

SB

305

(FILE 8)

ConocoPhillips

March 3, 2006

The Honorable Ralph Samuels
Alaska House of Representatives
Alaska State Capitol, Room 126
Juneau, AK 99801-1182

The Honorable Tom Wagoner
The Alaska Senate
Alaska State Capitol, 427
Juneau, AK 99801-1182

Dear Sirs:

I wanted to thank you again for the opportunity to express ConocoPhillips' views on HB 488/SB 305. During my testimony, there was some additional information requested by the committee members. This information is provided below:

House Resources Committee

1. (Rep. Berkowitz) What are your profit numbers for the last 10 years? How much of these are from your heavy oil investments?

Listed below are the publicly reported earnings for ConocoPhillips' operations in Alaska for the years 2000-2005 as reported in our Annual Reports. Earnings from heavy oil investments are not reported publicly. Unfortunately, ARCO did not separate out Alaska earnings data in their annual reports, so the figures for the years prior to Phillips Petroleum's acquisition of ARCO Alaska may not be disclosed.

	ConocoPhillips Alaska Operations					
	9 Months 2000	2001	2002	2003	2004	2005
Exploration and Production Earnings SMM	\$700	\$677	\$673	\$1,079	\$1,665	\$2,410
Other Earnings SMM (TAPS/Polar/LNG)	\$129	\$189	\$197	\$366	\$167	\$142
Total COP Alaska Earnings SMM	\$829	\$866	\$870	\$1,445	\$1,832	\$2,552

2. (Rep. Gatto) What is your public rate of return on investments for recent years (past 2 annual filings)?

Our Annual Report does include our corporate return on capital employed (ROCE) at a corporate level. The ConocoPhillips return on capital employed in 2004 was 15.2% and in 2003, the return on capital employed was 9.8% (GAAP

ROCE). The ConocoPhillips 2005 Annual Report has not been published as of this date.

3. (Rep. Berkowitz) What would be the decline in effective tax rate as a result of removing the Oil Spill 470 fund (AS 43.55.201)?

The conservation surcharge on oil has not been removed from the statute and must be paid by a producer of oil. The proposed legislation will allow this surcharge to be applied as a credit against the producer's taxes due. At a surcharge of \$0.03-\$0.05/bbl, this credit amounted to approximately \$3.4 MM for COP in 2005 and has essentially no impact on the effective tax rate at today's prices.

4. (Rep. Ramras) What is the depreciation mix of the \$700MM (this year's capital spend)? (e.g., 5-yr, 10-yr, etc.)

For 2005, ConocoPhillips Alaska's reported capital expenditures were \$746.2MM. A large portion of the assets have not yet been placed in service so no depreciation has occurred. Once the equipment is placed in service, it will be depreciated at IRS depreciation schedules for federal taxation purposes. The \$746.2MM can be broken down into these types of assets:

Field Life	2%	Leasehold Costs	<ul style="list-style-type: none">Costs which are depreciated on a per unit of production basis over the life of the fields
7-10 Years	62%	Lease and Well Equipment (L&W)	<ul style="list-style-type: none">Are tangible costs such as tankers, casing, tubing, wellheads, separators and producing equipment necessary to serve the well tanks, flowlines etc)
5 Years	11%	Intangible Drilling Costs (IDC) - Capitalized	<ul style="list-style-type: none">Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value
Immediate	25%	Intangible Drilling Costs (IDC) - Expensed	<ul style="list-style-type: none">Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value

5. (Rep. Kerttula) What would be the production tax on Fiord under the current ELF formula?

Fiord is expected to startup in the fourth quarter of 2006. In order to make the project economically viable, ConocoPhillips sought and obtained a letter from the Department of Revenue stating that Fiord would not be aggregated with Alpine for calculation of severance tax; hence, initial Fiord production would have an effective ELF severance rate of 0%. The ELF tax rate is currently expected to be

1.76% in 2007, and the total projected production would result in ELF production tax payments of just under \$20MM over the next 10 years at today's prices. This figure, of course, does not include royalties, State corporate income taxes, state and local property taxes, the oil and gas conservation surcharge, or federal corporate income taxes attributable to the Fiord project.

6. (Rep. Samuels) What have been your abandonment expenses over the transition period?

Abandonment expenditures are treated as expense rather than capital expenditures and thus do not result in tax credits under the proposed PPT production tax system. Our abandonment expenditures from 2001 to 2005 totaled \$33.7 MM. However, none of these expenditures would be counted as capital or included in the *transitional investment expenditures* under the proposed PPT HB 488. On a go-forward basis, we do experience limited abandonment expenditures each year for activities such as plugging and abandoning old wells and some gravel removal and restoration (e.g., \$12.6 MM in aggregate in 2005). However, these expenses, like our expenses for 2001 through 2005, are all anticipated to be operating costs that are not eligible for the capital credit. In addition, the bulk of the abandonment dollars would occur at the end of field life, when we expect limited, if any, production or revenue which will leave the production tax deductions associated with these expenditures with limited or no value.

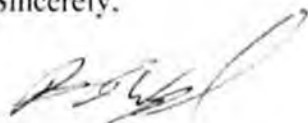
Senate Resources Committee

1. (Sen. Stevens) Please break down the 2005 capital expenditures into exploration, development, and production expenditures?

In 2005, ConocoPhillips reported capital expenditures of \$746.2 MM. Approximately, 67% was associated with development activities, 13% on production maintenance activities and 2% on exploration. The remaining 18% was associated with marine, pipeline and acquisition expenditures.

If you have any questions regarding this information, you may contact me at 907-265-1650 or make arrangements through our Juneau office at 907-586-3680.

Sincerely,



Brian R. Wenzel
Vice President, Finance & Administration
ConocoPhillips Alaska

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March 2, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras.

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings.

Received 2/28/06, 12:00 p.m.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production), by company.

The Department of Revenue model uses \$1 billion per year as capital costs, so for the transitional period, there would be about \$5 billion. This annual costs are based on compilations of historical data. The attached excel files outlines public data regarding investments.

2. How are mob, demob, and platform abandonment costs treated—as tax credits or deductions?

Mobilization costs are capitalized for federal tax purposes, as Intangible Drilling Costs. As such, they are a capitalized expenditure for PPT purposes, and therefore are deductible and creditable. We understand that demobilization and abandonment expenditures are both expensed as incurred. This would mean that these costs are deductible, but would not generate a credit.

3. Is there a "rating" for political stability – or one that reflects instability?

We do not have any information on a quantification of the risk of political stability.

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

Using a combination of our spring forecast and YTD actuals, the average ANS price between January 1, 2006 and July 1, 2006 was \$58.62.

- The loss of revenue using the 20/20 system would be about \$480 mm in additional tax.
- The loss of revenue using the 25/20 system would be about \$770 mm in additional tax.

5. Section 9 – what amount is involved in this section?

A very small amount, probably no more than 1% of total state revenue from oil and gas. It is limited to three areas: [1] Alpine and its satellites; [2] the National Petroleum Reserve Alaska; and [3] Cook Inlet.

6. Was there consideration of phasing out the \$73 million deduction over a certain period of time?

No, it was not considered.

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed \$73 million standard deduction?

With the merger of Chevron and Unocal, there are now 13 producers in Alaska. Of the 13 producers, BP, ConocoPhillips and ExxonMobil will pay severance tax at most price levels after employing the \$73 million standard deduction. At high oil and gas prices, and given our cost assumptions, Anadarko and ChevronUnocal will also pay severance tax after deducting the \$73 million dollar allowance, given the production volumes reported publicly by those companies.

8. Which other tax regimes – worldwide - have a progressivity structure?

TO BE PROVIDED

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total \$104. 8 million and claimed credits total \$33. 6 million [see table below]. A claim was received by the Department of Revenue last week, thus the totals has been updated from the \$95.5 million and \$29.0 million figures previously provided.

12. What is the rationale for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes; taxes that are assessed on any oil or gas production within Alaska's sovereign territory. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two fold. First any incentive to encourage Pt. Thomson improves the economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

We're not clear whether this question seeks more explanation of the definitions in the bill or is requesting that we consider modifying those definitions. Please clarify. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at Sec. 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

Section 21 (Sec. 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are deductible. Sec. 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Sub-section (d) provides clarification for items that are not clear, such as "payments made in lieu of property taxes."

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (Sec. 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the

legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel(not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this question. As a Sixth Circuit decision, it has no direct precedence for Alaska. It is currently before the U.S. Supreme Court and many analysts believe that it will not be sustained in its current form.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (Sec. 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (Sec. 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs. The capitalized expenditures are subject to a variety of useful lives under federal and state income rules. See Question 60 below.

21. Have any of the definitions in sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

This term only appears in the definition of "oil." It was not in the old definition, nor the new definition of "gas." The standard for "pipeline quality" has not changed under the bill. The standard is based on a series of court cases.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

TO BE PROVIDED

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

TO BE PROVIDED

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes \$100 million is spent on exploration per year. With average costs of \$20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations - reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

TO BE PROVIDED

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See Attachments A1 and A2. These tables contain effective tax rates since 1986 for all Alaskan fields on gross value at the point of production. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987 (when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

TO BE PROVIDED

Received 2/28/06, 2:30 p.m.

32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize through marketing. Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the oil profits for the PPT.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

See question 20.

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

Sale of credits under SB185 do not effect the ability of the seller to claim those credits as Transitional Investment Expenditures (that is to qualify for the claw back.)

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as:

- (a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the \$73 million dollar allowance).
- (b) Under the gas contract, the state will receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production is deductible from corporate tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. (AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state.")

Section 10 simplifies treatment of flared gas. Under current law there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no 'free use of oil' to produce more oil in statute. The bill

exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225 interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

TO BE PROVIDED

41. What are the penalties for under-payment when sure-up is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

43. Why does it seem the credits and incentive [sic] are on production along with exploration if our focus is to provide incentives for exploration?

(The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carry-forward amount be used for a credit for more than the first year after the loss?

Yes, the credit carry-forwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, nor for the optional credit codified in 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Dept. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, Sec. 43.55.024(g))

49. What is the estimated economic impact to the state of the ability to sell tax credits?

TO BE PROVIDED

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices, is subject to the same criminal penalties that apply to a state employee.

The current confidentiality law is very general in its exception language – information must be kept confidential “except in connection with official investigations or proceedings” The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above

51. In what circumstances would oil and gas taxes go straight into the CBR.

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from shall to is?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods, it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method or just calculating gross value according to the usual rules – NCT an election among several different alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. I don't think we can predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 1, line 8—why is this clause constrained by Dec. 1, 2005?

TO BE PROVIDED

55. Section 21, provision (h), which US CPI does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible from corporate income tax.

Other Questions

57. Do any other state taxes have a "standard deduction"?

- a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of \$50,000 or more in a calendar year. AS 16.51.120(g).
- b. Mining License Tax is not imposed when net income is less than \$40,000 in a fiscal year. AS 43.65.010(c).
- c. Gaming tax exempts gross receipts of less than \$20,000 from paying the additional fee under AS 05.15.020(b).
- d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under \$1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying royalties. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was \$81M. Total receipts from NPSL's from 2001—2005 were \$254M.

Out of 19 NPSL's, seven are paying net profit share payments (*in addition to royalties and production taxes*). These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was \$81M. Total NPS receipts from NPSL's from 2001—2005 were \$254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

Attached is an Xcel table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease. (See Attachment B)

59. What are the depreciable lives for O & G equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barge ^o other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value \$60M
 --Opex 15M
 --Capex 10M

Gross value	\$60M
Less: Opex	(15)
Capex	<u>(10)</u>
Tentative net profit	
Before standard deduction	\$35M
Less: standard deduction*	<u>(35)</u>
Net Taxable income	<u>\$ 0</u>

Tax	\$ 0
Capital investment credit available for carryforward (20% of \$10M)	\$5M

* this calculation assumes that taxpayer has not reached \$73M limit for the standard deduction.

61. Are net profit lease payments included as a direct cost under 43.55.160?

Net profit share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (Sec. 43.55.160(c)). Such costs are also eligible for credits under Section 12 (Sec. 43.55.024) by reference to definition of "qualified capital expenditure" at Sec. 43.55.024(f).

64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax to a tax on net profits, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21

(Sec. 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the related production is subject to tax.

65. Under Section 21 (Sec. 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No, Sec. 43.55.160(d) provides additional clarification for the general rule stated at sub-section (c). Sub-section (c) provides the general rule that lease costs are deductible. Sub-section (d) addresses only those items that may have been questionable under the general rule. Additionally, we note that under AS 01.10.040(b):

"When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

Questions Received 3/1/06 12:00 p.m.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO₂ re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

TO BE PROVIDED

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant tax benefits ever be realized?

TO BE PROVIDED

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

TO BE PROVIDED

69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

- a. 30/15
- b. 30/20
- c. 25/20
- d. 20/20

TO BE PROVIDED

Letter to Senator Wagoner and Representatives Samuels and Ramras
March 2, 2006

70. Please present Mr. Marks' charts on pages 14-16 to show the difference between a PPT and status quo, annually under the following PPT plans at \$20, \$40, and \$60/bbl:

- a. 25/20
- b. 30/20
- c. 30/15

TO BE PROVIDED

71. Please show the corporate take chart on page 24 of Mr. Marks' presentation given the following tax/credit scenarios:

- a. 25/20
- b. 30/20
- c. 30/15

TO BE PROVIDED

72. Please show the price point where DOR estimates corporate profit margins hit 15% and 20%.

TO BE PROVIDED

Attachment A1 (Question 30)

Effective Tax Rates, North Slope by Field, FY86 - FY05

	Prudhoe Bay	Midnight Sun	Polaris	Orion	Aurora	Borealis					
FY86	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.07%	0.00%	0.00%	0.00%	0.00%
FY87	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.47%	0.00%	0.00%	0.00%	0.00%
FY88	12.66%	0.00%	0.00%	0.00%	0.00%	0.00%	8.33%	0.00%	0.00%	0.00%	0.00%
FY89	12.33%	0.00%	0.00%	0.00%	0.00%	0.00%	8.71%	0.00%	0.00%	0.00%	0.00%
FY90	14.71%	0.00%	0.00%	0.00%	0.00%	0.00%	12.89%	0.00%	0.00%	0.00%	0.00%
FY91	14.91%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	0.00%	0.00%	0.00%	0.00%
FY92	14.90%	0.00%	0.00%	0.00%	0.00%	0.00%	13.33%	0.00%	0.00%	0.00%	0.00%
FY93	14.85%	0.00%	0.00%	0.00%	0.00%	0.00%	13.34%	0.00%	0.00%	0.00%	0.00%
FY94	14.81%	0.00%	0.00%	0.00%	0.00%	0.00%	13.09%	0.00%	0.00%	0.00%	0.00%
FY95	14.76%	0.00%	0.00%	0.00%	0.00%	0.00%	12.85%	0.00%	0.00%	0.00%	0.00%
FY96	14.67%	0.00%	0.00%	0.00%	0.00%	0.00%	12.35%	0.00%	0.00%	0.00%	0.00%
FY97	14.59%	0.00%	0.00%	0.00%	0.00%	0.00%	11.72%	0.00%	0.00%	0.00%	0.00%
FY98	14.44%	0.00%	0.00%	0.00%	0.00%	0.00%	11.38%	0.00%	0.00%	0.00%	0.00%
FY99	14.23%	0.00%	0.00%	0.00%	0.00%	0.00%	10.53%	0.00%	0.00%	0.67%	0.00%
FY00	13.96%	0.00%	0.00%	0.00%	0.00%	0.00%	8.97%	0.00%	0.00%	0.58%	0.00%
FY01	13.76%	0.00%	0.00%	0.00%	0.00%	0.00%	7.40%	0.00%	0.00%	0.05%	0.00%
FY02	13.44%	0.13%	0.00%	0.00%	0.00%	0.96%	5.29%	0.00%	0.00%	0.52%	0.00%
FY03	13.05%	0.10%	0.00%	0.00%	0.00%	1.40%	3.44%	0.00%	0.00%	1.22%	0.00%
FY04	12.82%	0.00%	0.00%	0.00%	0.00%	1.03%	2.70%	0.00%	0.00%	0.84%	0.00%
FY05	12.65%	4.43%	4.43%	3.63%	3.62%	3.69%	0.76%	0.00%	0.00%	0.15%	0.00%

Note: The effective tax rate for Midnight Sun, Polaris, Orion, Aurora, Pt. McIntyre, and Borealis for FY 05 reflects 5 months' effect of the aggregation decision effective Feb. 1, 2005.

Attachment A2 (Question 30)

	Millie Point	Endicott	Elder	Liaburne	Point McIntyre	Niakuk	West Beach	NPBS	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	12.25%	0.00%	6.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY90	0.00%	10.37%	0.00%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY91	0.00%	9.44%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY92	0.00%	9.51%	0.00%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY93	0.00%	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY94	0.00%	11.53%	0.00%	0.00%	7.28%	1.56%	0.00%	0.00%	0.00%	0.00%
FY95	0.00%	11.30%	0.00%	0.00%	11.30%	6.15%	0.00%	0.00%	0.00%	0.00%
FY96	0.00%	10.39%	0.00%	0.00%	11.60%	1.76%	0.00%	0.00%	0.00%	0.00%
FY97	0.29%	7.10%	0.00%	0.00%	11.63%	1.51%	0.00%	0.00%	0.00%	0.00%
FY98	0.46%	4.54%	0.00%	0.00%	11.29%	0.89%	0.00%	0.00%	0.00%	0.00%
FY99	0.64%	1.29%	0.00%	0.00%	11.75%	0.70%	0.00%	0.00%	0.00%	0.00%
FY00	0.38%	0.73%	0.00%	0.00%	9.45%	1.32%	0.00%	0.00%	0.00%	0.00%
FY01	0.16%	0.13%	0.00%	0.00%	6.47%	0.17%	0.00%	0.00%	4.24%	0.00%
FY02	0.02%	0.02%	0.00%	0.00%	3.10%	0.15%	0.00%	0.00%	10.76%	5.14%
FY03	0.00%	0.01%	0.00%	0.00%	2.40%	0.02%	0.00%	0.00%	10.50%	10.59%
FY04	0.00%	0.00%	0.00%	0.00%	1.63%	0.00%	0.00%	0.00%	10.33%	10.37%
FY05	0.00%	0.00%	0.00%	0.00%	4.78%	0.00%	0.00%	0.00%	10.17%	10.18%

Attachment B (Question 58)

By: G. Rogers, March 1, 2006, source
 DNR

NPS LEASES, NPS RATES & ROYALTY RATES & STATUS

Unit - lease number	Royalty Rate	NPS Rate	NPS Status
Duck Island			
1	312828	20%	79.5935% in payout
2	312834	20%	48.8703% in payout
Milne Point			
3	355016	12.5%	40.0000% in payout
4	355017	12.5%	40.0000% in payout
5	355018	12.5%	30.0000% in payout
6	355021	12.5%	30.0000% in payout
7	388235	12.5%	30.0000% in payout
Kuparuk River			
8	355023	12.5%	30.0000% not in payout
9	355024	12.5%	30.0000% not in payout
10	355030	12.5%	30.0000% not in payout
11	355032	12.5%	30.0000% not in payout
Colville River			
12	364470	12.5%	30.0% non producing
13	364471	12.5%	30.0% non producing
14	364472	12.5%	30.0% non producing
15	364477	12.5%	30.0% non producing
16	364478	12.5%	30.0% non producing
Point Thompson Unit			
17	312866	20%	52.352% non producing
18	343109	12.5%	40% non producing
19	343110	12.5%	40% non producing
20	343111	12.5%	40% non producing
21	343112	closed	closed non producing

Letter to Senator Wagoner and Representatives Samuels and Ramras
March 2, 2006

Oooguruk Unit

Royalty Modification and PPT

Division of Oil and Gas
March, 2006



Alaska Department of
**Natural
Resources**

Ooguruk Economics

- The Division analyzed four scenarios.
 - Case #1: A base case with no royalty modification and no PPT.
 - Case #2: The impact of just the royalty modification as awarded.
 - Case #3: The impact of just the PPT.
 - Case #4: The impact of both royalty modification and PPT.
- In the following slides these cases will be compared and differences displayed to protect the confidentiality of the producer data.

**Change in Oooguruk Unit Economics from
Only Royalty Modification
Case #1 versus Case #2**

	DOR Forecast Price	DNR Mean Price	High Price Case
ANS WC	<u>\$25</u>	<u>\$33</u>	<u>\$50</u>
Producer Cum Discounted Cash Flow @ 10% (\$ millions)	25	21	19
Producer IRR (%)	2.9%	1.3%	1.3%
State Cumulative Revenues @ 5% (\$ millions)	(50)	(45)	(43)

**Change in Oooguruk Unit Economics from
Only PPT
Case #1 versus Case #3**

	DOR Forecast Price	DNR Mean Price	High Price Case
ANS WC	<u>\$25</u>	<u>\$33</u>	<u>\$50</u>
Producer Discounted Cash Flow @ 10%	92	89	58
Producer IRR	6.9%	6.5%	6.6%
State Cumulative Revenues @ 5%	(151)	(147)	(75)

**Change in Oooguruk Unit Economics from
Both PPT and Royalty Modification
Case #1 versus Case #4**

	DOR Forecast Price	DNR Mean Price	High Price Case
ANS WC	<u>\$25</u>	<u>\$33</u>	<u>\$50</u>
Producer Discounted Cash Flow @ 10%	116	111	74
Producer IRR	9.4%	8.4%	8.2%
State Cumulative Revenues @ 5%	(200)	(193)	(114)

Observations: PPT without Royalty Modification

- PPT is expressly excluded from NPSL accounting. The State does not extract benefits of the PPT through NPSL payments.
- Qualified Capital Expenditure Credits and Net-loss carry-forward Credits substantially improve project economics. DOG assumes they are tradeable credits comparable to “vouchers.”
- Transitional Investment Expenditure deductions (TIE) are an additional help.
 - DOG assumes that only one-sixth of TIE may be used in any year.
 - TIE are subject to a \$40 price trigger below which they cannot be used. TIE cannot be transferred.
 - Assuming that Ooguruk is a stand-alone project, TIE cannot be fully absorbed. If the producer has PPT obligations arising from other projects the TIE can be used.
- PPT payments are deductible from SCIT when there is a liability, they are not added to income when there is a tax credit.
- The discounted state revenue (at 5%) attributable to net PPT (PPT obligations minus credits) is negative at all price levels modeled.
- The PPT improves the economics of the Ooguruk project by almost three times what the royalty modification award was able to achieve.

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Oooguruk Unit

Royalty Modification and PPT

Division of Oil and Gas
March, 2006



Alaska Department of
Natural
Resources

Oooguruk Economics

- The Division analyzed four scenarios.
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- In the following slides these cases will be compared and differences displayed to protect the confidentiality of the producer data.

Change in Ooguruk Unit Economics from Only Royalty Modification Case #1 versus Case #2

	DOR Forecast Price	DNR Mean Price	High Price Case
ANS WC	<u>\$25</u>	<u>\$33</u>	<u>\$50</u>
Producer Cum Discounted Cash Flow @ 10% (\$ millions)	25	21	19
Producer IRR (%)	2.9%	1.3%	1.3%
State Cumulative Revenues @ 5% (\$ millions)	(50)	(45)	(43)

**Change in Oooguruk Unit Economics from
Only PPT
Case #1 versus Case #3**

	DOR Forecast Price	DNR Mean Price	High Price Case
ANS WC	<u>\$25</u>	<u>\$33</u>	<u>\$50</u>
Producer Discounted Cash Flow @ 10%	92	89	58
Producer IRR	6.9%	6.5%	6.6%
State Cumulative Revenues @ 5%	(151)	(147)	(75)

**Change in Oooguruk Unit Economics from
Both PPT and Royalty Modification
Case #1 versus Case #4**

	DOR Forecast Price	DNR Mean Price	High Price Case
ANS WC	<u>\$25</u>	<u>\$33</u>	<u>\$50</u>
Producer Discounted Cash Flow @ 10%	116	111	74
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Observations: PPT without Royalty Modification

- PPT is expressly excluded from NPSL accounting. The State does not extract benefits of the PPT through NPSL payments.
- Qualified Capital Expenditure Credits and Net-loss carry-forward Credits substantially improve project economics. DOG assumes they are tradeable credits comparable to “vouchers.”
- Transitional Investment Expenditure deductions (TIE) are an additional help.
 - DOG assumes that only one-sixth of TIE may be used in any year.
 - TIE are subject to a \$40 price trigger below which they cannot be used. TIE cannot be transferred.
 - Assuming that Oooguruk is a stand-alone project, TIE cannot be fully absorbed. If the producer has PPT obligations arising from other projects the TIE can be used.
- PPT payments are deductible from SCIT when there is a liability, they are not added to income when there is a tax credit.
- The discounted state revenue (at 5%) attributable to net PPT (PPT obligations minus credits) is negative at all price levels modeled.
- The PPT improves the economics of the Oooguruk project by almost three times what the royalty modification award was able to achieve.



STATE OF ALASKA
DEPARTMENT OF
REVENUE

Responses to Committee Questions

LIB

Today's PPT Charts

- Comparisons to 20/20 PPT

- PPT 25/20

- PPT 30/20

- PPT 30/15

- ANS Crude Oil Prices

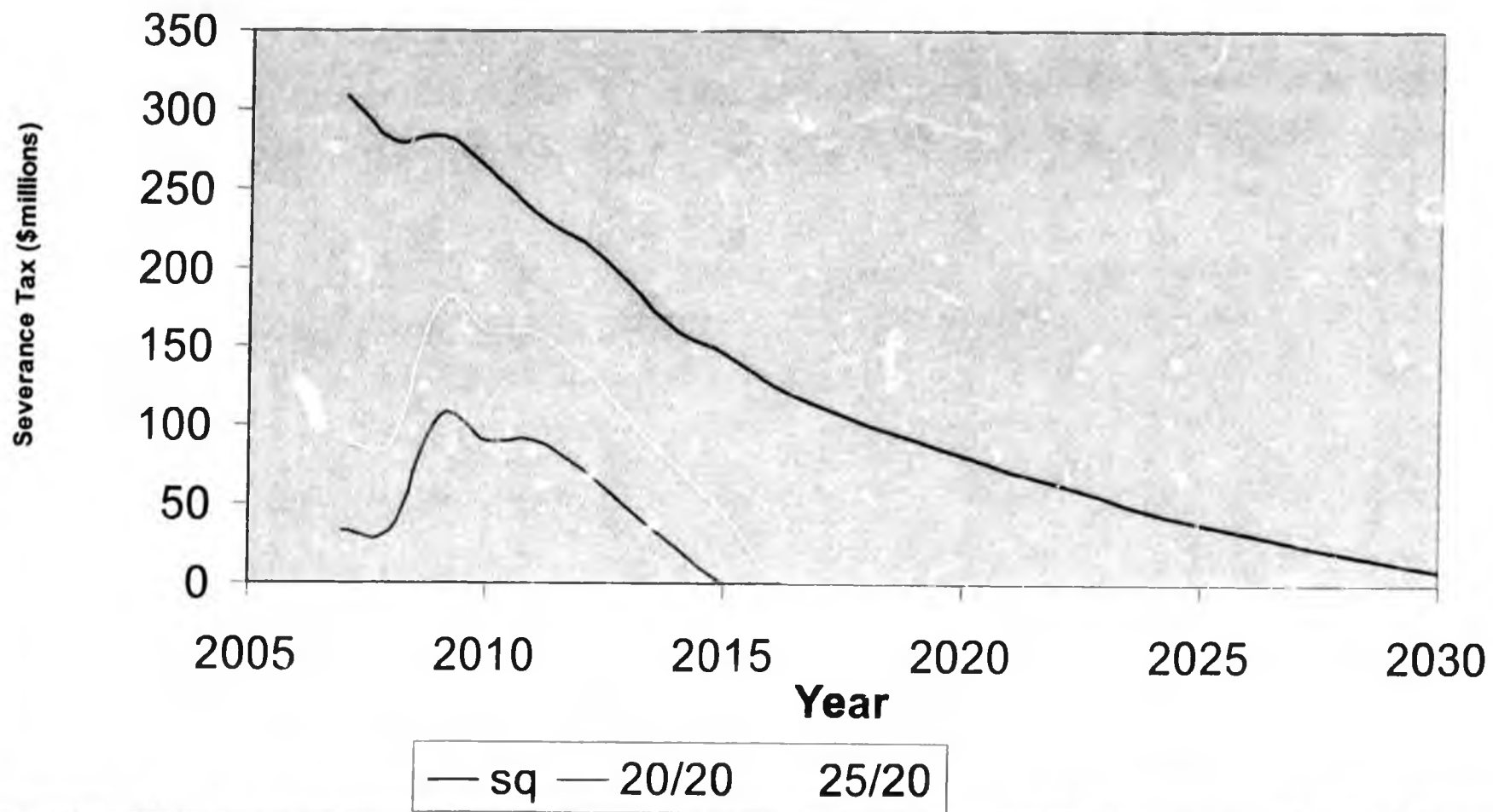
- \$20

- \$40

- \$60

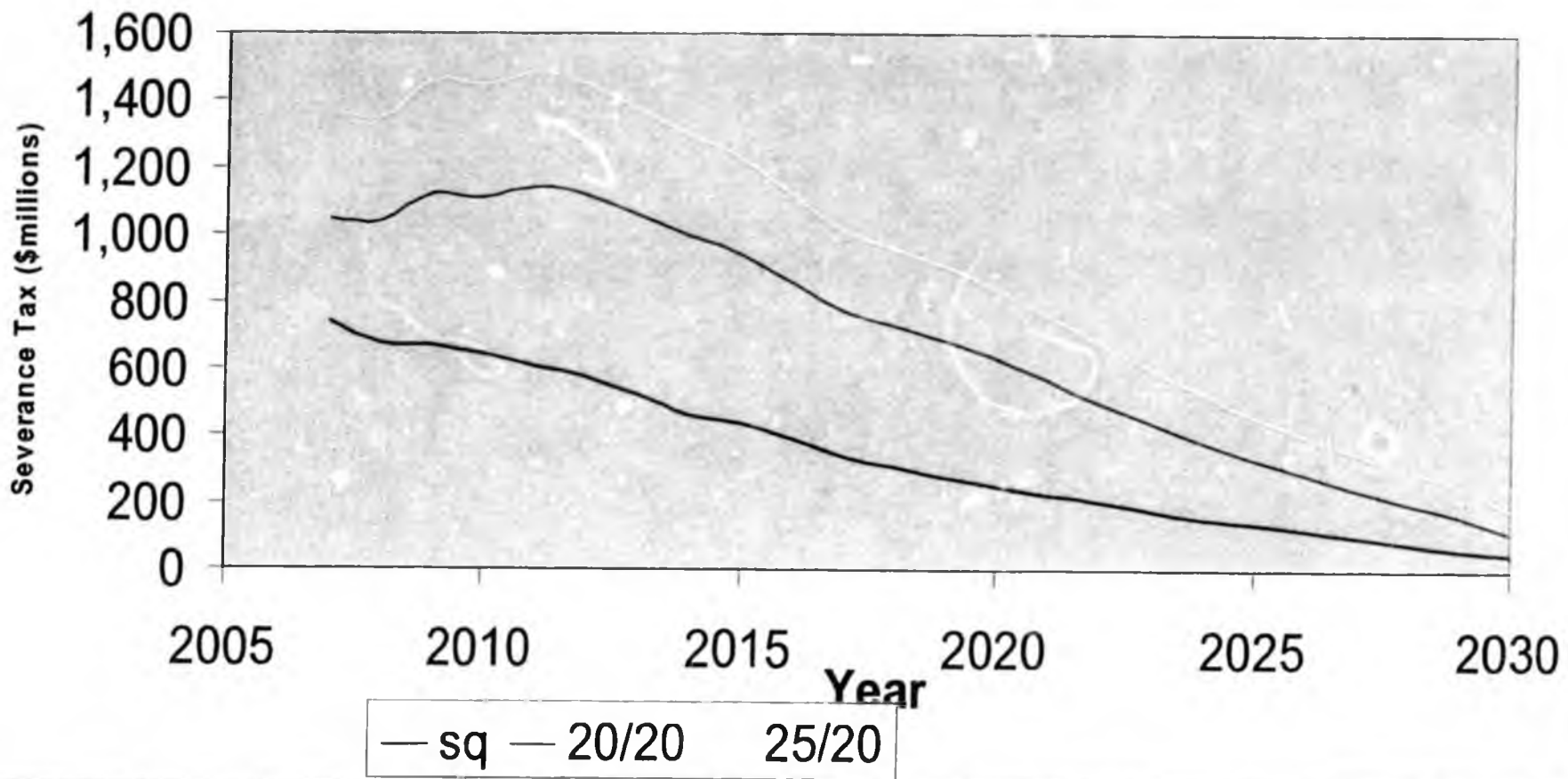


Figure 4a
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$20



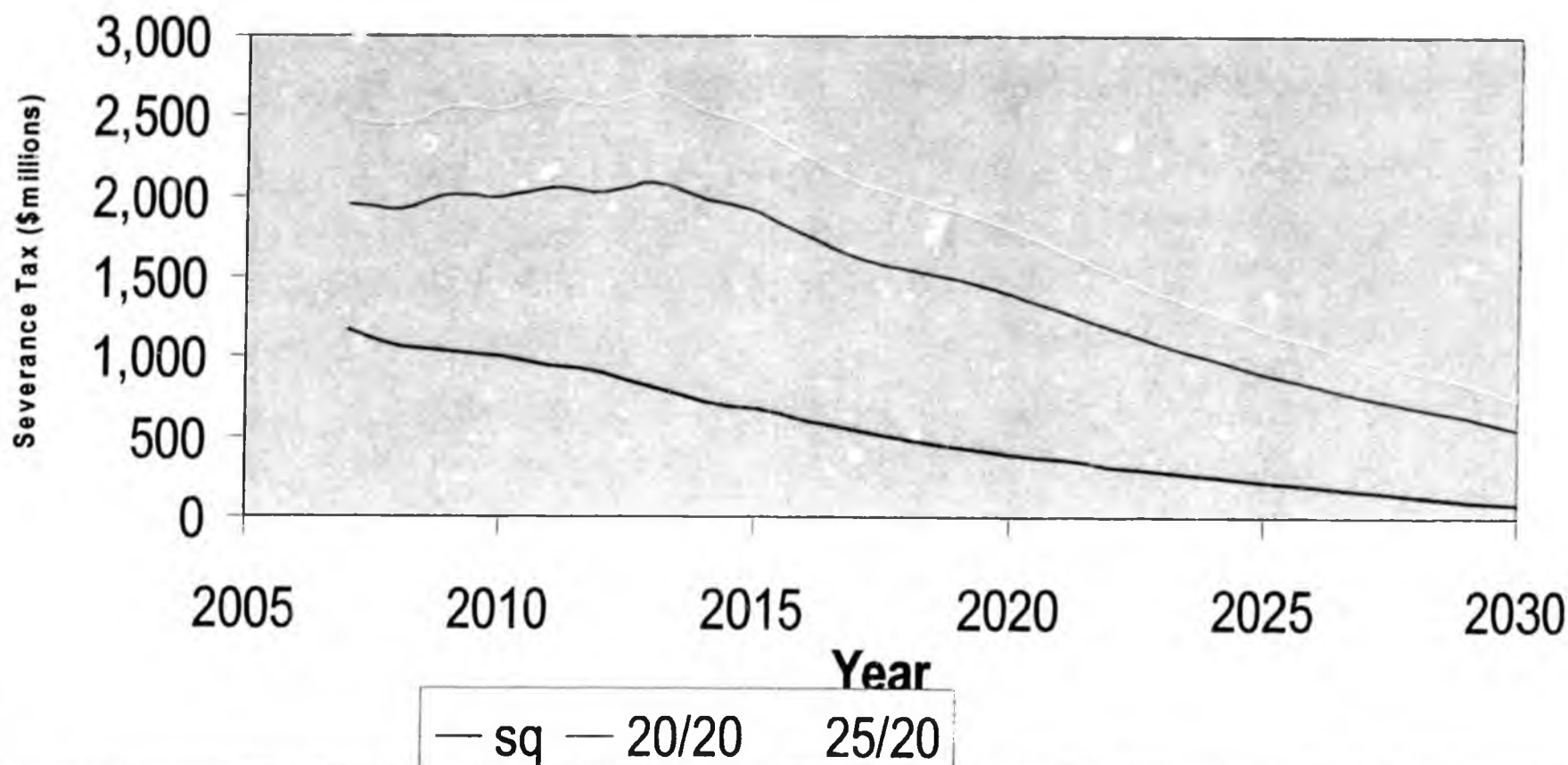
PPT 25/20 - Average annual revenues \$80 million less than status quo & \$20 million more than 20/20

Figure 5a
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$40



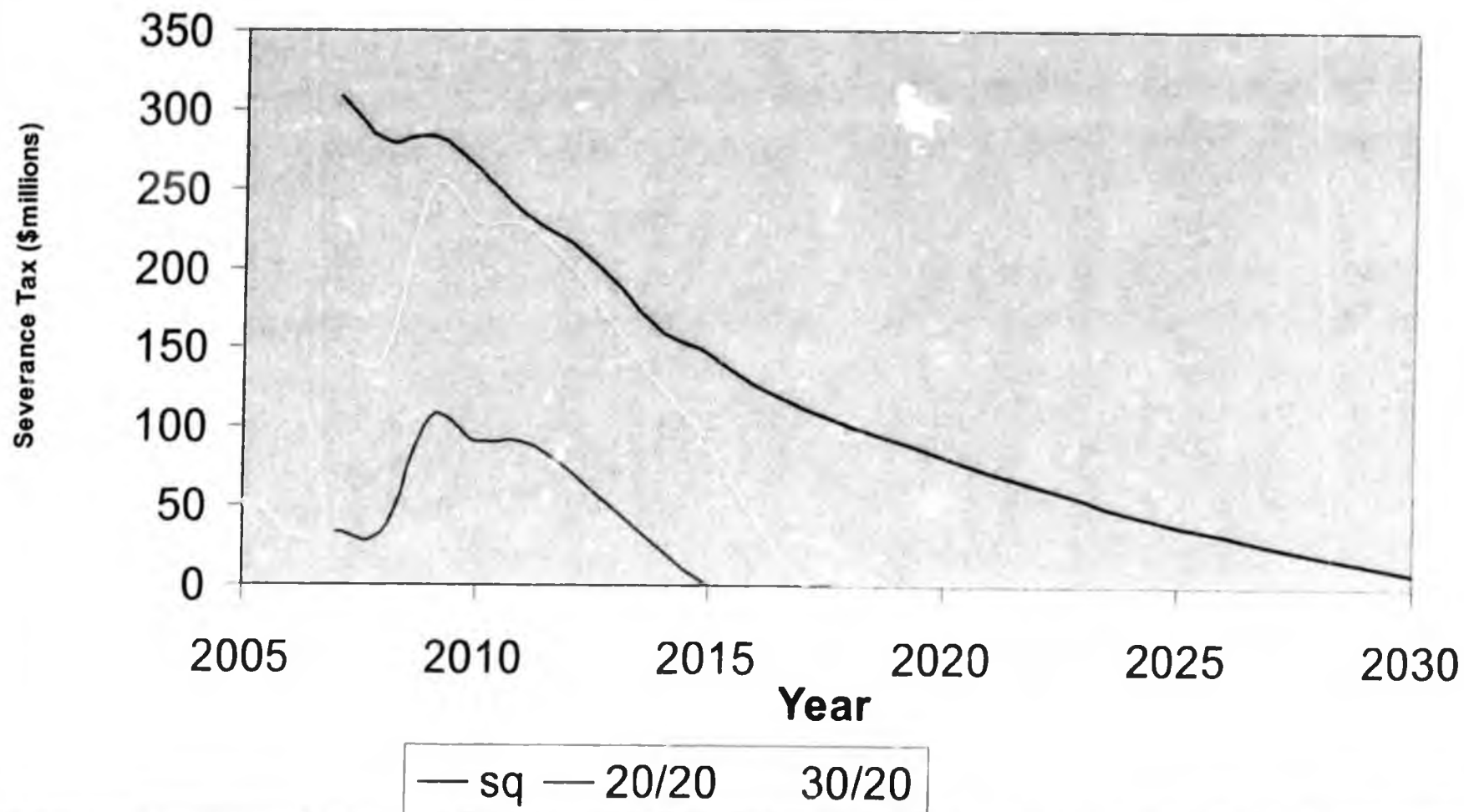
PPT 25/20 - Average annual revenues \$565 million more than status quo and \$220 million more than 20/20

Figure 6a
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$60



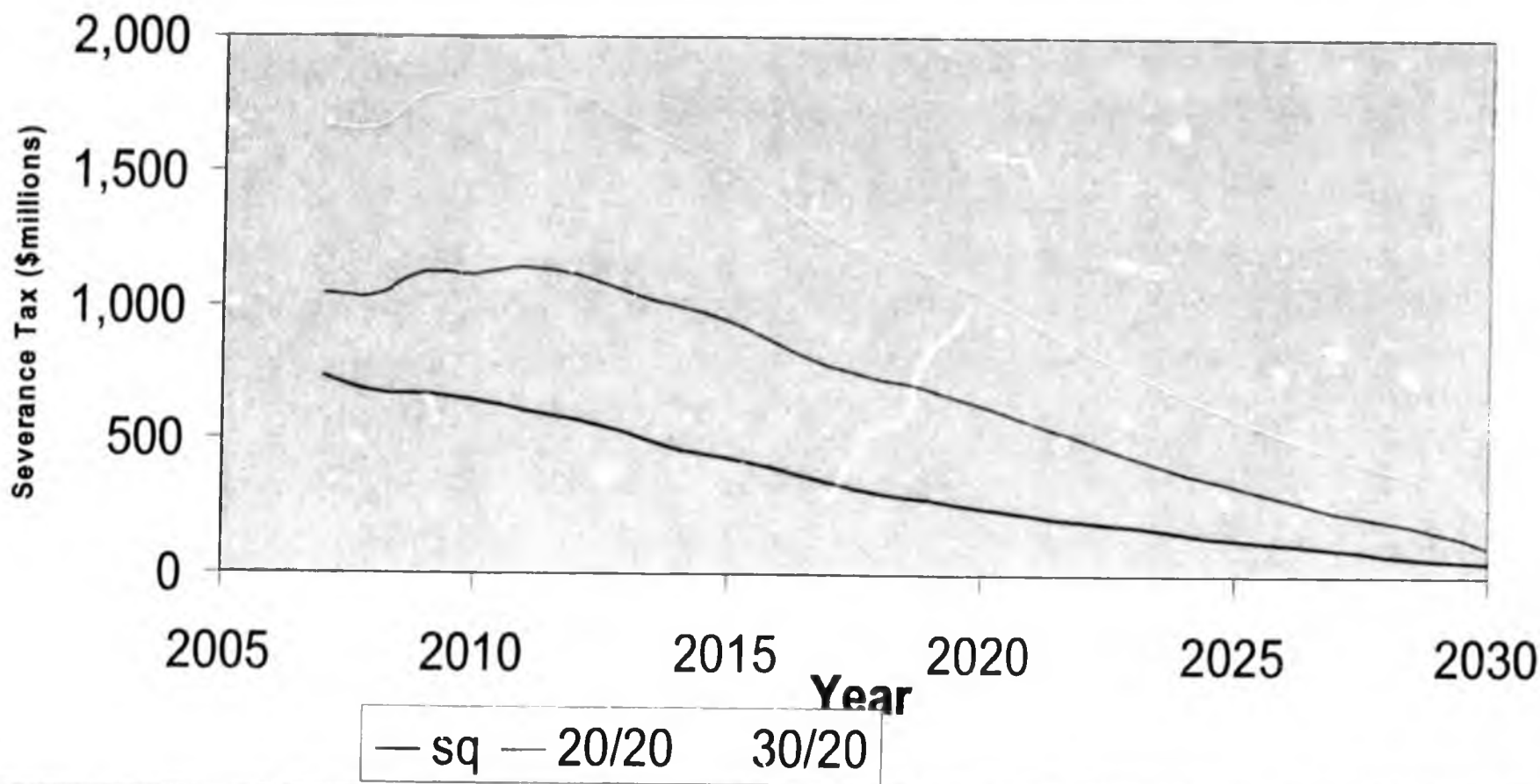
PPT 25/20 - Average annual revenues \$1,300 million more than status quo & \$400 million more than 20/20

Figure 4b
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$20



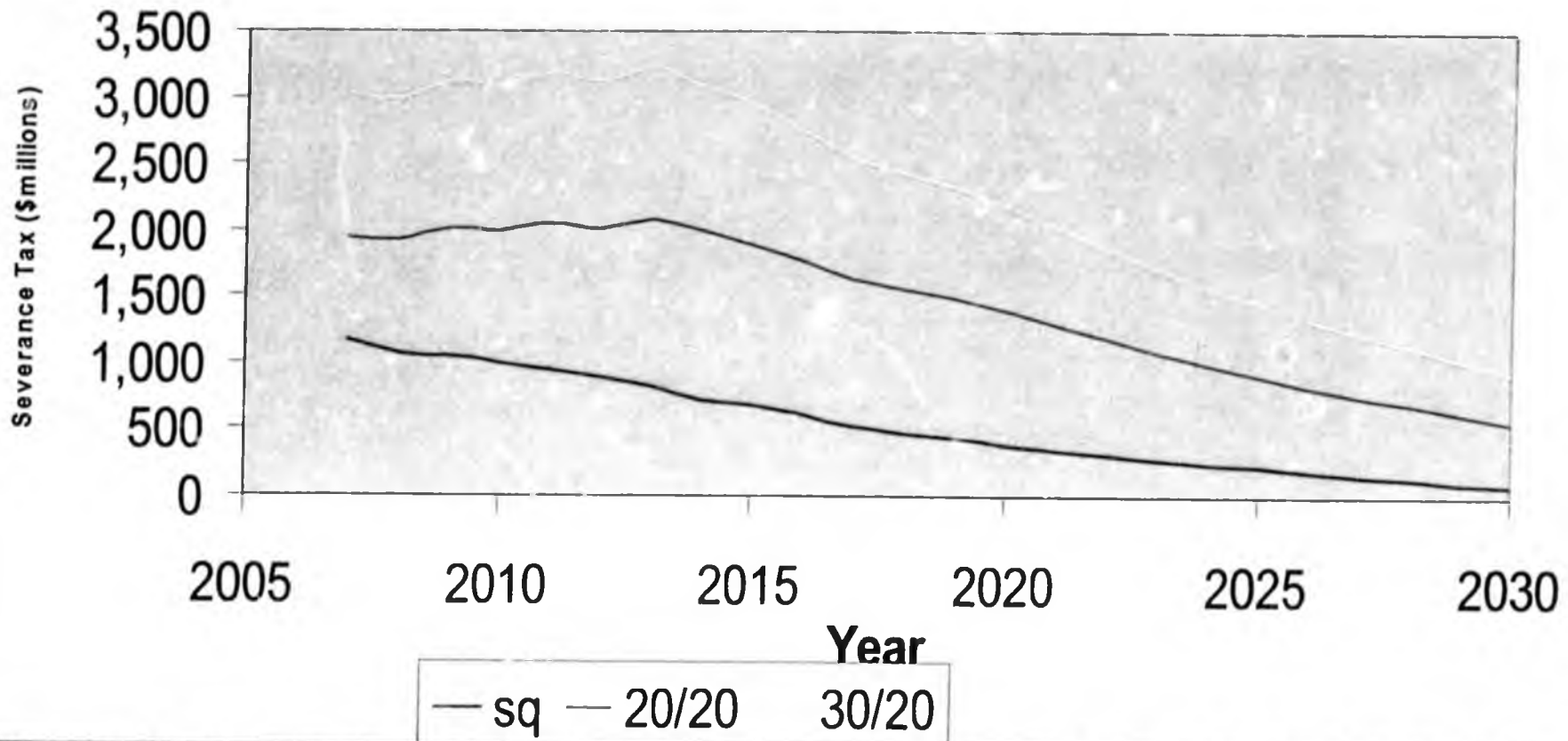
PPT 30/20 - Average annual revenues \$55 million less than status quo and \$45 million more than 20/20

Figure 5b
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$40



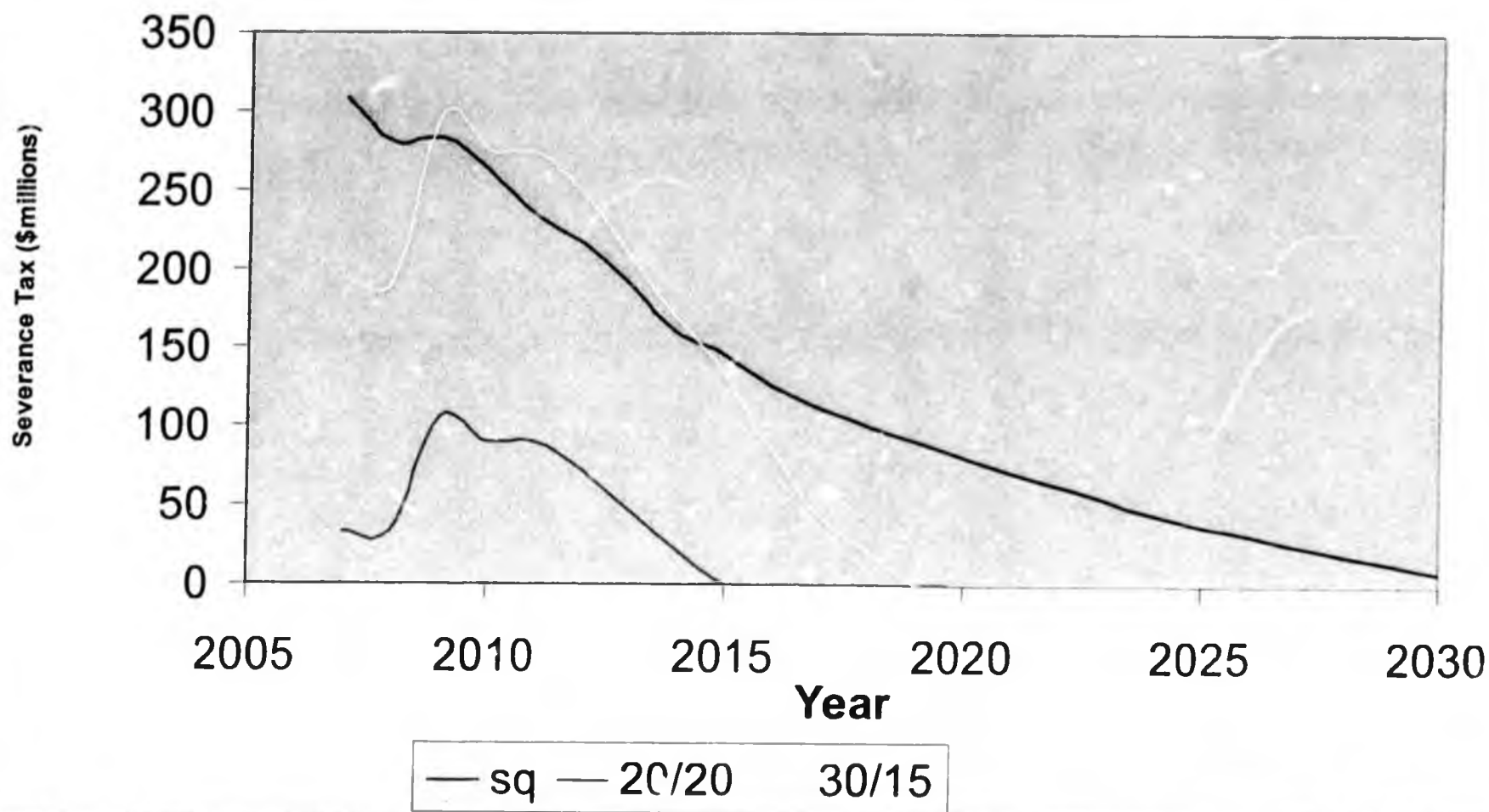
PPT 30/20 - Average annual revenues \$790 million more than status quo and \$440 million more than 20/20

Figure 6b
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$60



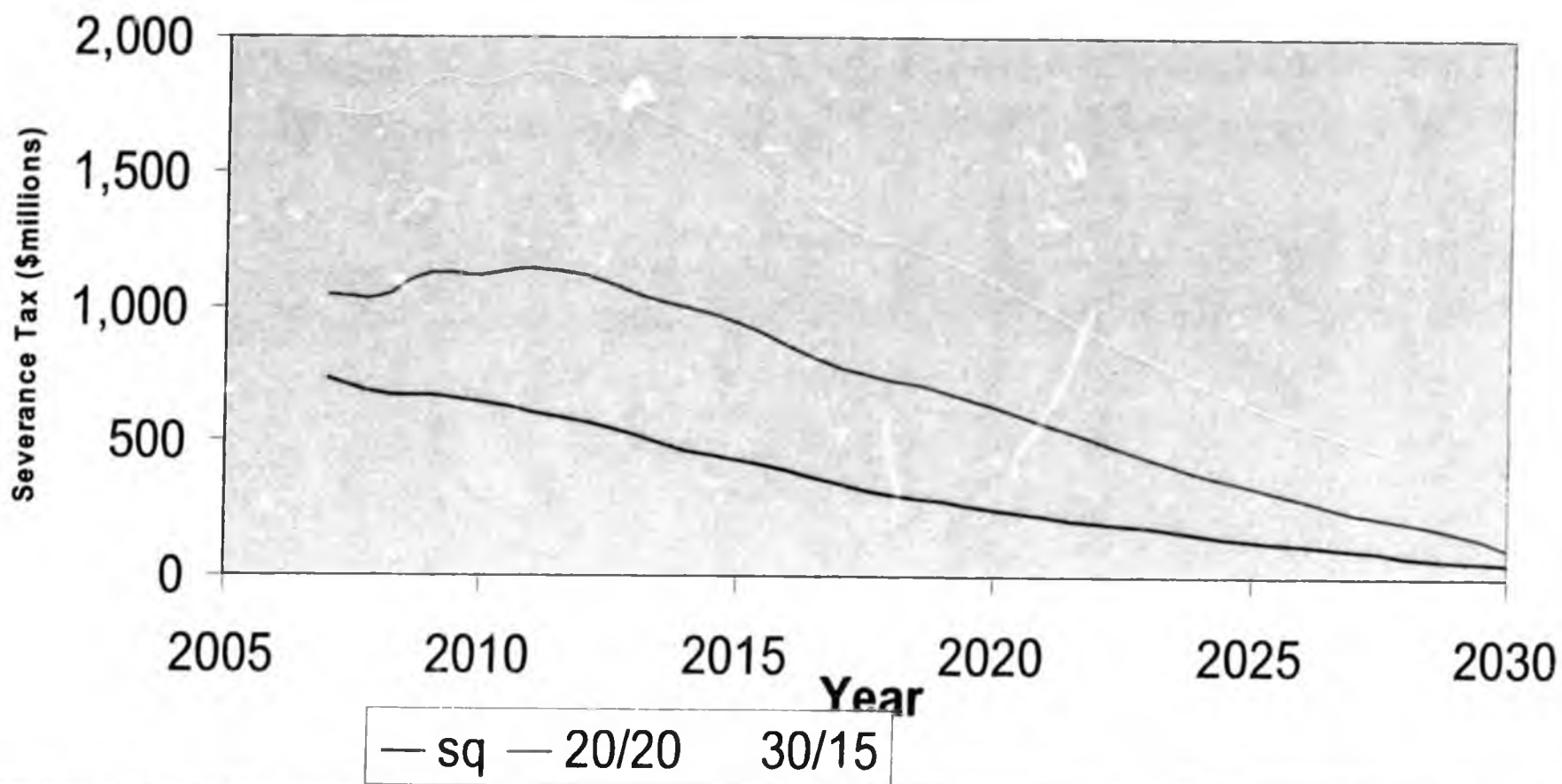
PPT 30/20 - Average annual revenues \$1,730 million more than status quo and \$820 million more than 20/20

Figure 4c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$20



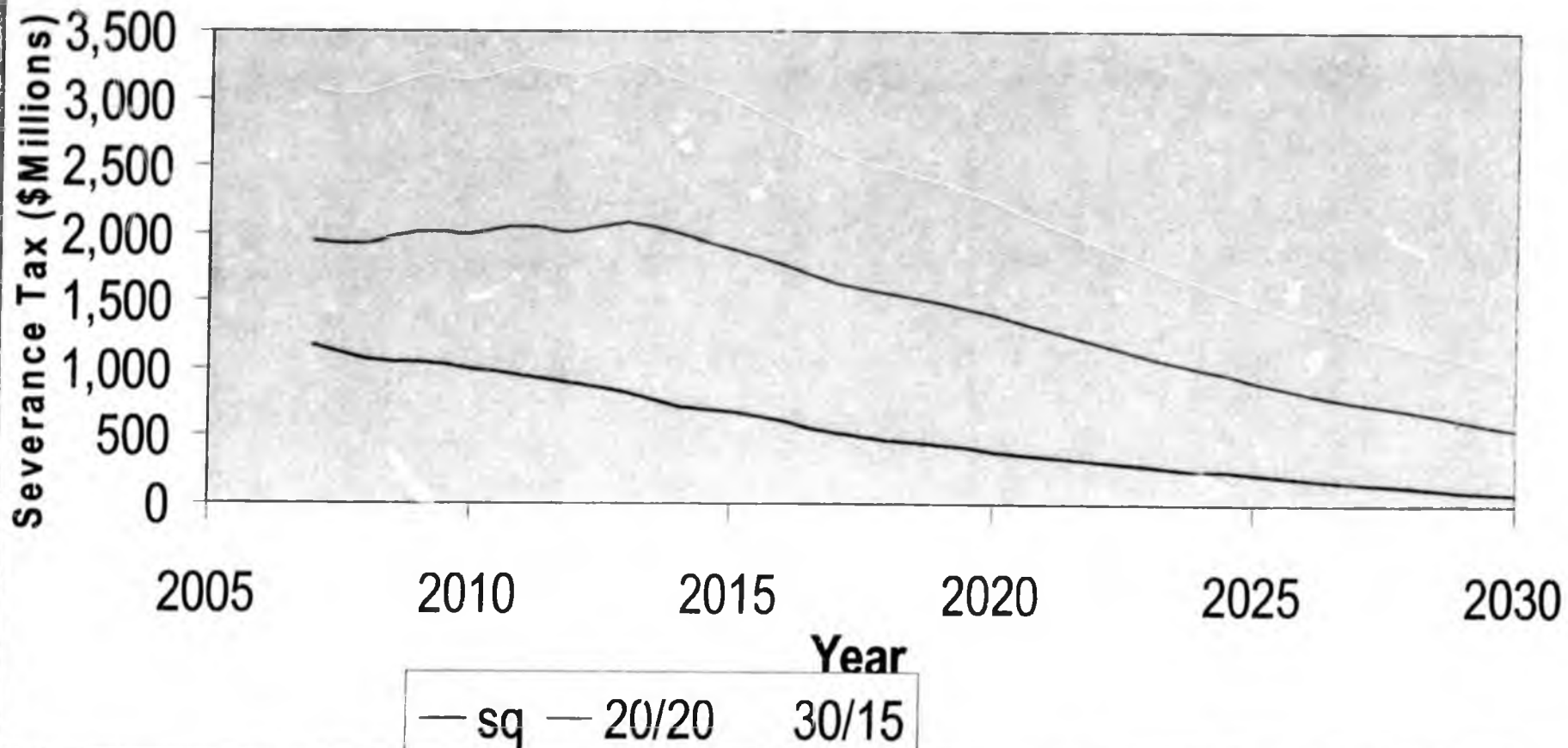
PPT 30/15 - Average annual revenues \$35 million less than status quo and \$70 million more than 20/20

Figure 5c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$40



PPT 30/15 - Average annual revenues \$840 million more than status quo and \$500 million more than 20/20

Figure 6c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
\$60



PPT 30/15 - Average annual revenues \$1,780 million more than status quo & \$870 million more than 20/20



STATE OF ALASKA
DEPARTMENT OF
REVENUE

**Robynn Wilson, Director,
robynn_wilson@revenue.state.ak.us
Alaska Department of Revenue**

March 2, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras,

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings.

Received 2/28/06, 12:00 p.m.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production), by company.

The Department of Revenue model uses \$1 billion per year as capital costs, so for the transitional period, there would be about \$5 billion. This annual costs are based on compilations of historical data. The attached excel files outlines public data regarding investments.

2. How are mob, demob, and platform abandonment costs treated—as tax credits or deductions?

Mobilization costs are capitalized for federal tax purposes, as Intangible Drilling Costs. As such, they are a capitalized expenditure for PPT purposes, and therefore are deductible and creditable. We understand that demobilization and abandonment expenditures are both expensed as incurred. This would mean that these costs are deductible, but would not generate a credit.

3. Is there a "rating" for political stability – or one that reflects instability?

We do not have any information on a quantification of the risk of political stability.

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

Using a combination of our spring forecast and YTD actuals, the average ANS price between January 1, 2006 and July 1, 2006 was \$58.62.

- The loss of revenue using the 20/20 system would be about \$480 mm in additional tax.
- The loss of revenue using the 25/20 system would be about \$770 mm in additional tax.

5. Section 9 – what amount is involved in this section?

A very small amount, probably no more than 1% of total state revenue from oil and gas. It is limited to three areas: [1] Alpine and its satellites; [2] the National Petroleum Reserve Alaska; and [3] Cook Inlet.

6. Was there consideration of phasing out the \$73 million deduction over a certain period of time?

No, it was not considered.

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed \$73 million standard deduction?

With the merger of Chevron and Unocal, there are now 13 producers in Alaska. Of the 13 producers, BP, ConocoPhillips and ExxonMobil will pay severance tax at most price levels after employing the \$73 million standard deduction. At high oil and gas prices, and given our cost assumptions, Anadarko and ChevronUnocal will also pay severance tax after deducting the \$73 million dollar allowance, given the production volumes reported publicly by those companies.

8. Which other tax regimes – worldwide - have a progressivity structure?

TO BE PROVIDED

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total \$104.8 million and claimed credits total \$33.6 million [see table below]. A claim was received by the Department of Revenue last week, thus the totals has been updated from the \$95.5 million and \$29.0 million figures previously provided.

12. What is the rationale for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes: taxes that are assessed on any oil or gas production within Alaska's sovereign territory. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two fold. First any incentive to encourage Pt. Thomson improves the economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

We're not clear whether this question seeks more explanation of the definitions in the bill or is requesting that we consider modifying those definitions. Please clarify. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at Sec. 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

Section 21 (Sec. 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are deductible. Sec. 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Sub-section (d) provides clarification for items that are not clear, such as "payments made in lieu of property taxes."

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (Sec. 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the

legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel(not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this question. As a Sixth Circuit decision, it has no direct precedence for Alaska. It is currently before the U.S. Supreme Court and many analysts believe that it will not be sustained in its current form.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (Sec. 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (Sec. 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs. The capitalized expenditures are subject to a variety of useful lives under federal and state income rules. See Question 60 below.

21. Have any of the definitions in sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

This term only appears in the definition of "oil." It was not in the old definition, nor the new definition of "gas." The standard for "pipeline quality" has not changed under the bill. The standard is based on a series of court cases.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

TO BE PROVIDED

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

TO BE PROVIDED

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes \$100 million is spent on exploration per year. With average costs of \$20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations - reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

TO BE PROVIDED

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See Attachments A1 and A2. These tables contain effective tax rates since 1986 for all Alaskan fields on gross value at the point of production. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987 (when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

TO BE PROVIDED

Received 2/28/06, 2:30 p.m.

32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize through marketing. Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the oil profits for the PPT.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

See question 20.

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

Sale of credits under SB185 do not effect the ability of the seller to claim those credits as Transitional Investment Expenditures (that is to qualify for the claw back.)

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as:

- (a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the \$73 million dollar allowance).
- (b) Under the gas contract, the state will receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production is deductible from corporate tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. (AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state.")

Section 10 simplifies treatment of flared gas. Under current law there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no 'free use of oil' to produce more oil in statute. The bill

exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225 interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

TO BE PROVIDED

41. What are the penalties for under-payment when sure-up is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

43. Why does it seem the credits and incentive [sic] are on production along with exploration if our focus is to provide incentives for exploration?

(The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carry-forward amount be used for a credit for more than the first year after the loss?

Yes, the credit carry-forwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, nor for the optional credit codified in 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Dept. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, Sec. 43.55.024(g))

49. What is the estimated economic impact to the state of the ability to sell tax credits?

TO BE PROVIDED

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices, is subject to the same criminal penalties that apply to a state employee

The current confidentiality law is very general in its exception language – information must be kept confidential “except in connection with official investigations or proceedings” The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above.

51. In what circumstances would oil and gas taxes go straight into the CBR.

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from shall to is?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods, it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method or just calculating gross value according to the usual rules – NOT an election among several different alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. I don't think we can predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 1, line 8—why is this clause constrained by Dec. 1, 2005?

TO BE PROVIDED

55. Section 21, provision (h), which US CPI does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible from corporate income tax.

Other Questions

57. Do any other state taxes have a "standard deduction"?

- a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of \$50,000 or more in a calendar year. AS 16.51.120(g).
- b. Mining License Tax is not imposed when net income is less than \$40,000 in a fiscal year. AS 43.65.010(c).
- c. Gaming tax exempts gross receipts of less than \$20,000 from paying the additional fee under AS 05.15.020(b).
- d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under \$1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying royalties. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was \$81M. Total receipts from NPSL's from 2001—2005 were \$254M.

Out of 19 NPSL's, seven are paying net profit share payments (*in addition to royalties and production taxes*). These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was \$81M. Total NPS receipts from NPSL's from 2001—2005 were \$254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

Attached is an Xcel table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease. (See Attachment B)

59. What are the depreciable lives for O & G equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barges, other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value \$60M
 --Opex 15M
 --Capex 10M

Gross value	\$60M
Less: Opex	(15)
Capex	<u>(10)</u>
Tentative net profit	
Before standard deduction	\$35M
Less: standard deduction*	<u>(35)</u>
Net Taxable income	<u>\$ 0</u>

Tax	\$ 0
Capital investment credit available for carryforward (20% of \$10M)	\$5M

* this calculation assumes that taxpayer has not reached \$73M limit for the standard deduction.

61. Are net profit lease payments included as a direct cost under 43.55.160?

Net profit share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (Sec. 43.55.160(c)). Such costs are also eligible for credits under Section 12 (Sec. 43.55.024) by reference to definition of "qualified capital expenditure" at Sec. 43.55.024(h).

64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax to a tax on net profits, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21

(Sec. 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the related production is subject to tax.

65. Under Section 21 (Sec. 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No, Sec. 43.55.160(d) provides additional clarification for the general rule stated at sub-section (c). Sub-section (c) provides the general rule that lease costs are deductible. Sub-section (d) addresses only those items that may have been questionable under the general rule. Additionally, we note that under AS 01.10.040(b):

"When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

Questions Received 3/1/06 12:00 p.m.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO₂ re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

TO BE PROVIDED

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant tax benefits ever be realized?

TO BE PROVIDED

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

TO BE PROVIDED

69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

- a. 30/15
- b. 30/20
- c. 25/20
- d. 20/20

TO BE PROVIDED

70. Please present Mr. Marks' charts on pages 14-16 to show the difference between a PPT and status quo, annually under the following PPT plans at \$20, \$40, and \$60/bbl:

- a. 25/20
- b. 30/20
- c. 30/15

TO BE PROVIDED

71. Please show the corporate take chart on page 24 of Mr. Marks' presentation given the following tax/credit scenarios:

- a. 25/20
- b. 30/20
- c. 30/15

TO BE PROVIDED

72. Please show the price point where DOR estimates corporate profit margins hit 15% and 20%.

TO BE PROVIDED

Attachment A1 (Question 30)

Effective Tax Rates, North Slope by Field, FY86 - FY05

	Prudhoe Bay	Midnight Sun	Polaris	Orion	Aurora	Borealis					
FY86	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.07%	0.00%	0.00%	0.00%	0.00%
FY87	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.47%	0.00%	0.00%	0.00%	0.00%
FY88	12.66%	0.00%	0.00%	0.00%	0.00%	0.00%	8.33%	0.00%	0.00%	0.00%	0.00%
FY89	12.33%	0.00%	0.00%	0.00%	0.00%	0.00%	8.71%	0.00%	0.00%	0.00%	0.00%
FY90	14.71%	0.00%	0.00%	0.00%	0.00%	0.00%	12.89%	0.00%	0.00%	0.00%	0.00%
FY91	14.91%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	0.00%	0.00%	0.00%	0.00%
FY92	14.90%	0.00%	0.00%	0.00%	0.00%	0.00%	13.33%	0.00%	0.00%	0.00%	0.00%
FY93	14.65%	0.00%	0.00%	0.00%	0.00%	0.00%	13.34%	0.00%	0.00%	0.00%	0.00%
FY94	14.81%	0.00%	0.00%	0.00%	0.00%	0.00%	13.09%	0.00%	0.00%	0.00%	0.00%
FY95	14.76%	0.00%	0.00%	0.00%	0.00%	0.00%	12.85%	0.00%	0.00%	0.00%	0.00%
FY96	14.67%	0.00%	0.00%	0.00%	0.00%	0.00%	12.35%	0.00%	0.00%	0.00%	0.00%
FY97	14.59%	0.00%	0.00%	0.00%	0.00%	0.00%	11.72%	0.00%	0.00%	0.00%	0.00%
FY98	14.44%	0.00%	0.00%	0.00%	0.00%	0.00%	11.38%	0.00%	0.00%	0.00%	0.00%
FY99	14.23%	0.00%	0.00%	0.00%	0.00%	0.00%	10.53%	0.00%	0.00%	0.87%	0.00%
FY00	13.96%	0.00%	0.00%	0.00%	0.00%	0.00%	8.97%	0.00%	0.00%	0.58%	0.00%
FY01	13.76%	0.00%	0.00%	0.00%	0.00%	0.00%	7.40%	0.00%	0.00%	0.05%	0.00%
FY02	13.44%	0.13%	0.00%	0.00%	0.00%	0.96%	5.29%	0.00%	0.00%	0.52%	0.00%
FY03	13.05%	0.10%	0.00%	0.00%	0.00%	1.40%	3.44%	0.00%	0.00%	1.22%	0.00%
FY04	12.82%	0.00%	0.00%	0.00%	0.00%	1.03%	2.70%	0.00%	0.00%	0.84%	0.00%
FY05	12.65%	4.43%	4.43%	3.63%	3.62%	3.69%	0.76%	0.00%	0.00%	0.15%	0.00%

Note: The effective tax rate for Midnight Sun, Polaris, Orion, Aurora, Pt. McIntyre, and Borealis for FY 05 reflects 5 months' effect of the aggregation decision effective Feb. 1, 2005.

Attachment A2 (Question 30)

	Milne Point	Endicott	Elder	Lieburne	P. 'nt McIntyre	Niakuk	West Beach	NPBS	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	12.25%	0.00%	6.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY90	0.00%	10.37%	0.00%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY91	0.00%	9.44%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY92	0.00%	9.51%	0.00%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY93	0.00%	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY94	0.00%	11.53%	0.00%	0.00%	7.28%	1.56%	0.00%	0.00%	0.00%	0.00%
FY95	0.00%	11.30%	0.00%	0.00%	11.30%	6.15%	0.00%	0.00%	0.00%	0.00%
FY96	0.00%	10.39%	0.00%	0.00%	11.60%	1.76%	0.00%	0.00%	0.00%	0.00%
FY97	0.29%	7.10%	0.00%	0.00%	11.63%	1.51%	0.00%	0.00%	0.00%	0.00%
FY98	0.46%	4.54%	0.00%	0.00%	11.29%	0.89%	0.00%	0.00%	0.00%	0.00%
FY99	0.64%	1.29%	0.00%	0.00%	11.75%	0.70%	0.00%	0.00%	0.00%	0.00%
FY00	0.38%	0.73%	0.00%	0.00%	9.45%	1.32%	0.00%	0.00%	0.00%	0.00%
FY01	0.16%	0.13%	0.00%	0.00%	6.47%	0.17%	0.00%	0.00%	4.24%	0.00%
FY02	0.02%	0.02%	0.00%	0.00%	3.10%	0.15%	0.00%	0.00%	10.76%	5.14%
FY03	0.00%	0.01%	0.00%	0.00%	2.40%	0.02%	0.00%	0.00%	10.50%	10.59%
FY04	0.00%	0.00%	0.00%	0.00%	1.63%	0.00%	0.00%	0.00%	10.33%	10.37%
FY05	0.00%	0.00%	0.00%	0.00%	4.78%	0.00%	0.00%	0.00%	10.17%	10.18%

Attachment B (Question 58)

By: G. Rogers, March 1, 2006, source
 DNR

NPS LEASES, NPS RATES & ROYALTY RATES & STATUS

	Unit - lease number	Royalty Rate	NPS Rate	NPS Status
Duck Island				
1	312828	20%	79.5935%	in payout
2	312834	20%	48.8703%	in payout
Milne Point				
3	355016	12.5%	40.0000%	in payout
4	355017	12.5%	40.0000%	in payout
5	355018	12.5%	30.0000%	in payout
6	355021	12.5%	30.0000%	in payout
7	388235	12.5%	30.0000%	in payout
Kuparuk River				
8	355023	12.5%	30.0000%	not in payout
9	355024	12.5%	30.0000%	not in payout
10	355030	12.5%	30.0000%	not in payout
11	355032	12.5%	30.0000%	not in payout
Colville River				
12	364470	12.5%	30.0%	non producing
13	364471	12.5%	30.0%	non producing
14	364472	12.5%	30.0%	non producing
15	364477	12.5%	30.0%	non producing
16	364478	12.5%	30.0%	non producing
Point Thompson Unit				
17	312866	20%	52.352%	non producing
18	343109	12.5%	40%	non producing
19	343110	12.5%	40%	non producing
20	343111	12.5%	40%	non producing
21	343112	closed	closed	non producing

Letter to Senator Wagoner and Representatives Samuels and Ramras
March 2, 2006