received. The slide did not include the price of oil at the time of the applications, but he could provide the information.

Representative Rasmussen thought that seeing a graphic showing production levels prior to the modifications on the three applications that had been approved would help to show that the policy the legislature was putting into place would work and would be in the state's best interest.

Representative Wool referenced the royalty modification analysis. He asked if it had been done for the NPSL royalty modification in 1996 shown on slide 10 in the Northstar Unit. Mr. Fitzpatrick was not familiar with the analysis that was conducted for the 1996 modification of Northstar. He would follow up.

Representative Wool referenced the \$1.73 billion that the state netted from royalty. He speculated that BP decided the field in the Northstar Unit was not feasible with the net profit share rates. However, by adjusting the net profit share rate to zero, it made it possible for BP to make a profit. He assumed that BP did a calculation before and after to verify their decision. He assumed the state would have made the same calculations. Any information would be interesting.

Mr. Fitzpatrick could look into the history of the modification. He was not personally familiar with the modification, but there might be others in the department that might be.

Representative Merrick indicated there was about 40 minutes left before the end of the meeting. She suggested that members hold their questions until the end of the presentation.

10:19:13 AM

Mr. Fitzpatrick moved to slide 13 to review flexibility for royalty modifications. The department believed that allowing for the modification of net profit shares would be useful. Currently, the department could only modify royalties. However, there were circumstances in which allowing for the modification of net profit share rates might give the department more flexibility when considering an application for a royalty modification. For instance, royalty payments were more certain. They started at the beginning of production, whereas payments from net profit shares might be delayed. The amount of royalty payments was more consistent over time. There might be circumstances in which the state would be better off allowing a modification of net profit share rates instead of allowing a modification of royalty rates.

Mr. Fitzpatrick elaborated that at present, the department could only modify royalty rates. However, if given the ability to modify net profit share rates in one of the modification scenarios, the department might elect only to modify the net profit share rates or modify net profit share rates while modifying less royalty and preserving more royalty payments for the state. With the option to modify NPSLs, royalty shares might not have to be modified or a blended modification could become an option.

Mr. Fitzpatrick addressed another way in which allowing for modification of net profit share rates could increase the department's flexibility. Currently, under the royalty modification system, the department was allowed to decrease royalty rates when considering a royalty modification application. Similarly, the bill would allow for the change in the net profit share rate to either decrease or increase. When thinking about the sliding scale mechanism for royalties, in a modification scenario there were circumstances in which the department might seek to add an increase in either royalty or net profit share rate in order to recapture foregone revenue if royalty modification was allowed early in a project's life or for lower oil

process in scenarios where process increased in the future. There could be an increase in the net profit share rate in addition to the royalty rate in order to recapture revenues that had been foregone earlier in the project's life. Additionally, in certain circumstances, it also might make sense if the state was willing to forego royalty revenues in low price environments to simply participate in higher price movements using either royalty or net profit share mechanisms. It might not be a recapture mechanism; it might simply be an increase in the rates of higher oil prices in order to capture more value for the state as part of one of the modifications.

[10:22:45 AM](#)

Mr. Fitzpatrick continued to slide 14: "Why would DNR allow the modification of the net profit share rate? A hypothetical example." He pointed to the first graph and the solid blue line. The slide had a pair of graphs that represented two different potential economic scenarios where modifications could make a difference in an investment decision. He pointed to the first graph and the solid light blue line with the economic evaluation from the point of view of the producer. The zero-dollar line would represent the total value to the producer. Where the solid light blue line was below the zero-dollar line on the graph, the project would be uneconomic. Based on the information, the producer would not make the investment. The dotted blue line above those lines represented a modification of the net profit share rate. The dotted orange line represented a modification of the royalty rate. The solid grey line at the top of the graph represented a modification of both the net profit share rate and the royalty rate. In the first graph the hypothetical project was uneconomic but very close to being economic. He suggested that a modification of the net profit share alone would be enough to push the line above the economic threshold and sufficient to encourage or induce the development in the investment by the lessee. In the example the royalty modification would be granted. The state would forego some portion of the net profit share payments but would receive all of the royalty payments represented by the difference of the dotted blue line and the dotted orange line.

Mr. Fitzpatrick addressed the second scenario which was similar in its construction. The lines represented the same

concepts. In the example net profit share leases consisted of a larger share of the potential production. The modification of net profit share rates contributed more to the potential difference in economic outcome. In the scenario the royalty relief alone would not be sufficient to make the project economic. It was likely that a producer would not invest in the project, and the state would receive no royalty, profit share, or production tax revenues at all.

Mr. Fitzpatrick continued that similarly, net profit share modification alone would be insufficient to make the project economic. If the state were to combine net profit share and royalty modification, the state could get the project to the economic threshold. The grey line represented the maximum potential modification of both the royalty and net profit share rates. However, the department's goal in granting a modification would not be to automatically move to the maximum potential modification of those rates. It would only be to allow enough modification of those rates to allow the project to become economic and induce investment. The department would strive to grant no more modification than was necessary to reach the economic threshold. Instead of the grey line, optimally, the department would strive to create a modification mechanism that would involve both royalty and net profit share modification but less than the total amount that might be had in order to move the grey line above the zero-dollar line so that the lessee invested in the project but the state maintained the highest potential returns for the project.

[10:27:47 AM](#)

Mr. Fitzpatrick turned to slide 15 to discuss the last objective behind the legislation which was to streamline the current process for net profit share modifications. He referenced the Northstar modification process described earlier. The modification required negotiations with the state and a presentation of the modification package to the legislature for its consideration. He indicated that the Supreme Court decision that was mentioned earlier was noted on the slide: *Baxley v. State*, 958 P.2d 422 (Alaskan 1998). He would follow up with citational information about the case.

allowing the net profit share modification along side the royalty modification currently in statute would allow the

department to modify those rates in the same process as the royalty modification presently and would streamline the process. It was one of the goals of the legislation.

[10:29:14 AM](#)

Mr. Fitzpatrick moved to the third section of the presentation starting on slide 16 which was an overview of the modification process.

Mr. Fitzpatrick turned to slide 17: "Stranded Resources Means Zero Production and Zero Revenues to the State." The slide was a description of one of the royalty modifications previously granted by the state to leases within the Ooguruk Unit. The slide contained an excerpt of part of the royalty modification decision. In the particular instance, Pioneer Natural Resources applied to the state for a royalty modification of the leases in Ooguruk claiming they would not be able to economically develop the project without a modification and would not proceed with the investment. He noted that Pioneer shared data with the state that allowed the state to conduct its own analysis of Pioneer's claims.

Mr. Fitzpatrick reported that the department came to a similar conclusion about whether the project was economic and agreed to modify the royalty rates at Ooguruk. He pointed to the bottom of the slide. The current payments from the Ooguruk Unit to the state included \$145 million in royalties and \$12 million in net profit share payments. In 2006 the Ooguruk field was initially authorized and came into production in 2008 or 2009. He noted that the royalty modification that was originally granted had phased out over time and ends completely in the current year. From present day on, the Ooguruk Unit would be paying the state royalties at the full rate that was originally in the contract, and no other modification had been allowed after 2021. He invited Mr. Meza to provide additional details.

[10:31:59 AM](#)

Mr. Meza indicated that the production from the Ooguruk Unit began in 2008. The royalty modification decision enacted in 2006 contemplated a reduction in the royalty rates in the first years of production until a certain trigger. He confirmed that the royalty levels would return to original rates beginning in 2021.

Mr. Fitzpatrick continued to slide 18 which provided a list of all of the royalty modification applications that had been received by the department since the royalty modification statute was originally enacted in 1995. He reported the department had received 8 modification applications since the statute was enacted. He pointed to the first application by BP from Milne Point which was denied. Between 1995 through 1999 two additional applications were received - one by Unocal and one by Phillips. Both applications were withdrawn after initial analysis. In 2005 the Ooguruk application was the first the department approved. The application was a joint application by Pioneer and Eni and was the project he had just discussed that was phasing out in the current year.

Mr. Fitzpatrick continued that two additional applications were received in 2006 and 2007. The first, for the Nikaitchuq Unit, was denied. The second application was similarly withdrawn. In 2008, Eni, after purchasing the entire Nikaitchuq Unit, applied again for royalty modification at Nikaitchuq. The modification was granted in 2008 and contained a trigger based on oil price. The royalty rate phased lower or higher overtime based on the price of oil at a particular time. The modification would phase out and end by 2036.

Mr. Fitzpatrick reported that the last application received by the department was received in 2014 for a new pool within the Ooguruk Unit, the Nuna Torok Pool. The department considered and granted the application with a provision included by the department in the grant of royalty modification for Nuna was that Caelus had to sanction the development and make a certain investment level within a certain period of time after the royalty modification as granted. Caelus did not make the investment in Nuna which nullified the royalty modification.

[10:35:43 AM](#)

Representative Wool referred to Eni's royalty modification application in 2008. The slide indicated that the NPSL had not reached the payout stage. He also referred to the previous graph on slide 14 containing different modifications. He suggested that even with full modifications, the fields did not become profitable for 18

years to 20 years. He wondered if it was typical for some of the payouts to be delayed for such a long period.

Mr. Fitzpatrick responded that it varied field-by-field. He referred to slide 9 containing the list of 26 NPSLs. He confirmed that it could take several years for a field to reach payout. Typically, it could take a while for the initial development costs to be recuperated and for the lease to reach payout. For certain fields if there was a significant amount of production and relatively inexpensive development, the payout period could be reached faster. Whereas, for other leases where there was marginal production or potentially more expensive development costs, the payout could be much later. In both instances it took some time after production began for the first net profit share payments to be made. There were times where the state waited 10 years to 20 years or longer for the first net profit share payment to be made. Whereas royalty payments were received the moment production began from the lease.

Representative Wool suggested that a royalty modification appeared to be more desirable. He thought an NPSL modification would be a lower priority. He asked if he was accurate.

Mr. Fitzpatrick agreed that from a lessee's point of view Representative Wool's statement was likely true. However, from the state's perspective, if it was possible to modify net profit share rates and if the modification of the net profit share rate alone would make the field economic, although the lessee might not benefit as much, the state could preserve more of its royalty income especially earlier in the field life while still making the field economic. The state would be better off only allowing a net profit share modification or a blended modification rather than modifying royalty alone. One of the objectives of the bill was to give the state the potential to craft a modification that helped to flip the trigger of investment by the lessee while preserving the state's interest to a large extent.

Representative Wool agreed with the purpose of the bill.

[10:40:13 AM](#)

Representative Carpenter referred to the timeline and the 25 [26] active leases. He asked Mr. Fitzpatrick to provide

the number of original lease holders who continued to be lease holders. He wondered how many of the original leases had changed hands. Mr. Fitzpatrick could look into it and see about providing some historical information.

Co-Chair Merrick asked how many applications the department anticipated with a change in legislation. She also asked if producers had requested the legislation. Mr. Fitzpatrick responded that it would be difficult to predict whether there would be a huge rush of applications. He believed there had been discussions about extending Duck Island production. He expected to receive more applications when smaller units started to reach the end of their field life. It was an area in which a legislative change could help to increase the number of production years.

Representative Josephson drew attention to slide 18 which highlighted the modifications and requests which were granted and denied. He noted that for the Ooguruk Unit the indirect expenditure report reflected that for 5 fiscal years from FY 15 to FY 19 the state forewent about \$90 million in royalties. The slide reflected royalties of \$142 million. He thought the slide suggested that without the royalty relief, the royalty would have been approximately \$230 million. However, without the relief the field might not have been developed. He highlighted that royalty relief added up. He asked Mr. Fitzpatrick to comment.

Mr. Fitzpatrick was not familiar with the methodology the Department of Revenue (DOR) used for their indirect expenditure report. He expected that Representative Josephson was correct in his observation that the core difference was whether the investment would have been made without the relief. He could follow up with DOR to look at their calculations and compare them to DNR's figures. Representative Josephson responded, "If it's not too burdensome, yes. Thank you."

[10:45:37 AM](#)

Representative LeBon asked about sunset dates. He wondered why a modification was not done that did not include a sunset date. He what the motive was for a sunset date. Mr. Fitzpatrick responded that the sunset dates were calculated for each project. In the first instance there were conditions that were sometimes conditions that were put on

the modification in order to ensure that the lessee invests in the field the way they represented they would in their application. In the second instance, once a modification was granted and occurred for a number of years, as part of that economic analysis, the department strived to allow a modification only sufficient to induce the lessee to make an investment or to keep a field in production. Inserting a sunset into that modification allowed the department to limit the amount of modification that it granted in such circumstances. At a certain point, the field returned to its original royalty rate or potentially a net profit share rate. The state received the additional revenues at that point in time. It was a way for the department to limit the amount of modification to only grant enough modification to change the investment decision and no more.

Representative LeBon commented that the bill reminded him of a bank being asked to modify a loan by a borrower because of a change in interest rates to their disadvantage. As a previous banker, he received that request frequently. The structure a bank would counter-propose to a borrower often included an element of shared risk or benefit. If a borrower no longer liked its rate, the bank would respond with some type of variable such as including a floor and a ceiling. He hoped that if the bill became reality that the state would be a good negotiator to make sure there was shared benefit and risk.

[10:49:19 AM](#)

Representative Carpenter had a question regarding the modification process. He wondered if economic factors other than monetary factors were considered such as jobs lost or local economic value. He pointed out that on slide 18 there were 11 platforms in or near his district on the Kenai Peninsula from the late 1990s. He noted that the Kenai Peninsula oil industry had seen a sharp decline in jobs over the previous decade. He wondered if the state had been able to make conditions more favorable, whether job losses would have been avoided. He reiterated his question as to whether the modification process included an analysis of job loss or local community impact.

Mr. Fitzpatrick responded in the affirmative. He elaborated that additional impacts beyond revenues were considered. The investments in the state and the jobs created were

potentially part of the best interest finding. Other factors the state had considered previously when looking at potential modifications were increases in production from the North Slope that could potentially drive the tariff rates on TAPS down. The tariffs were a function of the throughput on the pipeline in part. If the state could get additional barrels through the pipeline, it reduced the tariff rate for all production on the North Slope increasing the state's take from other fields. There was less of a transportation deduction against the state's royalty or tax revenues from other fields.

Mr. Fitzpatrick continued that there were definitely other factors other than only the economics of a particular field that were considered during the evaluation process. The department also spent a large portion of time evaluating the revenue and economics of a field because, ultimately, it was what drove the investment decision - what the state was attempting to influence through the modifications.

Representative Carpenter understood the importance of working with the lease holder. Ultimately, the state needed to maintain flexibility to keep jobs in the state. He reflected on a significant number of jobs lost in the state. He encouraged flexibility.

[10:53:48 AM](#)

Representative Josephson spoke of a Supreme Court decision regarding royalty. The court insisted that the legislature and the executive branch impose a royalty, as there was not one in the specific case. The Supreme Court indicated that the state had to take a share of the mineral interest. He wondered if the administration could request a lower share.

Mr. Fitzpatrick replied that it was possible to issue a lease with less than 12.5 or 16.66 percent royalty. He suggested that when there was limited geologic information about the prospects on a particular lease, the department's goal at the time of lease issuance was to try to capture as much value for the state as possible. He thought, from the department's perspective, the ability to propose a higher royalty rate upfront then have the flexibility to potentially modify the rate on the back end if warranted and only to the extent that economic circumstances were warranted allowed the department to capture more value upfront especially from leases that turned out to be as

prospective as expected and for the limited set of circumstances where the lease turned out to be not as prospective gave the state the ability to modify the rates to get the units into production without losing the economic benefit of the higher royalty rate for other leases. Representative Josephson commented that it made sense.

[10:56:33 AM](#)

Representative LeBon asked if there was ever a situation where the state would want to initiate a modification. Mr. Fitzpatrick suggested that because the leases were exercised through contracts, the state did not have the ability to reopen and impose new terms on an oil and gas the contract without the ascent of the counter party - the lessee. As pat of the royalty modification process, the state had to wait for an application to be received by the counter party in order to act on any modification. Representative LeBon knew the answer to the question. He encouraged the state to recognize that it was a one-way street.

Co-Chair Merrick indicated the committee had reached a good stopping place and reviewed the agenda for the afternoon.

HB 81 was HEARD and HELD in committee for further consideration.

ADJOURNMENT

[10:59:24 AM](#)

The meeting was adjourned at 10:59 a.m.