

SENATE FINANCE COMMITTEE  
March 27, 2012  
1:08 p.m.

[1:08:58 PM](#)

CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 1:08 p.m.

MEMBERS PRESENT

Senator Lyman Hoffman, Co-Chair  
Senator Bert Stedman, Co-Chair  
Senator Lesil McGuire, Vice-Chair  
Senator Johnny Ellis  
Senator Dennis Egan  
Senator Donny Olson  
Senator Joe Thomas

MEMBERS ABSENT

None

ALSO PRESENT

William C. Barron, Director, Division of Oil and Gas, Department of Natural Resources; Janak Mayer, Manager, Upstream and Gas, PFC Energy; Senator Joe Paskvan; Senator Cathy Giessel;

SUMMARY

SB 192 OIL AND GAS PRODUCTION TAX RATES

SB 192 was HEARD and HELD in committee for further consideration.

PRESENTATION: DEPARTMENT OF NATURAL RESOURCES

William C. Barron, Director, Division of Oil and Gas, Department of Natural Resources

Co-Chair Stedman discussed the meeting's agenda.

#sb192

SENATE BILL NO. 192

"An Act relating to the oil and gas production tax;  
and providing for an effective date."

^PRESENTATION: DEPARTMENT OF NATURAL RESOURCES

1:10:32 PM

WILLIAM C. BARRON, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, continued the Department of Natural Resources' PowerPoint presentation titled "Senate Finance Committee 26 March 2012" (copy on file) from the previous meeting. He stated that during the previous meeting, the presentation had covered the ways and means of the state's ability to dispose of land and furthered that the primary aspects of land disposition were through the area wide lease sale. He noted that some of the terms and conditions of the bonus and rental programs, which were in place on the North Slope and Cook Inlet areas, had also been discussed in the prior meeting.

Mr. Barron explained the slide on page 6 titled "exploration licensing system." He stated that the exploration licensing system was the other opportunity for land disposition.

Exploration Licensing System:

- Areas not within area wide lease sales
- No rental fee or upfront bonus payment
- Term up to 10 years
  - *When work commitment is fulfilled, licensee may convert part or all of license area to leases (subject to \$3/acre rental fee and, when producing, no less than 12.5% royalty)*
- State is provided all geological & geophysical information acquired
- If competing proposals, highest bid for minimum work commitment is selected

- Imposes financial work commitments (AS 38.05.131-.134)
- Licensee must commit 25% of total specified work commitment by fourth anniversary of license issuance

Mr. Barron stated that the exploration licensing system applied to areas that were not in the area wide lease sale and that the two programs were distinct and separate. He explained that the ten year term of an exploration license operated on the basis that companies would come forward to designate an area of interest and propose financial work commitments. A company's license could be revoked if it had not completed 25 percent of its fiscal commitment within the first four years. After the ten year term expired, the area within the exploration license could be converted to a lease, or multiple leases, for another five year term; the five year extension provided the program with additional exploration and delineation, and would hopefully progress the property into development. He stated that there were only four areas participating in the exploration licensing system and that the program was not widely utilized. He concluded that the area wide lease sale was more honed for the exploration of oil and gas in Alaska.

[1:13:31 PM](#)

Mr. Barron explained the slide on page 7 titled "current status of state leases."

- Active leases: 1416 leases (largest tract: 9 square miles)
- Of these, 46% of leases are in units (producing)
- 0.5% are leases producing without being in units
- 46% of leases are in the hands of companies currently actively exploring on part of their lease hold\*
  - *Apache, Buccaneer, Nordaq, LINC, Repsol, Great Bear, Brooks Range, Anadarko*

- *Included in this number are Foothills leases where lessees have conducted field work in the past (gas-prone areas)*
- The remaining 7.5% may or may not be under exploration
- *A majority of these leases (approximately 95%) are held by individuals or groups of individuals, not major corporations*

\*The list is not extensive; this only includes companies we know are currently actively exploring.

Mr. Barron explained that the slide did not include the December 2011 lease sale on the North Slope; most of the North Slope leases had yet to be adjudicated and were still within the confines of the state's ownership. He stated that the 9 square mile plot was included because it was the largest lease that was allowed by statutes. He pointed out that many of the international arenas used "blocks" and that in these countries, a block could be a single lease that was 180 to 190 square miles; a block this size was roughly half the size of Prudhoe Bay. He stated that there was a significant difference of understanding regarding concessions in international regimes and what occurred in Alaska. He explained that many countries packaged blocks together and might have as many as six different blocks that were offered at the same time. He referenced the 46 percent figure, which was in the fourth bullet point and explained that Apache had acquired and explored a number of tracts in the Cook Inlet lease sale the prior year. Apache was doing seismic work and was systematically "shooting seismic" that would eventually cover all of its tracts of land. He stated that the 46 percent figure showed that although companies might not be actively drilling or shooting seismic on every single tract of land, they were making progress through the activity.

Mr. Barron pointed out that Alaska's lease terms were competitive based and that anyone who was 18 years of age could own a lease in Alaska. He opined that there were many different kinds companies in the oil industry; some companies primarily focused on exploration, some had a primary paradigm of development, while others had a primary corporate function that was referred to as "brownfield operations." He explained that explorers and early

developers represented "greenfield operations", while activities on mature fields were referred to as "brownfield operations."

Mr. Barron stated that speculators actively purchased and marketed leases to other players and that they served a critical function in lease sales. He offered that Armstrong Alaska was a good example of company that was in a speculator mode. He explained that Armstrong Alaska's ability to market land had attracted companies like Repsol, Pioneer Natural Resources Alaska, and ENI Petroleum; furthermore, Armstrong was currently doing its own development work in the Kenai Peninsula. He observed that although a company like Armstrong tended to focus on land management, it served a valuable function in the state's development of oil and gas.

[1:19:54 PM](#)

Senator Thomas referenced the last bullet point on slide 6. He inquired if pursuing the sale of a lease was considered a "work commitment", or if the term meant that a company must commit to some form of exploration and/or drilling. Mr. Barron responded that slide 6 dealt with exploration licenses, but that a work commitment was not necessarily associated with the area wide lease sale. He offered that work commitments can be part of a lease sale opportunity and that the state had the ability to specify work commitments, as part of the original bid, during the exploration phase; work commitments were imposed in this fashion as recently as last year in the case of the Cook Inlet's Cosmopolitan Unit. He explained that for the Cosmopolitan Unit, the state had required entities to bid on leases that were packaged together and also required that over a period of time, the companies must identify, drill, and establish a participating area (PA) within the lease area. He stated that requiring a work commitment as part of bid might have some merit, but that it was problematic to require a company to know what its plans were before it had won the bid. He furthered that the bidding system was competitive and that the problem facing a company was how to put together a work plan without knowing what it had won or the level of prospectivity in the area that it was trying to develop.

Senator Thomas acknowledged that it was helpful to have speculators, but pointed out that most of the people who

were looking to develop oil or gas properties would be at the lease sale. He referenced a speculator's abilities to bid, buy, and hold onto land and stated that he had assumed that both the area wide lease sale and exploration license systems had work commitment requirements. He queried what the requirements were on potential buyer, and at what time was the lease holder required to deliver a work or development plan. Mr. Barron replied that with respect to an exploration license, a company would identify what it would spend on a property, but that it would not necessarily define the type of work. In the state's area wide leasing system, the state specified that companies pay a rental tax for the first seven years that they owned the property; if no or little work had been done by the seven year point, the rental rates would go up significantly for years eight, nine, and ten. He explained that the three year period of increased rental rates was intended to encourage companies of interest to develop. He observed that there was a possibility of blending the area wide lease sale and the exploration license systems, but that "is not where we are today." He concluded that if the state's area wide lease system required a bid and an assured financial commitment from an entity, it could limit the players that would be willing to participate in the oil and gas sector in Alaska. He offered that DNR's goal was to attract as many people or companies as possible to Alaska, encourage and support the exploration efforts of companies, and to quickly drive discoveries into development.

[1:26:48 PM](#)

Mr. Barron discussed the slide on page 8 titled "land management: When is PA formed?" A "unit" was formed when a discovery was proven to have moveable hydrocarbons. The purpose of forming a unit was the protection of all parties associated with the reservoir. He explained that some reservoirs crossed over lease boundaries and that as a result, multiple leases were sometimes formed into a unit.

- A PA is formed once the unitized reservoir is on "sustained production": wells are producing into a pipeline or other means of transportation to market
- Separate PA required for each producing horizon

- Approval of a PA includes approval of allocation factors
  - *Sets out proportions of costs and revenues paid and received by working interest owners*
  - *Approval meets 11 AAC 83.303: Protect all parties*

Mr. Barron explained the slide on page 9 titled "What is a plan of development (POD)?"

- Once a PA is formed, a POD is required under 11 AAC 83.343
  - *Must be filed for approval if a PA is proposed, or reservoir sufficiently delineated to initiate development activities*
  - *POD is submitted annually for review and approval*
  - *If POD deemed insufficient for approval, DNR may propose modifications. If Operator agrees to modifications, POD approved.*
  - *If not accepted by Operator, and no approved POD, current POD may expire.*
- Development activities must be conducted under an approved POD

Co-Chair Stedman requested an accelerated run through of the slides. He noted that the committee was focused on budget issues, while some of the slides were more geared towards resources.

Mr. Barron discussed the slide on page 11 titled "North Slope units and PAs: February 2012. 18 existing SOA units, 42 PAs, 2 units proposed." Mr. Barron related that there were 18 existing units, 42 PAs, and two proposed units on the North Slope.

Mr. Barron discussed the slide on page 12 titled "POD process" and explained that the process flow diagram was for the committee's future reference.

Mr. Barron discussed the slide on page 13 titled "evaluating PODs on a complex unit - DOG evaluation tools."

He stated that the state used the "score sheet" to compare past PODs. The "bubble map" helped DNR identify areas of concern or interest that it would like a company to target closer.

Mr. Barron explained the slide on page 14 titled "Kuparuk River Unit(KRU) bubble map." He stated that the slide depicted Kuparuk and that the map showed a "classic line drive waterflood" reservoir. He offered that the map very clearly showed where the water was pushing the oil to producers.

Mr. Barron discussed the slide on page 15 titled "southwest portion Kuparuk River Unit (KRU)." He observed that the lower left hand corner of the map was devoid of developments and that the state had several dialogues with ConocoPhillips, which had resulted in the well Sharks Tooth being drilled in the area "this winter." Sharks Tooth was a confidential well and DNR had not yet seen the logs from the development.

Mr. Barron explained the slide on page 16 titled "Prudhoe Bay Unit" and explained that the slide depicted how reservoirs were stacked on top of each other. PAs could be stacked on top of each other for every producing horizon.

[1:31:21 PM](#)

Mr. Barron discussed the slide on page 17. He stated that DNR was in constant discussion with the operators in the slide's the two mapped areas regarding future plans for development, increased production, and development area expansion.

Mr. Barron explained the slide on page 20 titled "Prudhoe Bay Unit, oil and water production rates." He related that there had been a lot of discussion regarding facilities, facility constraints, future development, and future operations. He offered that the perception was that there was excess capacity in the Trans-Alaska Pipeline System (TAPS). In the original development phase of any oil gas property, facilities were designed to handle fluids in a certain manner. He stated that in a 1,000 barrel per day (bbl/d) facility, 900 of the barrels might be oil, while 100 barrels would be water; it was still considered a 1,000 bbl/d facility. He furthered that as the life of the field neared its end, there may 100 bbl/d of oil and 900 bbl/d of

water being produced from the facility; this was also considered a 1,000 bbl/d facility. He added that regardless of the ratio of water to oil, a 1,000 bbl/d facility would only be able to handle 1,000 bbl/d. He stated that the slide showed that Prudhoe Bay's oil was declining.

Mr. Barron discussed the slide on page 21 titled "Prudhoe Bay Unit, total fluid production and water injection rates." The slide showed that the production total throughput of oil and water had basically remained constant since the year 2000. He added that after 2000, the rates did drop a little and that the question was, what else could be impacting the production. He added that there was excess capacity in the Prudhoe Bay Unit, but that the system was handling more gas.

Mr. Barron explained the slide on page 22 titled "Prudhoe Bay water oil ratio, Prudhoe Bay gas oil ratio." He stated that the water to oil ratio and the gas to oil ratio were depicted on the slide's two graphs. As the Prudhoe Bay Unit injected gas for pressure maintenance, more gas had to be processed; furthermore, water was injected to maintain the waterflood, which resulted in a higher demand for water processing. He concluded that many of the Prudhoe Bay facilities were limited in capacity by water or gas. He related that Prudhoe Bay's reservoir engineers had done an "amazing" job in the development and asset allocation for the field. He added that originally, the field was expected to have a 30 percent recovery rate, but that the current rate was approaching 60 percent. He stated that the engineers had sophisticated reservoir simulation tools and that they were able to prognostic which wells would produce more water or more gas; the engineers "shut in" the wells with more gas. The engineers' process limited the amount of investments that were needed for facility upgrades and "debottlenecking", and enabled the engineers to predict and control which wells to turn on or off; well work overs and recompletions would then be conducted for the appropriate wells.

Mr. Barron discussed the slide on page 23 titled "Kuparuk River, oil and water production rates." He stated that Kuparuk was experiencing the same curves for oil and water as Prudhoe Bay.

[1:35:32 PM](#)

Co-Chair Stedman asked for a clarification on slide 20. He observed that from 1987 and onwards, the green line fit the definition of a parabolic curve and inquired if it appeared to be flattening. Mr. Barron queried if Co-Chair Stedman was referring to the last three years of the green line. Co-Chair Stedman responded in the affirmative. Mr. Barron stated that the plot, from an engineer's perspective, was drawn incorrectly. He explained that the y axis for a decline curve should be a "log curve" [logarithmic] instead of a "Cartesian curve." He explained that in a semi-log presentation, the line would be close to straight and that although the decline appeared to be flattening, it was almost straight; the curve was referred to as a "straight-line depression."

Co-Chair Stedman requested that DNR's future charts reflect the oil production in logarithmic and nominal scales. Mr. Barron responded that DNR would be happy to do so.

Mr. Barron explained the slide on page 24 titled "Kuparuk River, total fluid production and water injection rates." He stated that the Kuparuk curves were similar to Prudhoe Bay's curves and that the gas to oil and water to oil ratios were elevating. He offered that the curves on the slide were very similar to any other primary, conventional oil and gas field in the world; he added that shale oil was an exception to the similarity. He concluded that the decline curve analysis, the oil decreasing with the gas increasing, and the water increasing with waterflooding were typical of other fields around the world.

Co-Chair Stedman asked how long ago DNR would have been able to "draw that conclusion." Mr. Barron stated that Prudhoe Bay's decline could have been predicted as early as 1989 to 1990.

Co-Chair Stedman inquired whether the decline curve would have been expected when the basin was opened. Mr. Barron replied that the curve was predictable in a conventional, sandstone reservoir. He added that the field would manage itself and that the exact rate of decline would be determined later on. He stated that a "type curve match" analysis, which used models of similar fields, could have predicted the flat section, the plateau, and some sort of a rate of decline.

Co-Chair Stedman inquired if the analysis in question was referred to as a "type curve analysis." Mr. Barron responded in the affirmative.

[1:39:30 PM](#)

Co-Chair Stedman observed that some people were surprised about where the rate of decline was today. Mr. Barron voiced his agreement.

Senator Thomas referenced slides 21 and 24. He stated that in 1993, the total liquids production from Prudhoe Bay and Kuparuk combined was approximately 3.2 million bbl/d. Mr. Barron replied that he would not argue the numbers. Senator Thomas inquired if gas handling issues were limiting the maximum level of the fluid production and water injections rates in the two fields. Mr. Barron responded in the affirmative. He referenced slide 22 and stated that gas handling limitations were indicative to some of the facilities.

Senator Thomas queried if the facilities in Prudhoe Bay and Kuparuk had a maximum level of oil and water production of about 3.2 million bbl/d. Mr. Barron agreed that 3.2 million bbl/d was probably a good number to use.

Mr. Barron explained the slide on page 25 titled "Kuparuk River water oil ratio, Kuparuk River gas oil ratio." He clarified that if DNR were examining shale oil, it would look at similar models, such as the Bakken, Eagleford, or Marcellus shale plays. He explained that DNR would examine the production profiles of different shale developments in order to form predictive models for shale oil in Alaska. He pointed out that in a new field, engineers typically examined the type and size the reservoir, as well as how many wells would need to be drilled. He concluded that originally, engineers had reservoir models, but that they were very simplistic; even still, the plateau and the inception of the decline curve could have been predicted. He reiterated that slides 21 through 25 represented a typical exhibit of a major oil field's decline curve.

Mr. Barron discussed the slide on page 26. General production facilities were listed on the slide. He stated that the table depicted information that the Division of Oil and Gas had gathered from various companies. He added that the information on the table might not be fully up to

date. There were red and green bars on the far right hand side of the slide; the red bars indicated that there were limitations on the unit, while the green bars meant that there were no limitations. He observed that the red and green bars did not render very clearly on the slide. He pointed out that the North Star Unit had a red bar and discussed the unit's limitations. He stated that DNR used the slide's information to assess the limitations on producers and that some of the information would be part of a company's POD. He stated that DNR wanted to know if companies were installing more facilities, if they were modeling efforts to control gas, if gas handling facilities were needed, and how the pressure maintenance was going. He pointed out that very few of the facilities had a green bar associated with it. He offered that the Badami Unit was an underutilized asset and that companies in the area would likely be open to a production sharing and processing facility sharing agreement. He stated that Oooguruk and Nikaitchug had no limitations; however, the CPF-3 Unit, which did have limitations, was processing Oooguruk's oil.

Mr. Barron explained the slide on page 27 titled "facilities access agreements." He explained that DNR's dialogue had tended to revolve around facilities access agreements and that the agreements were "incredibly complicated" and were between players that were sometimes competitive.

[1:45:38 PM](#)

Senator Thomas asked for a clarification of the chart on page 26. He inquired if flow stations 1, 2, and 3, as well as gathering centers 1, 2, and 3 all had gas or water handling limitations. Mr. Barron responded in the affirmative.

Senator Thomas queried if the stations and centers were limited to a total production capacity regardless of the makeup of what flowed through them. Mr. Barron responded in the affirmative.

Mr. Barron continued to discuss the slide on page 27.

- Facility access agreements are complicated commercial agreements between multiple parties
- Facility access agreements impact

- *Reservoir management*
- *Process management*
- *Influence and impact PODS, which in turn has an impact on expense and capital exposure in the state*

Mr. Barron stated that it became legally and commercially complicated when a new player joined a facility. He listed possible complications in the case of a facility shut down as follows: who was responsible for the loss or deferred production, who gets backed out of the facility first, who has the right to first access back in to the facility, are there penalty clauses involved, and would the state declare a loss of revenue; all of the eventualities needed to be considered from the perspectives of commerciality and their impact on companies' overall asset management. Many companies had an internal corporate culture, which dictated that it would build its own self-sufficient facilities. He pointed out that some companies preferred to ship oil via the existing pipeline network and have smaller production facilities rather than relying on someone else to process fluids; he offered that this model worked well in a number of areas. He stated that in Norway, using an existing offshore structure for the common good of many players was part of the program. He explained that Norway did not want to construct new platforms, but that it wanted to utilize the facilities that were in place; in that regard, Norway leased space on the platform for new facilities.

Mr. Barron explained a slide on page 28 titled "facilities summary."

- The Prudhoe and Kuparuk units are experiencing typical reservoir depletion which requires handling and processing of increasing amounts of water and gas, decisions on facility management, effective well utilization, and complex reservoir management.
- Facilities are designed to meet a wide range of production profiles with varying water-oil and gas-oil ratios (WOR and GOR, respectively). As the reservoir matures, reservoir management and facility debottlenecking for water and gas handling, water and/or gas injection to maintain

reservoir pressure, well workovers, and new infield development drilling is required.

- Pipeline capacity is available throughout most of the North Slope, thus companies with new oil discoveries will need to negotiate to share the existing transport facilities.
- Corporate culture and size of a discovery typically dictate decisions whether to build new process facilities or enter into commercial agreements to access existing facilities.

Mr. Barron related that Prudhoe Bay and Kuparuk were well managed properties and that the two areas' gas reinjection, waterflood, and miscible flood activities had all benefited the state. Companies were managing Prudhoe Bay and Kuparuk by turning wells on and off, examining which wells would have too much water or gas, moving the water and gas around, maintaining reservoir pressure, and knowing the location of the gas fronts and water fronts. He furthered that retrofits, debottlenecking, well workovers and recompletions, and the water and gas shutoff program were all done on a well by well and area by area assessment basis. He added that the pipeline capacity on the North Slope was robust and that new players should not have a problem entering into the existing pipeline networks.

[1:50:30 PM](#)

Co-Chair Stedman remarked that oil still had to be brought to the pipeline. Mr. Barron replied that on any new development, the producer could lay its own line from its own production facility that would tie into existing infrastructure; this was similar to how Alpine had tied into Kuparuk in order to get to Pump Station 1. He offered that if Repsol had a discovery on a well that it was drilling, it would install its own production facilities that tied into an existing line. He related that every field was managed differently, but that in general, every well had to be hooked up to a production system. He concluded that oil cannot flow from a well straight into the pipeline because of the water, gas, sand, or debris that was produced along with the oil.

Co-Chair Hoffman asked what involvement DNR had with the facilities agreements. Mr. Barron replied that DNR had very little involvement and that the agreements were between the two parties; if asked by either party, DNR could "lean in" to encourage facilities agreements. He concluded that DNR was very seldom engaged in those sorts of negotiations.

Co-Chair Stedman inquired if DNR had an idea of what it would take for facility upgrades in order to increase production. Mr. Barron replied that DNR did not. Co-Chair Stedman queried if DNR ever looked at that aspect of facilities. Mr. Barron responded that during the POD process, DNR examined companies' proposed activities relative to wells and facilities; this opportunity allowed DNR to assess whether companies would be making upgrades or modifications to the existing systems.

Co-Chair Stedman queried if DNR could provide information, which could be used to increase production, regarding the separation of "below ground" and "above ground" issues. He observed that a lot of time was spent discussing below ground well workovers or infill drilling, but that very little time was spent discussing facilities. He inquired if the state was dealing with facility constraints, below ground constraints, or a combination of both. He further inquired if DNR knew what it would take to stabilize production at 600,000 bbl/d. Mr. Barron replied that it would take a combination of new exploration and new infill drilling. He stated that infill drilling work had arrested the state's decline curve over time; the decline was occurring at a lesser pace because of the companies' investments, infield drilling, well workovers, and facility modifications. He stated that in order to further flatten the decline, all the parties involved would have to install more wells and facilities. He furthered that the state needed new entries into the market and cited the potential entrants as follows: Brooks Range Petroleum, Repsol, Pioneer Natural Resources, ENI Petroleum, the Schrader Bluff heavy oil, as well as Great Bear Petroleum's and Royale Energy Inc.'s shale oil; he stated that "all of those would be part of the play" and would need new facilities.

Co-Chair Stedman asked if DNR had recommendation or advice for the committee regarding potential costs. Mr. Barron replied that he did not.

1:55:22 PM

Co-Chair Hoffman stated that given the inevitable decline, it would potentially take hundreds of millions of dollars to increase facilities for new oil. He inquired if it would be more financially prudent for the state to keep the status quo rather than having the industry incur such a large investment. He observed that the question might be one that the committee or DNR would be unable to answer. Mr. Barron replied that the North Slope basin was still a robust and rich oil basin. He referenced British Petroleum's (BP) heavy oil development at Milne Point, which had a recent well test of 650 bbl/d in production; he indicated that this production level was "beyond world class" in terms of heavy oil production from a single well. He stated that developments like Milne Point, in aggregate across the state, are what would drive development beyond where it was today. He opined that the decline curve could be flattened and reversed, but that it would take a "tremendous effort" by industry beyond what it was currently spending. He added that the new development plays and new exploration work were critical to get to where the state wanted to be.

Senator Thomas asked for clarification on page 28 and inquired if the third bullet point was referring to "downstream" pipeline capacity. Mr. Barron responded in the affirmative. Senator Thomas queried if the non-downstream capacity was being used for water and gas handling. Mr. Barron replied in the affirmative. Senator Thomas asked if the water and gas injection was required to maintain well pressure, or whether gas and water were in the system because there was nothing else to do with it. Mr. Barron replied that water and gas injection was needed. He referenced slide 14's bubble map, which depicted the line drive waterflood in Kuparuk and stated that waterflooding was a viable technique for maintaining reservoir pressure; the water was used to "sweep" oil away from an injector and bring it closer to a producer. He stated that the reinjection of gas into the gas cap had greatly benefited Prudhoe Bay and that it resulted in oil moving from the upper elevations of the reservoir into the lower producing horizon. He pointed that water and gas injections were very viable techniques and mentioned that both Prudhoe Bay and Kuparuk were experimenting with new reservoir management techniques.

2:00:01 PM

Senator Thomas observed that the only solution seemed to be to build more facilities that could process water and gas. He pointed out that gas and water were needed, but that the facilities which processed them were currently at capacity limits. Mr. Barron responded that areas of development that were west of the heart of the existing Prudhoe Bay area still had some prospectivity; the prospectivity in these areas would involve new wells and facilities. He stated that water and gas came out of the wells naturally and that additional water was introduced in the general waterflood. He explained that in order to maintain the pressure, every barrel of oil that was taken needed to be replaced by a barrel of water. He concluded that in the case of the North Slope, the water came from the ocean and was re-injected; needing more facilities for water and gas processing was a "self-fulfilling prophecy."

Co-Chair Hoffman referenced the Society of Petroleum Engineers' western regional meeting in May of 1993 and quoted engineers from BP and ConocoPhillips, who had reported that,

"Prudhoe Bay is seen by many as a mature oil field on an inevitable and irreversible decline ... The field's oil production capacity dropped below 1.5 MMSTB/D in 1988 \*officially\* signaling the start of decline. The onset of decline was a direct result of limited gas handling capacity as opposed to limited oil production capacity."(copy on file) [The quote can be found in the backup document titled "gas and water handling constraints on Alaska's North Slope."]

Co-Chair Hoffman inquired if Mr. Barron agreed with the quoted statements. Mr. Barron replied that he tended to agree and that gas handling facilities seemed to be the bottleneck at the current time. He added that it was important to remember the necessity of being able to process and re-inject gas in order to maintain reservoir pressure and "sweep."

Co-Chair Stedman noted that ConocoPhillips had stated in prior testimony that increasing production to 700,000 bbl/d or 1 million bbl/d would be technically impossible. He observed that there was a technical issue versus a tax issue and that the committee was struggling with the

balance between the technology constraints and the impact of the tax system. He furthered that the committee was trying to separate what was technically feasible, what would be feasible under a zero tax structure, what was feasible under the current tax structure, and "where are we between that zero and where we are today." He pointed out that the state would not get to 1 million bbl/d in production and that some felt that it would difficult achieve 700,000 bbl/d. Mr. Barron responded that testimony tended to get misconstrued in the overall dialogue. He opined that it was unlikely that the decline could be arrested and reversed to 1 million bbl/d in the existing Prudhoe Bay and Kuparuk fields.

Mr. Barron related that there was still a lot of oil left to be discovered in the North Slope and that it was still a target rich environment. He stated that when Prudhoe Bay was discovered, the expectation was that it would have a 30 percent recovery rate and that the pipeline would be empty by the year 2000. He observed that in 2012, the North Slope was still producing 600,000 bbl/d, which was well beyond the original concepts of what was technically achievable at the time. He pointed out that 60 percent recovery from a reservoir was "astonishing" and that he did not discount scientists' and engineers' abilities to create new ways to develop oil and gas. He opined that it would possible to arrest the six percent decline in Prudhoe Bay and bring it down to four percent for a period of time. He furthered that it was possible to flat line Prudhoe Bay and Kuparuk, but that new technologies, new development concepts, new conventional fields, as well as heavy and shale oil needed to come on line and be brought to bear. He stated that Kuparuk and Prudhoe Bay could not be considered in singularity regarding the future development on the North Slope. He concluded the work of Savant Alaska LLC at Badami, the work of Repsol, ENI Petroleum, Pioneer Natural Resources Alaska, Brooks Range Petroleum, and Great Bear Petroleum all needed to be part of the equation regarding overall development on the North Slope; the opportunities in these areas were "robust" and "tremendous."

[2:07:34 PM](#)

Co-Chair Stedman queried if the magnitude of a one percent or two percent recovery rate would be much greater in Prudhoe Bay than it would be in other areas. Mr. Barron responded in the affirmative and related that changing the

decline profile of Prudhoe Bay by one percent, even for a period of time, would be an "amazing feat." He concluded that Prudhoe Bay was a huge field and that trying to drill the right number of wells, in the right locations, with the appropriate production facilities, and doing so at the right time were all part of the dynamics of reservoir and production management.

[2:08:28 PM](#)

AT EASE

[2:18:21 PM](#)

RECONVENED

#sb192

SENATE BILL NO. 192

"An Act relating to the oil and gas production tax; and providing for an effective date."

Co-Chair Stedman discussed the meeting's agenda. He stated that the PFC Energy presentation would discuss progressivity options. He observed that after the meeting, the committee should have a general idea of which options it would focus on and which ones would be taken off the table.

Co-Chair Stedman asked for a brief description of PFC Energy.

[2:19:37 PM](#)

JANAK MAYER, MANAGER, UPSTREAM AND GAS, PFC ENERGY, began a PowerPoint presentation titled "discussion slides: Alaska Senate Finance Committee." (copy on file) He stated that PFC Energy was a global consultancy that was focused solely on "upstream" and "downstream" oil and gas issues; upstream referred to all activities associated with getting oil out of the ground, while downstream was reflective of the refining, marketing, and retail sectors. PFC Energy had a particular expertise in above ground issues, such as understanding markets and market analysis, political risk assessments, understanding fiscal terms, and how a government set its rules for oil and gas. He added that companies needed to understand the rules that a government set in order to be able to do business. He concluded that

PFC Energy worked at the nexus between international oil companies, national oil companies, and governments.

Mr. Mayer explained the slide on page 2 of the presentation titled "assessing 10 different fiscal regime options." He stated that the slide summarized, in terms of revenue to the state, the different fiscal options that had been discussed in a previous meeting; the options were presented in the context of Alaska's Clear and Equitable Share (ACES), HB 110, as well as other permutations. He explained that under PFC Energy's model and at an oil price of \$100 per barrel, ACES netted the state \$3.686 billion in production revenue; by contrast, HB 110 netted the state \$2.721 billion at the same price level. The core of the slide's analysis focused on options for base levels of taxation and progressivity that slightly reduced government take at given price levels, but did not dramatically reduce revenue to the state; furthermore, the options would significantly reduce progressivity "beyond that point" in order to even the split of revenue between companies and government. He related that the committee had examined how CSSB 192 might look if the maximum rate was capped 50 percent instead of 60 percent. He stated that the committee had also looked at CSSB 192 with a base rate of 30 percent and a progressivity rate of .2 percent. He added that CSSB 192 with a cap of 40 percent on the maximum rate was also discussed; without a change to the base rate, this option did not necessarily generate a significant change in numbers from the current bill. He related that another option on the slide was taking progressivity out of production tax and instead instituting a severance tax. He explained that a severance tax was a tax on gross oil production and that it reflected the gross value at the point of production. He stated that there were a number of advantages to removing progressivity. He offered that the issue of "decoupling" had arisen specifically due to the inclusion of progressivity in the production tax. He observed that if the production tax was a flat tax, decoupling would not be an issue. He stated that using a flat severance tax and incorporating progressivity at the gross level solved the problem of decoupling without having to undergo the administratively more complex solution that was in CSSB 192. Currently, CSSB 192 specified that production and costs for oil and gas had to be separated and presumably required companies to submit two different tax returns. He reiterated that a progressive severance tax referred to when progressivity was taken out of the

production tax and was instead levied on the gross level. He added that a second benefit of having a progressive severance tax was that it allowed for more flexibility in incentivizing new production; however, as long as progressivity remained part of the profit-based production tax, incentivizing new production was significantly more difficult. He explained that under the existing system, there were few options for incentivizing new production; one incentive could be a dollar amount allowance that would be subtracted from the production tax value for "new oil." He discussed the different ways of defining what new oil was. He stated that regardless of how new oil was defined, the mechanism in the existing system that provided incentives for new production was complex; taking progressivity of the base production tax and levying it on a gross level created greater flexibility with incentives. He offered that if an entity wanted to provide a very high level of incentives for production from new areas, the severance tax could be structured to only apply to existing fields; new fields could have a zero severance tax and would only pay the 25 percent flat base tax. A lower level of severance tax could also be applied to new areas or to production over the base level. He shared that the HB 110 (new), the six percent severance tax, and the 25 percent flat tax options represented hypothetical exercises and that while they served an analytical purpose, the dollar values might not reflect reality; the three options were included to provide different ways of structuring a system in order to incentivize new production.

[2:29:48 PM](#)

Co-Chair Stedman asked for a clarification on slide 2 and inquired if the "total federal take" reflected the total government take in dollars. Mr. Mayer responded in the affirmative. Co-Chair Stedman queried why the industry take was not included on the table. Mr. Mayer responded that PFC Energy would include the requested information in the future. Co-Chair Stedman queried if the slide's revenue comparisons represented the current production in legacy fields, the aggregate of all production, or new production. Mr. Mayer replied that the slide's revenue reflected FY 13 data, including the production and cost levels, after it was run through PFC Energy's model. He added that anytime revenue figures were presented, the information reflected FY 13 data. Co-Chair Stedman remarked that the slide used the "homogenized" FY 13 data from the Revenue Sources Book.

He inquired if the values of the legacy fields and smaller producers would reflect a different set of numbers than the aggregated numbers on the slide. Mr. Mayer responded that Co-Chair Stedman was correct.

Co-Chair Stedman inquired what direction the presentation would go later in the meeting. Mr. Mayer replied that the presentation would examine the regimes on slide 2 in terms of their levels of government take and revenue to the state. He added that the presentation would conclude with an analysis of the marginal rates in the same regimes.

Mr. Mayer discussed the slide on page 3 titled "ACES (existing producer)." He stated that the upper left graph depicted a cash flow analysis for a 200,000 bbl/d producer, under the existing system, with recent cost levels and a six percent decline curve; it also showed different economic metrics regarding the Net Present Value (NPV) at different prices. He stated that the top right graph showed the level of government take at different price levels; the red showed the total government take and the blue reflected the total state share. Based on a price spread from \$100 to \$230 per barrel, the slide's scenario had total government takes ranging from 75 percent to 83 percent. The percentages on the top right table represented the divisible income and were added horizontally to get the total state or government takes. He related that the bottom right chart depicted the percentage levels of government take, while the bottom left chart showed the percentages in terms of dollars.

[2:35:03 PM](#)

Mr. Mayer discussed the slide on page 4 titled "HB 110 (existing producer)" and offered that companies had referred to HB 110 as the "threshold for meaningful reform." He observed that at a price of \$100 per barrel, HB 110 would have a government take of about 67 percent; at higher price ranges, it had a maximum level of government take of 71 percent. He explained that the slide's lower government take resulted in a corresponding effect of the cash flow line rising and the NPV going up.

Mr. Mayer discussed the slide on page 5 titled "CSSB 192 (existing producer)." He stated that under this scenario, there was very little difference in the government take

below the \$100 per barrel price level and that the 75 percent government take had dropped to 74 percent [Both statements were made in comparison to slide 3.]. He offered that the slide's one percent drop in government take was probably a function of rounding and that in reality the change was even smaller than the slide showed. He stated that the scenario did see changes to the government take at higher price levels and that its maximum level of government take flattened out at 79 percent to 80 percent. He added that the slide depicted a life cycle analysis and that it reflected the effect of inflation on some of the nominal thresholds; PFC Energy factored in the inflation and saw the government take flattening out at an oil price around the mid-\$100s per barrel. He furthered that if the slide had been forecasted solely on FY 13 basis, the flattening effect would probably not occur until the \$230 per barrel level; in that respect, there was relatively little difference between CSSB 192 and ACES as it currently stood.

Mr. Mayer explained the slide on page 6 titled "CSSB 192 with 50 % cap (existing producer)." He stated that if a maximum rate cap of 50 percent were put in place of the 60 percent cap, the levels of government take were "very slightly" reduced at a price of \$100 per barrel. He offered that under a 50 percent cap, the levels of government take remained flat in the mid-70 percent range, whereas the current form of CSSB 192 was projected to have almost an 80 percent government take at higher price levels. He stated that lowering the cap to 50 percent minimized the extent to which upside was reduced at high oil prices, such as prices above the \$120 to \$130 per barrel level; however, the 50 percent cap did not have a large effect at price levels below \$120 per barrel.

Mr. Mayer explained the slide on page 7 titled "CSSB 192 with 40 % (existing producer)." He stated that if the maximum rate cap was lowered even further to 40 percent, there would be a flattening of out of government take "altogether". He furthered that the 40 percent cap would result in a more neutral system that had a 69 percent to 70 percent government take at almost all of the price levels. He concluded that "correspondingly, in each of these cases we see the net present value for each of these portfolios rising."

Co-Chair Stedman asked for a clarification on slide 7. He noted that at \$40 per barrel, the slide's NPV was \$2.588 billion in comparison to ACES' NPV of \$2.812 billion at the same price level. He requested an explanation of the slide's NPV table. Mr. Mayer stated that at \$40 per barrel, the value of the portfolio was reduced under CSSB 192 in comparison to ACES; he added that the reduction was a function of CSSB 192's higher minimum level of tax. He explained that while current regime had a four percent minimum tax at lower price levels, CSSB 192 set a minimum tax of ten percent for certain larger producing assets. He concluded that at \$40 per barrel, the NPV was lower in all of the CSSB 192 options than it was under ACES. By contrast, the NPVs of ACES and the CSSB 192 were similar at \$60 per barrel; the similarity was a function of progressivity not coming into play at the \$60 per barrel price level, given the costs. He stated that at the \$100 per barrel level, there were modest differences in NPV between ACES and the CSSB 192 options.

[2:40:24 PM](#)

Mr. Mayer explained the slide on page 8 titled "30% base rate, 0.02% progressivity, 40% cap (existing producer)." He shared that the slide presented an option that had previously been discussed in the committee. The slide's option proposed to raise the base rate in CSSB 192 to 30 percent from 25 percent and to substantially lower progressivity to 0.2 percent from 0.4 percent. He pointed out that the slide had a typographic error and that the 0.02 percent figure, which was in the title of the slide, should be at 0.2 percent. The scenario also instituted a 40 percent cap on the minimum rate. The slide's analysis showed that compared to slide 7, reducing the progressivity to .2 percent and adjusting the base rate to 30 percent had relatively little difference at most price levels; he offered that the NPVs on slides 7 and 8 were almost identical at prices above the \$100 per barrel level. He observed that at \$60 per barrel, slide 8's addition of the increased base rate and the lower progressivity feature resulted in a "notably reduced" NPV in comparison to slide 7, which only had the 40 percent cap; by contrast, there was relatively little difference between the NPV of slides 7 and 8 at even lower price levels, such as \$40 per barrel. He stated that at \$40 per barrel level, the "floor binds" and that it was the floor, and not the progressivity scale,

that ultimately set the government take at that price level.

Co-Chair Stedman inquired if the \$50 to \$70 dollar per barrel price range was the point at which the 30 percent base rate began "pushing the present values under water." Mr. Mayer responded that Co-Chair Stedman was correct.

Mr. Mayer offered that a possible benefit of increasing the base rate to 30 percent was a reduction to the marginal rates under the production tax system. He added that high marginal rates had been perceived as a problem with the production tax system. He warned that addressing marginal rates with a solution that worked in the \$50 to \$70 per barrel range would worsen the economics on projects and would be a solution with a worse impact than the problem that it solved. He added that the next several slides would examine the 50 percent cap, the 40 percent cap, and the 30 percent base rate options as they would apply for new developments and that the 30 percent base rate option experienced a notable worsening of the NPV at the \$40 to \$60 per barrel price level for new developments.

Mr. Mayer discussed the slides on pages 9, 10, and 11. The three slides simulated the same options as slides 6, 7, and 8 but for new developments. He offered that slides 9, 10, and 11 showed the same "significant worsening" of NPV at lower price ranges that could be seen on slides 6, 7, and 8; this was particularly true at around a price of \$60 per barrel. The drop in NPV also occurred at the \$40 per barrel level because the language in CSSB 192 specified that the floor level of production value only applied to large existing fields, as opposed to smaller new developments. He concluded that for new developments, the negative impact of the higher base rate extended to the lowest price ranges because the floor level of taxation was not an issue.

[2:46:11 PM](#)

Mr. Mayer explained the slide on page 12 titled "severance tax- 20% maximum (existing producer) .25 % progressivity from \$70 to \$130, then .10% progressivity to 180." He stated that the slide showed what SB 192 would look like if progressivity were removed from the production tax and a severance tax was implemented. He explained that a severance tax was based solely on production volumes and that it was progressive over price. He related that he had

spent some time examining how the different progressivity thresholds and rates for a severance tax would work. He explained that the slide modeled a severance tax that was levied on the gross value at the point of production; all the prices quoted on the slide were under the definition in the legislation of the gross value at the point of production. He furthered that the gross volume and the net of royalties were what was being taxed on the slide. He stated that model's tax started at a zero rate and that it did not kick in until the \$70 per barrel price level; with each \$1 increase above \$70 per barrel, progressivity increased by .25 percent. He furthered that the progressivity in the tax reached a local maximum of about 16 percent at \$130 per barrel, and that for every \$1 price increase from \$130 to \$180 per barrel, the progressivity increased at a lower rate of .1 percent; the progressivity reached its maximum rate of 20 percent at \$180 per barrel. He explained that the model had a similar government take profile as the two 40 percent cap options on slides 7 and 8, but that it enabled an easier method of addressing the decoupling issue and allowed for particular incentives to be made for new production. The purple bar represented the severance tax and the yellow bar represented the production tax. The yellow of the production tax had a flat profile because the model had a flat 25 percent production tax. He stated that the model would normally be a slightly regressive regime because of the impact of the fixed royalty, but that the severance tax made it slightly progressive. He added that the model was "ever so slightly progressive," but that it was largely fixed around the 70 percent government take level.

Co-Chair Stedman asked for a clarification on slide 12. He observed that at a price of \$40 per barrel, the slide's NPV was lower than the NPV in the ACES existing producer scenario, which was on slide 3. Mr. Mayer responded that in the case of a \$40 per barrel price, the NPV on slide 12 should be similar to NPV under CSSB 192, which was on slide 5. Co-Chair Stedman queried what basis slides 3, 5, and 12 were run on. Mr. Mayer responded that slides 3, 5, and 12 had all used 200,000 bbl/d as the basis for production. He stated that at \$40 per barrel, the NPV on slide 12 should be identical to the NPV on slide 5. He related that there was a decrease to the NPV when you compared, at \$40 per barrel, the NPV of slide 12 to the NPV of ACES on slide 3. He stated that slides 5 and 12 were modeled on CSSB 192,

which had a higher price floor; the reduction in NPV at \$40 per barrel was a direct result of the higher price floor.

[2:51:42 PM](#)

Co-Chair Stedman clarified that the effect of the floor was responsible for moving slide 3's NPV of \$2.812 billion down to \$2.587 billion, which was the NPV on slide 12. Mr. Mayer responded that Co-Chair Stedman was correct.

Co-Chair Stedman inquired if PFC Energy could run the models with the NPV displayed in \$10 increments from \$40 per barrel upwards. Mr. Mayer responded that PFC could accommodate the request.

Co-Chair Stedman requested a clarification regarding the lower right hand chart on page 12 and inquired if the chart implied that the split of profit oil between the producers and the state remained constant at \$130 per barrel and onwards. Mr. Mayer responded that Co-Chair Stedman was correct. Co-Chair Stedman queried if this meant that "both dollars increase as the price advances, and/or decrease." Mr. Mayer responded in the affirmative.

Co-Chair Stedman related that how do deal with the split of profit oil when oil prices were high was major issue that the committee had been struggling with.

Mr. Mayer stated that one of the advantages of taking progressivity out of the production tax and instituting a gross progressive tax was that it made the issue of decoupling easier to deal with; the other advantage was in regard to the ways new production could be incentivized. He noted that the following two slides would cover options for incentivizing new production and that it was useful to think of the slides in the context of regimes that might be put in place for entirely new areas and new producers.

Mr. Mayer discussed the slide on page 13 titled "severance tax - 6 % maximum (existing producer) .05 percent progressivity from \$70 to \$190." He stated that for new production, the severance tax could be reduced to have a maximum rate of six percent. He added that the tax would start with a zero base and have .05 percent progressivity for each \$1 price increase from \$70 to \$190 per barrel; the maximum rate would remain flat at six percent at prices over \$190 per barrel. He stated that the government take

figures for this scenario would be around the mid-60 percent range.

Mr. Mayer explained the slide on page 14 titled "25 percent production tax." He related that if the state wanted to incentivize entirely new developments, it could take out the progressive severance tax and institute nothing but the 25 percent flat production tax; this scenario would see a reduction in government take to the 63 percent or 62 percent level. He explained that the 25 percent flat tax option could be instituted on an indefinite basis or it could be for particular time period, such as the first ten years of production. He stated that production from new areas, production from particular initiatives' agreed plans and development, and oil production that was above a set decline curve were three types of new production that an entity might wanted to incentivize. He added that for any of those three options, incentivizing could involve tweaking and a combination of the two options on slides 13 and 14, and that how this would be done depended on how great an incentive one wanted to provide. He concluded that removing progressivity and instead levying a gross production tax enabled incentivizing because it simplified the accounting that went into the production tax; under this system, it was simply a question of how many barrels were produced and what the oil price was.

[2:56:49 PM](#)

Mr. Mayer explained the slide on page 15 titled "assessing 10 different fiscal regime options." He stated that the slide showed the dollar figures that were associated with the options. He related that in terms of production tax revenue and at a \$100 per barrel basis, ACES generated about \$3.7 billion in comparison to the \$2.7 billion generated by HB 110. He reiterated that industry had testified that HB 110 was "threshold for meaningful reform." The three options that were modeled on CSSB 192 reduced the production tax revenue from ACES to just over \$3.5 billion. He related that the two CSSB 192 options that kept the base level the same had identical results to ACES at the \$60 per barrel level, higher results at \$40 per barrel, and generated significantly less revenue at "extremely high" price levels. He stated that the severance tax could be reworked to determine at what point it should kick in, whether it should have a zero or small base, and what its progressivity coefficient would be. He stated that

at the \$40 and \$60 per barrel price levels, the options that used a 25 percent base rate had identical results because the only thing occurring at those price levels was the base rate. In the 20 percent severance tax option, revenue was reduced to a little above \$3 billion at \$100 per barrel; at the prices of \$150 and \$200 per barrel, the option had similar revenue in comparison to some of the capped CSSB 192 variants. He related that for particular fields that were being incentivized through the six percent lowered severance tax and the 25 percent flat tax options, it was not accurate to think of the figures in terms of revenue to the state; these options showed what the reduced numbers would look like and how they would compare to the 15 percent reduced rate for new production, which was in HB 110.

Co-Chair Stedman discussed slide 15 and pointed out that at a price of \$100 per barrel, there was a significant spread between the \$7.2 billion in state take that was generated by ACES and the \$6.6 billion in state take that the 20 percent severance tax option generated. He inquired how the severance tax model could be changed in order to get close to the \$100 per barrel cash position of ACES. He noted that the 20 percent severance option "deteriorated" above \$100 per barrel and got "even worse" at extremely high prices. He requested Mr. Mayer to run the 20 percent severance scenario with a progressivity rate that was north of .25 percent. Mr. Mayer responded that he would do so. He added that the 20 percent severance option was the closest structure that he had found in terms of matching the percentage of government take figures, but that through further manipulation, the option could be adjusted to get closer to the levels of revenue the state currently had at \$100 per barrel; one way of doing this was to impose a small base on the severance tax instead of having a zero base rate, as well making other changes to progressivity.

[3:01:52 PM](#)

Co-Chair Stedman pointed out that the steeper the progressivity was, the more it impacted marginal tax structure. Mr. Mayer responded that Co-Chair Stedman was correct. He added that there were a number of factors that had led him to start with the 20 percent severance option, but that it could be refined.

Co-Chair Hoffman requested that future slides show \$10 increments between the price levels of \$100 and \$150 per barrel.

Co-Chair Stedman observed that the split of profit oil would probably be frozen at prices north of \$150 per barrel. He requested that future slides show \$10 increments from \$60 to \$150 per barrel. Mr. Mayer responded that he would provide the requested information.

Mr. Mayer discussed the slide on page 16 titled "revenue from production tax under different options" and stated that the slide graphically depicted the dollar figures from the previous slide. He related that the top two lines reflected ACES and CSSB 192 and that the two regimes had little difference between them. The next line down, which was navy blue with diagonal crosses on it, was the CSSB 192 50 percent cap option; this option was identical to CSSB 192 at the \$140 per barrel level, but "diverges" from that point onward. He noted that the CSSB 192 40 percent cap option, which was represented by the pink line with the vertical bar, was also identical to CSSB 192 until about the \$110 per barrel level, but that it diverged from that point onward. He observed that the CSSB 192 40 percent cap option generated significantly higher revenue than HB 110 at the \$110 per barrel level, but had slightly less revenue than HB 110 from the \$180 per barrel level and onward. He related that the 20 percent severance tax option, which was reflected by the light pink line, was a little above HB 110 at high price levels, but that it converged with HB 110 at the "top of the deck"; at the \$100 per barrel level, the 20 percent severance option was much closer to CSSB 192 than HB 110 was. The bottom three lines represented what some of the incentives for new production could look like. The electric blue line with the triangle marker represented what HB 110 would look like with the incentive for new production. The lighter blue line represented the six percent severance tax option. He related that at around the \$160 per barrel level, the six percent severance option generated higher revenue than HB 110 because of HB 110's low 15 percent base rate for new production; however, at the highest price levels, the six percent severance option was below HB 110 in terms of revenue. He related that from \$130 per barrel and upwards, the 25 percent flat tax option had a lower level of taxation than HB 110's new production.

[3:06:55 PM](#)

Co-Chair Stedman inquired if the chart was based on 200,000 bbl/d in production. Mr. Mayer responded that any analysis that included dollar figures would be based on the FY 2013 numbers. Co-Chair Stedman clarified that the chart was based on FY 2013 numbers. Mr. Mayer responded that Co-Chair Stedman was correct.

3:07:18 PM

AT EASE

3:20:41 PM

RECONVENED

Mr. Mayer discussed the slide on page 17 titled "total state take under different options" and stated that it depicted the data equivalent to slide 16 in total state take. He explained that slide 17 was similar to slide 16, but that it had less differentiation because of the other sources of revenue that accrued to the state.

Mr. Mayer stated that the next set of slides would examine the marginal take under each of the regimes that had been examined.

Mr. Mayer explained the slide on page 18 titled "ACES - marginal take (FY 2013 data)." He noted that one of the criticisms of the existing ACES system was how high the marginal government take could be, particularly at the current prices levels. He added that the slide included not just the production tax, but that it also calculated all the components of the regime combined. He observed that ACES generated a peak in marginal government take of more than 90 percent at the current price levels of ANS west coast crude; currently, for every \$1 increase to the price of ANS west coast crude, the state was retaining 90 percent. Co-Chair Stedman commented that the rate would decline soon.

Co-Chair Stedman requested that the effective tax rates be represented on the charts when future options were presented to the committee. Mr. Mayer replied that he would provide the requested information.

Mr. Mayer discussed the slide on page 19 titled "HB 110 - marginal government take (FY 2013 data)." He stated that HB 110 would put a bracketing system in place that would

enable it to substantially reduce the marginal levels of government take; this scenario had a marginal government take below 70 percent for all price ranges.

Mr. Mayer explained the slide on page 20 titled "CSSB 192 - marginal government take (FY 2013 data)." He stated that CSSB 192 looked very similar to ACES and that it also had a marginal government take that peaked above 90 percent. The peak occurred at slightly higher price range in comparison to ACES because of the .35 coefficient.

Mr. Mayer discussed the slide on page 21 titled "CSSB 192 with 50% cap - marginal government take (FY 2013 Data)" and observed that it did not have a significant difference in comparison to ACES regarding the peak of the marginal rates. After the 50 percent cap option's marginal peak, which was around the \$130 per barrel level, the marginal take flattened out because the progressivity did not increase past the 50 percent rate.

Mr. Mayer explained the slide on page 22 titled "CSSB 192 with a 40 % cap - marginal government take (FY 2013 data)." He stated that reducing the maximum rate to 40 percent would, in part, address areas of the marginal take issue; the system still had a peak that was characteristic of a non-bracketed progressivity system, but the peak occurred at the low-80 percent level instead of at 90 percent and above; the change to where the system's marginal take peaked was a result of lowering the maximum rate to 40 percent.

Mr. Mayer discussed the slide on page 23 titled "30 percent base rate, 0.02 % progressivity, 40 % cap - marginal government take (FY 2013 data)."[Mr. Mayer had previously pointed out that the .02 percent in the slides was a typo and that it should be .2 percent instead.] He stated that this scenario reduced the peak of the marginal government take to the mid-70 percent range. He pointed out that the scenario had worsened project economics for all assets, particularly at around the \$60 per barrel level and for small high cost developments. He added that under this model, small high cost developments might not trigger progressivity, even at higher prices, because of their high cost structure.

[3:25:51 PM](#)

Mr. Mayer explained the slide on page 24 titled "severance tax - 20 percent maximum - marginal government take (FY 2013 data)" and stated that following this structure resulted in a peak of marginal tax rates around the 80 percent rate.

Mr. Mayer discussed the slide on pages 25 titled "severance tax - 6 % maximum - marginal government take (FY 2013 data)." He explained that the six percent maximum severance tax rate was for incentivizing new production and that the marginal rates dropped even further on this slide in comparison to previous slides.

Mr. Mayer explained the slide on page 26 titled "25% flat production tax - marginal government take (FY 2013 data)." He stated that the slide's flat 25 percent production tax for particular categories of new production resulted in a flat marginal government take that was slightly over the 60 percent level.

Mr. Mayer discussed the slide on page 27 titled "regime competitiveness: average government take." He pointed out that there was an error in one of the data points and that he would provide a correction. He explained that HB 110 was represented too low on the slide because the 15 percent base rate for new production, rather than the 25 percent rate, had been applied; HB 110 should be around the 67 percent rate on the slide rather than the low-60 percent range. He apologized for the error.

Co-Chair Stedman noted that the slide could be reprinted in the future and that there were other modifications that needed to be done to several slides.

Co-Chair Stedman requested that PFC Energy tweak the numbers in the 20 percent severance option in order to work with the balance between the marginal and effective tax rates; He furthered that he wanted the option worked so that the state's current cash position did not change at a price of \$100 per barrel. Mr. Mayer responded in the affirmative.

Mr. Mayer continued to speak to slide 27 and stated that an ACES existing producer was only a little below Norway, which was the slide's highest taxing OECD jurisdiction. He stated that as the caps of 50 percent and 40 percent were implemented on progressivity, the government take levels

dropped closer to the 70 percent mark. He furthered that as it was currently structured, the 20 percent maximum severance tax option put Alaska just above Haynesville, which was the highest of the slide's North American onshore producers. He explained that under the slide, unconventional production from Haynesville, Louisiana had a government take in the high-60 percent range and that the 20 percent severance tax option reached 69 percent. He pointed out that potential changes to the 20 percent severance option could increase the expected maximum rate slightly. He related that if the 25 percent flat production tax was offered as an incentive for incremental production from new and existing fields, the government take could be in the low-60 percent range for that increment and would be competitive.

[3:30:30 PM](#)

Co-Chair Stedman pointed out that the flat tax option also showed the effect of a 25 percent base tax, which had no progressivity, in order to show a comparison of tax structures. He requested that PFC Energy change the x axis and "bring it in" to \$150 per barrel, tweak the 20 percent severance option, and show comparisons of the marginal and effective tax rates in percentages and dollars.

Co-Chair Stedman discussed the following meeting's agenda.

SB 192 was HEARD and HELD in committee for further consideration.

#

ADJOURNMENT

[3:32:14 PM](#)

The meeting was adjourned at 3:32 PM.