MINUTES
SENATE FINANCE COMMITTEE
April 6, 2006
9:05 a.m.

CALL TO ORDER

Co-Chair Lyda Green convened the meeting at approximately 9:05:53 AM.

PRESENT

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

Also Attending: JOHN P. ZAGER, General Manager, Chevron Alaska; JOHN A BARNES, Production Manager, Marathon Oil Company

Attending via Teleconference: From an Offnet Location: KEN THOMPSON, Managing Director, Alaska Venture Capital Group

SUMMARY INFORMATION

SB 305-OIL AND GAS PRODUCTION TAX

The Committee heard testimony from Chevron Alaska, Marathon Oil, and Alaska Venture Capital Group. The bill was held in Committee.

Co-Chair Wilken announced that public testimony on the FY 2007 operating budget would commence that evening and continue through Saturday, April 8, 2006.

#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 sixth hearing for this bill in the Senate Finance Committee.

Co-Chair Green announced that three oil and gas companies would be presenting testimony regarding this petroleum production tax (PPT) legislation.

JOHN P. ZAGER, General Manager, Chevron Alaska, informed the Committee that his remarks would be accompanied by a power point presentation [copy on file] dated April 6, 2006.

[Note: Each page of Chevron's power point presentation contained two diagrams; thus each diagram is referenced by both a page number and its location at either the upper or lower portion of the page. For reference purposes, the Senate Finance Committee

Secretary made a notation on each page of the corresponding timestamp in which that page was addressed in this hearing. General descriptive information of each page is provided in the body of these minutes when feasible. A copy of the handout can be obtained by contacting the Legislative Research Library at (907)465-3808.]

9:07:17 AM

Page 1(lower diagram)

Chevron's Alaska Presence

- Current Asset base is formed by combination of heritage Chevron and Unocal assets.
  *Both companies have been active in Alaska for many years.
- 4th largest producer in state
- 3rd largest operator
- 382 employees or full time contractors
  *272 on the Kenai Peninsula
  *Payroll of > $45 million
- Key customers: Tesoro, Enstar, Chugach Electric, Agrium, Aurora
- Chevron is the only producer in the state with a relative balance of assets in Cook Inlet and on the North Slope
  *Both production streams are large enough to trigger PPT
- Chevron's Cook Inlet offshore assets are uniquely positioned to suffer from the proposed PPT

Mr. Zager overviewed Chevron's activities in the State. He noted that Chevron acquired Unocal's Alaska operations in August 2005. Both companies had conducted "downstream" activities in the State since the late 1800s. Exploration and production activities in Cook Inlet and on the North Slope have existed since oil and gas activities first occurred in the State. Chevron's employees were based in Anchorage and on the Kenai Peninsula.

Mr. Zager noted that Chevron provided oil and gas commodities to a variety of customers including the Tesoro refinery in Nikiski, the Enstar Natural Gas Company which supplies natural gas for

home heating, the Agrium fertilizer plant in Nikiski, and to Chugach Electric and Aurora Power.

Mr. Zager specified that Chevron's Alaska operations, which are fairly split between Cook Inlet and the North Slope, would be large enough "to trigger" the PPT. "Chevron's position in Cook Inlet, and Cook Inlet in general, is uniquely positioned to suffer under the proposed tax regime."

Page 2 (upper diagram)

Alaska North Slope Fields

[This map depicts the locations of the North Slope oil and gas producing fields that Chevron is involved in. Its Net Production on the North Slope is 16,000 Barrels of Oil Equivalent (BOE) per day.]

Mr. Zager characterized the company's holdings on the North Slope "as a mile wide and an inch deep" in that it had a one percent interest in the Alpine field, a five percent interest in the Greater Kuparuk field, a one percent interest in Prudhoe Bay, an 11 percent interest in the Endicott field, a 25 percent interest in Point Thomson, and a "50 percent owner/operator of the leases that are currently held" within the Arctic National Wildlife Refuge (ANWR). At a recent State lease sale, the company, which "was one of the most active bidders", spent approximately seven million dollars to acquire, for exploration purposes, a large parcel of acreage in an area south of the Greater Kuparuk region.

9:10:00 AM

Page 2 (lower diagram)

Cook Inlet - CVX Asset Description

[This map depicts the location of the company's assets in Cook Inlet.]

Cook Inlet Offshore:

- 3 fields (all op.)
- 10 Platforms
- 145 wells
- 2 onshore plants

- 42 mile PL
- 10,900 BOEPD

Cook Inlet Onshore:

- 8 fields (6 op.)
- 60 wells
- 2 gas storage fields
- WI% in 4 PLs
- 14,100 BOEPD

Net Production

Offshore Oil 6,300 BOPD
Gas 112 MMCFPD
25,000 BOEPD

Mr. Zager informed the Committee that Chevron was the largest offshore operator in Cook Inlet. It operated ten of the total 15 offshore platforms in Cook Inlet. Eight of the ten were in production, including the McCarthy River field which was the largest offshore field in Cook Inlet. Chevron held a 52 percent interest in that field. Overall, Chevron operated 72 percent of the oil production in Cook Inlet.

Mr. Zager stated that Chevron's gas activities in Cook Inlet included a 33 percent interest in the Beluga River field, a 100 percent interest in the Swanson River field which was the State's original oil field, a 40 percent interest in Ninilchik which was operated by Marathon Oil, and a 100 percent interest in Happy Valley. The Ninilchik and Happy Valley fields, which began producing after 2001, significantly increased gas production in Cook Inlet.

Page 3 (upper diagram)

Trading Bay Unit

[This was a collage of pictures depicting platforms and production facilities in the Trading Bay unit of Cook Inlet.]

Mr. Zager stated the purpose of this pictorial was to remind people that the operating environment in the Trading Bay unit could be as harsh as those on the North Slope. Facilities in

Trading Bay were approximately 40 years old; tremendous maintenance would be required to meet the safe operation and environmental protection levels sought by Chevron. Ice floes were environmental obstacles of concern.

Page 3 (upper diagram)

Cook Inlet Offshore

[This "production graph … depicts a history of offshore Cook Inlet production" from the early 1970s through 2006.]

Mr. Zager stated that the green line on the graph represented Cook Inlet oil production in barrels per day. The graph's vertical axis depicted oil volume in logarithmic scale units of 1,000, 10,000, 100,000 and 200,000. During the field's initial years, daily oil production was approximately 200,000 barrels. Production has since declined to approximately 12,000 barrels per day, and consequently, platforms are only producing a fraction of the production they were designed for.

Mr. Zager pointed out that the solid blue line in the box at the top of the diagram reflected "the water cut line" or percentage of water in the oil. Fluids produced during Cook Inlet's initial years were 100 percent oil and zero percent water. However, overtime, the ratio has changed to being 90 percent water and only ten percent oil even though the same amount of fluid were being produced. Operating costs incurred by the separating, treating, and disposing of that water oil are significantly affecting costs in Cook Inlet.

Page 4 (upper diagram)

Trading Bay Unit

[This diagram mirrors the information of the previous diagram, however, it is specific to the production and water cut line of the Trading Bay unit in Cook Inlet.]

Mr. Zager pointed out that at its peak the Trading Bay unit, which produced approximately 120,000 barrels per day, was the biggest producer in Cook Inlet. Its production has declined to approximately 8,000 barrels per day with a water cut of approximately 92 percent. This information would substantiate that Cook Inlet is "very challenged" in this phase of its life

cycle. The North Slope has been likened to being in the teenage or young adult years of its life cycle; while Cook Inlet "is already collecting social security".

Page 4 (lower diagram)

Cook Inlet Oil Production History

[This chart depicts the production history of Cook Inlet. Net production has declined from 12.7 million barrels in 1997 to 6.4 million in 2005.]

Mr. Zager reviewed the information.

9:14:33 AM

Page 5 (upper diagram)

Cook Inlet Offshore Oil

- Cook Inlet is very high cost
  * Direct lift cost $20 - $25 per BOE
  * Currently breakeven on Cash Flow @ ~ $30/BOE
  * Currently breakeven on Earnings @ ~ $40 - $45/BOE
  * Further production declines will raise breakeven prices
- Significant operational risks
  * Two platforms are currently shut-in
  * Must maintain critical mass of operations
- Cook Inlet Offshore cannot afford an additional tax burden

Mr. Zager summarized Chevron's Cook Inlet activities. The breakeven on cash flow point, which is calculated to be approximately $30 barrel of oil equivalent (BOE), was significantly higher than other production areas in the State. Since the goal of business is to make money, any tax, such as the PPT, that would affect a company's cash flow, would negatively impact the financial market's view of the business, as it would affect company earnings.

9:15:08 AM

Mr. Zager noted that the affect of the PPT on cash flow on Chevron's offshore Cook Inlet activities, in conjunction with

"the depreciation that's required in the earnings contract", would increase the breakeven amount on earnings to $40 to $45 dollars. While the company might choose not to abandon its Cook Inlet activities based on the earnings calculations, it would be a consideration in future investment decisions.

9:15:57 AM

Mr. Zager disclosed that activities on two of Chevron's Cook Inlet platforms were halted several years ago when oil prices were too low to support them. Other platforms might also have been "shut in" since then had oil prices not increased to their current levels.

Mr. Zager advised that platforms are "co-dependent on each other" because the costs of such things as onshore facilities, helicopters, and boats are shared between them. Consequently when one is shut down, costs are allocated to the remaining platforms. This could be likened to a "domino effect" in that closing one platform could lead to the closure of others.

9:16:46 AM

Mr. Zager contended "the Cook Inlet offshore could not afford an additional tax."

9:17:01 AM

Page 5 (lower diagram)

Chevron Cook Inlet Strategic Study

- August 10, 2005 Chevron acquires Unocal
  * Much speculation about Cook Inlet asset fit in Chevron Portfolio
- October 2005 - January 2006 - Strategy work completed
  * Determined that there are incremental investment opportunities in the Cook Inlet although they are in the lowest quartile of Chevron's investment portfolio, many projects did not make the cut
- February 2006 - Great news - announce decision that Chevron will retain all Cook Inlet assets with the intent to begin a multiyear investment program
  * Chevron will retain the current office locations

Mr. Zager stated that when Chevron acquired Unocal in August 2005 there was wide speculation that it would sell Unocal's Cook Inlet assets. After conducting an internal study, Chevron concluded 35 to 50 projects were infeasible and would not be undertaken; however, there were approximately 35 to 50 other "incremental investment opportunities in the Cook Inlet". Thus, Chevron and its partners planned to spend approximately $200 million during the next four years on off-shore oil projects.

9:18:18 AM

Mr. Zager continued that Chevron's announcement in February 2006 that it would retain all of its Cook Inlet assets was a shift from its initial business plan. The decision was also made to continue to conduct technical and other work in its offices in Kenai and Anchorage rather than to consolidate that work in Houston Texas and other oil centers. These decisions were good not only for company employees but also for the State.

9:19:02 AM

Page 6 (upper diagram)

Great news, so what's the problem?

- The Cook Inlet reinvestment program was evaluated using the current severance tax assumptions (zero severance tax)
- When modeled under the proposed 20/20 PPT the economics on some projects are degraded, some projects are improved, overall poorer economics for the program
  * Oil production taxes will go up dramatically
  * Will cause investment decision to be reconsidered
  * Higher taxes will cause less capital to be spent
  * Enhanced PPT terms could significantly expand the list of economic projects in the investment program and significantly extend the life of offshore oil production

Mr. Zager pointed out that these decisions were based upon the State's current tax regime, the Economic Limit Factor (ELF), which had basically lowered the severance tax on oil production in Cook Inlet to zero. When re-factoring Cook Inlet economics under the 20 tax rate and 20 percent credit (20/20) provisions in the original PPT bill (SB 305) proposed by the Governor, the

determination was that under its tax and incentive increases, the economics of the best of the 35 to 50 projects deemed feasible under ELF, "got poorer", as the tax on the those projects would increase. "Conversely, the projects that were the poorest in the portfolio actually got a little better because they weren't generating as much profit, but the investment incentives were helping them." Therefore, the PPT "tended to level the portfolio. But overall, the economics of the entire program went down".

Mr. Zager noted that the 25 percent tax and 20 percent credit (25/20) provisions proposed in the Senate resources committee substitute, CSSB 305(RES) [NOTE: this bill is referred to as CSSB 305 in these minutes] would incur "a more significant impact on degrading the value of that overall investment package". This increased tax would result in investment decisions being reconsidered. "Higher taxes would ultimately cause less investment to occur."

9:20:39 AM

Mr. Zager noted however that were the PPT terms "enhanced", some of the economics of the 35 to 50 projects which had initially not made the economic cutoff might improve. Numerous things could be affected by "the ratio of the tax to the credits".

9:21:10 AM

Co-Chair Green asked whether the term "enhanced PPT terms" would be further defined.

Mr. Zager replied in the affirmative. This term would be addressed later in the presentation.

9:21:22 AM

Page 6 (lower diagram)

Cook Inlet Production Forecast with Four-Year Capital Plan

[This graph depicts projected Cook Inlet oil and gas offshore production absent further investment. In this case, production would decline "fairly dramatically and by 2009, numerous offshore platforms might be shut down. This

information had also been presented to Chevron's senior management.]

Mr. Zager communicated that the goal of the four year investment program would be to stabilize production above 10,000 barrels per day for four years. The hope was that during this four-year timeframe, additional projects would be identified and investments in the field would continue for several more years.

9:22:25 AM

Page 7 (upper diagram)

Alaska Oil Production
January 2006
BOPD

[This bar graph compares oil production of Cook Inlet to that of the North Slope. January 2006 North Slope oil production exceeded 810,000 barrels of oil per day (BOPD) compared to approximately 18,000 BOPD in Cook Inlet.

Mr. Zager communicated that the purpose of this graph was to depict Cook Inlet "in perspective" to the North Slope. Cook Inlet's January 2006 oil production amounted to approximately two percent of the total oil production in the State. Thus, the impact of the PPT on the oil production of Cook Inlet would be minimal. Were the PPT a net profits tax, the North Slope production would be significantly more profitable than that of Cook Inlet.

Page 7 (lower diagram)

Alaska Oil Production
January 2006
BOEPD

[This chart compares the January 2006 barrels of oil equivalent per day (BOEPD) production for oil on the North Slope to that for both gas and oil in Cook Inlet.]

Mr. Zager stated that the annual average gas production in Cook Inlet would be slightly less than that depicted in the chart as January was one of its peak gas production months. Cook Inlets'

combined oil and gas 112,000 BOEPD would equate to approximately 12 percent of the State's total production "on a BOE basis".

Mr. Zager noted that gas produced in Cook Inlet was utilized to heat homes in Anchorage, to power area electrical utilities, and to support "commercial activities in South Central Alaska "including commercial users such as the liquefied natural gas (LNG) plant and the Agrium nitrogen fertilizer plant. In other words, there was a large "economic multiplier on this gas". "The economy of Alaska in its current form" was dependent on having gas support the economy of South Central.

9:24:29 AM

Page 8 (upper diagram)

Chevron Cook Inlet Government Take Allocation
Combined Oil and Gas Production

[This pie chart indicates the percentage breakout of the total government take on oil and gas production in Cook Inlet: federal tax seven percent; property tax 11 percent; production tax eight percent; and State royalties 74 percent.]

Mr. Zager cautioned that in the endeavor to increase the State's portion of the revenue, the "pie" size could shrink were decisions made to lower investments made in the State. This would be true not only for Cook Inlet, but possibly for every area of the State.

9:25:18 AM

Page 8 (lower diagram)

Reasons to Lower Taxes and Provide Incentives for Additional Cook Inlet Investment

- Gas is running out
  * Home heating, electrical generation, industrial consumption
  * Additional gas supply is critical to state's economy
  * Other options are much more expensive than Cook Inlet gas

- Production tax is a pass through on most utility contracts
  * Tax increase represents increase in gas price to consumers

- Oil redevelopment will maintain and add new jobs and will extend field life

- Cook Inlet competes for capital with other areas in North America, does not compete for global capital
  * Under PPT Alaska will have the worst fiscal terms in U.S.

Mr. Zager communicated that these reasons support the position that a lower tax should be applicable to operations in Cook Inlet as its operations differed from those on the North Slope. A lower tax would encourage additional investment there. Gas supplies in Cook Inlet were dwindling. This past winter, gas production could not meet the demand and the Agruim fertilizer plant was forced to close for ten days. The option of importing LNG would not only be expensive, but it would ship money out of the State rather than spending it in-state. Another expensive option would be to construct a spur line. He would not anticipate such lines being commercial projects. In other words the State would be required to build them as there would be no other alternative to get gas to Anchorage.

9:26:54 AM

Senator Bunde noted that companies typically do not absorb taxes; they instead pass that expense on to customers. To that point, he questioned why an increase in the tax would discourage a company from investing in the State.

Mr. Zager replied that the tax would be passed on to the consumer in the case of gas being sold to a gas utility. However, the majority of gas being produced in Cook Inlet was sold to commercial businesses. The production tax should be considered in the "broad" sense."

9:28:14 AM

Senator Stedman asked the reason that State corporate income tax had not reflected on the "Chevron Cook Inlet Government Take Allocation" pie chart. He concluded that the pie chart was

incomplete as two pieces were not reflected, those being "the net to the producer and the cost". While it was helpful to see "the breakdown of the government take numbers, it is not that meaningful" unless the whole pie was accounted for.

9:29:18 AM

Mr. Zager understood that corporate income tax was reflected in the federal tax percentage.

Senator Stedman advised that the State corporate income tax should also be reflected.

Mr. Zager agreed.

Senator Stedman understood pie chart reflected fiscal year 2005 numbers.

Mr. Zager affirmed.

9:30:02 AM

Senator Stedman communicated that industry numbers, as a whole, were available. It was understandable that Chevron would not desire to depict their individual percentage take.

Senator Stedman referred back to the Cook Inlet Offshore Oil information depicted on page 5 of the presentation. It could be interpreted from the current break even on earnings price of $40 and $45 BOE depicted on that page that any price "above that would create shareholder wealth".

Mr. Zager responded that could be the interpretation if shareholder wealth was defined "in the terms that you would have positive earnings per share".

Senator Stedman communicated that his question pertained to CSSB 305's Progressivity provision's "trigger point" which was set at a price of $40 per barrel. Two issues have been raised in regards to Progressivity. The industry's "fundamental" concern was to the impact the Progressivity element would have on their earnings as the desire would be to not "retard their growth of shareholder wealth". The second concern was to what price would be the appropriate trigger point. The current $40 barrel trigger point seemed to be "a reasonable arena". A trigger point of $40

to $45 would be more appropriate than a $30 or $35 per barrel price.

9:31:52 AM

Senator Dyson voiced appreciation for a separate discussion he had with Mr. Zager. To that point, he hoped Mr. Zager would address the effect of a recent Regulatory Commission of Alaska (RCA) "decision to let new gas float to the Henry Hub prices"; specifically how that decision might impact Chevron's exploration activities in Cook Inlet in light of the "present limited market" conditions that exist due to long term contracts that have been in play there.

9:32:40 AM

Mr. Zager first addressed "the impact of Henry Hub pricing". Some of the remarks made by the Governor Frank Murkowski Administration could be interpreted to imply that Cook Inlet gas was sold at Henry Hub prices; however, "that is categorically not true". Henry Hub prices today range upwards of seven dollars per 1,000 Cubic Feet of Natural Gas (MCF). Chevrons' contracted gas prices with Enstar Natural Gas Company of $6.19 MCF could be some of the highest priced gas in Cook Inlet. In 2005, approximately 20 percent of Chevron's gas was sold to Enstar at that price and the remaining 80 percent was sold to the Agruim fertilizer plant.

Mr. Zager disclosed that this year, Chevron would be selling approximately 50 percent of its Cook Inlet gas production to Enstar with the balance going to other markets including Agruim. Even though certain price information was privileged for competitive reasons, "it would be fair to say that the price to Agruim is far below seven dollars." The public record would reflect that in an Agruim recent request for proposals (RFP) for gas, they requested bids be in the range of three dollars an MCF. The price of longer term gas contracts with other utilities and the LNG plant vary. "This gas is certainly not being sold for seven dollars; it's far below that on an average basis."

9:34:49 AM

Mr. Zager stated that increased prices in the past several years could explain the increase in exploration that has occurred in Cook Inlet. Nonetheless, Cook Inlet could not attract investors'

capital unless prices were competitive with projects in the continental United States. "Costs are higher, conditions are rough, and "the exploration risk is every bit as tough as it is down south". Thus gas price levels of one, two, or three dollars would not attract investors. "That's an economic realty that's not too hard to understand."

Mr. Zager stated that another effect of long term contracts with set prices and "a certain market" for the gas was that it would provide a base upon which a producer might decide to spend money. However "on the flip side" it would make it difficult for companies without contracts or a selling market, to conduct exploration activities.

Mr. Zager stressed that the structure of Cook Inlet traditionally included long term contracts with utility companies as such agreements assured utilities "they would have gas out into the future". Were Cook Inlet prices to follow the Henry Hub spot price for gas, "prices would fluctuate much more wildly".

Mr. Zager also communicated that due to the affects of Hurricane Katrina in the Gulf of Mexico area of the country in 2005, "Cook Inlet consumers are now going to see a slight increase in their price". He reminded that Alaska could have its own set of natural disasters such as an earthquake that could affect production. Such things would affect a spot price system. Thus, long term contracts would provide "assurance over the long term that your prices are going to be relatively stable and predictable".

9:36:56 AM

Senator Dyson communicated that the purpose of his inquiry had been to alert fellow Legislators that, rather than the government take being the sole consideration, numerous factors were involved in Chevron's "economic analyses". Long term contracts would provide stability but would also limit what could be charged for a product as costs increased. Conversely, "new explorers who don’t have a guaranteed market to sell their gas into" would also have challenges.

Senator Dyson asked Chevron to provide a timeline as to when Cook Inlet's long term contracts would terminate. The subsequent

renegotiation process would reflect more current commodity values.

9:38:01 AM

Mr. Zager could speak to Chevron's contracts. Their current contract with Enstar was volume rather than time based. The volume for that contract was set at 450 billion cubic feet of natural gas (BCF); 50 BCF had been utilized to date. Were this volume trend to continue, the contract could be in effect for another 20 years. Furthermore, that contract was renewable. Chevron's relationship with Chugiak Electric historically allowed five-year contract extensions. Chugiak Electric recently issued an RFP for additional gas in approximately 2011. One aspect of the Cook Inlet gas scenario which dramatically differed from that of the Lower 48 was that a new gas discovery in the Lower 48 could typically be hooked up and sold within a few weeks or months. In addition, the volume could be sold at capacity at current market prices. Conversely, "a company could not fully "enjoy the upside" of a very large discovery in Cook Inlet, "because you can't put it to a market. You've got to wait and stretch it out over 20 years. So there's a lot of give and take that makes the Cook Inlet gas business very unique." It is the "only market constrained environment in North America". The irony is that we "are talking about shortages and market constraints" at the same time.

9:40:15 AM

Senator Dyson asked when the present operating permits associated with Agruim would terminate.

Mr. Zager understood Agrium was not operating under a permit process. Their operation would continue indefinitely provided they could receive sufficient quantities of gas at a price which would allow them to operate profitably. Their current contract with Chevron would terminate in October 2006. He understood Agruim was "soliciting additional gas for 2006 and 2007". Limited gas supplies prohibit Agruim's ability to sign long term contracts.

Senator Dyson asked whether any conditions in Agruim's RFP would restrain the price of gas. In addition, he asked for information regarding Chevron's plans regarding LNG exports.

Mr. Zager noted that Agruim's fertilizing products were sold on the world market and therefore their price must be competitive. That would affect the price they would be willing to pay for gas. Any contracts established with Agruim would be finalized after a negotiation process.

Mr. Zager stated that the LNG export question would be more appropriately addressed by John Barnes with Marathon Oil during his forthcoming presentation. That was "his field of business".

Senator Dyson acknowledged.

Mr. Zager refocused Committee attention to the "Reasons to Lower Taxes and Provide Incentives for Additional Cook Inlet Investment" information on page 8 of the presentation. Any increase in the production tax would be passed on to a utility company's consumers. Additional Cook Inlet oil development would maintain and add new jobs and thereby extend field life. This would be a major component of a healthy economy; particularly in the Kenai area.

Mr. Zager addressed the issue of how Alaska's proposed tax regime would affect its ability to compete in the global market for capital investment. While that was a consideration for activities on the North Slope, he was "absolutely sure" that this issue would not apply to Cook Inlet as Cook Inlet projects did not compete "for capital against a major international project, it's competing for capital against lower 48 businesses". Cook Inlet competed with "Wyoming, New Mexico, and Texas for the investment dollar".

Mr. Zager communicated that Chevrons' activities in Alaska report to the company's business component which "allocates capital to North America". The 25 percent PPT tax proposed in CSSB 305 would place Alaska and the Cook Inlet number one in having the "worst fiscal terms" in the United States. Alaska would also have "some of the most expensive and difficult operating conditions at the same time…" He cautioned against implementing any tax regime change in the Cook Inlet.

9:44:18 AM

Senator Hoffman asked the percent of gas produced in Cook Inlet which is used for residential rather than industrial consumption.

Mr. Zager recalled that approximately 50 to 60 percent of the gas produced in Cook Inlet is utilized to support industrial activities.

Senator Hoffman asked whether the expectation is that that percentage would remain constant as Cook Inlet production diminished, as depicted in the "Cook Inlet Production Forecast with Four Year Capital Plan" on page 6 of the presentation.

Mr. Zager communicated that the LNG and Agruim fertilizer plants would continue to utilize a significant percentage of the gas produced in Cook Inlet. Were one of those operations to cease, the percentage "would shift in favor of the utilities". Were both the LNG plant and Agruim to close, gas would be available for small commercial users or home usages.

Senator Hoffman asked the usage forecast for Agruim.

Mr. Zager clarified that the purpose of the Production Forecast chart on page 6 was to provide an offshore oil and gas production forecast. Continuing, he conveyed that the Agruim fertilizer plant could at peak capacity consume approximately 165 MCF per day. Current operations were at half capacity or 80 MCF per day. Half of the plant had been shut down since the fall of 2005. During cold winters, their usage was less than that as gas supplies were not available. The plant could not produce products for a period of ten days in January 2006 due to a lack of gas. He understood that Agruim's plan would be to run at half capacity as long as gas was available.

9:48:01 AM

Page 9 (upper diagram)

Cook Inlet Provisions to Date

- House Resources - None

- Senate Resources - "5,000 BOPD exemption"
  * Fails to provide any real help to Cook Inlet
  * May be a "small company provision", but is not a "Cook Inlet provision"

- Any "Cook Inlet Provision" should be specific to the Cook Inlet

- Reasons given not to consider Cook Inlet provision
  * Adds complication
    - Some additional complication to help Cook Inlet is justified
  * System must be uniform over entire state
    - We already have statutes that distinguish geographic areas

Mr. Zager addressed the PPT provisions included in the House and Senate committee substitutes. He noted that when Chevron became aware of the proposed PPT bill, it quickly alerted the Administration and the Legislature of issues pertinent to Cook Inlet. They were assured by those entities "that those differences were recognized" and would be reflected in the bill. Continuing, he noted that the House PPT committee substitute, CSHB 488(RES) [NOTE: This bill is referred to as CSHB 488 in these minutes] did not include any Cook Inlet provisions. CSSB 305 included a 5,000 barrel per day exemption, which had been referred to as the Cook Inlet exemption. However, he took exception to that because it would "fail to provide any real help" to Cook Inlet.

Mr. Zager noted the 5,000 barrel per day exemption could be regarded as "a small company provision but it is not a Cook Inlet provision". Any consideration of Cook Inlet should be specifically identified as such. This could include provisions pertinent to "anything south of the Brooks Range". He reiterated that the different environment in Cook Inlet should be considered.

Mr. Zager noted that several arguments against applying differing provisions to Cook Inlet had been presented. One position was that it would complicate the bill. While this might be true, the complications could be minimal. As a representative of his company and its employees, he would be uncomfortable communicating to those employees that the effort to address Cook Inlet activities was halted because it proved to be "too complicated". This would not be accepted as "a good enough reason" not to address it.

Mr. Zager communicated another argument being made was that a single tax system should apply to the entire State. Even

"outside consultants" had voiced how difficult it was to apply "a one size fits all system" to Alaska. Cook Inlet was a perfect example of that. Thus, the argument in favor of a single tax structure would also be unacceptable. Geographic differences are already recognized in State Statute as evidenced by such things as royalty reductions and expiration incentives pertinent to oil and gas activity in Cook Inlet.

9:50:39 AM

Senator Stedman communicated that this issue had been discussed in the Senate Resources Committee and an amendment containing a tax formula had been adopted as a result.

Mr. Zager noted that the Senate Resources Committee amendment formula would be discussed in the next diagram.

Senator Stedman asked that in the discussion of that diagram, Mr. Zager specifically suggest a solution to the issue.

9:51:26 AM

Page 9 (lower diagram)

Senate CS - BOE Exempted

[This chart depicts how the producing companies in Cook Inlet would be affected by the up to 5,000 barrels per day exemption with a 0.2 modifier as proposed in CSSB 305 and a 0.1 modifier as initially considered by the Senate Resources Committee. The Exemption BOEPD is presented on the vertical axis and the Production BOEPD is reflected on the horizontal axis.]

Mr. Zager explained the chart. The reddish-purple line at the top left of the chart reflected the up to 5,000 barrel per day exemption with the 0.1 modifier initially proposed by the Senate Resources Committee. Under this scenario, the exemption would be zero for a company with a 55,000 barrel Average Daily Production (ADP). Chevron with a statewide production of approximately 40,000 barrels would have received a 187 barrel per day credit under that formula. That would not have been an incentive. He had assumed, when told the 0.1 formula would be modified, that the modifications "would be favorable" to Chevron. However, the modification was to change the modifier from 0.1 to 0.2. The

affect of that change was reflected as the blue line on the chart. The 0.2 modifier served to zero the incentive out at a 30,000 ADP rather than the 55,000 ADP under the 0.1 modifier. In addition, Chevron's 187 barrel credit would change to zero.

Mr. Zager noted that the impact of the formula on all producing companies in Cook Inlet was depicted on the graph. The only two companies that would receive the full benefit of the credit would be Aurora and XTO, which each produced less than 5,000 barrels ADP. The company, Forest, which produced approximately 7,000 barrels ADP would receive slightly less credits than Aurora and XTO. Marathon Oil with a daily production of approximately 30,000 barrels ADP would have had a 500 barrel per day credit under the 0.1 formula and less than a 100 barrel per day credit under the 0.2 formula. Chevron, Exxon, and ConocoPhillips would receive "no deductions at all" under the 0.2 formula.

Mr. Zager pointed out that "94 percent of Cook Inlet production is operated by companies that are not eligible for a significant exemption. So, to say that this is a Cook Inlet exemption" would be "stretching quite a bit".

Page 10 (upper diagram)

Senate Resources CS - The unique value and challenged position of the Cook Inlet is not adequately addressed

- Revisions as proposed in the CS lowers the economics of capital investments in the Cook Inlet
  - Puts Chevron's four year capital program in jeopardy
  - At the very least, increased taxes will lower investment
  - Without capital McArthur River Field is gone in ~ 4 years
  - Critical mass for Cook Inlet oil industry is gone

Mr. Zager was disappointed that the House or Senate committee substitutes did not really contain provisions that would address the situation in Cook Inlet "in a meaningful way". The PPT would cause Chevron "to re-examine its capital investment program, and at the very least, the increased taxes will put negative pressure on the amount of capital that's spent. Without additional capital, the McCarthy River Field" would likely shut

down in approximately four years. Its closure would eliminate a "critical mass" that is supporting the Cook Inlet industry oil business.

Page 10 (lower diagram)

Recommendation on Cook Inlet

Consider the following options:

- Carve out Cook Inlet
  - o Leave under current system
- Apply PPT methodology to keep taxes near current levels
  - o Adjust tax rates lower (5%)
  - o Retain overall incentive rates (20%)

Mr. Zager pointed out that these two recommendations could address the Cook Inlet dilemma. Eliminating Cook Inlet from the provisions of the PPT and leaving the current structure in place would negate increasing taxes in Cook Inlet, and operations would continue as long as they were economically viable. However, continuing the status quo would not incentivize investment which he believed would be "warranted given the very critical nature of the gas supply in Cook Inlet".

9:55:06 AM

Mr. Zager stated that the other recommendation would be to apply the PPT methodology on a statewide basis, but "lower the front end tax rate to the point where the tax in Cook Inlet would be more or less neutral on the current taxes" being paid. That would equate to approximately a five percent tax rate. Adding this minor complication would "solve a lot of the problems" and retain "the incentives available to encourage additional exploration and development".

Co-Chair Green asked whether the second recommendation had been embodied in any version of a Senate Resources PPT committee substitute.

Mr. Zager replied "no".

9:56:12 AM

Senator Dyson recalled previous [unspecified] testimony before the Committee which expressed that the companies operating in Cook Inlet should like any of the PPT versions because of the "credits or incentives for exploration and development" they provided. He asked Mr. Zager to comment on this as a separate issue from the tax rate.

Mr. Zager stated that "the investment incentives are a positive" if viewed "in isolation … or as part of an exploration program, but we all know there's no free lunch. If the State's getting more, the companies are getting less". While the upfront risk to a company would be lowered, the PPT would "take out the profits on the backside when you're successful". Thus the returns on a project would be lower, "although in an NPV [Net Present Value] sense, the projects are getting smaller" in that a company would be required to invest less capital upfront "because the State's subsidizing and you are getting less on the back side cause the State's taking more".

Mr. Zager also noted that "some of the numbers in terms of return on investment may not change significantly: on some projects they may get better, on some they'll get worse, but overall the projects are getting smaller on a NPV basis."

Mr. Zager communicated that the companies in this industry "are in the risk business. They are capable of funding the projects as long as they receive the full exposure to the results". Thus, "incentives would be an important part of it certainly, when you couple it with the increased taxes, but incentives alone can't compensate for taking the tax rate higher".

Senator Dyson understood however, that under any of the PPT versions being discussed, a company would be able "to write off much of its unsuccessful exploration costs". They were unable to do that under the current tax structure.

Mr. Zager affirmed that was correct. "In terms of investment incentives, allowing all capital to be counted as a credit is a vast improvement over the current system" which only provided advantages for successful exploration wells. Between 70 and 90 percent of the time, exploration efforts fail, and thus, no investment incentive was provided currently on the exploration side.

9:59:26 AM

Page 11 (upper diagram)

General Comments on CS

- 25% tax rate is too high and will discourage investment, a return to 20% overall rate is in the best interest of Alaska
- Prefer $12 million credit to 5,000 BOEPD exemption
- Transition capital must be earned again on 2:1 basis
  - Prefer original proposal, this is better than nothing, suggest extending time period to 10 years
- April 1, commencement rate, not practical, punitive penalty and interest rate
- Progressivity - do not support - taking away the "windfalls", no matter how you couch it, lowers expected value to investors, and therefore will lower overall investments

Mr. Zager communicated that, at this point, he would address the CSSB 305 PPT bill "in general" rather than continuing to dwell on its impact on Cook Inlet.

Mr. Zager deemed the 25 percent tax rate to be "too high". The company's analysis indicated that a 25/20 rate would reduce "the overall economics of a project". CSHB 488's PPT proposal allowing for a $12 million credit would be preferred over the 5,000 BOEPD in CSSB 305. Since the tax would be on profits, which was dollars, it would "make sense" to include "an exemption based on dollars and not on barrels". The 5,000 BOEPD "exemption at high prices could be worth significantly more" to "a highly profitable" company; conversely, it would "be worth a lot less" to a company that is not highly profitable.

Mr. Zager addressed the transition capital provision included in CSSB 305 which would be earned on a two to one basis. He preferred the provisions in SB 305 which "recognized past investments". While acknowledging that the inclusion of the two for one provision would be preferable to that of eliminating it

entirely, he communicated that the two for one "step up in spending to recover your money is pretty darn aggressive". Accepting the two for one ratio would be easier were the time period increased to ten years, for, "by the time you want to invest and get exploration going, ten years would, for most people, … still represent a very healthy investment program especially" in consideration of the fact that any year in which oil prices fell below $40 would be ineligible.

Mr. Zager stated that a significant tax increase would be experienced were the retroactive April first effective date adopted. He noted that British Petroleum addressed this issue at great length during it April fifth presentation to the Committee. He deemed "the nature of this penalty when we're kinda guessing what our taxes are as we go along… is a bit heavy handed".

10:01:51 AM

Page 11 (lower diagram)

Alternate Progressivity (Windfall Profit) Provision

- Reason for the state to support progressivity
  - To get a "fair share" when there is a price run up accompanied by large profits
  - NOT to raise taxes if the price increase is gradual over time and is accompanied by increases in costs and thus not accompanied by increased profits - NOT a creeping tax increase
- Problems with progressivity as currently proposed
  - "Trigger" price tied to WTI (or Henry Hub) is not inflated
    - Over time prices and costs will rise - 30 years is a long time
  - "High Cost" oil will be produced in increasing quantities
  - Over the long term a fixed trigger price will not work as intended
- Consider changing the trigger from commodity price to a "net profits" trigger

Mr. Zager did not support the inclusion of the Progressivity provision in the bill. Testimony had been provided regarding the inherent risks companies face when investing in this industry. Risks were weighed against a distribution of outcomes. A "very good outcome" would be when a company discovered a lot of oil and was able to sell it at a high price. A variety of outcomes were factored into a company's investment decisions. Thus, when you "start clipping out the high part of the distributions, it does affect in a significant way your attitudes towards the investments." The inclusion of progressivity in the PPT was not welcome, "because taking away those windfalls is going to affect people's investment decisions. We're in the risk business and we're happy to take those risks as long as we get the full distribution of the outcomes. So, having said that, I'm pretty concerned" about the current progressivity discussion.

To that point, Mr. Zager proposed a different way to consider progressivity, especially its trigger point. He understood that the Progressivity provision was included to assure that the State would "get a fair share when" prices increases were accompanied by large profits. An example of this would be when oil prices increased to $100, but costs to the industry did not increase. This would generate a significant level of profit for the company. The purpose of progressivity "was not to raise taxes" when price increases were "gradual over a long period of time" and were simultaneously accompanied by an increase in costs. In other words progressivity was not meant "to be a creeping tax increase that is triggered by inflationary pressures". Its intent was "to capture windfall profits".

Mr. Zager pointed out that a significant amount of discussion has occurred in regards to what should be the appropriate trigger for the Progressivity factor. To date, the trigger options that have discussed have included such things as West Texas Intermediate (WTI) oil prices, Henry Hub prices, ANS prices, or wellhead prices. His concern was that whatever option was identified as the trigger "would be locked in for 30 years". No one could predict what might occur during that timeframe. In the 1960s, a price of five dollars might have been considered the appropriate trigger point for windfall profits. A price indexed for inflation would include issues regarding what would be considered the appropriate inflation marker. For example, utilizing the national Gross Domestic Product (GDP) might not be appropriate because it "is not necessarily related to oil prices".

Mr. Zager identified another issue pertinent to a 30 year time. That would be that "lower and lower quality prospects and higher and higher costs" would come into play. "Higher oil prices may not be connected to higher profitability….Over the long term, a fixed price trigger is a disaster waiting to happen".

10:05:11 AM

Senator Bunde concluded therefore that a company in this risk industry would be opposed to Progressivity because the company taking "the risk should get the profit". However, a large portion of the PPT delved into reducing the risks investors would be taking. While the industry felt that 30 years was a long time, it was asking the State to provide "30 years of certainty". To that point, he stated that "when you're in the risk business, certainty costs money." He identified that as being "one of the arguments for Progressivity: that if you're going to get some bottom line certainty, there has to be some flexibility for windfall".

Senator Bunde found the trigger point information very interesting and worthy of further discussion. However, he asked the industry to consider the "certainty" factor when analyzing Progressivity.

Mr. Zager responded, "in general it's hard to disagree that certainty will cost some money if that's what's being requested".

10:06:30 AM

Senator Stedman corrected some information in Chevron's presentation: the transition language included in CSSB 305 specified a five-year look-back and "a two for one credit going forward, but there's no $40 price on it below which you can't use it". That provision was in SB 305, but was not included in CSSB 305.

Mr. Zager appreciated the clarifications.

Senator Stedman voiced discomfort with applying an "indexation" element to Progressivity, as there were "inherent problems" with that process. The State's current six billion dollar spending limit was an example of those "inherent problems". The problem

of utilizing indexation in the PPT would be further compounded since "oil prices and inflation are lowly correlated".

Senator Stedman expressed, however, that Progressivity was included in the PPT "to maintain" the "sharing relationship" between the government take, specifically that of the State and the industry as oil "prices advance forward from $60 to $80 to $100 a barrel". Absent the Progressivity factor, the State would be "leveraged" in that its percent of the pie would diminish and the producers' would increase. "And they're already in the area where they're enhancing shareholder wealth". That share would continue to be "magnified". Thus, the State should endeavor "to neutralize that so we aren't leveraged".

Senator Stedman continued that a mechanism must be developed to maintain that sharing relationship balance over time. Otherwise, the State could find itself in "the disadvantaged" position it is in today under ELF. While he could appreciate the industry's position against including a Progressivity factor in the PPT, "it's not in the best interest of the State to remove it".

Mr. Zager acknowledged Senator Stedman's position, but expressed that, even though the industry does not support the inclusion of a Progressivity element in the PPT, it recognized that its inclusion might be inevitable. In consideration of that, the industry would like to suggest implementing "net profits" as "an alternate" Progressivity trigger.

10:09:34 AM

Page 12 (upper diagram)

How would a "net profits" trigger work?

- Each company already will calculate a "net profits" every month
  - o Divide monthly net profits by production to get a "net profits/boe"

- Set trigger point and escalation factor based on "net profits/boe"

  - o Suggest $50/boe net profits trigger and 2.0% for each $10 increase in profits
  - o Minimum general rate of 20% tax on net profit

- Maximum general rate of 30% tax on net profit

- Advantages

  - Self correcting for inflation, costs, commodity, high cost production (avoid discussion of WTI, ANS, Henry Hub, well head etc)
  - Fully captures the "windfall" upside, without creating unintended consequences
  - System is fair, since taxes and progressivity will only be attached to actual company profits

Mr. Zager explained that the "net profits" trigger proposal would be preferred to a WTI trigger. Companies routinely calculate their net profits on a monthly basis. That figure would be divided by the company's production level to achieve a number referred to as the "net profits/BOE". Thus, a specified "net profits" level could replace language the WIT Progressivity trigger price in CSSB 305. "The beauty of this system is that it is self-correcting." For example, if the WTI price increased but costs did not, companies would experience a direct increase in profits. The tax would be triggered at a higher ratio. However, in 20 years, for example, were oil prices to increase to $100 per barrel and costs to increase from $20 per barrel to $80 a barrel, a company would not experience an increase in profits.

Mr. Zager also noted that the net profits trigger could be appropriately applied to a company conducting a heavy oil project whose costs might be double or triple those of light oil projects. The net profits trigger would also be appropriate for gas projects. Progressivity could be applied to any company regardless of whether they were in the gas, heavy oil or light oil industry, when their profitability level met the progressivity component qualifications.

10:12:01 AM

Co-Chair Green asked whether the calculation formula currently utilized to determine a company's net profits could be used or whether it would require changes.

Mr. Zager anticipated "that the exact same net profits" formula currently utilized to pay the industry net profits tax would be used.

Senator Stedman clarified that while the WTI price had initially been considered as the trigger for Progressivity by the Senate Resources Committee, the Committee ultimately decided to specify ANS West Coast as the trigger even though WTI "is more actively traded and less likely to be manipulated because it is a very active market and there is a lot of financial derivatives off of it". ANS "is basically Alaska oil at Los Angeles".

Mr. Zager stated he had used WTI solely as an example, as various Progressivity benchmarks had been considered. CSSB 488 specified Henry Hub as the benchmark for gas Progressivity. He reiterated that Cook Inlet companies were concerned about their "contracts that are fixed over a number of years being connected to Henry Hub".

Mr. Zager suggested the benchmark for the net profits Progressivity tax be $50 a barrel, with a minimum tax rate of 20 percent. Each ten dollar increase in profits could subject the rate to an additional two percent tax, with a maximum tax rate of 30 percent. This maximum tax level "is an important feature" for it would provide "investors some assurance that at least a bigger percent of the upside would remain … and business could be planned a little better for sharing in the increased profits between those ranges".

Mr. Zager summarized the advantages provided by a net profits trigger. "It would be self correcting for inflation, costs, what commodity you're producing, if you decide to get into higher cost type of production. We don't know what could be coming out there in the future". Basing the trigger on net profits would be easier to implement than WTI, ANS, Henry Hub, or wellhead prices. It would also "fully capture the windfall upside without creating unintended consequences of simply increasing taxes because price of oil has gone up" without being connected to increased profitability. This would be a "fair system since taxes and Progressivity will only be attached to actual profits".

Page 12 (lower diagram)

Examples of "Net Profits" Trigger

1. Windfall Case - Price double - Costs fixed		
Average Rev/BOE	60.00	110.00

Expense Per BOE	7.00	7.00
Capital Per BOE (incl. Cap. Credit)	3.00	3.00
Net "Profit" per BOE	50.00	100.00
PPT%	20.0%	30.0%
Actual Tax per BOE	10.00 $	30.00

2. Increase Profits - Price double- Costs up

Average Rev/BOE	60.00	110.00
Expense Per BOE	7.00	37.00
Capital Per BOE (incl. Cap. Credit)	3.00	3.00
Net "Profit" per BOE	50.00	70.00
PPT%	20.0%	24.0%
Actual Tax per BOE	10.00 $	16.80

3. Constant Profit - Price double - Costs keep pace

Average Rev/BOE	60.00	110.00
Expense Per BOE	7.00	57.00
Capital Per BOE (incl. Cap. Credit)	3.00	3.00
Net "Profit" per BOE	50.00	50.00
PPT%	20.0%	20.0%
Actual Tax per BOE	10.00 $	10.00

Mr. Zager reviewed three examples of how the suggested net profits Progressivity trigger would work. Example 1 would reflect a "true windfall profits" scenario with barrel prices increasing from $60 to $110. Fixed costs remained at ten dollars. $60 less the ten dollars of fixed costs would result in a net profit of $50. That would be subject to a 20 percent tax equating to ten dollars. A $110 barrel price less the ten dollars in fixed costs would result in a net profit of $100. This would be subject to a maximum 30 percent tax rate for an actual BOE tax of $30.

Mr. Zager stated that Example 2 would reflect a situation in which both the BOE price and expenses increased: BOE prices increased from $60 to $110 and expenses increased from seven dollars to $37. Capital investment remained constant at three dollars BOE. The next profit would be $70 BOE at the $110 price. This would qualify for a 24 percent PPT tax equating to $16.80 BOE.

Mr. Zager noted that Example 3 would reflect a situation in which both BOE prices and expenses significantly increased in alignment, resulting in a constant net profit level. Absent the net profits Progressivity approach, and were the PPT "tied only to oil" prices, a company's profitability would not increase, but the tax percent could increase "dramatically". That would be "fundamentally unfair because it's a net profits tax; the escalator should be tied to tax and not just to gross revenue".

10:18:24 AM

Senator Stedman assured that this issue was being addressed. While Mr. Zager had presented advantages of basing the Progressivity trigger on net profits, the advantage of it being based on gross should also be discussed. One was "that it's less likely to be manipulated"; it would be "un-impacted by moving expenditures" or credits. "Credits can be triggered, if they're accumulated, when they want to be triggered". There was also the potential impact of expenditures "moving from quarter to quarter, month to month". That would affect the bottom line. It was "a generally accepted concept" that "a corporation would try to minimize their tax and maximize their profit". A progressivity trigger based on gross dollars would eliminate the possibility of such manipulation.

Senator Stedman stated the reason the Progressivity trigger was initially based on WTI oil prices instead of ANS West Coast was that placing it on a more active market would remove possible manipulations. The historical two dollar difference between the two markets would be accounted for when setting the trigger price. A third "benefit" of basing the trigger on the gross was that it would be "much more predictable" in the effort of keeping the government share percentage relatively constant at various price ranges.

10:20:32 AM

Senator Stedman acknowledged there being advantages and disadvantages to both approaches; however, it would be in the "State's best interest" to base the trigger on gross rather than net profits. The trigger and the slope of the tax could be adjusted to address concerns. The State must avoid a situation in which "expenditures and credits could be moved around to try to impact" the tax rate. The effort should be to hold the government's take constant.

Senator Stedman reminded the Committee that the effect of the credits on the tax was unknown. He shared that Dr. Pedro van Meurs, an economic consultant to the Administration, had communicated to him his concern that the impact of the credits on the State's revenue "could be substantial". Economic analyses should be conducted to determine how the State's revenue would be affected by a net profits trigger. An in-depth discussion with State economic consultants should occur before any changes were considered in this regard as it was a complex issue and the impacts might not be "readily apparent".

10:21:59 AM

Senator Hoffman voiced concern that under Example 3 the risk to the State could increase were expenses to exceed beyond $57 BOE to approximately $70 BOE. At a 20 percent tax rate, the actual amount of revenue the State would receive could be zero under the net profits Progressivity formula.

Mr. Zager expressed that that scenario could occur under the PPT regardless of the Progressivity formula. He clarified that the net profits methodology being proposed was specific "to the Progressivity feature of the formula". Were a company's profits to reduce to zero, the State's take would also be zero. His effort was to address "how to capture this windfall" and what would be "the fairest way to implement the windfall trigger". There would be problems were the trigger simply "pegged to something like WTI" without being connected to profitability; "this is a tax on profits, it's not a tax on gross revenue".

10:23:26 AM

Senator Stedman qualified that CSSB 305 would implement a 25 percent tax rate rather than the 20 percent rate depicted in the presentation. Nonetheless, the concept being discussed was valid. The details could be addressed later.

10:24:00 AM

Senator Stedman also noted that "imbedded" in the CSSB 305 Progressivity formula, "is the impact of having it deductible by one less the tax rate". In effect, a company "would get a tax deduction indirectly, but clearly it is a tax on gross". It was "intentionally set that way".

Co-Chair Green understood the State currently recognized net profits as the basis for determining a business's State corporate tax. Thus, basing the Progressivity feature on net profits would not be "a new contrived formula; it's an accepted calculation".

Senator Stedman affirmed; however, expressed that introducing the credit mechanism into the tax formula would alter things as a company with credits "could move its income around". Any proposal to incorporate a net profits Progressivity trigger must be first thoroughly discussed with the State's consultants. He maintained his position that it would be in the State's best interest to base the Progressivity feature on gross revenue. Were it determined in the future that it was a deterrent "to getting the commodity out of the ground", it could be revisited and adjusted. "It would be virtually impossible to come up with something that would last the test of time without some minor adjustments; otherwise we're going to have our necks stuck out ten miles."

10:26:32 AM

Senator Olson observed that, as a businessman, he had hired accountants to deal with the complications accompanying such things as depreciation schedules, deductions, and credits. Manipulation of numbers could occur in the endeavor to avoid paying taxes. Thus, he was uncomfortable with the proposal to utilize net profits in the Progressivity component.

10:27:03 AM

Mr. Zager reiterated that the PPT was a net profits tax. Therefore, proposing to base the Progressivity trigger on net profits "is no more subject to manipulation than the basic monthly tax payment. Whatever it is, it's going to be highly scrutinized." He questioned how this could "add another layer of manipulation" since the trigger would be based on an already agreed upon level of tax owed by a company. A net profits trigger formula would recognize each month that, when a company was highly profitable, the State could take a higher percent of the profits. Conversely it would recognize when a company's "profits didn't go up cause your costs went up as much as your revenue, and therefore you shouldn't be subject to a higher percentage tax".

Senator Stedman referred the Committee to an April 5, 2006 presentation [NOTE: See April 5, 2006 House Finance Committee minutes on HB 488] in which Barry Pulliam and Dr. Anthony Finizza, consultants with Econ Research, the economic research and consulting firm hired by the Administration, reviewed a chart [copy not provided] which depicted their estimates of how the credits in the PPT would the impact the State's revenue at oil prices ranging from $25 to $70 as affected by the tax rates proposed in SB 305, CSSB 305 and CSHB 488. The credits proposed in the bill would decrease the tax rates. Decisions must be made carefully as numerous things must be considered in the decision making process. He suggested that Econ One present their findings in regards to additional investment in the State would affect the effective tax rate under the provisions of CSSB 305.

10:29:51 AM

Mr. Zager determined that "having a lot of credits to deal with would be a good thing", as that would indicate "a lot of investment" was occurring. It would equate to "growing the pie and that royalty piece over there's getting a lot bigger". Thus, he agreed with Senator Stedman "that the credits can have a significant affect here, but it could only be a positive affect from the State's perspective if we're investing so much money that our severance tax is going down". There were tradeoffs. There was danger in looking at pieces of the proposal in isolation.

Co-Chair Green interjected to note that the Committee would meet until 11:00 AM and then reconvene at approximately 3:00 PM.

10:30:54 AM

General Comments on CS

- Debate between "get it now" and "grow the pie"
  - "Get it now" option will balloon short term revenue creating a state windfall that must be well managed
  - "Grow the pie" option will create long term opportunities for investors and for Alaska
  - I am optimistic about the ingenuity and technology available in out industry and the people of Alaska to greatly extend oil production for the next generation

- Consultants will one day leave and we will be left to deal with our decisions
  - First you vote on behalf of the people of Alaska
  - Then over the coming years investors vote with their dollars
    - Original industry support was astounding
    - However, Investors big and small, old and new, are now saying that the Senate Resources CS structure will discourage investment in Alaska

Mr. Zager overviewed the information. Chevron believed it would be in the best interests of the State to "grow the pie".

10:31:13 AM

Summary Comments on CS

- Chevron cannot support the Senate Resources CS in its current form
- Urge return to original PPT terms, while inserting a 5/20 Cook Inlet provision
- Recommend inclusion of an additional capital credit for heavy oil or tertiary recovery (CO2) projects statewide
- Chevron has been in Alaska for many years and intends to continue an active exploration and production operation in the state if a sound and stable fiscal regime can be offered

Mr. Zager shared that Chevron did not support the 25 percent tax rate proposed in CSSB 305 and urged the Committee to further the provisions of SB 305 with the inclusion of a five percent tax rate and 20 percent credit on Cook Inlet activities. Additional credits for heavy oil and other tertiary projects should also be added to the bill. Chevron hoped to continue its operations in Alaska.

10:31:59 AM

Senator Bunde asked whether Chevron desired the five percent tax/20 percent credit provisions to apply solely to existing activity in Cook Inlet or to both existing and new activity there.

Mr. Zager expressed the desire that the five percent tax/20 percent credit apply uniformly to all activity in Cook Inlet. This would encourage more activity. A higher tax rate would be a disincentive. In addition, the five percent tax/20 percent credit would "encourage investors and owners to try new things" they might not try otherwise.

10:32:57 AM

Senator Hoffman asked whether the application of a five percent tax/20 percent credit should be extended to other new fields in the State including those in the Tanana Basin and Bristol Bay.

Mr. Zager thought this should be a policy call of the State. His "immediate interest" was to Cook Inlet. However, other "virgin basins" such as the Nenana Basin near Fairbanks could be included as it was a "challenged" field. At this time, he had "no opinion" on how the State should address Bristol Bay.

10:33:37 AM

Co-Chair Wilken appreciated both the presentation and Chevron's recognition and assistance in addressing some of the decisions the Committee must make.

Co-Chair Wilken asked whether, in an effort to "realize economies of scale" that would benefit the various entities, Chevron had long term operating agreements with, for example, Marathon Oil Company, Exxon, ConocoPhillips, and Forest in its exploration, production, and operation activities in Cook Inlet and on the North Slope.

Mr. Zager responded that Chevron had numerous agreements in Cook Inlet. Each field or recognized government unit that had more than one owner would "be governed by a joint operating agreement". Some agreements had been in effect since the 1960s. However, such agreements were primarily "confined to the operations within the given unit" such as the Trading Bay Unit or the Granite Point Unit. "Specific rules that govern who does what, who pays what, etc. etc." On occasion, Area of Mutual Interest agreements (AMIs), which are "fairly transient, shorter term, come and go as companies see fit", were made for "larger areas usually outside of existing units." They were typically exploration agreements in which parties "agree to work together

to explore". Chevron was not currently involved in any "significant" AMI outside of its current units. He was aware however that other companies had AMIs to conduct work in Cook Inlet.

Co-Chair Wilken shared the basis for his question: he was troubled about "this notion of a 30 year" or longer commitment without a re-opener. "It would seem to me that those that operate in unit agreements and AMIs are fairly comfortable with re-openers if the terms of the re-opener are agreed to" before the agreement was signed. He asked whether he was drawing the wrong analogy between unit agreements and AMIs and how the oil companies talk and interact with each other. "Why that wouldn't be applicable to the State and the producers entering into re-openers given we struggled through the terms for those?" The point was that since the industry routinely operated in this matter, it would not be "foreign territory".

10:36:48 AM

Mr. Zager was unaware of any re-openers in the industry's joint operating agreements (JOAs). Issues might become contentious were one party to feel that a JOA was no longer working. Unfortunately when a contract agreed upon in the 1960s, for example, was no longer working, areas of conflict and possibly litigation could develop. A common term used in the 1960s would have been "how much money can you spend without your partner's approval". While that amount might have been $10,000 in the 1960s, it would not accomplish anything substantial today. Such things had been addressed from time to time in recognition that changes must be made. Difficulties would arise were partners to disagree on the changes.

Co-Chair Wilken appreciated this insight as it helped clarify the re-opener relationship in terms of the industry and to the State.

There being no further questions, Mr. Zager concluded his presentation.

AT EASE 10:38:19 AM / 10:43:44 AM

State of Alaska Petroleum Production Tax
Testimony to Senate Finance Committee
(SB 305 RES)

John A Barnes, Marathon
April 6, 2006

[Note: The pages in this document are not numbered; therefore, for reference purposes, the Senate Finance Committee Secretary made a notation on each page of the corresponding timestamp in which that page was addressed in this hearing. General descriptive information of each page is provided in the body of these minutes when feasible. A copy of the handout can be obtained by contacting the Legislative Research Library at (907)465-3808.]

10:43:49 AM

JOHN A BARNES, Production Manager, Marathon Oil Company, informed the Committee that Marathon's activity in the State was limited to natural gas production in Cook Inlet. The company had operated in the State for more than 50 years. He appreciated this opportunity to present Marathon's perspectives on CSSB 305. He also noted that the information provided by Chevron was very informative.

Mr. Barnes stressed it was impossible to compare the PPT's impact on gas production in Cook Inlet to other global markets, as Cook Inlet does not have "world class exploration potential". Cook Inlet was "disadvantaged by price" and the future projections of its "types of reserves and resources".

10:45:05 AM

Marathon Testimony - Alaska PPT
Impact of SB 305(RES) on Alaska Natural Gas

- Cook inlet Natural Gas summary: Pre PPT
- Financial Impacts of PPT
- Consequences of PPT
- What is Needed

Mr. Barnes stated that these four issues would be the focus of this presentation (copy on file).

10:45:24 AM

Cook Inlet Natural Gas Summary: Pre PPT

- Declining reserves and production rate.
- High operating and capital costs as compared to lower 48 natural gas provinces.
- Difficult permitting and regulatory arena.
- Need for additional exploration and development to moderate price increase to consumers and to continue to provide industrial feedstock.
- Historic price differential to Henry Hub.

Mr. Barnes reviewed existing conditions in Cook Inlet.

10:46:09 AM

Mr. Barnes shared some "Cook Inlet Areawide Lease sale Results" for the years 2000 to 2004 which were compiled by the Division of Oil and Gas, Alaska Department of Natural Resources. The information could be summarized as "encouragement for the Inlet". He remarked favorably about the State's lease sale program conducted in Cook Inlet. The number of tracts sold increased from 27 in the year 2000 to 72 in 2004. In addition, the increase in the number of multiple bids on tracts would indicate there being increased interest in the development of gas in the Cook Inlet.

10:46:45 AM

Timeline of Cook Inlet Exploration

[This graph depicts a timeline of the exploration activities in Cook Inlet between 1950 and 2004. Exploration activities peaked in the late 1960s and early 1970s. Exploration activities declined and remained steady thereafter. Increased exploration activities began to occur shortly after the year 2000.]

Mr. Barnes noted that the State experienced a boom in exploration activities in the 1960s and 1970s. At that time, Cook Inlet "was truly a world class opportunity". Lean years followed that boom. An increase in gas exploration wells drilled has occurred during the last several years. While "seven wells is a pretty good step", it was not enough. It was however, a good indicator that some of the incentives and lease programs the State implemented have been beneficial. Higher gas sales prices also assisted in increasing well activity.

10:47:27 AM

Mr. Barnes stated that the comparison chart depicted on the graph titled "Historic HH, Department of Revenue PV and DNR Royalty Value" depicted Henry Hub (HH) prices, Department of Revenue (DOR) Cook Inlet Prevailing Values (PV), and Department of Natural Resources (DNR) royalty values from January 2001 through January 2005. As reflected on the chart, Henry Hub prices could be "very volatile". While gas prices ranged from approximately $1.50 per MCF to $8.00 per MCF during this timeframe, Henry Hub gas prices spiked to $18 in the year 2005 as a result of the immense impact of that year's hurricane season. The DOR PVs and the DNR royalty value lines on the chart were recognized as "very good proxies for any type of indexing or snapshot about what's really going on in the Cook Inlet". Gas prices have trended upward in recent years due "to indexing of old legacy contracts as well as new contracts" such as the Chevron gas contract with Enstar Natural Gas Company.

10:48:27 AM

Future of Supply

- We have moved from an "Excess Supply" market to a "Supply & Demand" market
  - Cost of Natural Gas will go up
  - More supply contracts are needed and will likely be for smaller volumes
  - Supply contracts will likely be more complicated
  - Pipeline system will be more complicated to operate

- We are working to identify and evaluate options to meet future demand
  - LNG imports may be economic at some point
  - Storage options are being explored for peaking purposes
  - We have achieved Federal support for an in-depth DOE study of In-State demand and for conceptual engineering of a spur pipeline to Nenana Basin/Fairbanks

Source: Enstar Natural Gas Company - Energy Supply in South Central Alaska, November 14, 2005

Mr. Barnes stated that this information indicated that "the energy situation in Cook Inlet is being recognized by all parties. Enstar is working diligently to try to provide new opportunities, new incentives, to bring gas to the Cook Inlet".

10:48:49 AM

Residential Costs by Region

Natural Gas Cost ($/Mcf)

Western States:
Washington, Oregon and California … $14.87
Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, and New Mexico … $11.63
Midwest:
North Dakota, Minnesota, South Dakota, Nebraska, Kansas, Iowa, and Missouri … $15.33
Oklahoma, Arkansas, Texas, and Louisiana … $16.45
Wisconsin, Michigan, Illinois, Indiana, and Ohio … $15.63
Kentucky, Tennessee, Mississippi, and Alabama … $17.78
East:
New Hampshire, Maine, Massachusetts, New York, Pennsylvania, Connecticut, Rhode Island, New Jersey …$19,67
West Virginia, Virginia, Delaware, Maryland, Washington DC, North Carolina, South Carolina, Georgia, and Florida … $19.39
Alaska $6.70

Source: Enstar Natural Gas Company: Energy Supply in South Central Alaska November 14, 2005

Mr. Barnes stated that the price ranges of residential costs of delivered gas in various regions of the country would indicate "the disconnect that exists in the gas business between Cook Inlet and the Lower 48 gas provinces." Delivered gas prices included such things as transportation fees, storage, and delivery of gas by a local distributing company (LDC). The $6.70 price of delivered gas in Alaska was less than half of practically every other state's price. Western states gas prices were lower than other continental gas province prices because of less demand and the fact that some of those areas had their own gas exploration. The prices depicted were the delivered price to consumers rather than the prices gas producers received. This

chart demonstrated the benefits consumers of Cook Inlet gas received now and would receive in the future were sufficient exploration activity to occur.

10:49:46 AM

Senator Hoffman understood that the $6.70 delivered gas price depicted for Alaska was solely relative to Cook Inlet.

Mr. Barnes affirmed.

Senator Olson asked for confirmation that the gas prices depicted for the contiguous states were to delivered gas.

Mr. Barnes stated that the entirety of prices depicted was delivered gas to the consumer. The price of gas in Cook Inlet benefited the area.

10:50:35 AM

Conceptual Competitive Comparison
Common Input - Per Well Analysis

Recoverable Reserves	5 BCF
Development Cost (Capital)	$5 million
Operating Cost	$.050/mcf
Royalty	1/8

Based on House PPT (SB305,RES) and domestic severance tax rates

Competitiveness Comparison:
Cook Inlet Natural Gas Investments
Disadvantaged Against Competition

[This analysis compares the BFIT Profit/Inv. for Alaska to that of Oklahoma, Texas, Wyoming, and Louisiana.]

Based on Senate PPT (SB305, RES) and domestic severance tax rates

[NOTE: The presentation incorrectly specified that the analysis was based on the provisions of CSHB 488. It was actually based on the provisions of CSSB 305.]

Mr. Barnes informed the Committee that this analysis presented the conceptual economics of a well drilled in Alaska to opportunities in other parts of the country. The comparison was based on recoverable reserves of five billion cubic feet (BCF); development costs of five million dollars; operating costs of 50 cents per million cubic feet (MCF), and, for Alaska, a one/eighth royalty share. The effective domestic severance tax rate pertinent to each of the other states was used in the comparison. Oklahoma, Texas, Wyoming, and Louisiana were chosen for this comparison analysis because they were areas in which companies could drill for natural gas.

Mr. Barnes informed the Committee that the analysis was based on the provisions of CSSB 305 rather than CSHB 488 as incorrectly reflected on the chart.

10:51:44 AM

Mr. Barnes reminded the Committee that Henry Hub gas prices were approximately six or seven dollars MCF while Cook Inlet prices were in the three dollar MCF range. A Cook Inlet MCF price of four dollars was used in this comparison to determine the "BFIT Profit to Investment" (Profit/Inv.) reflected on the vertical axis. Cook Inlet gas was also factored at a MCF price of seven dollars in order to compare it to other markers. "BFIT Profit/Inv." was defined as "for every dollar after you've taken out your capital costs" and royalty and PPT severance taxes, "that's the profit that you would make before you go through a tax calculation". It was important to note that under the Cook Inlet four dollar and other markets seven dollar price scenario, a project in Alaska would yield slightly more than $1.50 profit; other markets would yield profits exceeding four dollars. When Cook Inlet gas was factored at a seven dollar price, its profit exceeded $3.50. Cook Inlet's profit levels, when compared to those of other markets, would substantiate the claim that Cook Inlet gas was "disadvantaged". "All things being equal", it was obvious where investors would spend their money. However, in spite of this economic background, "money is being spent in the Inlet" for a variety of reasons.

10:53:10 AM

Cook Inlet Competitive Analysis

- Must compare Cook Inlet to N American gas opportunities
  - Cook Inlet does not have world class exploration opportunities
  - However, viable smaller exploration opportunities exist
- Good access to lands
- Disadvantaged by high costs
- Disadvantaged by permitting and regulatory burden
- Disadvantaged by price and closed market
- Disadvantaged or incentivized by fiscal regime??????

Mr. Barnes reviewed the competitive advantages and disadvantages of Cook Inlet.

10:54:10 AM

Consequences of SB 305 (RES) - Cook Inlet Gas

- Existing Fields
  - Nothing wrong with ELF for Cook Inlet natural gas
  - Loss of ELF and higher tax rate in low gas price environment will result in
    - Higher rate required to pay for costs (economic limit)
    - Fields will be shut in at higher production rates
    - Reserves will be lost

- New Exploration and Development
  - Higher taxes will result in:
    - Less competitive opportunities compared to N American gas provinces
    - Renewed decline in Cook Inlet exploration and development
    - Cancelled projects
    - NO NEW RESERVES DEVELOPED

- Loss of industrials and jobs

- Higher and volatile costs to utility customers

Mr. Barnes claimed there was nothing wrong with the existing Cook Inlet gas ELF tax regime. "It's keeping old fields that are very much near their economic limit producing. It was put in place to moderate State take in recognition of the desire to keep the field on production." Changing the current ELF tax regime would require the amount of money generated by the field to increase. Absent this, uneconomic fields would become be shut in and reserves would be lost. He reviewed the information regarding the impact the PPT would have on exploration and development in Cook Inlet.

10:55:58 AM

Senator Dyson asked Mr. Barnes his view of the provisions in the PPT which would allow credits for unsuccessful exploration and development efforts occurring within three miles from shore. ELF did not allow such credits.

Mr. Barnes presented his view of how the credits should work. They credits should encourage companies to spend money on drilling efforts to find new gas. Further information on the credits proposed in CSSB 305 for successful explorations were included in his presentation's Competitive Comparison chart [See Time Stamp 10:50:35 AM]. While the credits increased the economic merit, they did not increase it beyond the threshold of being competitive. A dry hole credit would be helpful once or twice, but he voiced that few companies would desire to have unsuccessful wells beyond that number, as "you don't make a lot of money drilling dry holes."

Mr. Barnes concluded therefore that the exploration credit would "not drive the business". Marathon had some alternate Cook Inlet tax proposal recommendations similar to those suggested by Mr. Zager. The goal would be to "balance the State take and then the credit opportunity which clearly would be part of an economic analysis".

10:57:48 AM

Senator Hoffman recalled ConocoPhillips stating that the vast majority of available production on the North Slope was in existing fields. Known discoveries were located in four percent of the fields and exploration activities were occurring in three percent of the fields. Furthering that point, he anticipated

that the level of exploration activities in Cook Inlet was lower than that occurring on the North Slope.

Mr. Barnes disclosed that exploration activity in Cook Inlet slightly exceeded that of the North Slope as the result of such things as incentives provided by the State. 50 MCF per day of new gas was brought to market in the last few years from Cook Inlet: the Ninilchik field produced approximately 40 MCF per day and the Happy Valley field might produce approximately 10 MCF per day. Marathon anticipated having a new field at Kasilof in production around the end of this year.

Senator Hoffman defined those fields as "known discoveries" rather than new exploration fields.

Mr. Barnes estimated that approximately ten percent of the current gas production in Cook Inlet was new gas.

Senator Hoffman communicated that the intent of his question was to determine the "piece of the pie" that would be classified as exploration. This would assist in understanding the potential for projects occurring there. He would appreciate this information being provided.

Mr. Barnes responded that an attempt would be made to provide such information. To further clarify Senator Hoffman's request, he advised there being two issues: "one is recent new gas or activity level and then maybe a projection of what the future might look like as to cancelled projects.

Senator Hoffman qualified the issue to consist of "known discoveries and future exploration".

11:00:40 AM

Mr. Barnes noted that another issue of concern with CSSB 305 was the "pass through" of expenses to consumers. Approximately 50 percent of the severance taxes in Cook Inlet were "passed onto industrials" and approximately 50 percent were passed on to consumers. Any tax increase under the PPT would be passed on. The amount could increase were gas Cook Inlet "linked" or "indexed" to "a volatile outside market"; thus he would discourage that linkage. It would also create additional problems associated with the monthly calculations of an index for the utilities. Dialogue should occur with utilities in

regards to how they would determine their rate structure in consideration of this volatility. "Most utilities prefer to understand for their upcoming year what their cost of gas will be." Problems would be anticipated were the utility to incorporate a monthly variable into the equation as to what would be charged to consumers.

11:02:04 AM

Cook Inlet - What is Needed

- Problems with Progressivity
  - Potential higher tax rate at lower margins
  - Must not link Cook Inlet PPT to volatile non-related index
  - Link to Cook Inlet Department of Revenue Prevailing Value
- Must include provision for marginal low rate fields
  - 5/20 Plan for Cook Inlet
- Prioritize efforts to incentivize, not hinder exploration and development
  - Include some form of transitional investments credits
- Actions by this Legislature will have immediate and measurable impact on Cook Inlet oil and gas industry

Mr. Barnes reviewed the information. He supported including a Cook Inlet specific five percent tax/20 percent credit provision in the PPT. The average tax currently paid in Cook Inlet was approximately five percent.

Mr. Barnes reiterated that when production in Cook Inlet was analyzed under a 20 percent PPT tax rate, the incentives were insufficient to maintain viability in Cook Inlet. He estimated that the impacts of the PPT would be "felt sooner" in Cook Inlet than they would on the North Slope.

Senator Hoffman recalled that approximately $1.5 billion in investments were being made on the North Slope. The proposed credits could increase that amount to $2.5 billion. To that point, he asked the current and forecasted investment scenario for gas in Cook Inlet.

Mr. Barnes was uncertain of the overall Cook Inlet investment picture. He recalled Chevron stating they might invest $200 million over the next four years. That number would not be "dissimilar to what Marathon has spent over the last several years" in its drilling activities. Marathon drilled 50 wells in the last five years, several fields were brought into production, and a new pipeline was laid. A similar level of activity would be anticipated in the future. That was really "what's at stake".

Mr. Barnes noted that Cook Inlet "currently burns" approximately 200 BCF annually. In order to replace reserves at a 50 cent exploration and development cost, $100 million a year must be spent "just on your wells". That activity level had not been occurring. However, the construction of exploration wells was one of "many good signs" of increased activity in Cook Inlet.

Co-Chair Wilken requested that information provided by the Department of Revenue and other presenters to be made available on the internet. He also asked that a meeting be scheduled to allow "invited" individuals to testify on the PPT via teleconference, as there were some who could not attend in person.

Co-Chair Green concurred.

Co-Chair Green specified that the Committee would recess and reconvene at approximately 1:00 PM. She noted that public testimony on the PPT bill would be held Saturday, April 8th.

Co-Chair Wilken announced the tentative schedule for the Operating Budget hearings.

RECESS TO CALL OF CHAIR 11:07:51 AM / 1:09:55 PM

Co-Chair Green called the Committee back to order.

KEN THOMPSON, Managing Director, Alaska Venture Capital Group, testified via teleconference from an offnet location. He read his testimony [copy on file] as follows.

> April 6, 2006, Comments to Alaska Senate Finance Committee
> CS For SB305 - Petroleum Production Tax
> By Ken Thompson

Introduction

For the record, my name is Ken Thompson. I reside in Anchorage. I am the Managing Director of Alaska Venture Capital Group, or AVCG, an independent oil exploration company with a focus on the North Slope of Alaska. AVCG is a consortium of 15 independent oil and gas companies and individuals from Kansas and my personally owned company, Pacific Star Energy, here in Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with newly opened offices in Anchorage. Many of you know me as the former President of ARCO Alaska, Inc., and a past Executive Vice-President over ARCO's Asia Pacific region.

Mr. Thompson had 12 years of professional experience on the North Slope and Cook Inlet.

AVCG has been very active in the past six North Slope (NS) areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired in the recent March 1, 2006, NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-150+ million barrels range, fields that may be too small for the giant producers but fields that can be produced profitably by smaller companies like ours. We believe there are hundreds of millions if not billions of barrels of oil left on the North Slope in smaller fields of this size and these fields near infrastructure can be brought on more quickly. Our first exploration well in partnership with Pioneer Natural Resources – the Cronus #1 about 10 miles southwest of the large Kuparuk Field – completed drilling last week but results will remain confidential for some time.

AVCG plans two NS exploration wells next winter and two wells the following winter. Our 3-year exploration budget is $46 million and with any future discovery success, we could have a gross development budget of $500 million to $1 billion in future years.

Let me now focus my comments on the CS for Senate Bill 305. As background, I reluctantly supported the Governor's

proposed 20/20 PPT and even many details of the initial House version of the bill, HB 488. But, somehow, things are beginning to derail. The CS SB 305 and CS HB 488 with their revisions from the original draft of a simple petroleum profits tax have evolved into very complex bills that are no longer a win-win for the State and industry, in my opinion. I don't fully understand how things began to derail into such complexity…perhaps it was due to anger at the Big 3 producers and the Governor for not revealing the natural gas contract details before demanding a new oil tax fiscal structure. Perhaps its anger at the Big 3 companies who are demanding tax certainty for 30 years when asking for three full decades of certainty truly is an unreasonable demand with Alaska's legislative type of democracy.

1:14:05 PM

Mr. Thompson clarified that AVCG and other independent oil exploration companies "are not asking for 30 years of certainty. We realize the world and circumstances do change".

1:14:14 PM

I don't understand all the dynamics of the past three weeks in the legislature, but this I do know. The CS for SB 305 needs to be greatly simplified and it needs to move somewhere between what it is now and the Governor's proposal if a win-win solution is to be the end result that balances more revenue share for the State but in balance with attracting more new entrants and increased investment amounts.

I am an optimist. I personally think there is still time to avoid a train wreck in this complicated business of restructuring Alaska's petroleum taxation system … if the Senate Finance Committee acts quickly. I, for one, have not given up hope that there is a version – easier to understand and to implement - that can be a win-win for both the State and the industry. There is a simpler and better way, in my opinion, for the State to improve government take while not dampening exploration and development investment. Let me outline my suggestions for a win-win and my suggestions for simplification.

1:15:30 PM

AVCG Owners' Perspectives

First, however, let me say that while I am Managing Director of AVCG, our other owners disagree strongly that any change should be made to the 20/20 PPT formula proposed by the Governor. The 20% PPT tax rate and the 20% credit originally presented in the Governor's bill should be the tax rate and credit enacted. Some of the AVCG owners, however, do not even support the PPT concept and believe the petroleum tax should be as simple as 10-14% of revenues and exclude any economic limit factor.

Quite honestly, the AVCG owners listened in disbelief when I told them the production profits tax rate being considered in the current CS to SB305 draft could add a "surcharge" at high prices that could significantly ramp up the additional taxes above the base PPT rate of 25%. And this surcharge will be in addition to the higher other revenues the State and Federal governments will already benefit from at higher oil prices: the State's 12.5-16.7% royalty, the ad valorem property tax, the 3-9% corporate income tax, lease bonus bid amounts, the ongoing annual lease rental amounts, and the Federal income tax rates averaging 20-35% of taxable income.

It all adds up, and AVCG Owners are saying, "enough is enough."

When I was communicating the latest CS to SB305 details to the AVCG owners by teleconference and email recently, I felt two overwhelming emotions. The first emotion was discouragement. My business judgment tells me the State crossed the line to excessive taxation that will dampen capital investment. Why invest in Alaska where you loose the upside gain at high oil prices to offset exploration risk when the government take will exceed 60%? There are politically secure opportunities in other U.S. states, Canada, the Gulf of Mexico offshore, the U.K., and other nations where government take is 55% or less. CS to SB305 takes away too much of the upside potential from the investor who is taking the risk.

But I also found interesting another strong emotion during that teleconference which surprised me a great deal. I was embarrassed. Here I was, telling a group of outside investors that recently put all of their focus and personal exploration budgets on the North Slope of Alaska, and now I was telling them that Alaska was creating the most complex, confusing production tax bill ever created since the disastrous Federal windfall profits tax. The windfall profits tax – structured similarly to the CS SB 305 revenue surcharge - stalled investment in the U.S. oil and gas industry, resulting in an alarming increase in U.S. foreign oil imports which our nation lives with to this day. I was telling them that Alaska was levying the highest tax rate and government take in North America.

1:19:27 PM

Mr. Thompson expressed his love for the State. It was his home and he hoped it would prosper. However, he was embarrassed to tell AVCG's investors the State was considering implementing the highest severance tax in North America.

To back my points up, please let me cite some statistics. Currently, the total Alaska and Federal governments' take is just over 50%.

Mr. Thompson understood and supported the State's desire to increase "its share of the take at higher prices".

The Governor's proposal moved this to 53% or so then the original SB 305 moved the government take closer to 55%. Then the CS to HB 488 [NOTE: SB 305 was incorrectly referenced in the written testimony] moved the government take closer to 55 %. Then the CS to SB 305 with a 25% PPT boosted the government take to over 60% with its "surcharge." This compares to following total government take including Federal government shares:

Alaska currently	50%+ or less, dependent on oil price and field size
Alaska Governor's bill	53%
Alaska original HB488	55%
Alaska CS SB305	60%+
U.S. Gulf of Mexico	45%

Colorado	51%
Wyoming	52%
Kansas	53%
Texas	53%
New Mexico	53%
Oklahoma	53%
California	53%
Louisiana	57%

These tax rates apply to newer fields. Older, more mature fields at low production rates typically get exempted from these maximum tax percentages in various ways.

Mr. Thompson noted that the average state tax rate was approximately 53 percent.

U.K.	50%
Canada	39-56%

The lower rates in Canada apply to the oil sands projects where billions of dollars for new investment are occurring with Canada's vision to lower government take on this resource base.

1:21:44 PM

Mr. Thompson noted that the 39 percent tax rate in Canada was "typically the result of incentives in the very viscous oil sands". He found it "interesting how capital varies" in the differing tax regimes. Capital investments between $1.5 billion and two billion had been annually invested in Alaska's oil and gas industry under its current tax structure. Those amounts would increase due to tax credits. The investment in the United States Gulf of Mexico (GoM) with a 45 percent government take had experienced annual five to ten billion dollar investments and on occasion $15 billion a year. Lower government take had been accompanied by continued investment to improve production.

Mr. Thompson noted that a March 28, 2006 New York Times article specified that major companies had committed ten billion dollars a year for the next ten years in capital spending to the Alberta oil sands. While those fields had immense prospectivity and reserve potentials, the 39 percent government tax rate was also an important factor in that investment.

1:22:47 PM

My overall key recommendation in my comments today is this: the State should not exceed a threshold of 55% total government take, 45% producer take. The State does own the resource and may be due more than a 50% take. On the other hand, it is the producer who is taking the capital risks and deserves at least 45% for making things happen … for moving an innovative exploration or development idea into production without which no revenues would flow.

Let me say that I'm excited about what's happening in Alaska's oil patch right now, and let's not dampen the spirit. The current versions of SB 305 and HB 488 have dampened my spirit. I am discouraged. Let's have a new tax bill that encourages, not discourages new entrants. But I do believe it is time the State share more in the take at high prices but there is a much simpler way.

1:24:07 PM

My Personal Perspective

Now let me shift gears in my comments to you. Because I could not get buy-in for any alternatives from the AVCG owners except the 20/20 case, I have decided to speak out alone. As an Alaskan, I am concerned and feel I must try to share a personal perspective trying to balance what is best for my continued involvement in Alaska's oil and gas industry in balance with how the State must change its system to be competitive in the world and realize a higher government share.

So, let me turn my attention to what key changes I would make to the CS of SB 305. Again, my views are not supported by AVCG owners or others in industry; rather they are my personal views.

1:25:28 PM

Mr. Thompson stated that were a bumper sticker created to reflect his foremost position on the appropriate State take, it would be "55/45". A 55 percent government take would increase revenue to the State without dampening capital investment in the oil and gas industry. He provided an overview of five

suggestions as to how to accomplish the "55/45" tax regime. Each of the five suggestions were addressed individually as follows.

1:27:27 PM

1) Make Tax Rate Progressive But Greatly Simplify The Taxation Formula

When the Governor's office first announced a 25% tax rate then amended that to 20%, I could see the move by legislators to somehow bridge the gap from 20% to 25%. However, the approach used by the legislative committees based on the legislature's outside consultants' work is simply too complex and will be arduous to implement. I think – and perhaps all of you think – the Federal tax code is too complex. The changes to SB 305 are also too complex and will lead to different interpretation, "gamesmanship" possibly by some companies because of the unwieldy progressive tax structure formula, and future costly lawsuits when the State disagrees with a company's calculations. And the number of accountants to keep track of these complexities on both sides will balloon! I urge you to simplify, simplify, simplify...yet still have some progression at higher prices.

For my company which drills the smaller oil traps that may add up, we do not have a lot of upside potential in seeing these smaller fields grow much larger in reserves over time in contrast to the giant Prudhoe Bay and Kuparuk fields. So our main upside is in oil price escalation to offset exploration risks and to offset the cycles of oil prices downward, a reality over time for any commodity. I urge you to consider a PPT rate of 20% at lower prices but gradually escalating to the 25% level only at higher prices.

I found it so interesting to see the Econ1 consultants and consultant Daniel Johnston saying the government should take more and more at high prices when not one member of the legislature asked them a very important question they should have been asked: "how much are you and your company investing in Alaska?" I was shocked to see that these consultants, when calculating the future revenues to the State at various escalating rates, used the same oil production curves. In reality, less capital will be spent by industry at exorbitant production profits tax rates (tax

> rates above 25% when coupled with all other payments such as royalty, corporate income tax, ad valorem tax, lease costs and rentals, etc.). With less capital spending, the production curve will be lower … an increasingly higher tax rate may not in the end yield the forecasted revenues for the State.

1:31:03 PM

Mr. Thompson reiterated that capital spending in Canada and the GoM, which were areas with lower government take percentages than Alaska, far exceeded capital investments made in Alaska.

1:31:26 PM

> On a related note, our company plans to go into the private or public equity markets to raise capital for future development. Such equity investors invest in the oil markets to be fully exposed to crude price upside. When they look at investments all over the world, and see that Alaska could tax with an escalating "surcharge" when others have a predictable flat tax, they will place their capital elsewhere to continue their exposure to higher crude prices. The consultants did not address this issue of the private and public equity markets and the desire for such investors to fully benefit from upside commodity price swings without hedging or escalated taxation at high prices. This was indeed a major oversight by Econ 1 and Daniel Johnston.

1:32:59 PM

> I also could not believe that the consultants failed to show capital spending elasticity graphs from different countries. They did the legislature a disservice by not doing so. By convincing legislative committees to adopt a complex progressive tax rate structure, or windfall profits tax, the consultants may feel they have been successful, but not one of these consultants will be around to defend their views in the future when capital spending declines at increasingly higher tax rates above the 25% level.

1:33:55 PM

So, what is a simpler alternative? What is an alternative to yield more revenues to the State at higher oil prices with a balance to attract increased investment?

I suggest that the Finance Committee revise the bill to keep the production profits tax simply that … a tax on production profits, and not a complex way to further burden gross revenues with a surcharge. A simpler way in getting the progressive rate from 20% to 25% without the surcharge treatment complexity is to adopt a graduated PPT that does accomplish a higher State take at higher prices, yet leaves a reasonable producer take.

I recommend the following production profits tax schedule as a suggested one to "simulate" revenue results somewhere between the Governor's proposal and the CS to SB 305 proposal. It is one that everyone could easily understand and implement with the State realizing upside at higher oil prices yet not too much upside is taken away from explorers/producers for re-investment:

1:34:39 PM

Up to monthly average wellhead price of $50/barrel for a company:	PPT rate of 20%

1:34:48 PM

When monthly average wellhead price is between $50-75/barrel:	PPT rate of 22.5%
When monthly average wellhead price exceeds $75/barrel:	PPT rate of 25%

1:35:17 PM

Let's be honest with ourselves: the surcharge is simply a windfall profits tax under a different name. I highly respect industry consultant Daniel Yergin who has an excellent reputation among industry personnel and government officials alike. In November, 2005, Mr. Yergin said this about a windfall profits tax: "What a windfall profits tax does is introduce a lot of distortion. It reduces investment, it increases a sense of political risk

and it doesn't achieve the goal that is intended … it will really lead to decreased supply."

I urge the Finance Committee to seriously consider this simpler approach. I personally ask that you have the Department of Revenue run the above case to compare the State revenues from the Governor's proposal to the current CS SB305 proposal, and to the existing ELF severance tax program. But when DOR models this approach, also ask them to run some sensitivity cases to reduced capital expenditures and reduced future oil production levels if CS SB305 stays in its current form. Please greatly simplify the bill. The complexity is simply not needed.

1:36:47 PM

2) "Trigger Points" For Escalating PPT Should Not be WTI But Wellhead Value

Let me now address a second, very leveraging issue. The "trigger point" that increases the PPT tax rate from 20% should not be based on ANS West Coast (ANS) oil price. The "trigger point" should be when a company's average realized wellhead price in Alaska exceeds $50 per barrel. Some say the trigger point should be at a lower price like in SB 305, but I do think there is strong merit that those who have invested and taken exploration risk and exposure to low prices should be able to benefit from the increased profits at higher prices…"share the pain, share the gain"…to this $50/barrel wellhead level. However, I personally am fine with the State gradually increasing the PPT tax rate eventually to a cap of 25% when wellhead prices exceed $50/ barrel.

Why should the State tie the PPT calculation to a company's realized wellhead price instead of to West Coast crude price? In reality on the North Slope, not one company ever sees West Coast crude prices. Every crude oil in Alaska is different in quality with viscous crude receiving less than the lighter crude oils, and oil produced from wells farther away from infrastructure receiving less wellhead value due to higher shipping costs. Conversely, oil in the Cook Inlet is close to actual refining or on the water to ship out of state and thus realizes on average a much higher wellhead value than most North Slope crude oils, a substantial plus

to Cook Inlet operators who face higher operating costs with maturing fields.

Mr. Thompson referenced Co-Chair Green's earlier question as to whether the net profits calculation suggested by Chevron had been included in any version of the PPT proposals. He suggested that perhaps what she had in mind was actually to a company's gross wellhead value.

1:38:56 PM

So I ask, why should the tax rate increase with a price index such as West Coast price when there is such a variance in crude oil pricing factors on the Slope at the wellhead that directly affect each field's economics and economic limit differently? The production profits tax rate should not escalate at the same time for those who produce viscous crude or oil from a farther distance as compared to those who have good quality oil right next to the TAPS line. If there is a "trigger point", it should be one based on a company's average monthly realized wellhead price for production.

1:40:05 PM

I recommend that the "trigger point" for PPT tax rate escalation be $50 per barrel realized wellhead price based on a company monthly average and not be based on $40 West Coast price, thus allowing explorers and producers to share in the upside profits at prices to this level with no higher burden than the 20% PPT tax rate (plus burden of royalty, corporate income tax, ad valorem tax, Federal tax, etc.). Dr. Pedro van Meurs also recommended that the threshold level of $40/bbl be re-considered. As also recommended by Dr. van Meurs, this threshold price should be linked with inflation.

1:41:37 PM

3) The Transitional Deductible Allowance

Jumping immediately from the prior ELF severance tax to the PPT formula overnight wreaks havoc with a company's budgeting and their forecast of available cash flow for

near-term capital investment. A transition adjustment of some sort is appropriate and is fair.

I support the CS to SB305 that allows for a producer to take a credit with part of a producer's transitional investment expenditures between April 1, 2001, and before April 1, 2006.

1:42:10 PM

4) The Tax Credit "Standard Allowance"

The Governor proposed a $73,000,000 annual allowance of production profits that would not be taxed by the PPT, essentially giving a $14.6 million tax credit per company. The Senate Resources Committee revised this downward to a $50,000,000 annual allowance as a reasonable compromise, or a $10,000,000 tax credit; CS HB 488 further changed this to a flat $12,000,000 annual credit. The CS to SB 305 further proposed that this be changed to an annual "standard tax credit allowance" for the first 5,000 barrels per day of production.

This "standard deduction" is very important to a startup company like AVCG/Brooks Range Petroleum trying to establish a foothold in Alaska and someday contribute substantial oil revenues to the State.

I favor the HB 488 solution of a $12,000,000 annual flat tax credit exemption due to its simplicity and it is a level playing field for producers of various crude oils with different wellhead values.

1:43:59 PM

5) Institute A Tax Credit Repurchase Program

As protection for explorers and new entrants to Alaska, the version of the profits tax in the House, CS to HB 488 devised a tax credit repurchasing program for those credits a company earns on expenditures up to $10,000,000 per year for investments in exploration and/or lease purchases in Alaska.

This is important to explorers like AVCG who does not yet have production revenues. Without such a repurchase program, our company might be able to sell our annual tax credits to one of the major producers but have to accept only 90-95% on the dollar or less. On the other hand, the State would not be giving up anything to repurchase the credits at 100% of value because the major producers would otherwise use the credits to reduce their tax bill and reduce revenue to the State. But using the State repurchase approach, the small explorer could turn around and re-invest the State-refunded credit into new leases, seismic or exploration drilling.

I recommend the Finance Committee support the tax credit repurchase program outlined in the CS to HB 488 and amend CS to SB 305 to incorporate a similar tax credit repurchase program.

And the Alaska gas pipeline revenues will be significant. The State should own 20%.

1:45:35 PM

Other Revenue Sources

As a concluding remark, I urge the State in this period of high oil prices to not simply try to gain into that upside by pulling only one lever excessively … the lever of petroleum production taxes. The State could be well advised to ensure they gain additional revenues from oil in Alaska by being an entrepreneur and considering revenues from other new related business, such as acquiring a 12.5% interest in the TAPS pipeline and stop paying $3.70/barrel profitable tariffs to major producers when you could be sharing in those profits.

1:46:47 PM

And work with the Federal government now to ensure that they share part of the Federal royalties with the State on future offshore oil and gas production from the Beaufort Sea which I consider to be of great potential as evidenced by major leasing recently by Shell and other companies. Other states are pursuing a share of Federal offshore royalties.

1:47:36 PM

Mr. Thompson shared that Congress was currently considering legislation, proposed by a senator from Louisiana, which would allow energy producing states to receive 50 percent of the federal revenue generated by oil and gas production off their coasts. While he was uncertain of the degree this might apply to Alaska, the adoption of this bill would provide Louisiana $600 million per year. In a decade or so, such revenues might be provided to Alaska for activity occurring in the Beaufort Sea, were the State to participate in that federal legislation.

Mr. Thompson expressed that the State could garner additional revenues were it to adopt a tax regime of "55/45". It would also benefit from revenues generated by an Alaska gas line. The State should own a minimum of 20 percent in such a project.

1:48:47 PM

Concluding Remarks

The above comments are my personal views offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices. I do believe the Senate Finance Committee can get things “back on track” and better balanced.

I sincerely thank the Committee for the opportunity to present my comments.

Mr. Thompson reiterated that a tax rate of "55/45" would be the "winning" tax structure for the State. He concluded his remarks.

1:49:38 PM

Co-Chair Wilken acknowledged being educated about the term "prospectivity" and its association with how the State was graded for investment potential. He was surprised that potential reserves in ANWR and NPR-A hade been ignored in this discussion. Thus, he asked whether the State might be "selling ourselves short by not recognizing those giant fields in our grade for prospectivity".

1:51:06 PM

Mr. Thompson responded that entities from outside the State view prospectivity in Alaska as having diminished "significantly". While this might be true when considering the central portion of the North Slope and the mature fields in Cook Inlet, he believed there were "very very significant oil reserves" in NPR-A. He had personally viewed "a large number of good looking stratographic" seismic tracks there. He anticipated "major discoveries being announced" there in the next few years. The prospectivity of fields in near shore State waters was also promising. "One of the best strategic moves" he had witnessed in the oil and gas industry in several years was the "very bold strategic move by Shell" to acquire Beaufort Sea leases. One reserve in that area had "a proven 200 million barrels of reserves, yet was not commercial at $18 because it was far from shore" in the Arctic Icepack. Nonetheless, he thought Shell would be successful in their endeavor. There was also increased interest in areas such as Bristol Bay.

1:53:05 PM

Mr. Thompson suggested that in order to determine the prospectivity of an area, the Committee should "look out the window and see who's flying". In addition to Shell's recent reentry in the Alaska marketplace, large companies from Italy and France and large, respected independents such as Pioneer Natural Resources were also active in the State. While some people consider there to have been a prospectivity decline on the central part of the North Slope, companies such as AVCG were "playing" the area because "25 to 50 million barrels" was "a company maker to us". Fields that size were not even reflected as reserves in a major company's records.

Mr. Thompson considered the prospectivity of Alaska to have been "sold short" by many. There could be the potential for another hundred trillion cubic feet of natural gas yet to be found.

1:54:18 PM

Mr. Thompson urged the Committee to conduct an internet search and view industry journals about the State's proposed PPT. "Article after article" would be presented. "People are being

turned off by it: they don't understand it but they know it is complex, they know it would increase taxes and take away some of the upside at high prices". He was concerned that the effect of the proposed tax would be to discourage newcomers in the industry. A simpler method could be developed which would allow a government take of 55 percent. A balance of "55/45" would increase State revenue without discouraging industry from operating in the State.

1:55:45 PM

Senator Dyson appreciated the comments. Earlier in today's hearing, it was suggested that a different tax rate be applied to Cook Inlet because exploration and production activities there differed dramatically from those on the North Slope. He asked Mr. Thompson to comment in that regard.

Mr. Thompson affirmed that Cook Inlet was "a very mature basin". The tax rate comparisons he had shared earlier, which averaged approximately 53 percent, were specific to new production. "Most of those states have some type of exemption that can allow less of a tax burden on more mature areas". He did not have any recent experience in Cook Inlet, however, his "old view" was that, while "something different needed to be done", it was not that a different production tax structure should be applied since that might require separate sets of accounting to occur. He preferred there being different "investment tax credits to try to spur on new exploration". There could be a "special increased incentive for Cook Inlet exploration".

Mr. Thompson thought that "an experiment that has done wonders for spending in the Gulf of Mexico" could be applied to Cook Inlet. "That was a straight royalty reduction". While a royalty reduction law was currently available in Alaska, it was complex and a company must provide a significant amount of data and paperwork to the State. The methodology utilized in the Gulf of Mexico "simply" lowered the royalty from 12.5 to five percent. The result was that capital "flew to that area" and prospectivity increased. Thus, he suggested a blanket reduction in royalties in Cook Inlet be considered. Nonetheless, he deferred to the expertise of current Cook Inlet producers.

There being no further questions, Mr. Thompson concluded his remarks.

2:00:10 PM

Co-Chair Green asked Committee members to advise her of any issue they desired desire additional information about. Suggestions for changes and other questions would also be appreciated. The purpose would be to garner as much information as possible going forward.

Co-Chair Green noted that the House of Representatives had conducted a "very successful" PPT panel discussion earlier in the day. She suggested that a similar event be considered by this Committee.

2:01:34 PM

Co-Chair Wilken stated he had personally developed a list of 12 items he would like further information about. This list would be provided to Co-Chair Green. Continuing, he shared his understanding that the cost of transporting a barrel of oil from Prudhoe Bay to the West Coast was $4.31. Within that $4.31 cost was an item referred to as a "profit component" which was being claimed by the producers. Thus his question to Senator Stedman and Senator Dyson, who were members of the Senate Resources Committee, was whether the State currently recognized "profit as a cost and if so, was that a policy call or is that standard procedure in the way we transport oil around the nation".

2:02:54 PM

Senator Stedman stated that while this issue had been discussed, it was not addressed in great detail. The answer to "the issue of a profit on a profit and the majors owning the Trans Alaska Pipeline System (TAPS) and having a regulated profit in that and then being able to layer another profit on top of that" was yes. The Committee should explore the impact of that.

Co-Chair Wilken communicated that this question would be included on his list, "cause it just doesn’t make sense…" It would be interesting to delve into the reasoning behind this.

Senator Stedman agreed it would be a good question to present to the Department of Revenue and Econ One.

2:04:20 PM

Senator Hoffman communicated that the profit component was included in the Transportation expense because the industry's investment in the Trans Alaska Pipeline Service (TAPS) was considered "a risk". He did not view this as an issue, as the line had to be built. The question would not have been asked had another company made that investment. Continuing, he stressed that one of the reasons the State was interested in investing in the proposed gas pipeline would be to make a profit, rather than to "simply break even".

Co-Chair Green understood that investing in such an endeavor would be considered "high risk".

Senator Hoffman affirmed.

Senator Stedman noted there was also concern about how TAPS tariffs were levied and how that ultimately affected the State.

Co-Chair Green asked whether such things were regulated.

Senator Stedman stated they were, but communicated "that a regulated return on that tariff gets to be a … contested issue".

Co-Chair Green was uncertain as to how action by the Legislature could address that.

Senator Stedman concluded that the concern was to how these things "play into the mathematical modeling". They might not have any affect.

Co-Chair Wilken communicated that these questions could best be addressed by Dan Dickinson, the consultant hired by the Administration.

Co-Chair Green expected "lots more information" on the bill would be forthcoming. The Committee would then dissect the bill section by section.

There being no further discussion, Co-Chair Green ordered the bill HELD in Committee.

AT EASE 2:07:30 PM / 2:07:47 PM

#

ADJOURNMENT

Co-Chair Lyda Green adjourned the meeting at 2:08:00 PM.