

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

February 24, 2006

12:34 p.m.

MEMBERS PRESENT

Representative Jay Ramras, Co-Chair
Representative Ralph Samuels, Co-Chair
Representative Jim Elkins
Representative Gabrielle LeDoux
Representative Kurt Olson
Representative Paul Seaton
Representative Harry Crawford
Representative Mary Kapsner

MEMBERS ABSENT

Representative Carl Gatto

COMMITTEE CALENDAR

HOUSE BILL NO. 488

"An Act repealing the oil production tax and gas production tax and providing for a production tax on the net value of oil and gas; relating to the relationship of the production tax to other taxes; relating to the dates tax payments and surcharges are due under AS 43.55; relating to interest on overpayments under AS 43.55; relating to the treatment of oil and gas production tax in a producer's settlement with the royalty owner; relating to flared gas, and to oil and gas used in the operation of a lease or property, under AS 43.55; relating to the prevailing value of oil or gas under AS 43.55; providing for tax credits against the tax due under AS 43.55 for certain expenditures, losses, and surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, under AS 43.55; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, under AS 43.55; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the oil and gas production tax; relating to the deposit of money collected by the Department of Revenue under AS 43.55; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the net value of taxable oil and gas for purposes of a production tax on the net value of oil and gas; relating to the definitions

of 'gas,' 'oil,' and certain other terms for purposes of AS 43.55; making conforming amendments; and providing for an effective date."

- HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 488

SHORT TITLE: OIL AND GAS PRODUCTION TAX

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

02/21/06	(H)	READ THE FIRST TIME - REFERRALS
02/21/06	(H)	RES, FIN
02/22/06	(H)	RES AT 12:30 AM HOUSE FINANCE 519
02/22/06	(H)	Heard & Held
02/22/06	(H)	MINUTE(RES)
02/23/06	(H)	RES AT 12:30 AM HOUSE FINANCE 519
02/23/06	(H)	Heard & Held
02/23/06	(H)	MINUTE(RES)
02/24/06	(H)	RES AT 12:30 AM HOUSE FINANCE 519

WITNESS REGISTER

ROGER MARKS, Petroleum Economist
Department of Revenue

POSITION STATEMENT: Presented HB 488 on behalf of the administration.

ROBYNN WILSON, Director
Tax Division
Department of Revenue

Anchorage, Alaska
POSITION STATEMENT: Presented HB 488 on behalf of the administration.

DAN DICKINSON, CPA, Consultant
to the Office of the Governor
Anchorage, Alaska

POSITION STATEMENT: Presented HB 488 on behalf of the administration.

ROBERT MINTZ, Assistant Attorney General
Oil, Gas & Mining Section
Civil Division
Department of Law
Anchorage, Alaska

POSITION STATEMENT: Presented HB 488 on behalf of the administration.

ACTION NARRATIVE

CO-CHAIR RALPH SAMUELS called the House Resources Standing Committee meeting to order at [12:34:58 PM](#). Representatives Elkins, Seaton, Olson, Samuels, and Ramras were present at the call to order. Representatives Kapsner, Crawford, and LeDoux arrived as the meeting was in progress. Also in attendance were Representative(s) Wilson, Hawker, Kohring, Berkowitz, Joule, McGuire, Rokeberg, Gardner, Meyer, Gara, and Kerttula.

HB 488-OIL AND GAS PRODUCTION TAX

CO-CHAIR SAMUELS announced that the only order of business would be HOUSE BILL NO. 488, "An Act repealing the oil production tax and gas production tax and providing for a production tax on the net value of oil and gas; relating to the relationship of the production tax to other taxes; relating to the dates tax payments and surcharges are due under AS 43.55; relating to interest on overpayments under AS 43.55; relating to the treatment of oil and gas production tax in a producer's settlement with the royalty owner; relating to flared gas, and to oil and gas used in the operation of a lease or property, under AS 43.55; relating to the prevailing value of oil or gas under AS 43.55; providing for tax credits against the tax due under AS 43.55 for certain expenditures, losses, and surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, under AS 43.55; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, under AS 43.55; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the oil and gas production tax; relating to the deposit of money collected by the Department of Revenue under AS 43.55; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the net value of taxable oil and gas for purposes of a production tax on the net value of oil and gas; relating to the definitions of 'gas,' 'oil,' and certain other terms for purposes of AS 43.55; making conforming amendments; and providing for an effective date."

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ROGER MARKS, Petroleum Economist, Department of Revenue (DOR), stated that he would be explaining the provisions in the bill that were crafted to help small producers and new investors, which are the main goals of the legislation. Referring to a document entitled "PPT [Petroleum Production Tax]: Small Producers New Investors," he explained that small producers bring several advantages to the state, including a bigger appetite for smaller targets, diversity, and evidence has shown that small producers are more likely to explore "risky" prospects. In addition, he said that new [large] investors will bring benefits, with the possibility of developing the Arctic National Wildlife Refuge (ANWR) and National Petroleum Reserve-Alaska (NPR-A) opening.

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MR. MARKS explained that the three basic mechanisms that support these goals are selling losses, selling credits, and a \$73 million allowance. He said he will also go over the affect this bill will have on Cook Inlet.

MR. MARKS referred to page 4 of the handout, which gave an overview of the oil & gas producing companies in the area.

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CO-CHAIR RAMRAS stated that he is very interested in development in the Nenana Basin and asked if Cook Inlet includes all the peripheral areas.

MR. MARKS explained that the chart includes areas that are currently producing, adding that currently there is not production in the Nenana Flats and the state hopes [HB 488] will encourage development there. He pointed out a mistake in the chart, and said that it should read: Chevron/Union Oil Company of California (Unocal) 7,800 barrels a day and ExxonMobil Corporation 1,100 barrels a day. He explained that Cook Inlet is more focused on gas production than oil production.

MR. MARKS said page 5 shows a delineation of companies in the North Slope, which currently produces close to 1 million barrels per day. Anadarko Petroleum Corporation is expected to become more important as they move out to the western North Slope and the NPR-A. He added that HB 488 is designed to make production more attractive to the Shell Group. In addition, Kerr-McGee Corporation is developing the Nikaitchuq field and Pioneer Natural Resources is developing the Ooguruk field. He opined

that both the Nikaitchuq and Oooguruk fields will produce 20 thousand barrels per day at peak production. He noted that page 6 of the handout combines the North Slope and Cook Inlet projects to create a "Statewide Barrels of Oil Equivalent."

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MR. MARKS turned to the mechanisms for attracting new investors, both large and small. Referring to page 8, he explained that selling losses means that if a new company loses \$1 million in its first year, the company would be able to convert this loss to a credit. The credit is set at the tax rate, which is 20 percent. Multiplied by the \$1 million, the total credit would be \$200,000 dollars. This credit would be sellable at 90 percent of the face value, which is \$180,000. This allows the company to monetize the loss immediately, instead of carrying it forward until revenue is earned. He added that on a net present value basis, this is important for boosting the rate of return.

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CO-CHAIR SAMUELS commented that if the credit sells for less than the full value, the state would still be "on the hook" for the 20 percent credit.

MR. MARKS agreed and said that [Company A] would sell the credit to [Company B] for \$200,000 and [Company B] would then have \$20,000 in credit.

CO-CHAIR SAMUELS pointed out that [Company A] is losing a percentage on the sale of the credit and asked if it would be better to have a mechanism in place for the state to give the money directly to [Company B]. He opined that this may encourage [Company A] to spend more.

MR. MARKS asked how Company A would benefit from this.

CO-CHAIR SAMUELS said Company A can only sell 90 percent, so will be receiving an 18 percent credit instead of 20 percent. This is a loss of a loss, and he opined that the state and Company B do not care. If Company A were able to receive the full value of the credit, it may be more likely to spend money.

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CO-CHAIR SAMUELS asked if there is any way to make it so that [Company B is paying the full value].

MR. MARKS replied that the credits are only marketable because they are sold for less than they are worth.

REPRESENTATIVE SEATON gave an example in which the cost to the state would be the same while [Company A] would receive the full value of \$200,000.

MR. MARKS said that he needed to think about this and that the credits are "worthless" if sold at face value.

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REPRESENTATIVE BERKOWITZ noted that if a company earns a credit and tries to market it in a small market, it must be severely discounted, which undercuts the utility of having a tax cut.

MR. MARKS stated that in the Exploration Incentive Credit Program (EIC) credits have been selling at about 90 percent of market value. He commented that as long as there are competitors, there is a good chance to receive a high percentage of face value and opined that this is "risk-less, free money."

REPRESENTATIVE BERKOWITZ remarked that the state would be creating a market for something from which someone else would profit, which does not necessarily work to benefit the state.

MR. MARKS stated that if Shell comes into the state because it is able to monetize its investment sooner, then all parties are better off.

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CO-CHAIR SAMUELS stated that his intent in regard to previous questions was to help Company A, but agreed that if there is no reason to buy the credit, the market "needs to work."

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REPRESENTATIVE MCGUIRE noted that the goal is to incentivize development and exploration by small companies, and asked why the legislature does not give a dollar for dollar tax credit for any capital investment made.

MR. MARKS said that is possible but may cost the state money.

REPRESENTATIVE MCGUIRE remarked that it would cost money, but it wouldn't cost money in terms of the taxes of the larger companies.

CO-CHAIR SAMUELS reminded the committee that the current portion of the presentation was an overview of credit sales and that taxes would be discussed at a later time.

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REPRESENTATIVE LEDOUX said that the companies are going to receive a tax credit, and [selling credits] would only occur if the company cannot use the tax credit.

MR. MARKS replied yes; this is merely if there is a loss and the company wants to monetize the loss sooner.

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REPRESENTATIVE LEDOUX asked if the companies can sell the tax loss to any company or if it needs to be a producer.

MR. MARKS replied that it is limited to the petroleum industry.

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ROBYNN WILSON, Director, Tax Division, Department of Revenue, agreed that this is correct, adding that the losses and credits may only be used against the production tax, and may not be used for other taxes, such as the state income tax.

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REPRESENTATIVE LEDOUX asked why, if the state is attempting to maximize tax losses and encourage investment, the losses and credits would not be applicable to anyone.

MR. MARKS explained that this is to protect the state's revenue.

REPRESENTATIVE LEDOUX asked why this is not an option and opined that if the state is going to "take the hit," it does not matter whether it is in the proposed profit-based petroleum production tax (PPT) or the state income tax.

MR. MARKS replied that the losses would only be used in situations when the companies were losing money and reiterated

that applying the losses to the PPT is intended to protect the state's revenue base in periods of very low prices.

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CO-CHAIR RAMRAS asked if [the state] is selling losses or selling investment.

MR. MARKS replied these are losses and explained the process for selling losses.

CO-CHAIR RAMRAS said one of the scenarios he is concerned about is someone takes 3-5 years to develop oil prospects. And, in the meantime, the price of oil decline. He said he just hear that the price of oil is headed back to \$30 per barrel, which would mean some dire things for the state budget, and it means the state would be more reliant than ever on the state's tax "skins" like the PPT. He said companies will be allowed to sell the credits, and he asked if the administration done "any modeling to determine how much of a credit can be used by those companies that are presently enjoying profits, that are interested in sheltering profits that they are deriving today by companies small, large or otherwise that are investing, with the horizon the that's going to generate revenue and profitability over the next three, five, seven years, but they are interested in monetizing their credits today, and they are selling those credits to companies that can use those credits today and shelter those credits."

CO-CHAIR RAMRAS continued:

Which goes back to my theme, which is: I'm worried about accountants being able to drive a Mack truck through [HB 488], and that's going to be where I continue to come down here, is this paradigm shift toward the power of accountants and the big oil companies taking advantage of the tax code that we create. So, I'm uncomfortable with the fact that you put [\$1 million] up here, which I'm sure you thought was a good thing to do, but nobody invested \$1 million up on the slope. So I want to make sure we don't get taken for a ride there, that it should be \$10 million, \$50 million or \$100 million, so that we're looking at credits that are \$20 million credit, cause nobody's going to ... have a \$200,000 credit to sell. These are going to be large increment credits that are going to get applied to the majors, who are going to be

buying at discount, as Chair Samuels indicated. And so, that's the concern that I have, is what exposure does the state have if the price of oil goes from \$60 to \$30, \$35, the producers that are still making a lot of money and paying a lot of taxes are now buying every available credit from every small, medium, large guy that's coming in here, and what kind of financial or fiscal exposure does that create for the state of Alaska?

MR. MARKS said there is a provision in the bill that limits the amount of tax liability credits to 20 percent of the tax bill.

REPRESENTATIVE CRAWFORD remarked that one of the concerns he has heard is that the big producers will be the only market to sell the credits, which may force down the price of the credits. In this scenario, the producer would get the benefit of the credit, not the state. He asked about the state being the willing buyer at 90 or 95 percent, to keep the price up so that major producers wouldn't get too much of a windfall.

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MR. MARKS said he would have to think about this and added that as the bill evolves there may be some interesting things to think about regarding the face value of the credit versus the actual credit.

CO-CHAIR SAMUELS asked Representative Crawford if, in his scenario, the state would have a floor for selling the credit.

REPRESENTATIVE CRAWFORD said there is a time value for money, and there would be a point where the state would benefit by buying the credit.

REPRESENTATIVE MCGUIRE said small companies are going to reach their losses early, so then there is no benefit to keep exploring, if they can't use that loss to offset it. "And so, what you're trying to do is allow a market to be created to essentially recoup part of those extra losses." She asked if there has been modeling to show what would happen in terms of incentivizing the small companies "rather than open up to transferability, you simply confined it to the small companies but you ran it out to infinity, and maybe even increased the percentage, so that you really wouldn't be expanding the universe to other taxpayers." She noted that the oil and gas companies are 80 percent of the state budget, and the state

greatly values their investments, "but with this transferability, you have this really noble goal of getting small companies investing Alaskan and exploring and making new finds where everybody benefits, but when you're staying with these tax credits, it's like me saying I'm going to make an offering of \$1 bills and you can buy them for 80 cents." She said she understands the 20 percent threshold, but companies will buy as many as they can since there is no time limit, "they're transferable into infinity and they're transferable up to 100 percent." She said there is no way of knowing what it will bring to the future of oil and gas revenue to the state.

Because I don't know how many of these companies are going to take advantage, but if it works the way we want, a lot of people are going to be exploring, there are going to be a lot of losses and a lot of these tax credits floating around. So, not only are the small companies going to be taking advantage of it, but they're selling these credits, and then you've got the three majors who are contributing the large sum to our tax base, reducing, with no limit to that reduction, what they're paying to us. So, ... to the extent that [Mr. Marks] can let us know what thought process has gone into that, and whether or not you've thought about how to incentivize these small companies, but to minimize the potential loss to the state. I would be interested to hear. Is it not enough of an incentive to say "we're going to give this back to you individually as a company, but we'll let you run it out, so once you've reached your maximum losses, in the year 2007, you can use it 2008, 2009, 2015." That's pretty generous, ... I think the value of being able to write those losses off into the future for anybody is great, and the fact that we haven't even put a 50 percent threshold on it is great.

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MR. MARKS said this incentive allows new investors to monetize their losses immediately. He explained that this is called "back end loading the fiscal system" which means that the tax obligations are moved farther back in time. He noted that net present value is very important to investors and rate of return depends on timing. He said there are more than three companies, and if there are at least two [companies] in the market for the credits, they will sell at a high [rate]. He opined that the vitality of the market would be good.

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CO-CHAIR SAMUELS remarked that some of the companies will be finding oil, and he asked if the model shows, per dollars spent, how much more production is expected.

MR. MARKS replied that they would create a model to see how this might work.

REPRESENTATIVE BERKOWITZ said the floor for the claw back provision is \$40 per barrel oil, and the credit does not have a floor. He asked what would happen to state revenue if there was a large amount of credit and the price of oil was low.

MR. MARKS replied that limiting the credits to 20 percent of the tax liability was intended to reduce this problem.

REPRESENTATIVE BERKOWITZ asked if the department had considered the possibility of the credits exceeding the revenue from new production and inquired as to the type of protection the state would have in this situation.

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MR. MARKS opined that the amount of new investments subject to a credit relative to the amount of existing oil production means it would take an extraordinary amount of investment and credit sales to make a noticeable dent in the total tax statement, but he said he would attempt to quantify this.

REPRESENTATIVE GARA said the bill now raises \$1.5 billion less than it did on Friday, and it's a bill that allows for changes [to the] gas tax law as well as the oil tax law. He said:

So, on the credit you have a system where people who've been coming to the state saying, "We want to develop Alaska's gas." The big cost item is the gas pipeline, but ... the gas is marketable apart from that. Now we're giving them, in addition, a credit that they can now take off of someone else's oil taxes. ... So, I'm wondering, if the gas was producible and marketable, leaving the pipeline aside, before, why are we now coming up with an additional credit for gas ... out of oil taxes? And the real question I want to ask is this: Given that it's now extended to gas credits on oil taxes ... it seems more

compelling to me that what we should be doing is giving a credit to be used on the project you're getting the credit for once it becomes profitable. ... People are going to invest in gas because they believe it's going to be a profitable gas deal. The time value of money, I know, is important to the companies, but it's important to the state, too. So, what would be wrong with saying "You get the credit on your gas investment when your gas comes online." You know you're going to get it; it's going to be a few years later, that's a big benefit. Why make it such a benefit now that you can take it off your oil taxes? What's the big detriment to just saying [that a] four-year gas project ... becomes profitable when it becomes profitable; you get a credit later on.

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MR. MARKS replied that the main upstream investment is Pt. Thompson. He explained that this plan makes Pt. Thompson a more attractive investment, which would incentivize the gas line.

REPRESENTATIVE GARA said that his earlier comments were in regard to Pt. Thompson. He stated that Pt. Thompson was profitable prior to this, and now a tax credit is being developed as if this additional incentive is needed.

MR. MARKS replied that Pt. Thompson's profitability is an open question and to incentivize Pt Thompson would incentivize the gas line as a result.

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MS. WILSON, in response to a question from Representative Rokeberg, noted that the limit of credits to 20 percent of the tax liability can be found on Page 6(e).

REPRESENTATIVE SEATON asked for an analysis showing the state as a willing buyer at 90 percent and making this a mandatory option. He opined that the only downside would be that if oil prices were low, the state would not be protected by the 20 percent if purchasing the credits was the only option. Making it optional removes the "downside", which would be a good investment. In response to a question from Mr. Marks, he said:

The state would have ... a bid ... that they would buy the credits for 90 percent. In other words, ... [two

oil companies] ... producing, they're paying their taxes. ... Instead of us having those two companies sell amongst themselves, ... and ... at 85 percent the second company that has the tax they're going to pay, make 15 percent on it, if we would have a standing offer that we--cancelable at our option--would buy those credits, [at 90 percent]. That means we're getting a 10 percent reduction on the amount that we have to pay, and yet, [company A] would actually be ... if a major [oil company] would be out paying them 85 percent, they would be getting 5 percent more back to that company. We would be saving 10 percent. ... Can you look at that in your model and see if it makes any difference?

MS. WILSON opined that the concept of allowing transferable credits was to keep the state out of the process. She added that if the state were to get involved, the simplest mechanism may be a refundable credit. She remarked that there may not be much advantage to being the "middle man."

CO-CHAIR SAMUELS said that he does not see this as being a "middle man," and instead suggested looking at the total loss of tax revenue to the state. If the state buys the credit for \$195,000 instead of taking the \$200,000 loss, the state would do better. He noted that the floor does not need to be 95 percent; it could be whatever the "break even" point is. He stated that this would ensure that the state received the best scenario.

REPRESENTATIVE SEATON stated that he is talking about a refundable credit, but it needs to be optional to take advantage of when oil prices are low.

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MR. MARKS, moving on to page 9 of the handout, said there is a mechanism in the bill for converting losses to credits and selling them. "Everything is exactly the same, the benefit is the same, you're back-end loading the tax, he said." These two mechanisms can work together. If pure wildcatters came into the state to explore, people with no connection to the state, and if they found oil, they would make a lot of money. But, if, for example, they spend \$10 million and drill a dry hole and leave. Under the current system, they would get nothing. They're out the entire \$10 million. But under the PPT, between the ability to convert the \$10 million loss to a credit and selling the

credit, the state would actually be paying for 40 percent of the cost of the dry hole. He continued:

So, what's happening with the PPT? We're sharing risk where we weren't before. Also note, if we went to a 25/20 system, we'd be sharing 45 percent of the dry hole cost as well. So, that's one thing to keep in mind when contemplating higher tax rates, in situations like this, you're also sharing more risk.

REPRESENTATIVE SEATON asked if selling losses and operational costs are both taken as credits.

MR. MARKS replied that "page 8 refers to selling the losses, an operation loss, that's converted to a credit, and you sell the credit." He said page 9 explains the credit received from a qualified capital expenditure, which is sold directly. "So the first example was converting a loss to a credit and selling the credit, and the second example is where you generate credits directly and sell them."

REPRESENTATIVE SEATON asked if drilling a dry hole is an operating expenditure or a capital expenditure.

MR. MARKS replied that much of what occurs during exploratory drilling qualifies as capital expenditure per [HB 488].

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MR. MARKS, referring to page 10, said that under the current system, small fields pay little or no tax. The administration feels this should continue. He opined that small companies are good for the state, and the best way to help these companies is with a tax-free allowance. He said:

Our goal was that at about a \$50 market price--or \$40 at the wellhead specifically--a 5,000 barrel-a-day field should pay no tax. And at lower prices, larger fields should pay no tax, but at higher production, there should be a lower price threshold. We'll show you how this works. Go back to the costs we laid out--your cost estimates yesterday--the amount of cost to get from the West Coast ... back to a net income is about \$14, if you look at both the downstream and upstream costs. That's for the North Slope. Cook Inlet is not dissimilar, but Cook Inlet has lower downstream and higher upstream costs. So, if you take

about a \$53 per barrel market price on the West Coast, you take these \$14 in deductions to get the net income, add, say, \$1 back for the credit, you're left with net revenue of \$40. At 5,000 barrels-a-day that's \$200,000 a day in income, and [multiplied by] 365 days a year is \$73 million in income. So, a \$73 million allowance, at a \$53 per barrel price, or \$40 net income, a 5,000 barrel-a-day field would pay no tax. If [the prices are lower], say \$30, with the \$73 million, the way the arithmetic works, the first 12 thousand barrels a day would pay no tax. Or, if you have higher production, say 20,000 barrels a day, it would be at \$23 per barrel, ... the first 20 thousand barrels a day would pay no tax.

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MR. MARKS said the allowance would apply to each company up to \$73 million. If a company has \$40 million in losses, it would only be able to take a \$40 million allowance. Not all companies will take the full \$73 million, he said. Current producers are estimated to have 7 full deductions. With the 20 percent tax rate applied to the \$73 million, it is about a \$14 million reduction in net tax per company per year. He said this would be \$100 million a year in less taxes. He opined that there will be few small companies coming to the North Slope to realize this credit. Under the current system [Pioneer and Kerr McGee] would pay zero in severance tax and produce around 20 thousand barrels per day. The administration does not believe that thousands of new companies will come in and take advantage of this in the North Slope. If new companies do come in, he opined, they would look at new targets such as the Nenana Basin. He said if a company finds a prospect in one basin, the next company will come in and take advantage of the allowance, so it will encourage smaller companies. However, this would create stress between old and new investors. Companies could not split up in order to take further advantage, he stated, because there are anti-splitting provisions in Section 21 of the bill. He added that at higher prices, after the first 5,000 barrels, there would be a tax.

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CO-CHAIR SAMUELS said that he envisions the same problems found in the economic limit factor (ELF); Prudhoe Bay will decline and the state will be left with "a bunch" of small companies not paying any tax. He asked how the state can be sure that the

North Slope will not attract "a bunch" of [companies] with the allowance. He noted that in the short-term, this is not a problem, but added that 20 years from now, "there we are again, wishing we had the \$73 million."

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MR. MARKS said the North Slope oil is heavy and viscous and small companies won't be interested in it. It takes \$8 barrel just to get to market, he stated.

REPRESENTATIVE LEDOUX asked about the anti-splitting provision.

CO-CHAIR SAMUELS said that may be covered later.

REPRESENTATIVE BERKOWITZ commented that there has been a lot of discussion regarding how the state will incentivize small companies. He inquired as to how the bill deals with the cost of tariff and transportation.

MR. MARKS said the Trans-Alaska Pipeline System (TAPS) settlement methodology (TSM) ends in the year 2011, and the state has the ability to challenge it in the year 2009. He opined that the tariff will be noticeably reduced.

REPRESENTATIVE BERKOWITZ asked if that decline in tariff was factored into the bill.

MR. MARKS said no. He added that the tariff notwithstanding, there are large challenges for small companies operating on the North Slope.

REPRESENTATIVE BERKOWITZ asked about a similar analysis at different oil prices.

MR. MARKS said the \$40 and the 5,000 barrels were somewhat arbitrary; it was just a judgment call based on the goal to continue the current treatment for small fields. He continued:

Under the old bill, again, take the Pioneer and Kerr-McGee prospects that are around 20 thousand barrels a day. They're going to pay tax on the last 15,000. Under the current bill they would pay nothing. They came to the slope ... with a certain set of expectations.

REPRESENTATIVE BERKOWITZ asked who made the judgment on the amounts used. He said that the legislature would like to see another analysis at different tax rates and dollar amounts.

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REPRESENTATIVE GARA said that the bill is trying to mimic a rule that gives a 5,000 barrel-per-day field tax-free status. He opined that most fields of this size are very profitable, and would need to be shown otherwise. He expressed concern that the current plan helps the bigger companies more than the smaller companies. He asked, "Why give the \$73 million tax-free to the biggest companies in order to give a smaller portion of that to the smaller companies? Isn't that giving way too much money to reach the goal?"

MR. MARKS said that each company is treated the same in terms of the tax code. He added that giving companies different benefits is an invitation for "monkey business."

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REPRESENTATIVE SEATON asked if the allowance is only against the PPT. Referring to page 14 of the handout, he asked how many full deductions are estimated at 25/50.

MR. MARKS confirmed that the allowance is only against the PPT. In regard to the full deductions, he said that at the long-term price it would be less than seven companies.

REPRESENTATIVE BERKOWITZ asked what the cost to the state treasury would be if the allowance were applied today.

MR. MARKS replied that it would be about \$100 million per year, the bulk of which would go to the seven biggest companies. He explained that the seven is equivalent and noted that some are partial allowances. The three big companies would receive it, along with a few of the smaller companies.

REPRESENTATIVE BERKOWITZ said the big three would get the full \$73 million, however, the smaller companies would be "doing cartwheels" if they were to make the full amount. He opined that the three big companies would get \$210 million.

MR. MARKS replied that after tax it is \$14 million per company.

REPRESENTATIVE BERKOWITZ noted that the federal government would receive some money as well.

MR. MARKS said yes.

[1:45:09 PM](#)

CO-CHAIR SAMUELS said that this will incentivize small companies.

REPRESENTATIVE BERKOWITZ remarked that this is inefficient.

REPRESENTATIVE SEATON said that in a previous presentation the emphasis was to move away from a field-by-field tax and instead go to a company-wide tax. He stated that the proposed system seems to be field by field, and asked if the state will receive the worst of both systems by having the field by field within the company-wide system.

MR. MARKS said the allowance is company wide, not per field.

REPRESENTATIVE LEDOUX said that she can understand the desire not to treat the companies differently, but suggested that the state differentiate by the amount of revenue per company, which is done in tax codes "all the time."

MR. MARKS said that this is possible; however, stresses between new and old companies remain a concern. If BP, for example, is looking at a small field and does not receive the allowance that a [smaller company] does, this puts BP at a professional disadvantage. He added that leveling the playing field is good.

[1:47:42 PM](#)

REPRESENTATIVE GARA remarked that it may make more sense to require a tax after a profit is made, as the company is receiving a 20 percent tax credit and a 20 percent deduction, and the PPT says no tax until a company makes a profit. He added that it would also make sense to grant the allowance to the areas the state is trying to reach.

MR. MARKS reiterated that small producers are not interested in heavy oil because it is too expensive.

REPRESENTATIVE GARA asked why the state does not aim at the areas where it is trying to encourage [development] and not

include other areas such as Prudhoe Bay, Alpine and Northstar Unit.

MR. MARKS replied that uniform treatment is important, otherwise there would be room for "monkey business."

CO-CHAIR SAMUELS, in regard to the anti-splitting provision, used the Kuparuk River Unit as an example in explaining the fear that a large company would split into a series of limited liability companies (LLC). If this were to occur, the money would still flow to the same company, and each individual LLC would receive the \$73 million allowance. He noted that the anti-splitting provision in Section 21 of the bill would be explained in detail during the next presentation.

1:50:40 PM

MR. MARKS, in regard to the PPT and the effect it will have on Cook Inlet, said that Cook Inlet is 80 percent gas. The industry at Cook Inlet is evolving; oil and gas production is decreasing, as many of the assets in the area are old and depreciated out. He said that there is increased investment in exploration, particularly for gas. In addition, the regulatory division has granted contract provisions that require high prices. He noted that Chevron has been awarded contracts that allow it to sell gas to ENSTAR at the Henry Hub price. He noted that this price is historically higher than it has been. He remarked that gas prices have gone up since Hurricane Katrina. The impact of oil taxes on Cook Inlet won't be significant unless prices are high and profits are earned. Other than Chevron, most of the companies in Cook Inlet are small. Gas taxes on existing fields will go up as a result of the PPT, particularly due to the current prices. He said that the PPT will encourage exploration in Cook Inlet.

MR. MARKS went on to explain that there is a gas economic limit factor (ELF). The Cook Inlet gas fields produce 600 million cubic feet (mcf) per day, which is about 200 billion cubic feet per year. He stated that this gas is shipped all over the world for different uses. The average ELF in Cook Inlet is .50, which implies 6,000 mcf per well, per day, tax-free. He explained that the revenue from tax-free gas is intended to cover operating costs, adding that the estimated operating cost is 50 cents. Mr. Marks said that the operating costs are \$3,000 per well, per day. The revenue from the \$3,000 tax-free gas is worth \$21,000, so with the current ELF, the state is recovering

three times what the operating costs should be. This is the reason that the tax rates on existing fields will increase.

[1:58:22 PM](#)

MR. MARKS stated that the crossover point for existing fields is estimated at about \$4.00/mcf. An increase to \$5/mcf would mean an increase of \$25 million annually. This is out of \$1 billion in gross revenues. He stated that Cook Inlet gas [production] is declining, and the state hopes the PPT will incentivize development in Cook Inlet, adding that new production may see reduced taxes as a result.

CO-CHAIR SAMUELS expressed concern with adding "and gas" to the entire bill, and asked if this was done to help Cook Inlet. He opined that it is irrelevant because North Slope gas has no contract.

MR. MARKS said no, and stated that the PPT was designed to apply to all upstream assets from statewide oil and gas. He added that upstream expenditures would be subject to deductions and credits.

[2:00:43 PM](#)

MR. MARKS, in response to a question from Co-Chair Samuels, said that the \$73 million allowance is limited to the companies' income and applies to each producer in the state, regardless of location.

CO-CHAIR SAMUELS asked how many Cook Inlet fields would be above the \$73 million threshold.

MR. MARKS replied that while he is not able to disclose confidential data, a person may look at this and draw his or her own conclusions.

REPRESENTATIVE GARA noted that the \$73 million applies to all the Cook Inlet producers, and asked if any producers make more than that amount in profit.

MR. MARKS replied that he is uncomfortable talking about specific taxpayers in a public setting and suggested that a meeting time be arranged to discuss this.

REPRESENTATIVE WILSON asked for an idea of what an [oil] company would pay if BOE was over or under 27 what would occur.

[2:03:20 PM](#)

MR. MARKS replied that Chevron taxes will go up and Marathon oil taxes will go up.

REPRESENTATIVE ROKEBERG asked if, with the current ELF and current pricing, there will be increased revenues from Cook Inlet with the PPT.

MR. MARKS said it depends on operating and capital costs.

REPRESENTATIVE ROKEBERG said that the total amount of sales in Cook Inlet may not exceed the \$4/mcf.

MR. MARKS said there are old contracts that will not require any tax under the bill.

MR. MARKS, in response to questions from Representative Rokeberg, said that the additional \$25 million is an estimate and added that if the Cook Inlet gas production declines over the years, the estimate would be proportionally lower. He said that the PPT would apply to all the gas in the state, and the natural gas liquids (NGL) on the North Slope are considered gas, because they are a product of gas processing. He confirmed that the same terms and conditions apply to gas and oil.

[2:07:22 PM](#)

REPRESENTATIVE GARA asked for projections showing how the proposal would compare to current law or North Slope gas production.

MR. MARKS said that could be provided.

CO-CHAIR SAMUELS asked if it would it be more fair to say the rules were written for Cook Inlet and a PPT, rather than a gas line, which has a different set of rules and regulations.

MR. MARKS replied that the provisions in the PPT that affect Pt. Thompson development may provide a "big incentive" to build the gas line.

[2:09:06 PM](#)

MR. MARKS concluded by saying that the bill reflects the administration's judgments on attracting small and new

investments. He noted that for the new investors, taxes may increase at high prices, which is appropriate. He stated that the administration has briefed the potential new investors on the bill and has not received a response regarding where they stand on the issue. He encouraged the committee members to "listen to what they have to say," and remarked that the administration looks forward to crafting the legislation to assist the new investors.

REPRESENTATIVE RAMRAS explained the situation regarding the Nenana Basin and the difficulty in getting resources to Fairbanks. He stated that alternative energy is needed in Fairbanks and asked for suggestions on how this might be done. He asked to be taken through the process of incentivizing exploration in the Nenana Basin.

MR. MARKS explained that under the current system the fields would be small and pay no production price, regardless of price, which is an incentive. He remarked that the \$73 million is the state's attempt to incentivize. He said that under the current system, the state does not help with capital and operating costs. Under the proposed system, the state will pay 40 percent of costs from day one.

[2:12:40 PM](#)

REPRESENTATIVE RAMRAS asked if a company that spends \$20 million and comes up with a dry hole would be able to recapture \$3.6 million by selling credits.

MR. MARKS replied that between converting losses to credits and the credit itself, the company would have \$8 million in credits to sell. He added that 90 percent of \$8 million is \$7.2 million, and under the status quo the company would receive nothing. He reiterated that under the net present value, the company would receive the \$7.2 million on day one, rather than being required to wait until money is earned.

CO-CHAIR RAMRAS, in regard to bringing the gas to market, asked if the transport for a small line would be covered.

MR. MARKS replied that it is not, and he explained that the gas cuts off upstream of the lease boundaries.

[2:14:04 PM](#)

CO-CHAIR RAMRAS said that the committee previously discussed a gas treatment plant and indicated that he was unsure of what the specific reasoning was.

CO-CHAIR SAMUELS asked whether credits could buy the treatment plant or the tariff should pay for it, and he asked the about a production facility, which is used to process excess gas, "but you need those whether you have a gas line or not." He noted that small players have to pay to use the large companies' processing plants. He asked if the state wants to encourage [small players] to build their own, which would encourage more oil investments. "So they don't have to pay the major producers for the use of their facilities as well as the use of TAPS." He continued:

The GTP [gas treatment plant] is a facility which makes the gas - pipeline quality gas to go. Everybody will have to go through the GTP. That should be paid for by tariffs. The users - part of tariffs should go through there, the credits ... there are no credits in the bill which would allow to use for the GTP. They are different animals on what they're needed for. The gas processing plant is needed, even for oil production. We have to do something with the gas to reinject. The GTP is solely a gas pipeline facility. That should be paid for by tariffs and by users, and not by tax credits.

MR. MARKS agreed.

[2:15:45 PM](#)

The committee took an at-ease from 2:16 to 2:27.

[2:27:16 PM](#)

DAN DICKINSON, Consultant to the Governors office, said that in addition to previous handouts, there is a new sectional titled "SB 305/HB 488, The Rest of the PPT Story."

ROBERT MINTZ, Assistant Attorney General, Oil, Gas & Mining Section, Civil Division, Department of Law, spoke of an earlier question as to the relationship between the two types of credits. He said there are two cost concepts in the bill. There are lease expenditures, which cover all the deductible costs of exploration, development, and production, and there are

capital expenditures, which are a subset of a lease expenditure. He continued:

Capital expenditures qualify for a capital credit, and all of these expenditures qualify for a deduction against gross value. But not all of these expenditures qualify for the capital credit. I think one of the points that Representative Seaton was getting at, is when you drill a well, a lot of the expenses are what look like, we think of as, operational expenses, yet they're considered a capital expenditure. That's because the definition of "qualified capital expenditure" includes not only costs of acquiring plant and equipment that is typically considered a capital asset, but also [includes] what are considered "intangible development costs" under the Internal Revenue Code, and that's the cost of drilling a well. It is important to understand that not everything that is deductible as a lease expenditure also qualifies for a capital investment credit.

[2:31:03 PM](#)

MR. MINTZ, referring to page 3 of the handout titled "Bill Slideshow Pt 1& 2", said that the fundamental provision of the production tax is AS 43.55.011(a), and the highlights include a single tax on oil and gas which is equal to 20 percent of the net value. He said that "net value" is a new concept and the definition can be found in AS 43.55.160. The net value is made up of three elements and begins with the gross value of oil and gas at the point of production. There are two types of deductions: lease expenditures and transitional investment expenditures. He noted that a portion of AS 43.55.160(a) is not included in the handout, and this portion begins with "Except as provided in (f) and (i) of this section." Mr. Mintz went on to say that (i) refers to the \$73 million allowance, which could also be considered a deduction. In regard to net value, he said the definition can be found in Section 31 of the bill. He noted that the current definitions have been changed. The main change moves the point of production downstream of gas processing. The gas processing is then deductible and subject to capital expenditure credit.

MR. MINTZ moved on to page 6 and said that this shows the existing law for calculating gross value at the point of production. The bill does not change the fundamental concept.

He explained that this page shows the net back method for calculating value. To calculate, the net back method begins with the value of oil and gas where it is sold or disposed of and subtracts transportation costs. The most significant change to the calculation of gross value at the point of production is allowing the department to authorize producers to use simplified calculation formulas, when appropriate. For example, if there is a simple way to calculate the value of oil and gas for royalty purposes, under leases that the Department of Natural Resources (DNR) administers, the department could then allow this calculation to be used for tax purposes.

MR. MINTZ, referring to page 9, said that "lease expenditures" is defined in AS 43.55.160(c). He stated that lease expenditures are the total statewide costs of the producer incurred upstream at the point of production, and they must be direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas. He explained that the department is able to determine how to interpret the statutory terms and is referred to two main sources for guidance. The first is industry practice, which is expressed in joint operating agreements. Under these agreements, an operator bills the lessees for the exploration and production costs. He said that these practices are well developed. The second source of guidance is the DNR standards regarding which costs are deductible for net profit share lease calculations.

[2:36:46 PM](#)

REPRESENTATIVE SEATON asked if industry practice and standards and unit agreements are different for individual fields.

MR. MINTZ said yes, and the department has the ability to look at examples of practices both in the state and throughout the country.

REPRESENTATIVE SEATON asked if it was company wide or field based.

MR. MINTZ said the operating agreement is typically for a unit and would be applied to the different lessees with an interest in the unit.

REPRESENTATIVE SEATON asked if the costs that are deducted are company wide but determined based on a particular field.

MR. DICKINSON replied that the operator will spend the dollars and then the owner looks at the costs and decides how to approve them. The owner will pay a percentage of the cost incurred at the site. He explained that there would typically be "joint venture" billing for a field. The operator would bill each owner a piece of the cost. He said that a field owned by a single company may result in some problems, adding that it would be necessary to develop rules regarding how to look at the costs. Referring to the handout, he noted that in regard to industry practice, there must be a minority owner with substantial bargaining power.

[2:40:07 PM](#)

MR. DICKINSON, in response to a question from Representative Seaton, confirmed that the regulations have not yet been written; however, the intent is for the costs to be relative to the particular field and would not be company wide.

REPRESENTATIVE BERKOWITZ asked about the term "substantial weight" in regard to assessing costs, and inquired as to what would happen if there was a conflict between industry standards and DNR standards.

[2:41:28 PM](#)

MR. MINTZ replied that "substantial weight" gives the department the ultimate authority to make a decision. He stated that while he is unable to predict how a conflict would be resolved, industry practice is a broad concept that varies with each operating agreement. He opined that the DNR regulations will be within the same range as the industry practices; therefore, conflicts would be rare or nonexistent.

REPRESENTATIVE BERKOWITZ noted that it is important to include a statement of legislative intent.

MR. MINTZ agreed. In regard to an earlier comment made by Mr. Dickinson, he said:

It's important to understand that industry practice-- or joint operating agreements--can have, potentially, two different roles under [AS 43.55.160]. One role is in a source of the general standards that the department would apply in determining whether costs are deductible. For example, if the department surveyed a number of joint operating agreements and

found that, say, 90 percent of them allowed a particular cost and 10 percent of them did not, then the department might determine that that cost is not allowed in general. But, the second way that joint operating agreements can play a role is that the end of this subsection says that, in particular cases, the department may allow a producer to actually simply rely on the billings under a joint operating agreement as the lease expenditures. So that you wouldn't go through the intermediate stage of looking at the general standards. Those are two different ways that could occur.

MR. MINTZ pointed out that subsection (d) includes more information as to what costs are allowable. Referring back to AS 43.55.160(a), he noted that net value is gross value, less two types of deductions. He explained that the lease expenditures have to be adjusted before being deducted. "I think the concept here is very simple," he said, "All that the producer should be allowed to deduct are the net costs, so if there are reimbursements, sales of assets, and so forth, they have to be subtracted from the gross costs."

REPRESENTATIVE BERKOWITZ, in regard to the transitional investment expenditures, said 1/72 is an unusual fraction.

MR. DICKINSON explained that discussions on the transitional investment expenditures have resulted in a six-year time frame. However, since this is a monthly expenditure, when multiplied by 12, the end fraction is 1/72. This means that a company can take the transitional investment expenditures in the first 72 months, when the average price is higher than \$40. He noted that this is a slightly more complex formula that has been addressed at length. In regard to the state allowing lease expenditures as a deduction, he added that 100 percent of these costs are allowed. He said:

In other words, we do not try to parse out a royalty share. Typically the royalty owner doesn't reimburse those, isn't part of that. So we are allowing 8/8s of the upstream cost to be allowed. Therefore, if a royalty owner, for example, the state, were paying a field cost allowance or reimbursing, those will now become a deduction. Those will now, if I can make a deduction, a contra-expense account, if you will, that will lower the amount of expenses that a company can deduct. If they're spending \$100 for upstream costs

and the Department of Natural Resources is reimbursing them 20 cents under a lease, then they're really only spending 80 cents, and that's all they're going to be allowed to deduct for purposes of the tax.

[2:47:08 PM](#)

MR. MINTZ explained that transitional investment expenditures are capital expenditures incurred from 7/2001 to 6/2006, less proceeds from the sale of assets acquired as a result of those capital expenditures. He noted that AS 43.55.160(i) is an exception to the basic calculation of net value. This exception states that if there is net value remaining after all of the deductions, there is an allowance of up to \$73 million per year. He added that because this is a monthly tax, the producer receives a monthly allowance, which can be allocated in any way. There are three limits on this allowance: It may not exceed \$73 million per year, it may not reduce the net value of oil and gas below zero, and if not used within the year, the \$73 million may not be carried forward.

REPRESENTATIVE SEATON opined that the \$73 million could be used all at one time if the company owed the full amount in taxes.

MR. MINTZ said that this is correct. He stated that AS 43.55.011(a) applies a 20 percent tax rate to the net value calculation. He said that before the producer determines the monthly payment, there is the possibility of applying credits. He explained that one of the major credits the bill establishes include the qualified capital expenditure credit which is defined in AS 43.55.024(b). He said that capital expenditures fall under three categories. The first category is anything required to be capitalized under the Internal Revenue Code. The second is intangible drilling costs, and the third is geological and geophysical exploration costs. He added that this last category is not usually considered a capital investment. The credit is limited to new assets.

CO-CHAIR SAMUELS asked if there is any advantage to pushing money into the capital column instead of the operating column.

MR. MINTZ replied that, overall, there is no incentive for the producer since it is preferable to use an item as an expense as opposed to an expenditure for federal income tax. He noted that this is why the bill tracks the IRS categorization.

[2:51:38 PM](#)

MR. DICKINSON added that it will be deductible either way; however, the federal categorization will have a larger dollar effect.

CO-CHAIR SAMUELS asked if, for auditing purposes, the state will have access to the companies' federal income tax information.

MR. DICKINSON replied that the state has an information sharing agreement with the IRS, adding that the only information that would be audited is whether or not the information was given, not whether or not the decision [made by the IRS] was correct.

[2:52:50 PM](#)

REPRESENTATIVE SEATON asked, "With the 20 percent tax credit on either operating or capital;...is there any gaming?"

MR. DICKINSON replied that for the deduction it is equal. "Operating gets a 20 percent deduction; capital gets a 20 percent deduction, so there's no reason to game that." He said only the capital gets the 20 percent credit in addition. "And so we believe that just the categorization of credit or non-credit, the lower incremental tax rate in the state, production tax means that you won't try to do it here and then suffer the consequences of the federal tax."

[2:53:39 PM](#)

MR. MINTZ stated that the second credit can be found in AS 43.55.160(b). He explained that a producer with excess lease expenditures during a calendar year, can carry them forward and use them as credit. He said a 20 percent credit is equivalent to carrying forward the deduction, as the tax rate is 20 percent. He mentioned an additional credit that allows the conservation surcharges to be credited against the production tax, and commented that this is only at 2-3 cents per barrel.

CO-CHAIR SAMUELS asked if there is a limit on the amount that can be carried forward from year to year.

MR. DICKINSON said yes, and added that there are credits established in AS 43.55.025 that will remain the same; however, only one can be used. He also noted that there is an education credit that is also available.

MR. MINTZ, referring to page 21 of the handout, said that calculating tax begins with gross value. The main difference in the new calculation is that the entire value of oil and gas from a producer is added together. The second step is to calculate the adjusted lease expenditures. He explained how to calculate transitional investment expenditures. The third step is deducting the \$73 million allowance.

MR. MINTZ referred to the anti splitting provision and said:

In order to qualify for a deduction, a producer has to be qualified by the Department of Revenue. As everyone here has recognized, the incentive here is to multiply the number of producer entities so that each can qualify for the \$73 million, and that's what we need to protect against. Now, the most obvious way to do that, is probably not that much of a problem, which is to set up a number of different producers which are subsidiaries or in some way related. The reason I say that's probably not that much of a problem is because the department [regulations] already have a definition of "producer," which essentially includes entities that are ... affiliated and would be considered part of a consolidated entity under normal tax law consideration.

[2:59:15 PM](#)

CO-CHAIR SAMUELS asked if two companies merged and had the same board of directors but different presidents, would they be considered affiliated companies?

MR. DICKINSON said that this is correct.

CO-CHAIR SAMUELS asked what percentage of the board of directors would need to be the same.

MR. DICKINSON replied that he would look up this information and opined that this is the substantial control standard.

REPRESENTATIVE SEATON asked if the 72-month period is only applicable to transitional investment expenditures.

MR. DICKINSON said that this is correct, adding that if the price dropped for one month, this month would be added to the end of the queue and show up six years and one month later.

3:01:11 PM

MR. MINTZ stated that the definition of "producer" in the current regulation says that owner includes all members of a group in which one exercises significant influence over the others within the meaning of accounting principles aboard opinion number 18. He opined that this is limited only by the creativity and imagination of those attempting to receive the benefit of the allowance. For this reason, he noted, the bill attempts to use the most basic language, adding that the more specific the language, the easier it would be for companies to "get around" this, if the specific terms are not met. He quoted from Page 16, Subsection (j) of HB 488, which reads in part [original punctuation provided]:

To qualify under this subsection, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any net value of taxable oil and gas ... that would be reasonably expected to be attributed to a single producer entity if the allowance provision of (i) of this section did not exist.

MR. MINTZ reiterated that existing as a producer in the state triggers the \$73 million allowance, and the danger is a multiplication of producers. He said:

To rephrase the standard, if a single producer would do the job without the \$73 million allowance, then we have to be suspicious if there are two or more producers that just show up. It's a very tricky area because we don't want to say that it's not going to be ... allowed to a producer that wouldn't be in the state or wouldn't be operating were it not for the allowance, because you want that to happen. That's the incentive that you're trying to provide. What you don't want to happen is for there to be an artificial multiplicity of entities.

3:04:01 PM

CO-CHAIR SAMUELS said:

The other fear is all these corporations do business around the globe, and if it behooves you, I'll give

you half of my small field here. And we'll do something for you in Kuwait, or Angola, or Venezuela ... and everybody wins if both companies get the \$73 million tax deduction ... and then you could get it back somewhere else in the world, and ... there's no way you can audit for that.

MR. DICKINSON expressed hope that there would be a way to audit this. He pointed out that the bill says "Any information the department may require," which means that if the department is auditing for this, it would be appropriate for it to request access to the books and records showing how this was brought about.

REPRESENTATIVE BERKOWITZ said the benefit between multiple producers should be incorporated in the department's assessment. He inquired as to the standard used for the producer demonstration and if there is a penalty for violation of the splitting provision.

MR. MINTZ replied that the producer would have to demonstrate to the Department of Revenue, which must then determine whether the producers qualify.

MR. DICKINSON said there is no penalty for violating the splitting provision. He opined that a company would come to the department beforehand in an attempt to qualify. The department would then examine the application, choosing whether or not to grant the qualification. The idea is to remain prospective. He said that while there is no penalty for trying, this probably would not occur.

REPRESENTATIVE BERKOWITZ remarked that if the department is concerned that splitting could happen, there needs to be a sanction. He expressed concern with the possible exchange of benefits in addition to the division of ownership.

MR. MINTZ said that this needs to be given more thought; however, the term "ownership" is used because it is only the status of producer that triggers the eligibility for the allowance. He noted that it does not matter if a benefit is received from another producer, if they do not also receive the eligibility for the allowance.

[3:08:09 PM](#)

REPRESENTATIVE ROKEBERG referred to hearings on de-aggregation and a discussion on letters of opinion which were not answered in a timely fashion. He asked about the speed of response to inquiries without a good track record.

MR. DICKINSON replied that the letters in question were sent after production had begun. He opined that if individuals were concerned, they would make application prior to stepping into the state. If the department felt that the decision of whether or not to come into the state was dependant on the department's decision, the commissioner would respond as soon as possible.

REPRESENTATIVE SEATON asked if a company new to Alaska interested in purchasing 10 percent of Prudhoe Bay would qualify.

MR. DICKINSON stated that this brings up the issue of drawing a line between economical development on the North Slope and tax motivated development, which the state is trying to discourage. He said that many interests in Prudhoe Bay have changed hands over the years, and this was not tax motivated. He added that if a producer wanted to buy out an existing interest, the state would look at the new producer and if it was a matter of replacing one producer with another, the new producer would most likely qualify. He explained that the definition is broad enough to enable the commissioner to examine the facts and circumstances.

REPRESENTATIVE SEATON commented that the state is worried about tying into a long-term fix. He asked if there would be a downside to applying a ten-year sunset provision to the \$73 million provision.

[3:11:56 PM](#)

MR. DICKINSON replied that if there is abuse, the legislature has the ability to step in and fix this. If some portions were tied to a contract with elements of fiscal certainty, additional anti-splitting provisions can be added to the contract. For example, if producers with major interests were signing the contract, an additional provision can be added which would require the issue to go to an arbitrator to decide if the behavior was tax motivated. He noted that when the legislature relinquishes the right to "fix" an abuse, other tools must be available.

[3:12:58 PM](#)

REPRESENTATIVE SEATON asked if Mr. Dickinson was stating that a sunset would not work for this purpose.

MR. DICKINSON replied that while several of the amounts in the bill are tied to inflation, [the \$73 million] is not. He said that this will become a smaller incentive, although it will still remain a significant amount. The benefits of the allowance should continue to attract new producers to the North Slope and Cook Inlet. He stated that removal or adding a sunset provision was not seriously considered.

[3:14:13 PM](#)

CO-CHAIR SAMUELS asked how much power the DNR commissioner currently has in regard to the sale of a portion of a field. He asked how much confidential sale information the state has access to and inquired as to whether the commissioner currently has the power to stop a sale.

MR. MINTZ replied that while he does not have a complete answer, the lease assignments require the approval of the commissioner. However, the lease assignments are broad enough to perform the reclamation that is required after the lease has terminated. He stated that he is not sure what financial details can be known.

MR. DICKINSON added that the department receives information about sales because of appraisals of comparable sale for property tax.

[3:16:26 PM](#)

REPRESENTATIVE JOULE asked how long the allowance would be in existence.

MR. DICKINSON said every year.

REPRESENTATIVE JOULE asked if it would be possible to slow down development and calculate the barrels so that the allowance would be received each year. He asked if there would be any reason to calculate every year.

MR. DICKINSON opined that there may be reason to do this; however, anyone attempting to time the profits would need a crystal ball to know future prices. He added that in general, the only changes that could be made at the margin include delaying sales if the producer felt prices were rising. He

opined that a person may make an attempt to do this based on future estimates of price, which could possibly go awry.

[3:18:25 PM](#)

CO-CHAIR SAMUELS commented that in 15 years, \$73 million will only be worth one third of what it is today and may not be as much of a concern. However, there is still a lot of opportunity.

REPRESENTATIVE ROKEBERG, in regard to the inflation clause for the \$40 barrel, asked why the index was not specified now.

MR. MINTZ replied that there are a number of different indices and the department needs a chance to study the issue and determine the most appropriate formula.

REPRESENTATIVE ROKEBERG remarked that it would be logical to use the U.S. All Cities Index.

MR. DICKINSON replied that this could have been used, however, in time, this may change. He stated that the statute gives broad authority and the specifics are left up to the regulations.

REPRESENTATIVE ROKEBERG asked if subsection (1) is the "bail out clause."

MR. MINTZ replied that this section is confirming the department's general authority and added that if the statute specifies an index, this could not be adjusted through regulations. He opined that there is no correct answer.

MR. DICKINSON pointed out that current regulations consider the oil price to be the average of the Reuters Reporting Service, the Telerate Reporting Service, and Platts. He explained that up until three years ago, spot price was defined as the Platts value. He said that these things change over time, as long as the broad statutory authority is in place.

REPRESENTATIVE BERKOWITZ asked why the \$40 was increasing by an inflation rate which is determined by regulation, rather than allowing the amount to be determined by regulation on a regular basis.

MR. MINTZ replied that the \$40 trigger applies to the 1/72 transitional investment expenditure deduction and does not apply to the \$73 million allowance.

REPRESENTATIVE BERKOWITZ asked if this only applies to the claw back.

CO-CHAIR SAMUELS said the claw back does not come into effect unless the price is over \$40 per barrel and only with inflation. He stated that if three years are missed at under \$40 barrel, with the claw back, the missed years can be added to the "back end" to collect when the price is above \$40 per barrel.

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MR. MINTZ went through the chart on page 25 of the handout, describing the calculation of net value. He explained that the calculation begins with the gross value of oil and gas. The next step is to subtract the adjusted lease expenditures, which must not exceed the gross value. He went on to say that if there is a positive remainder, the transitional investment expenditures can be deducted. If a positive net value remains, the monthly allocation of the \$73 million allowance can be deducted. He noted that none of these deductions may go below zero. Mr. Mintz pointed out that AS 43.55.160(f) allows the producer to deduct 1/12 of the annual lease expenditures, rather than deducting the monthly lease expenditures. This is a safe harbor and allows "lumpy" costs to be spread over 12 months.

MR. DICKINSON, in response to a question from Representative Seaton, said the relationship between gas and oil prices is "fairly tight," and in general only one standard is set. In response to further questions, he stated his belief that the relationship is close, adding that in Cook Inlet, prior to world pricing, the relationship was not close, as the BTU equivalency was around 6-1.

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MR. MINTZ noted that the current regulation defines "producer" as a working interest owner or lessee. He stated that one of the goals of HB 488 is to allow exploration expenses to qualify for loss and capital expenditure credits. He said that exploration is often not conducted on a lease, but rather is conducted by permit on land that is owned by the state or other land which the permittee has no interest in. He explained that

in subsection (m), it states that for purposes of these credits, an explorer is considered a producer.

REPRESENTATIVE ROKEBERG, referring to Page 17, Section 2, asked why "target zones" only apply to land located in the state and does not include federal lands off shore. He requested an update of the status of the state's share of federal lands.

MR. MINTZ said the production tax applies to Alaska regardless of whether the land is federal, state, or private. He noted that there is a tax exemption for oil and gas royalty shares which are owned by the state or federal government. He stated that the outer continental shelf (OCS) is outside the State of Alaska; therefore, the state's taxing authority does not apply. He added that because the production tax applies to production from leases or properties within the state, it is good public policy to allow credits and deductions for exploration and production of oil and gas within the state. In the case of a stratigraphic well, which is typically drilled for the purpose of obtaining geological information, he explained that this is defined based on target zones.

REPRESENTATIVE ROKEBERG asked if the state receives benefits for OCS and Minerals Management Services (MMS) leases beyond the three-mile zone.

MR. MINTZ replied that there is revenue sharing from the federal government, although the state does not tax the production or property used in the production and does not receive royalties from the production.

REPRESENTATIVE ROKEBERG asked if the state receives benefits from National Petroleum Reserve-Alaska (NPR-A) and Arctic National Wildlife Refuge (ANWR).

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MR. MINTZ replied that the state taxes NPR-A, and the federal government shares royalties.

MR. DICKINSON, in response to questions from Representative Rokeberg, added that the state would apply a tax of 8/8 instead of 7/8. He explained that this means if it is a state lease, the state is not taxed. If the land is privately owned, there is no state exemption; therefore the producer pays tax on 8/8 of the production.

CO-CHAIR SAMUELS, referring to Page 17, Line 7, asked for confirmation that "only if the wells target zones are located in the state" means the political boundaries of the state, not state owned land.

MR. DICKINSON confirmed that this is correct.

MR. MINTZ, in regard to transferable tax credit certificates, explained that if any tax credits are unused and the producer wishes to transfer the credits to a different company, the producer must apply to the department for a tax credit certificate. He said that to maximize the economic value of the certificate to the applicant, it is necessary to act in a timely manner; therefore, there is an expedited process which requires the department to make a decision within 60 days. He noted that information may come up later that casts doubt regarding the eligibility for the credit. If the marketability for the certificate is impaired, this undermines the purpose of providing the incentive to the original explorer or producer. He said that once the certificate is issued, the buyer can rely on it. If a problem comes up, and there is a deficiency for the original credit on the part of the producer that incurred the cost, the department retains the ability to assess a tax deficiency from the original producer.

MR. MINTZ went on to explain the process of calculating the tax. He stated that this begins with the net value of oil and gas, followed by the application of a 20 percent rate to find the amount of tax before the credit. The producer can then subtract the desired amount of its credit, not to exceed zero. He noted that on any given month, not more than 20 percent of the remaining tax liability may be subtracted by credit from a certificate. The remainder is the tax payable for the month.

REPRESENTATIVE SEATON asked if this is set up subsequently so the producer cannot take the purchase credits first.

MR. MINTZ replied that the timing is not specified; however, the current language is sufficient, as it does state that the tax cannot be reduced below 80 percent of the full amount without taking the credit. He went on to say that if the purchased credit was applied first, this would result in taking more than 20 percent of the full tax.

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CO-CHAIR SAMUELS asked how the overhead is allocated and how the costs given by the industry are audited.

MR. MINTZ, in regard to the overhead, stated that AS 43.55.160(d) gives the department the ability to determine a reasonable allowance for overhead.

MR. DICKINSON noted that there are several pages in the bill dedicated to the costs. He stated that currently, the state believes that the major units on the North Slope have several joint owners and spend time and effort checking in on each other. The state has the ability to check in and make sure that costs are not migrating and are lined up with the agreements as they existed prior to HB 488 becoming effective. He opined that Kuparuk River Unit and Prudhoe Bay cover a fair amount of the costs. He stated that this is an area which needs strong regulations, and the state intends to contact firms which specialize in joint venture audits to help with this. He agreed that this is an area where there may be erosion of forecasted revenues if the cost is different than that which the forecast was based on.

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MR. MINTZ, turning to the final page, explained the payment of the production tax. He stated that under current law, production tax for one month is due at the end of the following month. He said that this is retained; however, under the bill, 90 percent of the tax is due at the end of each month, and the remainder is due at the end of March in the following year. He said that the reason for this is to deal with issues that cannot be resolved until the year is over. These issues are coordinated with income tax. He remarked that this is a safe harbor, adding that if the producers' estimate is incorrect, there would be interest on the any amount that was not paid.

MR. DICKINSON added that if the producer pays too much, the state does not owe interest until the producer requests the refund check. The state then has 90 days to issue the check.

REPRESENTATIVE SEATON asked how many producers currently overpay.

MR. DICKINSON replied that the state income tax includes four estimated payments. He said that at the end of the year, when the tax return is filed, any overpay or underpay would be discovered. If underpaid, then interest would be owed.

REPRESENTATIVE SEATON asked if a penalty is owed for underpayment.

MR. DICKINSON replied that this is correct, and said there are penalties in place for willful neglect.

REPRESENTATIVE SEATON remarked that this is a significant amount of the budget, and opined that if the state is allowing a 10 percent hold back throughout the year, it would make sense to calculate interest on the underpayment. He said "We're talking about significant revenue here, when we're trying to invest in [Public Employees' Retirement System (PERS)] and [Teachers' Retirement System (TRS)] and ... Permanent Fund, and we could be talking about amounts that are ... fairly large." He requested a report from the department as to the effect of this.

MR. DICKINSON said that they would do this.

CO-CHAIR SAMUELS said "So, in January we're going to write off everyone's \$73 million and in March we're going to get a big check."

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REPRESENTATIVE BERKOWITZ asked who the claw back provision affects and by how much.

MR. DICKINSON said anyone who made investments; he continued:

Roughly speaking, I think you could tell that the major Prudhoe Bay owners ... if you remember the slides that [Mr. Marks] pointed out ... if you ... think about \$1 per barrel for basic baseline capital costs in Prudhoe Bay for the baseline production ... that would be about \$300-\$400 million a year total on the baseline production, and about half of that ... is ... from Prudhoe Bay itself.

REPRESENTATIVE BERKOWITZ asked what this means to the state treasury.

MR. DICKINSON replied that if the estimates are correct, it would be about \$170 million per year for six years.

REPRESENTATIVE BERKOWITZ voiced his concern with retrospective application of law and asked if this would affect past taxes collected by the state and federal government.

MR. DICKINSON replied that it will not affect past tax collection, but will affect collections made during the first 72 months in which the prices are above the benchmark.

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REPRESENTATIVE BERKOWITZ noted that the effective date for the tax is July 1, and asked how far into the past this date potentially could have gone.

MR. MINTZ replied that he is unaware of any attempts to retroactively change a tax law by multiple years, but noted that short retroactivity periods have been upheld by the courts.

REPRESENTATIVE BERKOWITZ said:

So, it would seem to me that if we're accepting the premise that we can retroactively give a tax benefit for investments that have been made for the past five years, we could, theoretically, retroactively apply the PPT for a portion of that time as well

MR. MINTZ replied that in general this is correct. He said that this is different from giving affect to a past investment or transaction in terms of its affect on future taxes. He explained that this is different from changing the taxpayers' liability during previous tax periods.

REPRESENTATIVE BERKOWITZ commented that the state could make the PPT effective in 2003, but allow time to make up the payments.

MR. MINTZ said he did not know how far back the retroactive changes would be upheld.

REPRESENTATIVE BERKOWITZ commented that January of 2006 would be possible.

MR. MINTZ agreed that this would most likely be upheld.

REPRESENTATIVE BERKOWITZ asked if January of 2005 would be more problematic.

MR. MINTZ stated that this is his impression.

CO-CHAIR SAMUELS asked if there is any way for the state to differentiate between the producers who take general, ongoing capital expenditures and recoup costs quickly and the producers who use a ten-year look-forward and recoup their costs over a long period of time.

[3:53:05 PM](#)

MR. DICKINSON replied that most fall under the second category. He said that in all companies, every capital upgrade and capital maintenance is calculated to find out whether the investment is worthwhile. He said there is a concept known as "license to operate" which is generally things such as health and safety or environmental issues, where the return is intangible.

REPRESENTATIVE ROKEBERG, referring to retrospective changes to the tax laws, commented that in the past, the legislature has made retroactive changes to tax laws in order to conform public policies. He opined that there needs to be a compelling state interest in order to make the changes retroactive, and added that the collection of revenue alone is not an appropriate reason to do this. He asked if, during the drafting of the legislation, the department looked into the history of retrospectivity and if the department would be able to provide the committee members information on the constitutionality of this practice.

MR. MINTZ replied that the cases he researched used due process to evaluate retroactivity and the tax content, and only required a general government interest in the retroactivity. He added that he would look into this further.

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REPRESENTATIVE SEATON asked if anything in the bill eliminates the depreciation ability for capital projects from state, corporate or federal tax.

MR. DICKINSON said that this is correct.

REPRESENTATIVE SEATON asked if the bill would eliminate credits that exist under the current tax system.

MR. DICKINSON said no.

REPRESENTATIVE SEATON asked if the purpose of the claw back is provide an incentive to companies that invested for other reasons.

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MR. DICKINSON replied that the state is going to be taxing profitability, and opined that the producer should be comforted with the knowledge that if they are not making a profit, they will not be taxed.

REPRESENTATIVE SEATON remarked that the claw back is credit for old investment, and the purpose of the credit is to stimulate new investment. He expressed trouble understanding why this is being discussed.

MR. DICKINSON replied that this is not giving a credit, instead this allows companies to include investments made over the past five years which are continuing to pay off, in order to determine profitability over the next six years.

REPRESENTATIVE SEATON referred to the separation of satellite fields, and he requested information on tax amounts for 2004 and 2005 and how much would have been paid to the state if the aggregation had been made at the time.

[4:00:53 PM](#)

REPRESENTATIVE LEDOUX asked if the claw back would allow companies to deduct from the current profitability or if it would allow the producers to amend past income tax amounts.

MR. DICKINSON replied that the claw back would have no affect on income tax and would only apply to production tax. He explained that it would allow them to deduct investments from prior years which continue to produce income from their calculation of profitability in the first six years the tax exists. He noted that it would be longer than six years if the price drops below \$40 per barrel. He stated that there would not be a retroactive amendment on prior returns. He said that taking the purchase price of assets into account when calculating profitability will lower state revenues by around \$170 million per year.

REPRESENTATIVE LEDOUX asked why the discussion turned to the constitutionality of retroactivity clauses.

MR. MINTZ replied that this was a result of other members questioning other possibilities.

REPRESENTATIVE ROKEBERG requested a list of current credits provided for oil and gas production. He questioned whether these should be repealed and, if not, how they fit into this bill.

[4:03:14 PM](#)

MR. DICKINSON replied that there are three that have been identified. He said they are the 025 within the production tax, an educational credit, 040 credit in the income tax, and additional federal credits that are imported.

[4:04:52 PM](#)

REPRESENTATIVE ROKEBERG asked how these will be treated in relation to this bill.

MR. DICKINSON replied that those related to the income tax can not be changed, the 025 taxes will be left in place and will sunset. There will be an option to take one of the two programs. Companies will not be able to take both.

REPRESENTATIVE ROKEBERG asked where the claw back fits into the calculations.

MR. MINTZ replied that this is part of the way to get the net value.

MR. DICKINSON said that this is call "Transitional Investment Expenditures."

MR. MINTZ said that the credits only apply after the tax has been calculated and are then applied to the tax itself.

REPRESENTATIVE BERKOWITZ remarked that he does not recall hearing any discussion of a claw back until the introduction of HB 488. He asked what inspired this term.

[4:06:40 PM](#)

MR. DICKINSON replied that the department has always focused on transitional provisions.

REPRESENTATIVE BERKOWITZ asked if other jurisdictions that have made changes to oil and gas fiscal system have had comparable provisions and requested to see this information.

MR. DICKINSON replied that he did not have this information but would research this.

[HB 488 was held over]

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at [4:08 PM](#).