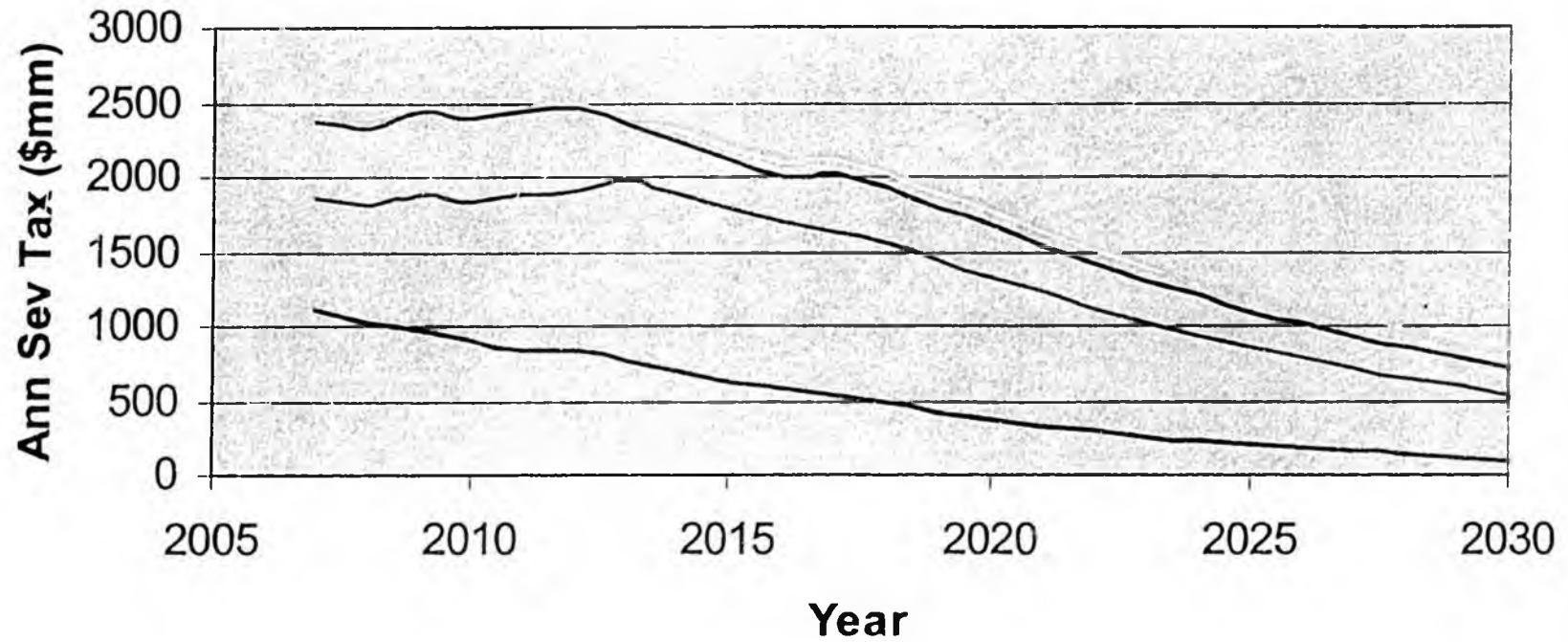


ALASKA LEGISLATURE

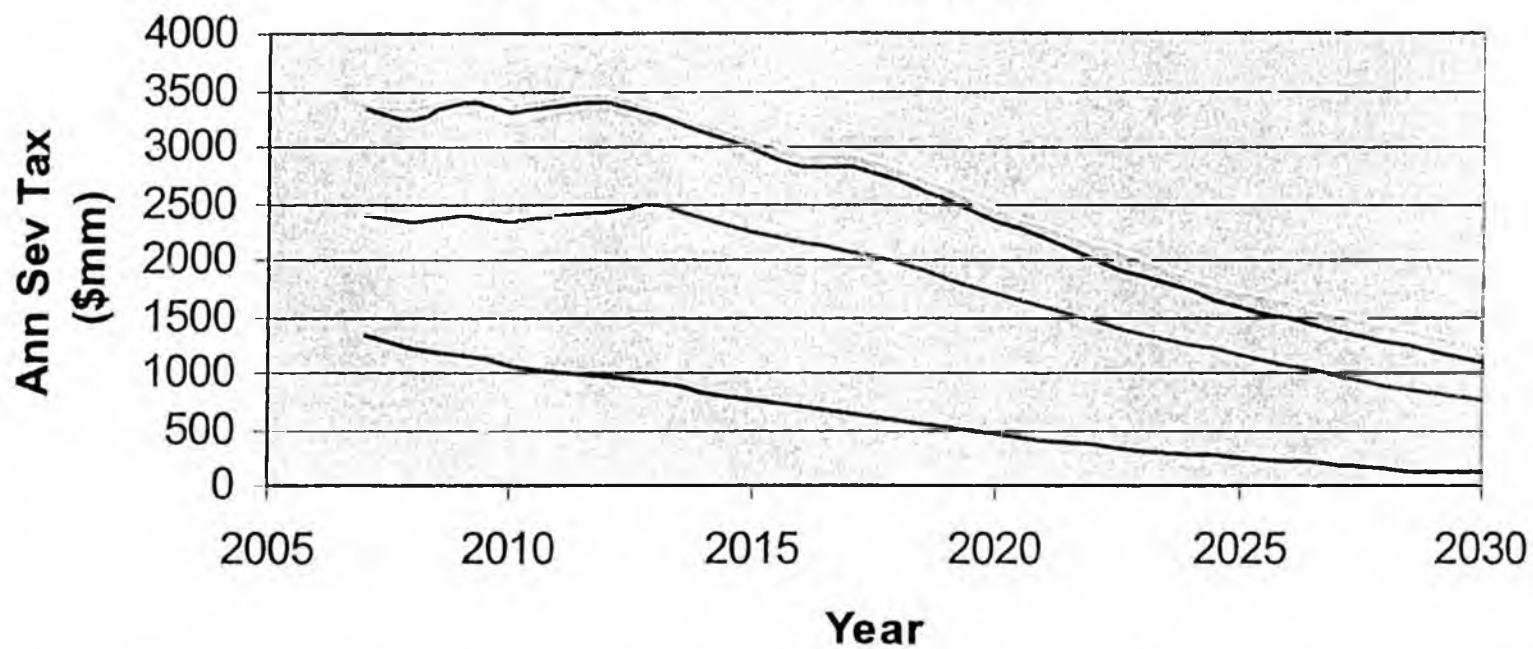
HOUSE and SENATE FINANCE COMMITTEE FILES, 2005-2006 3089

Annual Severance Tax @ \$60 2007-2030 (\$Millions)



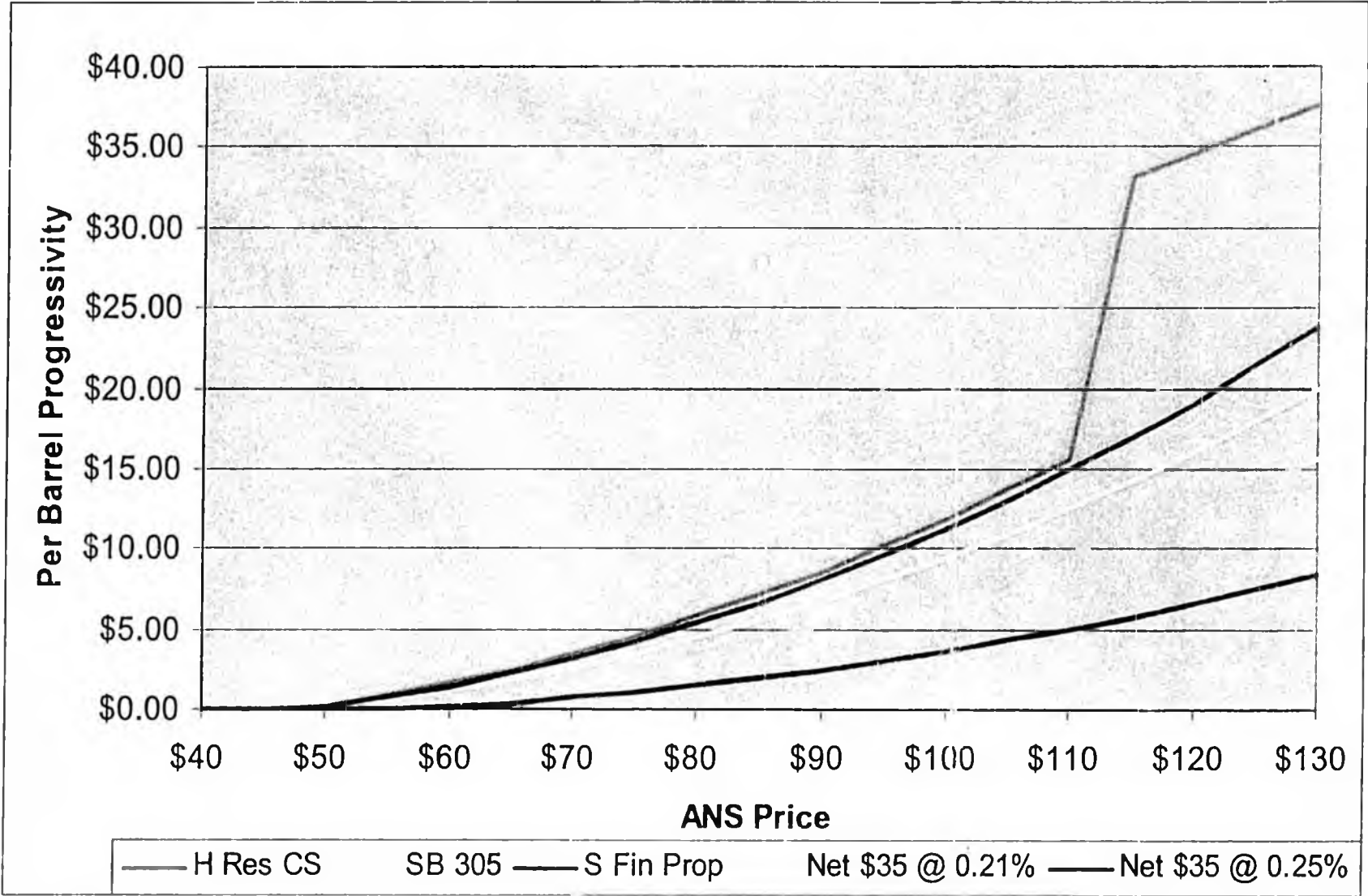
sq
 gov
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 sb 305
 house fin cs

Annual Severance Tax @ \$70 2007-2030 (\$Millions)



— sq — gov house res cs sb 305 — house fin cs

Per Barrel Progressivity Surcharge on Net \$35 at 0.21% and 0.25%



Feb 23 2006

Costs and Prices

- Costs
 - \$100 mm/yr exploration through 2040
 - \$1/bbl on-going capital on all barrels
 - \$3.50/bbl developmental capital on 2/3 of existing conventional oil
 - \$8/bbl developmental capital on 2/3 of existing heavy oil
 - \$3.50/bbl developmental capital on new conventional oil
 - \$8/bbl developmental capital on new heavy oil
 - \$3/bbl operating costs on conventional oil
 - \$5/bbl operating costs on heavy oil
- Costs and prices are real \$2005 dollars
- Heavy oil discounted 8% for quality



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Judith Brady, Executive Director

**TESTIMONY OF THE ALASKA OIL AND GAS ASSOCIATION
TO THE HOUSE FINANCE COMMITTEE
REGARDING THE PPT LEGISLATION (CSSB 305(FIN) am)**

April 29, 2006

Mr. Chairman and members of the Committee, good afternoon.

My name is Judy Brady, and I am the Executive Director of the Alaska Oil and Gas Association (AOGA). On behalf our members, I thank you and the Committee for the hearings you have been holding on this legislation to replace the existing ELF-based production tax with a new "Petroleum Production Tax" (PPT) based on the value of oil and gas after costs of producing it have been deducted. AOGA is a non-profit trade association whose 17 member companies represent the majority of oil and gas exploration, production, transportation, refining and marketing activities in Alaska. Our present comments and recommended technical amendments to the legislation have been approved by the Tax Committee without dissent.

With something as complex as the PPT, producers will need to have as much certain: .d clarity as possible about how to calculate their PPT correctly. The Legislature too — as the Branch of government that sets state tax policy — deserves to know that any PPT law which it enacts will be administered and applied as the Legislature intends. We believe the PPT could be improved to better achieve these objectives. To this end we offer a number of technical amendments for your consideration. The actual text of our proposed amendments is attached to the written copies of this testimony. What follows below are explanations of what each amendment would do and why it should be adopted.

Amendment No. 1

This amendment relates to the so called 90% or 95% "safe harbor" provisions in the House Resources CS and the Senate-passed Bill, respectively. As structured, these provisions are unworkable and inappropriate.

Two key elements of PPT are based on federal income-tax concepts. One is the use of the federal definition of "ordinary and necessary" in determining the scope of field expenditures that will be deductible under the PPT. The other is the use of the federal definition of "capital expenditure" to determine whether an expenditure gives rise to a tax credit against PPT.

Using these federal concepts offers three major advantages. One, everybody among the producers and in DOR understands what these concepts mean. There is a large and detailed body of federal statutes, regulations, rulings, and administrative and judicial precedents that establish these meanings. Two, using the federal concepts greatly simplifies DOR's task in writing regulations to implement the PPT, which will save time in getting the regulations in place to start implementing and complying with this

new tax. Three, using the federal definitions lets the IRS do the heavy lifting in terms of auditing these expenditures and determining that they have been classified properly. When the IRS is done auditing, this allows DOR auditors to say "me too" to those audit adjustments just as they do now for federal items incorporated into the state income tax.

The present 90% and 95% safe-harbor provisions are structured on the assumption that the bookkeeping and accounting for deductible expenditures and credit-generating investments is on a monthly basis, thus allowing this level of precision in estimating the PPT payment each month. However, the records, accounting and IRS audits of the federal concepts being used for PPT are all maintained and performed on a full-year basis rather than a monthly one. There is nothing in this federally based approach that divides a year's cost items into individual monthly packets cleanly.

This does not mean that PPT cannot be paid on a monthly basis. The IRS, and Alaska and many other states in the context of their state income taxes, require businesses to make estimated payments during the tax year, with a final true-up the following March to the actual numbers for that year. In the income tax area these estimated payments are most commonly done on a quarterly basis, but there is nothing to prevent monthly estimated payments for PPT. We believe monthly estimated payments are possible and can be done on a reasonable and fair basis.

The IRS, Alaska in its income tax, and other states with their income taxes recognize that taxpayers making the early estimated payments for a tax year cannot accurately predict how the year will turn out for them. But as the year goes by, there are fewer months left to estimate and more months of actual data to use in calculating the estimated payments. By the last estimated payment for the year, that estimate should be pretty accurate even though the books for the year may not yet have closed and the figures become final. The IRS, and Alaska and the other states, figure that by the time the last estimated payment is made, taxpayers should be able to get it right so that at least 90% of the actual tax for the year is paid up with that last estimated payment. This is the source of the safe harbor concept and the original 90%, and we believe this federal and state rule in the income tax context is appropriate for PPT as well.

We all know that in the business world, it is better to come in under budget than over. But in the PPT world, being under budget means that, if you relied on your budget in the early months of the year to estimate your total deductions and credits for the remaining months, you will have overstated those deductions and credits if the actual expenditures for the year end up being under budget. But by the time you first start becoming aware of this toward the middle or end of the year, you are likely to have already filed and paid your monthly PPT for a fair number of prior months.

Under the Senate's version of the PPT and the House Resources CS, a producer in this situation would be subject to an underpayment penalty, perhaps with interest, if it fails to estimate the correct amount of monthly PPT for the early months of each year. This penalizes the producer, essentially, for not having the ability to see into the future how the year will turn out. Such a penalty is neither fair nor appropriate.

Our proposed amendment adapts the income-tax system of estimated payments so they are made monthly instead of quarterly. It also prevents the possibility that taxpayers might exploit the time-value of money by reporting very low estimated payments for the early months and then getting caught up to the 90% level with their last one or two estimated payments for the year.

Amendment No. 2

The provisions on the capex credit in SB 305 as passed by the Senate do not allow a credit for acquiring a capital asset that has already been used in this state by someone else, unless no more than an "immaterial portion" of that asset is used. See proposed AS 43.55.024(h) in CSSB 305(FIN) am. We do not disagree with this basic concept. However, we do believe that the term "immaterial" is too vague and subjective, and that using it as the test will lead to numerous disputes and squabbles over relatively minor items.

Our proposed amendment would replace this vague standard of immateriality by saying the credit for acquiring a used asset is not allowed unless no more than 15% of that asset is used (e.g., a replaced fender or windshield on an otherwise unused motor vehicle).

Amendment No. 3

Currently the House Resources CS and the Senate's version of PPT provide in AS 43.55.160(c) that deductions are allowed for "total costs upstream of the point of production of oil and gas that are incurred[.]"

We believe this description of the costs is potentially ambiguous. For instance, there can be no plausible dispute that the costs of the operations centers and dormitories for the workers in the fields on the North Slope should be deductible costs for those fields, nor is there any question that the cost of helicoptering workers out to the platforms in Cook Inlet should be deductible. But if you follow the course of the production fluids as they flow from the Christmas tree through the surface facilities and gathering lines to the point of production, neither of these costs shows up anywhere along that route. Are these costs "upstream of the point of production"? Clearly, this is the wrong test.

We also believe this description is potentially too narrow. It may be that simulations of well work or other processes in the field may be conducted on computers physically removed from the site of the field itself. If these costs are so directly related to the field work that the operator can bill them out to the working-interest owners as field operating costs, why should it matter whether they are "upstream of the point of production" or not? For that matter, the same ambiguity about whether they physically are "upstream" or not, also applies to them as it does to the operations centers and dormitories.

We believe it would be unambiguous, fairer and more appropriate to allow deductions for the "total costs in support of activities upstream of the point of production[.]" This is especially true whenever DOR utilizes the authority elsewhere in AS 43.55.160(c) to authorize the use of a producer's billings from the operator as that producer's deductible expenditures for that field.

Amendment No. 4

Proposed AS 43.55.160(c)(1) in the Senate's version and the House Resources CS provides that DOR, in determining the scope of the categories and kinds of expenditures that will be deductible for PPT, "shall give substantial weight" to industry practices and standards as reflected in existing unit operating agreements. We believe DOR should be required to "apply" the practices and standards reflected in those operating agreements, instead of merely giving them "substantial weight."

In recommending this for your consideration, we would emphasize that there are two similar-appear-

ing, but very different issues surrounding AS 43.55.160. One is the identification of the kinds and categories of expenditures that are deductible at all. The other is verification that the expenditures reported as falling into these deductible categories are properly included in those categories. The former is fundamentally a question of tax policy. The latter is primarily an audit issue.

Our concern is that the tax policy in the first question not be allowed to become just an audit issue as well.

We believe the cash expenditures that an operator under a unit operating agreement or similar agreement is allowed to bill to the other working-interest owners, partners or other participants will reflect appropriate and reliable boundaries for what kinds of costs should be deductible. No one gives authority to an operator to spend their money without making certain that those expenditures are going to be spent on the right things. The operating agreements set tight limits on what an operator may or may not spend money for.

Those other participants have drawn a tight circle, and a clear one, about what is or is not an appropriate expenditure by the operator on their behalf. We believe DOR should "adopt" the wisdom and experience that are reflected in the operating agreements that arise from a true adversity of interest between the operator and those whom the operator bills and are patterned closely after other agreements where there was such an adversity of interest.

Amendment No. 5

Proposed AS 43.55.160(e) requires that a producer's deductible lease expenditures for a field be offset for "any payment or credit" that it receives from someone else as payment for the use of facilities in the field, that was a reimbursement of chargeable field costs against a royalty interest of the state or federal government, or that is the proceeds from the sale of a capital asset.

We do not disagree with the purpose of these provisions. Rather, we want to avoid uncertainty in their administration and application to producers. This amendment clarifies that to the extent a reimbursement is for a producer's deductible expenditures under AS 43.55.160, the reimbursement will offset the deduction. This will ensure that every barrel is taxed once and no expenditure is deducted twice under 43.55.160.

Amendment No. 6

Alaska and many other states do not allow a deduction under their income taxes for taxes paid to another jurisdiction that are based on or measured by net income. Washington, for example, has an excise tax that allows a credit for other excise taxes paid to another jurisdiction. Currently there is no question that the ELF-based severance tax is an excise tax and is not an income tax, and there is similarly no question that it is creditable against the State of Washington's Business and Occupation ("B&O") excise tax and that it is deductible the income taxes of many states.

The PPT is based on the gross value of oil or gas, minus the expenditures incurred to produce that oil or gas. The PPT legislation explicitly provides that PPT is deductible for Alaska's corporate income tax because it is not an income tax. However, Alaska cannot pass legislation that binds other states so that the PPT is creditable against Washington's B&O tax and deductible under the income taxes of other states.

What Alaska can do to keep PPT deductible and creditable is to clarify that it is not a tax on income or profits, but rather is an excise tax imposed on the act of severing and producing the oil or gas. Our proposed changes in terminology would make it clear that the PPT is an excise tax, not an income tax, and maintain the status quo of how the present production tax is treated in Alaska and elsewhere.

Thank you for this opportunity to share our recommendations with you and for your consideration of the amendments we offer. Please do not hesitate to contact us if you have any questions or comments about our present suggestions, or if we may be of further assistance to you.

AOGA APRIL 13TH AMENDMENTS – UPDATED FOR CSSB 305(FIN)AM

AMENDMENT NO. 1. SAFE HARBOR

In CSSB 305(FIN)am, on p. 6 line 2 insert the following between “month” and the period at the end of that sentence: “except to the extent the producer has reasonable cause under (g) of this section”

In CSSB 305(FIN)am, on p. 6 line 6 insert the following between “delinquent” and the period at the end of that sentence: “unless the producer has reasonable cause under (g) of this section”

In CSSB 305(FIN)am, on p. 7 at line 17 insert the following new Bill Section 12, redesignate present Bill Sections 12 – 40 as 13 – 41 respectively, and revise the cross-references in present Bill Sections 35 – 39 accordingly:

“* **Sec. 12.** AS 43.55.020 is amended by adding a new subsection to read:

(g) A producer has reasonable cause for an underpayment of its total tax levied under AS 43.55.011(c) – (g) on taxable oil and gas production during a month if its total tax paid under this section for taxable production during that month and the prior months of that calendar year is at least 90 percent of the total amount of tax due under AS 43.55.011(c) – (g) for taxable production during that month and those prior months as determined on the basis of the producer’s cumulative actual lease expenditures for the year as of the last day of that production month and the lease expenditures budgeted for the remainder of the year as of that same day. A producer may also establish reasonable cause under this subsection on the basis of “reasonable cause” as defined for purposes of AS 43.05.220(a) or 26 U.S.C. 6651 (Internal Revenue Code) and Treasury Regulation §301.6651-1(c).”

AMENDMENT NO. 2. DEFINING AN “IMMATERIAL” USED PORTION OF AN OTHERWISE UNUSED ASSET

In CSSB 305(FIN)am, on p. 10 line 21, delete “an immaterial portion” and replace with “15 percent”

AMENDMENT NO. 3. DEDUCTIBLE “UPSTREAM” COSTS

In CSSB 305(FIN)am, on p. 20 line 2, at the beginning of the line insert “in support of activities” before “upstream”

AMENDMENT NO. 4. DEFINING SCOPE OF DEDUCTIBLE COSTS BY APPLYING INDUSTRY PRACTICE

In CSSB 305(FIN) am, on p. 20 line 12, delete “give substantial weight to” and replace with “apply”

In CSSB 305(FIN) am, on p. 20 line 13, delete “as to costs” and replace with “in determining the amount”

In CSSB 305(FIN) am, on p. 20 line 17, delete “not” and replace with “other than”

In CSSB 305(FIN) am, on p. 20 lines 19 – 20 inclusive, delete all material and delete “practices and standards are not clear or are not uniform” in line 21, and replace with the following:

“(B) in the absence of unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, other than the operator, with substantial bargaining power”

In CSSB 305(FIN) am, on p. 20 line 21, delete “shall” and insert “may”

AMENDMENT NO. 5. CLARIFYING OFFSETS AGAINST LEASE EXPENDITURES

In CSSB 305(FIN) am, on p. 23 line 9, insert “the net working interest share of” before “payments” at the beginning of the line

In CSSB 305(FIN) am, on p. 23 line 13, between “fee” and the semicolon following it, insert “to the extent the payment or credit is a deductible lease expenditure for that payor under 43.55.160”

In CSSB 305(FIN) am, on p. 23 line 15, between “expenditures” and the comma following it, insert “to the extent the payment or credit is a deductible lease expenditure for that payor under 43.55.160”

AMENDMENT NO. 6. TO HELP PPT GET THE SAME TREATMENT AS THE PRESENT ELF-BASED PRODUCTION TAX FOR PURPOSES OF OTHER STATES' TAXES (NO CHANGE TO PPT SUBSTANCE)

In CSSB 305(FIN) am, on p. 1 line 1, delete “oil production tax and gas production tax” and replace with “oil and gas properties production tax”

In CSSB 305(FIN) am, on p. 1 lines 2, 4, 5 (twice) and 10, delete “production tax” and replace with “severance tax”

In CSSB 305(FIN) am, on p. 1 line 3, insert “gross severance” between “the” and “value”

In CSSB 305(FIN) am, on p. 2 line 6, delete “production tax” and replace with “severance tax”

In CSSB 305(FIN) am, on p. 2 line 11, delete “section” and replace with “sections”

In CSSB 305(FIN) am, on p. 2 at line 12, insert the following as a separate paragraph before the existing material:

“INTENT OF AS 43.55.011(e) AS ENACTED BY THIS ACT. In enacting AS 43.55.011(e) under Sec. 5 of this Act, it is the intent of the legislature to tax the activity of severing oil and gas from the ground and the tax is to be measured on the value of oil and gas production as it is severed. The legislature recognizes that the costs permitted to be deducted under AS 43.55.160 are not properly included in the measure of the gross value of the oil and gas as they are severed, but rather are a measure of the cost and effort needed to complete the production of the oil and gas after severance; and therefore such costs are excluded from the measure of the tax.”

In CSSB 305(FIN) am, on p. 3 lines 5 and 11, delete “tax” and replace with “taxes”

In CSSB 305(FIN) am, on p. 3 line 31, delete “production tax value” and replace with “gross severance value”

In CSSB 305(FIN) am, on p. 4 line 2, delete “production tax value” and replace with “gross severance value”

In CSSB 305(FIN) am, on p. 5 at line 30, insert the following new Bill Section 7 and renumber present Bill Sections 7 – 40 as 8 – 41 respectively:

“* Sec. 7. AS 43.55.017(c) is amended to read:

(c) The taxes imposed by the chapter are excise taxes on severing or extracting oil and gas from the ground. The taxes are not income or franchise taxes or taxes upon the sale of oil or gas products and are not imposed in lieu of such taxes.”

In CSSB 305(FIN) am, on p. 6 line 14, delete “production tax” and replace with “taxes under AS 43.55.011 [PRODUCTION TAX]”

In CSSB 305(FIN) am, on p. 6 line 26, delete “multiplied by a figure that is a quotient, in which” and replace with “multiplied by a fraction, of which” [alternatively, “numerator” in line 27 should be “dividend” and “denominator” in line 29 should be “divisor”]

In CSSB 305(FIN) am, on p. 7 line 22, delete “production tax value” and replace with “gross severance value”

In CSSB 305(FIN) am, on p. 12 line 29, p. 13 line 10, p. 14 line 9 and p. 15 line 13, delete “production tax” and replace with “[PRODUCTION] tax”

In CSSB 305(FIN) am, on p. 15 line 14, delete “production taxes” and replace with “[PRODUCTION] taxes”

In CSSB 305(FIN) am, on p. 15 line 15, delete “production tax” and replace with “tax”

In CSSB 305(FIN) am, on p. 15 lines 19, 26, 27, 29 and 30, delete “production tax” and replace with “[PRODUCTION] tax”

In CSSB 305(FIN) am, on p. 16 lines 2, 4, 6 and 8, delete “production tax” and replace with “[PRODUCTION] tax”

In CSSB 305(FIN) am, on p. 16 line 3, delete “production” and replace with “[PRODUCTION]”

In CSSB 305(FIN) am, on p. 19 line 2, delete “production tax value” and replace with “gross severance value”

In CSSB 305(FIN) am, on p. 19 lines 4, 9, 11, 17, 22 and 29, delete “production tax value” and replace with “gross severance value”

In CSSB 305(FIN) am, on p. 25 lines 16, 19, 23 and 28, delete “production tax value” and replace with “gross severance value”

In CSSB 305(FIN) am, on p. 27 line 18, delete “tax” and replace with “taxes”

In CSSB 305(FIN) am, on p. 28 line 4, delete “tax” and replace with “taxes”

In CSSB 305(FIN) am, on p. 33 line 8, delete “Production Tax and Oil Surcharge;” and replace with “Severance Taxes and Oil Surcharges;”

In CSSB 305(FIN) am., on p. 33 line 10, delete “Production Tax’;” and replaces with “Severance Taxes’;”

In CSSB 305(FIN) am, on p. 33 line 11, delete “ ‘Oil and gas production tax’ ” and replace with “ ‘Oil and gas severance taxes’ ”

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CHAMBER OF COMMERCE

Introduced By: Board of Directors
 Date Introduced: April 10, 2006
 Date Passed: April 10, 2006
 Date Transmitted: April 11, 2006
 Date Amended: April 18, 2006

**A RESOLUTION OF THE
 GREATER FAIRBANKS CHAMBER OF COMMERCE (GFCC)
 IN SUPPORT OF A NEW PETROLEUM PRODUCTION TAX (PPT) FOR
 ALASKA**

Resolution 06-0410, as amended

WHEREAS, it is the mission of the Greater Fairbanks Chamber of Commerce (GFCC) to support and advocate for a strong investment and economic development climate; and

WHEREAS, the oil and gas industry dramatically impacts multiple segments of the private-sector economy; and

WHEREAS, oil and gas royalties and taxes currently provide nearly 90 percent of the State's general revenue; and

WHEREAS, Alaska's oil production rate of decline urgently requires arrest; and

WHEREAS, the current rates of investment by industry are inadequate to arrest or improve this decline; and

WHEREAS, once declining oil production reaches 600,000 bpd, the viability of Interior refineries will be severely compromised; and

WHEREAS, the existing severance tax system - Economic Limit Factor (ELF) - is currently not in the best interest of all stakeholders; and

WHEREAS, a globally recognized new tax system- petroleum production tax (PPT) - has been proposed by the Governor; and

WHEREAS, the PPT ultimately approved by the Legislature will directly impact how attractive Alaska is for investment;

NOW THEREFORE BE IT RESOLVED, that the Board of Directors of the GFCC supports legislation that embodies the following goals and tenets:

- a reasonable increase of return to Alaska;
- provides strong incentive for maximum statewide oil and gas exploration and development investment by the industry;
- furthers a 50-year vision to extend the North Slope oil production infrastructure;
- is nationally and globally competitive;
- lends itself to ease of administration;
- expeditiously advances a gas pipeline project;

AND BE IT FURTHER RESOLVED that a tax rate higher than 20 percent and a total tax take that substantially exceeds the PPT legislations' original version - as does the Senate Resources CS - could very well be counter productive to the GFCC goals and tenets outlined above,

AND BE IT FURTHER RESOLVED that copies of this resolution be sent to Governor Frank Murkowski, the Alaska Legislature, the GFCC membership, the statewide media, Alaska State Chamber of Commerce, Anchorage Chamber of Commerce, Resource Development Council, Alaska Oil and Gas Association, The Alliance and FEDC.

Approved the 18th day of April, 2006

Marilyn Romano

Marilyn Romano
GFCC Board Chair

Lanien M. Livingston

Lanien Livingston
President/CEO

Margaret Russell

Margaret Russell
Government Affairs Committee Co-Chair

Charlie Boddy

Charlie Boddy
Government Affairs Committee Co-Chair

Rhonda P. Boyles

Rhonda P. Boyles
Natural Resources Committee Chair





GREATER * FAIRBANKS
CHAMBER
OF COMMERCE

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website: www.fairbankchamber.org

April 18, 2006

The Honorable Frank Murkowski, Governor
& The Alaska State Legislature
Alaska State Capitol
Juneau, AK. 99801

Dear Governor and Legislators,

The Greater Fairbanks Chamber of Commerce (GFCC) recognizes and applauds the efforts of the Governor and the Legislature thus far in addressing the shortfalls of the current economic limit factor severance tax (ELF), through the introduction of a new tax system - petroleum production tax (PPT).

The mission of the GFCC is to support and advocate for a strong investment and economic development climate. Therefore, we have been carefully following the testimony, deliberations and developments of HB488 and SB305 - clearly, the most critical legislation set forth in decades.

As these bills continue to progress, the GFCC remains strong that the final PPT product should embody:

- *A reasonable increase of return to Alaska*
- *Strong incentive for maximum statewide oil and gas exploration and development investment by industry*
- *Furtherance of a 50-year vision to extend the North Slope oil production infrastructure*
- *Competitiveness both nationally and globally*
- *Simplified administration*
- *Expedient advancement for a gas pipeline project*

With these goals and tenets in mind, we offer you the following input regarding key components of the PPT legislation for your thoughtful consideration.

Tax Rate

A 20% tax rate, combined with other government royalties and takes, represents a fair and reasonable return on Alaska's oil and gas resources. A higher tax rate could exceed that fair and reasonable threshold and become a barrier to vitally needed investment - including a gas pipeline project.



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Progressivity

A reasonable progressivity factor which allows the State to share in a highly profitable market may be appropriate. However, it should be in direct ratio to the greater risk that Alaska bears in a low price environment, easy to understand, simple to process, and should be based on Alaska prices (ANSC) rather than West Texas Intermediate (WTI).

Transition or claw-back

A simplified transition or claw-back provision for recovery of capital expenditures is an appropriate and responsible policy that advances Alaska's partnership and reputation with the industry by acknowledging investment in the last five years, even during periods of extremely low oil prices.

Standard deduction

The standard deduction provision is an important tool to attract new, smaller companies and investors in the oil and gas industry. It should encourage investment statewide - exploration and development on the North Slope and in promising basins, including Bristol Bay, Yukon Flats and Nenana Basin.

Effective Date

A retroactive tax is counter-intuitive to any good tax policy. Therefore, the effective taxation date should not precede the effective date of the legislation.

Cook Inlet

A provision to address the Cook Inlet gas industry and protect Alaska's natural gas consumers from direct adverse consequences of PPT should be further considered.

Testimony and debate regarding these provisions centers around "fair share", "attractive climate for investment", and what the "tipping or breaking point" might be. Legislative discussion also occasionally unveils a disturbing mindset of some - one that a gas pipeline project "probably won't happen" or "is speculative at best".

To approach a new tax regime at this critical juncture with any short term vision - one that focuses on maximization of short-term revenue gains while potentially jeopardizing long-term revenue and development - is simply unacceptable.

GREATER * FAIRBANKS CHAMBER OF COMMERCE

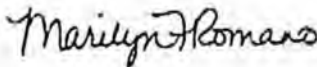
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Ultimately, a tax rate higher than 20 percent and a total tax take that substantially exceeds the PPT legislations' original version – as does the Senate Resources CS - could very well be counter productive to the GFCC goals and tenets outlined above

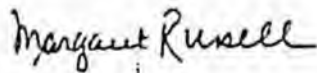
The GFCC will remain engaged as you progress in your deliberations and search for balance and consensus. Your Legislative charge contained in Alaska's Constitution Article 8, Section 2 is one that we all take very seriously. It states "*The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the State, including land and waters, for the maximum benefit of its people.*" (emphasis added)

The maximum benefit is predicated upon an attractive investment climate that will encourage and further maximum development of Alaska's oil and gas resources.

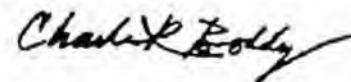
Sincerely,




Marilyn Romano
GFCC Board Chair



Margaret Russell
Government Affairs Committee Co-Chair



Charlie Boddy
Government Affairs Committee Co-Chair



Rhonda Boyles
Natural Resources Committee Chair

Distribution: The GFCC Membership, the statewide media, Alaska State Chamber of Commerce, Anchorage Chamber of Commerce, Resource Development Council, Alaska Oil and Gas Association, The Alliance and FEDC.

4-29-06



Alaska State Legislature

Please enter into the record my testimony to the HFIN
Committee name

Committee on HB488, dated 4-19-06
Bill/Subject

If the oil & petroleum and mining industries can afford all the advertising and the expensive lobbyists, then they can afford to pay the taxes. If they are so righteous why don't they pay up everything that they already owe.

I believe that failing to increase the taxes will simply mean that the legislature is in the pocket and on the payroll of the petroleum industry. Our resources are going to be gone someday and if they leave as they threaten, we will just end up selling the oil to someone else because it is a precious and dwindling commodity. Alaska is like the only girl at the prom, if one doesn't dance with us there'll be 25 others that will want to. **Lobbyist do not reflect the constituency, they reflect the money!**

Signed: Geoffrey Tamplin
Testifier

PO Box 545 Palmer, Alaska 99645
Address

373-3910
Phone number

PPT is it non-progressive and non-incentive??

by Ed Martin

4-29-06

Is this the way Alaska should encourage it's non-renewable resource development particularly oil & gas? World market influence on oil production & price has met it's match "Peak Oil" and soon in ever increasing cost to the worlds consumers. So how do we as good State citizen's and corporate partners deal with this at the same time realize our resource's profit potential as a maximum benefit to our State?

It's Simple follow Corporate America's universal proven method "Profit Sharing" it work's like this: First we get the mind set that profit is good, second we recognize that "Alaska" is a 50/50 partner in this development and share in those profits equally, Third we understand what is fair profits in the resource extraction/production industry and not ballooned profits on the whole sale market as which is seen today in the world market. Fourthly we start this profit share plan with establishing that a fair production profit at 40% is in good faith with our producers well above industry standard.

Most all resource extraction/ production projects only produce a 10 to 25 % profit margin traditionally across the world, due to their primary and single product production activity for whole sale markets. Alaska Producers are in that position when producing and suppling only "crude oil" from Alaska's oil field's today. Until that changes that is where the profit's are made.

The "world market" is the controlling factor and Alaska and it's Producers can depend on that as it's revenue source until it's oil resources are completely depleted. Simply, at 40 % Oil Producers profit, Alaska starts getting 50 % per barrel dollar profit on the world oil price. WE share in the same progressive and incentive way as our Producers making us as wealthy as they are getting and whereby a better partner in any future developments of our non-renewable resources!

Alaska's Petroleum Profit Share Plan

Alaska's profit share plan works like this : After Alaska's producers reach 40 % profit per barrel at current existing petroleum tax law, the state starts a "new petroleum profit share" rate per barrel. That rate is 50 % on every dollar in profit earned, measured against the current world price per barrel. This 50 % rate reflects Alaska's true partnership with it's Producers!

So presuming that Alaska's producers reach 40 % profit at 40 dollars a barrel that is the point at which Alaska starts to get it's fair share. Currently at today's world prices per barrel Alaska would realize somewhere between 4.5 and 4.8 billion dollars yearly. This profit share concept is universal in accounting practices and is simple enough that daily calculation could keep the state on a more pro-active and accurate account of it's finances. It would be payed each day also whereas it's budget would not wait for a end of year collection process.

The Profit Sharing Concept is what all modern corporation's use in distribution of their profits and likewise what is used by the Alaska's Producers and their stockholders!

11-29-06



Alaska State Legislature

Please enter into the record my testimony to the ___House Finance
Committee on _____SB305 _____, dated__ 042606_____.

Alaska's Petroleum Profit Share Plan

Alaska's profit share plan works like this : After Alaska's producers reach 40 % profit per barrel at current existing petroleum tax law, the state starts a "new petroleum profit share" rate per barrel. That rate is 50 % on every dollar in profit earned, measured against the current world price per barrel. This 50 % rate reflects Alaska's true partnership with it's Producers!

So presuming that Alaska's producers reach 40 % profit at 40 dollars a barrel that is the point at which Alaska starts to get it's fair share. Currently at today's world prices per barrel Alaska would realize somewhere between 4.5 and 4.8 billion dollars yearly. This profit share concept is universal in accounting practices and is simple enough that daily calculation could keep the state on a more pro-active and accurate account of it's finances. It would be payed each day also whereas it's budget would not wait for a end of year collection process.

The Profit Sharing Concept is what all modern corporation's use in distribution of their profits and likewise what is used by the Alaska's Producers and their stockholders!

Signed: Ed Martin Jr.
PO BOX 521
Cooper Landing , AK 99572-0521

DIXIE A. HOOD, M.A.
Marriage, Family & Child Counselor

April 29, 2006

House Finance Committee
State of Alaska Legislature

Dear Chair and Members,
My name is Dixie Hood. I am self-employed and have been a resident of Alaska for over 30 years. I moved here in 1975 when oil production revenue was seen as a panacea for economic growth in our state and the state income tax was soon abolished. A comprehensive fiscal policy has never been created. Corporate lobbying and legislative loopholes have undermined the public interest.

I would like to trust that the Alaska State Legislature, if not our state governor, acts in the public interest. Much of what I have read and heard in the news in regard to oil tax proposals is not encouraging. I object to Frank Murkowski's withholding details of a contract with the oil companies from the public and the legislature and I am suspicious of his motivation and manipulative behavior. But that is just one problem.

I am cynical about the proposed change from taxing production to taxing "net profit." I think that corporate accountants are all too able to "cook the books" to come up with numbers that work in their favor and less to the benefit of Alaska.

Providing "incentives" to encourage oil or gas development in our state doesn't seem appropriate or based on reality. International demand for petroleum resources is increasing at a significant rate and shows no sign~~ing~~^{ing} of abating in the future. Profits are reaching all-time highs. How could there be anticipated "need" for providing incentives?

Oil consultants testifying before the legislature and providing information to public media seemingly ridicule the cautious direction of this legislature. They state that even 25% taxes on declared profits is way below what oil companies have agreed to and are paying to other oil-producing countries.

Legislative nervousness about confronting the oil companies on these matters should not hold precedence over acting on behalf of the economic interests of Alaska and its citizens.

Please take a more aggressive action in developing oil tax legislation. The public will thank you.

Yours truly,
Dixie A. Hood

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House Finance
Public Hearing SB305
Wasilla, Alaska
April 29, 2006

George Trabits
Trabits Group, LLC
P.O. Box 870404
Wasilla, Alaska 99687

My name is George Trabits. I am managing member of Trabits Group, a small family owned business here in Alaska. Trabits Group develops industrial minerals that are necessary for oil and gas production. We live here; our trucks are serviced at Mr. Lube in Wasilla, we buy our dog food at Animal Food Warehouse and on Sunday we have breakfast at The Colony Kitchen in Palmer. Senate Bill 305 is disturbing to us because it will stifle exploration and new development in Alaska.

Throughout history increased taxes have, in all cases, caused an immediate downturn in development. Increased taxes are not an incentive for business and create a hostile business environment. Oil and gas exploration and development in Alaska is already an expensive venture, more expensive than anywhere else in the United States. Oil and gas development in Alaska must compete with fields in the Lower 48 and elsewhere in the world.

Our small business is directly dependant upon the success of the oil and gas industry. The proponents of Senate Bill 305 have the misguided opinion that taxing big oil does not hurt the little guy, but they are wrong. Increased taxes will make development here less desirable and will result in the decline of an industry that is vital to many small businesses.

Alaska needs to encourage development. A rising tide raises all ships.

4-39

parts of the world. The oil companies have been a strong steady community partner in the State and they are truly appreciated. They are great businessmen, expertise in their field, and drive a hard bargain. We as Alaskans could learn from them, as well as, other countries, i.e. England, Norway, etc. If China is making arrangements with Africa for their oil and many other part of the world are spoken for I doubt very much that the oil companies will pull out of Alaska. Norway exports 3x more oil than Alaska and generated 6x more profit than the \$34B in Alaska Permanent Fund. We Alaskans & specifically you our legislators who represent us need to step up to the plate and strike an equitable bargain, which has not been accomplished to date.

In closing I would like to say that the Governor's proposed tax reduction for the oil companies will definitely help the oil companies and harm the people of Alaska. Alaska is not meeting the needs of their citizens in the areas of health, education and welfare. The taxes on oil, a major natural resource, in Alaska will be instrumental in meeting these needs of our citizens.



111 W. 16th Avenue
Anchorage, AK 99501
Phone: 907-770-9400
Fax: 907-770-9460

Testimony Given Saturday, April 29, 2006

Mr. Chairman, thank you for this opportunity to comment on Senate Bill 305. My name is Mark Hylen and I am a lifelong Alaskan. I am also the President of Kakivik Asset Management. Kakivik provides inspection and engineering services to the oil and gas industry. We are a subsidiary of Bristol Bay Native Corporation and employ nearly 200 employees. 100% of our revenues are derived from the oil and gas industry in Alaska- this includes the major producers, the smaller independents, the pipeline and the Cook Inlet refiners and producers.

I have been actively following this bill and would like to start by saying thank you to all of you as I know a considerable amount of time has been spent on this effort. After all, this bill will have a significant influence on the future of our state.

I feel privileged to work in the oil and gas industry in this state. Every single Alaskan is directly impacted by the benefits this industry has on us. Whether it is thru the many jobs the industry provides, or just thru receiving a permanent fund dividend and not paying state sales or income tax we all benefit from this industry.

We are experiencing a robust period in the oil industry in the state of Alaska and my company and many other companies have seen job and revenue growth as a result of it. I am concerned about the impact new taxes may have on investment in this state. There is a careful balance between getting the most for the state and getting too much and costing Alaskans jobs.

The bill the governor proposed increases taxes tremendously. I am opposed to new taxes on the industry but if a stable fiscal environment can be created that will provide certainty to investors to see a new gas pipeline be built than I am for it, but I am very concerned how the impact of new taxes may affect Alaskan jobs for the future.

In specific response to the changes between the governors proposed tax increase and the senate's version I would like to make the following comments:

1. PPT by nature is already a 'progressive' tax if you will. More profits, more tax. The windfall tax is something we wouldn't even be talking about 2 years ago when the price was down. It's short sighted and unfair. Please reconsider no windfall increases.
2. It is April 29th. Once again what is fair about a retroactive tax date.....nothing. July 1st is much more reasonable as it allows all parties to understand the game after the rules are set.

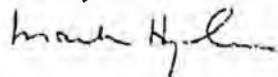
I understand this is a bad time to talk about being fair with 'big oil' because everyone is seeing their profits and believe we should all grab our share. They've agreed a bigger share is in order. What is the state going to do with this surplus? Grow government?

4-29

Let's not get greedy. I oppose any increases in tax but it's inevitable, so let's keep it fair. Let's then focus on the more concerning issue of a state fiscal plan. Let's get ourselves a gas pipeline that could add even more to the state coffers and let's keep Alaskan's working.

Good luck in bringing resolution to this significant bill. It means everything today and to future generations.

Thank you.



Mark Hylan
President and CEO

29 April 2006

To: Members of the House Finance Committee:-

My name is Maynard Tapp, I am an Alaska dreamer since 1954; an Alaskan worker since 1972; and an Alaskan business owner since 1985

I strongly recommend a Production Profits Tax of 15% / 20%.

What SHOULD the primary driver in the debate regarding CSSB305 and CSHB488.

HOW DO WE CREATE AN INVESTMENT CLIMATE THAT PUTS ALASKA AT (OR NEAR) THE TOP OF INVESTMENT OPPORTUNITIES FOR OUR PARTNER'S THE "PRODUCERS".

This same climate will also raise the opportunity to attract new investors.

WILL THIS BILL STOP THE DECLINE IN PRODUCTION?

If you stop the decline in production with exploration or more field development, doesn't that meet the goal of ALASKAN'S GETTING THEIR FAIR SHARE?

IS OIL LEFT IN THE GROUND REALLY A RESOURCE, OR IS IT AN INTERESTING GEOLOGICAL FACT?

What are you as legislators doing to GROW THE SOURCE OF OUR WEALTH?

I BELIEVE WE MUST TRUST OUR PARTNERS, OUR FELLOW CITIZENS, THOSE WHO HAVE INVESTED BILLIONS IN THE STATE OF ALASKA ACCRUING BILLIONS TO THE ALASKA TREASURY.

A ratio of 1% increase in the Profits Tax would be offset by a Investment Tax credit of 4.5%. If that is true shouldn't the requested tax figures be 20%/31.25%. The "experts" say that is too much risk for the state. Why is it fair or smart to ask our partners/investors to take a risk we are not ourselves willing to take?

PROGRESSIVITY or PROGRESSIVITY SQUARED

It seems progressivity is already factored in based on this tax being applied to the production PROFITS.

I am against progressivity, however, if it is here to stay, shouldn't these prices be adjusted for inflation so that a \$70/bbl in 2006 may be worth \$70 + Inflation and therefore not trigger any progressivity factoring.

We are all partners in this state, the government, the people, and the "producers".

The "producers" reinvest the revenues and grow the source of those revenues.

The Alaska people get jobs from/and related to the "producers" reinvestment, grow their wealth; spend money in their community sustaining its wealth, and viability.

The government takes its share and fund's the government.

As a partner, shouldn't the government support the growth of the revenue resource and not the growth of the government. Ultimately, the growth of the revenue source supports the growth of government but within our means.

I believe the 20% / 20% is the wrong number, it should be closer to a 15% / 20% PPT. What do your expert say the PPT number should be to attain 0% to 3% rate of decline? What are you doing to ensure the states revenue source lasting long enough to meet the needs of Alaska's next generation?

Today production is declining at 6% per year. Starting at 880,000 bbl/d I calculate the pipeline being mechanically inoperable by 2015. Then what?

The new technologies to bring viscous oil to market are not easy, guaranteed, or cheap.

What are you doing to encourage investment in Alaska and not somewhere else? It doesn't seem like raising the tax does anything to put more money into exploration.

We cannot tax our way to state solvency, in the long run we must invest/grow our way to state solvency and success.

Please consider that how much the producers make is a completely different discussion than where do they invest those profits to get the best return on their investment.

Ultimately it is your responsibility firstly, to do no harm; secondly to leave Alaska in better condition than when you got here; and thirdly leave a legacy in leadership, where you took the long tough view to grow the Resource and not grow the Government

Thank-you
 Maynard Tapp
 200 West 34th Ave. #809
 Anchorage, Alaska -- 99503

Legislators:

You know there is not going to be an Alaska gasline nor is there a valid gasline contract.

There is no amount to which the oil taxes could be raised, that would impede a gasline. In fact, the higher the oil taxes are raised the sooner Alaska will obtain a gasline. Conversely, the lower the oil taxes, the less the incentive to produce the gas. You have rigged the tax system against a gasline with your giveaway oil taxation.

When Governor Murkowski told the legislature, the press and the public that he wanted the McKenzie River Gasline to be COMPLETED before the start of an Alaska gasline; you legislators knew that there would be least a ten year delay before the start of any Alaska gasline. Thus, every one of you legislators know that there is no urgency in passing this give away of Alaska's oil revenues for a gasline because the passage of this oil tax bill has absolutely no bearing on obtaining an Alaska gasline.

You legislators know that Pedro van Meurs told the press, for Murkowski, that the signing of a gasline contract by BP, Exxon and Conoco would Not obligate them to construct a gasline. Further, that the producers could terminate Murkowski's gasline contract at any time for any reason. Murkowski's gasline contract is meaningless and you know it.

You know the North Slope Producers have less than half enough gas for the Alcan gasline and that the oil Companies need another 30 tcf gas, an insurmountable task both financially and physically. But they have enough gas for an OTG, Over the Top Gasline.

You legislators also know that the Producers, having constructed the McKenzie River Gasline, it does not make any sense for them to construct any other Alaska gasline except an OTG, which is only is only 250 miles from Point Thom, to the McKenzie Delta and for which they have enough gas Vs. 2140 miles to Carlin Alberta for which they have less than half enough gas and cannot obtain enough gas to justify its construction.

You Legislators know with the passage of this oil taxation bill, you are condemning the State of Alaska to endless litigation with the oil companies; setting the State of Alaska up for an endless war with the oil companies which you and the oil companies both know only the oil companies will win because there will always be another Governor that will settle the law suits for ten cents on the dollar just like the last time.

JERRY McCutcheon Box 101838 Anchorage 99510
SUSITON@HYDRONET.COM



THE ALLIANCE

... for responsible development of Alaska's Oil, Gas & Mineral Resources

ALLIANCE HOUSE FINANCE TESTIMONY

SB 305

April 29, 2006

Thank you, Chairman Chenault. My name is Paul Laird, and I'm general manager and testifying on behalf of the Alaska Support Industry Alliance.

Mr. Chairman and members of the Finance Committee, many things have changed with this bill since legislation was introduced in the House and Senate more than two months ago.

The tax rate went up ... and it came partway down.

The tax became progressive ... then the rate went up ... and down ... and back up again.

The bill became retroactive ... then not ... then retroactive again.

Other key provisions have changed as well.

But several basic principles have remained constant.

The musings of some so-called economists notwithstanding, higher taxes still mean less investment. Less investment means fewer jobs and business opportunities for Alaskans, less production and less tax revenue for the state over the long term.

A 22.5% tax rate still means less investment than a 20% tax rate, and a trigger price mechanism for progressivity that fails to take costs into account still means less investment than one that does.

A retroactive tax increase is still morally reprehensible, as well as procedurally problematic.

Regardless how much money they're making in Alaska, companies will still invest where their capital generates the greatest returns. If the prospects are better somewhere else, that's where their investments will go ... that's still how a free enterprise system works.

ALASKA SUPPORT INDUSTRY ALLIANCE

360 W. Benson Blvd., Suite 200 • Anchorage, Alaska 99503 • Phone: (907) 563-2226 • Fax: (907) 561-8870 • www.alaskaalliance.com

Alaska still has a \$1.5 billion budget surplus this year, and the original proposal negotiated between the administration and the producers will still generate an additional \$1 billion a year in state revenues at current prices and production levels. It's also still the only one that's guaranteed to bring us a giant step closer to a gas pipeline.

Higher taxes still mean more government at the expense of private sector growth, and that still means something to fiscal conservatives who prefer a strong private economy to a burgeoning bureaucracy.

The Alliance and our 400 member organizations with more than 30,000 Alaskan employees still prefer lower taxes that promote jobs, business opportunities and long-term, sustainable economic growth to higher taxes that fuel short-term, unsustainable government growth, Mr. Chairman, and we still have faith that you and your colleagues in the legislature share that value.

Thank you.



P.O. Box 230126
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fax (907) 562-5816

RE: House Finance Hearing RE: CS SB # 305 April 29, 2006.

Good afternoon Chairman Chenault and Chairman Meyer and other esteemed and distinguished members of the House Finance Committee. My name is Lynn Johnson and as most of you know, I am the President and co-founder of Dowland-Bach Corporation and a past President of the Alaska Support Industry Alliance. First of all, I would like to thank you all for all of your diligent and thoughtful work during the past couple of months on the PPT tax legislation. I suspect that you all have had more visits, e-mails and letters regarding this single issue of PPT legislation than on any other single issue of your legislative career. I know from my personal experience this session that I have made more visits to Juneau, give more public testimony, and written more letters this session than ever before. This is evidenced by the fact that today is Saturday April 29th and here I am giving another testimony and there you are in Juneau listening to me once again. This only goes to show that this PPT issue is extremely important to all Alaskans.

Six weeks or so ago myself and my fellow Alliance members were going around talking to our non-oil industry friends about the PPT tax issue and the Governor's original proposal. At that time, these non-industry related friends and relatives would only look at us and say "PP What"??? Now even my dog Louie knows what the 20/20 or 22.5/25% tax rate/tax credit debate is about. Bottom line is everyone now knows about the PPT and is aware that their future depends on the decisions made in this legislative session.

My recommendation is very simple. Return to the Governor's original PPT proposal and insure that the investments will continue to be made in North Slope

and Cook Inlet plant and equipment. As a business owner, I am a firm believer that economies grow through the private sector, and not necessarily public sector expansion and spending. Several of you on the Finance Committee are small business owners like me and I am sure that you have a great deal of empathy for my point here. With excessive taxation, as we have all heard time and time again, investment capital from the major producers will flow from Alaska to other oil basins of the world.

In summary, we need to encourage investment and insure that Alaska is a competitive basin for both large and small oil companies. We need to let the Industry know this by making Alaska a good climate in which to invest over the long term. Please think long and hard about making any substantial changes in the Governor's original PPT plan as submitted. This plan in itself is a compromise that benefits everyone in the long run. The long term economic health and economic future of Alaska depends on your decisions. I have confidence that you all will make the correct decision for the economic future of Alaska. Thank you very much.

To: Anchorage LJO. Fax 269-0229

28 April 2006

Don't Pass the Proposed Oil and Gas Tax

- Don't pass a new oil and gas tax (PPT) before you've seen the secret gasline contract and how the two are interconnected.
- Don't bind future legislatures to the new oil and gas tax for 30 plus years as suggested by the Governor and the producers. That clearly violates the Constitution and ensures litigation and delay.
- Avoid a net profits tax. Net profit taxes will be nearly impossible to manage and will result in unending disputes audits and litigation, resulting in the State receiving less than modeled or expected. The Governor's proposed 20/20 PPT is a huge giveaway to the producers.
- Instead repeal ELF for the major North Slope production units and add a progressive increase above the 15% of production severance tax rate for oil when prices exceed \$40 ANS West Coast.
 - If you do choose to take the risk of a net profit share severance tax, at a bare minimum support the Senate Resource version of the PPT, tax rate of 25% with a 20% tax credit and a progressive increase with price. However make sure that there is a minimum severance tax of at least 5% regardless of the price of oil to protect the state when oil prices fall to the historical average. Tax rate for gas should be the same as for oil and should contain a progressive increase with price. Give the Department of Revenue similar audit authority to that of the IRS.
 - Don't be rushed. Listen to expert and unbiased consultants like Daniel Johnson and Econ One who have no political agenda or financial conflicts. Discount the advice of those "experts" with a vested political or economic interest in selling a specific deal. Make sure that you understand the full fiscal impact of the tax structure you are creating. Don't make political compromises such as those made by the Senate Finance Committee. Take the time to fully understand what you are voting on including: 1) the value of the deductions to the producers, 2) the revenue stream to the state at various prices and production levels, 3) how the tax compares to the current system at various prices, 4) the administrative costs and management structure the state will need to manage the tax, 5) the proper balance for the state between upside dollars at high prices versus little to no income at low prices. Approve an oil tax system only after you fully understand it and you've discussed these issues with your constituents. If that requires a special session or the next legislative session, that is okay. Remember, accepting the Governor's and Producer's proposal or the Senate bill will not guarantee either a gasline or more investment on the North Slope, but it will mean less money for our schools and communities. Alaska's oil is an extremely valuable commodity to the oil companies and will be produced by either the producers or others if they choose not to invest. Require the companies to back up their claims with hard data on the profitability of the fields at various tax rates and structures. Get beyond their rhetorical threats to the bottom line. Make sure that whatever you do is for the maximum benefit of the people of Alaska who are counting on you.
- From: Floyd K Mitchell, P.E., Anchorage

Floyd K Mitchell
28 APR 06

Illustration of Effective Tax Rate on Gas Production Under Different Tax Systems
Potential Prudhoe Bay Gas Development

	Administration's 20/20			Senate Finance 22.5/25 With Gas Revenue Reduction To 1/3 of Actual Value			Current Elf System		
Gross Volume (MCF)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Royalty Volume (12.5% Royalty)	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125
Taxable Volume	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875
Downstream Value (\$/MCF)	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000
Cost to Downstream Market	\$ (2,000)	\$ (2,000)	\$ (2,000)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)
Wellhead Value	\$ 1,500	\$ 3,500	\$ 5,500	\$ 1,500	\$ 3,500	\$ 5,500	\$ 1,500	\$ 3,500	\$ 5,500
Taxable Wellhead Value	\$ 1,500	\$ 3,500	\$ 5,500	\$ 0.500	\$ 1.167	\$ 1.833	\$ 1,500	\$ 3,500	\$ 5,500
Production Costs (\$ Per Taxable MCF)									
Prop Tax	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)
OPEX	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CAPEX	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Net "Profit" Per Taxable MCF	\$ 1,477	\$ 3,477	\$ 5,477	\$ 1,477	\$ 3,477	\$ 5,477	\$ 1,477	\$ 3,477	\$ 5,477
Taxable Value	\$ 1,477	\$ 3,477	\$ 5,477	\$ 0,477	\$ 1,144	\$ 1,810	\$ 1,500	\$ 3,500	\$ 5,500
PPT Tax (20% or 22.5%)	\$ 0.295	\$ 0.695	\$ 1.095	\$ 0.107	\$ 0.257	\$ 0.407	N/A	N/A	N/A
Current Elf System (10%, 0.7 ELF)	N/A	N/A	N/A	N/A	N/A	N/A	\$ 0.105	\$ 0.245	\$ 0.385
Less Capital Credit (20% or 25%)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	N/A	N/A	N/A
Total Tax (\$ Per Taxable MCF)	\$ 0.295	\$ 0.695	\$ 1.095	\$ 0.107	\$ 0.257	\$ 0.407	\$ 0.105	\$ 0.245	\$ 0.385
Tax as % of Wellhead Value	19.7%	19.9%	19.9%	7.2%	7.4%	7.4%	7.0%	7.0%	7.0%

Note: Assumes no incremental capital costs or operating costs associated with gas production at PBU; property taxes of \$0.02/gross mcf of production; ELF = 0.7 over first 10 years of production; average royalty rate of 12.5%.

**Illustration of Potential Effective Tax Rate on Gas Production Under Different Tax Systems
Potential Pt. Thompson Development**

	Administration's 20/20			Senate Finance 22.5/25 With Gas Revenue Reduction To 1/3 of Actual Value			Current Elf System		
Gross Volume (MCF)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Royalty Volume (16.67% Royalty)	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167
Taxable Volume	0.833	0.833	0.833	0.833	0.833	0.833	0.833	0.833	0.833
Downstream Value (\$/MCF)	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000
Cost to Downstream Market	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)
Wellhead Value	\$ 1,350	\$ 3,350	\$ 5,350	\$ 1,350	\$ 3,350	\$ 5,350	\$ 1,350	\$ 3,350	\$ 5,350
Taxable Wellhead Value	\$ 1,350	\$ 3,350	\$ 5,350	\$ 0.450	\$ 1.117	\$ 1.783	\$ 1,350	\$ 3,350	\$ 5,350
Production Costs (\$ Per Taxable MCF)									
Prop Tax	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)
OPEX	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)
CAPEX	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)
Net "Profit" Per Taxable MCF	\$ 1.029	\$ 3.029	\$ 5.029	\$ 1.029	\$ 3.029	\$ 5.029	\$ 1.029	\$ 3.029	\$ 5.029
Taxable Value	\$ 1.029	\$ 3.029	\$ 5.029	\$ 0.129	\$ 0.795	\$ 1.462	\$ 1.350	\$ 3.350	\$ 5.350
PPT Tax (20% or 22.5%)	\$ 0.206	\$ 0.686	\$ 1.006	\$ 0.029	\$ 0.179	\$ 0.329	N/A	N/A	N/A
Current Elf System (10%, 0.9 ELF)	N/A	N/A	N/A	N/A	N/A	N/A	\$ 0.122	\$ 0.302	\$ 0.482
Less Capital Credit (20% or 25%)	\$ (0.033)	\$ (0.033)	\$ (0.033)	\$ (0.041)	\$ (0.041)	\$ (0.041)	N/A	N/A	N/A
Total Tax (\$ Per Taxable MCF)	\$ 0.173	\$ 0.573	\$ 0.973	\$ (0.012)	\$ 0.138	\$ 0.288	\$ 0.122	\$ 0.302	\$ 0.482
Tax as % of Wellhead Value	12.8%	17.1%	18.2%	-0.9%	4.1%	5.4%	9.0%	9.0%	9.0%

Note: Assumes total capital costs of \$1.3 billion; annual operating costs of \$50 million; property taxes of \$0.02/gross mcf of production; ELF = 0.9; average royalty rate of 16.67%; total production of 8 TCF. 85% of OPEX/CAPEX costs are allocated to gas production based on BOE production of gas v liquids.

Illustration of Potential Effective Tax Rate on Gas Production Under Different Tax Systems

Potential New Field Development

	Administration's 20/20			Senate Finance 22.5/25 With Gas Revenue Reduction To 1/3 of Actual Value			Current Elf System		
Gross Volume (MCF)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Royalty Volume (12.5% Royalty)	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125
Taxable Volume	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875
Downstream Value (\$/MCF)	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000
Cost to Downstream Market	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)
Wellhead Value	\$ 1,350	\$ 3,350	\$ 5,350	\$ 1,350	\$ 3,350	\$ 5,350	\$ 1,350	\$ 3,350	\$ 5,350
Taxable Wellhead Value	\$ 1,350	\$ 3,350	\$ 5,350	\$ 0.450	\$ 1.117	\$ 1.783	\$ 1.350	\$ 3.350	\$ 5.350
Production Costs (\$ Per Taxable MCF)									
Prop Tax	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)
OPEX	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)
CAPEX	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)
Net "Profit" Per Taxable MCF	\$ 0.756	\$ 2.756	\$ 4.756	\$ 0.756	\$ 2.756	\$ 4.756	\$ 0.756	\$ 2.756	\$ 4.756
Taxable Value	\$ 0.756	\$ 2.756	\$ 4.756	\$ (0.144)	\$ 0.522	\$ 1.189	\$ 1.350	\$ 3.350	\$ 5.350
PPT Tax (20% or 22.5%)	\$ 0.151	\$ 0.551	\$ 0.951	\$ (0.032)	\$ 0.118	\$ 0.268	N/A	N/A	N/A
Current Elf System (10%, 0.7 ELF)	N/A	N/A	N/A	N/A	N/A	N/A	\$ 0.095	\$ 0.235	\$ 0.375
Less Capital Credit (20% or 25%)	\$ (0.086)	\$ (0.086)	\$ (0.086)	\$ (0.086)	\$ (0.086)	\$ (0.086)	N/A	N/A	N/A
Total Tax (\$ Per Taxable MCF)	\$ 0.083	\$ 0.483	\$ 0.883	\$ (0.118)	\$ 0.032	\$ 0.182	\$ 0.095	\$ 0.235	\$ 0.375
Tax as % of Wellhead Value	6.1%	14.4%	16.5%	-8.8%	0.9%	3.4%	7.0%	7.0%	7.0%

Note: Assumes total capital costs of \$0.30/mcf; operating costs of \$0.20/mcf; property taxes of \$0.02/gross mcf of production; ELF = 0.7; royalty rate of 12.5%;

Illustration of Effective Tax Rate on Gas Production Under Different Tax Systems
Potential Prudhoe Bay Gas Development

	Administration's 20/20			Senate Finance 22.5/25 With Gas Revenue Reduction To 1/3 of Actual Value			Current Elf System		
Gross Volume (MCF)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Royalty Volume (12.5% Royalty)	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125
Taxable Volume	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875
Downstream Value (\$/MCF)	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000
Cost to Downstream Market	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)	\$ (2,500)
Wellhead Value	\$ 1,500	\$ 3,500	\$ 5,500	\$ 1,500	\$ 3,500	\$ 5,500	\$ 1,500	\$ 3,500	\$ 5,500
Taxable Wellhead Value	\$ 1,000	\$ 3,500	\$ 5,500	\$ 0.500	\$ 1.167	\$ 1.833	\$ 1,500	\$ 3,500	\$ 5,500
Production Costs (\$ Per Taxable MCF)									
Prop Tax	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)
OPEX	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CAPEX	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Net "Profit" Per Taxable MCF	\$ 1.477	\$ 3.477	\$ 5.477	\$ 1.477	\$ 3.477	\$ 5.477	\$ 1.477	\$ 3.477	\$ 5.477
Taxable Value	\$ 1.477	\$ 3.477	\$ 5.477	\$ 0.477	\$ 1.144	\$ 1.810	\$ 1.500	\$ 3.500	\$ 5.500
PPT Tax (20% or 22.5%)	\$ 0.295	\$ 0.695	\$ 1.095	\$ 0.107	\$ 0.257	\$ 0.407	N/A	N/A	N/A
Current Elf System (10%, 0.7 ELF)	N/A	N/A	N/A	N/A	N/A	N/A	\$ 0.105	\$ 0.245	\$ 0.385
Less Capital Credit (20% or 25%)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	N/A	N/A	N/A
Total Tax (\$ Per Taxable MCF)	\$ 0.295	\$ 0.695	\$ 1.095	\$ 0.107	\$ 0.257	\$ 0.407	\$ 0.105	\$ 0.245	\$ 0.385
Tax as % of Wellhead Value	19.7%	19.9%	19.9%	7.2%	7.4%	7.4%	7.0%	7.0%	7.0%

Note: Assumes no incremental capital costs or operating costs associated with gas production at PBU; property taxes of \$0.02/gross mcf of production; ELF = 0.7 over first 10 years of production; average royalty rate of 12.5%.

**Illustration of Potential Effective Tax Rate on Gas Production Under Different Tax Systems
Potential Pt. Thompson Development**

	Administration's 20/20			Senate Finance 22.5/25 With Gas Revenue Reduction To 1/3 of Actual Value			Current Elf System		
Gross Volume (MCF)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Royalty Volume (16.67% Royalty)	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167	-0.167
Taxable Volume	0.833	0.833	0.833	0.833	0.833	0.833	0.833	0.833	0.833
Downstream Value (\$/MCF)	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000	\$ 4,000	\$ 6,000	\$ 8,000
Cost to Downstream Market	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)	\$ (2,650)
Wellhead Value	\$ 1,350	\$ 3,350	\$ 5,350	\$ 1,350	\$ 3,350	\$ 5,350	\$ 1,350	\$ 3,350	\$ 5,350
Taxable Wellhead Value	\$ 1,350	\$ 3,350	\$ 5,350	\$ 0.450	\$ 1.117	\$ 1.783	\$ 1,350	\$ 3,350	\$ 5,350
Production Costs (\$ Per Taxable MCF)									
Prop Tax	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)	\$ (0.024)
OPEX	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)	\$ (0.132)
CAPEX	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)	\$ (0.166)
Net "Profit" Per Taxable MCF	\$ 1.029	\$ 3.029	\$ 5.029	\$ 1.029	\$ 3.029	\$ 5.029	\$ 1.029	\$ 3.029	\$ 5.029
Taxable Value	\$ 1.029	\$ 3.029	\$ 5.029	\$ 0.129	\$ 0.795	\$ 1.462	\$ 1.350	\$ 3.350	\$ 5.350
PPT Tax (20% or 22.5%)	\$ 0.206	\$ 0.606	\$ 1.006	\$ 0.029	\$ 0.179	\$ 0.329	N/A	N/A	N/A
Current Elf System (10%, 0.9 ELF)	N/A	N/A	N/A	N/A	N/A	N/A	\$ 0.122	\$ 0.302	\$ 0.482
Less Capital Credit (20% or 25%)	\$ (0.033)	\$ (0.033)	\$ (0.033)	\$ (0.041)	\$ (0.041)	\$ (0.041)	N/A	N/A	N/A
Total Tax (\$ Per Taxable MCF)	\$ 0.173	\$ 0.573	\$ 0.973	\$ (0.012)	\$ 0.138	\$ 0.288	\$ 0.122	\$ 0.302	\$ 0.482
Tax as % of Wellhead Value	12.8%	17.1%	18.2%	-0.9%	4.1%	5.4%	9.0%	9.0%	9.0%

Note: Assumes total capital costs of \$1.3 billion; annual operating costs of \$50 million; property taxes of \$0.02/gross mcf of production; ELF = 0.9; average royalty rate of 16.67%; total production of 8 TCF. 85% of OPEX/CAPEX costs are allocated to gas production based on BOE production of gas v liquids.

Illustration of Potential Effective Tax Rate on Gas Production Under Different Tax Systems

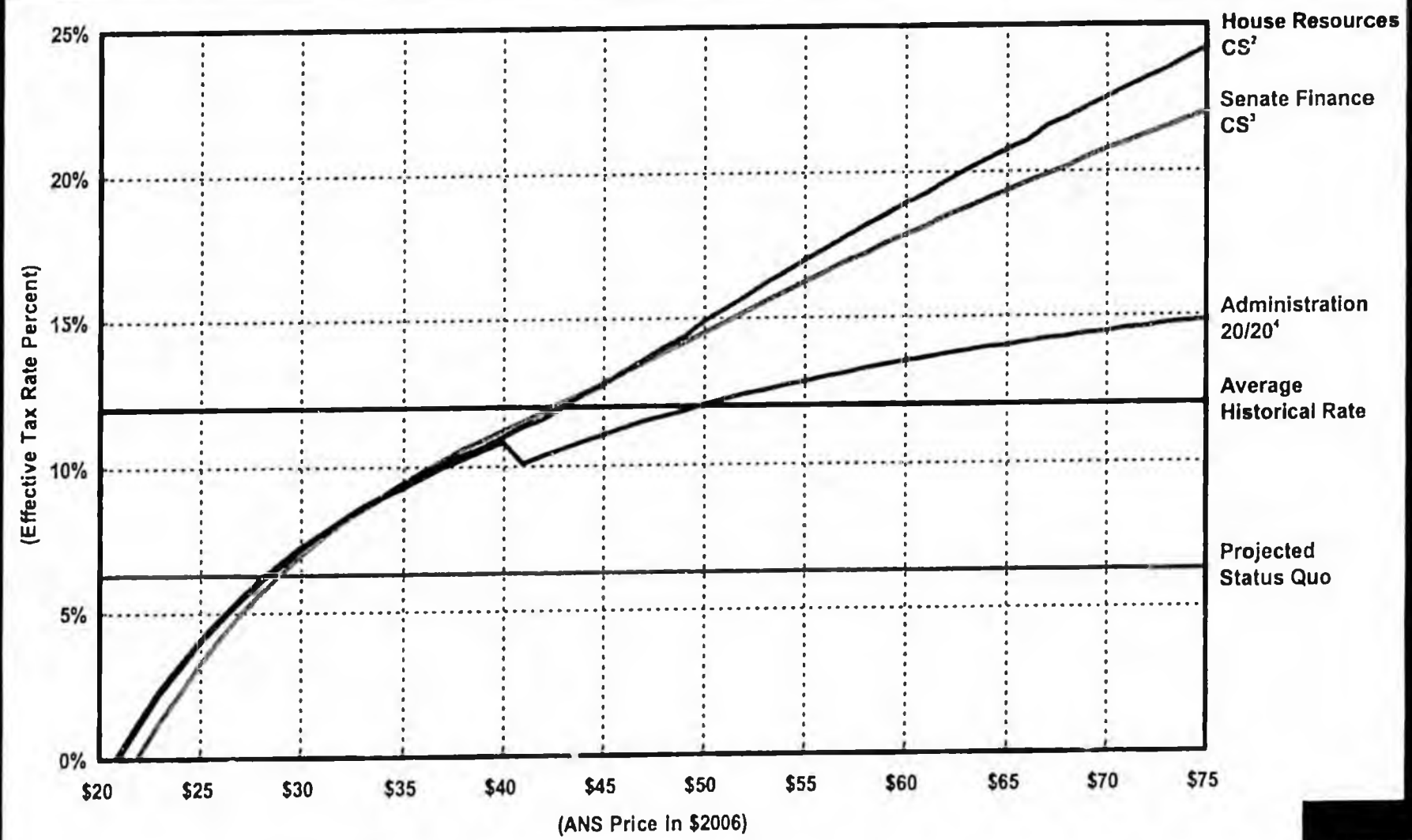
Potential New Field Development

	Administration's 20/20			Senate Finance 22.5/25 With Gas Revenue Reduction To 1/3 of Actual Value			Current Elf System		
Gross Volume (MCF)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Royalty Volume (12.5% Royalty)	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125	-0.125
Taxable Volume	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875	0.875
Downstream Value (\$/MCF)	\$ 4.000	\$ 6.000	\$ 8.000	\$ 4.000	\$ 6.000	\$ 8.000	\$ 4.000	\$ 6.000	\$ 8.000
Cost to Downstream Market	\$ (2.650)	\$ (2.650)	\$ (2.650)	\$ (2.650)	\$ (2.650)	\$ (2.650)	\$ (2.650)	\$ (2.650)	\$ (2.650)
Wellhead Value	\$ 1.350	\$ 3.350	\$ 5.350	\$ 1.350	\$ 3.350	\$ 5.350	\$ 1.350	\$ 3.350	\$ 5.350
Taxable Wellhead Value	\$ 1.350	\$ 3.350	\$ 5.350	\$ 0.450	\$ 1.117	\$ 1.783	\$ 1.350	\$ 3.350	\$ 5.350
Production Costs (\$ Per Taxable MCF)									
Prop Tax	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)	\$ (0.023)
OPEX	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)	\$ (0.229)
CAPEX	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)	\$ (0.343)
Net "Profit" Per Taxable MCF	\$ 0.756	\$ 2.756	\$ 4.756	\$ 0.756	\$ 2.756	\$ 4.756	\$ 0.756	\$ 2.756	\$ 4.756
Taxable Value	\$ 0.756	\$ 2.756	\$ 4.756	\$ (0.144)	\$ 0.522	\$ 1.189	\$ 1.350	\$ 3.350	\$ 5.350
PPT Tax (20% or 22.5%)	\$ 0.151	\$ 0.551	\$ 0.951	\$ (0.032)	\$ 0.118	\$ 0.268	N/A	N/A	N/A
Current Elf System (10%, 0.7 ELF)	N/A	N/A	N/A	N/A	N/A	N/A	\$ 0.095	\$ 0.235	\$ 0.375
Loss Capital Credit (20% or 25%)	\$ (0.069)	\$ (0.069)	\$ (0.069)	\$ (0.086)	\$ (0.086)	\$ (0.086)	N/A	N/A	N/A
Total Tax (\$ Per Taxable MCF)	\$ 0.083	\$ 0.483	\$ 0.883	\$ (0.118)	\$ 0.032	\$ 0.182	\$ 0.095	\$ 0.235	\$ 0.375
Tax as % of Wellhead Value	6.1%	14.4%	16.5%	-8.8%	0.9%	3.4%	7.0%	7.0%	7.0%

Note: Assumes total capital costs of \$0.30/mcf; operating costs of \$0.20/mcf; property taxes of \$0.02/gross mcf of production; ELF = 0.7; royalty rate of 12.5%;

Effective Average Tax Rates at Various Price Levels

(FY 2007-2016)



Assumes no major gas sale.
 Calculated from April 2006; \$80 Million exemption over 8 companies for 10 years, volumes per DOR Fall 2005 Forecast with Oooguruk projection.
 Calculated from July 2006; includes transition (50% of capex over 1st 7 years to maximum of \$3 Billion) and revised 3 MBO exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.
 Calculated from July 2006; includes 6-year transition (100% 2001-2006) and \$73 Million exemption over 7 companies, volumes per DOR Fall 2005 Forecast with Oooguruk projection.
 Source: Historical, Alaska Department of Revenue.



Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

<i>Effective Tax Rate (Percent)</i>							
Administration 20/20 ²	0.0%	7.1%	10.8%	12.0%	13.5%	14.5%	15.2%
House Resources CS ³	0.0%	7.2%	10.9%	14.9%	18.9%	22.5%	25.9%
Senate Finance CS ⁴	0.0%	6.9%	11.2%	14.5%	17.8%	20.7%	23.3%
<i>Alaska Government Take (Percent)</i>							
Administration 20/20 ²	32.8%	31.3%	31.5%	30.8%	31.0%	31.1%	31.2%
House Resources CS ³	32.8%	31.5%	31.7%	33.7%	36.3%	38.8%	41.2%
Senate Finance CS ⁴	32.8%	31.1%	31.9%	33.3%	35.2%	37.1%	38.8%
<i>Total Government Take (Percent)</i>							
Administration 20/20 ²	62.9%	58.9%	58.1%	57.3%	57.2%	57.1%	57.1%
House Resources CS ³	62.9%	59.0%	58.2%	59.1%	60.6%	62.0%	63.5%
Senate Finance CS ⁴	62.9%	58.7%	58.4%	58.9%	59.9%	60.9%	61.9%
<i>Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)</i>							
Administration 20/20 ²	(\$256)	\$55	\$416	\$683	\$1,044	\$1,405	\$1,766
House Resources CS ³	(\$256)	\$62	\$431	\$1,022	\$1,826	\$2,771	\$3,867
Senate Finance CS ⁴	(\$256)	\$42	\$453	\$975	\$1,673	\$2,470	\$3,356

¹ Assumes no major gas sale

² Calculated from July 2006; includes 8-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection

³ Calculated from April 2006; \$60 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

⁴ Calculated from July 2006; includes transition (50% of capex over 1st 7 years to maximum of \$8 Billion) and revised 5 MBD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection



SB

305

(FILE 3)

HFIN

FILE

FISCAL NOTES

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: _____
Bill Version: CS for HB 488(RES)
() Publish Date: _____

Revision Date/Time (Note if correction): _____ Dept. Affected: Revenue
Title An Act Relating to the Production Tax on RDU Tax and Treasury
Oil and Gas Component Tax
Sponsor Rules Committee
Requester Governor Component No. 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	359.2	366.4	373.7	381.2	388.8	396.6
Travel						
Contractual	400.0	370.0				
Supplies	24.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous (OH office, etc)	18.0	18.0	18.0	18.0	18.0	18.0
TOTAL OPERATING	801.2	754.4	391.7	399.2	406.8	414.6

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()	<i>See analysis section</i>
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	801.2	754.4	391.7	399.2	406.8	414.6
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type-Do not abbreviate)						
TOTAL	801.2	754.4	391.7	399.2	406.8	414.6

Estimate of any current year (FY2006) cost: 275.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time	4	4	4	4	4	4
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

Relative to Status Quo

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes. The net income would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production. There would also be a progressive surcharge based on .3% of the difference between actual West Texas Intermediate (WTI) oil price and \$50 applied to the gross value at the point of production. There would be no surcharge when the WTI price was under \$50. The surcharge would also be considered a deductible lease expenditure. There would be an additional annual credit per company of up to the lesser of actual net income or \$12 million per year. In addition, as a transition provision, there would be a deduction for capital costs incurred over the 3 month period January through March 2006, which can be realized over the 9 month period April

Prepared by: Robynn Wilson, Michael Williams, and Roger Marks
Division: Tax Division

Phone 269-1019
Date/Time 3/24/06 2:00 PM

Approved by: Jerry Burnett
Agency: Department of Revenue

Date 3/25/2006

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for HB 488 (RES)

ANALYSIS CONTINUATION

through December 2006. It is estimated this would reduce revenues about \$50 million total over that 9 month period. Finally, the conservation surcharge on oil is decreased from 2 cents/bbl to 1 cent/bbl, while the additional conservation surcharge on oil is increased from 3 cents to 4 cents. The net impact of this, assuming that the oil and hazardous substance release prevention account is at capacity, would be a 1 cent/bbl increase in revenues.

The bill would be effective April 1, 2006.

Relative to Governor's Bill

The Governor's bill had no progressive surcharge. There was an deductible allowance of up to \$73 million of net income per company per year. There was a transition provision where all qualified capital expenditures incurred between July 1, 2001 through July 1, 2006 would be deductible over six years. The 3 cent additional conservation surcharge on oil would have been a credit against the oil tax.

The bill would have been effective July 1, 2006.

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. Columns 1-3 reflect the original fiscal note for the bill. Columns 4-5 reflect adjustments to the original fiscal note to reflect net adjustments in state corporate income tax from changes in the severance tax, the recognition of the credit for the additional conservation surcharge on oil, the re-assessment of the number of full allowances from 7 company equivalents to nine, and minor model changes. Columns 6-8 reflect changes from converting from the Fall 2005 Department of Revenue Source Book data to Spring 2006. The volumes for the last quarter have been adjusted to reflect short-term adjustments resulting from the North Slope oil spill in March. Finally, Columns 9-11 reflect the House Resources CS. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- \$100 mm/yr exploration
- \$1/bbl on-going capital on all barrels
- \$3.50/bbl developmental capital on 2/3 of existing conventional oil
- \$8/bbl developmental capital on 2/3 of existing heavy oil
- \$3.50/bbl developmental capital on new conventional oil
- \$8/bbl developmental capital on new heavy oil
- \$3/bbl operating cost on conventional oil
- \$5/bbl operating cost on heavy oil

The table shows the 2006-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a \$40 price, and a \$60 price. (Note that the status quo numbers are slightly different from what is reflected in the Spring 2006 Revenue Sources Book because of volume adjustments from the oil spill, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 3 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 1 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 1 additional position for a Tax Tech III (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenses include \$100,000 and \$70,000 for programming in FY 07 and FY 08, respectively, and \$300,000 in each of FY 07 and FY 08 for help in writing regulations. Supplies include computers and other supplies necessary for new positions.

See Page 3 for revenue estimates

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

GOVERNOR'S BILL
ORIGINAL FISCAL NOTE

GOVERNOR'S BILL
WITH CORPORATE INCOME TAX,
CONSERVATION SURCHARGE
NINE COMPANY ALLOWANCES
MINOR MODEL CHANGES

Fiscal Year	DOR Forecast	Col. 1 Status Quo Tax	Col. 2 Tax from Bill	Col. 3 Gain from Bill	Col. 4 Tax from Bill	Col. 5 Gain from Bill
2006	na	na	na	na	na	na
2007	\$49.20	934	1,363	429	1,317	383
2008	\$40.95	697	915	217	876	179
2009	\$25.50	404	349	-55	320	-84
2010	\$25.50	387	339	-48	310	-77
2011	\$25.50	362	351	-11	319	-43
2012	\$25.50	343	332	-10	300	-42

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill	Tax from Bill	Gain from Bill
2006	na	na	na	na	na	na
2007	\$40.00	737	1,038	301	997	260
2008	\$40.00	679	1,031	353	988	309
2009	\$40.00	673	1,118	445	1,070	397
2010	\$40.00	646	1,106	460	1,058	411
2011	\$40.00	606	1,138	532	1,086	480
2012	\$40.00	576	1,112	536	1,059	483

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill	Tax from Bill	Gain from Bill
2005	na	na	na	na	na	na
2007	\$60.00	1,165	1,938	773	1,879	714
2008	\$60.00	1,069	1,917	848	1,855	786
2009	\$60.00	1,042	2,007	965	1,939	897
2010	\$60.00	1,003	1,992	989	1,923	921
2011	\$60.00	941	2,051	1,110	1,977	1,036
2012	\$60.00	896	2,014	1,117	1,939	1,043

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for HB 488 (RES)

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

GOVERNOR'S BILL
CHANGES FROM FALL 2005 FORECAST
TO SPRING 2006 FORECAST

Fiscal Year	DOR Forecast	Col. 6 Status Quo Tax	Col. 7 Tax from Bill	Col. 8 Gain from Bill	Col. 9 Status Quo Tax	Col. 10 Tax from Bill	Col. 11 Gain from Bill
2006	na	na	na	na	262	517	255
2007	\$53.60	989	1,514	526	989	1,825	836
2008	\$46.90	759	1,136	377	759	1,318	558
2009	\$25.50	355	302	-52	355	323	-32
2010	\$25.50	315	283	-32	315	304	-11
2011	\$25.50	281	291	10	281	312	31
2012	\$25.50	271	291	20	271	312	41

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill	Status Quo Tax	Tax from Bill	Gain from Bill
2006	na	na	na	na	174	227	53
2007	\$40.00	713	978	270	708	967	259
2008	\$40.00	655	953	298	655	974	319
2009	\$40.00	631	1,021	390	631	1,042	411
2010	\$40.00	582	990	408	582	1,011	429
2011	\$40.00	544	1,012	468	544	1,033	489
2012	\$40.00	536	1,021	485	536	1,042	506

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill	Status Quo Tax	Tax from Bill	Gain from Bill
2006	na	na	na	na	275	572	297
2007	\$60.00	1,120	1,840	720	1,120	2,380	1,260
2008	\$60.00	1,032	1,786	754	1,032	2,350	1,318
2009	\$60.00	978	1,848	871	978	2,421	1,443
2010	\$60.00	901	1,800	899	901	2,366	1,465
2011	\$60.00	842	1,841	999	842	2,414	1,572
2012	\$60.00	831	1,861	1,029	831	2,438	1,606

INCLUDES VOLUMES, PRICE, TAPS, MARINE, UPSTREAM, WELLS

SPRING 2006 VOLUMES FOR THE LAST QUARTER OF FY 2006 HAVE BEEN REDUCED TO REFLECT SHORT TERM ADJUSTMENTS FROM THE NORTH SLOPE OIL SPILL

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: HB 488
(H) Publish Date: 2/21/06

Revision Date/Time (Note if correction): _____ Dept. Affected: Natural Resources
Title: Repealing the oil production tax and gas RDU: Resource Development
production tax etc. Component: Oil & Gas Development
Sponsor: Rules by Request of Governor
Requester: Governor Component No.: 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()						
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2006) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

There is no anticipated fiscal impact for DNR associated with implementation of this legislation.

Prepared by: Bill VanDyke, Acting Director
Division: Oil & Gas
Approved by: Michael Menge, Commissioner
Agency: Natural Resources

Phone: 907-269-8800
Date/Time: 2/15/2006
Date: 2/15/2006

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: HB 488
(H) Publish Date: 2/21/06

Revision Date/Time (Note if correction): _____ Dept. Affected: Revenue
Title: An Act Relating to the Production Tax on RDU: Tax and Treasury
Oil and Gas Component: Tax
Sponsor: Rules Committee
Requester: Governor Component No.: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	359.2	366.4	373.7	381.2	388.8	396.6
Travel						
Contractual	1,200.0	520.0				
Supplies	24.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous [OH office, etc]	18.0	18.0	18.0	18.0	18.0	18.0
TOTAL OPERATING	1,601.2	904.4	391.7	399.2	406.8	414.6

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES () *See analysis section*

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	1,601.2	904.4	391.7	399.2	406.8	414.6
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	1,601.2	904.4	391.7	399.2	406.8	414.6

Estimate of any current year (FY2006) cost: 275.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal.

POSITIONS

Full-time	4	4	4	4	4	4
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)
This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes, and an additional \$73 million per year allowance for each producer. (The allowance can be no greater than the net value before the allowance.) The net income would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production. In addition, there would be a deduction for capital costs incurred over the previous five years, which can be realized over the next six years, but only in years where the ANS price is over \$40. It is estimated this would reduce revenues about \$170 million in years when it was realized. In years where the ANS price is under \$40 the deduction can be carried forward.

Prepared by: Robynn Wilson, Michael Williams, and Roger Marks Phone 269-1019
Division: Tax Division Date/Time 2/21/06 12:00 AM
Approved by: Jerry Burnett Date 2/21/2006
Agency: Department of Revenue

FISCAL NOTE #2

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. HB 488

ANALYSIS CONTINUATION

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. They are predicated on the oil volumes in the Department of Revenue Fall 2005 Revenue Sources Book. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. They assume that seven producers utilize the full allowance. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- \$100 mm/yr exploration
- \$1/bbl on-going capital on all barrels
- \$3.50/bbl developmental capital on 2/3 of existing conventional oil
- \$8/bbl developmental capital on 2/3 of existing heavy oil
- \$3.50/bbl developmental capital on new conventional oil
- \$8/bbl developmental capital on new heavy oil
- \$3/bbl operating cost on conventional oil
- \$5/bbl operating cost on heavy oil

The following table shows the 2007-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a \$40 price, and a \$60 price. (Note that the status quo numbers are slightly different from what is reflected in the Fall 2005 Revenue Sources Book because of some minor changes in assumptions introduced since Fall 2005, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 3 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 1 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 1 additional position for a Tax Tech III (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenses include \$100,000 and \$70,000 for programming in FY 07 and FY 08, respectively, \$250,000 in each of FY 07 and FY 08 for help in writing regulations, and \$850,000 and \$200,000 in FY 07 and FY 08, respectively, for auditing costs related to the new transition rules. Supplies include computers and other supplies necessary for new positions.

FISCAL NOTE #2

STATE OF ALASKA
 2006 LEGISLATIVE SESSION
ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

BILL NO. HB 488

Fiscal Year	DOR Forecast	Status Quo Tax	Tax from Bill	Gain from Bill
2007	49.20	934	1,363	429
2008	40.95	697	915	217
2009	25.50	404	349	-55
2010	25.50	387	339	-48
2011	25.50	362	351	-11
2012	25.50	343	332	-10

.....

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007	40.00	737	1,038	301
2008	40.00	679	1,031	353
2009	40.00	673	1,118	445
2010	40.00	646	1,106	460
2011	40.00	606	1,138	532
2012	40.00	576	1,112	536

.....

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007	60.00	1,165	1,938	773
2008	60.00	1,069	1,917	848
2009	60.00	1,042	2,007	965
2010	60.00	1,003	1,992	989
2011	60.00	941	2,051	1,110
2012	60.00	896	2,014	1,117

BILLS

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

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5/4/2006

source: DOR

	governor's bill	House Resources CS Version L	SENATE (page refs = S. Fin. CS)	House Finance CS Version
tax rate	20% .011(a)-page 3	20% .011(a)-page 3	22.5% general 5% on Cook Inlet oil .011(e)-pages 3-4	20.0% .011(e)-page 3 3/4 rev. excl. for Cook Inlet oil .160(a) -page 20 tax ceiling on Cook Inlet gas .011(i) -page 5
credit rate	20% .024(a)-page 5	20% .024(a)-page 8	25% .024(a)-page 7	20% .024(a)-page 7
private royalty tax rate	no special rate	5% .011(e)-page 3-4	5% oil & 1.67% gas Report from Commish .011(f)-page 4 & .180 pg 26	5% oil & 1.67% gas Report from Commish .011(f)-page 3 & .180 pg 27
Gas (GRE)	n/a		Gas Revenue Exclusion in 160 equivalent to rate approximating 7%(also applies to private royalty rate creating equivalent rate below 1.5%) .160(a) page 19	Gas Revenue Exclusion in 160 equivalent to rate approximating 7%(also applies to private royalty rate creating equivalent rate below 1.5%) .160(a) page 20
progressivity surcharge	none	over \$50/bbl WTI. (.3% x (WTI - \$50) x gross; <\$110 rate is 37.5% .011(f)-page 4	over \$50/bbl, (ANSwc - \$50) x .002 x ANSwH x .775 x bbls (oil only) .011(g) and (h)-pages 4-5	over \$35/bbl (net value/boe) x 0025 x net value .011(g) and (h) page 4-5
special gas progressivity?	n/a	yes .011(i)-page 4-5	no	n/a
progressivity deductible?	n/a	yes .160(a)-page 18	no .160(d)(2)(O)-page 22	no .160(d)(2)(O)-page 23
transition	5 yr lookback of capex .160(g)-page 15	3 mo. of capex & opex. ? Sec. 42 uncodified-page 30	5 yrs.lookback capex 2 for 1 recoupment .024(i)-pages 10-11	5 yrs.lookback capex 2 for 1 recoupment .024(i)-page 10
transition treatment	deduction over 6 yr, if ANSwc >=\$40 .160(g)-page 15	deduction over 9 mo, no oil price test Sec. 42 uncodified-page 30	20% credit; no oil price test .024(i)-pages 10-11	20% credit; no oil price test .024(i)-page 11
unset of transition	no	n/a	3/31/2013 .024(i)-page 11	7 yr rolling .024(i)(3) page 11
base allowance	\$73M deduction .160(i)-page 16	\$12M credit (equates to \$60M ded.) .170(a)-page 23	Revised 5000 bbl equivalent credit capped at 14 million .170(a)-pages 25-26	\$12M credit (equates to \$60M ded.) .170(a)-page 26
gold-plating solution				avail. up to 1/2 curr invest .170(a)-page 26
sunset of base allowance	none	3/31/2016 (exp incurred) .170(e)-page 24	3/31/2016 w/commissioner report .170(a)-page 25. 180 pg 26-27	10 yr rolling .170(a)-page 27
safe harbor	90%, annual true-up, no interest .020(a)-page 3	90% with interest .020(g)-page 7	95%, annual true-up, no interest .020(a)-pages 5-6	95%, annual true-up, no interest .020(a)-page 6
pmt < safe harbor??	interest only .020(a)-page 3	5% penalty + interest .020(h)-page 7	interest only .020(a)-pages 5-6	interest only .020(a)-page 6
effective date	7/1/2006 page 20	4/1/2006 Section 45-page 30	4/1/2006 Sec. 40 -page 33	7/1/2006 Sec. 40 -page 35

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

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5/4/2006

source: DOR

	governor's bill	House Resources CS Version L	SENATE (page refs = S. Fin. CS)	House Finance CS Version
transition payment	none	6 mos. pymt on old system; true-up in 7th mo. <i>sec. 39--page 28</i>	6 mos. pymt on old system; true-up in 7th mo. <i>sec. 37(g)--pages 31-32</i>	6 mos. pymt on old system; true-up in 7th mo. <i>Sec. 36(h)--page 34</i>
spill surcharge total spill surcharge split (.201/.300) spill surcharge payable	no change (5 cents) 2/3 no change	no change (5 cents) 1/4 increase 1 cent <i>page 24-25</i>	increase 1 cent, to 6 cents 1/5 increase 2 cent <i>.201, .300 pages 27-28</i>	no change (5 cents) 1/4 increase 1 cent <i>pages 28-29</i>
surcharge treatment	creditable against PPT <i>page 17-18</i>	not creditable, not ded. <i>.160(d)(2)(L)--page 21</i>	not creditable, not ded. <i>.160(d)(2)(L)--page 22</i>	not creditable, not ded. <i>.160(d)(2)(L)--page 23</i>
SB 185 credit	no change	extends 10 years; only usable against PPT <i>.025(b), .025(f)--page 11-12</i>	extends 10 years; fixes \$20 m issue <i>.025(b), .025(f)--page 12-14</i>	extends 10 years; fixes \$20 m issue <i>.025(b), .025(f)--pages 13-14</i>
abandonment	no provision	no credit <i>.024(i)(2)--page 11</i>	no deduction or credit for abandonment on old production <i>.160(d)(2)(P) page 22</i>	no deduction or credit for abandonment on old production (Improved language) <i>.160(d)(2)(P)--page 22</i>
credits usable	against PPT only <i>.024(a)--page 3</i>	against PPT only <i>.024(a)--page 8</i>	against PPT only <i>.024(a)--page 7</i>	against PPT only <i>.024(a)--page 7</i>
credits transferable	yes--20% tax limit <i>.024(d)-(e)--page 6</i>	yes--20% tax limit <i>.024(d)-(e)--page 8-9</i>	yes--20% tax limit <i>.024(d)-(e)--page 8-9</i>	yes--20% tax limit <i>.024(d)-(e)--page 9-10</i>
credits refundable?	no	up to \$10M depends on investment <i>.024(f)(5)--page 9-10</i>	no	no
credits for annual loss	yes, at 20% <i>.024(b)--page 5</i>	yes, at 20% <i>.024(b)--page 8</i>	yes, at 22.5% <i>.024(b)--page 8</i>	yes, at 20% <i>.024(b)--page 8-9</i>
point of production	upstream of gas treatment upstream <i>.900(7)--page 19</i>	upstream of gas treatment upstream <i>.900(7)--page 25-26</i>	upstream of gas treatment upstream <i>.900(7)--pages 28-29</i>	upstream of gas treatment upstream (definition added) <i>.900(7)--page 29-30</i>
DNR royalty value	yes <i>.150(d)--page 11</i>	yes <i>.150(d)--page 17-18</i>	no	yes <i>.150(d)--page 19</i>
IRC sec 482 as a tool	no	no	yes (incl. §6662) <i>.160(i)--page 24</i>	yes (w/o §6662) <i>.160(i)--page 26</i>
catastrophic oil spill deductible?	yes, if on lease (not precluded)	no <i>.160(c)--page 19</i>	yes, if on lease (not precluded)	yes, if on lease (not precluded)
DNR gets exploration Data			yes <i>.024(a) page 8</i>	yes <i>.024(a)--page 7</i>
020 (f) Sales Language			yes <i>.020(f) page 7</i>	yes <i>.020(f)--page 7</i>
NPSL regs after industry practice			yes <i>.160(c)(1)(B) page 20</i>	yes <i>.160(c)(1)(B)--page 21</i>

24-GS2052N
Chenoweth
5/4/06

HOUSE CS FOR CS FOR SENATE BILL NO. 305(FIN)
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-FOURTH LEGISLATURE - SECOND SESSION

BY THE HOUSE FINANCE COMMITTEE

Offered:
Referred:

Sponsor(s): SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL
FOR AN ACT ENTITLED

1 "An Act repealing the oil production tax and the gas production tax and providing for a
2 production tax on oil and gas; relating to the calculation of the gross value at the point
3 of production of oil and gas and to the determination of the value of oil and gas for
4 purposes of the production tax on oil and gas; providing for tax credits against the
5 production tax on oil and gas; relating to the relationship of the production tax on oil
6 and gas to other taxes, to the dates those tax payments and surcharges are due, to
7 interest on overpayments of the tax, and to the treatment of the tax in a producer's
8 settlement with the royalty owners; relating to flared gas, and to oil and gas used in the
9 operation of a lease or property under the production tax; relating to the prevailing
10 value of oil and gas under the production tax; relating to surcharges on oil; relating to
11 statements or other information required to be filed with or furnished to the
12 Department of Revenue, to the penalty for failure to file certain reports for the tax, to

1 the powers of the Department of Revenue, and to the disclosure of certain information
2 required to be furnished to the Department of Revenue as applicable to the
3 administration of the tax; relating to criminal penalties for violating conditions
4 governing access to and use of confidential information relating to the tax, and to the
5 deposit of tax money collected by the Department of Revenue; amending the definitions
6 of 'gas,' 'oil,' and certain other terms for purposes of the production tax, and as the
7 definition of the term 'gas' applies in the Alaska Stranded Gas Development Act, and
8 adding further definitions; making conforming amendments; and providing for an
9 effective date."

10 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

11 * Section 1. The uncodified law of the State of Alaska is amended by adding a new section
12 to read:

13 LEGISLATIVE INTENT. (a) It is the intent of the legislature through sec. 11 of this
14 Act to confirm by clarification the long-standing interpretation of AS 43.55.020(f) by the
15 Department of Revenue.

16 (b) It is the intent of the legislature that the division or other unit of the Department of
17 Environmental Conservation assigned responsibility for administration of the programs under
18 AS 46.08 that are principally supported by the conservation surcharges on oil levied under
19 AS 43.55.201 - 43.55.299 and 43.55.300 - 43.55.310

20 (1) reduce program costs, including personnel costs, as necessary to operate
21 within the revenue anticipated to be generated by those surcharges, in the amounts of those
22 surcharges as amended by secs. 27 and 29 of this Act; and

23 (2) request appropriations for exceptional program needs and expansions
24 beyond what can be provided from the estimated amounts collected from those surcharges
25 from alternative funding sources.

26 * Sec. 2. AS 43.05.230(f) is amended to read:

27 (f) A wilful violation of the provisions of this section or of a condition
28 imposed under AS 43.55.040(1)(B) is punishable by a fine of not more than \$5,000.

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1 or by imprisonment for not more than two years, or by both.

2 * Sec. 3. AS 43.20.031(c) is amended to read:

3 (c) In computing the tax under this chapter, the taxpayer is not entitled to
4 deduct any taxes based on or measured by net income. The taxpayer may deduct the
5 tax levied and paid under AS 43.55.

6 * Sec. 4. AS 43.20.072(b) is amended to read:

7 (b) A taxpayer's business income to be apportioned under this section to the
8 state shall be the federal taxable income of the taxpayer's consolidated business for the
9 tax period, except that

10 (1) taxes based on or measured by net income that are deducted in the
11 determination of the federal taxable income shall be added back; the tax levied and
12 paid under AS 43.55 may not be added back;

13 (2) intangible drilling and development costs that are deducted as
14 expenses under 26 U.S.C. 263(c) (Internal Revenue Code) in the determination of the
15 federal taxable income shall be capitalized and depreciated as if the option to treat
16 them as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) had not been
17 exercised;

18 (3) depletion deducted on the percentage depletion basis under 26
19 U.S.C. 613 (Internal Revenue Code) in the determination of the federal taxable income
20 shall be recomputed and deducted on the cost depletion basis under 26 U.S.C. 612
21 (Internal Revenue Code); and

22 (4) depreciation shall be computed on the basis of 26 U.S.C. 167
23 (Internal Revenue Code) as that section read on June 30, 1981.

24 * Sec. 5. AS 43.55.011 is amended by adding new subsections to read:

25 (e) There is levied on the producer of oil or gas a tax for all oil and gas
26 produced each month from each lease or property in the state, less any oil and gas the
27 ownership or right to which is exempt from taxation or constitutes a landowner's
28 royalty interest. Except as otherwise provided under (i) of this section, the tax is equal
29 to 20 percent of the production tax value of the taxable oil and gas as calculated under
30 AS 43.55.160.

31 (f) There is levied on the producer of oil or gas a tax for all oil and gas

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produced each month from each lease or property in the state the ownership or right to which constitutes a landowner's royalty interest, except for oil and gas the ownership or right to which is exempt from taxation. The provisions of this subsection apply to a landowner's royalty interest as follows:

(1) the rate of tax levied on oil is equal to five percent of the gross value at the point of production of the oil;

(2) the rate of tax levied on gas is equal to 1.667 percent of the gross value at the point of production of the gas;

(3) if the department determines that, for purposes of reducing the producer's tax liability under (1) or (2) of this subsection, the producer has received or will receive consideration from the royalty owner offsetting all or a part of the producer's royalty obligation, other than a deduction under AS 43.55.020(d) of the amount of a tax paid,

(A) notwithstanding (1) of this subsection, the tax is equal to

(i) for oil that is produced from a lease or property in the Cook Inlet sedimentary basin, five percent of the gross value at the point of production of the oil;

(ii) for oil, except oil described in (i) of this subparagraph, 20 percent of the gross value at the point of production of the oil; and

(B) notwithstanding (2) of this subsection, for gas the tax is equal to 6.67 percent of the gross value at the point of production of the gas.

(g) In addition to the taxes levied under (e) and (f) of this section, during each month for which the price index determined under (h) of this section is greater than zero, there is levied on the producer of oil or gas a tax for all oil and gas produced during that month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation or constitutes a landowner's royalty interest. Except as otherwise provided under (i) of this section, the tax levied under this subsection is equal to .25 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160, multiplied by the price index determined under (h) of this section.

1 (h) For purposes of (g) of this section, the price index for a month is calculated
 2 by subtracting 35 from the number that is equal to the quotient of the production tax
 3 value of the taxable oil and gas produced during that month, as calculated under
 4 AS 43.55.160, divided by the number of barrels of oil equivalent of that oil and gas.
 5 For purposes of this subsection, a barrel of oil equivalent is a barrel of oil, in the case
 6 of oil, or 6,000 cubic feet of gas, in the case of gas.

7 (i) If a producer produces gas during a month from a lease or property in the
 8 Cook Inlet sedimentary basin, and if the imputed gas tax rate for that month under (j)
 9 of this section exceeds \$.019 per Mcf, the producer's total tax for that month levied
 10 under (e) and (g) of this section is reduced by the amount equal to the number of Mcf
 11 produced by the producer from all leases or properties in the Cook Inlet sedimentary
 12 basin and taxable under (e) and (g) of this section, multiplied by the difference
 13 between that imputed gas rate and \$.019 per Mcf.

14 (j) For purposes of (i) of this section, a producer's imputed gas tax rate for a
 15 month is equal to

$$1/6 \times TT/BOE$$

16 where

17 (1) TT = the producer's total tax for the month levied under (e) and (g)
 18 of this section, calculated without regard to (i) of this section and net of any credits
 19 that are available to be applied under this chapter; and

20 (2) BOE = the amount of oil and gas produced by the producer during
 21 the month and taxable under (e) of this section, expressed as barrels of oil equivalent;
 22 for purposes of this paragraph, a barrel of oil equivalent is

23 (A) one barrel of oil, in the case of oil;

24 (B) six Mcf of gas, in the case of gas.

25 (k) In (i) and (j) of this section, "Mcf" means 1,000 cubic feet.

26 * Sec. 6. AS 43.55.017(a) is amended to read:

27 (a) Except as provided in this chapter, the taxes imposed by this chapter are in
 28 place of all taxes now imposed by the state or any of its municipalities, and neither the
 29 state nor a municipality may impose a tax on [UPON]
 30

31 (1) producing oil or gas leases;

1 (2) oil or gas produced or extracted in the state;

2 (3) the value of intangible drilling and development costs, as
3 described in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through
4 January 1, 1974 [EXPLORATION EXPENSES].

5 * Sec. 7. AS 43.55.020(a) is repealed and reenacted to read:

6 (a) Ninety-five percent of the total tax levied under AS 43.55.011(e) - (g), net
7 of any credits applied under this chapter, is due on the last day of each calendar month
8 on oil and gas produced from each lease or property during the preceding month. The
9 remaining portion of the tax levied under AS 43.55.011(e) - (g) net of any credits
10 applied under this chapter, is due on March 31 of the year following the calendar year
11 during which the oil and gas were produced. An unpaid amount of tax that is not paid
12 when due in accordance with this subsection becomes delinquent. An overpayment of
13 tax with respect to a month may be applied against the tax due for any later month.
14 Notwithstanding any contrary provision of AS 43.05.280, interest on an overpayment
15 is allowed only from a date that is 90 days after the later of (1) the March 31 described
16 in this subsection, or (2) the date that the statement required under AS 43.55.030(a)
17 and (e) to be filed on or before that March 31 is filed. Interest is not allowed if the
18 overpayment was refunded within the 90-day period.

19 * Sec. 8. AS 43.55.020(b) is amended to read:

20 (b) The production tax on oil and [OR] gas shall be paid by or on behalf of the
21 producer.

22 * Sec. 9. AS 43.55.020(d) is amended to read:

23 (d) In making settlement with the royalty owner for oil and gas that is
24 taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on
25 taxable royalty oil and [OR] gas, or may deduct taxable royalty oil or gas equivalent
26 in value at the time the tax becomes due to the amount of the tax paid. Unless
27 otherwise agreed between the producer and the royalty owner, the amount of the
28 tax paid under AS 43.55.011(e) and (g) on taxable royalty oil and gas for a month,
29 other than oil and gas the ownership or right to which constitutes a landowner's
30 royalty interest, is considered to be the gross value at the point of production of
31 the taxable royalty oil and gas produced during the month multiplied by a figure

1 that is a quotient, in which

2 (1) the numerator is the producer's total tax liability under
3 AS 43.55.011(e) and (g) for the month of production; and

4 (2) the denominator is the total gross value at the point of
5 production of the oil and gas taxable under AS 43.55.011(e) and (g) produced by
6 the producer from all leases and properties in the state during the month.

7 * Sec. 10. AS 43.55.020(e) is repealed and reenacted to read:

8 (e) Gas flared, released, or allowed to escape in excess of the amount
9 authorized by the Alaska Oil and Gas Conservation Commission is considered, for the
10 purpose of AS 43.55.011 - 43.55.180, as gas produced from a lease or property. Oil or
11 gas used in the operation of a lease or property in the state in drilling for or producing
12 oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and
13 Gas Conservation Commission to be waste, is not considered, for the purpose of
14 AS 43.55.011 - 43.55.180, as oil or gas produced from a lease or property.

15 * Sec. 11. AS 43.55.020(f) is amended to read:

16 (f) If oil or gas is produced but not sold, or if oil or gas is produced and
17 sold under circumstances where the sale price does not represent the prevailing value
18 for oil or gas of like kind, character, or quality in the field or area from which the
19 product is produced, the department may require the tax to be paid upon the basis of
20 the value of oil or gas of the same kind, quality, and character prevailing for that field
21 or area during the calendar month of production or sale [FOR THAT FIELD OR
22 AREA].

23 * Sec. 12. AS 43.55 is amended by adding a new section to read:

24 **Sec. 43.55.024. Tax credits for certain losses and expenditures.** (a) A
25 producer or explorer may take a tax credit for a qualified capital expenditure as
26 follows:

27 (1) notwithstanding that a qualified capital expenditure may be a
28 deductible lease expenditure for purposes of calculating the production tax value of oil
29 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
30 AS 38.05.180(d), AS 41.09.010, AS 43.20.043, or AS 43.55.025,

31 (A) a producer or explorer that incurs a qualified capital

1 expenditure may also elect to take a tax credit against a tax due under
2 AS 43.55.011(e) in the amount of 20 percent of that expenditure;

3 (B) for a calendar year for which the producer makes an
4 election under AS 43.55.160(f), instead of taking a tax credit at a rate
5 authorized by (A) of this paragraph as to each separate qualified capital
6 expenditure after it has been incurred, a producer that incurs a qualified capital
7 expenditure during that year and that wishes to apply a credit based on that
8 expenditure against a tax due under AS 43.55.011(e) shall calculate and apply
9 every month an annualized tax credit in an amount equal to $1 \frac{2}{3}$ percent of the
10 total qualified capital expenditures incurred during that year and for which the
11 tax credit is taken for that year;

12 (2) a producer or explorer may take a credit for a qualified capital
13 expenditure incurred in connection with geological or geophysical exploration or in
14 connection with an exploration well only if the producer or explorer provides to the
15 department, as part of the statement required under AS 43.55.030(a) for the month for
16 which the credit is sought to be taken, the producer's or explorer's written agreement

17 (A) to notify the Department of Natural Resources, within 30
18 days after completion of the geological or geophysical data processing or
19 completion of the well, or within 30 days after the statement is filed, whichever
20 is the latest, of the date of completion and to submit a report to that department
21 describing the processing sequence and provide a list of data sets available;

22 (B) to provide to the Department of Natural Resources, within
23 30 days after the date of a request, specific data sets, ancillary data, and reports
24 identified in (A) of this paragraph;

25 (C) that, notwithstanding any provision of AS 38, the
26 Department of Natural Resources shall hold confidential the information
27 provided to that department under this paragraph for 10 years following the
28 completion date, after which the department shall publicly release the
29 information after 30 days' public notice.

30 (b) A producer or explorer may elect to take a tax credit in the amount of 20
31 percent of a carried-forward annual loss. A credit under this subsection may be applied

1 against a tax due under AS 43.55.011(e) and may be applied irrespective of whether
2 the producer or explorer also claims a credit for transitional investment expenditures
3 authorized by (i) of this section. For purposes of this subsection, a carried-forward
4 annual loss is the amount of a producer's or explorer's adjusted lease expenditures
5 under AS 43.55.160 for a previous calendar year that was not deductible in any month
6 under AS 43.55.160(a) and (b).

7 (c) A credit or portion of a credit under this section may not be used to reduce
8 a person's tax liability under AS 43.55.011(e) for any month below zero, and any
9 unused credit or portion of a credit not used under this subsection may be applied in a
10 later month.

11 (d) Except as limited by (i) of this section, a person entitled to take a tax credit
12 under this section that wishes to transfer the unused credit to another person may
13 apply to the department for a transferable tax credit certificate. An application under
14 this subsection must be on a form prescribed by the department and must include
15 supporting information and documentation that the department reasonably requires.
16 The department shall grant or deny an application, or grant an application as to a lesser
17 amount than that claimed and deny it as to the excess, not later than 60 days after the
18 latest of (1) March 31 of the year following the calendar year in which the qualified
19 capital expenditure or carried-forward annual loss for which the credit is claimed was
20 incurred; (2) if the applicant is required under AS 43.55.030(a) and (e) to file a
21 statement on or before March 31 of the year following the calendar year in which the
22 qualified capital expenditures or carried-forward annual loss for which the credit is
23 claimed was incurred, the date the statement was filed; or (3) the date the application
24 was received by the department. If, based on the information then available to it, the
25 department is reasonably satisfied that the applicant is entitled to a credit, the
26 department shall issue the applicant a transferable tax credit certificate for the amount
27 of the credit. A certificate issued under this subsection does not expire.

28 (e) A person to which a transferable tax credit certificate is issued under (d) of
29 this section may transfer the certificate to another person, and a transferee may further
30 transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and
31 notwithstanding any action the department may take with respect to the applicant

1 under (f) of this section, the owner of a certificate may apply the credit or a portion of
2 the credit shown on the certificate only against a tax due under AS 43.55.011(e).
3 However, a credit shown on a transferable tax credit certificate may not be applied to
4 reduce a transferee's total tax due under AS 43.55.011(e) on oil and gas produced
5 during a calendar year to less than 80 percent of the tax that would otherwise be due
6 without applying that credit. Any portion of a credit not used under this subsection
7 may be applied in a later period.

8 (f) The issuance of a transferable tax credit certificate under (d) of this section
9 does not limit the department's ability to later audit a tax credit claim to which the
10 certificate relates or to adjust or deny the claim if the department determines that the
11 applicant was not entitled to the amount of the credit for which the certificate was
12 issued. The tax liability of the applicant under AS 43.55.011(e) and 43.55.017 -
13 43.55.180 is increased by the amount of the credit that exceeds that to which the
14 applicant was entitled. That amount bears interest under AS 43.05.225 from the date
15 the transferable tax credit certificate was issued. For purposes of this subsection, an
16 applicant that is an explorer is considered a producer subject to the tax levied under
17 AS 43.55.011(e).

18 (g) The department may adopt regulations to carry out the purposes of this
19 section, including prescribing reporting, record keeping, and certification procedures
20 and requirements to verify the accuracy of credits claimed and to ensure that a credit is
21 not used more than once, and otherwise implementing this section.

22 (h) A person may not elect to take a tax credit under (a) or (i) of this section
23 for an expenditure incurred to acquire an asset (1) the cost of previously acquiring
24 which was a lease expenditure under AS 43.55.160(c) or would have been a lease
25 expenditure under AS 43.55.160(c) if it had been incurred on or after July 1, 2006; or
26 (2) that has previously been placed in service in the state. An expenditure to acquire an
27 asset is not excluded under this subsection if not more than an immaterial portion of
28 the asset meets a description under (1) or (2) of this subsection. For purposes of this
29 subsection, "asset" includes geological, geophysical, and well data and interpretations.

30 (i) For the purposes of this section,

31 (1) a producer's or explorer's transitional investment expenditures are

1 the sum of the expenditures the producer or explorer incurred on or after July 1, 2001,
2 and before July 1, 2006, that would be qualified capital expenditures if they were
3 incurred on or after July 1, 2006, less the sum of the payments or credits the producer
4 or explorer received before July 1, 2006, for the sale or other transfer of assets,
5 including geological, geophysical, or well data or interpretations, acquired by the
6 producer or explorer as a result of expenditures the producer or explorer incurred
7 before July 1, 2006, that would be qualified capital expenditures, if they were incurred
8 on or after July 1, 2006;

9 (2) a producer or explorer may elect to take a tax credit against a tax
10 due under AS 43.55.011(e) in the amount of 20 percent of the producer's or explorer's
11 transitional investment expenditures, but only to the extent that the amount does not
12 exceed

13 (A) one-half of the producer's or explorer's qualified capital
14 expenditures that are incurred during the month for which the credit is taken, if
15 the producer or explorer does not make an election under AS 43.55.160(f);

16 (B) 1/24 of the producer's or explorer's qualified capital
17 expenditures that are incurred during the calendar year that includes the month
18 for which the credit is taken, if the producer or explorer makes an election
19 under AS 43.55.160(f);

20 (3) a producer or explorer may not take a tax credit for a transitional
21 investment expenditure

22 (A) for any month that ends the later of

23 (i) July 31, 2013; or

24 (ii) the seventh anniversary of the last day of the month
25 for which the producer first applies a credit under this subsection
26 against a tax due under AS 43.55.011(e), if the producer did not have
27 commercial production of oil or gas from a lease or property in the state
28 before July 1, 2006;

29 (B) more than once; or

30 (C) if a credit for that expenditure was taken under
31 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025;

1 (4) notwithstanding (d) - (f) of this section, a producer or explorer may
2 not transfer a tax credit or obtain a transferable tax credit certificate for a transitional
3 investment expenditure.

4 (j) As a condition of receiving a tax credit under this section, a producer or
5 explorer that obtains the tax credit for or directly related to a pipeline, facility, or other
6 asset that

7 (1) is or becomes subject to regulation by the Federal Energy
8 Regulatory Commission or the Regulatory Commission of Alaska, or a successor
9 regulatory body shall at all times support and in all rate proceedings file to flow
10 through 100 percent of the tax credits to ratepayers as a reduction in the costs of
11 service for the pipeline, facility, or other asset;

12 (2) is not regulated by the Federal Energy Regulatory Commission or
13 the Regulatory Commission of Alaska, or a successor regulatory body, and that
14 charges third parties for use of a pipeline, facility, or other asset shall flow through
15 100 percent of the tax credits as a reduction in the costs of service on which the
16 charges set by the producer or explorer for the pipeline, facility, or other asset are
17 based.

18 (k) In this section, "qualified capital expenditure" means, except as otherwise
19 provided in (h) of this section, an expenditure that is a lease expenditure under
20 AS 43.55.160 and is

21 (1) incurred for geological or geophysical exploration; or

22 (2) treated as a capitalized expenditure under 26 U.S.C. (Internal
23 Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c)
24 (Internal Revenue Code), as amended, and is

25 (A) treated as a capitalized expenditure for federal income tax
26 reporting purposes by the person incurring the expenditure; or

27 (B) eligible to be deducted as an expense under 26 U.S.C.
28 263(c) (Internal Revenue Code), as amended.

29 * Sec. 13. AS 43.55.025(a) is amended to read:

30 (a) Subject to the terms and conditions of this section. [ON OIL AND GAS
31 PRODUCED ON OR AFTER JULY 1, 2004, FROM AN OIL AND GAS LEASE,

1 OR ON GAS PRODUCED FROM A GAS ONLY LEASE.] a credit against the
2 production tax due under AS 43.55.011(e) [THIS CHAPTER] is allowed for
3 exploration expenditures that qualify under (b) of this section in an amount equal to
4 one of the following:

5 (1) 20 percent of the total exploration expenditures that qualify only
6 under (b) and (c) of this section;

7 (2) 20 percent of the total exploration expenditures for work performed
8 before July 1, 2007, and that qualify only under (b) and (d) of this section;

9 (3) 40 percent of the total exploration expenditures that qualify under
10 (b), (c), and (d) of this section; c:

11 (4) 40 percent of the total exploration expenditures that qualify only
12 under (b) and (e) of this section.

13 * Sec. 14. AS 43.55.025(b) is amended to read:

14 (b) To qualify for the production tax credit under (a) of this section, an
15 exploration expenditure must be incurred for work performed on or after July 1, 2003,
16 and before July 1, 2016 [2007], except that an exploration expenditure for a Cook Inlet
17 prospect must be incurred for work performed on or after July 1, 2005, [AND
18 BEFORE JULY 1, 2010, AND EXCEPT THAT AN EXPLORATION
19 EXPENDITURE, IN WHOLE OR IN PART, SOUTH OF 68 DEGREES, 15
20 MINUTES, NORTH LATITUDE, AND NOT PART OF A COOK INLET
21 PROSPECT MUST BE INCURRED FOR WORK PERFORMED ON OR AFTER
22 JULY 1, 2003, AND BEFORE JULY 1, 2010.] and

23 (1) may be for seismic or geophysical exploration costs not connected
24 with a specific well;

25 (2) if for an exploration well,

26 (A) must be incurred by an explorer that holds an interest in the
27 exploration well for which the production tax credit is claimed;

28 (B) may be for either an oil or gas discovery well or a dry hole;

29 and

30 (C) must be for goods, services, or rentals of personal property
31 reasonably required for the surface preparation, drilling, casing, cementing

1 and logging of an exploration well, and, in the case of a dry hole, for the
2 expenses required for abandonment if the well is abandoned within 18 months
3 after the date the well was spudded;

4 (3) may not be for testing, stimulation, or completion costs;
5 administration, supervision, engineering, or lease operating costs; geological or
6 management costs; community relations or environmental costs; bonuses, taxes, or
7 other payments to governments related to the well; or other costs that are generally
8 recognized as indirect costs or financing costs; and

9 (4) may not be incurred for an exploration well or seismic exploration
10 that is included in a plan of exploration or a plan of development for any unit on
11 May 13, 2003.

12 * Sec. 15. AS 43.55.025(f) is amended to read:

13 (f) For a production tax credit under this section,

14 (1) an explorer shall, in a form prescribed by the department and
15 within six months of the completion of the exploration activity, claim the credit and
16 submit information sufficient to demonstrate to the department's satisfaction that the
17 claimed exploration expenditures qualify under this section;

18 (2) an explorer shall agree, in writing,

19 (A) to notify the Department of Natural Resources, within 30
20 days after completion of seismic or geophysical data processing, completion of
21 a well, or filing of a claim for credit, whichever is the latest, for which
22 exploration costs are claimed, of the date of completion and submit a report to
23 that department describing the processing sequence and providing a list of data
24 sets available; if, under (c)(2)(B) of this section, an explorer submits a claim
25 for a credit for expenditures for an exploration well that is located within three
26 miles of a well already drilled for oil and gas, in addition to the submissions
27 required under (1) of this subsection, the explorer shall submit the information
28 necessary for the commissioner of natural resources to evaluate the validity of
29 the explorer's claim that the well is directed at a distinctly separate exploration
30 target, and the commissioner of natural resources shall, upon receipt of all
31 evidence sufficient for the commissioner to evaluate the explorer's claim, make

1 that determination within 60 days;

2 (B) to provide to the Department of Natural Resources, within
3 30 days after the date of a request, specific data sets, ancillary data, and reports
4 identified in (A) of this paragraph;

5 (C) that, notwithstanding any provision of AS 38, information
6 provided under this paragraph will be held confidential by the Department of
7 Natural Resources for 10 years following the completion date, at which time
8 that department will release the information after 30 days' public notice;

9 (3) if more than one explorer holds an interest in a well or seismic
10 exploration, each explorer may claim an amount of credit that is proportional to the
11 explorer's cost incurred;

12 (4) the department may exercise the full extent of its powers as though
13 the explorer were a taxpayer under this title, in order to verify that the claimed
14 expenditures are qualified exploration expenditures under this section; and

15 (5) if the department is satisfied that the explorer's claimed
16 expenditures are qualified under this section, the department shall issue to the explorer
17 a production tax credit certificate for the amount of credit to be allowed against
18 production taxes due under AS 43.55.011(e) [THIS CHAPTER]; however,
19 notwithstanding any other provision of this section, after the end of the calendar
20 year following the calendar year in which the total of production tax credit
21 certificates issued by the department under this section based on exploration
22 expenditures for Cook Inlet prospects reaches \$20,000,000, the department may
23 not issue to an explorer a production tax credit certificate [IF THE TOTAL OF
24 PRODUCTION TAX CREDITS SUBMITTED FOR COOK INLET
25 PRODUCTION,] based on an exploration expenditure for a Cook Inlet prospect
26 [EXPENDITURES FOR WORK PERFORMED DURING THE PERIOD
27 DESCRIBED IN (b) OF THIS SECTION FOR THAT PRODUCTION, THAT HAVE
28 BEEN APPROVED BY THE DEPARTMENT EXCEEDS \$20,000,000].

29 * Sec. 16. AS 43.55.025(h) is amended to read:

30 (h) A producer that purchases a production tax credit certificate may apply the
31 credits against its production tax liability under AS 43.55.011(e) [THIS CHAPTER].

1 Regardless of the price the producer paid for the certificate, the producer may receive
2 a credit against its production tax liability for the full amount of the credit, but for not
3 more than the amount for which the certificate is issued. A production tax credit
4 allowed under this section may not be applied more than once.

5 * **Sec. 17.** AS 43.55.025(i) is amended to read:

6 (i) For a production tax credit under this section,

7 (1) the amount of the credit that may be applied against the production
8 tax for each tax month may not exceed the total production tax liability under
9 AS 43.55.011(e) of the taxpayer applying the credit for the same month; and

10 (2) an amount of the production tax credit that is greater than the total
11 tax liability under AS 43.55.011(e) of the taxpayer applying the credit for a tax month
12 may be carried forward and applied against the taxpayer's production tax liability
13 under AS 43.55.011(e) in one or more immediately following months.

14 * **Sec. 18.** AS 43.55.030(a) is amended to read:

15 (a) The tax shall be paid to the department, and the person paying the tax shall
16 file with the department at the time the tax or a portion of the tax is required to be
17 paid a statement, under oath, on forms prescribed by or acceptable to the department,
18 giving, with other information required, the following:

19 (1) a description of each [THE] lease or property from which the oil
20 and [OR] gas were [WAS] produced, by name, legal description, lease number, or
21 [BY] accounting codes [CODE NUMBERS] assigned by the department;

22 (2) the names of the producer and the person paying the tax;

23 (3) the gross amount of oil and the gross amount of [OR] gas
24 produced from each [THE] lease or property, and the percentage of the gross amount
25 of oil and gas owned by each producer for whom the tax is paid;

26 (4) the gross [TOTAL] value at the point of production of the oil
27 and of the [OR] gas produced from each [THE] lease or property owned by each
28 producer for whom the tax is paid; [AND]

29 (5) the name of the first purchaser and the price received for the oil
30 and for the [OR] gas, unless relieved from this requirement in whole or in part by
31 the department; and

1 (6) the producer's lease expenditures and adjustments as
2 calculated under AS 43.55.160 [IF SOLD IN THE STATE].

3 * Sec. 19. AS 43.55.030(d) is amended to read:

4 (d) Reports by or on behalf of the producer are delinquent the first day
5 following the day the tax is due. [EACH PRODUCER IS SUBJECT TO A PENALTY
6 OF \$25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH THE
7 REPORT IS NOT FILED. THE PENALTY FOR FAILURE TO FILE A REPORT IS
8 IN ADDITION TO THE PENALTY FOR DELINQUENT TAXES, AND IS A LIEN
9 AGAINST THE ASSETS OF THE PRODUCER.]

10 * Sec. 20. AS 43.55.030 is amended by adding a new subsection to read:

11 (e) In addition to other required information, the statement required to be filed
12 on or before March 31 of a year must show any adjustments or corrections to the
13 statements that were required under (a) of this section to be filed for the months of the
14 preceding calendar year during which the oil or gas was produced.

15 * Sec. 21. AS 43.55.040 is amended to read:

16 Sec. 43.55.040. Powers of Department of Revenue. Except as provided in
17 AS 43.05.405 - 43.05.499, the department may

18 (1) require a person engaged in production and the agent or employee
19 of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil
20 or gas to furnish, whether by the filing of regular statements or reports or
21 otherwise, additional information that is considered by the department as necessary to
22 compute the amount of the tax; notwithstanding any contrary provision of law, the
23 disclosure of additional information under this paragraph to the producer
24 obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a);
25 before disclosing information under this paragraph that is otherwise required to
26 be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department
27 shall

28 (A) provide the person that furnished the information a
29 reasonable opportunity to be heard regarding the proposed disclosure and
30 the conditions to be imposed under (B) of this paragraph; and

31 (B) impose appropriate conditions limiting

1 arm's length transaction or is not representative of the market value of that
2 transportation; and

3 (3) [WHEN THE] method of transportation of oil or gas is not
4 reasonable in view of existing alternative methods of transportation.

5 * Sec. 25. AS 43.55.150 is amended by adding a new subsection to read:

6 (d) Under regulations adopted by the department, the department may allow a
7 producer, subject to limitations prescribed by the department as to the frequency of
8 making elections, to elect prospectively to calculate the gross value at the point of
9 production of oil or gas based in whole or part on

10 (1) a royalty value determined under a royalty settlement agreement
11 between the producer and the state, with adjustments if appropriate;

12 (2) a formula prescribed by the department that uses, with adjustments
13 if appropriate, a royalty value or valuation methodology accepted by the

14 (A) Department of Natural Resources under AS 38.05, in the
15 case of oil and gas produced from a lease issued by the Department of Natural
16 Resources or produced from a lease or property that is part of a unit approved
17 by the Department of Natural Resources;

18 (B) United States Department of the Interior under applicable
19 federal oil and gas leasing statutes, in the case of oil and gas produced from a
20 lease issued by the United States Department of the Interior that is not part of a
21 unit approved by the Department of Natural Resources, or produced from a
22 lease or property that is part of a unit approved by the United States
23 Department of the Interior but not approved by the Department of Natural
24 Resources; or

25 (3) another formula prescribed by the Department of Revenue that
26 reasonably estimates a value for the oil or gas at a specific geographical location, such
27 as the point of tender or delivery into a common carrier pipeline; the formula may use
28 factors such as published price indices for oil or gas in or outside the state, quality
29 differentials for oil or gas, transportation costs between markets, and inflation
30 adjustments.

31 * Sec. 26. AS 43.55 is amended by adding new sections to article 1 to read:

1 **Sec. 43.55.160. Determination of production tax value of oil and gas. (a)**

2 Except as provided in (f) of this section, for purposes of AS 43.55.011(e) and (g), the
3 production tax value of the taxable oil and gas produced during a month is (1) the total
4 of (A) the gross value at the point of production of the oil taxable under
5 AS 43.55.011(e) and (g) and produced by the producer from all leases or properties in
6 the state, less three-quarters of the gross value at the point of production of the oil
7 taxable under AS 43.55.011(e) and (g) and produced by the producer from leases or
8 properties in the Cook Inlet sedimentary basin, and (B) one-third of the gross value at
9 the point of production of the gas taxable under AS 43.55.011(e) and (g) and produced
10 by the producer from all leases or properties in the state, (2) less the producer's lease
11 expenditures for the month as adjusted under (e) of this section. However, the
12 production tax value calculated under this subsection may not be less than zero. If a
13 producer does not produce taxable oil or gas during a month, the producer is
14 considered to have generated a positive production tax value if the calculation
15 described in this section yields a positive number because the producer's adjusted
16 lease expenditures for a month are less than zero as a result of the producer's receiving
17 a payment or credit under (e) of this section or otherwise.

18 (b) For purposes of administration of (a) of this section,

19 (1) any adjusted lease expenditures that would otherwise be deductible
20 in a month but whose deduction would cause the production tax value calculated under
21 (a) of this section of the taxable oil and gas produced during the month to be less than
22 zero may be added to the producer's adjusted lease expenditures for one or more other
23 months in the same calendar year; the total of any adjusted lease expenditures that are
24 not deductible in any month during a calendar year because their deduction would
25 cause the production tax value calculated under (a) of this section of the taxable oil
26 and gas produced during one or more months to be less than zero may be used to
27 establish a carried-forward annual loss under AS 43.55.024(b);

28 (2) an explorer that has taken a tax credit under AS 43.55.024(b) or
29 that has obtained a transferable tax credit certificate under AS 43.55.024(d) for the
30 amount of a tax credit under AS 43.55.024(b) is considered a producer, subject to the
31 tax levied under AS 43.55.011(e), to the extent that the explorer generates a positive

1 production tax value as the result of the explorer's receiving a payment or credit
2 described in (e) of this section.

3 (c) For purposes of this section,

4 (1) a producer's lease expenditures for a period are the total costs
5 upstream of the point of production of oil and gas that are incurred on or after July 1,
6 2006, by the producer during the period and that are direct, ordinary, and necessary
7 costs of exploring for, developing, or producing oil or gas deposits located within the
8 producer's leases or properties in the state or, in the case of land in which the producer
9 does not own a working interest, direct, ordinary, and necessary costs of exploring for
10 oil or gas deposits located within other land in the state; however, lease expenditures
11 do not include the costs incurred to satisfy a work commitment under an exploration
12 license under AS 38.05.132; in determining whether costs are direct, ordinary, and
13 necessary costs of exploring for, developing, or producing oil or gas deposits located
14 within a lease or property or other land in the state,

15 (A) the department shall give substantial weight to the typical
16 industry practices and standards in the state and in the United States in
17 determining costs that an operator is allowed to bill a working interest owner
18 that is not the operator, under unit operating agreements or similar operating
19 agreements that were in effect on or before December 1, 2005, and were
20 subject to negotiation with at least one working interest owner with substantial
21 bargaining power, other than the operator; and

22 (B) as to matters that are not addressed by the industry
23 practices and standards described in (A) of this paragraph or as to which those
24 practices and standards are not clear or are not uniform, the department shall
25 give substantial weight to the standards adopted by the Department of Natural
26 Resources that determine the costs, other than interest, that a lessee is allowed
27 to deduct from revenue in calculating net profits under a lease issued under
28 AS 38.05.180(f)(3)(B), (D), or (E);

29 (2) the Department of Revenue may authorize a producer, including a
30 producer that is an operator, to treat as its lease expenditures under this section the
31 costs paid by the producer that are billed to the producer by an operator in accordance