SENATE FINANCE COMMITTEE
March 22, 2012
9:11 a.m.

9:11:57 AM

CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 9:11 a.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

Janak Mayer, Manager, Upstream and Gas, PFC Energy; Senator Joe Paskvan;

SUMMARY

SB 192 OIL AND GAS PRODUCTION TAX RATES

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

#sb192
SENATE BILL NO. 192

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

9:13:40 AM

Co-Chair Stedman announced that PFC Energy was contracted by the Legislative Budget and Audit Committee and worked on behalf of the legislature.

JANAK MAYER, MANAGER, UPSTREAM AND GAS, PFC ENERGY, presented a PowerPoint Presentation, "Discussion Slides: Alaska Senate Finance Committee" (March 22, 2012) (copy on file).

Co-Chair Stedman requested a definition of the word "upstream" and a brief explanation of what services PFC Energy provided. Mr. Mayer replied that in the oil and gas industry "upstream" referred to all activities leading to the production of oil or gas at the well head. The upstream sector included exploration, project development, and gas or oil production.

9:16:21 AM

Mr. Mayer explained that PFC Energy was a global oil and gas consultancy. He elaborated that the business focused on all of the "above ground" aspects of the oil and gas industry and the risks associated with producing oil and gas for government and industry. The firm operated under the premise that governments set the terms for oil and gas development and industry needed to understand how to operate under the conditions. The company analyzed markets; commercial, economic, and political risks; and how fiscal policies impact project development. He furthered that an integral aspect of PFC Energy's work examined the relationships between governments, international oil companies, and nationalized oil companies.

Co-Chair Stedman announced that the presentation would begin with a historical data review of the dollar value of Alaska's oil basins adjusted for inflation. He noted that PFC examined comparisons of analyses made under ACES (Alaska's Clear and Equitable Share) and re-evaluated and updated the data according to actual costs and market prices of oil. The presentation would conclude with an analysis of SB 192.

9:21:41 AM

Mr. Mayer identified Slide 4, "ANS West Coast Crude Historical Average Price (Real vs. Nominal)," that depicted a graph of Alaska crude oil daily production & ANS (Alaska

North Slope) annual average price (real & nominal). He relayed that a blue dotted line represented Alaskan daily production by thousands of barrels per day beginning in 1978 until 2011. The red line depicted ANS (Alaska North Slope) crude oil price (dollars per barrel (bbl.)) in nominal terms and the yellow line depicted the price in real terms. He pointed out that the ANS price of $35/bbl. in 1981 equated to $75/bbl. in 2010.

Mr. Mayer discussed Slide 5, "ANS West Coast Crude Historical Average Price (Real vs. Nominal)." The graph portrayed Alaska crude oil daily production and the annual value of ANS Production (real and nominal) from 1978 to 2011. The ANS crude oil price was multiplied by production to determine the actual total value over time. He underlined that in the early years the total values of production were high until 1988 when the production peaked and began to steadily decline along with the actual values. In 2000 the total value began to rise from rising oil prices to a new high period despite continued decline in production. The early years marked high value and high production in contrast to the current climate of high value and low production.

9:25:29 AM

Mr. Mayer highlighted Slide 6, "ANS West Coast Crude Historical Average Price (Real vs. Nominal)." The slide contained a graph that illustrated the split of the real value (gross value) of production in millions of dollars between the government (state and federal) and the producers and the percentage of gross value to producers between 1978 and 2011. He delineated that the percentage to producers was not the same as the percentage of government take. Government take represented divisible income; the revenue after costs. The percentage to producers represented gross revenue. The percent of gross value to producers was 65 to 80 percent in the mid-eighties and began to fall in 2006 and sharply decline to under 50 percent in 2008. He attributed the decline to the enactment of PPT (Petroleum Production Tax) in 2006 and ACES in 2008. He remarked that in 2008 the price of oil was consistently high which triggered "high levels" of progressivity in ACES. The result shifted revenue away from the producers to government.

9:28:16 AM

Mr. Mayer highlighted Slide 7, "ANS West Coast Crude Historical Average Price (Real vs Nominal)." The slide graphed the composition and amount of the state's oil revenues: NPR-A (National Petroleum Reserve) Royalties, Rents, Bonuses, CBRF (Constitutional Budget Reserve Fund)

Settlements, Royalty to Public School Trust, Royalty to Permanent Fund, Conservation Tax, Special Settlements (non-CBRF), Conservation Surcharge (Hazardous Release), Bonuses, Rents and Interest, Property Tax, Corporate Income Tax, Royalties, and Production Tax, from 1978 until 2011. He noted that the production tax spiked dramatically in 2008 under ACES from increased levels of progressivity that resulted in amplified state revenues.

Mr. Mayer discussed Slide 8, "ANS West Coast Crude Historical Average Price (Real vs. Nominal)." The bar graph depicted the Alaska crude oil daily production and the ANS annual average price from 2006 to 2010. The totals were quantified by qualified costs, net value to producers, and the total government tax royalty. He detailed that in 2006, costs to producers were relatively low in relation to its net value. The producer's net value was substantially higher than total government royalty. In 2008, costs to producers were a higher percentage of their net value, which declined while government royalties spiked much higher than producers net value. The trend of higher costs, declining net value to producers and higher government take began in 2007 and continued into 2010 caused by the combination of high oil prices triggering higher levels of progressivity.

Co-Chair Stedman referred to Slide 5, and determined that the high annual real value of ANS production was approximately $40 billion (1980) compared to roughly $20 billion today. Mr. Mayer confirmed.

Co-Chair Stedman added that the annual real value was approximately $22 billion in 1990. Mr. Mayer confirmed and added that coincided with the period of ANS peak production of two million barrels per day. He remarked that today's real value was the same with declining production, due to increased government take.

Co-Chair Stedman felt that any discussion on oil taxes should include the value and prospectively of the Alaska oil basin.
9:33:06 AM

Senator Thomas cited Slide 8. He asked for clarification of qualified costs. Mr. Mayer replied that qualified costs were the costs (defined by the Department of Revenue (DOR)) claimed by the producers.

Senator Thomas queried how the deductions and credits were represented on the graph. Mr. Mayer responded that the deductions and credits were reflected in the qualified costs (depicted as a green portion of the bar) and reduced government royalty (depicted as a red portion of the bar).

Senator Thomas wondered who shared in the costs. Co-Chair Stedman replied that the green portion was the industry cost, and the government royalty was identified in red. He clarified that the impact of the 20 percent capital expenditure (capex) and immediate write-off of capital expenditure shrank the red bar. Mr. Mayer confirmed.

Co-Chair Stedman wondered if the qualified costs offset the producer's net value (depicted as an orange portion of the bar) in the analysis. He recalled previous testimony that industry did not count the net impact of the credits or the immediate write-off of capital. Mr. Mayer responded that the qualified cost on the green bar reflected the actual costs without credits or write-offs. He stressed that the credits and write-offs were reflected in the net value to the producer (yellow portion of bar) and reduced the government royalty depicted in red.

Mr. Mayer communicated that the next set of Slides re-examined previous analyses of ACES. He pointed to Slide 10, " “ACES Preserves Investment Climate”: What has changed since 2007?" The Slide depicted the cover page of a presentation dated October 21, 2007 titled, "ACES Preserves Investment Climate." Mr. Mayer related that in order to determine whether ACES had preserved or enabled an investment climate, it was important to re-examine the analysis at the inception of ACES and evaluate the conclusions in retrospect.

9:38:35 AM

Mr. Mayer turned to Slide 11, "Revisiting the Previous Modeling Work," which contained three condensed slides that depicted data from the 2007 presentation. The analysis concluded that ACES preserved an investment climate. The conclusion was discerned from an analysis of 7 hypothetical oil field scenarios. A production profile that built-in capital and operating costs predicated on a certain dollar per barrel was the basis for the analyses.

Mr. Mayer chose a scenario depicted in the slide as "Field B." He referred to the table of data at the bottom of the slide, and noted the highlighted second row. The net present value was calculated for the various scenarios and all were positive values with the exception of a heavy oil development scenario. He interpreted the assumptions of the analyses. The analyses did not reflect ACES as the program functions currently but as it was proposed to the legislature at the time. He revealed the conflicting assumptions as noted in Slide 12:

Key Assumptions to Consider

•Regime modeled is ACES as proposed, not as enacted:
- 0.02% progressivity above the $30 level, not 0.04%
–50% maximum production tax rate, not 75%

•Cost assumptions are much lower than recent experience suggests:
–$10/bbl. capex and $9/bbl. opex, vs.
–$17/bbl. capex and opex

•Analysis performed from $20 to $100 crude oil price, with focus on $40 “stress-test” price, and $60 “base case”

•Assumed production profile is one that will maximize economic returns for a given field size

–High peak production rate with high decline rate means most production value occurs within 10 years

Mr. Mayer noted that scenario "B" calculated the progressivity rate of .02 percent. The legislature enacted a rate of .04 percent. In addition, the legislation as proposed contained a maximum progressivity rate of 50 percent. The legislature enacted a maximum 75 percent progressivity rate. He added that the hypothetical field analyses included estimated reserves. Scenario B characterized a 60 million barrel (MMB) reserve. The high peak production profile was not consistent with the actual historical production profile that peaked at a lower production rate and declined at a much slower and steady rate.

9:45:13 AM

Mr. Mayer discussed Slide 13, "Benchmarking Government Take - at $60/bbl." The Slide depicted a chart that compared international median government take by tax systems. The chart reported Norway at 81 percent, above Alaska's 70 percent.

Mr. Mayer turned to Slides 14 and 15, "Regime Competitiveness: Average Government Take." The slides illustrated a graph of average government take of global fiscal regimes at $100/bbl. and $140/bbl., represented by country. He reported that at $100/bbl. Alaska was above Norway at the high end of the median in new development and close to Norway in existing production. At $140/bbl. the US was above Norway and at the high end of most regimes in both new and existing production. He attributed both outcomes to the high oil price coupled with progressivity in ACES.

Mr. Mayer cited Slide 16, "ANS West Coast Crude Spot Price - Last 30 Days." The graph peaked at $128/bbl. in late February and ended at $122/bbl. March 22, 2012. He observed that a high oil price environment currently existed.

Mr. Mayer looked at Slide 17, "Field B in Our Model, Under ACES as Proposed." The slide depicted four graphs and charts of cash flow analysis and the level and composition of government take of the "B" scenario from PFC Energy's current model. He relayed that the results were fairly similar using the same assumptions that were used when ACES was proposed at $40/bbl., $60/bbl. and $100/bbl.

9:50:16 AM

Mr. Mayer offered Slide 18, "Field B", Under ACES as Enacted." The graphs and charts reflected the same "Field B" scenario under ACES as it was enacted by the legislature. The analysis was similar at the $40/bbl. level; below the price where progressivity was applicable. At the level of $100/bbl. the net present value of a project that was worth $400 million was 25 percent less with ACES as enacted because of the higher cap on progressivity. The total government take rose from 71 percent under ACES as proposed to 77 percent under ACES as enacted. The total government take was 84 percent under ACES as enacted and 75 percent under ACES as proposed at over $200/bbl. price of oil.

Mr. Mayer looked at Slide 19, "'Field B', Under ACES as Enacted, with $17/bbl. Costs." The graphs depicted the "Field B" scenario that reflected the costs assumptions used by PFC Energy's model and reflected the actual current costs. The net present value (NPV) was negative for a producer at the $40/bbl. and $60/bbl. but gained substantial positive value at $100/bbl. The level of government take was similar to the previous scenarios. The value for the producer was marginal.

Mr. Mayer discussed Slide 20, "'Field B', Under ACES as Enacted, with $17/bbl. Costs and Flatter Production Profile." The Slide depicted the "Field B" scenario under ACES as enacted with more realistic costs and a historically accurate production profile in contrast to the ACES as proposed model where production swiftly peaked and declined rapidly. At the $40/bbl. and $60/bbl. the net present value to the producer was negative and only slightly positive at the $100/bbl.

Senator Egan wondered whether the producer or geologic factors determined the production profile. Mr. Mayer replied that geologic and technical limitations determine the production profile. The producer would prefer to produce an oil field as quickly as possible to maximize its net present

value (NPV). He furthered that PFC's production profile was modeled after actual production profiles.

9:55:36 AM

Co-Chair Stedman wondered if there was any link between the government take and the net present value. He cited the chart on slide 20, which indicated that at approximately $80/bbl. the government take was 75 percent and the NPV was zero. He remarked that in previous HB 192 testimony the state was recommended to target 75 percent government take on current production and less than that for incremental production. Mr. Mayer replied that it was coincidental that the government take was 75 percent at $80/bbl. The various outcomes were a result of a coincidence of forces interacting rather than specific design. He elaborated that there was an interaction of forces that moved in opposite directions. He pointed out that government take was very high when oil prices were low. He opined that was due to the "regressive nature of the royalty." He cited the bottom graph on Slide 20, which illustrated that at $40/bbl. it would take more than double the divisible income to pay the royalty, even after the strongly negative production tax of more than 200 percent of the total. He believed that the tax system should better incentivize economically challenged projects.

9:58:28 AM

Co-Chair Stedman surmised that the state experienced a much different outcome with the enacted ACES system than ACES as proposed after cost and price adjustments. Mr. Mayer confirmed.

Mr. Mayer addressed Slide 22, "CSSB 192 Using ACES Minimum PTV (Existing Producer)" and Slide 23," CSSB 192 Using 10% of Revenues for Minimum PTV(Existing Producer)," that examined the impact of the revised production tax floor proposed in SB 192. The Slides contained bar graphs and charts that depicted what government take and economic value was for an existing producer at 200,000/bbl. per day. Slide 22 presented the scenario under ACES. He explained that slide 23 examined the production tax value (PTV) established in SB 192, set at 10 percent of gross revenue as the minimum level of total production tax value. The previous production tax minimum was set at $20. He showed that with the minimum proposed in SB 192 at $40/bbl., the government take increased to 74 percent. The result under the ACES minimum was 72 percent. He opined that the fixed percent royalty system was regressive and was challenging at low oil prices. He believed that the proposed minimum exacerbated the high government take at low oil prices, similar to ACES without the floor, due to the fixed royalty rates. He

considered the impact on marginal projects at low oil prices problematic.

10:03:40 AM

Mr. Mayer discussed methods of incentivizing new oil production. He turned to Slide 25:

ACES – A Harvest Area Regime, Not a Growth Regime

ACES appears to work well as a “harvest” regime
–Existing mature fields remain profitable, including capital work required to achieve ~6% decline (renewal capex) [capex - capital expenditure]
–Maximum ‘rent’ extracted from a declining production base is captured for the state

•ACES inhibits the development of new projects and resources that might help stem or even reverse the decline

–ACES is not progressive with regard to costs, so high government take applies even to very high cost projects

–Existing system of capital credits etc. appears to do more to encourage ‘renewal capex’ than it does new production spending

–Progressivity can have a major detrimental impact on breakeven prices for high-cost projects at current oil prices

Mr. Mayer observed that production from new fields tell a different story from ACES. New production economics were hampered by high costs for new production. He noted that the graph (contained in the slide) depicted the NPV at a range of prices and illustrated that as progressivity kicked in at high oil prices the effect reduced the NPV to oil producers and captured the value for the government on new development. The impact increased the breakeven oil price for producers and decreased or eliminated the economic viability on marginal projects.

Mr. Mayer spoke to ways of incentivizing new production, distinct from base production. Government take on base production and new developments could simply be lowered. He cautioned that the more changes to the system as a whole, both new and base production, the less change can occur specifically for new production. The government would lose a large amount of economic "rent" on base production. Without the distinction between base production and new development in the tax system, incentives targeted for new development

would be more limited. Conversely, the benefit of an across the board approach was in the ease of administering the tax system rather than a more complex tax system that distinguished between new and base production. In Alaska most new production would come from new investment in existing areas, which made distinguishing between new and existing production difficult. The choice was a system designed for administrative simplicity reducing overall government take, by bracketing, reduced progressivity, and lower caps on progressivity, or targeted new development via specific tax measures.

10:09:58 AM

Senator Thomas asked whether ACES caused the lack of reinvestment by creating a harvest regime. He observed that the oil decline occurred for the past 18 years. Mr. Mayer did not feel that ACES created the problem and acknowledged that the oil decline and investment climate occurred sometime before ACES. He explained that ACES could be viewed as a fiscal regime that maximized declining production. He cautioned that in addition to maximizing returns, new production especially in high cost environments needed to be incentivized.

Senator Thomas suggested that a harvest regime hampered new oil development. Mr. Mayer agreed and clarified that new development, either inside or far outside of existing fields were more expensive, difficult, and technologically challenging to develop. He exemplified development of reservoirs that required horizontal drilling, and heavy, or viscous oil. Technology and costs can inhibit development; similarly high progressivity and government take on high cost new developments impede progress.

Senator McGuire observed that capital credits were equally valid for renewal or new production and questioned why developers chose to use them only for renewal. She shared that she voted for ACES because she believed that capital credits incentivized production for development in a costly environment like the Artic. She was troubled that new jobs were not created and oil producers were only redeeming capital credits as renewals. Mr. Mayer responded that some of the renewal capex was non-discretionary. The capital expenditure was crucial infrastructure maintenance in order to maintain production. He reiterated that the capital improvement work that maintained a 6 percent decline was profitable for existing production. He added that capital credits do improve the economics of new development, but was not sufficient in an environment of high government take and high costs.

10:19:03 AM
AT EASE

10:27:13 AM
RECONVENED

10:28:06 AM

Mr. Mayer continued his response. He stressed the importance of understanding new investment versus base production. He explained that new investment was not just investment in new fields. New investment included capital investment using costly new technologies in existing infrastructures by existing producers. New investment required "significant" new capital in a cost challenged environment. The producer must attract investment capital based on the viability of the project in a competitive international business environment. He declared that his examination of incentivizing new production did not include a tax system that would distinguish between new and existing production. All of the proposals to incentivize new production were fundamentally compatible with the system of administration used for ACES. He avoided a system that used the "mechanics of production tax itself" as a basis to distinguish between the production streams because of the difficulty and complexity to administer. He reiterated that a tax system that distinguished between different production streams created a much greater level of complexity. The system required multiple tax returns and precise accounting among separate production streams.

10:33:02 AM

Mr. Mayer continued to explain that a system with different base rates required accounting and sophisticated auditing for new volumes of production and allocating its precise costs. Complex accounting was required to prevent an oil company from taking advantage of the more favorable terms for new production by allocating more costs to the new production stream. In contrast, a tax system that provided an allowance through the production tax was much easier to administer.

Mr. Mayer began his analyses of the SB 192's provisions to incentivize new production. He related that the allowance (an allowance on production that in any given year was above the level of production from the previous year) for new production only incentivized production in any given year that was incremental to the previous year's production. A production threshold was determined in order to demonstrate the impacts of the allowance. He pointed to Slide 26:

> "New Oil Allowance: Incremental Production on a Declining Base."

Central to understanding the impact of the "allowance for 'new oil'" is an understanding of the impact of new source production on a company's total production volumes, when that new source production is added to a declining base portfolio.

- The charts at the bottom assumed a 6 percent decline rate for an existing North Slope producer currently producing 200mb/d, and examine hypothetical new source projects that peak at 10mb/d, 50mb/d and 100mb/d respectively (on a working interest basis.)

- Given the pace at which such projects typically reach peak production, only the 100 mb/d peak production new source development is actually capable of adding production that is incremental to prior years' volumes.

The slide included 3 graphs that illustrated the allowance at 10mb/d (thousand barrels per day), 50mb/d, and 100mb/d peak for new source projects.

Mr. Mayer informed the committee that the SB192 allowance did not have an impact on new production as defined in the bill at 10mb/d and 50mb/d. The 100mb/d projection triggered the allowance in SB192 and revealed a significant impact on the decline curve.

10:37:34 AM

Senator Thomas cited the middle graph that represented 50mb/d peak new source projects. He deduced that every four or five years 50 mb/d of new development was needed just to flatten the decline curve of a 200mb/d field. Three times the amount of the 200mb/d field of incremental production was needed for a 600mb/d field to offset the 6 percent decline for each 4 or 5 year period. He estimated that over a 12 year period a 600mb/d field would need 450 mb/d of incremental production to produce the offset. He remembered from previous testimony that a $25 billion investment was needed to maintain that level of incremental production. Mr. Mayer guessed that the calculations seemed reasonable. He referred to previous testimony (Senate Finance Committee, March 21, 2012, 1:10PM) by Dale Pittman (Vice President, Production, ExxonMobil Alaska) and reported that he made a similar point. The Oooguruk and Nikaltchug oil fields came on line in recent years and flattened out the decline curve. Equivalent new developments would be needed each year to maintain a flat production decline.

Mr. Mayer highlighted Slide 27:

"A Hypothetical 100 mb/d (Working Interest) Development."

- A new source development that produced 100 mb/d at peak for a working interest partner would be a very significant new development. By way of comparison, Kuparak, the second largest field in North America, peaked at ~320 mb/d gross production
  - This represented working interest production to ConocoPhillips (the operator and majority shareholder) of 170 mbo/d
  - Kuparak took 11 years (from 1981 to 1992) to reach this peak level of production
- Since it would take a development on the scale of 100 mb/d (working interest) to achieve “new oil” for an existing producer under the terms of the amendment, a development of this size has been modeled in the following analysis
  - A 7 year ramp-up to peak production has been assumed
  - Such a development would likely eclipse today’s production from Kuparak (122 mb/d gross, 66mb/d working interest to the majority shareholder)
  - It is important to note that this is a significantly more aggressive new-source production profile than is currently foreseen in recent statements by the major operators on their current development pipelines, even in the most optimistic circumstances

Two additional graphs illustrated Conoco Phillips working interest in the Kuparak production profile and the hypothetical 100mb/d working interest development production profile.

10:42:26 AM

Mr. Mayer looked at Slide 28:

Assumptions

- The following analysis assumes
  - A 6% base portfolio decline, in the case of a producer currently producing 200 mb/d
  - Costs for the base production portfolio of:
    - $12/ flowing bbl. operating expenditure

•$5/ flowing bbl. maintenance capital expenditure

–Costs for the 100 mb/d (working interest) New Development project of:

•$13/ flowing bbl. operating expenditure
•$13/bbl. reserves development capital expenditure
•$1/ flowing bbl. maintenance capital expenditure

–These costs are deliberately somewhat lower than the previously referenced 10 mb/d new development, since the hypothetical development modeled is significantly larger, and thus likely to have somewhat lower costs on a $/bbl. basis

Mr. Mayer identified Slide 29, "CSSB 192 Excluding New Oil Allowance (Existing Producer)." The Slide depicted three bar graphs and a chart that represented the cash flow analysis of 100mb/d new development field without the allowance. The government take ranged from 74 percent at $100/bbl. to 79 percent at $230/bbl. He turned to Slide 30, "CSSB 192 Including $10 New Oil Allowance Over 1 Year (Existing Producer)." He noted that the application of the $10 allowance applied in a single year on production over and above last year's production, had no effect on the 100mb/d scenario.

10:46:18 AM

Mr. Mayer examined the allowance with different variables. He turned to Slide 31, "CSSB 192 Including $20 New Oil Allowance Over 7 Years (Existing Producer)." The Slide depicted through graphs and a chart the cash flow analysis of a 100 mb/d new development with a $20/bbl. allowance applied over 7 years. He identified a slight increase in the NPV for a producer and virtually no change in government take. He looked at Slide 32, "CSSB 192 Including $60 New Oil Allowance Over 7 Years (Existing Producer)." The slide illustrated the cash flow analysis of a 100mb/d new development coupled with a $60/bbl. allowance applied over 7 years. He relayed that a greater increase in NPV occurred but the government take remained about the same. The impact of incremental production was slight because the allowance only applied to production over the decline base. Incremental production was a relatively small amount compared to the base amount.

Co-Chair Hoffman noticed that the presentation did not contain slides with data for new producers, and wondered why. Mr. Mayer replied that the data showed only a

marginally greater effect and felt that it was superfluous to include.

10:50:09 AM

Mr. Mayer directed attention to Slide 34, "CSSB 192 Including Tax Holiday Based on 3 Year Rolling Decline (Existing Producer)." The slide used the existing format from the previous slides to illustrate the impact of a tax holiday based for an existing producer. He outlined that the proposal was based on incentivizing production above a given level. The target level was set by averaging the decline rate of a producer over 3 years. Any amount of production over the average decline rate counted as new production and received an exclusion from production tax for one year. He cautioned that the tax holiday was problematic. The exclusion was only applicable for one year and was minimal when compared to the producer's investment in new production.

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

#

ADJOURNMENT

10:52:42 AM

The meeting was adjourned at 10:52 AM.