MINUTES
SENATE FINANCE COMMITTEE
April 1, 2006
9:07 a.m.

CALL TO ORDER

Co-Chair Lyda Green convened the meeting at approximately 9:07:12 AM.

PRESENT

Senator Lyda Green, Co-Chair
Senator Gary Wilken, Co-Chair
Senator Con Bunde, Vice-Chair
Senator Fred Dyson
Senator Bert Stedman
Senator Lyman Hoffman

Also Attending: CHERIE NIENHUIS, Petroleum Economist, Department of Revenue; DAN DICKINSON, CPA, former Director of the Tax Division, secured as a consultant by the Office of the Governor

Attending via Teleconference: From Offnet Locations: ROGER MARKS, Petroleum Economist, Department of Revenue; ROBERT MINTZ, Assistant Attorney General, Oil, Gas & Mining Section, Department of Law

SUMMARY INFORMATION

SB 305-OIL AND GAS PRODUCTION TAX

The Committee heard from the Department of Revenue, the Department of Law, and a consultant to the Office of the Governor. The bill was held in Committee.

#sb305

> CS FOR SENATE BILL NO. 305(RES)
> "An Act providing for a production tax on oil and gas; repealing the oil and gas production (severance) tax; relating to the calculation of the gross value at the point of production of oil or gas and to the determination of the value of oil and gas for purposes of the production tax on

oil and gas; providing for tax credits against the tax for certain expenditures and losses; relating to the relationship of the production tax on oil and gas to other taxes, to the dates those tax payments and surcharges are due, to interest on overpayments of the tax, and to the treatment of the tax in a producer's settlement with the royalty owners; relating to flared gas, and to oil and gas used in the operation of a lease or property under the production tax; relating to the prevailing value of oil or gas under the production tax; relating to surcharges on oil; relating to statements or other information required to be filed with or furnished to the Department of Revenue, to the penalty for failure to file certain reports for the tax, to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue as applicable to the administration of the tax; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the tax, and to the deposit of tax money collected by the Department of Revenue; amending the definitions of 'gas,' 'oil,' and certain other terms for purposes of the production tax, and as the definition of the term 'gas' applies in the Alaska Stranded Gas Development Act, and adding further definitions; making conforming amendments; and providing for an effective date."

This was the second hearing for this bill in the Senate Finance Committee.

Co-Chair Green informed the Committee that the Tax Division, Department of Revenue would continue their previous day's presentation about the proposed Petroleum Production Tax (PPT).

CHERIE NIENHUIS, Petroleum Economist, Department of Revenue, stated that the "PPT Revenue Studies" presentation, dated March 31, 2006, [copy on file], would resume at page eight. Pages one through seven had been addressed during the previous Committee hearing. Her remarks would focus on cumulative and annual revenues and co-worker, Roger Marks, would address the effective tax rate and the State's revenues generated from Cook Inlet.

Volume Scenarios

- No enhanced volumes / No gasline
  - Totals 5.7 billion barrels through 2030
    * Including 0.6 billion barrels of heavy oil
      - No additional heavy oil at prices under $30
- Gasline and enhanced volumes
  - Totals 10.5 billion barrels through 2050
    * Includes additional 3.1 billion barrels conventional
      - 700 million barrels net stemming from gasline
  - Including additional 1.7 billion barrels heavy oil
    * No additional heavy oil at prices under $30

Ms. Nienhuis specified that numerous assumptions accompany economic modelings. To that point, she noted that the Department incorporated volume and cost assumptions into its PPT modeling. It also modeled high and low volume scenarios with consideration of the construction of a natural gas pipeline. The Department is projecting a low production volume forecast for the State, as reflected in its Spring 2006 Revenue Sources Book [copy not provided], based on oil currently under production, oil under development, and oil under evaluation with no new discoveries being assumed.

Ms. Nienhuis stated that this low volume scenario anticipated that approximately 5.7 billion barrels of oil would be produced through the year 2030. It would be expected that, absent a gas pipeline or additional oil volumes, the Trans-Alaska Pipeline System (TAPS) would cease to operate at that time.

Ms. Nienhuis communicated that the high volume scenario is also referred to as the enhanced volume scenario. This scenario is typically "coupled" with the development of a gas pipeline, as the anticipation is that a gas pipeline would be accompanied by additional exploration and subsequently the discovery of additional oil volumes. Thus an enhanced volume scenario would include the cumulative effect of the additional volumes. In addition, a gas pipeline would affect oil production in three ways: while there would be a slight decrease in Prudhoe Bay production, the life of the field would be extended to 2050; it would include additional volumes of oil from the Point Thompson Unit; and additional oil would accompany, as of yet,

undiscovered gas reserves. In summary, the high-volume scenario, at 10.5 billion barrels, would approximately double the State's low-volume scenario and oil production could extend out until the year 2050. This volume would include approximately 1.7 billion barrels of heavy oil.

Ms. Nienhuis noted that when oil prices fall below $30 a barrel, a mechanism is included in the economic modeling scenarios to limit the production of heavy oil as it is expensive to produce.

9:11:51 AM

Page 9

Volume Scenarios

[The blue line depicted on the graph reflects the low volume scenario from the year 2005 to 2030. The red line depicts the high volume scenario from 2005 through 2050.]

Ms. Nienhuis stated that the "waves" in the high volume scenario line would indicate "the addition of enhanced volumes coming online every five years or so".

Page 10

Costs and Prices

- Costs
  - $100 mm/yr exploration through 2040
  - $1/bbl on-going capital on all barrels
  - $3.50/bbl developmental capital on 2/3 of existing conventional oil
  - $8/bbl developmental capital on 2/3 of existing heavy oil
  - $3.50/bbl developmental capital on new conventional oil
  - $8/bbl developmental capital on new heavy oil
  - $3/bbl operating costs on conventional oil
  - $5/bbl operating costs on heavy oil
- Costs, prices, and revenues are all real $2005 dollars
- Heavy oil discounted 8% for quality
- 2.5% of production subject to small company allowance (5,000 b/d)

- 70% of transition expenditures realized (2 for 1) as 20% credit
  - Costs $100 mm/year over 7 years

Ms. Nienhuis noted that the Department incorporated several cost assumptions in its modeling scenarios. The assumptions were based on public and non-public sources including partnership returns and other tax information.

Ms. Nienhuis pointed out that several types of expenses were considered in determining the cost per barrel (bbl) of Alaska North Slope (ANS) crude oil. These expenses included exploration expenses, operating costs associated with both conventional and heavy oil, and three types of capital costs: on-going capital costs; developmental capital costs for existing and new conventional oil; and developmental capital costs associated with existing and new heavy oil.

9:13:40 AM

Ms. Nienhuis noted that the costs and prices depicted on page 10 were 2005 dollars and were not adjusted for inflation. Heavy oil had been discounted eight percent for equality.

Ms. Nienhuis disclosed that the modeling has been adjusted to reflect changes included in the Senate Resources committee substitute, Version 24-GS2052\C, before the Committee, specifically its inclusion of the 5,000 barrel per day (b/d) allowance for small companies.

9:14:03 AM

Ms. Nienhuis stated that after analyzing the production of companies producing 5,000 b/d or less, it was determined that this allowance would apply to 2.5 percent of ANS oil production. This percent would increase annually, as additional companies fell into the 5,000 b/d or less category due to overall declining oil production.

Ms. Nienhuis communicated that the one dollar for two dollar recoupment transition provision included in Version "C" would allow 70 percent of transition expenditures to qualify for the 20 percent credit. This would equate to credits of approximately $100,000,000 per year for a seven year period.

Ms. Nienhuis expressed that in addition to price and production levels of ANS crude oil risks, the PPT would expose the State to cost risks. Each one dollar differential in the costs depicted on page 10 would affect State revenues by approximately $70 million each year.

Ms. Nienhuis repeated a statistic previously shared by Mr. Marks: a $200 million discrepancy would occur were three of the Department's cost projections incorrect.

9:15:42 AM

Co-Chair Wilken understood therefore that a one dollar deviance of any of the costs depicted on page 10 could equate to a $70 million difference.

Ms. Nienhuis affirmed.

9:16:29 AM

Page 11

Feedback Effects Not Modeled

- Production depends on investment
  - More investment with incentives
  - Credits are incentive
- More investment with higher prices
- Less investment with higher taxes
- Investment driven by competitive international opportunities … which are always evolving

Ms. Nienhuis discussed elements which were not modeled, but which could affect production. These elements were excluded from the modeling because the Department "wanted to keep the results of our modeling purely a tax effect". These "feedback effects could be subject to debate and possibly result in modeling error".

9:16:55 AM

Ms. Nienhuis reminded the Committee that the Department had included in the modeling a mechanism, "relative to price", through which to decrease heavy oil volumes. "The reason for that is that heavy oil is very expensive to produce."

9:17:35 AM

Page 12

Cumulative Revenues

- Without enhanced volumes / without gasline (through 2030)

- With enhanced volumes / with gasline (through 2050)
  - Does not include gasline severance taxes
  - Includes gasline costs

Ms. Nienhuis stated that the Department recognized cumulative revenues as being "the most important point in the presentation on revenue". Cumulative revenues would be generated through the low-volume scenario through the year 2030. Revenues would be generated through the year 2050 under a high volume scenario with a gas pipeline. One important distinction between the high volume scenario with a gas pipeline and the low volume scenario without one is that the high volume scenario includes "the upstream costs" of the gasline; specifically the gas processing plant and various other costs associated with developing gas. The cost of the pipeline itself would not be included.

Ms. Nienhuis stressed that, while the high volume scenario would include additional gasline expenses, it would not reflect gas pipeline revenues; those revenues would be a component of the gas pipeline contract rather than the PPT. Thus, the PPT high volume modeling would include the increased costs, but not the revenue associated with the gas pipeline. It would be reasonable to anticipate an increase in revenue, separate from this modeling.

9:19:29 AM

Ms. Nienhuis encouraged Committee members to focus on cumulative long-term expenses and revenues since it is difficult to forecast when capital expenditures might occur; therefore, such things were "smoothed over the life of the project to show a long-term effect". Spreading anticipated expenses over a long-term period of time would better represent expected trends in spending and revenue.

9:20:13 AM

Page 13

Low Volume Scenario Cumulative Severance Tax Chart

[The three graph lines on the "Figure 4" chart reflect Low Volume Scenario's cumulative severance tax revenues in billions of dollars for the years 2006 through 2030 under the PPT formula proposed by the Governor; the formula proposed by the Senate Resources Committee; and the status quo Economic Limit Factor (ELF) severance tax revenue, based on ANS West Coast barrel prices.]

Ms. Nienhuis noted that the severance tax revenues garnered under the Senate Resources committee substitute would exceed the revenue generated under ELF at the ANS West Coast barrel price of $21.60. That "crossover point" under the Governor's PPT proposal would be $27.70. The slight upward bend in the graph line of the Senate Resources committee substitute at the $40 ANS West Coast price was caused by that proposal's Progressivity mechanism, which would be activated at that price.

Page 14

High Volume Scenario Cumulative Severance Tax Chart

[The three graph lines on the "Figure 5" chart reflect the High Volume Scenario cumulative severance tax revenues in billions of dollars for the years 2006 through year 2050, under the PPT formula proposed by the Governor, the formula proposed by the Senate Resources Committee, and ELF, based on ANS West Coast barrel prices.]

Ms. Nienhuis reminded the Committee that the High Volume Scenario would be accompanied by higher expenses due to the increased cost of producing heavy oil. The crossover point relative to ELF would be $25.60 under the Senate Resources committee substitute and $34.20 under the Governor's PPT proposal.

Ms. Nienhuis pointed out that, in addition to expanding the production timeframe and increased oil projections, the revenue scale on the High Volume Scenario chart would be significantly higher than that of the Low Volume Scenario.

9:21:39 AM

Co-Chair Wilken, referring to the vertical "Y" axis which depicted cumulative severance tax revenues, observed that under the High Volume Scenario, the Senate Resources committee substitute proposal would, at a $45 West Coast ANS Price, generate a cumulate severance tax of $50 billion dollars.

Ms. Nienhuis affirmed.

Co-Chair Wilken asked, for comparison purposes, whether a graph reflecting the PPT proposal being furthered by the House of Representatives could be developed.

Ms. Nienhuis responded that such a chart could be developed.

Senator Hoffman asked for confirmation that the $50 billion severance tax revenue referred to by Co-Chair Wilken would be the cumulative amount for the 44 year timeframe between 2006 and 2050.

Ms. Nienhuis affirmed. She also noted that the effective date of the Senate Resources committee substitute differed from that proposed by the Governor. The Governor's bill would not become effective until 2007.

Senator Stedman pointed out that the effective date of the bill could be further explored.

Senator Stedman asked that further discussion occur regarding "the discounting" associated with real verses nominal dollars; since it is difficult to make a one year forecast, it would be "near impossible" to forecast out 30 or 40 years.

Senator Stedman also requested that, in the future, the "Y" axis scale be keep constant on presentation charts. Such uniformity would make comparing High and Low Volume graphs easier.

Senator Stedman re-emphasized his desire to further discuss the Department's decisions regarding "the time value of money". To that point, he asked whether the Department's PPT modeling was "substantially different" than the PPT modeling developed by Econ One Research, Inc, [Econ One] the economic and research consultant firm hired by the Legislature.

9:23:59 AM

Ms. Nienhuis specified that the Department's earliest PPT presentations included a two-percent inflation factor. The decision was made to eliminate inflation as it magnified the scenarios "beyond what we should be expecting", in other words, revenues would exceed Department projections.

ROGER MARKS, Petroleum Economist, Department of Revenue, testified via teleconference from an offnet location and noted that the Department did not utilize "discounted numbers" in its presentations, although "it would not be difficult to do … discounting would reduce all the numbers."

Senator Stedman impressed the point that it would be easier to compare data were the same methodology utilized. As it was, the reports presented by the various consultants working for the Administration, the Legislature, and other entities used an array of methodologies. Footnotes specifying the methodology utilized in the report would be appreciated.

Mr. Marks clarified that the dollars depicted in the Department's March 31st presentation were actual 2005 numbers. The Department's initial PPT data utilized nominal number; however, the Department determined that the inflation factor significantly affected the outcome. "A more accurate picture" would be presented by the use of real dollars.

Mr. Marks communicated that the Department had consulted numerous times with Econ One. The determination was that their individual "modeling results are quite similar". Both analyses of the PPT proposals' "crossover points, for instance, were within pennies".

Senator Dyson understood that the ANS West Coast prices reflected on the "X" axis horizontal bar were real dollars. He asked that real and nominal dollars be defined.

Ms. Nienhuis clarified that real dollars would be defined as today's dollars; nominal dollars would reflect inflation over time.

Senator Dyson acknowledged.

9:27:53 AM

DAN DICKINSON, CPA, former Director of the Tax Division, secured as a consultant by the Office of the Governor, stated that the best scenario in which to define real dollars would be in terms of purchasing power. $55 spent today would purchase a larger quantity of an item than it would purchase in, for instance, ten years as, due to inflation, more money would be required to purchase the same quantity of goods. Nominal dollars would include "an inflation component" to maintain the purchasing power.

Mr. Dickinson communicated that the Department utilized real dollars in its presentations due to the concern that building a two percent annual inflation factor into a 50 year projection would mislead people into thinking a plan would have more purchasing power than it really would, "because most of it isn't an increase in purchasing power, it's just inflation at work". A two percent inflation factor compounded over a 50 year time frame would add a "huge amount".

Co-Chair Green stated that a glossary of terms was being developed. Real and nominal dollars would be included on the list. Committee members should advise her of other terms they would like added.

Senator Dyson asked whether real dollars could be defined as "dollars of the day".

Mr. Dickinson recognized dollars of the day as nominal dollars.

Senator Dyson acknowledged.

Ms. Nienhuis specified that the Department's presentation expressed monetary amounts in terms of today's dollars as opposed to, for instance, 2010 dollars.

Senator Stedman asked for information about "discount factors".

Mr. Dickinson exampled that discount factoring would be used when determining how much "a stream of payments" would represent were that money available today. In other words, if a payment schedule included an inflation factor, the money would be "discounted back down to today's dollars … a great deal of

mischief can occur if you were to inflate it one rate and discount it a different rate".

In response to an earlier request by Co-Chair Wilken, Mr. Dickinson noted that a copy of a presentation the Department developed based on the House of Representatives PPT committee substitute was available [copy not provided].

Co-Chair Wilken requested the "X" and "Y" axis grid lines on future charts be kept to a minimum, as cleaner charts would be easier to interpret.

Mr. Dickinson acknowledged the request.

Senator Hoffman requested charts be developed to reflect how the Progressivity factors being considered might affect the Governor's PPT proposal.

Ms. Nienhuis qualified that the Governor's PPT proposal did not include a progressivity factor.

Senator Hoffman agreed, but explained that a chart portraying how the progressivity factors being proposed by the Senate would affect the provisions of the Governor's PPT bill, would be helpful.

Mr. Dickinson conferred with Senator Hoffman to clarify the information being sought.

Page 15

Annual Revenues

- Without enhanced volumes / without gasline (through 2030)
  - $20
  - $40
  - $60
- With gasline / with enhanced volumes (through 2050) (does not include gasline severance taxes; includes gasline costs)
  - $20
  - $40
  - $60

Ms. Nienhuis stated that page 15 explained that the High and Low Volume Scenarios charts depicted on pages 16 through 21 were based on ANS West Coast oil prices of $20, $40, and $60 per barrel.

Page 16

Figure 6

Annual Severance Tax Revenues @$20 Price
Low Volume Scenario ($ millions)

[The graph lines depicted on this chart indicate that at a $20 ANS West Coast Price barrel price, declining revenues would be experienced under each of the three scenarios: ELF, the Governor's PPT proposal, and the Senate Resources committee substitute.]

Average annual revenues $40 million less than status quo (both proposals).

Note: Status quo averages $116 million annually.

Ms. Nienhuis noted the severance tax revenue generated under ELF reflected current production rates. Revenue would decline with production. The Senate Resources committee substitute chart lines reflects a downward slope with a few upward bumps: the bump depicted around 2009 would reflect increased revenues resulting from an expected decrease in the TAPS tariff due to anticipated renegotiations; the upward bump depicted at approximately 2014 would reflect the termination of the allowances and transitions provisions proposed in the bill. The downward slope of all three scenarios "is fairly graphic at $20 prices because the costs and the taxes have a significant effect" at that price.

9:34:25 AM

Senator Stedman recalled major oil producers testifying "they would go broke at $20 a barrel". Thus, he asked the Department's opinion on oil producers' vitality in the year 2020 were oil prices in the $20 range. He understood British Petroleum's (BP) breakeven point to be slightly above $20 a barrel.

Mr. Dickinson understood oil producers' remarks to imply that rather than going broke, their revenue would not allow them to support significant reinvestment efforts.

Senator Stedman inquired to the financial condition of the State at that price.

Mr. Dickinson responded that, at $20 a barrel, the State's financial condition would to be "a terrible one".

Senator Stedman pointed out that at $20 a barrel the State would face numerous concerns, many of which would outrank concern about the severance tax.

Co-Chair Green remarked that it would be one of numerous issues the State would be required to address.

9:36:06 AM

Senator Stedman stated that it has been difficult to accept some producers' claims that the $20 range is their break-even point. He could not support the inclusion of such things as annual "capital cost infusions" in their break even calculations. He characterized producers' definition of breaking even as being "fairly liberal".

Mr. Dickinson suggested that, rather than distributing copies of a presentation regarding the House of Representative's PPT committee substitute, the Department would revise today's presentation and include the House PPT provisions in the comparisons. The revised presentation would then be distributed electronically.

Co-Chair Green acknowledged. She asked Co-Chair Wilken his preference in this matter.

Co-Chair Wilken preferred that the House committee substitute proposal be included as another graph line on the Figure 4 and Figure 5 charts, depicted on page 13 and 14.

Co-Chair Green reminded the Department to also include a consistent "Y" axis scale on those charts.

9:38:01 AM

Senator Stedman also requested the Department provide a set of graphs depicting "the total government take" in addition to the severance tax revenue. This would enable the Committee to view the severance tax component within the entire scenario.

Mr. Dickinson clarified that the scope of the presentation had been made in consideration of time. Initial presentations included such information but exceeded two hours to discuss.

Co-Chair Green acknowledged, but assured the Department the Committee would devote time to review the information.

Page 17

Figure 7

Annual Severance Tax Revenues @$40 Price Low Volume Scenario ($millions)

[This chart reflected the Low Volume scenarios of ELF, the Governor's PPT proposal, and the Senate Resources committee substitute at a $40 barrel price from the years 2005 through 2030.]

Senate CS has average annual revenues $600 million more than status quo and $300 more than Governor's bill.

9:39:12 AM

Ms. Nienhuis read the information, and noted that "the bumps in the graph become less pronounced" at this price range.

Page 18

Figure 8

Annual Severance Tax Revenues @$60 Price Low Volume Scenario ($millions)

[This chart reflects the Low Volume scenarios of ELF, the Governor's PPT proposal, and the Senate Resources committee substitute at a $60 barrel price from 2005 through 2030.]

Senate CS has average annual revenues $1.6 billion more than status quo and $800 million more than Governor's bill. Annual progressive surcharge $200-$400.
Note: This is equivalent to State gasline revenues at $6.00/mmbtu Chicago price without the gasline.

Ms. Nienhuis reviewed the information on page 18.

In response to a question from Senator Dyson, Mr. Nienhuis revisited the information in Figure 7 page 17, and stated that, at $40 per barrel in the Low Volume Scenario, the Senate committee substitute would generate annual revenues of approximately $600 million more than ELF and $300 million more revenue than the Governor's bill.

9:40:02 AM

Ms. Nienhuis noted that the "Y" axis scale, which measured the Annual Severance Tax, on Figure 8 ranged from zero to $3,500,000,000 whereas it ranged from zero to $1,600,000,000 on Figure 7.

Ms. Nienhuis stressed that, as depicted in Figure 8, the Senate committee substitute would generate annual revenues of $1.6 billion more than ELF and $800 million more than the Governor's bill.

9:40:50 AM

Ms. Nienhuis noted the Progressivity surcharge included in the Senate committee substitute would generate revenue ranging from $200,000,000 to $400,000,000. The $1.6 billion resulting from the Senate committee substitute would equate to State gasline revenues at the Chicago price of $6.00 per million British Thermal Unit (BTUs) absent the gas pipeline. This information was depicted on the bottom of page 18.

Mr. Marks observed that $1.6 billion in revenue would be generated under the Senate committee substitute at current ANS West Coast barrel prices. This would equate to gasline revenues at $6.00 per million BTUs, absent the gasline.

Senator Hoffman asked the current Chicago price for gas.

Mr. Marks replied that the current Chicago price for gas was approximately $7.00 Mcf.

Senator Stedman suggested the Committee consider this information as being "an integral piece of this whole gasline puzzle". The revenues being discussed in the PPT "are substantial in comparison to the gasline". The PPT would not produce "a minor revenue stream relative to" what would be generated by the gasline. Some people believe the revenues generated for the State after the completion of the gas pipeline "would be the key to the future". While he would not disagree with that position, people should not discount the fact that the revenue being addressed in this legislation "is a huge piece of the revenue stream". This issue should not be "minimized, because there is the possibility" that a gasline might not come to fruition.

Page 19

Figure 9

Annual Severance Tax Revenues @$20 Price High Volume Scenario ($millions)

[This chart reflects the High Volume scenarios of ELF, the Governor's PPT proposal, and the Senate Resources committee substitute at a $20 barrel price from 2005 through 2050.]

Average annual revenues $80 million less than status quo (both proposals). Note: Status quo averages $112 million annually.

Ms. Nienhuis stated this chart reflects the High Volume Scenario with a gas pipeline. The "fairly large dip" in the Senate committee substitute graph line from approximately 2010 to 2013 would reflect the money that would be required to develop Point Thompson. The severance tax revenue during those years could decline to zero.

9:44:20 AM

Senator Stedman pointed out that, when viewing Low Price Scenarios, people should be mindful that the industry would also be subject to royalty payments, property taxes, and perhaps corporate income taxes. In addition to the challenge the State

might face during low price per barrel years, the industry might request additional consideration on their other taxation levels. Such "dynamic issues" should be part of the discussion.

Mr. Dickinson communicated that "one year at the higher price … would generate enough" revenue to offset approximately four years at the lower price. As reflected in Figure 9, ELF revenue's would peak at $300,000,000 in the year 2005 and then taper downward. While the State might garner zero severance tax under the Senate committee substitute during the development years of Point Thompson, ELF would only be generating $200,000,000.

Mr. Dickinson asked the Committee to advance to the Figure 11 chart on page 21, which depicted the Annual Severance Tax Revenues under the High Volume Scenario at the a ANS West Coast Price of $60. At that price, the Senate committee substitute would generate approximately a billion dollars more than ELF during the years of the Point Thompson development. That would equate to a six or seven to one ratio: "seven years of low price would be recovered in one year of high price." The focus should be on the fact that it is not an even offset. "One year of high prices puts us above one year of low prices."

Mr. Dickinson agreed that, as the Committee had pointed out, this revenue difference might not be obvious due to the differing "Y" axis scales from one figure to the next.

9:46:48 AM

Page 20

Figure 10

Annual Severance Tax Revenues @$40 Price
High Volume Scenario ($millions)

[This chart reflects the High Volume scenarios of ELF, the Governor's PPT proposal, and the Senate Resources committee substitute at a $40 barrel price from 2005 through 2050.]

Senate CS has average annual revenues $500 million more than status quo and $300 [million] more than Governor's bill

Ms. Nienhuis affirmed that the "Y" axis scale differences would be addressed. To that point, she advised that the "Y" axis scale on Figure 10 was higher than that of Figure 9.

Ms. Nienhuis noted that the monetary impact of developing a gasline were reflected during the years 2010 and 2013 in Figure 10. Oil revenues from the Point Thompson unit would begin around the year 2015. In approximately 2030, "the costs for the yet to be defined gas fields" would be reflected. Thus, the up and down lines on this chart reflect alternating costs and revenues.

Page 21

Figure 11

Annual Severance Tax Revenues @$60 Price
High Volume Scenario ($millions)

[This chart reflects the High Volume scenarios of ELF, the Governor's PPT proposal, and the Senate Resources committee substitute at a $60 barrel price from 2005 through 2050.]

Senate CS has average annual revenues $1.5 billion more than status quo and $800 million more than Governor's bill. Annual progressive surcharge $200-$400 mm.

Ms. Nienhuis stressed that the Senate committee substitute would generate approximately $1.5 billion more in annual revenues that the status quo. The Progressivity factor would generate an additional $200,000,000 to $400,000,000 at this price.

9:48:36 AM

Page 22

Effective Tax Rate

Severance Tax / (Wellhead less Royalty)
- Without enhanced volumes / without gasline

- With enhanced volumes /with gasline

Ms. Nienhuis reported that several members of the Senate Resources Committee requested the Department to provide a comparison between the status quo taxes on gross revenues minus

royalties or the Value at the Point of Production (VPP), and the net tax being proposed in the PPT. In order to provide such a comparison, the Department developed what is being referred to as the Effective Tax Rate (ETR). As depicted on page 22, the ETR "is the severance tax as a function of the wellhead less royalty". In other words, it is the value of the oil at the wellhead after the royalty fee is removed, as "that is the point where we start taxing". Caution should be taken in regards to this term, as it could be used in different contexts.

Ms. Nienhuis reviewed the two scenarios pertaining to the ETR: the first scenario would be without either enhanced volumes or a gasline; the second would be enhanced volumes with a gasline.

9:49:58 AM

Page 23

Figure 12

Effective Severance Tax Rate
Sev Tax / Wellhead (less royalty)
Low Volume Scenario

[This chart depicts the effects of Effective Severance Tax Rates ranging from 0.0 percent to 25 percent and ANS West Coast oil prices ranging from $15 to $65 in a Low Volume Scenario. The lines on the graph reflect the impact of these elements on the status quo, the provisions of the Governor's bill, and the Senate Resources committee substitute.]

Ms. Nienhuis communicated that under this scenario, the status quo would remain constant at approximately the five percent taxation level because the status quo system was not sensitive to price. The tax levels of both the Governor's bill and the Senate Resources committee substitute would be affected by price. The Senate Resources committee substitute would exceed the status quo tax rate at a price of $21.60. The Governor's bill would exceed the status quo rate at a price of approximately $27.70.

9:50:37 AM

Mr. Dickinson explained that even though the provisions of the Governor's bill specify a tax rate of 20 percent on net revenue, the Figure 12 graph is based on gross, as that is the basis for the tax rate in ELF. Utilizing the same measure for the three scenarios would provide "an apples to apples comparison".

9:51:13 AM

Senator Stedman remarked that, perhaps with the exception of "the people paying the bill", most people would agree the ELF tax system "is broken". To that point, utilizing ELF as the benchmark for the comparisons would not be the proper comparison base, "because it's dysfunctional at this time". It has "limited value" other than providing a reference point.

Senator Stedman, stressing that his remarks should not be misconstrued as being critical of the charts, suggested it would be helpful where the Department to align its ANS West Coast price designations on the chart with those of other entities such as Econ One, as this might allow discrepancies or data errors between the information to be more visible. Differences within a reasonable range could be tolerated.

In response to a question from Co-Chair Green, Senator Stedman clarified his request. For instance the price points on Figure 12 were in increments of $15, $25, $35 and so forth. The price points on Econ One's charts, while also in ten dollar increments, are $10, $20, and $30 and so forth. Thus, his request would be that an effort be made to align these and other "data labels" with other presentations when the charts were revised. This would allow for easier comparisons.

Co-Chair Green acknowledged.

Senator Stedman stated that having comparable data labels would be particularly helpful in identifying an error in estimates or "expectations that go out for decades". The goal would be to have "a reasonable tight range between the different presenters".

9:54:00 AM

Senator Hoffman pointed out however, that Figure 12 would reflect that, at a $45 barrel price, the Governor's PPT proposal would increase the tax by approximately 100 percent.

Senator Stedman asserted that a 100 percent increase over the status quo might not "be enough".

Ms. Nienhuis assured Senator Stedman that additional data points could be incorporated into the presentations.

9:54:44 AM

Page 24

Figure 13

Effective Severance Tax Rate
Sev Tax / Wellhead (less royalty)
High Volume Scenario

[This chart depicted the effects of Effective Severance Tax Rates ranging from 0.0 percent to 25 percent and ANS West Coast oil prices ranging from $15 to $65 in a High Volume Scenario. The lines on the graph reflect the impact of these elements on ELF, the Governor's bill, and the Senate Resources committee substitute.]

Ms. Nienhuis stated that an ANS West Coast Price of $40 would generate slightly less revenue under this High Volume Scenario, when compared to the Low Volume Scenario depicted in Figure 12. This is due to the inclusion of the costs of both the gas pipeline and the production of heavy oil.

Ms. Nienhuis stated that incorporating additional data points on the Department's charts would allow for easier and more "direct comparisons".

Senator Stedman asked the Department the numbers it was utilizing for the cost of developing the gas pipeline. The cost could be in the $25 to $30 billion range.

Mr. Dickinson clarified that rather than the expense associated with developing the gas pipeline being actual costs, the costs that would be deductible under the PPT would be limited to the upstream costs associated with developing the project. He declared that "when investments are made in Prudhoe Bay, it's very hard to distinguish between oil and gas". Therefore, "the actual costs of the gasline are not what is being deducted".

What would be deducted would be "the ancillary costs upstream". The anticipated cost of developing Point Thompson would be three billion dollars, and "the incremental costs of developing Prudhoe Bay" could be approximately several hundred million dollars.

Senator Stedman stated that the Senate Resources committee substitute included a 20-percent credit factor. He opted to further his questions about this and other issues with the Department at another time.

Ms. Nienhuis concluded her portion of the presentation.

Page 25

State Take

State Revenues / Economic Rent

ROGER MARKS, Petroleum Economist, Department of Revenue, testified from an offnet location and communicated that his presentation would explore the revenues the State could receive under the High and Low Volume Scenarios.

Page 26

Figure 14

State Take
State Rev / Econ Rent
Low Volume Scenario

[This graph on this chart depicted State revenues generated in the Low Volume Scenario at differing ANS West Coast Prices under ELF, the Governor's PPT proposal, and the Senate Resources committee substitute.]

Mr. Marks defined "State take" as the total amount of revenue the State would receive from royalties, severance tax, property tax, and corporate income tax "divided by economic rents which is pre-tax profits". State take is "generally" thought of as being "a percent of the economic rents".

9:57:27 AM

Mr. Marks stated that Figure 14 would indicate that at low prices under the Low Price Scenario the State would experience "a regressive system". A regressive system is defined as one in which the State take, as low prices, is high. This was due to three things: the first being that the State's oil industry property tax was based on assessed value and was not affected by the price of oil. "Our State corporate income tax is based on world wide apportionment and profits of the oil companies worldwide." A company's income tax would be dependant on worldwide oil prices as well as the industry's refinery margins. "An integrated producer is quite hedged in that they make a lot of money on the refining arm of their business when oil prices are low". Thus, the modeling conducted by the Department reflected "a significant correlation between our corporate income taxes and refinery margins." Corporate income taxes are elevated at low prices because of that.

Mr. Marks communicated that the State's royalties "are based on the gross value at the point of production and do not reflect the upstream costs". This is the reason that all three PPT proposals, the State would continue to receive "a high share of the rent at low prices".

Mr. Marks noted that, as depicted on the Figure 14 chart, the State take under ELF would decrease at an ANS West Coast Price of $25 or higher. As prices increase, the take under the Governor's PPT proposal would "be fairly level" and the take under the Senate Resources committee substitute would "increase slightly" due to the progressivity surcharge.

Page 27

Figure 15

State Take
State Rev / Econ Rent
High Volume Scenario

[This graph on this chart depicted the State revenue generated in the High Volume Scenario at differing ANS West Coast Prices under ELF, the Governor's PPT proposal, and the Senate Resources committee substitute.]

Mr. Marks stated that the chart lines on Figure 15 were similar to those of Figure 14. "The results are not materially different."

9:59:48 AM

Figure 16

Total Government Take
Senate CS 25/20 vs. 20/20
Low Volume Scenario

[This chart depicted the Total Government Take in percentages as reflected on the vertical "Y" axis at ANS prices ranging from $15 to $65 per barrel as reflected on the horizontal "X" axis. The lines on the graph reflected two Government Take scenarios for under the Senate Resources committee substitute: one with a 25/20 percent tax rate and the other with a 20/20 percent tax rate.]

Mr. Marks referred the Committee to a Department handout titled "Figure 16" that portrayed Total Government Take figures [copy on file] for the Senate Resources committee substitute factored at a 25/20 tax/credit rate and a 20/20 tax/credit rate. Other provisions of the committee substitute had not been changed. While this graph depicted only the Low Volume Scenario, similar results would be expected from the High Volume Scenario.

Mr. Marks communicated that the five percent variance between the two tax rates would equate to approximately a 3.75 percent difference in Total Government Take. The State's severance tax on the industry would be eligible as a deduction on an entity's federal corporate business tax, thus, "on an after tax basis", the federal government would absorb approximately 35 percent of the cost of the State's severance tax. In addition, there would also be a slight adjustment in an entity's state corporation income tax as the severance tax would also qualify as a deduction. Thus, 90 percent of the 3.75 percent Total Government Take difference would be the result of "the federal affect and about ten percent is on the State affect".

10:01:52 AM

Senator Stedman asked whether the information depicted in Figure 16 reflected the Total Government Take of the State or the total

of both the State and the federal government. He thought it might reflect solely the State government take as a combined State/federal should be approximately 60 percent.

Mr. Marks apologized. Apparently incorrect numbers were utilized in Figure 16.

Senator Hoffman perceived the information on Figure 16 to reflect solely the State take.

Senator Stedman requested the information in Figures 14, 15, and 16 be revised to individually reflect the State and federal government take, as information on the Total Government Take was readily available. The desire would be to have the State and federal government take components differentiated.

Co-Chair Green understood therefore that the request was to have the federal and State government takes individually reflected on each of the three aforementioned charts.

Senator Stedman affirmed. Doing so would allow the Committee to understand the State, federal, and producers' takes, in percentages, at different ANS prices.

Mr. Marks again apologized for the incorrect information in Figure 16. He calculated that the total State and federal government take would be approximately 60 percent. There would be approximately a three percent variance between the 25/20 and 20/20 tax rates as applied to the Senate committee substitute.

Senator Stedman reminded the Committee that some citizens in the State were concerned that the State was not getting its "fair share" of the oil revenue. He asked those individuals to recognize that the federal government and the producers must also be considered in the equation.

10:03:59 AM

Co-Chair Wilken asked Mr. Marks whether the 25/20 and 20/20 tax rate lines on Figure 16 would remain "essentially flat" even were the ANS Price to reach $120 or $150 a barrel.

Mr. Marks replied that, under the Senate Resources committee substitute with its Progressivity factor, the slope of the lines would increase slightly at higher prices.

Co-Chair Wilken understood that the lines depicted on the chart would continue to reflect a gradual upward slope at higher prices.

Mr. Marks affirmed. He additionally noted that the relationships between the three graph lines would remain "constant".

Page 28

Cook Inlet

Page 29

Cook Inlet

[The table on this page depicted oil production in terms of barrels per day, gas production measured in Mcf (thousand cubic feet) per day, and gas production in terms of barrels of oil equivalency (BOE) for eight different producers operating in Cook Inlet.]

Mr. Marks stated that pages 28 through 34 of the presentation focused on the affects of the Senate Resources committee substitute on Cook Inlet oil and gas production.

10:05:56 AM

Mr. Marks characterized Cook Inlet as "a gas province" since, on a barrels of oil equivalency (BOE) basis, gas would account for approximately 80 percent of production and oil 20 percent. The 200 Bcf (billion cubic feet) of natural gas that is annually produced in Cook Inlet is primarily utilized for heat, power generation, and to support the Liquefied Natural Gas (LNG) plant and the Agruim urea producing facility in the area.

Page 30

Cook Inlet Gas

- Cook Inlet is 80% gas on a BOE basis
- Industry is evolving
  * Decreased production?
  * Higher prices?
  * Increased investment?

- PPT impact on oil taxes not significant
- Gas taxes on existing fields may increase at higher prices
- New fields may see lower taxes/higher npv

10:07:16 AM

Mr. Marks communicated that the impact of the PPT on Cook Inlet oil taxes would not be significant "because the costs of producing oil in Cook Inlet are fairly high; those fields are mostly depleted out". However, some additional taxes could be realized were oil prices "very high".

Mr. Marks communicated that "the Cook Inlet gas industry is evolving". Most of the fields are old, "production is decreasing", and the majority of "capital on these fields have been recovered". The outlook for further investment in the area is unpredictable at this time.

Mr. Marks stated that during the 40 year history of gas production in Cook Inlet, the market has been limited to a few "sets of buyers and sellers". This established "market dynamics" with fairly low prices since there were "few options outside the system". However, a few "revolutionary turn of events" occurred in the past few years: one being that the Regulatory Commission of Alaska (RCA) authorized Unocal to sell its gas to ENSTAR Natural Gas Company at Henry Hub prices, which are Gulf of Mexico prices. This was significant because it "suggests a leakage from outside the system in". Nonetheless, other than that pricing change, "it is still a closed system".

Mr. Marks stated that while current Henry Hub prices are high, gas contract prices not subject to Henry Hub pricing in Cook Inlet are selling in the mid-two dollar range. However, Marathon Oil, another Cook Inlet producer, recently requested RCA to allow it to also charge Henry Hub prices. Thus, there is uncertainty about future prices in the area.

Mr. Marks noted that the issue of whether the Cook Inlet LNG plant would be issued an export permit by the federal Department of Energy in 2009 furthered compounded the Cook Inlet market uncertainty. Were this permit authorized, the Agrium nitrogen plant in Nikiski might be forced to shut down as a by-product of higher gas prices. In addition, the prospect of North Slope gas being added to the market could deter further investment in the

Cook Inlet area. In summary, future activity in Cook Inlet is a complicated issue.

Mr. Marks expected that higher oil prices would result in higher taxes. However, the PPT could lower taxes because it contained provisions providing deductions and tax credits for the development of new fields. It also included provisions geared at attracting "new and small investors". These factors could serve to increase development in Cook Inlet.

10:10:15 AM

Page 31

GAS ELF

1 - (3000 / Average Well Productivity)

Example: 10,000 mcf/well/day
ELF = 0.70

6,000 mcf/well/day
ELF = 0.50

Mr. Marks stated that the information on page 31 would assist in clarifying the context of the statement that taxes in Cook Inlet could increase. He communicated that, in addition to the oil ELF, the State also has a gas ELF, which is applicable to gas produced in Cook Inlet and on the North Slope.

Mr. Marks explained that the gas ELF formula is simpler than the oil ELF, in that the gas ELF exempts the first 3,000 Mcf per well per day from taxation. For example, the ELF on a well producing 10,000 Mcf per day would be 0.70. The ELF on a well producing 6,000 Mcf per day would be 0.50. The Gas ELF has not been adjusted since being established in 1977, in other words, the Gas ELF, which is "a nominal gas severance tax of ten percent", has been "fiscally stable" for 30 years.

Mr. Marks stated that both the gas ELF and the oil ELF were based "on the principle that a producer should be able to recover his operating cost based on the price of gas and the operating costs so the tax itself doesn't make the field shut down". In 1977 gas was selling for 65 cents Mcf. The Gas ELF economics have changed significantly in 30 years and, the

Department believes, that, like the oil ELF, "the Gas ELF is broken as well", at least as far as Cook Inlet is concerned. It would be considered "appropriate" were the Gas ELF tax to increase as a result of the PPT "if prices are high enough".

10:12:34 AM

Senator Bunde recalled Mr. Marks' earlier comment that the affect of "the PPT tax in Cook Inlet would be insignificant".

Mr. Marks clarified that the PPT affect on oil in Cook Inlet would be insignificant.

Senator Bunde acknowledged. To that point, he had a conversation with some representatives of Chevron Corporation who felt otherwise. He asked Mr. Marks why Chevron believed the PPT "would make the older Cook Inlet wells uneconomical".

10:13:06 AM

Mr. Marks reiterated that oil production in Cook Inlet was very low. Producers were "not getting a lot of bang for their buck right now on their wells". Since a minimal amount of new investment was occurring, the tax credits and deductions provided under PPT would be insignificant. Operating costs, in the range of $15 per barrel, are high. That cost could be deducted.

Mr. Marks referred the Committee back to the chart on page 29 which depicted per day oil and gas quantities by producer in Cook Inlet. Other than the Forest Oil field which produced 6,891 barrels and the Chevron/Unocal daily oil production of 7,885 barrels, other producers' oil production in Cook Inlet was less than the 5,000 barrel a day allowance and therefore would be exempt from the tax. The issue with Chevron/Unocal is that the 5,000 barrel per day allowance "would not be very effective" for them as the PPT would be "a company wide tax" and their Cook Inlet and North Slope production would be combined in the PPT calculation. Were Cook Inlet production isolated, the 5,000 allowance would be beneficial; however, having to combine it with other fields' production would negate its effectiveness.

Mr. Marks stated that at current prices, Chevron/Unocal would be paying higher taxes under the PPT. Because the Department has not investigated the affect of the PPT on individual companies,

the "crossover point" at which Chevron/Unocal would be affected has not been calculated. Nonetheless, his determination was that "if anyone's taxes would go up for oil in Cook Inlet, it would be them", as the 5,000 barrel a day oil allowance would be negated by their North Slope production. Thus, he would not disagree with Chevron/Unocal's position.

10:15:40 AM

Senator Dyson noted that active oil producers judged previous efforts to incentivize oil exploration and production in Cook Inlet as being the wrong methodology as it only allowed deductions for successful exploration. The incentives were not enough to encourage exploration of "wild cat" areas. A better incentive would have been to allow deductions for exploration regardless of its success. To that point, he asked Mr. Marks whether the producers were right.

Mr. Marks agreed with the producers, as the majority of exploration efforts are failures. Any tax benefit or provision based on successful production "is worth nothing if you don't have any production". He stressed that "those same people should love the PPT" as it contained provisions to encourage small and new producers. Under ELF, the State shared none of the costs incurred by "a pure wildcatter" who spent ten million dollars on an exploration well that came up dry. Under the provisions of the PPT, that wildcatter's ten million dollar loss would be multiplied by a tax rate of 25 percent and converted to a $2.5 million credit which could be sold immediately. In addition, he would be entitled to a 20 percent credit on that ten million dollars. Thus, under the terms of the Senate Resources committee substitute, the wildcatter would be entitled to $4,500,000 of credit that would be available immediately. This would be "incredibly valuable" on a Net Present Value (NPV) basis. Therefore, instead of the State sharing none of the risks, "the State is sharing 45 percent of his dry hole risk … the PPT is a fabulous mechanism for sharing dry hole risk." It would encourage new exploration.

10:18:49 AM

Senator Dyson appreciated the information. He asked whether the PPT would preempt previous incentive programs.

Mr. Marks responded that the PPT bill would allow an entity to choose whether to utilize an existing exploration incentive program or the PPT credit provisions.

Mr. Marks explained that some existing credit allowances were based on the distance an exploration field was from an existing well. For instance, "a completely new prospect would receive a 40 percent credit." In that case, an explorer would choose that method rather than the credits available under the PPT. The various incentive programs could not be combined.

Senator Dyson characterized this as "valuable" information. Continuing, he asked for confirmation that the producer rather than the State would be able to choose which incentive program to use.

Mr. Marks affirmed.

10:20:40 AM

Mr. Dickinson informed the Committee that the existing 40 percent exploration credit incentive was authorized under SB 185. However, due to the program's distance requirements and other criteria, less than two million dollars of the total $33 million in exploration credits that have been issued under that program pertained to exploration work conducted in Cook Inlet. Thus, while SB 185 "was a step" it contained numerous restrictions, and, as a result, State audits conducted on the exploration activities disallowed many of the exploration expenses. Many of the expenses disallowed under SB 185 rules would qualify for the 20 percent credit under the PPT.

Senator Dyson understood that under the provisions of the Governor's bill, all development and exploration costs, including those in existing fields such as Prudhoe Bay, could qualify for exploration credits. He asked whether the Senate Resources Committee substitute would disallow any of those credits.

Mr. Marks responded that the credits and deduction provisions in the Senate Resources committee substitute were "identical" to those of the Governor's bill.

Mr. Dickinson concurred; the exception being "minor exceptions" in regards to abandonment expenses.

10:23:03 AM

Senator Hoffman asked for specifics regarding exploration in Bristol Bay fields.

Mr. Dickinson communicated that the PPT credits and deductions were uniform; there were no geographical restrictions or limitations in either the Governor's bill or the Senate Resources committee substitute, with the exception being that the Senate Resources committee substitute included restrictions specific to private royalty holdings.

Page 32

COOK INLET GAS FIELDS

Field	MCF/day	Avg Elf
Beluga River	155,740	0.751
Beaver Creek	17,554	0.088
Cannery Loop	40,636	0.601
Granite Point	208	0.000
Happy Valley	5,083	0.170
Ivan River	4,348	0.000
Kaloa Field	3,269	0.424
Kenai Unit	60,907	0.001
Lewis River	1,042	0.000
Lone River	4,240	0.358
Middle Ground Shoal	61	0.000
Moquawkie	5,188	0.354
North Cook Inlet	108,421	0.648
Nicolai Creek	1.593	0.000
Ninichik	30,783	0.373
North Trading Bay Unit	587	0.000
Pretty Creek	1,967	0.000
Redoubt Shoals	2	0.559
Sterling Gas Field	2,094	0.278
Trading Bay Unit	146,343	0.474
Swanson River	10,539	0.000
Wolf Lake	163	0.000
	600,768	0.500

Mr. Marks stated this was a listing of all the gas fields operating in Cook Inlet and their associated gas ELF rates. The "weighted average" ELF rate in Cook Inlet was 0.500 percent.

This would indicate an average relative productivity of approximately 6,000 Mcf per day. 3,000 of that 6,000 Mcf would be tax exempt.

10:24:07 AM

Page 33

Gas ELF

- A 0.50 ELF implies 6,000 mcf/well/day
- Therefore, 3,000 mcf/well/day is tax-free
- The revenue from tax-free gas is supposed to recover operating costs
- Operating costs for Cook Inlet is estimated to be 50 cents
- Therefore operating costs are $3,000/well/day
- Henry Hub prices are over $7/mcf
- The revenue from the 3,000 tax-free mcf/well/day is worth $21,000
- This is 7X more than it should be recovering

Mr. Marks reminded the Committee that the gas ELF was based on the economic scenario of 1977. "The bottom line is if you are getting a Henry Hub price for your gas in Cook Inlet through the ELF, you're probably recovering seven times more than you should, given what the ELF is supposed to be doing." That being to consider how much gas a company would "need at the market price to cover your operating costs".

Mr. Marks communicated that, regardless of "the function or dysfunction" of the gas ELF in Cook Inlet, the gas ELF function on the North Slope would be "vastly different" where a gasline available in that region; specifically in regards to the upstream costs and the "very very high downstream costs". Therefore, the focus at this time should be on Cook Inlet.

Page 34

Cook Inlet Gas Tax

- We estimate crossover point at about $3/mcf on existing fields

- At $4/mcf increase of $35 million annually on existing fields
- Out of $1 billion gross revenues annually
- Decrease as production goes down
- New production may see reduced taxes

Mr. Marks reviewed the information. The three dollar Mcf crossover point would be approximately two dollars higher under the Governor's bill due to the inclusion of the $73 million allowance. As previously explained, when production increased beyond 5,000 barrels BOE a day, the percent of tax free production would decrease. Since the PPT's affect on the gas tax in the Cook Inlet region would be "relatively small and highly uncertain", it was not included in the bill's fiscal note.

Senator Dyson appreciated the "valuable" information provided in the presentation.

This concluded the Department of Revenue's "PPT Revenue Studies" presentation.

AT EASE 10:27:21 AM / 10:37:02 AM

Navigating CSSB 305(RES)
(With the Differences from SB 305 Highlighted)
April 1, 2006

Co-Chair Green advised the Committee that this presentation [copy on file] was developed for two purposes: to explain the mechanics of the proposed PPT and to identify the differences between the Governor's PPT bill, SB 305, and the Senate Resources committee substitute, CSSB 305 (RES) which was before the Committee.

Mr. Dickinson pointed out that a color coding mechanism was utilized in the presentation: red text indicated language in SB 305 and green text indicated language in CSSB 305(RES). {NOTE: In these minutes, SB 305 would refer to the Governor's bill and the Senate Resources committee substitute would be indicated ass CSSB 305.]

10:39:26 AM

ROBERT MINTZ, Assistant Attorney General, Oil, Gas & Mining Section, Department of Law testified via teleconference from an

offnet location. The presentation would focus on the "core elements" of the PPT and key provisions differing between SB 305 and CSSB 305(RES). The presentation also included a flow chart depicting how the tax would be calculated.

Page 2

SB 305, Section 35
CSSB 305, Section 32

New production tax provisions apply to oil and gas produced on or after:

July 1, 2006 (SB 305)

April 1, 2006 (CSSB 305)

Mr. Mintz stated that one of the differences between the two versions of the bill is the effective dates: SB 305 would be effective as of July 1, 2006; CSSB 305 would be effective April 1, 2006.

Senator Hoffman asked how the differing effective dates would affect the amount of money collected under the PPT, were oil prices $60 per barrel.

Mr. Dickinson stated that this information would be forthcoming.

Page 3

SB 305, Section 5

AS 43.55.011(a)

There is levied upon the producer … a tax for all oil and gas produced each month … The tax is equal to 20 percent of the net value …. under AS 43.55.160.

Mr. Mintz identified this language as being "the most fundamental core provision" of the PPT. Like the current production tax, the PPT would be levied on a monthly basis. The change, however, would be that, rather than continuing the current practice of taxing oil and gas at differing rates, the Governor's PPT bill would uniformly apply a 20 percent rate tax to both oil and gas under "a new concept called Net Value of oil

and gas" as defined in "a new section of the production tax statute, AS 43.55.160".

Page 4

CSSB 305, Section 5

AS 43.55.011(e)

There is levied upon the producer … a tax for all oil and gas produced each month … [except for] a lessor's royalty interest ….
The tax is equal to 25 percent of the production tax value … under AS 43.55.160.

Mr. Mintz stated that the oil and gas tax being proposed in CSSB 305 would be 25 percent. CSSB 305 would also utilize the term "Production Tax Value" rather than the term "Net Value".

Page 5

CSSB 305, Section 5 (cont.)

AS 43.55.011(f)

There is levied upon the producer … a tax for all oil and gas produced each month … the ownership or right to which constitutes a lessor's royalty interest …. The tax is equal to five percent of the gross value at the point of production …[for existing leases]

- BUT …

Page 6

CSSB 305, Section 6 (cont.)

AS 43.55.011(f) (cont.)

The tax is equal to 1.5 percent of the gross value at the point of production … [for existing *COOK INLET BASIN* leases]

- AND …

Mr. Mintz stated that another difference between SB 305 and CSSB 305 would be how the PPT would be uniformly applied throughout the State, without "a defined tax on a particular lease". To this point, SB 305 adopted an allocation formula. CSSB 305 instead opted to include a provision about the "tax treatment of the royalty interest of lessors under private oil and gas leases" This provision would apply to a "very tiny portion of the oil and gas produced in the State" specifically "oil and gas leases leased by regional Native Corporations" such as Arctic Slope Regional Corporation (ASRC) and Cook Inlet Region, Inc. (CIRI). In the case of existing leases, the "share of oil and gas that goes to the owner as royalty is taxed at a rate of five percent of the gross value at the point of production".

Mr. Mintz pointed out however that instead of being taxed five percent of the gross value at the point of production, existing Cook Inlet leases would be taxed at 1.5 percent.

Mr. Mintz qualified however that "even though this is a tax on the royalty share" tax obligations of the producer would continue as specified in existing State production tax statutes.

Page 7

CSSB 305, Section 6 (cont.)

AS 43.55.011(f) (cont.)

The commissioner shall recommend to the legislature the rate of tax [for FUTURE leases]

Mr. Mintz noted that, rather than identifying a tax rate in the bill for future private oil leases, this CSSB 305 provision would specify that the Commissioner of the Department of Revenue would provide a recommendation to the Legislature.

10:44:37 AM

Page 8

CSSB 305, Section 6 (cont.)

AS 43.55.011(g) – (h)

[When West Coast ANS is above $40/Bbl] there is levied upon the producer of oil a tax … equal to

(West Coast ANS – 40) * .2% *
(ANS Prevailing Value) * 75% *
(amount of oil production)

Mr. Mintz stated that this CSSB 305 provision is what is being referred to as the Progressivity tax. This tax, which would be specific to oil, would be an extra tax reactivated when ANS West Coast Oil prices reached $40 per barrel.

10:45:12 AM

Senator Stedman, referring back to the royalty rate that would be established by the Legislature as specified on page 7, requested that, at some point in the future, the Committee readdress that issue.

Senator Bunde also asked whether the royalty rate determined by the Legislature would be specific to private leases. The wording of the provision however, raises "the question of certainty" in that respect.

10:45:56 AM

Mr. Dickinson communicated that the actual language in the committee substitute was "The rate of tax levied on oil and gas produced from a lease in the State that is in effect on the effective date of this subsection" or in other words, "leases in effect at time of bill signing". This language is located in Sec. 5(f)(1) page 3, line 26. The intent of the provision was to differentiate between current leases and future leases. Questions about the intent of this language could include such things as rather re-negotiated leases would be exempt from the tax. He agreed that this provision should be further addressed, as it would be important in terms of administering the plan.

10:47:21 AM

page 9

So …

The original bill has a single production tax: 20% of net value.

The CS has three production tax components:
(1) 25% of net value (now called “production tax value”) *except* for lessor royalty share
(2) 5% or 1.5% of gross value for lessor royalty share
(3) A progressive-rate tax on prevailing value of *oil* only, including lessor royalty share

Mr. Mintz stated that this information summarized the major differences between SB 305 and CSSB 305(RES).

Page 10

SB 305, Section 21

AS 43.55.160(a)

net value … is the total of the gross value at the point of production of … oil and gas … from all leases or properties in the state, less … lease expenditures … as adjusted … and … 1/72 of … transitional investment expenditures.

Mr. Mintz read the definition of net value. The net value concept has been included in the State's production tax statutes for many years; "and this is not something that the bill changes". Net value would continue to be based on gross value at the point of production of oil and gas, minus certain deductions, referred to as "lease expenditures". Further information about lease expenditures adjustments would be forthcoming.

Mr. Mintz noted that the Governor's bill also contained a deduction relating to "transitional investment expenditures", commonly referred to as "the clawback or the look-back provision".

Page 11

CSSB 305, Section 22

AS 43.55.160(a)

production tax value … is the total of the gross value at the point of production of … oil and gas … from all leases or properties in the state,
less lease expenditures … as adjusted

Mr. Mintz reminded the Committee that CSSB 305 would substitute the term "production tax value" for the existing "net value" term. The gross value at the point of production would continue to be the first step in the calculation. Lease expenditures, as adjusted, would then be deducted.

Mr. Mintz noted that CSSB 305 would not allow a deduction for transitional investment expenditures as specified in SB 305.

Page 12

SB 305, Section 31
CSSB 305, Section 28

AS 43.55.900(7)
"gross value at the point of production" means

for oil, the value … at the … meter … in … pipeline quality

for gas … the value … where … metered
[after any separation or gas processing]

Mr. Mintz stated that the terms identified on this page were those terms in the PPT bill whose definitions "are somewhat changed from the current definitions in the production tax statute".

Mr. Mintz shared the Department's view that, rather than being substantive, the definitional changes regarding the point of production for oil would "simplify" and "update" language. The metering point of production for oil would continue to be the point at which the oil was "pipeline quality".

Mr. Mintz pointed out, however, that the definition for the point of production for gas was "substantively changed"; specifically in regards to the activity called gas processing. This process typically "involved refrigerating a gas stream to remove valuable hydrocarbon liquids" known as natural gas liquids (NGLs). Under existing State statute, gas processing occurred downstream from the point of production. Under the PPT,

the point of production would be downstream from gas processing. This definitional change would allow gas processing costs to be deductible. The Department of Revenue could provide further information about this policy change if desired.

Page 13

SB 305, Section 19
CSSB 305, Section 20

AS 43.55.150(a)

… gross value at the point of production is calculated using the reasonable costs of transportation …

10:51:33 AM

Mr. Mintz stated that this information mirrored that in existing law and was included as a refresher of "the basic principal called the net-back method of calculating value". This concept was developed in consideration of the fact that ANS oil, while produced on the North Slope, was typically sold on the West Coast. Thus, the calculation for net value was based on the destination value less the cost of transporting the oil. This calculation is referred to the gross value at the point of production.

Page 14

SB 305, Section 20

AS 43.55.150(d)

… the department may allow … gross value [to be calculated based upon] … a royalty settlement agreement … [or]
a formula … that uses … [DNR or U.S. Dep't of Interior] royalty … valuation [or]
another formula … that reasonably estimates a value …

Mr. Mintz pointed out however, that there was one change in "how the gross value concept is addressed" in the PPT. The PPT would allow the Department of Revenue to simplify formulas where they deemed appropriate. Under SB 305, this permissive authority allowed the Department to develop a formula that would allow "a producer to use the royalty value under a royalty settlement

agreement" with the Department of Natural Resources, "or, in the case of federal leases, United States Department of the Interior royalty values," or the Department could develop alternate simplified formulas that, for example would consider transportation costs, price indices, and other factors. The purpose of this change would be to increase efficiency in the process of achieving a "reasonable estimate of gross value".

10:53:31 AM

page 15

CSSB 305, Section 21

AS 43.55.150(d)

if the commissioner completes a detailed fiscal analysis and determines … the long-term fiscal interests of the state [would be served] … the department may allow … gross value [to be calculated based upon DNR or U.S. Dep't of Interior] royalty … valuation [or] another formula … that reasonably estimates a value ...

Mr. Mintz stated that this information reflected a change CSSB 305 made to the provision depicted on page 14. CSSB 305 would mandate that in order to use a simplified formula with a producer, the Department must conduct "a detailed fiscal analysis and make a determination" that a particular formula would, in the long term, be in "the fiscal interest of the State". In addition, CSSB 305 removed the option that allowed the Department to develop a formula "utilizing a royalty settlement agreement".

Page 16

SB 305, Section 21

AS 43.55.160(c)
… lease expenditures ... are the total costs upstream of the point of production … on or after July 1, 2006 … that are the direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas … in the state.

Mr. Mintz stated that the first step in calculating "net value or production tax value" would be to determine gross value.

Certain lease expenditures could then be deducted from that figure. Eligible lease expenditures would include "the total costs upstream of the point of production that are direct ordinary and necessary costs of exploring for, developing, or producing oil or gas". This "very general statement" would be further addressed in later provisions of the bill. The focus at the moment should be on how the committee substitute changed the lease expenditures definition.

Page 17

CSSB 305, Section 22

AS 43.55.160(c)
… lease expenditures ... are the total costs upstream of the point of production ... on or after April 1, 2006 ... that are the direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas … in the state.

Mr. Mintz identified the "only change in the fundamental definition of lease expenditures" between the two versions of the bills was that CSSB 305 had an effective date of April 1 and SB 305 had an effective date of July 1. CSSB 305's effective date would allow costs to be accounted for earlier.

Page 18

Section 21/22

AS 43.55.160(c) (continued)

In determining … [direct, ordinary, and necessary] costs … the department shall give substantial weight ... to typical industry practices and standards ... as to [billable] costs ... under unit operating agreements ... and [DNR net profits share lease regulations].

Mr. Mintz stated that this language would provide the Department "very meaningful statutory guidance" in determining what would qualify as lease expenditures. The PPT would allow the Department to draw on two sources for guidance: one would be typical industry practices and standards regarding the costs that could be billed by an operator.

10:55:41 AM

Mr. Mintz identified the second existing source of guidance as being "the Department of Natural Resources' standards for what costs are deductible under their net profit share/lease regulations".

Page 19

CSSB 305, Section 22

AS 43.55.160(n)(2)

CS adds a definition of “ordinary and necessary” to make clear that Internal Revenue Code meaning is adopted.

Mr. Mintz noted, however, that CSSB 305 would alter one element of the definition of "direct, ordinary and necessary". While SB 305 would likely "incorporate Internal Revenue Service (IRS) precedent" of those terms, CSSB 305 would "explicitly incorporate" it. Thus the definition of "ordinary and necessary" would adopt the meaning "those terms have for federal income tax purposes".

Page 20

Section 21/22

AS 43.55.160(d) provides specific examples of, and exclusions from, “direct costs”

CSSB 305 has several improvements recommended by the Administration: e.g.,

- (d)(1)(A) and (d)(2)(A), clarifying treatment of capitalized expenditures
- (d)(2)(L), ensuring that conservation surcharges are not deductible

Mr. Mintz stated that this Statute would specifically identify which costs would or would not be deductible as direct costs. At the request of the Governor Murkowski Administration, CSSB 305 expanded the direct cost provisions to provide further clarity.

Page 21

CSSB 305, Section 22 (cont.)

CSSB 305 has several additional exclusions:

- (d)(2)(M) Costs of dismantlement, removal, restoration, etc., re: previous oil or gas production
- (d)(2)(N) Costs above fair market value, in non-arm's length transactions
- (d)(2)O) Costs to acquire a company

Mr. Mintz reviewed the exclusions added to CSSB 305.

10:58:27 AM

Senator Stedman asked that further discussion occur in regards to which business overhead expenses would be included or excluded under the criteria such as "buildings and offices in or out of the State…"

10:59:07 AM

Mr. Mintz expressed that business overhead expenses are "explicitly" addressed in CSSB 305. "Overhead would generally be considered an indirect cost and the general rule in the bill is that only direct costs are deductible." This is the reason the committee substitute would "allow reasonable allowance … for overhead expenses," directly related to exploring, developing, or producing oil and gas deposits in the State, as determined through regulation by the Department.

Mr. Mintz stated that the issue of whether a building in Anchorage would qualify as an overhead expense had been discussed. The general response was "just because a producer incurred costs in running his business, does not necessarily mean those costs are deductible". Viable overhead deductions would be those costs "incurred directly for oil and gas exploration, development or production".

Mr. Dickinson agreed. While a building would not be recognized as an overhead expense, industry practice would recognize as an overhead component an additional employee's salary. An example of this would be an instance in which British Petroleum (BP), in its capacity as an operator, billed another working interest owner for the salary of a BP engineer working on a Prudhoe Bay project. This is anticipated to reflect "the general approach" allowed under this legislation. This bill would allow the

Commissioner to "develop an allowance for overhead" as opposed to allowing "certain categories of costs" be the rule.

Co-Chair Green asked whether a "standard calculation procedure" for operators' overhead expenses currently existed.

Mr. Dickinson responded in the negative. A variety of overhead standards, rather than a singe one, currently exists in the State. A business person would recognize this as being "the classic negotiation about how overhead gets passed through one's projects".

Co-Chair Green stated that this issue would be further addressed.

Senator Stedman acknowledged.

Page 22

SB 305, Section 21

AS 43.55.160(e)

[Lease expenditures must be adjusted by subtracting payments the producer receives for (1) another's use of a production facility; (2) reimbursement, e.g. field costs paid by state, that offset lease expenditures; and (3) sale of assets acquired through lease expenditures or of non-taxable oil or gas used in lease operations.]

Mr. Mintz stated that this section provided further information regarding lease expenditures, as adjusted, as previously referenced in SB 305, Section 21, AS 43.55.160(a) on page 10 of the presentation. The "simple" concept would be to allow net costs to be deducted. For example, were a producer "reimbursed for some of the costs, those reimbursements should be netted against the costs that are deductible"; were a producer to acquire an asset that incurred costs against the deductible and then sold the asset, "the sale receipts should also be netted out against the costs".

Page 23

CSSB 305, Section 22

AS 43.55.160(e)

[Lease expenditures must be adjusted by subtracting payments the producer receives for (1) another's use of – or for managing -- a production facility; (2) reimbursement, e.g. field costs paid by state, that offset lease expenditures; and (3) sale – or removal from the state – of assets acquired through lease expenditures or of non-taxable oil or gas used in lease operations.]

Mr. Mintz noted that this information identified changes CSSB 305 made regarding lease expenditures specified in SB 305. SB 305 specified that the payment a producer received for allowing another entity to use their production facility should be an adjustment. CSSB 305 added the words "or for managing a production facility"; thereby mandating that the management fee should also be a deduction. This also served to "close a loophole" pertaining to the sale of an asset, as earlier addressed on page 22. The removal of an asset from the State for use somewhere else should be treated in the same manner as the sale of that asset for purposes of adjustments.

Page 24

CSSB 305, Section 22

AS 43.55.160(a), (b)(2), and (e)

At the Administration's recommendation, the CS addresses potential timing mismatches between lease expenditures and adjustments, ensuring that the tax effect of an adjustment will be recognized even if a producer or explorer has no production, or has low lease expenditures, when an adjustment payment is received.

Mr. Mintz stated this provision "summarizes the intent of several groups of text" in AS 43.55.160. "The adjustment to lease expenditures is intended to implement the rule of allowing only net costs to be deducted." However, timing mismatches might make this difficult.

Mr. Mintz recalled the earlier example of an explorer who spent ten million dollars drilling wells. Since an explorer does not produce oil or gas, there would be no production tax to which to apply the credits provided by that expenditure. Nonetheless, the

ten million dollar expenditure would qualify as deductible lease expenditures and therefore "can be converted" into a 25 percent credit under the provisions of the PPT.

11:05:10 AM

Mr. Mintz continued that, in this case, the monies garnered from an asset purchased as part of the ten million dollar expenditure and then sold "ought to be netted out against the ten million dollars". The question, therefore, was how to apply that adjustment when the sale of the asset occurred the following calendar year and after the explorer had received the 25 percent credit. This provision would specify that were "an adjustment to occur in a time period where a producer" or an explorer had no "taxable oil or gas production or if the lease expenditures are too low to deduct the adjustment from without getting to a negative number", then the negative number should be used. This would generate a tax liability that recognized the adjustment even though its might occur in a later time period.

11:05:58 AM

Page 25

CSSB 305, Section 22

AS 43.55.160(k) and (*l*)

For purposes of (1) excluding from lease expenditures costs that exceed fair market value, and (2) determining the amount of an adjustment to lease expenditures due to the sale of an asset, standard = “a producer dealing at arm’s length with an uncontrolled entity”; and IRS rules may be adopted.

Mr. Mintz stated that CSSB 305 added this language to allow the Department to follow IRS standards of fair market value to purchases made "by a producer dealing at arm's length with an uncontrolled entity".

11:07:19 AM

Page 26

SB 305, Section 21

AS 43.55.160(g)

… transitional investment expenditures are … capital expenditures [incurred 7/2001 through 6/2006] … less … [proceeds from] the sale ... of assets … acquired ... as a result of [those] capital expenditures

[This provision is *not* in the CS; instead CS provides for a tax credit for some transitional investment expenditures.]

Mr. Mintz stated that one of the deductions allowed in SB 305 was a transitional investment expenditure. This expenditure would be recognized as a capital expenditure were the expenditure to occur five years prior to the effective date of the bill. The committee substitute deleted this provision and instead included tax credit provisions.

Page 27

SB 305, Section 21

AS 43.55.160(i)

… a producer that is qualified ... may reduce the net value by deducting an allowance … [T]he total of the allowances … during the calendar year does not exceed $73,000,000. An unused allowance ... may not be carried forward …

[This provision is *not* in the CS; instead CS provides for an allowance that depends on the average daily oil and gas production.]

Mr. Mintz stated that the $73 million per producer annual allowance provision included in the Governor's bill was omitted from the committee substitute and replaced with an allowance based on average daily oil and gas production.

Page 28

CSSB 305, Section 22

AS 43.55.160(g)

> … a producer that is qualified ... and produces under 55,000 BOE/day may reduce the net value by deducting an allowance ... equal to the following fraction of the production tax value:
>
> (5,000 – 0.2 * [average daily production – 5,000]) ÷ average daily production

Mr. Mintz stated that this language was a summary of CSSB 305's allowance provision. The 5,000 BOE/day allowance would a producer's total amount of oil and gas production in the State. While "oil and gas are treated as equivalent" in the example, he noted that 6,000 cubic fee of gas would be equivalent to one barrel of oil. Were a producer to produce less than 5,000 barrels of oil or gas equivalent per day, they would receive a "100 percent allowance against" their taxable oil and gas production. As production increased, the percentage of allowance would decrease rapidly until it reached zero.

Mr. Mintz pointed out that the correct BOE/day production volume should be 30,000 BOE per day rather than the 55,000 BOE per day depicted on both this page and in Sec. 22(g), line one, page 20 of CSSB 305.]

Mr. Dickinson affirmed the number should be 30,000 BOE; however, having the incorrect number in the formula was mathematically acceptable as "the formula takes you below zero at that point".

11:10:34 AM

Senator Stedman informed the Committee that the Senate Resources Committee initially utilized a 0.1 percent multiplier in their tax allowance formula. That multiplier was subsequently increased 0.2 percent. The 0.2 percent multiplier served to run the tax allowance to zero at 30,000 BOE/day.

11:11:11 AM

Mr. Mintz concurred with Senator Stedman' observation.

Mr. Mintz noted that both the $73 million allowance specified in SB 305 and the revised allowance based on oil and gas production in CSSB 305 were per producer allowances.

CSSB 305, Section 22

AS 43.55.160(h) – producer's qualification for an allowance - ability to qualify expires in 2013

This is an anti-splitting provision to prevent abuse of the *per producer* allowance under AS 43.55.160(g).

It is essentially the same anti-splitting provision that is in sec. 21 of the original bill, for the $73 million *per producer* allowance.

Mr. Mintz stated that this provision would address concerns about possible loopholes or abuse of the allowance by producers. One concern was that a producer might spin off, divide up, "or generate a multiplicity of different producers" and thereby "generate a multiplicity of allowances". Thus, this "anti-splitting provision" was incorporated into both SB 305 and CSSB 305. This provision would require a producer desiring to get an allowance "to demonstrate to the Department that that kind of gaming" had not occurred. In addition, in order to qualify for the allowance a producer must be qualified by the Department each calendar year.

11:12:36 AM

Senator Bunde asked the reason a five year time period had been specified as the time in which a producer could qualify for an allowance. He had been told this time frame was simply "a policy call".

11:12:59 AM

Mr. Mintz thought that Senator Bunde might be referring to the five year look-back period for transitional investment expenditure. That issue was separate from the per producer allowance specified in AS 43.585.160(g). The transitional investment provision would be a component of the forthcoming "credits" discussion.

11:13:24 AM

Senator Bunde clarified that his question pertained to the timeframe specified in AS 43.55.160(h).

Mr. Dickinson clarified that this provision's qualifying period would end in the year 2013. Therefore, a PPT with a 2006 effective date would allow a producer a seven year time period in which to qualify.

Mr. Mintz communicated that while he could address issues pertaining to the PPT formula, he would defer to others in regards to policy issues.

Page 30

SB 305, Section 7
CSSB 305, Section 7

AS 43.55.020(a)

… the tax levied under AS 43.55.011, net of any credits applied under this chapter, is due …

… the tax levied under AS 43.55.011(e) ... net of any credits applied under this chapter, is due …..

Mr. Mintz noted that the calculation of net value, which is referred to as production tax value (PTV) under the PPT had been discussed earlier. Once the PTV is determined, the tax rate of 25 percent would be applied to it under AS 43.55.011 in CSSB 305. However, before "the actual tax liability" was determined, "there is the possibility of applying tax credits to the amount" due. Both SB 305 and CSSB 305 "recognize that the tax that's due is after credits" are applied.

Page 31

SB 305, Section 12
CSSB 305, Section 13

AS 43.55.024(a)

… a producer ... that incurs a qualified capital expenditure ... may ... elect ... to take a tax credit in the amount of 20 percent of that expenditure.

Mr. Mintz stated that this provision would further explain tax credits relating to capital expenditures. The provisions in SB 305 and CSSB 305 were identical in this regard. Both would allow a 20 percent credit on qualified capital expenditures.

Page 32

Section 12/13 (cont.)

AS 43.55.024(h)(1) and (j)(2)
[AS 43.55.024(h)(2) in original bill]

"qualified capital expenditure" -

- [is a lease expenditure for G&G exploration, intangible drilling costs, and other expenditures capitalized under IRC]
- [does not include purchase of a previously acquired or used asset]

Mr. Mintz stated that these provisions would clarify what would suffice as a qualified capital expenditure. This language is similar in both bills. A qualified capital expenditure must foremost be a lease expenditure. "A lease expenditure is everything that is deductible for purposes of calculating taxable value of oil and gas."

11:16:03 AM

Co-Chair Wilken assumed chair of the meeting.

Mr. Mintz responded to Senator Dyson's earlier question regarding "credits availability for existing operations". Senator Dyson had also voiced support for allowing credits "for all exploration development, and production costs". To that point, he clarified that while all lease expenditures would be eligible as a deduction, only "capital type expenditures" associated with exploration, development, and production projects would also be eligible for the 20 percent credit.

11:16:42 AM

Mr. Mintz continued that, "for the most part", these qualified capital expenditures would be those "treated as capitalized under federal income tax rules. In addition to that, the bills would allow exploration expenditures for geological and

geophysical (G&G) activities" such as seismic exploration to qualify for the credit.

11:17:08 AM

Mr. Mintz pointed out that provisions were incorporated into the PPT bill "to avoid the problem of churning". This term described the situation in which a producer might buy an asset, receive a credit, and then sell the asset to a second producer who would also get a credit. The PPT bill would only allow a credit for an asset "if it has not previously been placed in service in the State or previously been acquired as a result of an expenditure that would qualify for the credit".

11:17:47 AM

Page 33

CSSB 305, Section 13 (cont.)

AS 43.55.024(h)(2)

“qualified capital expenditure” does not include

an expenditure incurred ... for ... an extended period of disuse, dismantlement, removal ... or abandonment ... or for the restoration of a lease, field, [etc.]

Mr. Mintz identified restoration activities as another important element of the bill. The "extended period of disuse" verbiage would apply to suspended or mothballed operations.

In response to a question from Co-Chair Wilken, Mr. Mintz explained that the term "G&G exploration" as denoted on page 32 was an abbreviation for "geological and geophysical exploration", primarily seismic exploration.

11:18:47 AM

Senator Stedman ascertained from Mr. Mintz's remarks that there might be a question about how the provision on page 33 could be interpreted. To that point, he asked whether there was a "language issue" that should be addressed.

Mr. Mintz responded that the wording "extended period of disuse" could be further clarified. This language is located in Sec. 13(h)(2), on page 9, line 28 of CSSB 305.

Mr. Dickinson qualified that there were two issues with the verbiage in question. Further clarification of the definition of "disuse" would be desired, to include a review of whether this might involve safety or health issues. The second issue would pertain to "the notion of "extended period". Either the bill drafters must provide "more clarity" of the term "extended period of disuse" or the issue must be addressed in regulations as the language is "open to a lot of interpretation".

11:20:14 AM

Senator Stedman noted that, as the review of this "complicated bill" continued, other issues might require further interpretation. To that point, he asked whether the Administration would be developing a list of elements they deemed to require further attention.

Mr. Dickinson assured the Committee that an ongoing list of issues needing further review would be maintained.

11:20:59 AM

Page 34

HB 305 Section 12 (cont.)

AS 43.55.024(b)

A producer may elect to take a tax credit ... of 20 percent of a carried-forward annual loss [which is the amount of a previous year’s lease expenditures that were not deductible because they would have reduced the net value of the oil and gas below zero].

Mr. Mintz identified this provision as "the second major category of credit. This is basically just a different form of allowing losses to be carried forward in a calendar year where a producer's lease expenditures exceed the gross value of the oil and gas." In this case, a producer would be prohibited from utilizing the entirety of their deductions in that year if doing so would result in a negative value and thereby a negative tax.

This provision would allow those deductions to be "converted to a credit" toward the following year. "A carried forward annual loss" under the Governor's bill with its 20 percent tax rate would thereby allow a 20 percent credit of "carried forward excess lease expenditures".

Page 35

CSHB 305 Section 13 (cont.)

AS 43.55.024(b)

> A producer ... may elect to take a tax credit … of 25 percent of a carried-forward annual loss [which is the amount of a previous year's lease expenditures that were not deductible because they would have reduced the production tax value of the oil and gas below zero].

Mr. Mintz stated that CSSB 305 modified SB 305's "carried forward annual loss" provision to align this allowance with the committee substitute's 25 percent tax credit provision and its "production tax value" terminology.

Mr. Mintz noted that, unlike the qualified capital expenditure credit options explained earlier by Roger Marks in which the producer could opt between utilizing the qualified capital credit program in this bill or an existing exploration incentive credit program, this carried-forward annual loss credit provision would be automatically available to a producer.

11:23:27 AM

Senator Bunde understood therefore that the carried-forward annual loss credit differed from the 20 percent investment credit.

Mr. Mintz affirmed. He stressed that these credits would be "additive" in that the 20 percent qualified capital expenditure credit would be in addition to the 25 percent carried-forward annual loss credit allowed under CSSB 305.

Senator Bunde asked whether, as a result of the various credits provided in the bill, there might be a point at which the State would be required to return money to producers.

Page 36

Section 12/13 (cont.)

AS 43.55.024(d) – (f)

A producer entitled to a tax credit may apply to the Dep't of Revenue for a transferable tax credit certificate. Once issued, a certificate may be used for its face value, but a transferee may not apply a certificate to reduce its tax liability by more than 20 percent during a calendar year.

Mr. Mintz stated that this language would "indirectly" address Senator Bunde's question. "An important feature of realizing the incentive nature of the credits, particularly for explorers and producers that do not have a lot of current production, is for them to monetize the credits that they can't use against their own taxes." Both SB 305 and CSSB 305 would allow producers and explorers to apply to the Department of Revenue to have their credits turned into transferable tax credit certificates. The Department would expedite the request in order not to impair the value of the credit. This would assure the producer buying the credit that their tax could be reduced by the "face value" of the certificate.

Mr. Mintz disclosed that were an audit or other information to later discover "something amiss" which affected the credit, the Department could address any tax deficiency with the original producer or explorer who had been issued the certificate.

Mr. Mintz also noted that the entity purchasing the certificate could not utilize the certificate to reduce their tax liability by more than 20 percent during a calendar year. This would "prevent excessive impacts on total State revenue". This limit would not apply to an entity utilizing its own credits.

11:26:24 AM

Senator Hoffman asked whether the credit certificate could be transferred "only to producers or explorers".

Mr. Mintz responded that the legislation did not contain any "express limitation on who could buy" the credit certificate. However, the only entities "who could ultimately benefit" would be those with "a production tax liability". Those entities

"would be the producers". He allowed that "an intermediary could conduct a trade".

Mr. Dickinson affirmed Mr. Mintz's remarks. The credit certificate would be useless to an entity that did not have a production tax liability. It could not be "applied against an income tax or royalty obligation.

Senator Olson ascertained therefore that the credit certificates could be transferred between the major three producers.

Mr. Dickinson clarified that the credit certificates could be available to any producer. The expectation would be "that these would generally be generated by explorers who would then sell them to the producers who have the income tax liability". This would allow an explorer "to monetize these immediately by selling them to someone who can use them".

11:27:51 AM

Page 37

CSSB 305, Section 13 (cont.)

AS 43.55.024(i) – nontransferable credit for transitional investment expenditures

… transitional investment expenditures [TIE] are ... capital expenditures [incurred 4/2001 through 4/2006] ... less ... [proceeds from] the sale ... of assets ... acquired ... as a result of [those] capital expenditures

Mr. Mintz noted that AS 43.55.024(i) in CSSB 305 served to substitute a third credit into CSSB 305 for the transitional investment expenditure (TIE) deductible specified in SB 305. A TIE was defined as "what would be qualified capital expenditures if they were taking place in the future"; however, "they're expenditures that were incurred in the previous five years".

Page 38

CSSB 305, Section 13 (cont.)

AS 43.55.024(i) (cont.)

- a producer may ... take a tax credit ... of 20 percent of the producer's [TIE] but only [up to] one-half of the producer's qualified capital expenditures ... during the month
- credits are non-transferable
- credit provision expires April 1, 2013

Mr. Mintz explained that the third credit incorporated into CSSB 305 would be "tied to new investment"; thus "a credit for previous investments can only be taken in a time period when the producer makes new capital investments". The maximum credit that could be taken in a time period would be limited "to one-half of the amount of the new capital investment". This credit is often referred to as "the two for one provision".

Mr. Mintz stated that the TIE credit differs from the two previously discussed credits because it would not be transferable. In addition, the TIE credit provision would expire in 2013.

11:29:21 AM

Senator Stedman noted that the TIE credit language was located in Sec. 13(i)(4) lines 26-28, page 10 of CSSB 305. This language might require revising were confusion to arise from the intermingling of the terms "transferable and nontransferable" in the text.

Senator Stedman also suggested that a summary page be developed that would define the various tax credits. This would be helpful when discussing the credit aspects of the bill.

Co-Chair Green asked whether TIE and the other credit terms being discussed were currently defined in State Statute.

Mr. Dickinson communicated that the credit terms included in the PPT were not currently defined in State Statute. Their definitions however, were contained within the bill.

Co-Chair Green asked whether including the credit definitions within the bill would suffice.

Senator Stedman responded that due to the complexities of the bill a summary sheet would be helpful; particularly in assuring

that everyone is "on the same page" when issues were being discussed.

Co-Chair Green stated that this information could be included with the glossary of terms directory previously discussed.

Page 39

SB 305, Sections 22-29
CSSB 305, Sections 23-26

Original bill allowed a credit to be taken for conservation surcharge payments; CS does not.

CS reduces sec. 201 surcharge from $.02 to $.01 per barrel and increases sec. 300 surcharge from $.03 to $.05 per barrel.

Mr. Mintz stated that these provisions would address "one last credit issue"; specifically the conservation surcharges which currently exist in the State's production tax statute. The conservation surcharge has typically amounted to two or three cents per barrel. SB 305 proposed a credit to be taken against the production tax for the surcharge payments. CSSB 305 eliminated that credit. CSSB 305 also reduced one of the conservation surcharges from two cents to one cent per barrel and increased the other from three cents to five cents per barrel.

11:32:21 AM

Mr. Mintz summarized the presentation to this point: "the calculation of gross value has been discussed and "we've looked at lease expenditures, adjustments, deducting the lease expenditures, getting the taxable value, and applying credits against the tax" in order to determine the actual tax amount that would be owed.

Page 40

SB 305, Section 7

Ninety percent of production tax, net of credits, is due each month.

The remainder is due March 31 of the next calendar year.

Mr. Mintz remarked that the material on pages 40 through 42 would address the manner in which the PPT would be paid under SB 305 and CSSB 305. The production tax would continue to be paid monthly under both bills. However, the inclusion of upstream costs in the equation would require "longer term aspects" to be considered in the calculations. This could require adjustments to be made throughout the year.

Mr. Mintz explained that SB 305 addressed the adjustment issue by requiring producers to make a monthly "safe harbor" payment equating to 90 percent of the tax owed. SB 305 also included a "true-up provision" which required the balance of the actual tax amount to be paid by March 31 of the next calendar year.

Page 41

CSSB 305, Sections 7, 12

AS 43.55.020(e) and (f)

- 95 percent of principal production tax (AS 43.55.011(e)), net of credits, due each month. Remaining portion due at end of next calendar quarter.
- 100 percent of tax on lessor royalty interest (AS 43.55.011(f)) due each month.
- Bill does not specify payment of progressive-rate oil tax (AS 43.55.011(g)).

Mr. Mintz pointed out that the approach taken in CSSB 305 differed from that of SB 305 in that it would require producers to pay a 95 percent "safe harbor". The balance of the actual tax would be due at the end of the next calendar quarter.

Mr. Mintz specified there to be three components in how the tax would be paid under CSSB 305. The 95 percent safe harbor provision would apply "to the principal tax which is the 25 percent tax on production tax value". Another component was "the separate tax on the private royalty share"; 100 percent of this tax was due each month under ELF. This tax could continue to be paid in its entirety because, being based on the gross value at the point of production, it did not contain many variables in its calculation.

Mr. Mintz communicated that, "in its current form", CSSB 305 was not specific about when the third component, which is the progressivity tax, would be paid. This omission should be addressed.

Senator Stedman understood the rationale behind the safe harbor and true-up provisions included CSSB 305, however, he expressed that further discussion should occur in regards to the concept of collecting 100 percent of the tax on lessor royalty interest each month as specified in AS 43.55.011(f). This discussion should include how to deal with a situation in which the tax paid was only equivalent to, for instance, 99 percent of the royalty tax.

Senator Stedman also requested the Administration to be included in the effort to develop the appropriate Progressivity rate payment language. The goal would be to insure that the tax would be collected rather than treated as a pledge of payment such as an IOU "into perpetuity".

Page 42

SB 305, Section 9
CSSB 305, Section 9

[P]roducer may deduct [from royalty] the amount of the tax paid on taxable royalty oil and gas ...

- Original bill provides a default formula for allocating the 20% tax on net value to royalty share.
- CS provides a slightly different formula for allocating the 25% tax on net value ("production tax value") to *non-lessor* royalty share.

Mr. Mintz stated that this provision focused on the "private royalty share of the tax". Even thought this tax would be "on a small amount of production", the issue was complicated. While "the whole production tax is a liability of the producer, including that part of the production tax on the royalty share, … the producer has the legal right to collect against the royalty owner for their royalty share of the tax". SB 305 included "a default formula" for how the royalty share would be calculated on the 20 percent tax.

Mr. Mintz stated that a default formula would not be required under CSSB 305 because it contained a specific royalty tax. "However, there are other types of royalty interests besides the royalty owed by a lessor under an oil and gas lease. These are usually called overriding royalty interests. These would be typically carved out of the producer's or the lessee's share of the production. Those are usually invisible to the regulators, to the tax authorities", or to the Department of Natural Resources as "they are private transactions". Since "the producer has the right to collect that share of the tax against the overriding royalty owner and because this 25 percent tax on net value doesn't actually define a particular tax for a particular lease, the bill does provide a default formula for doing that". Were the royalty owner and the producer to agree on "something else that's fine and the bill recognizes that"; however, in the absence of an agreement, the default formula would be utilized. CSSB 305's default formula varied slightly from that proposed in SB 305. This issue is "complicated", but does not affect a significant amount of production.

11:38:26 AM

Mr. Mintz stated that pages 42 through 54 of the presentation provided flow charts summarizing "how the new tax regime" being proposed in CSSB 305 "would work in terms of how a producer would calculate the production tax".

Page 43

Steps in Tax Calculation

Under CSSB 305(RES)

Page 44

GROSS VALUE OF OIL AND GAS
AS 43.55.150, AS 43.55.900

[This flow chart depicts how the gross value of oil and gas at each property a producer is producing from in the State would factor into the producer's Total Statewide Gross Value of Producer's Oil & Gas.]

Mr. Mintz reiterated that "the main tax" being proposed in CSSB 305 would be a statewide tax. Thus, the first component in the

tax calculation would be the producer's total statewide gross value of taxable oil and gas, consisting of the total value of oil and gas produced at each of the producer's properties.

Page 45

LEASE EXPENDITURES
AS 43.55.160(b) – (e)

[This flow chart depicts the manner through which the total of allowable deductions would be determined]

Mr. Mintz stated that the Lease Expenditures depicted on this flow chart represented "the deduction part" of the calculation. This calculation would include exploration, development, and production costs of activities statewide, "modified by those concepts of direct, ordinary, and necessary" expenses. Facility fees, reimbursements, asset sales and other eligible adjustments would be subtracted to provide the net cost, referred to as the Adjusted Lease Expenditure amount.

Mr. Mintz revisited the earlier discussion about lease expenditure credits. These credits would be generated, "when, in the course of a calendar year", lease expenditures exceeded the gross value of the producer's production"; that excess could be carried forward as a credit. He explained that rather than getting a credit when lease expenditures exceeded the gross value "within a calendar year, excess expenditures of one month could be added to the Lease Expenditures of another month, as depicted in the flow chart. This would provide the total amount that could be deducted from the Gross Value of Oil and Gas.

Page 46

PRODUCTION TAX VALUE
AS 43.55.160 (a) and (g)

[This flow chart depicts the elements of the tax calculation, beginning with the producer's Total Gross Value of Oil and Gas. The Adjusted Lease Expenditure amount would then be deducted. Any allowances provided to the producer could also be deducted. The remaining amount is referred to as the Production Tax Value of Oil and Gas.]

Mr. Mintz reviewed the flowchart. The allowance provided to producers producing less than 30,000 BOE of oil or gas per day

on a statewide basis. [NOTE: Mr. Mintz inadvertently stated 30,000 barrels per month] could then be deducted from any taxable value remaining after Adjusted Lease Expenditures were deducted. The amount remaining would be the Production Tax Value of Oil and Gas.

Page 47

SEC. 024 TRANSFERABLE TAX CREDITS
AS 43.55.024 (a) and (b)

[One of the transferable tax credits depicted in this flow chart is the Carried Forward Annual Loss Credit calculation, which is 25 percent of a producer's Excess Lease Expenditures in a Calendar Year

The second transferable tax credit is the Qualified Capital Expenditure Credit. This credit is calculated at 20 percent of the producer's Qualified Capital Expenditures.]

Mr. Mintz stated that the two types of transferable credits contained in CSSB 305 could be deducted from the Production Tax Value of Oil and Gas.

11:41:47 AM

Page 48

TRANSFERABLE TAX CREDIT CERTIFICATES - AS 43.55.024 (d)-(f)

[This flowchart depicts how a producer, with a tax credit, could receive their Transferable Tax Credit Certificate. First, the producer would submit an application for the credit certificate to the Department of Revenue. If approved by the Department, the certificate would be issued. The producer could then sell that certificate to another producer.]

Mr. Mintz reviewed the application process.

11:42:15 AM

Page 49

TIE CREDIT 43.55.024(i)

[This flow chart depicts how non-transferable Transitional Investment Expenditure credits (TIEs), which are factored at 20 percent of their value, could be applied as a credit toward current qualified capital expenditures in a month. TIE credit usage is restricted, in that the amount of credit being utilized could amount to no more than one half of a month's qualified capital expenditures.

Mr. Mintz stated that the non-transferable TIE credits were associated with the "look-back provision for capital investments during the previous five years". A producer possessing these credits could only apply them in a month in which capital investments were currently being made. The amount of credit allowed would be restricted to less than one half of the current investment. The credit would be factored at 20 percent of the value of the investment.

Page 50

TAX CALCULATION: AS 43.55.011(e), 43.55.024

[As depicted on this flowchart, the "Production Tax Value of Oil and Gas" would be taxed at 25 percent. This would provide the Tax Before Credit amount. Then the producer's own credits would be subtracted. Purchased credit certificates, capped at 20 percent of the remaining tax, would then be subtracted. The remaining tax amount would be the Tax Payable.]

Mr. Mintz stated that this flowchart depicted the tax calculation in its entirety under the PPT. The amount of a producer's own credits that could be subtracted from the "Tax Before Credit" amount would be unlimited except that the resulting tax amount could not be a negative number. Any credit certificates utilized by a producer would be limited in any calendar year to 20 percent of the remaining tax payable.

Page 51

TAX CALCULATION: AS 43.55.011(f)

[This flowchart depicts how the Tax Payable under the royalty share provisions of the bill would be determined. The Gross Value at Point of Production of Lessor's Royalty

Share of Oil and Gas would be multiplied by 1.5 percent in Cook Inlet or five percent tax rate otherwise.]

Mr. Mintz stated that this information would reflect how the production tax on private lessor royalty share would be factored. Even through the tax was on the royalty share, the producer would continue to be responsible for the payment.

Page 52

TAX CALCULATION: AS 43.55.011(g)

[This flowchart reflects that the Progressivity tax calculation would be activated when ANS West Coast Oil prices reached a certain level.]

Mr. Mintz specified that the Progressivity element would be implemented when ANS West Coast barrel prices exceeded $40 a barrel. State Statutes would contain an "arithmetic formula" that would calculate the tax rate based on the value of ANS.

Page 53

TAX PAYMENT
AS 43.55.020(e)

[This flowchart reflects that the committee substitute would require a producer to remit 95 percent of their Tax Payable on Oil and Gas produced in a Month. The remaining tax for that and other months in the calendar quarter must be paid by the end of the next calendar quarter.]

Mr. Mintz reviewed the flowchart.

11:45:34 AM

Mr. Mintz stated that the proposed payment schedule mirrored that of ELF. For example, 95 percent of the tax due on oil and gas produced in March would be due at the end of April. Any remaining balance from the first calendar quarter months of January, February or March would be due by the end of June, which would be the end of the second calendar quarter.

Page 54

TAX PAYMENT
PS 43.55.020(f)

[This flowchart depicts that 100 percent of the tax due on royalty shares in any month must be paid by the end of the next month.]

Mr. Mintz reviewed the flowchart. This timeframe would mirror that of existing production tax statutes.

The presentation concluded.

11:46:38 AM

Senator Stedman asked that an implementation plan, to include insight on any expected implementation difficulties, for the PPT be provided.

Co-Chair Green agreed.

Mr. Dickinson stated that several implementation issues were addressed in the Department of Revenue's fiscal note. The primary concern relative to both SB 305 and CSSB 305 was how to include "the area of upstream costs which currently do not form a part of either royalty" into the equation. This component has not been audited and was unfamiliar territory. Getting this element "to a point where the State's auditors are comfortable with what they are doing and what they are seeing will be the biggest challenge". Disputes would be expected. Downstream costs, amounting to approximately $1.5 billion, were audited under ELF; however only "eleven words" pertaining to downstream costs were contained in current Statute. During the past 30 years, "hundreds of pages of regulations" have been generated in the effort to interpret the words "…the actual costs of transportation of that oil or gas".

Mr. Dickinson noted therefore that the effort undertaken in this bill was to "strike a balance" in this regard. More direction was given to the Department. However, more regulatory language would be required to assure the appropriate interpretation.

Mr. Dickinson advised that while "more guidance" was included in the bill, disputes would still occur. Extra effort was made to address and further define areas which had been identified as disputable.

Mr. Dickinson noted that three new positions were requested in the Department of Revenue's fiscal note. These would be in addition to three existing but unfilled staff positions. Additional funded was also requested to let contracts to assist the Department with the initial rounds of audits and in building capacity relating to staff training and developing manuals. Such efforts would be important and necessary to support the effort to encourage resource investment in the State.

11:50:09 AM

Senator Stedman suggested that another handout be developed to clarify upstream and downstream expenses in relation to the point of production. Clearly defining these terms would be helpful since their usage would be frequent.

Co-Chair Green suggested that a pictorial be developed in that regard.

Mr. Dickinson noted that an upstream/downstream pictorial was available and would be provided.

11:51:17 AM

Senator Olson recalled a prior fiscal analysis to indicate that only three tax auditors and one technician would be required to support this effort. Such a complicated bill would require more manpower.

Mr. Dickinson clarified that that fiscal note requested three new auditors in addition to the current nine production tax auditors. The "notion of sharing" resources and eliminating duplicated efforts in the Department of Natural Resources and the Department of Revenue would also be factored. Further labor force determinations would be made after the study specified in the committee substitute was conducted.

Senator Olson asked whether SB 305 included the three positions in its fiscal analysis. .

Mr. Dickinson understood that the changes made to the committee substitute had not altered the fiscal note which accompanied SB 305.

Co-Chair Wilken echoed Senator Dyson's earlier remarks complimenting the information provided in today's presentations.

Co-Chair Green thanked the Committee for their attention to the details of the bill and the presenters for their information. Housekeeping regarding the future hearings on the bill was conducted.

The bill was HELD in Committee.

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ADJOURNMENT

Co-Chair Lyda Green adjourned the meeting at 11:54:09 AM.