SB

305

(FILE 13)

STATE OF ALASKA

DEPARTMENT OF REVENUE

Tax Division

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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. This letter incorporates answers presented during testimony which was based on our interim draft reports dated March 2 and March 7, 2006, and provides additional information not previously available. In addition, this letter expands some of the answers in response to followup questions posed during the hearings. We have included a substantial number of attachments which are indexed to the question number. Lastly, we have included an index, by topic, which should prove helpful.

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

(millions)	Exploration	Dev. & Production*	Total
2001	152	1,636	1,788
2002	125	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047

* We do not have information on the split between development and production expenditures.

Although we have not completed this work, we have some evidence about costs in 2005 and the first half of 2006 and it appears they will continue the downward trend seen in the four years presented.

2. How are mobilization, demobilization, 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 is estimated as $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 production of oil and gas. Currently it is limited to Alpine and its satellites and Cook Inlet, though production expected soon from the NPRA will also have private leasehold interest.

6. Was there consideration of phasing out the $73 million allowance 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 allowance?

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 anticipated price levels after employing the $73 million standard allowance. At high oil and gas prices, and given our cost assumptions, Anadarko, Marathon, 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?

Note: this question answers progressivity generally, but see definition at Question 91.

Progressive features are relatively common around the world. Following is a list of the main fiscal regimes with such features. "Old" features are defined as features that have been in existence for more than 20 years. "New" less than 20 years.

There is a wide variety of systems that are progressive with the level of well production or field production. These systems are not included in the list.

Country	Region/Type	Feature	Oil/Gas	Old/New
Canada	NWT	IRR based profit sharing royalty	Both	Old
	Newfoundland	IRR based profit sharing royalty	Oil	Old
	Nova Scotia	Payout based profit sharing royalty	Both	New
	Alberta	Production/Price sensitive royalty	Oil	Old
	Alberta	Price Sensitive royalty	Gas	Old
	Alberta oil sands	IRR based profit sharing royalty	Oil	Old
Colombia		Price sensitive windfall profits tax	Oil	New
Venezuela	Conventional	IRR based profit share	Oil	New

	Oil			
Peru		R-factor royalty	Both	New
Bolivia		Profit sensitive Surcharge with uplifts	Both	New
Trinidad & Tobago	Conventional Oil	Supplemental Petroleum Tax, Price sensitive	Oil	New
	Deep water	Production/Price sensitive profit oil/gas shares	Both	New
Norway		Uplifts on Hydrocarbon Tax	Both	Old
UK	Old licenses	Uplifts and Oil Allowance on PRT	Both	Old
Denmark		Uplifts on Hydrocarbon Tax	Both	Old
The Netherlands		Uplifts on Special Profit share	Both	Old
Algeria		Cumulative Revenue sensitive PRT and uplifts	Both	New
Tunisia		Sliding scale taxation	Both	New
Libya		R-factor based profit oil splits	Oil	Old
Nigeria		Uplifts and tax credits	Oil	Old
Angola		IRR based profit oil shares	Oil	New
Qatar		R-factor based profit oil shares	Oil	New
Saudi Arabia		IRR based corporate income tax rates	Gas	New
Iran		Buy Back contracts	Both	New
Pakistan	Offshore	Price Sensitive Windfall profits tax	Both	New
India		R-factor based profit oil shares	Both	New
Thailand		Profit sensitive SRB	Both	New
Malaysia		Price sensitive windfall profits tax	Both	Old
Indonesia		Uplifts	Both	Old
Australia	Offshore	IRR based PRT	Both	Old
PNG		IRR based API	Both	Old
Russia	Sakhalin	IRR based profit oil shares	Both	New
Kazakhstan	Tengiz	IRR based profit share	Oil	New
	General	New models with variety	Oil	New

		of progressive features		
Azerbaijan	AIOC	IRR based profit oil share	Oil	New
	Other	R-factor based profit oil shares	Oil	New

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 recently received by the Department of Revenue, thus the totals has been updated from the $95.5 million and $29.0 million figures previously provided.

Exploration Production Tax Credit Program Summary, AS 43.55.025
As of February 28, 2006

	No. of Projects	Claimed Expenses	Claimed Credits
FY 04, 05			
Audited & Issued:	7		
N. Slope wells		$51,050,000	$13,308,000
Cook Inlet wells		$ 3,430,000	$ 392,000
Cook Inlet seismic		$ 3,178,000	$ 1,085,000
Audits In progress:	5		
N. Slope wells		$26,615,000	$10,646,000

N. Slope seismic		$ 7,957,000	$ 3,182,000
Other - seismic		$ 3,295,000	$ 1,318,000
Other - wells		$ 9,286,000	$ 3,714,000
Total	12	$104,811,000	$ 33,646,000

12. What is the rational 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 borders. 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?

See the answers to questions 22-24, below. 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 AS 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?

AS 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Section 21 AS 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are also deductible.

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 (AS 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) has been consulted and such assessments have been discussed but have not generally been generated in formal written form.

Did such advice result in any changes to the legislation?

The bills reflect discussions with counsel that took place during the drafting process, so in that sense such advice did affect the legislation.

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 matter. The court decision calls into question, under the Commerce Clause of the United States Constitution, investment tax credit provisions that are found in state tax laws throughout the country. However, the decision's applicability to tax credits under a production tax, rather than an income tax, is not clear. In any event, the decision is currently being reviewed by the United States Supreme Court, and we should learn within the next several months whether it will be sustained.

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 (AS 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 (AS 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 tax rules. See Question 59 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.

For crude oil, the point of production will not change under our proposal. It will remain the point where the oil is first metered or measured in a condition of pipeline quality. (Note that certain oil used on the lease will no longer be taxable under the proposed production tax reforms, but that is not a point of production issue.) As examples, the points of production for oil are and will be the LACT (lease automatic transfer custody) meters at the inlets to TAPS (for Prudhoe Bay) and the Kuparuk Pipeline (for Kuparuk), and at the onshore production facilities for the Cook Inlet platforms.

What will change, in some cases, is the point of production for some gas. At Prudhoe Bay, while the current point of production for most gas is the inlet to the Central Gas Facility (CGF), there are other potential points of production for other gas uses. For example, in the separation facilities, gas is taken right out of the flow stream and burned in that facility (however this gas is not taxable under the free use of gas rules.) For taxable gas, the ***inlet*** to the CGF is generally the point of production for all gas that emerges from the CGF, including the NGLs that are recovered in liquid form.

This compares to other gas plants that are or have been operating at Kuparuk, Endicott, and Lisburne. For these facilities, the point of production for gas under current law is the ***outlet*** where the facility is tied to a sales or other line that take the gas off the unit. Why? Because in each of these facilities, the liquid hydrocarbons extracted from the processed gaseous streamare reblended with oil and run through gas-oil separators again. Therefore, the gaseous stream entering the facility has not yet been "completed separated" from oil, and the point of production for gas must be downstream of the facility

Under the bill, all gas processing operations (as long as they do not also include gas treatment) are considered upstream of the point of production. Therefore, the point of production for gas run through the Prudhoe Bay CGF will be where the gas is metered after leaving the CGF. In this respect, the point of production for gas will change at Prudhoe Bay but remain the same – downstream of the gas processing facilities – at the other North Slope fields using gas processing.

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 date in administering the tax, there are no gas treatment facilities on the North Slope. The only "gas processing plant" currently in the state is the Central Gas Facility (CGF), because by definition in the Department's regulations, a facility is a gas processing plant only if it is located downstream of the point of production for gas. 15 AAC 55.900(b)(7). However, the Lisburne, Endicott, and Kuparuk facilities conduct "gas processing," as defined in the regulations, 15 AAC 55.900(b)(6) even though they are not "gas processing plants."

Under the definitions in the bill, it will no longer matter whether a facility is a "gas processing plant." All four of the North Slope facilities will continue to be characterized as conducting "gas processing," which will be upstream of the point of production for gas.

Under the proposed definitions, plants removing CO_2 and H_2S from gas for delivery to a sales line – which in the sponsor group proposal is assigned to a new Gas Treatment Plant (GTP)--would be a new Gas Treatment Plant.

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"?

The current production tax statute taxes the "gross value at the point of production" of oil and gas. The quoted phrase was enacted in 1977 and replaced the previous statutory phrase "gross value at the well." This change was aimed at ensuring that costs of production operations downstream of the well would not be deductible in calculating the taxable value of oil or gas; rather, taxable value would be calculated at the point that production is complete.

In the case of oil, "gross value at the point of production" was defined as the value of oil where it is metered "in a condition of pipeline quality," and "pipeline quality" was defined as "good and merchantable condition." This definition essentially adopts commercial standards of marketability for oil. HB 488 and SB 305 would simplify and shorten the definition of gross value at the point of production for oil but do not materially change it. In addition, the definition of "oil" is broadened to include liquid hydrocarbons recovered by gas processing in the case of leases or properties whose production is subject to gas processing. The bottom line is that the point of production under these bills would still be the point where oil is metered in a condition of pipeline quality, and "pipeline quality" would mean the same thing it has always meant under the production tax statute.

In the case of gas, neither the existing statute nor the new bills use the phrase "pipeline quality" or "good and merchantable condition" with respect to gross value at the point of production. Rather, the statutory definitions of "gross value at the point of production" for gas, as interpreted and clarified by the Department's regulations, 15 AAC 55.900(a)(6)(B) and (C), focus on where gas is accurately metered after separation from oil. The new bills retain this concept but, in effect, expand "separation" to include gas processing, so that in the case of leases or properties whose production is subject to gas processing, the point of production for gas recovered by gas processing is the point where it is metered downstream of the processing.

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.

a. North Slope:

While there is much that is parallel in the calculation of gross value between royalty and tax, many differences have developed. Both start with destination value in the market, and then subtract the tankering, pipeline and other costs to arrive at a royalty or tax value. The Department of Revenue's (DOR) valuation for tax comes from statute and regulation. The Department of Natural Resources' (DNR) valuation for royalty comes from lease contracts supplemented by Royalty Settlement Agreements (RSAs) which set forth different methods for each large North Slope producer.

Destination value, for DOR, is what the oil was sold for, or when the oil is not sold or is sold for a below-market price, the so called prevailing value, generally based on spot price. Destination value for DNR is a formula driven by the price of ANS or a basket of similar crudes.

From the destination value, each method subtracts marine transportation costs, TAPS costs (including tariffs, losses and quality bank changes from mid-point refineries), feeder line costs (including tariffs, losses and quality bank differences), and other miscellaneous costs. DOR deducts the costs specific to each taxpayer, while for royalty, some of the RSAs have formulaic deductions and others use the royalty payer's actual cost. In addition, DNR subtracts field costs for most DL-1 lease form leases on the North Slope whereas DOR does not.

A critical point is that DOR uses actual proceeds, and only resorts to Prevailing Value when the conditions of AS 43.55.020 (f) are met, thereby taxing on the higher of proceeds or Prevailing Value. For production covered by Royalty Settlement Agreements, DNR uses a single destination formula based on spot prices, not actual proceeds.

b. Cook Inlet

In the Cook Inlet, the Oil ELF has been at zero for quite some time so there is no developed DOR methodology. Instead, it is appropriate to compare Department of the Interior royalty methodology with DNR methodology.

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?

AS 43.55.160(j) does not establish a maximum number of companies entering the market that could utilize the standard allowance. However, this section requires that the Department of Revenue evaluate each company claiming the deduction, on an annual basis, to determine if the company qualifies for the deduction. This section goes on to require the company to show that it has not split operations or property ownership among multiple entities in order to gain usage of multiple $73M deductions, when only one deduction should have been granted.

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.

Resources estimated are those that would enter the Trans Alaska Pipeline System [TAPS] north of the Brooks Range. These include estimates of recoverable oil from the National Petroleum Reserve – Alaska [NPRA], the Central North Slope, the Beaufort Sea and the Alaska National Wildlife Refuge [ANWR]. Estimates are presented in terms of barrels of technically and economically recoverable reserves. Technically recoverable estimates are mean estimates. Economic recovery is based upon the Department of Revenue [DOR] long term forecast of Alaska North Slope [ANS] crude oil delivered on the west coast at $25.50 per barrel in nominal terms. For purposes of analysis, all economically recoverable oil is presumed to be produced by 2046 [within 45 years]. Estimates are obtained from United State Federal government sources – the United States Geological Service [USGS], the Minerals Management Service [MMS] and the Energy Information Administration [EIA].

	Oil		
	Technically	**Economically**	**Natural Gas**
NPRA	10.6 Bbl	2.95 Bbl	59.7 Tcf
Central North Slope	3.98 Bbl	0.88 Bbl	35 Tcf
Beaufort Sea	6.94 Bbl	1.79 Bbl	Remainder plus existing PBU
ANWR	10.40 Bbl	4.21 Bbl	
Total	**32.38 Bbl**	**9.83 Bbl**	**200 Tcf +**

- **NPRA** – The entire area is estimated to contain 10.6 billion barrels of technically recoverable oil. Economically recoverable reserves consist of 2.95 billion barrels of oil.[1] (U.S. Geological Survey, 2002, Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA), USGS Fact Sheet 045-02, Table 3 and Figure 7)

- **Central North Slope** – The technically recoverable yet-to-be-discovered barrels of oil are estimated at 3.98 billion. Economically recoverable reserves are set at 0.88 billion barrels (USGS, 2005, Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska, Open-File Rpt 2005-1276, Table 5).

- **Beaufort Sea** – There are 6.94 billion barrels of oil technically recoverable. Economically recoverable reserves during the period under consideration are set at 1.79 billion barrels, the mean estimate at lower oil prices. (Mineral Management Service, Beaufort Sea Planning Area Oil and Gas Lease Sales 186, 195, and 202 OCS FEIS, 2003, MMS 2003-001, Appendix B, Table B-1)

- **ANWR** – There are 10.4 billion barrels of technically recoverable oil. Economically recoverable reserves consist of 4.21 billion barrels. (Energy Information Administration, Analysis of Oil and Gas Production in the Arctic National Wildlife Refuge, March 2004, pg 5 and Table 1)

- **Natural Gas** – Most natural gas that is technically recoverable is considered economically recoverable provided there is a means of transmission to market. Assuming gas flow through a pipeline beginning in 2015, the period through 2046 production totals 49.6 trillion cubic feet. Best estimates of natural gas reserves on the north slope far exceed this amount and include: proven reserves – 35 trillion cubic feet within Prudhoe Bay Field, Pt. Thomson, and other fields (EIA, March 2004), NPRA - 59.7 trillion cubic feet (USGS Fact Sheet 045-02); and, together with ANWR and offshore undiscovered reserves totals above 200 trillion cubic feet (USGS, Conventional Natural Gas Resource Potential, Alaska North Slope, 2004, Rpt 2004-1440).

The studies also set ranges for technically recoverable oil with a 5% and 95% confidence interval. These wide ranges are presented below. Economically

[1] Economically recoverable estimates were based on 2001 dollars so that $23.50 equates to approximately $25.50 in 2005 dollars.

recoverable oil volumes will vary by price of oil. However, higher valued oil will also be higher cost oil to produce with each increase in price resulting in increased volume strictly related to the cost of production.

Range of Technically Recoverable Oil

	5th Percentile	Mean	95th Percentile
NPRA	5.90 Bbl	10.6 Bbl	13.20 Bbl
Central North Slope	2.87 Bbl	3.98 Bbl	5.85 Bbl
Beaufort Sea	3.56 Bbl	6.94 Bbl	11.84 Bbl
ANWR	5.70 Bbl	10.40 Bbl	16.00 Bbl

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 attachment section, indexed by question number. These tables contain effective production oil tax rates since 1986 for all Alaskan fields on gross value at the point of production on non-royalty volumes. 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 (NPSL's) 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?

Production taxes are currently deductible for NPSL purposes. This legislation is not intended to change the deductibility of the production tax. However, NPSL leases are administered by the Department of Natural Resources, which is better equipped to address these questions and which we understand is doing so.

Also see Question 58.

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 taxable statewide value of a producer's oil and non-gasline gas under the bill.

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.

The assumption made for this request is that the Pre-PPT cost claw-back will be the last adjustment made to the tax. All other deductions and credits allowed under the PPT will have been exercised.

There was approximately $4.8 billion of capitalized investment made by the industry during in the period 2001 through 2006.

Using the Department of Revenue price forecast, which has prices falling and remaining below $40 after 2008:

Legacy Field Owners:	$316.6 million
Frontier Field Owners:	None. Due to no production or the inability to generate revenues sufficient to have a tax liability after other deductions or credits are taken.

Assuming a flat price of $45 for 2007-2050.

Legacy Field Owners:	$935 million
Frontier Field Owners:	15 million
Total	$950 million

Assuming a flat price of $60 for 2007-2050.

Legacy Field Owners:	$936 million
Frontier Field Owners:	15 million
Total	$951 million

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?

a. Only 2 credits that have been issued have been sold to another party.

b. The Division will first obtain a waiver of confidentiality from the seller allowing the Division to confirm the credit amount to the prospective purchaser. Once sold, the Division makes the transfer and issues a new credit certificate to the purchaser

upon receipt of documentation and confirmation of the transaction from the seller of the credit. The credit exists as an electronic entry in a Division database, therefore only the Division can make the actual transfer of the credit in that database. A new certificate is entered in the database to the purchaser and the old certificate is marked as transferred and its balance is zeroed out. The Division then notifies both the purchaser and the seller, in writing, of the completed transfer of the credit, at which time the purchaser may then apply the credit to its own production tax liability. When a credit is applied to a tax liability by a producer, the Division then verifies the holder and amount of the claimed credit against the credit certificates in the database.

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 a gas contract as now contemplated, the state would 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 tax is deductible from corporate income 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?

a. Net profits systems in the world typically work on the basis of three different concepts:

(a) monthly payments based on actual production, revenues and expenditures, without an annual true-up, as is the case in most production sharing agreements
(b) yearly payments based on a yearly return, filed within a few months after the year, without a need for monthly payments on account, as is the case for the Thai SRB, for instance. This means there is only a single annual payment.
(c) Yearly payments based on a yearly return, filed within a few months after a calendar year or a lease/contract year, with monthly payments on account. In this last case, the monthly payments could be based on:

a. Estimates for each month, as for instance with the Nova Scotia profit sharing royalty. These estimates can be challenged by government and different estimates may be required.
b. Payments based on a mixture of actual information from the previous month and estimates, such as in Algeria
c. Corporate income tax style procedures, whereby payments are based on taxes paid in the prior year (Norway for the Hydrocarbon Tax).

The 90% rule proposed for Alaska is unique. The overall economic impact would depend on the taxpayers' cost estimates for each month. We expect that taxpayers will experience underpayments in some months, but will experience overpayments (because of estimates used) in other months. In addition, falling production amounts or unforeseen costs will serve to likely create overpayments in later months. Overall, we do not expect any material net economic impact.

41. What are the penalties for under-payment when sure-up [true-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 carryforward amount be used for a credit for more than the first year after the loss?

Yes, the credit carryforwards 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 or 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, or for the optional credit codified in AS 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 Department. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, AS 43.55.024(g))

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

We believe the economic impact on the state will be positive as the credits will cause additional exploration, investment and development in the state creating jobs and demands for local goods and services. We believe there will also be a positive impact on the state treasury, and that while the cost of the credits will be considerable as discussed below, a better comparison is total revenue collected with the incentive driven investment and with the incentive driven investment. Because

we don't know exactly how much investment will occur as a consequence of these credits (and because without having some certainty about that number, comparing two sets of revenues from two different sets of volumes can become an exercise in wishful thinking, the rest of this answer focuses on the narrow question of the cost to the states PPT collections from the credits

In short, the proposed twenty percent capital credit against production tax would result in total credits of between $5,369.9 and $12,506.0 million depending on whether there are additional major (Alpine like) fields discovered on the ANS and whether or not a gas line is built triggering additional discovery and development (the gas line itself will have no direct effect on the PPT credits). These will amount to between 25.0% and 37.4%, respectively, of total pre credit PPT owed. Transferable credits, presuming that 95% of production is by major three companies but only 75% of credits are generated by them, result in an overall cost to the State of financing these credits of between $1,342.5 and $3,126.5 million.

Background

Permitting transferability of tax credits provides a strong economic incentive for full use of the credits. Credits accruing to companies with insufficient offsetting revenues would be more likely to be used rather than banked or lapsed. This will result in less production tax revenue to the State.

Capital credits as proposed in the Governor's PPT are equal to 20% of capital expenditures (Section 12, AS 43.55.024(a)). They may be used in the year of expenditure, carried forward to following years, or transferred (they are fungible). If transferred, the credit can not lower a producer's production tax liability below 80% of what it would otherwise be (AS 43.55.024(e)). These credits will have market value that would not exceed their face value, and will frequently be less than face value. A company generating them but unable to use them faces a choice – use them in some following year (if they have taxable income), or sell them for a discount. The value to the purchaser is in the size of the discount they get in the purchase.

Each company that conducts exploration or development work within the State will accrue capital credits. However, only those with production tax obligations will be able to deduct a credit. In order to determine production tax obligation, each company will deduct from gross value, operating costs and capital costs. From this net amount each company will have a $73 million allowance that effectively exempt that much taxable value from the PPT. Analysis based on publicly available information indicates that at anything but high prices, only three companies will have significant production tax liabilities remaining following these deductions and exemptions.

During FY06, three oil companies (BP, ConocoPhillips, ExxonMobil) account for 95% of oil production on the ANS. Future production modeling is based on known reserves and these three companies continuing to account for this level of ownership.

The capital credit system is designed to provide incentives to invest in infrastructure and exploration. Taken with the $73 million allowance, it particularly encourages companies which do not already have a major presence in Alaska. To the extent this system is successful, the major three companies will see a decrease in their share of production. However, without modeling ownership percentages, it is not possible to accurately estimate who will be spending what and selling credits to whom. Therefore, we assume in our modeling that all capital credits will be generated generally as they would be now.

In order to estimate the capital credits, it is necessary to estimate total oil and gas development spending in Alaska. This is problematic in that a successful program will incentivize more exploration and development and therefore more spending both on the North Slope and elsewhere in the State.

Capital costs for the ANS are modeled based on the following cost assumptions: $100 million per year in exploration expenditures through either TAPS closure 2030 (without gasline); $1.00 per barrel in ongoing capital costs; and, $3.50 per barrel in capital costs for conventional oil and $8.00 per barrel in capital costs for heavy oil, both taken across 100% of barrels in new fields and 2/3s of barrels in existing fields. There are four scenarios: with and without additional large finds and with and without a gas line. The four capital cost totals are:

	Millions of Dollars	
ANS – Oil	Without Gas Line	With Gas Line
Without Finds	$23,798.6	$32,688.1
With Finds	$51,543.8	$55,462.2

Gas related capital costs in the ANS are accrued only to the scenarios that include a gas line. These total $4,701 million per scenario.

Capital costs for Cook Inlet (and by proxy, the rest of the State other than North Slope) are modeled to be $3.051 billion through 2050. This is based on capital costs of $4.00 per barrel of oil and $0.50 per Mcf of gas as forecast to be produced through 2050 in the Spring RSB.

Taking ANS oil, Cook Inlet (and the remainder of the state), and ANS gas capital expenditures together results in a range of investment until 2050 of between $26,849.4 and $62,530.0 million. The twenty percent credit would amount to between $5,369.9 and $12,506.0 million.

The total production tax owed the State prior to credits is modeled using a constant $40 per barrel ANS west coast price. Depending on the scenario, this results in total production taxes of $21,488.4 to $33,416.6 million. The total credits amount to between 25.0% (no gas line and no finds) to 37.4% (gas line with finds) of the total production tax owed.

Scenario	ANS Explore	ANS Oil Ongoing	ANS Oil Develop	ANS Gas	C.I.	Total Capital Costs	20% Credit	Production Tax	Credit % of Prod. Tax
w/Gas w/o Finds	$3,500.0	$7,096.5	$22,091.7	$4,017.0	$3,050.8	$39,755.9	$7,951.2	$22,007.6	36.1%
w/Gas w/Finds	$3,500.0	$10,468.1	$41,494.1	$4,017.0	$3,050.8	$62,530.0	$12,506.0	$33,416.6	37.4%
w/o Gas w/o Finds	$2,000.0	$5,543.5	$16,255.1		$3,050.8	$26,849.4	$5,369.9	$21,488.4	25.0%
w/o Gas w/Finds	$3,500.0	$9,674.0	$38,369.9		$3,050.8	$54,594.6	$10,919.0	$32,388.1	33.7%

Sensitivity analysis was run with 95% production by major three companies and both 95% and 75% of credits owned by majors. In both cases all credits were usable. The largest State exposure to transferability of credits is when there is this wide distribution, i.e. when 95% of the production comes from the three majors. In that case, between $1,342.5 and $3,126.5 million in credits are transferred, depending on scenario.

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 and 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. It is difficult to 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 13, line 8— why is this clause constrained by Dec. 1, 2005?

This constraint is intended to avoid industry changing cost allocations in contemplation of this legislation, in order to avoid taxation.

55. Section 21, provision (h), which US CPI [Consumer Price Index] 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 for corporate income tax purposes.

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

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). However, note that if value exceeds $50,000, then tax is imposed on the entire amount.

b. Mining License Tax is not imposed when net income is less than $40,000 in a fiscal year. AS 43.65.010(c). However, note that if net income exceeds $40,000, then tax is imposed on the entire amount.

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 net profit share payments *(in addition to royalties and production taxes in cases of a positive ELF)*. 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 a table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease.

Also see Question 31.

59. What are the depreciable lives for Oil & Gas 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	(10)
Tentative net profit Before standard allowance	$35M
Less: standard allowance*	(35)
Net Taxable income	$ 0
Tax	$ 0
Capital investment credit available for carryforward (20% of $10M)	$2M

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

61. Are net profit lease payments included as a direct cost under AS 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 (AS 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 (AS 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 (AS 43.55.160(c)). Such costs are also eligible for credits under Section 12 (AS 43.55.024) by reference to definition of "qualified capital expenditure" at AS 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 from a tax on gross value to a tax on net values, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21 (AS 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 royalty share of production is subject to tax.

65. Under Section 21 (AS 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. As provided 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.'"

There are specific reasons why each of the enumerated categories of costs is set out in AS 43.55.160(d)(1). "Outlays for capital assets" is set out to avoid any doubt that the bill intends to deviate from the usual principle that capital expenditures are recovered over time through depreciation allowances. Instead, under the bill, the entire outlay for an allowable capital expenditure is potentially deductible when incurred. (Correspondingly, AS 43.55.160(d)(2)(A) makes clear that "depreciation or amortization of capital assets" is *not* deductible.)

"Payments in lieu of property taxes" is set out to clarify that when a producer makes payments that are the equivalent of property taxes; those payments are deductible just as property taxes themselves are deductible.

"A reasonable allowance . . . for overhead expenses . . . " is set out to implement a policy decision that a certain amount of overhead expenses should be deductible even though "overhead" is often not considered a "direct" cost.

Just as the enumeration in AS 43.55.160(d)(1) is not intended to be an exhaustive list of direct costs for purposes of AS 43.55.160(c), neither is the enumeration in AS 43.55.160(d)(2) intended to be an exhaustive list of costs that are *not* direct costs for purposes of AS 43.55.160(c). Some of the items listed in AS 43.55.160(d)(2) are set out to implement policy decisions that certain types of costs should not be deductible whether or not they might ordinarily be considered "direct" costs; other items are set out simply for clarity, or to avoid any potential disputes over deductibility of categories that past experience indicates may be prone to controversy.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO_2 re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

At Prudhoe Bay about 8.5 billion cubic feet of gas a day is reinjected into the field for pressure maintenance. After stripping out certain hydrocarbon liquids, CO_2 is reinjected along with the other hydrocarbons (and non-hydrocarbons). When an export line is built on the North Slope, the CO_2 will be stripped (in "gas treatment"), and there is some question about what will happen with that CO_2, whether it will be treated as waste, or whether it will be treated as a by-product.

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

Assume 20 new companies suddenly showed up on the North Slope and each qualified for the $73 million dollar allowance. A total of $1.4 billion in oil and gas value would be sheltered from taxes. If these companies had simply purchased their way in, then taxes would be lower by $280 million (20% of 1.4 billion) than they would be otherwise. At current prices, or say even at $40 oil, this could be a material portion (though not all) of the tax.

If that is the future of the North Slope and the sell off was for business purposes, the legislature may choose to act and make it less attractive to new firms coming in. If these were tax motivated sales, we hope the powers of the commissioner that are built into the bill would prevent the new entrants from using the $73 million allowance

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?

a. The first part of this question appears to be intended to be answered by oil companies.

b. We should offer a transition deduction because we are converting from a tax on gross, to a tax on net value. When measuring net value, it is necessary to allow deductions, not only for current expenses, but also a deduction for the capital investment that is generating the value. For new assets acquired after the PPT is in effect, a full deduction for the cost the capital investment is allowed in the year acquired. Assets acquired within the last five years are currently producing taxable oil and gas, and a deduction should be allowed for, in effect, depreciation on those assets.

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

The following tables are a competitiveness index overview for a number of alternative fiscal options. The methodology of determining the competitiveness index has been described earlier in my February 14, 2006 report.

Four fiscal options were evaluated:

- 20% tax rate 20% tax credit rate
- 25% tax rate 20% tax credit rate
- 30% tax rate 20% tax credit rate
- 30% tax rate 15% tax credit rate

Furthermore these four scenarios were evaluated under two corporate alternatives:

- Investment is a re-investment by a large producer which has already used its corporate tax free allowance
- Investment is a first investment with full use of the $ 73 million tax free allowance

Large Producer Economics

The tax rate is an important economic factor for the large producers.

This can be studied in the following three tables. These tables display the competitiveness at a WTI price of $ 26 per barrel and at $ 36 per barrel. The two indexes are then added up to provide the total index.

$26	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	196	193	192	191
Alaska PPT	154	158	162	177
Norway	182	181	180	175
UK	68	68	68	68
US GOM	27	27	27	26
Nigeria	80	80	80	80
Alberta-Oil Sands	80	80	80	80
Angola	151	151	150	146
Russia-Sakhalin	214	214	214	212
Azerbaijan	168	168	167	165

$36	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	161	158	157	156
Alaska PPT	147	153	160	166
Norway	214	214	214	213
UK	63	63	63	63
US GOM	25	25	25	25
Nigeria	92	92	90	89
Alberta-Oil Sands	74	74	74	73
Angola	160	158	157	156
Russia-Sakhalin	226	226	224	224
Azerbaijan	158	157	156	155

TOTAL	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	357	351	349	347
Alaska PPT	301	311	322	343
Norway	396	395	394	388
UK	131	131	131	131
US GOM	52	52	52	51
Nigeria	172	172	170	169
Alberta-Oil Sands	154	154	154	153
Angola	311	309	307	302
Russia-Sakhalin	440	440	438	436
Azerbaijan	326	325	323	320

The $ 26 per barrel table shows how the PPT is more attractive than the Alaska current system under any combination. This is due to the fact that the current system is very front end loaded and regressive.

Therefore at low prices the current Alaska fiscal system is rather unattractive in a world wide comparison. This is the reason for the low level of activity on the North Slope during the last two decades. It is also the reason why the PPT will provide significant encouragement for investment for companies with conservative long term price forecasts.

Many large and major companies, however, are now moving to a long term price forecast in the range of $ 30 - $ 40 per barrel. This makes the $ 36 per barrel rating an important rating.

At $ 36 per barrel the PPT is clearly more attractive than the current system under the 20-20 scenario.

Under the 25-20 scenario the PPT is only marginally better than the current system. This is consistent with the opinions expressed by Anadarko and the major oil companies that a 25-20 system would not lead to more investment. However, it is

also my opinion that 25-20 will not result in a significant drop in investment by large producers. I believe that the level of investment by large producers will stay about the same.

The 30-20 system is marginally less attractive than the current system and could therefore result in a drop in investment in my view.

The 30-15 system would be more unattractive and would under a $ 36 per barrel price forecast result in a considerably less attractive system with very likely a substantial drop in investment. It is for this reason that I did not recommend a 30% tax rate.

The Total Rating reflects the combination of the $ 26 and $ 36 per barrel ratings.

New Investor Economics

The following three tables show the same ratings but now for first investors which can fully benefit from the $ 73 million allowance.

$26	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	198	199	196	197
Alaska PPT	130	124	126	135
Norway	185	188	189	186
UK	70	72	72	71
US GOM	27	27	27	27
Nigeria	82	83	83	82
Alberta-Oil Sands	84	84	85	84
Angola	157	156	156	153
Russia-Sakhalin	217	217	217	216
Azerbaijan	170	170	169	169

$36	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	165	164	163	162
Alaska PPT	119	120	121	130
Norway	214	214	214	214
UK	67	67	67	66
US GOM	26	27	29	27
Nigeria	96	96	93	91
Alberta-Oil Sands	79	79	79	78
Angola	167	166	164	162
Russia-Sakhalin	228	228	228	228
Azerbaijan	159	159	159	159

TOTAL	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	363	363	359	359
Alaska PPT	249	244	247	265
Norway	399	402	403	400
UK	137	139	139	137
US GOM	53	54	56	54
Nigeria	178	179	176	173
Alberta-Oil Sands	163	163	164	162
Angola	324	322	320	315
Russia-Sakhalin	445	445	445	444
Azerbaijan	329	329	328	328

The three tables show that both for the $ 26 and $ 36 price levels the PPT for any tax rate and credit rate combination is significantly more attractive than the current system. The $ 73 million tax free allowance is therefore very important in order to encourage new investment.

It can be seen how the rating "wobbles" from 249 at 20-20 to 244 at 25-20 and 247 at 30-20. This is due to the fact that for new investors a higher tax rate is actually more attractive for the 50 million barrel field since they receive a higher tax credit for the loss carry forward, but do not have to pay the tax. For the 500 million barrel case, a higher tax rate is less attractive. These two effects offset each other in the rating.

It can also be seen how the tax credit of 20% is far more attractive to new investors than the 15% tax credit.

Overview

The expected level of investment as a result of the four fiscal options can therefore be summarized as follows:

	20-20	25-20	30-20	30-15
Large Producers	More	Same	Less	Much less
New Investors	More	More	More	More

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

d. 15/20
e. 25/25
f. 15/25
g. 22.5/22.5
h. A summary chart showing all above scenarios at $40
i. A chart showing the effect of a incremental change of 1% in tax rate and credit.
j. A summary table showing the effective tax rate for all scenarios.

Please see attachment section, indexed by question number.

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
d. 15/20
e. 25/25
f. 15/25
g. 22.5/22.5

Please see attachment section, indexed by question number.

72. Please show the price point where DOR estimates corporate profit margins hit:

a. 15%
b. 20%.

Please see attachment section, indexed by question number.

73. Will the new confidentiality provisions extend to or have an effect on any other taxes besides the production tax?

The general confidentiality requirements for all taxes are contained in AS 43.05.230. The new confidentiality language added by Secs. 4 and 16 of the bill applies only to information relating to the oil and gas production tax, not other taxes. This is because:

(1) AS 43.55.040(1) addresses information "necessary to compute the amount of the tax," and the phrase "the tax" is used throughout AS 43.55 as referring only to the production tax; and

(2) AS 43.55.040(1) deals only with information obtained from persons "engaged in production," or their agents, and with purchasers "of oil or gas," and with owners of a "royalty interest in oil or gas."

74. Model the Cook Inlet gas producers (presumably including their CI oil production, but do not include NS production from Chevron, Forest, Phillips or Exxon): Are their taxes going up or going down in the future.

Assuming that all provisions of the proposed PPT are in place (that is, the $73M deduction and the credits), and assuming that gas prices rise gradually to Henry Hub levels ($7-$9/Mcf), and that companies in the future maintain current levels and market shares of production in Cook Inlet, most likely Marathon, Chevron/Unocal, and ConocoPhillips will see their severance tax liability increased, based on their Cook Inlet production alone. If however, gas prices stay low ($3/Mcf), these companies will not see an increase in their severance tax burdens under the PPT, and in fact, will probably pay less under the PPT system than under the ELF tax system.

75. Same as Question 74, except apply retroactively, with and without $73M allowance

We applied the PPT retroactively to Cook Inlet oil and gas production in fiscal years 03, 04, and 05. During those years, the prices received for natural gas were extremely low, with average wellhead prices of less than $3 per Mcf. We believe that producers will gradually see increased prices for Cook Inlet gas over time, and for that reason, this analysis is of limited use.

Under the current tax system, severance tax collections for the three fiscal years used in this analysis were as follows: FY03--$23M; FY04--$24.7; FY05--$24.4.

Without the $73M allowance, and based on Cook Inlet production alone, Chevron/Unocal, Marathon, and ConocoPhillips would have seen moderate increases in their severance tax liability under the PPT in FY03-05. Aurora, and Municipal Light and Power (assuming they pay taxes), would have owed about the same amount as under the current severance tax system.

With the $73M allowance, and with all credits of the PPT in place, none of the companies would have had to pay severance tax under the PPT in FY03-05, based on their Cook Inlet production alone. Many companies paid some tax in FY03-05 under the current system, and this would represent a reduction for them.

76. Model a newcomer to the Cook Inlet that explores for, finds, develops and sells gas. What will their taxes look like under the status quo and the PPT?

It is impossible to answer this question with any accuracy because of the numerous assumptions one would have to make. Generally, a newcomer to Cook Inlet would spend at least a couple of years exploring for gas, and during this time, would presumably not produce any gas and in fact may not realize any income from these operations. So for the years of exploring, the newcomer would not pay any tax under either the status quo or the PPT system.

Under the PPT system, the newcomer would have earned capital credits in the first couple of years that they can either hold or sell, as well any loss carryforwards they may have accrued. Most investors would probably choose to monetize the credits or losses immediately, as this would increase the net present value of their investment. Under the current system, the newcomer would have no such opportunity and would not be able to take any credits until production begins (assuming the newcomer would be eligible for the credit under AS 43.20.043). This credit is currently available for 10% of exploration costs.

After all credits have been used or monetized, the PPT system continues to allow a $75 million standard allowance per year. Therefore, the newcomer would not have to pay tax under the PPT if his net income was less than $73 million. The current system may require the payment of severance tax, depending on the productivity of the wells and the price paid for natural gas, without regard to the newcomer's income. Once production has reached a fairly high level, and if gas prices were high, there is a chance that the PPT system would create higher severance tax liabilities for the newcomer than the current system.

77. How much gas was flared so as to trigger taxes and/or penalties in recent years?

During FY 2005, 351,000 Mcf of gas was flared that was considered gross taxable production. Of that, only 120,000 Mcf was from fields with a positive ELF and subject to tax. During the same period 31,000 Mcf was flared and considered waste and subject to both tax and penalty.

78. Could we look at (1) a standing offer to purchase tax credits for 10% of their face value – with the implication that the department could treat that as a receipts funded program so that the legislature would not have to authorize the purchase amount and (2) "Alaska bucks" – ie allow credit certificates to be used in lease sales or other lease acquisition activities as cash – or even at 110% of face value.

We assume this means a 10% discount from face value, or 90% of which is where the one set of credits traded. As this market is created by the state, and is driven by state restrictions, it is not out of line for the state to become a price maker in the market as well. It is the legislators' call to make tax receipts program. Among the considerations the legislature might bring to this is how much of tax receipts they wish to make program receipts, and are they willing to buy back $100 million plus, in

credits if a major investment (say at Pt. Thomson) were followed by a radical price correction lasting over a year.
Again – this is a policy call about how far the state wants the effects of the investment credits to run; we believe the governor has made a balanced set of calls. Do we want them to both lower and distort our bidding lease sale markets? Does the state really want to have to readit what the money it hands out in credits is spent? Do we want to create advantages to for investors who have a history here of at least a year of investment and loss over folks considering entering the market? Before the Department undertakes further modeling on these matters it would help to get clearer insight into the outcome hoped for by the legislature.

79. Could we draft up alternative standards for the anti-hiving provision so the legislature can choose.

A possible alternative might be along these lines:

"The department will disallow an allowance deduction if it finds that a benefit attributable to a producer's allowance is shared with or enjoyed by another producer."

This concept might be more effective if it were adopted as a supplement to, rather than a substitute for, the current language in proposed AS 43.55.160(j). For example, the new language could be added to proposed AS 43.55.160(i), as follows:

(i) For a month for which the net value of the taxable oil and gas produced during the month calculated under (a) of this section exceeds zero, a producer that is qualified under (j) of this section may reduce the net value by deducting an allowance in an amount calculated such that (1) the net value for the month is not reduced below zero; and (2) the total of the allowances deducted for all months during the calendar year does not exceed $73,000,000. However, the department will disallow an allowance deduction if it finds that a benefit attributable to a producer's allowance is shared with or enjoyed by another producer. An unused allowance or portion of an allowance under this subsection may not be carried forward to a later calendar year or used to establish a carried-forward annual loss under AS 43.55.024(b).

80. When the 1989 ELF change was enacted, was it retroactive and were there transition provisions?

The 1989 ELF changes were made retroactive to January1, 1989, and applied to oil produced after December 31, 1988. There was a transition provision to the effect that tax payable as a result of the retroactive changes would be due on the 20th day of the calendar month following the effective date of the Act. (The effective date of the Act was August 6, 1989.)

81. Please provide the 20/20 modelling.

The PPT model is very large and complicated (nearly 5.5 megabytes over . worksheets). Its complexity is exacerbated by the inclusion of the gasline model and the proposed negotiated gasline fiscal terms. It also includes confidential producer data.

Moreover, it is our experience that when models become this large and this complicated, it is practically impossible for an outsider to use the model because of all the interdependencies. Nevertheless, we are absolutely dedicated to the goal where legislators are comfortable with the mechanics of the tax and the model and its results. Accordingly, we are willing to work with any legislator to that end.

82. Under the new gas and oil definitions what will the net change to the spill fee be? In other words, looking at FY 2005, how much, if any (a) oil did we tax for its use in production operations and (b) how many ngls were put in TAPs?

During FY 2005 tax was collected on 1,222,400 barrels of crude oil used in production operations. During FY 2005 16,445,000 barrels of NGLs were put in TAPS.

83. Please model the smaller interests and their sale of credits and estimate the price at which those credits will no longer have a market among the big three.

See Question 49.

84. If aggregation at Prudhoe Bay had been implemented on July 1, 2001 [the start of the claw back period], how much more would the State have received between then and the actual aggregation date?

The State would have received $430 milllion additional revenue. See estimates below:

ANS Oil Severance Tax
With and without aggregation of
PBU
FY2001 thru Jan 2005 Production
(millions)

FY	No Agg	With Agg	Delta
2001	667	713	46
2002	444	501	56
2003	550	644	95

2004	595	721	126
2005	466	573	107
	2,722	3,152	430

Note: Estimate with Aggregation assumes all taxpayers are paying under the aggregated Elf

85. Why are the status quo lines in the three graphs presented by Ms. Wilson flat once the forecast price effect is adjusted for? Wouldn't falling production and ELF move those down?

The status quo drops from $378 mm in 2009 to $291 mm in 2012. It looks flat because of the scale on the graph.

86. What will the actual cost to the investor be for these upstream investments, and what is the total government underwriting, state and federal, all tax types included. Is it different for large companies and small companies?

After state and federal tax the investor would bear about 38% of the marginal capital. There is no reason to think it would differ appreciably between large and small investors.

87. Lord Browne famously said two years ago that any profits over $20 a barrel were being returned to shareholders as they weren't needed in BP's business. What tax rate, credit rate would be needed to have a cross over [unspecified period] at $20 [presumably Brent].

With a 20% credit it would take a tax rate of about 36% to effect a crossover at $20 Brent, based on our low-volume scenario. With a high-volume scenario, the tax rate would be about 51%. These calculations were made using our standard assumptions, as outlined in the fiscal note.

88. Please explain how the conservation surcharge is affected by oil price and what effect this bill has on the surcharge.

a. The conservation surcharge is a 3 cent per barrel charge on all oil produced less royalty barrels, so therefore it is not sensitive to price.

b. There will be changes in the quantity of oil subject to both production tax and conservation surcharges under the bill. One change will be positive, one negative. The positive change is that natural gas liquids extracted by gas processing and blended in the TAPS stream that are now taxed as gas, will be treated as oil under the bill. The negative change is that oil that is used in lease operations will not be taxed

or subject to surcharge under the bill. Oil may be used to make fuel for lease operations and perhaps used for other production purposes. The overall result is an expected increase of the total surcharge amount of $444,000 per year, based on FY 2005 amounts. (See Question 82.)

The bill should not affect the assessment or collection of the surcharge, other than the quantity-of-oil effects described above. Any surcharge paid will be allowed to be credited against production taxes, but that would only reduce the amount of tax collected, not the amount of surcharges collected.

89. Why are we including gas in the PPT calculation?

The bill includes gas in the PPT calculations because it is a stand-alone bill. The bill does not require implicitly or explicitly that a Stranded Gas Contract be subsequently concluded. Therefore, a PPT law would be entirely functional in case a Stranded Gas Contract is not presented to the Legislature or in case the Legislature rejects such a Contract.

The ELF system for gas is "broken". Just as the ELF is "broken" for oil, the gas ELF does not encourage reinvestment and it is not sensitive to price.

It should be noted that under high gas prices the Alaska State take for gas would increase significantly relative to the status quo. This would be beneficial in case significant gas reserves would be developed outside the scope of the Stranded Gas Development Act.

90. Please show the cumulative production tax from 2007—2030 under the PPT given the following tax/credit scenarios:

a. 25/20
b. 30/20
c. 30/15
d. 15/20
e. 25/25
f. 15/25
g. 22.5/22.5
h. A summary chart showing all above scenarios
i. A summary table showing all above scenarios

Please see attachment section, indexed by question number.

91. What is the meaning of the term "progressive tax"?

According to *Black's Law Dictionary* (2004), a progressive tax is

> "A tax structured so that the effective tax rate increases more than proportionately as the tax *base* increases..."

This is consistent with taxation and economics literature.[2] In other words, a progressive tax is any tax in which the rate increases as the amount subject to taxation increases. If a tax is levied on "net income", then a progressive tax scheme will increase the tax rate based on increasing levels of net income. If a tax is levied on "gross income", then a progressive tax scheme will increase the tax rate based on increasing levels of gross income.

92. What is the meaning of the term "proportional tax"?

According to Black's Law Dictionary, a proportional tax is:

> "A tax whose rate remains fixed regardless of the amount of the tax base."

Black's equates a "proportional tax" with the term "flat tax." Thus, a proportional tax is neutral since the relative share does not change with amount.

93. What is the meaning of the term "marginal tax rate"?

According to WG&L Tax Dictionary (2004), a marginal tax rate is:

> "The rate of tax applied to the last dollar of the tax base."

Therefore, if a tax is based on net income, a marginal tax rate is measured based on the last dollar of net income. This is most often found in income tax law such as AS 43.20.011 where the top marginal rate is 9.4% and this tax rate is applied to amounts of Alaska corporate taxable income over $90,000.

94. What is the meaning of the term "effective tax rate"?

In general, whenever there are several factors at play this measure cuts through all their effects, and typically divides the tax paid by some measure.

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[2] See WG&L Tax Dictionary written by Richard A. Westin (2004), and Principles of Microeconomics written by Karl E. Case and Ray C. Fair (1989).

For an income tax, the effective tax rate is normally expressed as the actual income tax paid divided by taxable income, expressed as a percentage. For example:

Gross income	$100
Less: deductions	(90)
Net income	$ 10
Tax at 20%	$ 2
Less: credits	(1)
Tax due	$ 1

In this example, the effective tax rate is 10%, which compares the $1 tax due with the taxable income of $10.

In Question 30, the effective production tax rate was the percentage of gross revenue, without taking into account exploration credits.

95. Please differentiate the definition of "exploration," "development," and "production."

Please note that in general, the bill provides the same tax treatment to oil and gas exploration, development, and production. In other words, it generally makes no difference whether an expenditure is for exploration, or for development, or for production, and it was therefore not felt necessary to define the terms in the bill. (An exception to the rule is that *geophysical or geological* exploration can qualify for capital expenditure credits under proposed AS 43.55.024(a) and (h)(2) even though those expenditures are not ordinarily capitalized.)

The terms exploration, development, and production are addressed inFASB (Financial Accounting Standards Board) Current Text Section Oi5, Oil and Gas Producing Activities (as of January 1, 2000), as set out below. The Department has not, however, had an opportunity to evaluate these definitions as to their suitability for purposes of production tax legislation, in the event that the legislature desired to incorporate definitions for those terms in the bill.

a. Exploration involves identifying areas that may warrant examination and examining specific areas that are considered to have prospects of containing oil and gas reserves. Exploration costs include drilling exploratory wells and exploratory-type stratigraphic test wells. Principal types of exploration costs include costs of topographical, geological, and geophysical studies.

b. Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. These costs include such things as expenditures to gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific

development drilling sites, clearing ground, road building, power lines, drilling and equipping development well; platforms; casing; tubing; pumping equipment; and the wellhead assembly.

c. Production involves lifting the oil and gas to the surface, gathering and field storage. Production costs are those costs incurred to operate and maintain wells and related equipment and facilities, such as labor to operate the wells, repairs and maintenance, and materials, supplies, and fuel consumed to operate wells.

I hope that this information is helpful. Please let us know if you would like any additional information. Thank you for the opportunity to be of assistance.

Sincerely,

Robynn J. Wilson
Director, Tax Division
Department of Revenue

Letter to Senator Wagoner and Representatives Samuels and Ramras
March 13, 2006

Topical Index to Questions

Question 30—Table A

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%	0.87%	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.

Question 30—Table B

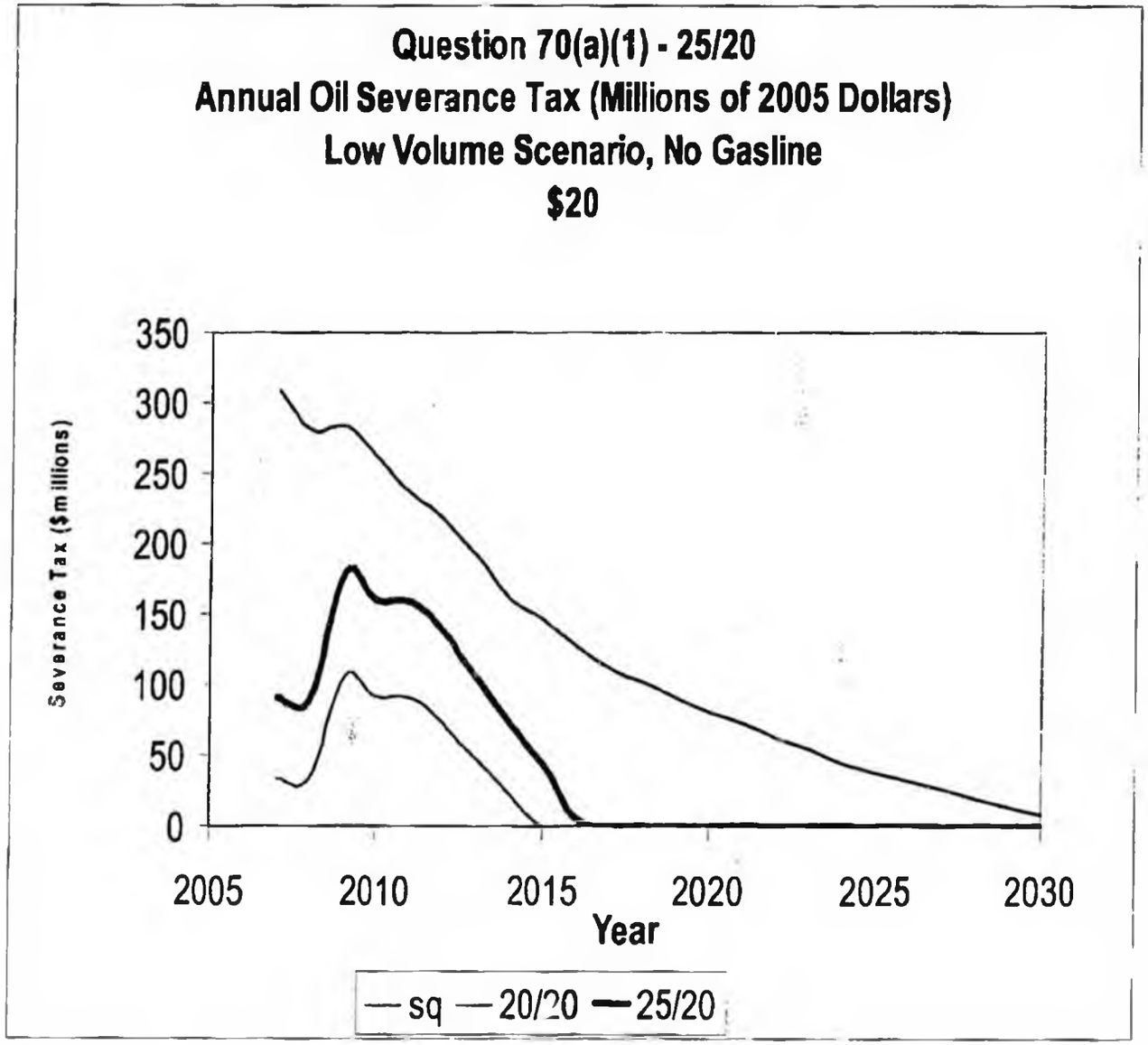
	[redacted]	[redacted]	[redacted]	Lisburne	Point McIntyre	Niakuk	West Beach	NPBS	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	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%

Question 58

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

NPS LEASES, NPS RATES & ROYALTY RATES & STATUS

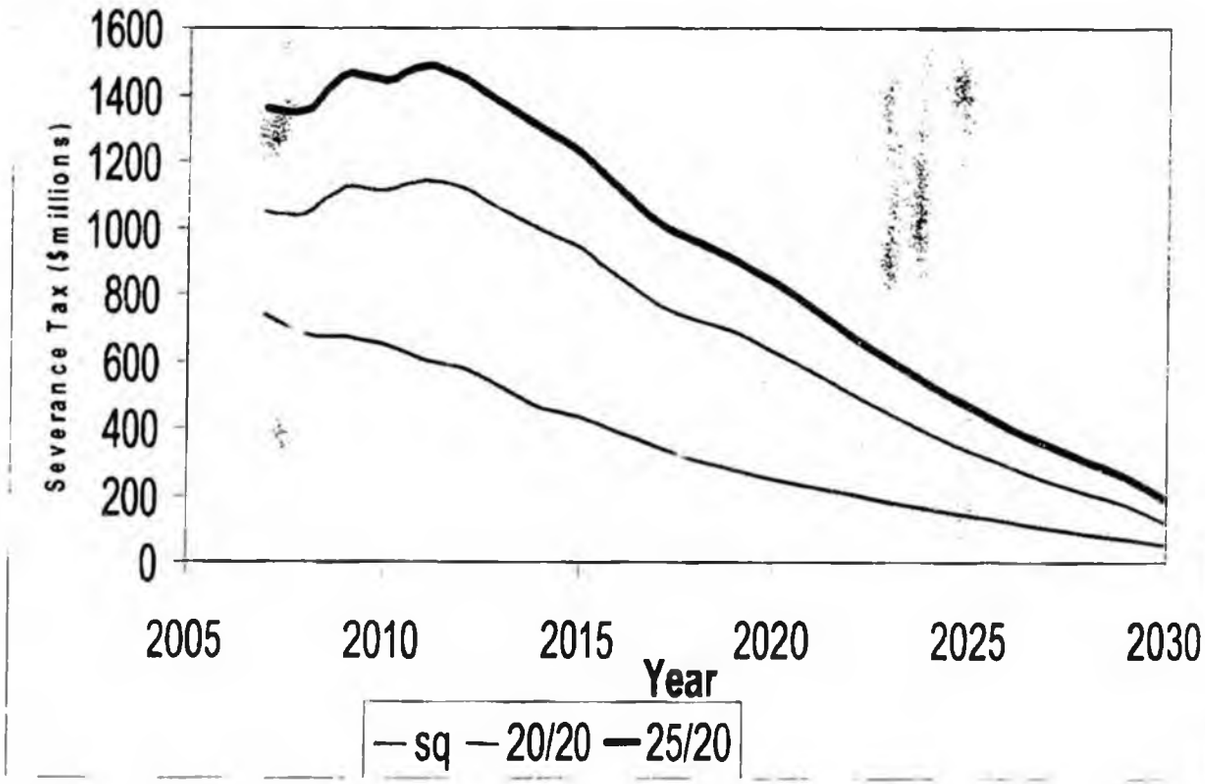
	Unit - lease number	Royalty Rate	NPS Rate	NPS Status
	Duck Island			
1	312828	20%	79.5935%	in payout
2	312834	20%	48.8703%	payout
	Milne Point			
3	355016	12.5%	40.0000%	in payout
4	355017	12.5%	40.0000%	in payout
5	355018	12.5%	30.0000%	in payout
6	355021	12.5%	30.0000%	in payout
7	388235	12.5%	30.0000%	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



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/20
2007	309	34	90
2008	280	34	89
2009	283	106	179
2010	262	91	160
2011	235	90	159
2012	216	73	137
2013	190	47	104
2014	159	22	72
2015	146	0	44
2016	126	0	6
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	1,041

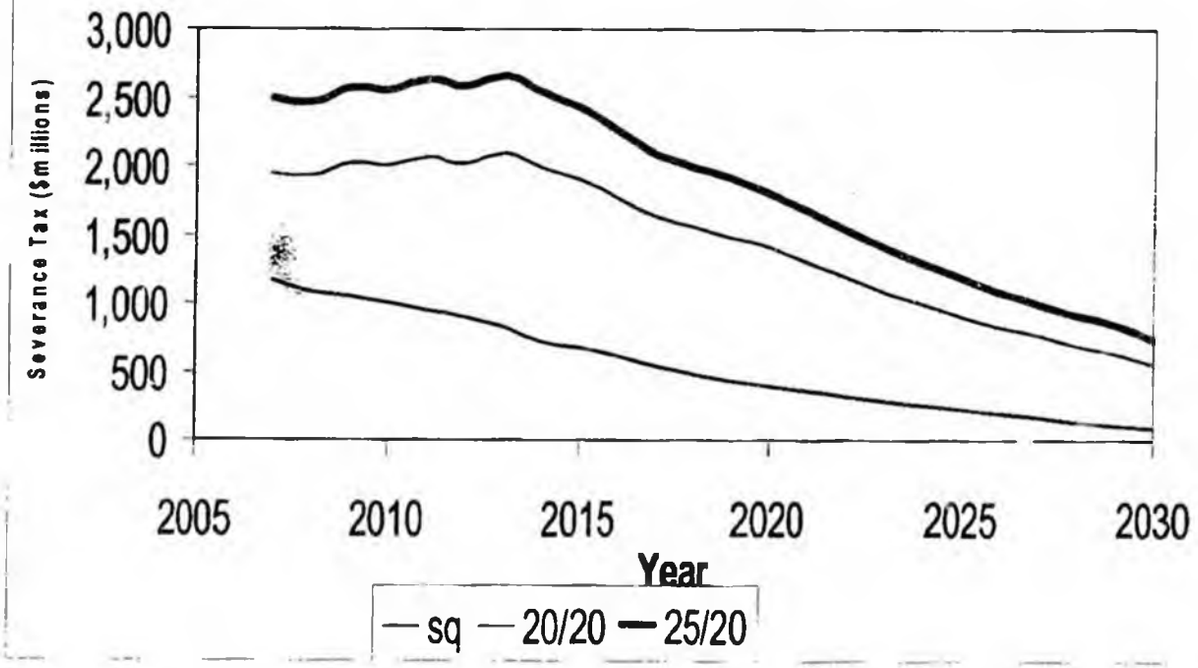
Question 70(a)(2) - 25/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/20
2007	737	1,045	1,361
2008	679	1,038	1,352
2009	673	1,124	1,459
2010	646	1,112	1,444
2011	606	1,143	1,483
2012	576	1,117	1,450
2013	523	1,056	1,373
2014	459	992	1,293
2015	431	937	1,224
2016	388	853	1,119
2017	340	770	1,014
2018	306	726	958
2019	275	683	904
2020	248	629	837
2021	224	566	756
2022	201	499	673
2023	180	439	597
2024	156	384	528
2025	138	332	462
2026	119	284	402
2027	103	243	349
2028	83	204	301
2029	67	169	256
2030	52	113	186
Totals	8,211	16,458	21,782

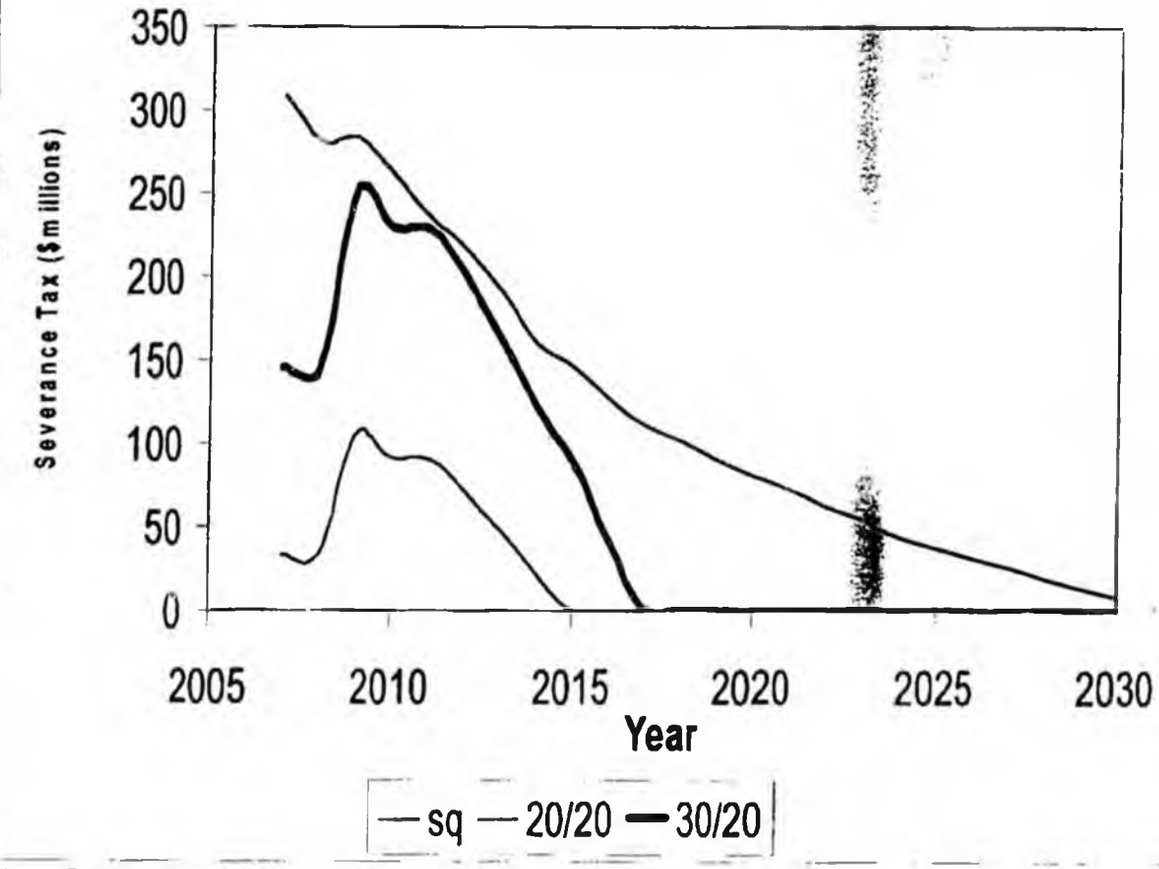
Question 70(a)(3) - 25/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/20
2007	1,165	1,945	2,486
2008	1,069	1,924	2,459
2009	1,042	2,013	2,570
2010	1,003	1,998	2,551
2011	941	2,056	2,624
2012	896	2,019	2,578
2013	815	2,088	2,664
2014	716	1,987	2,537
2015	674	1,898	2,425
2016	607	1,761	2,254
2017	533	1,625	2,082
2018	480	1,552	1,991
2019	432	1,483	1,905
2020	390	1,396	1,795
2021	353	1,292	1,664
2022	318	1,181	1,526
2023	286	1,081	1,400
2024	248	990	1,285
2025	219	903	1,176
2026	191	824	1,077
2027	165	755	990
2028	134	691	910
2029	108	632	836
2030	85	555	739
Totals	12,870	34,649	44,521

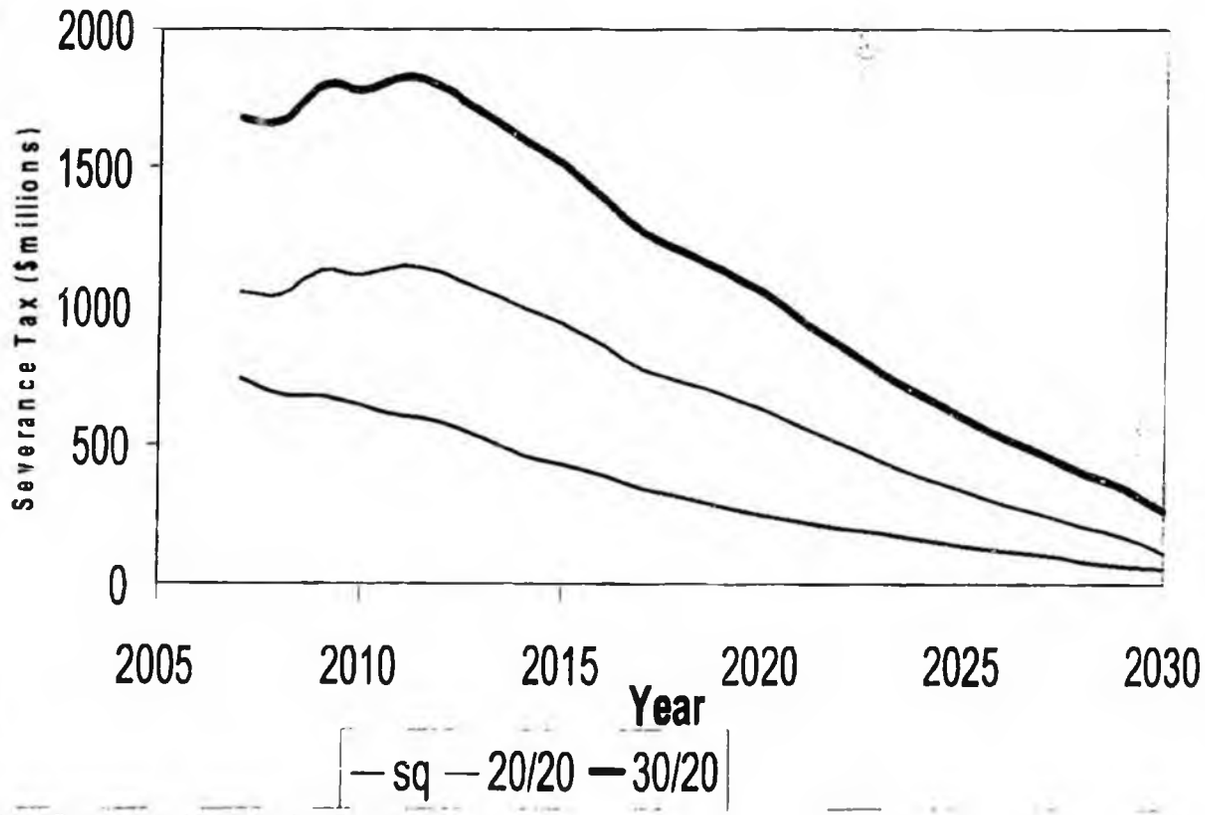
Question 70(b)(1) - 30/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/20
2007	309	34	146
2008	280	34	144
2009	283	106	252
2010	262	91	229
2011	235	90	228
2012	216	73	201
2013	190	47	161
2014	159	22	122
2015	146	0	89
2016	126	0	42
2017	111	0	1
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	1,614

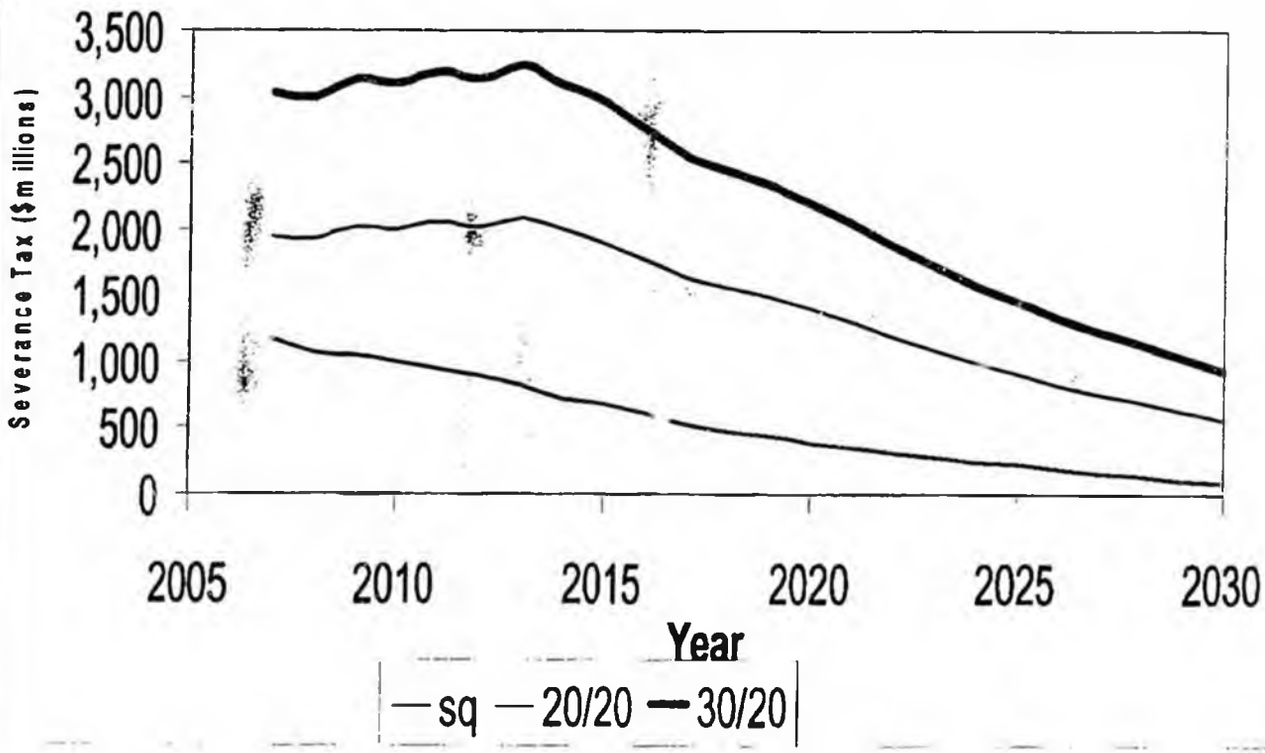
Question 70(b)(2) - 30/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/20
2007	737	1,045	1,677
2008	679	1,038	1,665
2009	673	1,124	1,794
2010	646	1,112	1,776
2011	606	1,143	1,823
2012	576	1,117	1,784
2013	523	1,056	1,691
2014	459	992	1,595
2015	431	937	1,511
2016	388	853	1,384
2017	340	770	1,258
2018	306	726	1,191
2019	275	683	1,125
2020	248	629	1,044
2021	224	566	947
2022	201	499	846
2023	180	439	755
2024	156	384	671
2025	138	332	592
2026	119	284	520
2027	103	243	456
2028	83	204	398
2029	67	169	344
2030	52	113	260
Totals	8,211	16,458	27,107

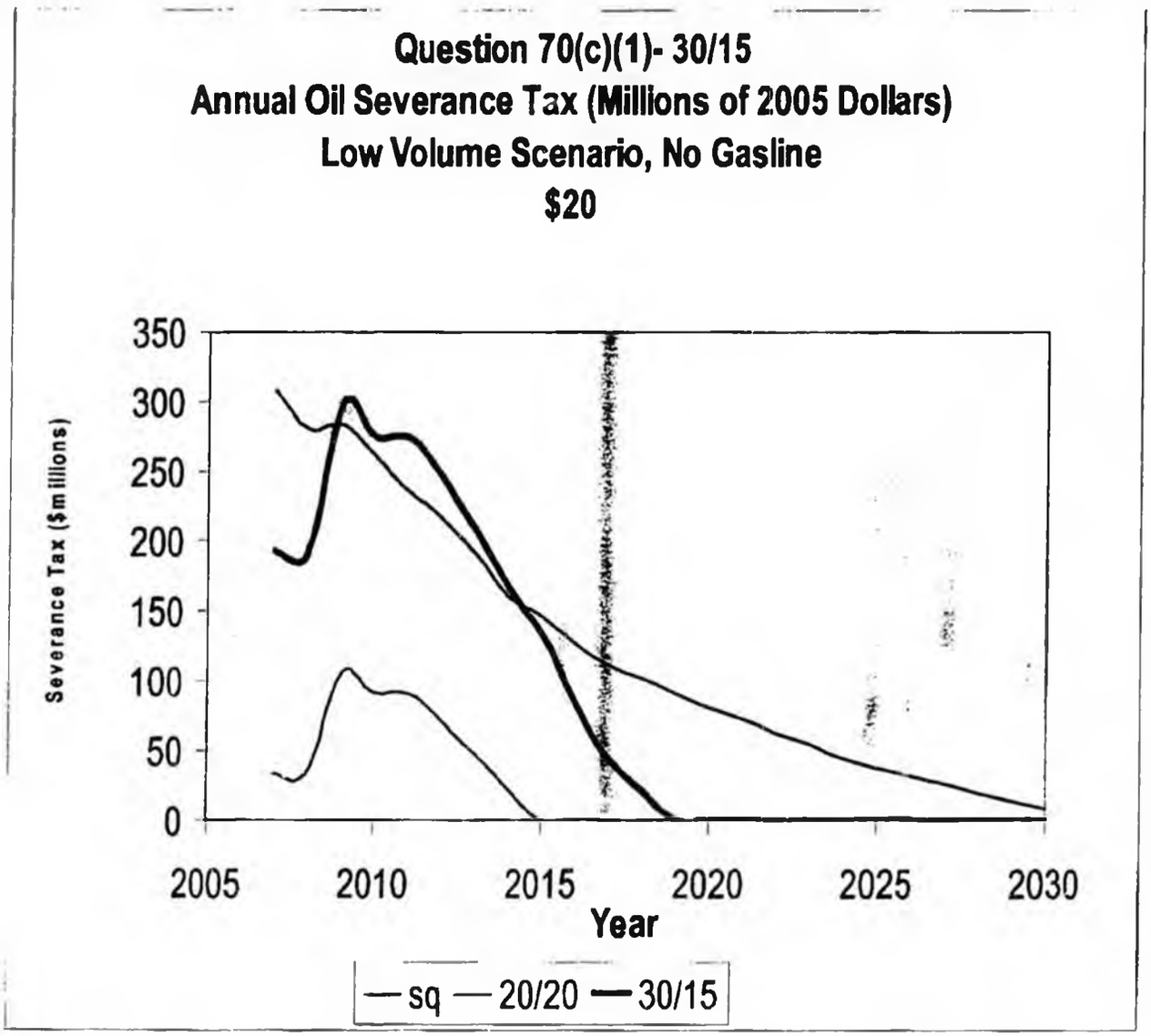
Question 70(b)(3) - 30/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

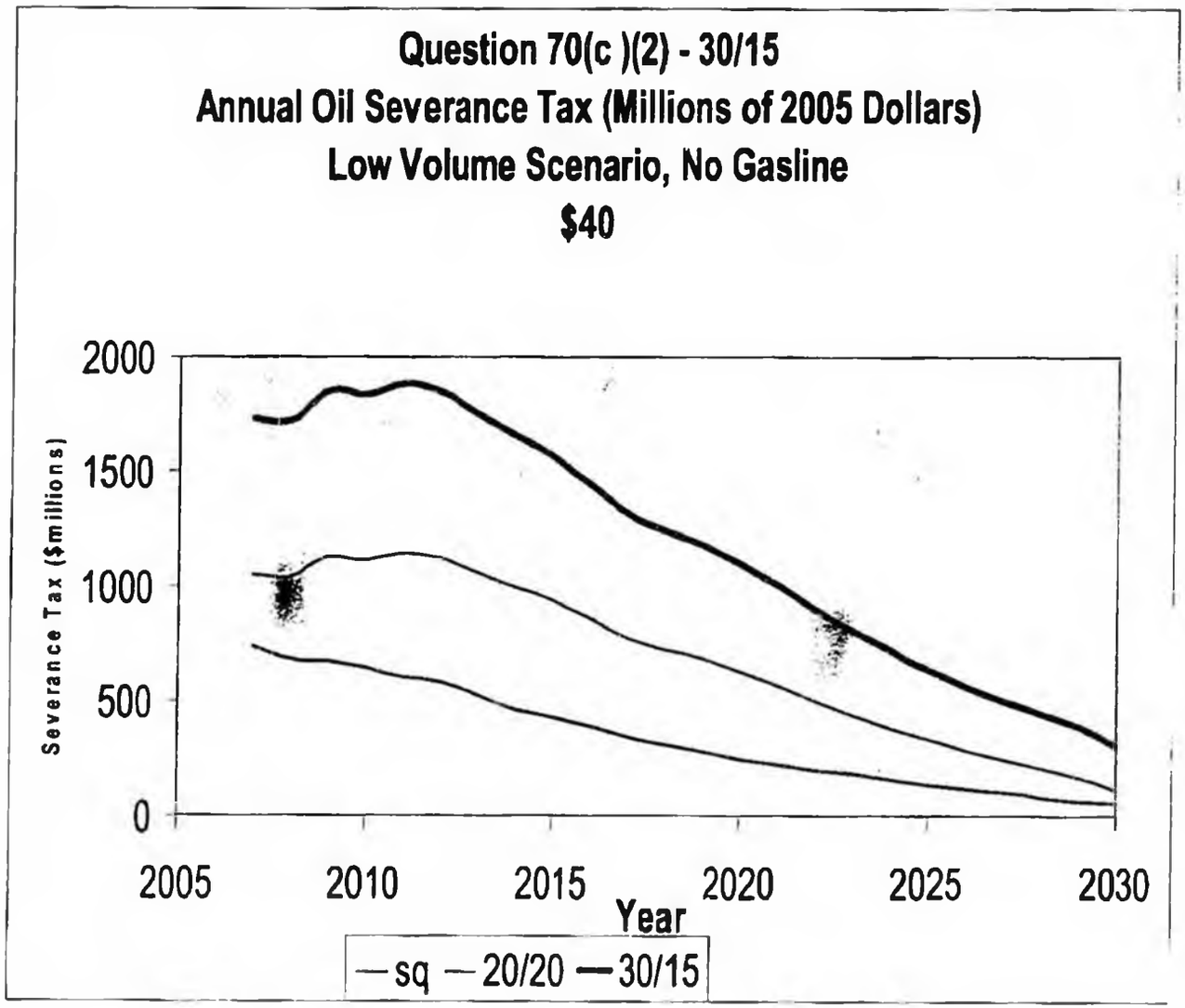
Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/20
2007	1,165	1,945	3,026
2008	1,069	1,924	2,994
2009	1,042	2,013	3,127
2010	1,003	1,998	3,104
2011	941	2,056	3,193
2012	896	2,019	3,136
2013	815	2,088	3,240
2014	716	1,987	3,087
2015	674	1,898	2,952
2016	607	1,761	2,746
2017	533	1,625	2,539
2018	480	1,552	2,430
2019	432	1,483	2,326
2020	390	1,396	2,194
2021	353	1,292	2,037
2022	318	1,181	1,870
2023	286	1,081	1,719
2024	248	990	1,580
2025	219	903	1,448
2026	191	824	1,330
2027	165	755	1,225
2028	134	691	1,129
2029	108	632	1,039
2030	85	555	922
Totals	12,870	34,649	54,393

Question 70(c)(1)- 30/15
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



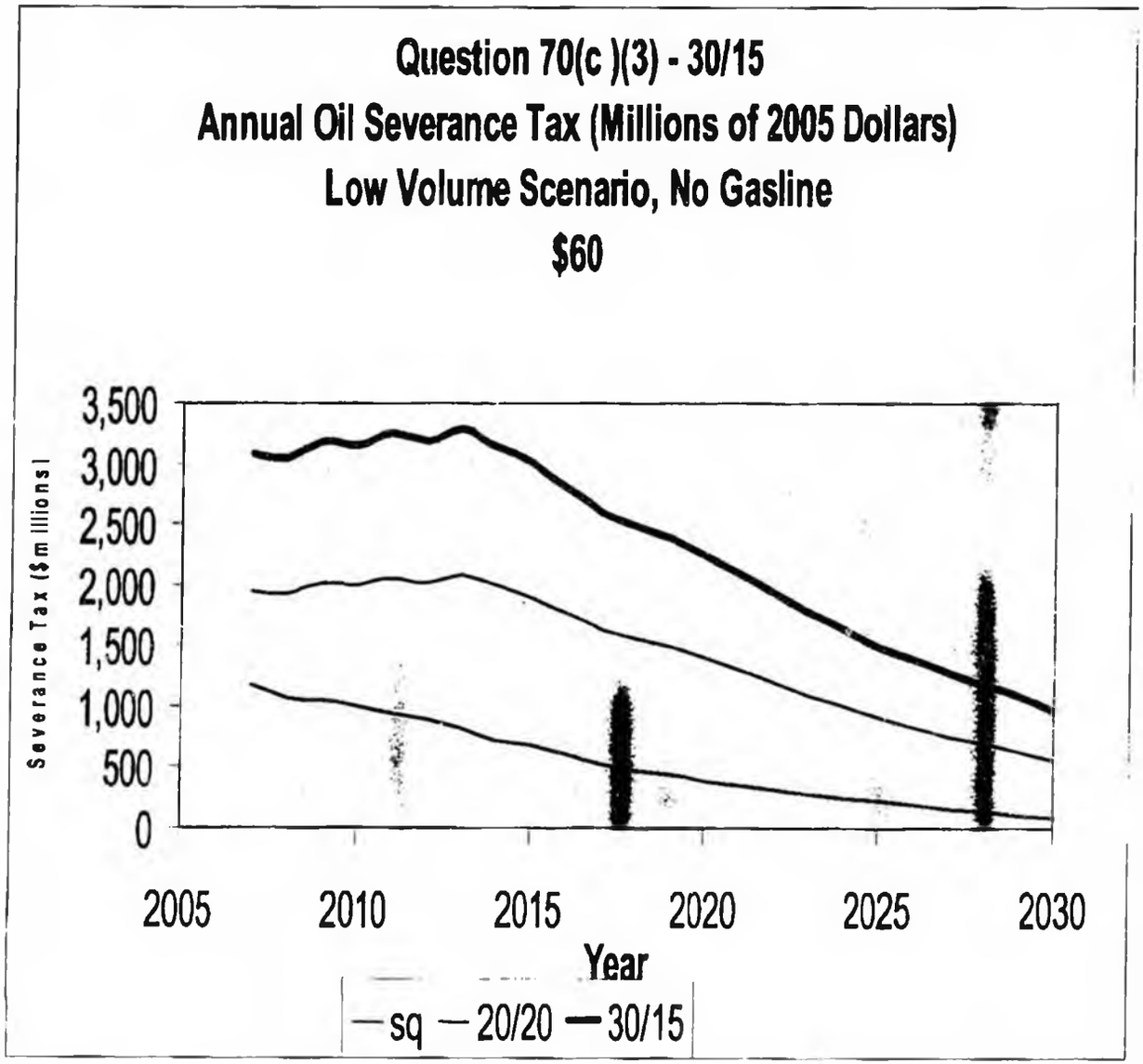
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/15
2007	309	34	193
2008	280	34	191
2009	283	106	298
2010	262	91	275
2011	235	90	274
2012	216	73	247
2013	190	47	206
2014	159	22	167
2015	146	0	133
2016	126	0	85
2017	111	0	44
2018	101	0	21
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	2,133



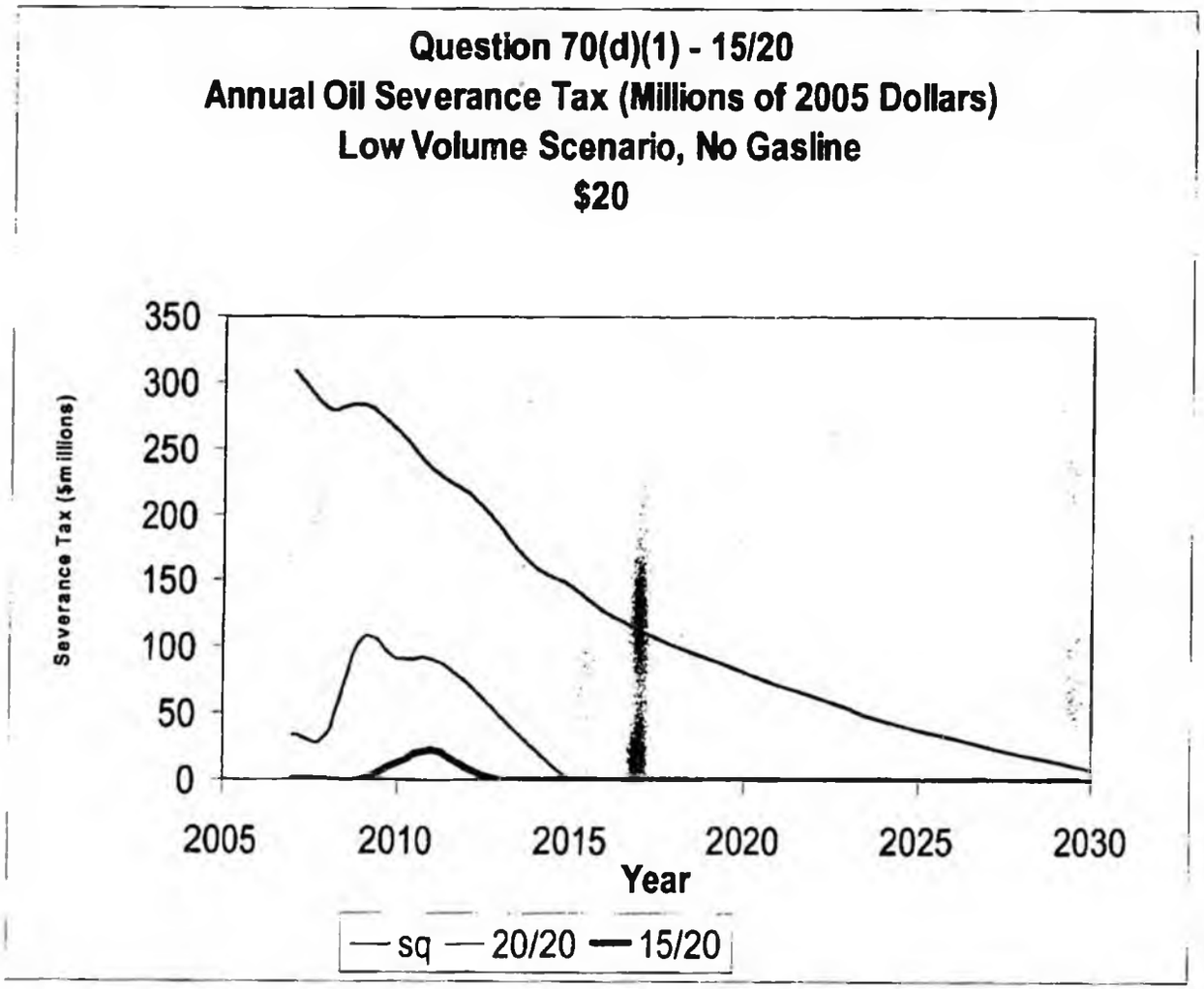
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/15
2007	737	1,045	1,731
2008	679	1,038	1,719
2009	673	1,124	1,848
2010	646	1,112	1,830
2011	606	1,143	1,878
2012	576	1,117	1,838
2013	523	1,056	1,745
2014	459	992	1,648
2015	431	937	1,564
2016	388	853	1,436
2017	340	770	1,309
2018	306	726	1,241
2019	275	683	1,176
2020	248	629	1,094
2021	224	566	997
2022	201	499	895
2023	180	439	803
2024	156	384	719
2025	138	332	639
2026	119	284	567
2027	103	243	503
2028	83	204	444
2029	67	169	389
2030	52	113	305
Totals	8,211	16,458	28,317



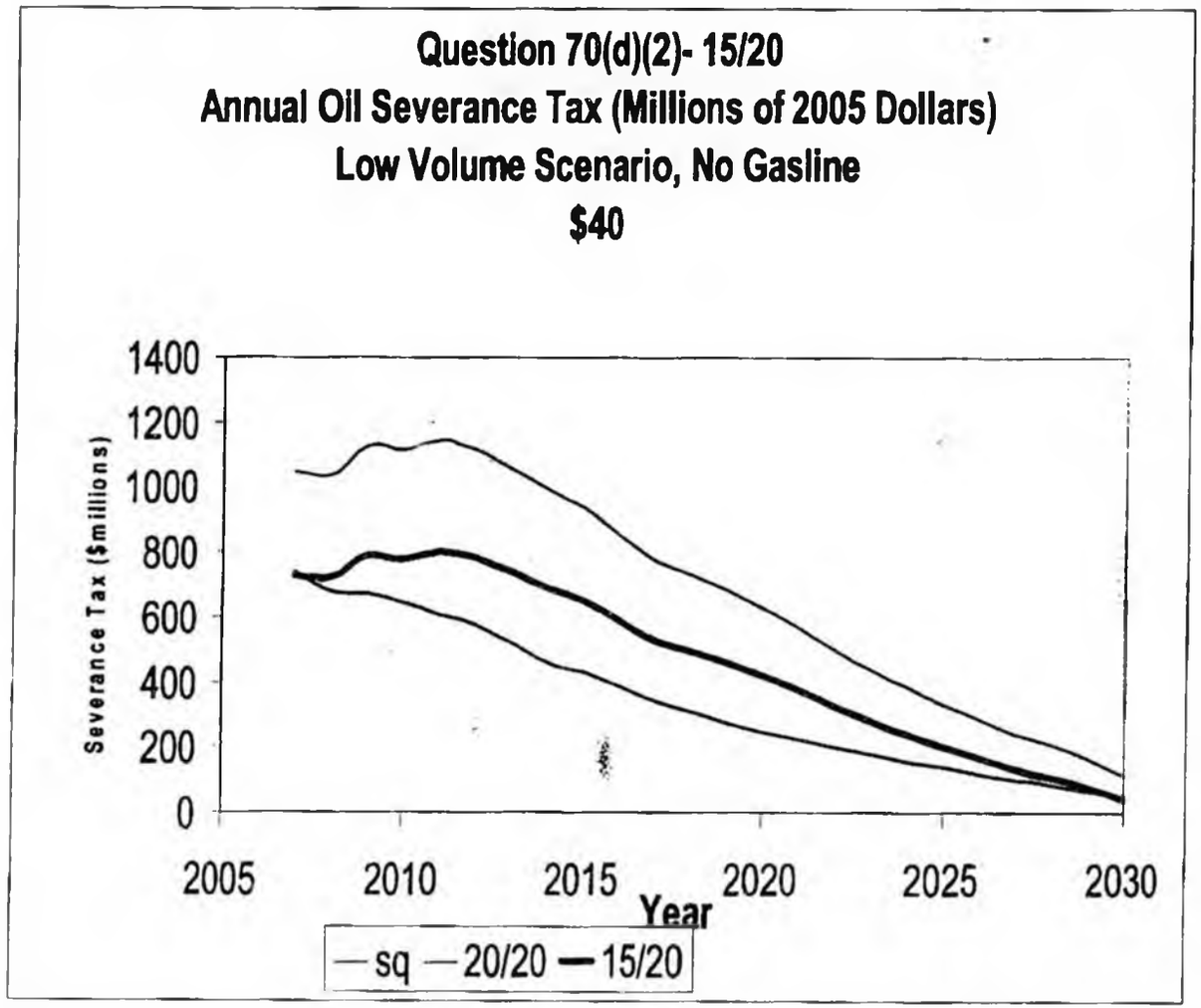
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/15
2007	1,165	1,945	3,081
2008	1,069	1,924	3,048
2009	1,042	2,013	3,181
2010	1,003	1,998	3,158
2011	941	2,056	3,247
2012	896	2,019	3,191
2013	815	2,088	3,293
2014	716	1,987	3,140
2015	674	1,898	3,005
2016	607	1,761	2,798
2017	533	1,625	2,590
2018	480	1,552	2,481
2019	432	1,483	2,376
2020	390	1,396	2,244
2021	353	1,292	2,086
2022	318	1,181	1,918
2023	286	1,081	1,767
2024	248	990	1,628
2025	219	903	1,496
2026	191	824	1,376
2027	165	755	1,271
2028	134	691	1,175
2029	108	632	1,085
2030	85	555	968
Totals	12,870	34,649	55,603



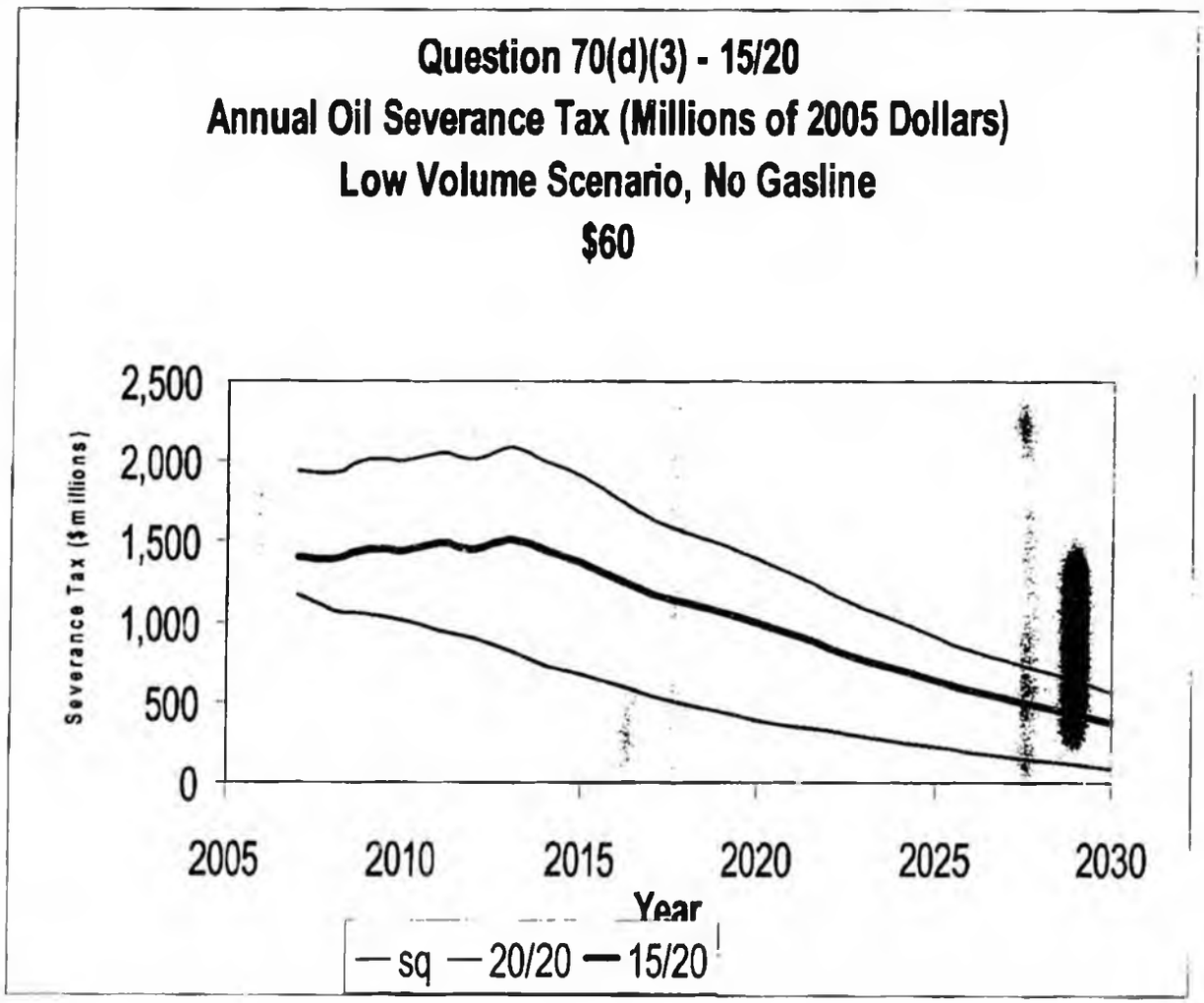
Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/20
2007	309	34	0
2008	280	34	0
2009	283	106	0
2010	262	91	13
2011	235	90	22
2012	216	73	9
2013	190	47	0
2014	159	22	0
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	43

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/20
2007	737	1,045	730
2008	679	1,038	725
2009	673	1,124	789
2010	646	1,112	780
2011	606	1,143	803
2012	576	1,117	783
2013	523	1,056	738
2014	459	992	691
2015	431	937	650
2016	388	853	588
2017	340	770	527
2018	306	726	494
2019	275	683	462
2020	248	629	422
2021	224	566	375
2022	201	499	326
2023	180	439	281
2024	156	384	240
2025	138	332	202
2026	119	284	167
2027	103	243	136
2028	83	204	107
2029	67	169	81
2030	52	113	39
Totals	8,211	16,458	11,134

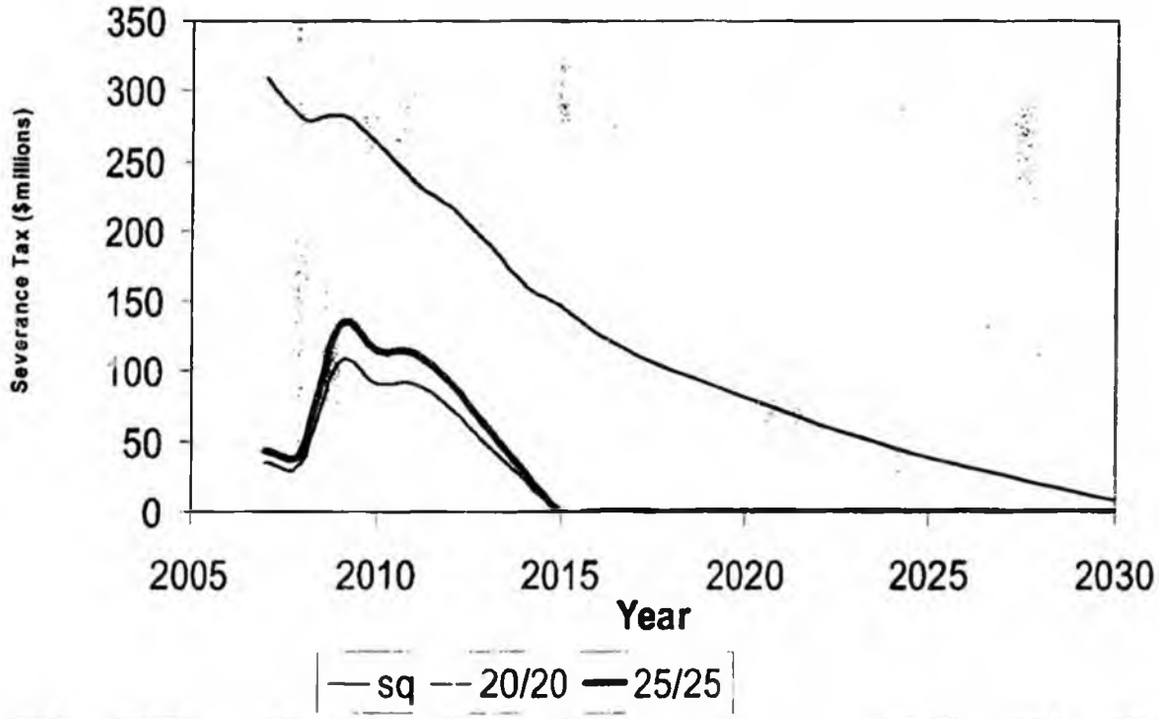
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/20
2007	1,165	1,945	1,405
2008	1,069	1,924	1,389
2009	1,042	2,013	1,455
2010	1,003	1,998	1,444
2011	941	2,056	1,488
2012	896	2,019	1,460
2013	815	2,088	1,512
2014	716	1,987	1,437
2015	674	1,898	1,370
2016	607	1,761	1,269
2017	533	1,625	1,167
2018	480	1,552	1,113
2019	432	1,483	1,062
2020	390	1,396	997
2021	353	1,292	920
2022	318	1,181	837
2023	286	1,081	763
2024	248	990	695
2025	219	903	630
2026	191	824	571
2027	165	755	520
2028	134	691	473
2029	108	632	428
2030	85	555	371
Totals	12,870	34,649	24,777

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

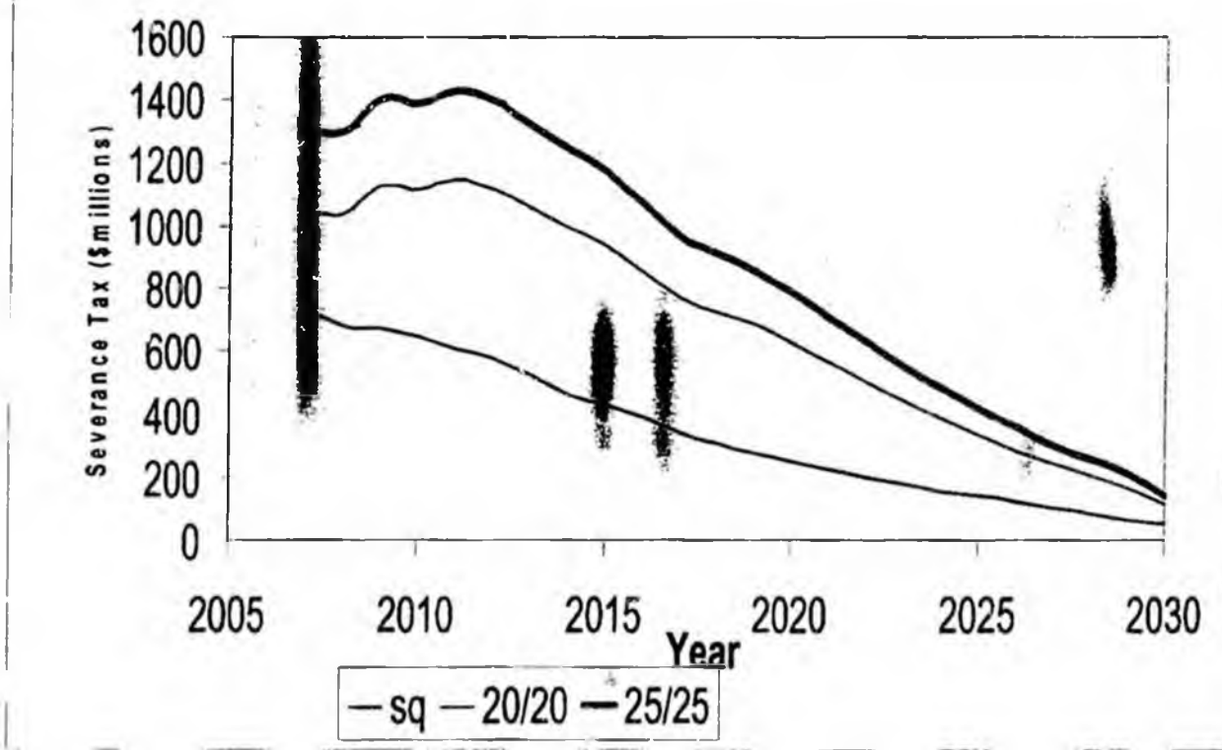
Question 70(e)(1) - 25/25
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/25
2007	309	34	43
2008	280	34	42
2009	283	106	133
2010	262	91	114
2011	235	90	113
2012	216	73	91
2013	190	47	59
2014	159	22	27
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	622

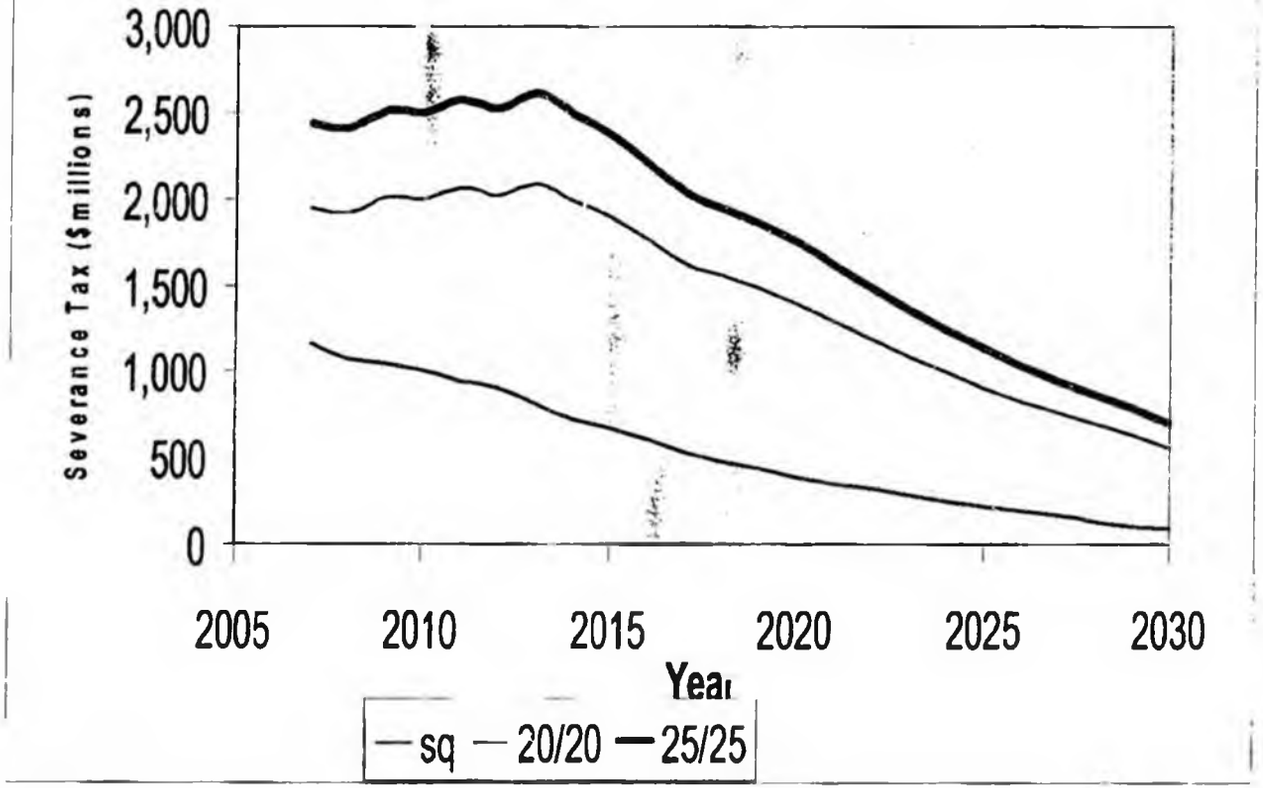
Question 70(e)(2) - 25/25
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

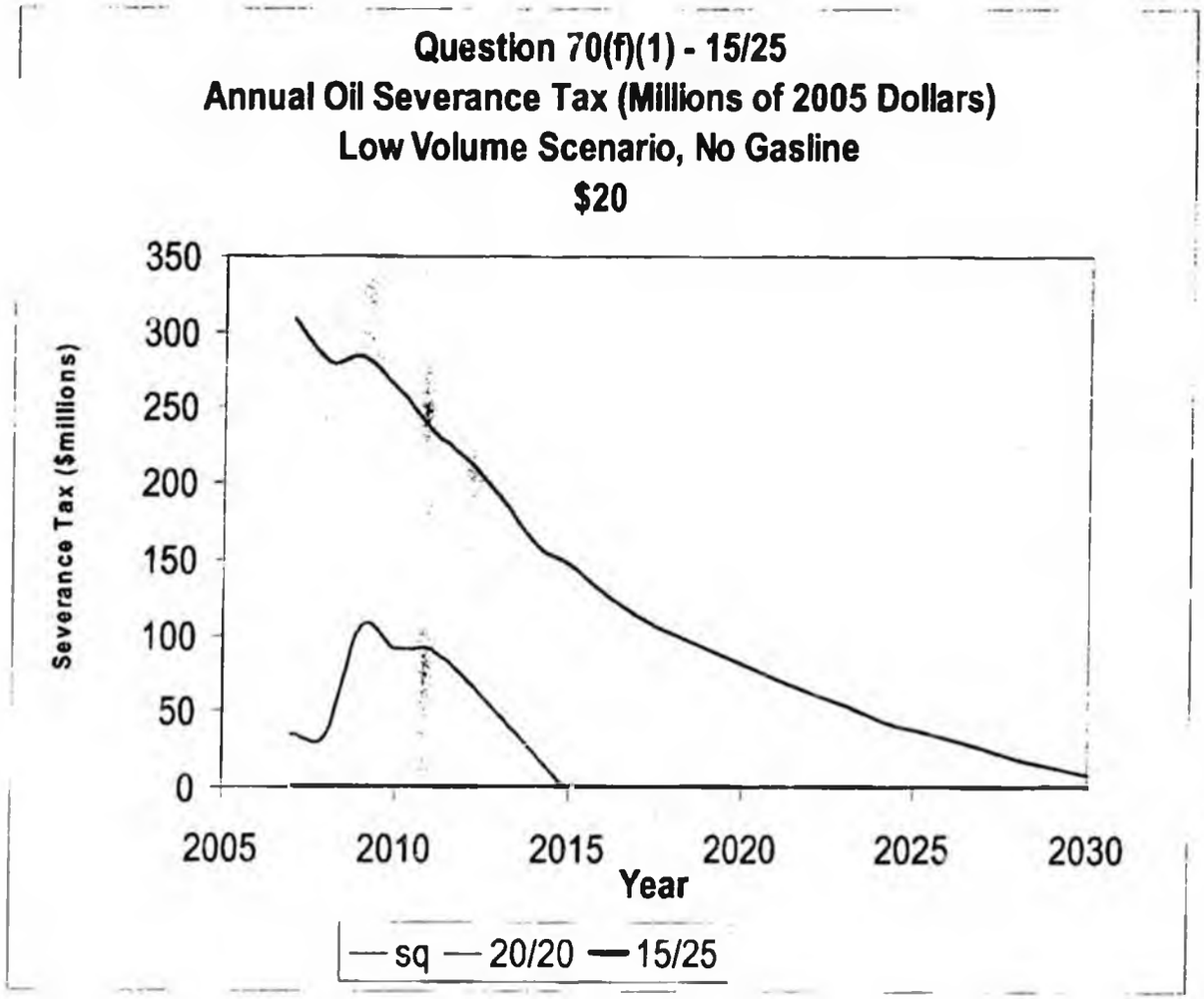
Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/25
2007	737	1,045	1,307
2008	679	1,038	1,298
2009	673	1,124	1,405
2010	646	1,112	1,390
2011	606	1,143	1,429
2012	576	1,117	1,396
2013	523	1,056	1,319
2014	459	992	1,240
2015	431	937	1,171
2016	388	853	1,067
2017	340	770	963
2018	306	726	908
2019	275	683	854
2020	248	629	787
2021	224	566	707
2022	201	499	624
2023	180	439	549
2024	156	384	480
2025	138	332	415
2026	119	284	355
2027	103	243	303
2028	83	204	256
2029	67	169	211
2030	52	113	141
Totals	8,211	16,458	20,572

Question 70(e)(3) - 25/25
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



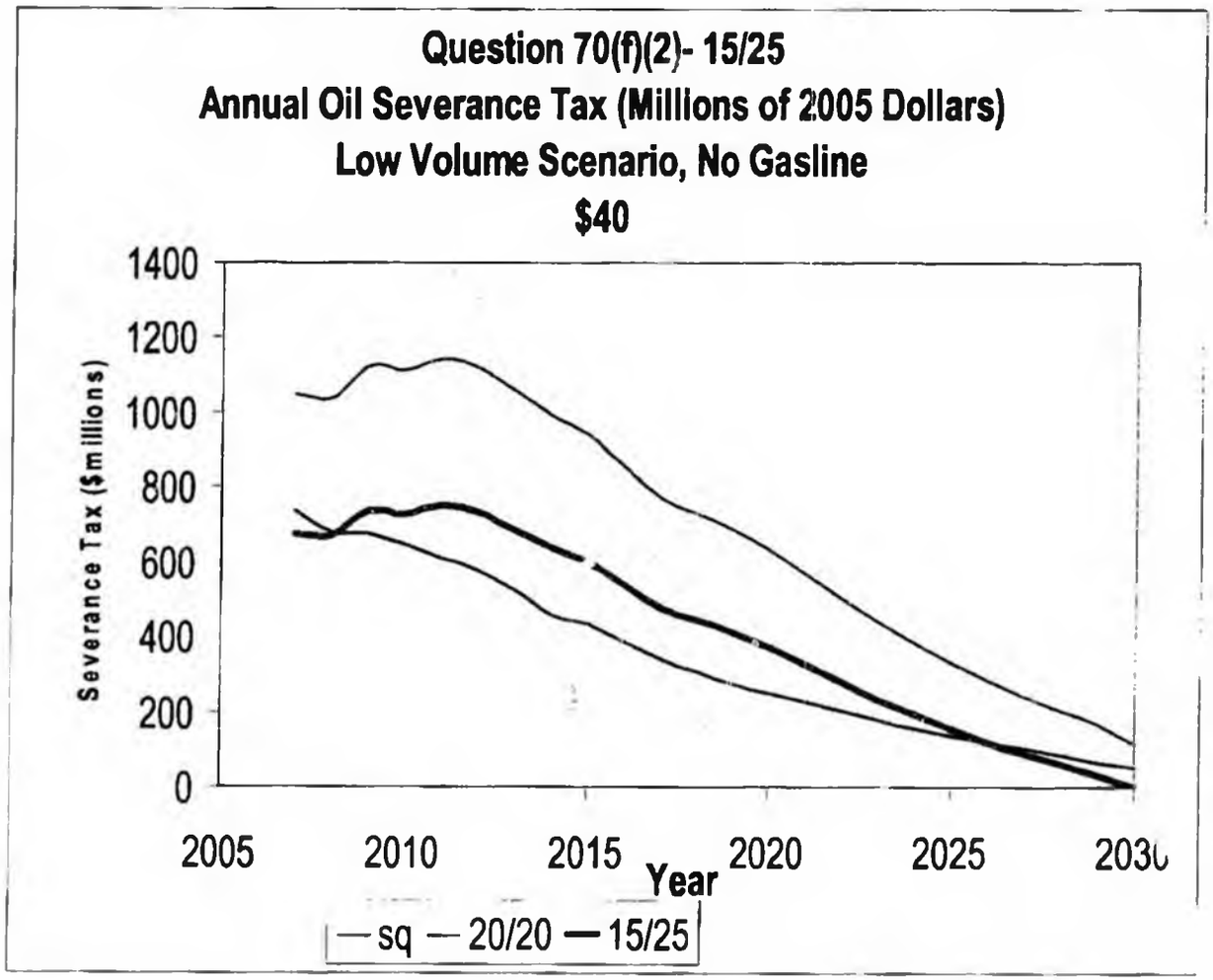
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/25
2007	1,165	1,945	2,432
2008	1,069	1,924	2,405
2009	1,042	2,013	2,516
2010	1,003	1,998	2,497
2011	941	2,056	2,570
2012	896	2,019	2,523
2013	815	2,088	2,610
2014	716	1,987	2,483
2015	674	1,898	2,372
2016	607	1,761	2,202
2017	533	1,625	2,031
2018	480	1,552	1,940
2019	432	1,483	1,854
2020	390	1,396	1,745
2021	353	1,292	1,615
2022	318	1,181	1,477
2023	286	1,081	1,352
2024	248	990	1,238
2025	219	903	1,128
2026	191	824	1,030
2027	165	755	944
2028	134	691	864
2029	108	632	790
2030	85	555	693
Totals	12,870	34,649	43,311



Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/25
2007	309	34	0
2008	280	34	0
2009	283	106	0
2010	262	91	0
2011	235	90	0
2012	216	73	0
2013	190	47	0
2014	159	22	0
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	0

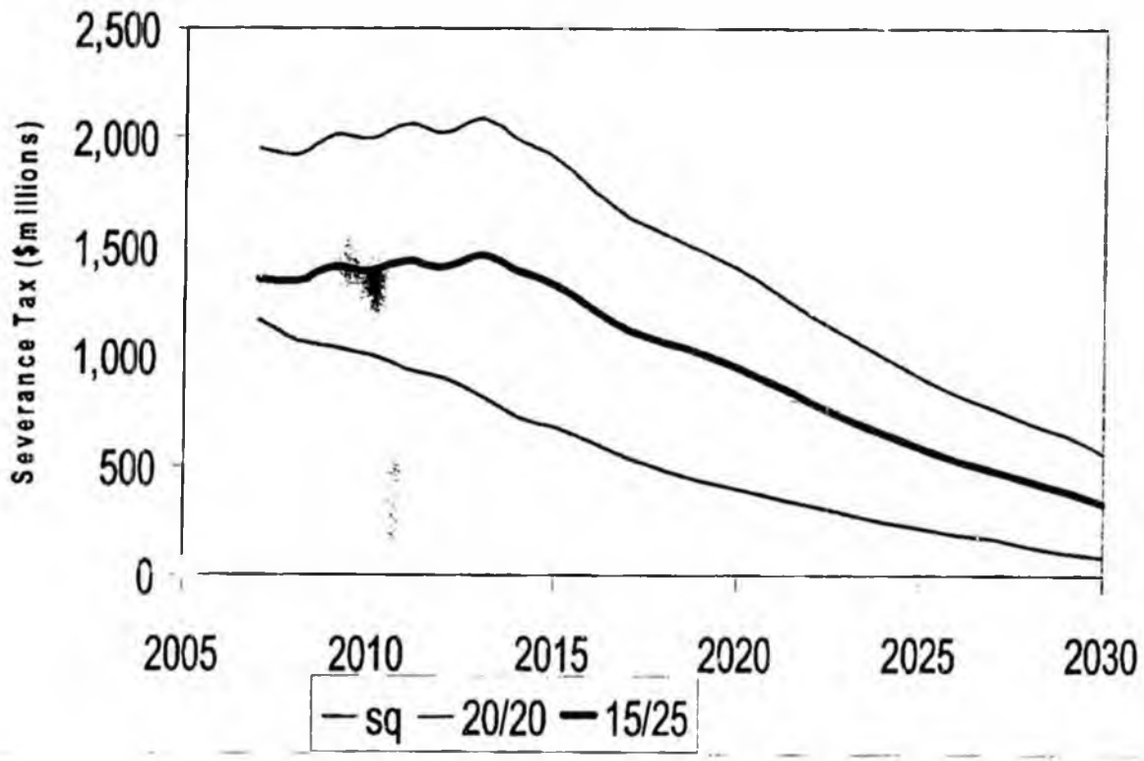
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/25
2007	737	1,045	676
2008	679	1,038	671
2009	673	1,124	735
2010	646	1,112	726
2011	606	1,143	748
2012	576	1,117	729
2013	523	1,056	684
2014	459	992	638
2015	431	937	597
2016	388	853	536
2017	340	770	475
2018	306	726	443
2019	275	683	411
2020	248	629	372
2021	224	566	326
2022	20.	499	277
2023	180	439	233
2024	156	384	193
2025	138	332	154
2026	119	284	120
2027	103	243	89
2028	83	204	62
2029	67	169	35
2030	52	113	0
Totals	8,211	16,458	9,930

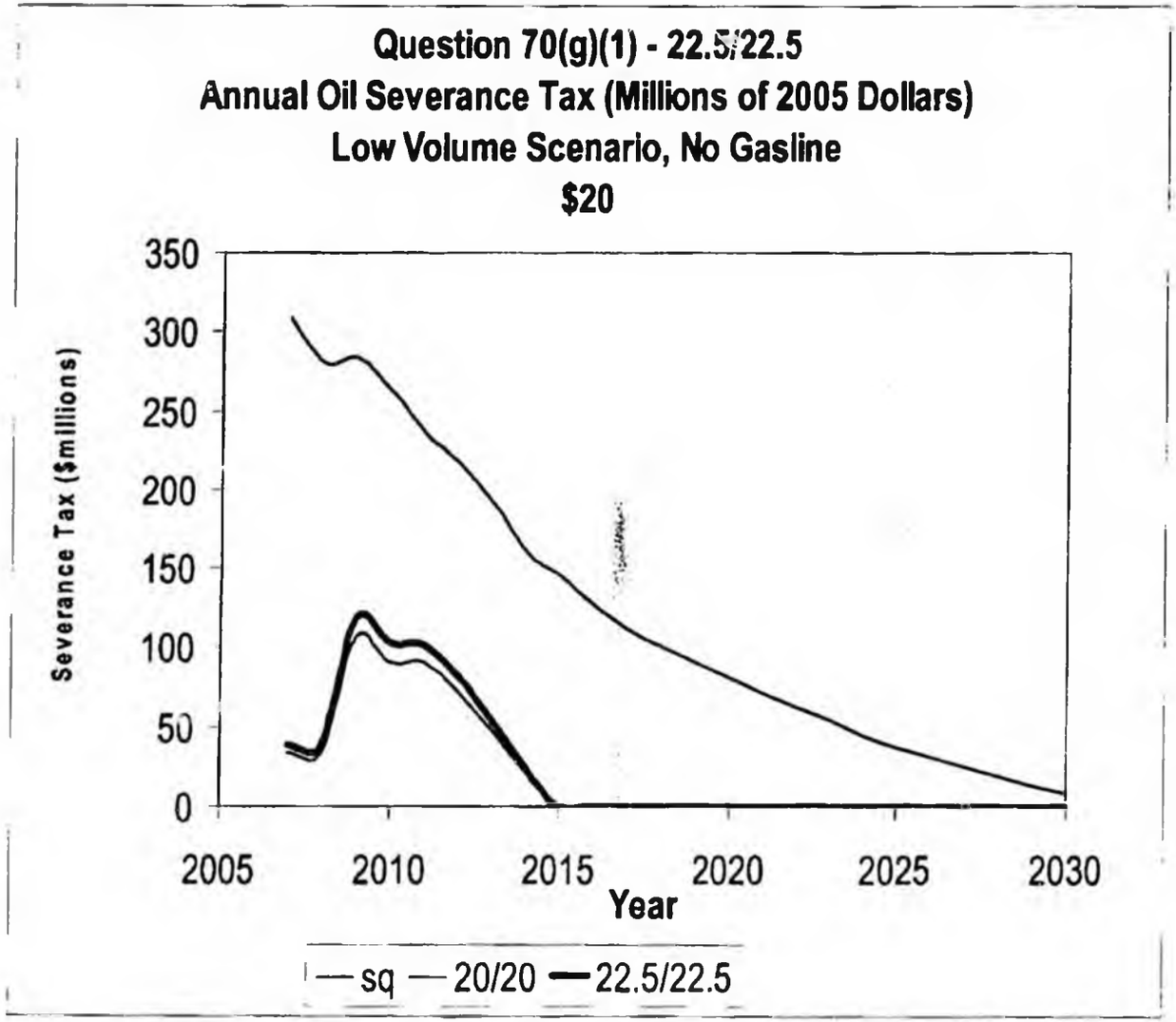
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 70(f)(3) - 15/25
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



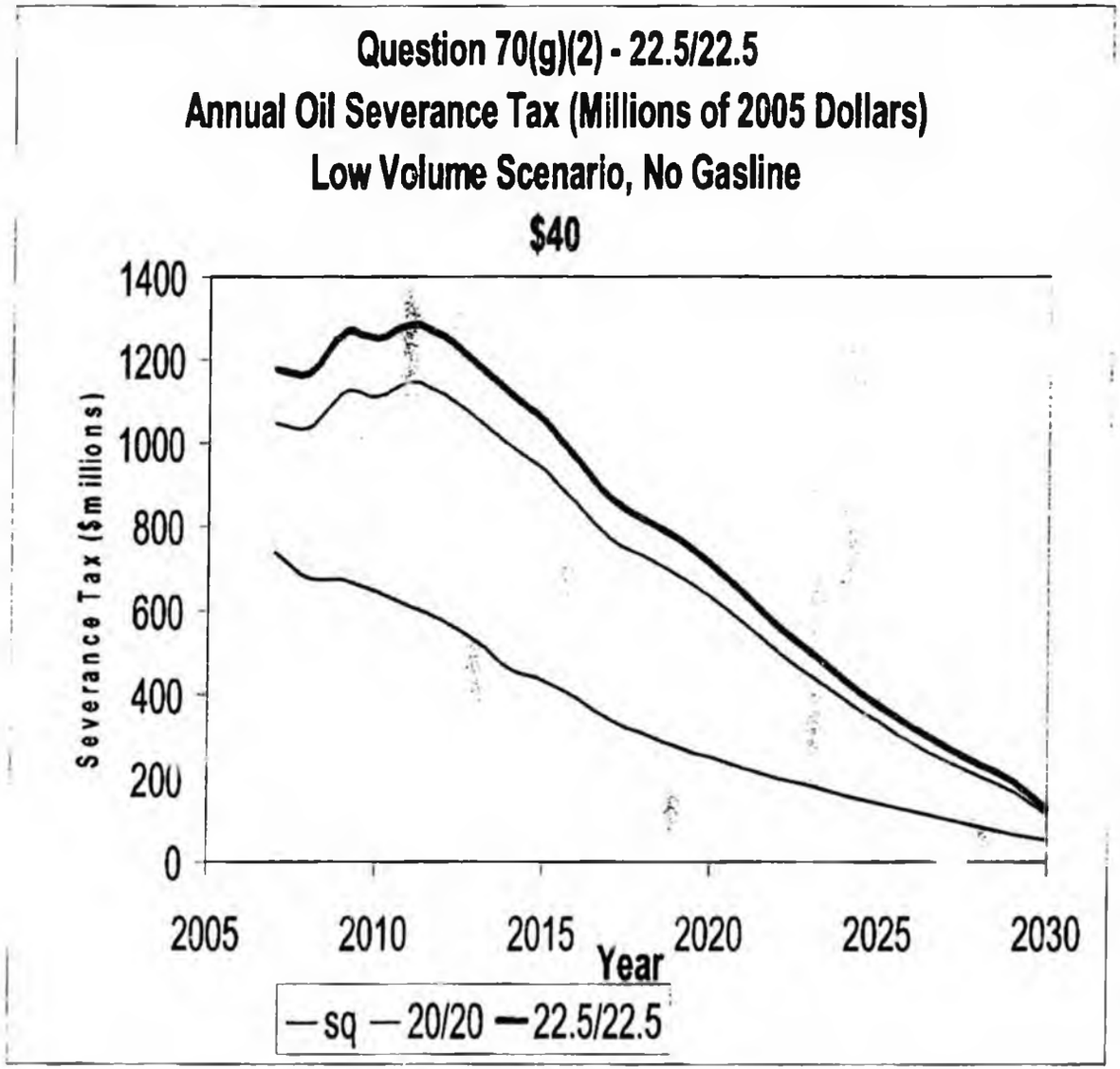
Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/25
2007	1,165	1,945	1,351
2008	1,069	1,924	1,335
2009	1,042	2,013	1,401
2010	1,003	1,998	1,390
2011	941	2,056	1,433
2012	896	2,019	1,405
2013	815	2,088	1,458
2014	716	1,987	1,384
2015	674	1,898	1,318
2016	607	1,761	1,217
2017	533	1,625	1,116
2018	480	1,552	1,063
2019	432	1,483	1,012
2020	390	1,396	947
2021	353	1,292	870
2022	318	1,181	789
2023	286	1,081	715
2024	248	990	647
2025	219	903	583
2026	191	824	525
2027	165	755	474
2028	134	691	427
2029	108	632	383
2030	85	555	325
Totals	12,870	34,649	23,567

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

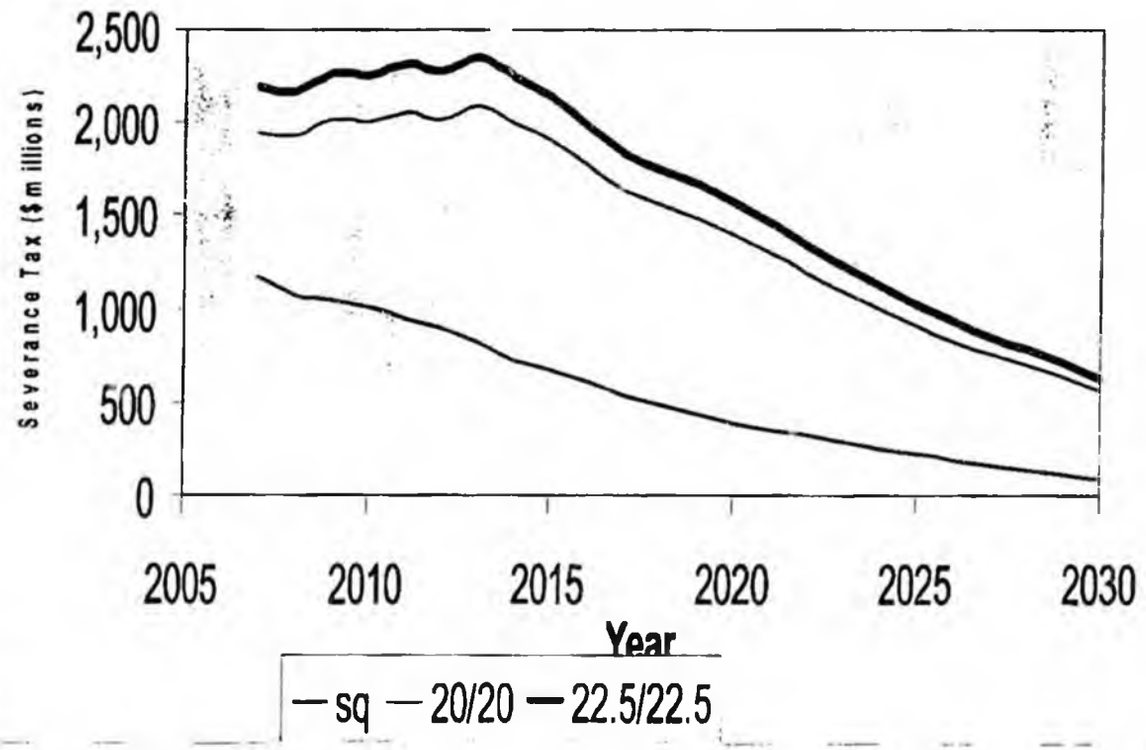
Annual Oil Severance Tax ($Millions)			
	sq	20/20	22.5/22.5
2007	309	34	38
2008	280	34	38
2009	283	106	119
2010	262	91	103
2011	235	90	102
2012	216	73	82
2013	190	47	53
2014	159	22	25
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	560



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	22.5/22.5
2007	737	1,045	1,176
2008	679	1,038	1,168
2009	673	1,124	1,264
2010	646	1,112	1,251
2011	606	1,143	1,286
2012	576	1,117	1,256
2013	523	1,056	1,187
2014	459	992	1,116
2015	431	937	1,054
2016	388	853	960
2017	340	770	867
2018	306	726	817
2019	275	683	768
2020	248	629	708
2021	224	566	636
2022	201	499	562
2023	180	[illegible]	494
2024	156	384	432
2025	138	332	373
2026	119	284	320
2027	103	243	273
2028	83	204	230
2029	67	169	190
2030	52	113	127
Totals	8,211	16,458	18,515

Question 70(g)(3) - 22.5/22.5
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	22.5/22.5
2007	1,165	1,945	2,188
2008	1,069	1,924	2,165
2009	1,042	2,013	2,264
2010	1,003	1,998	2,247
2011	941	2,056	2,313
2012	896	2,019	2,271
2013	815	2,088	2,349
2014	716	1,987	2,235
2015	674	1,898	2,135
2016	607	1,761	1,981
2017	533	1,625	1,828
2018	480	1,552	1,746
2019	432	1,483	1,669
2020	390	1,396	1,571
2021	353	1,292	1,453
2022	318	1,181	1,329
2023	286	1,081	1,217
2024	248	990	1,114
2025	219	903	1,016
2026	191	824	927
2027	165	755	849
2028	134	691	778
2029	108	632	711
2030	85	555	624
Totals	12,870	34,649	38,980

Question 70(h)(1)
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40

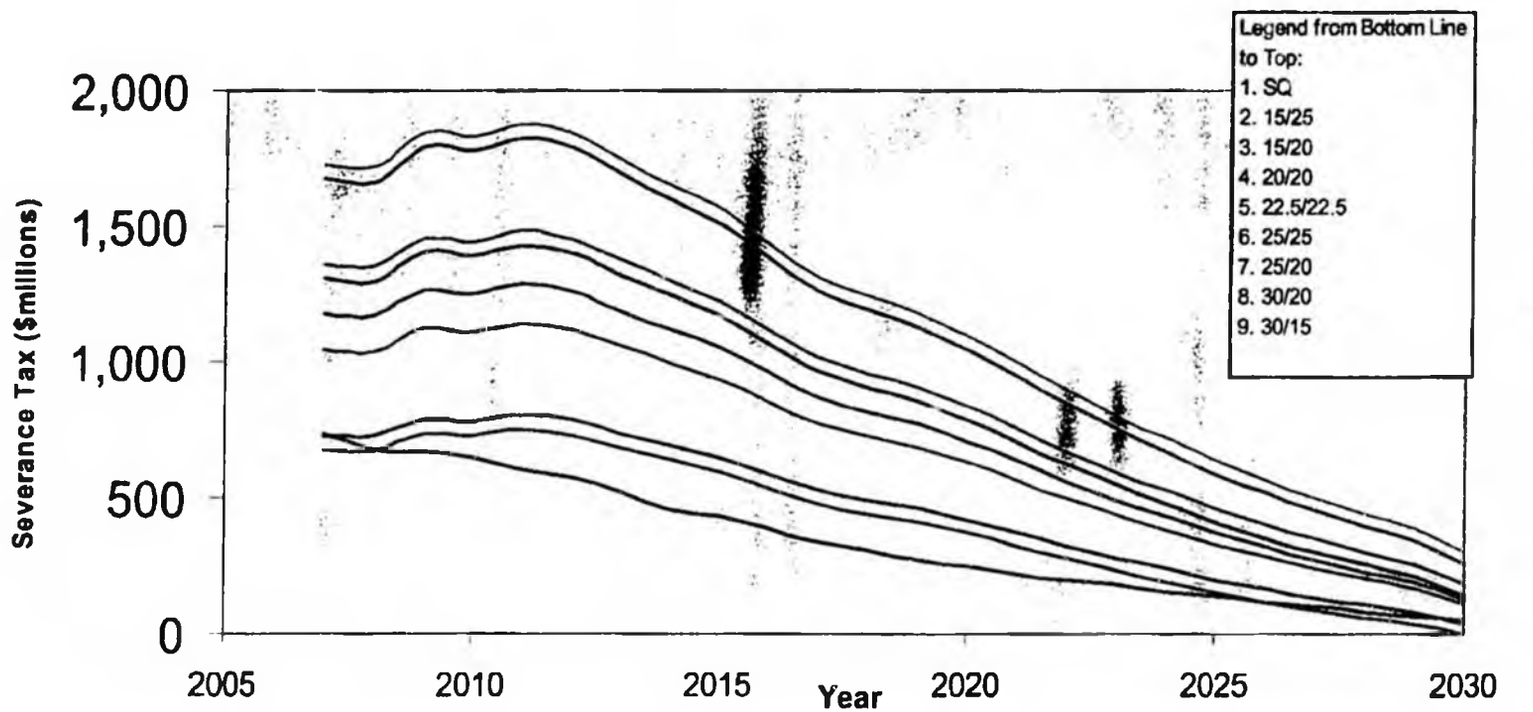
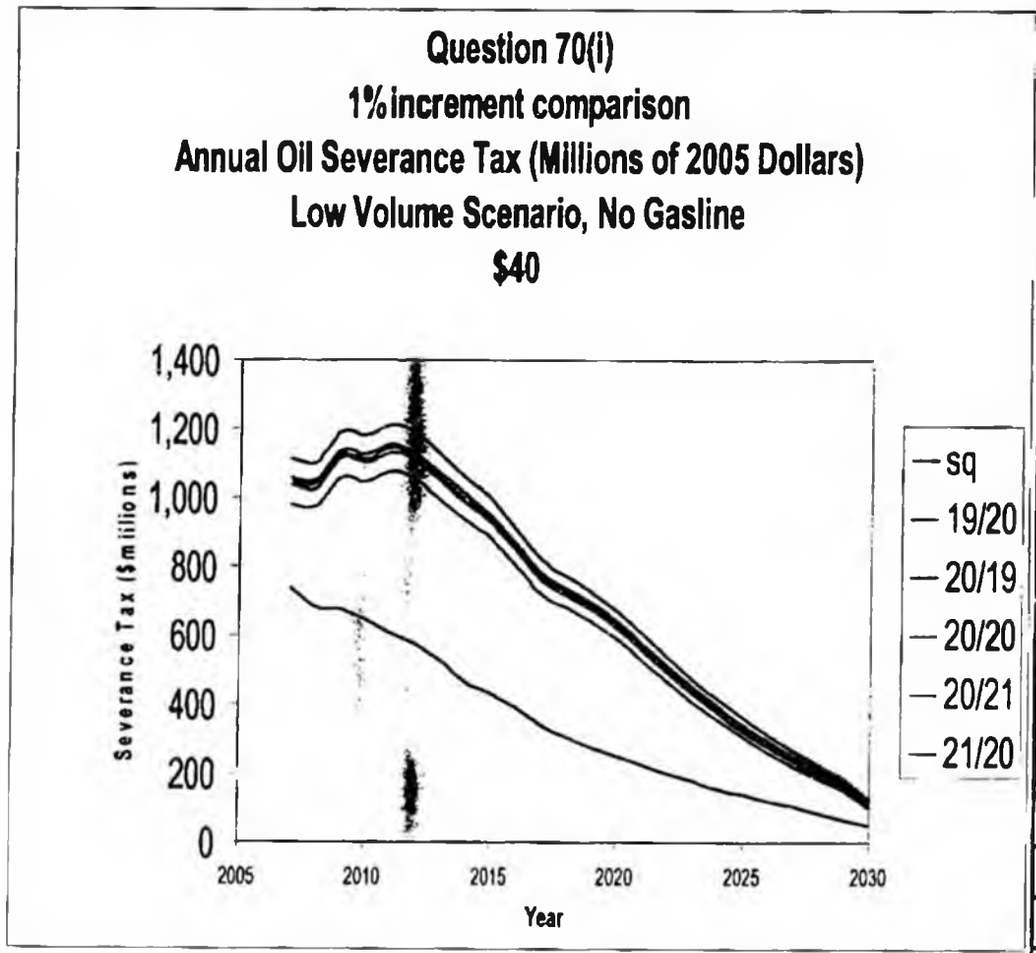


Table with Values on Next Slide

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 70(h)(2) Table: Annual Oil Severance Tax ($Millions), $40/bbl									
Fiscal Yr	sq	15/25	15/20	20/20	22.5/22.5	25/25	25/20	30/20	30/15
2007	737	676	730	1,045	1176	1307	1,361	1,677	1731
2008	679	671	725	1,038	1168	1298	1,352	1,665	1719
2009	673	735	789	1,124	1264	1405	1,459	1,794	1848
2010	646	725	780	1,112	1251	1390	1,444	1,776	1830
2011	606	748	803	1,143	1286	1429	1,483	1,823	1878
2012	576	729	783	1,117	1256	1396	1,450	1,784	1838
2013	523	684	738	1,056	1187	1319	1,373	1,691	1745
2014	459	638	691	992	1116	1240	1,293	1,595	1648
2015	431	597	650	937	1054	1171	1,224	1,511	1564
2016	388	536	588	853	960	1067	1,119	1,384	1436
2017	340	475	527	770	867	963	1,014	1,258	1309
2018	306	443	494	726	817	908	958	1,191	1241
2019	275	411	462	683	768	854	904	1,125	1176
2020	248	372	422	629	708	787	837	1,044	1094
2021	224	326	375	566	636	707	756	947	997
2022	201	277	326	499	562	624	673	846	895
2023	180	233	281	439	494	549	597	755	803
2024	156	193	240	384	432	480	528	671	719
2025	138	154	202	332	373	415	462	592	639
2026	119	120	167	284	320	355	402	520	567
2027	103	89	136	243	273	303	349	456	503
2028	83	62	107	204	230	256	301	398	444
2029	67	35	81	169	190	211	256	344	389
2030	52	0	39	113	127	141	186	260	305
Totals	8,211	9,930	11,134	16,458	18,515	20,572	21,782	27,107	28,317



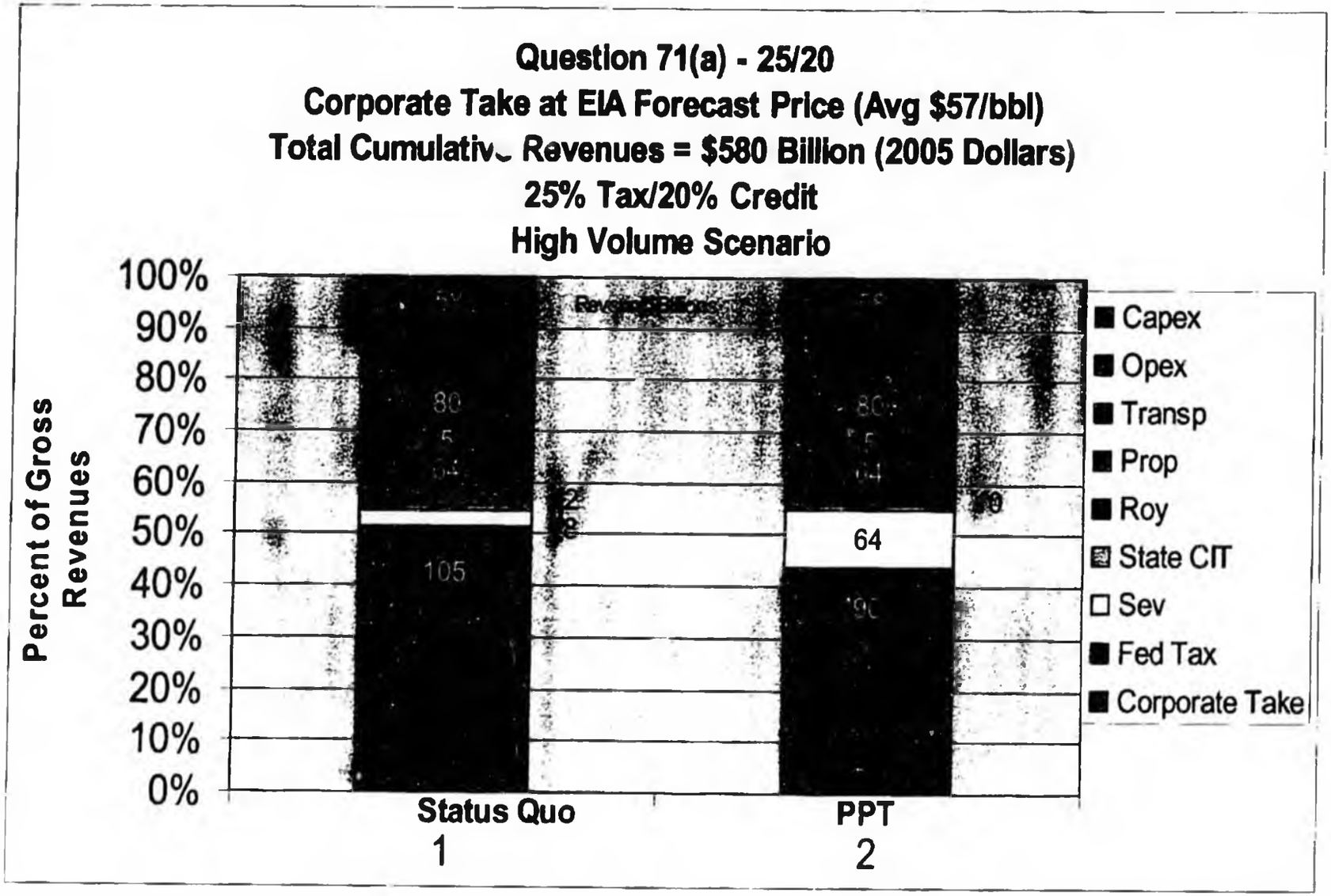
Question 70 - Annual Oil Severance Tax ($Millions)						
	sq	19/20	20/19	20/20	20/21	21/20
2007	737	982	1,056	1,045	1035	1109
2008	679	975	1,049	1,038	1027	1101
2009	673	1,057	1,135	1,124	1113	1191
2010	646	1,045	1,123	1,112	1101	1178
2011	606	1,075	1,154	1,143	1132	1211
2012	576	1,050	1,127	1,117	1106	1183
2013	523	992	1,066	1,056	1045	1119
2014	459	932	1,003	992	982	1052
2015	431	879	947	937	926	994
2016	388	800	864	853	843	906
2017	340	722	781	770	760	819
2018	306	680	736	726	716	772
2019	275	639	693	683	673	727
2020	248	588	639	629	619	671
2021	224	527	576	566	556	604
2022	201	465	509	499	489	534
2023	180	407	449	439	429	471
2024	156	355	394	384	375	413
2025	138	306	341	332	322	358
2026	119	261	294	284	275	308
2027	103	221	252	243	233	264
2028	83	185	214	204	195	224
2029	67	151	178	169	159	186
2030	52	98	122	113	104	127
Totals	8,211	15,393	16,700	16,458	18,515	20,572

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 70(j) - Average Effective Tax Rates*, Low Volume Scenario, No Gasline			
Tax Rate/Credit Rate	$20/bbl	$40/bbl	$60/bbl
Status Quo	4.1%	4.5%	4.4%
PPT 20/20	0.6%	9.3%	13.0%
PPT 25/20	1.2%	12.4%	16.8%
PPT 30/20	1.8%	15.5%	20.5%
PPT 30/15	2.5%	16.3%	21.0%
PPT 15/20	0.1%	6.2%	9.2%
PPT 25/25	0.7%	11.6%	16.3%
PPT 15/25	0.0%	5.4%	8.7%
PPT 22.5/22.5	0.6%	10.4%	14.6%
PPT 19/20	0.4%	8.6%	12.3%
PPT 20/19	0.7%	9.4%	13.1%
PPT 20/21	0.5%	9.1%	12.9%
PPT 21/20	0.7%	9.9%	13.8%

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

*Average Effective Tax Rate = Severance Tax divided by Gross Wellhead Value Less Royalty



Alaska Department of Revenue, Tax Division
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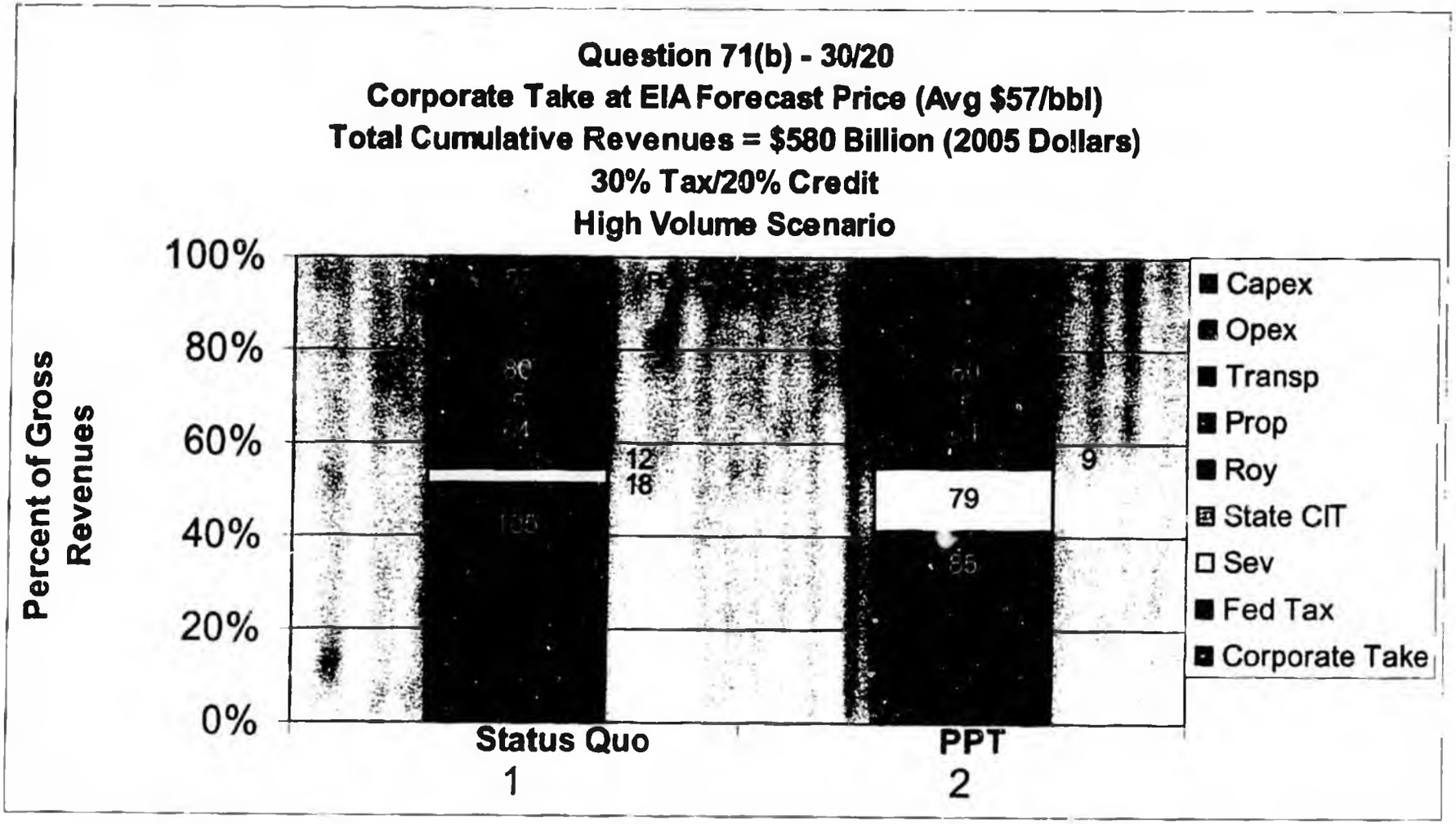
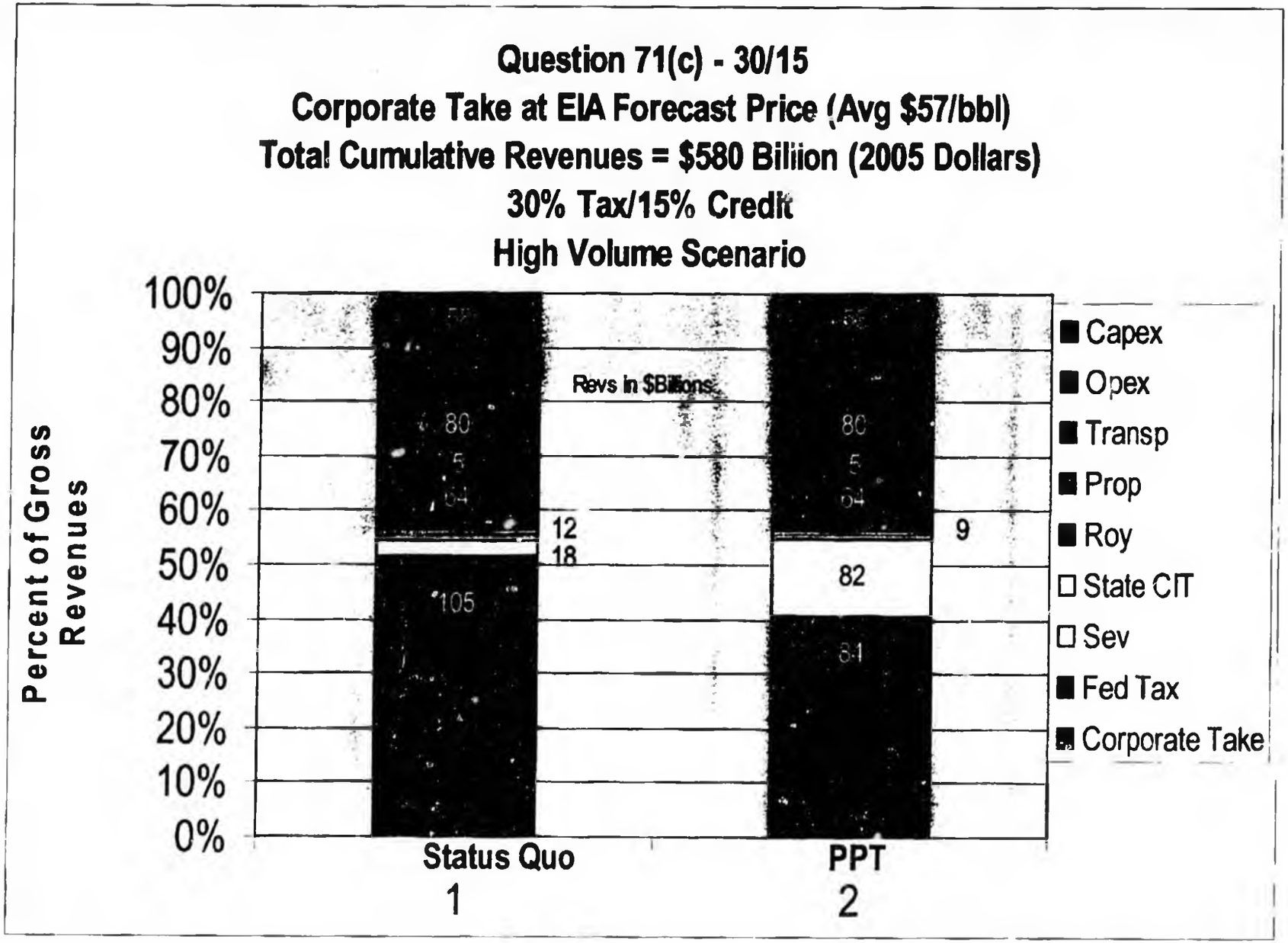


Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Alaska Department of Revenue, Tax Division
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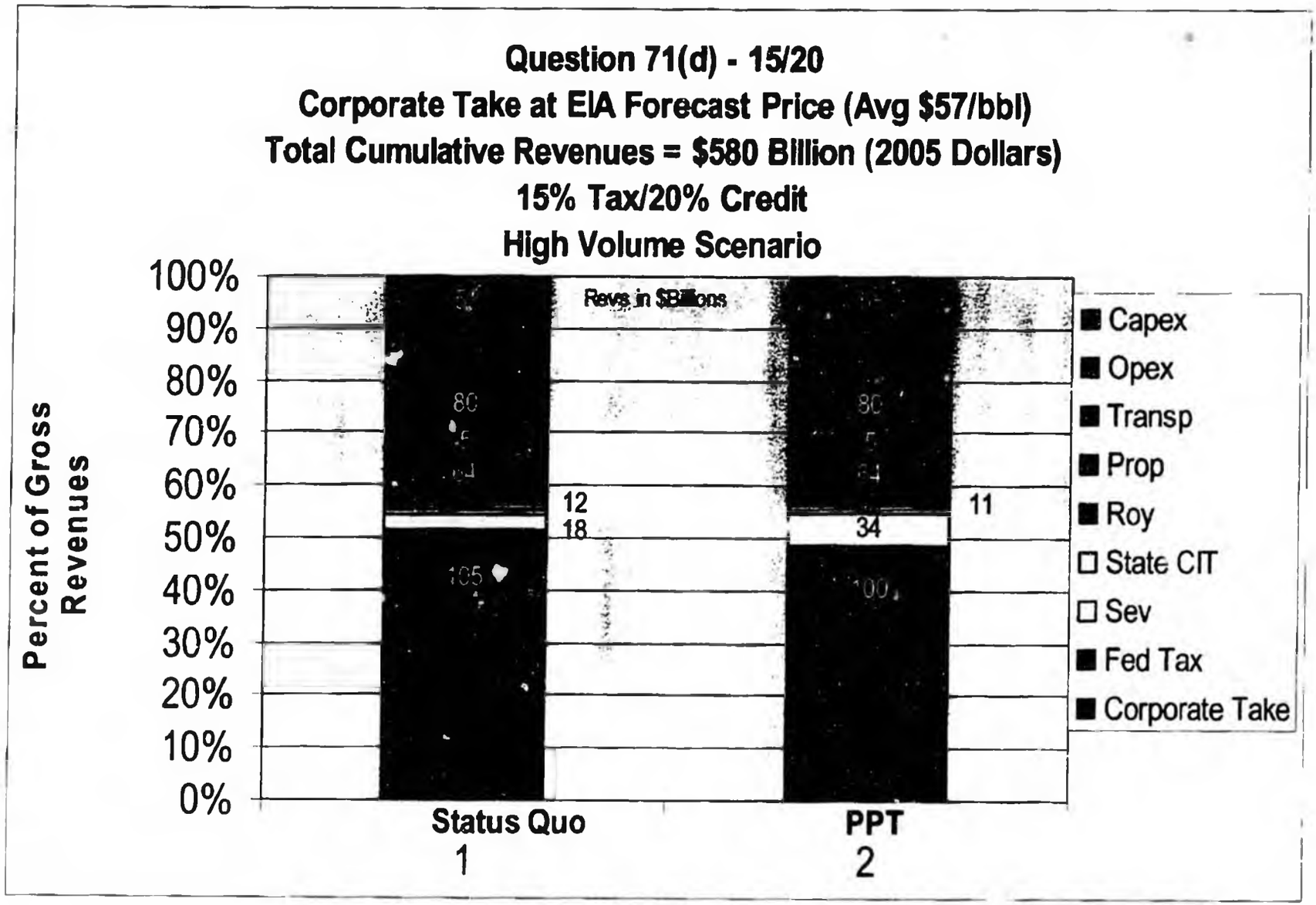

Alaska Department of Revenue, Tax Division
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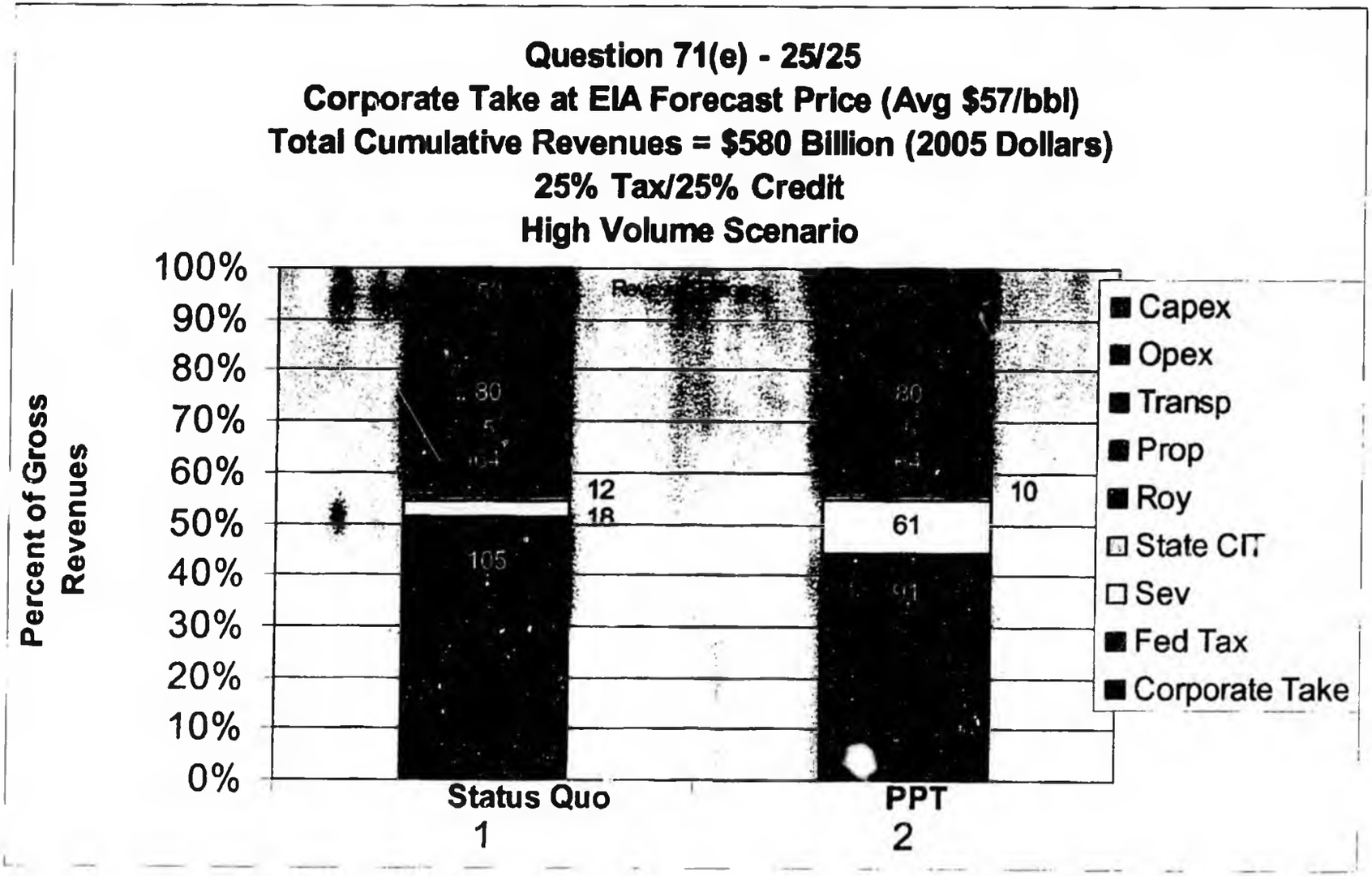

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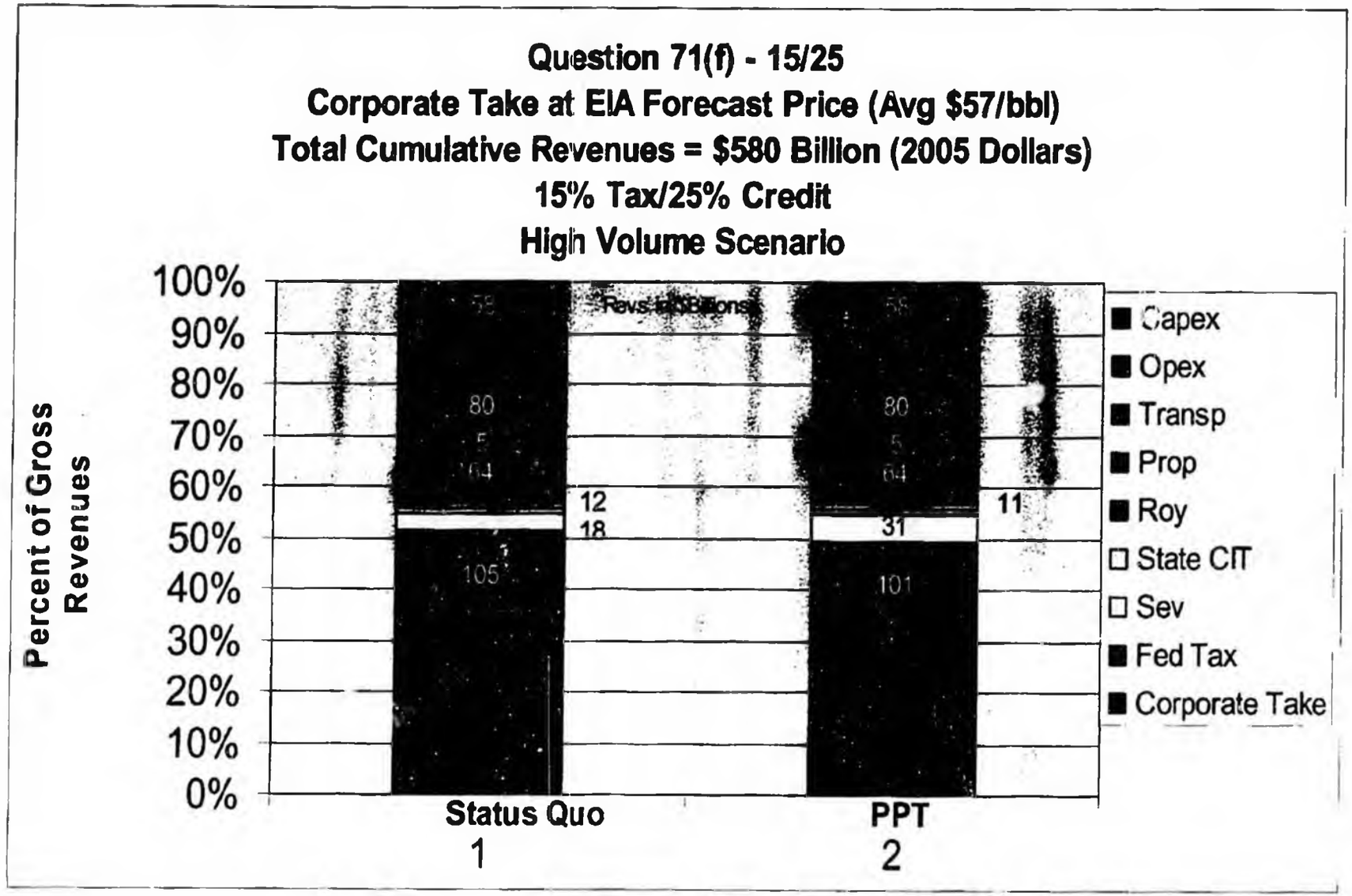

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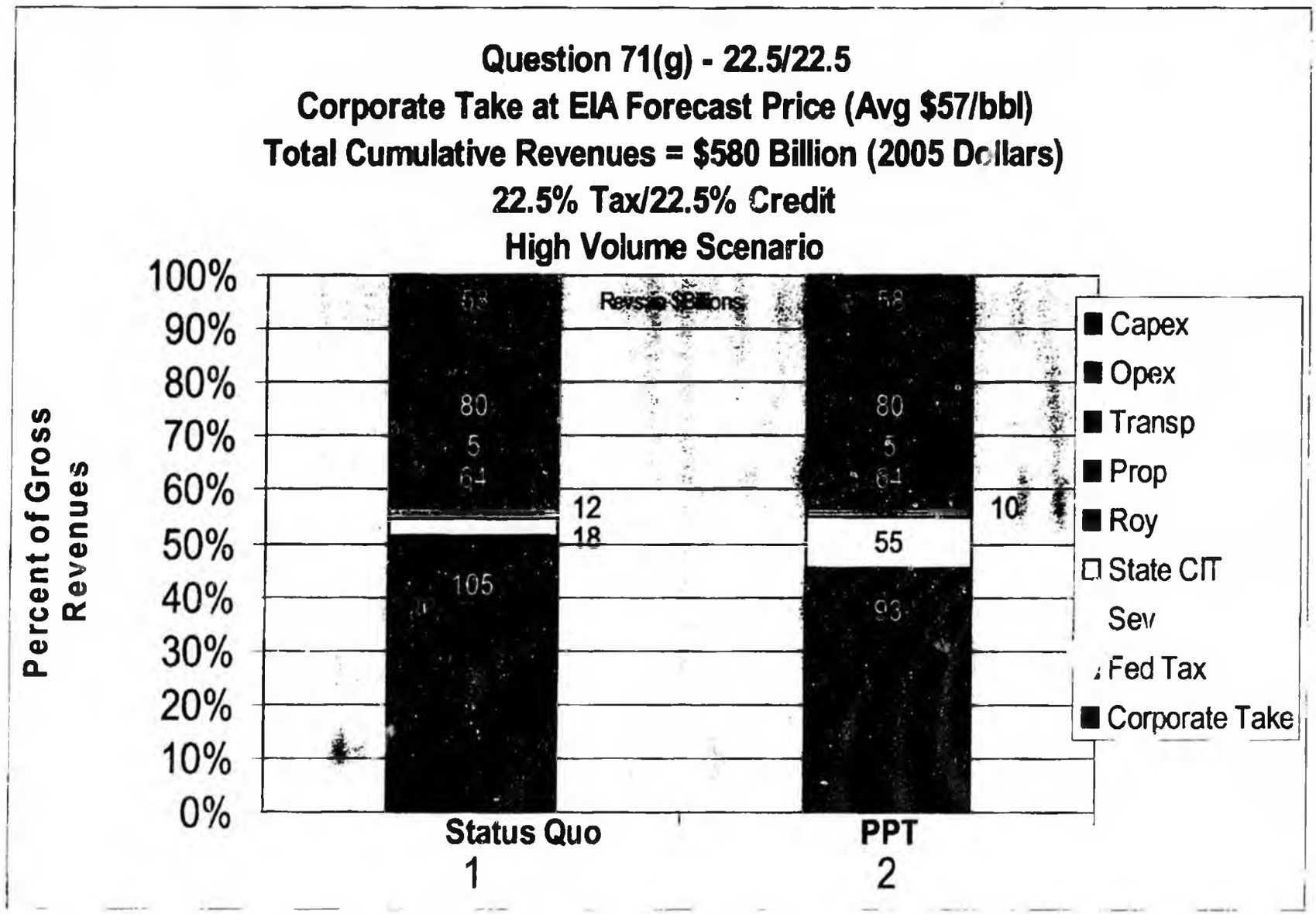
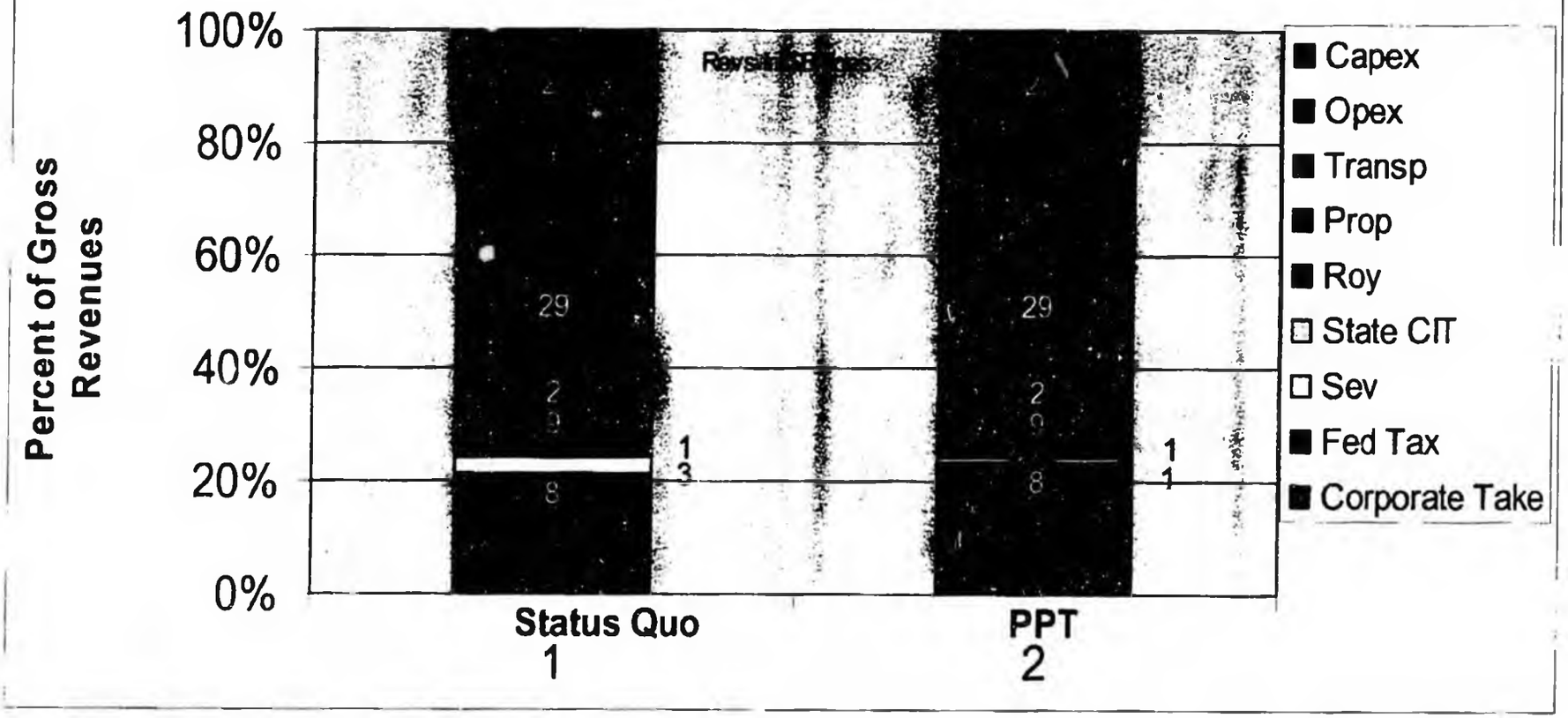


Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 72(a)
Price Corp Take @ 15% = $20.50/bbl ANS
Total Cumulative Revenues = $100 Billion (2005 Dollars)
20% Tax/20% Credit
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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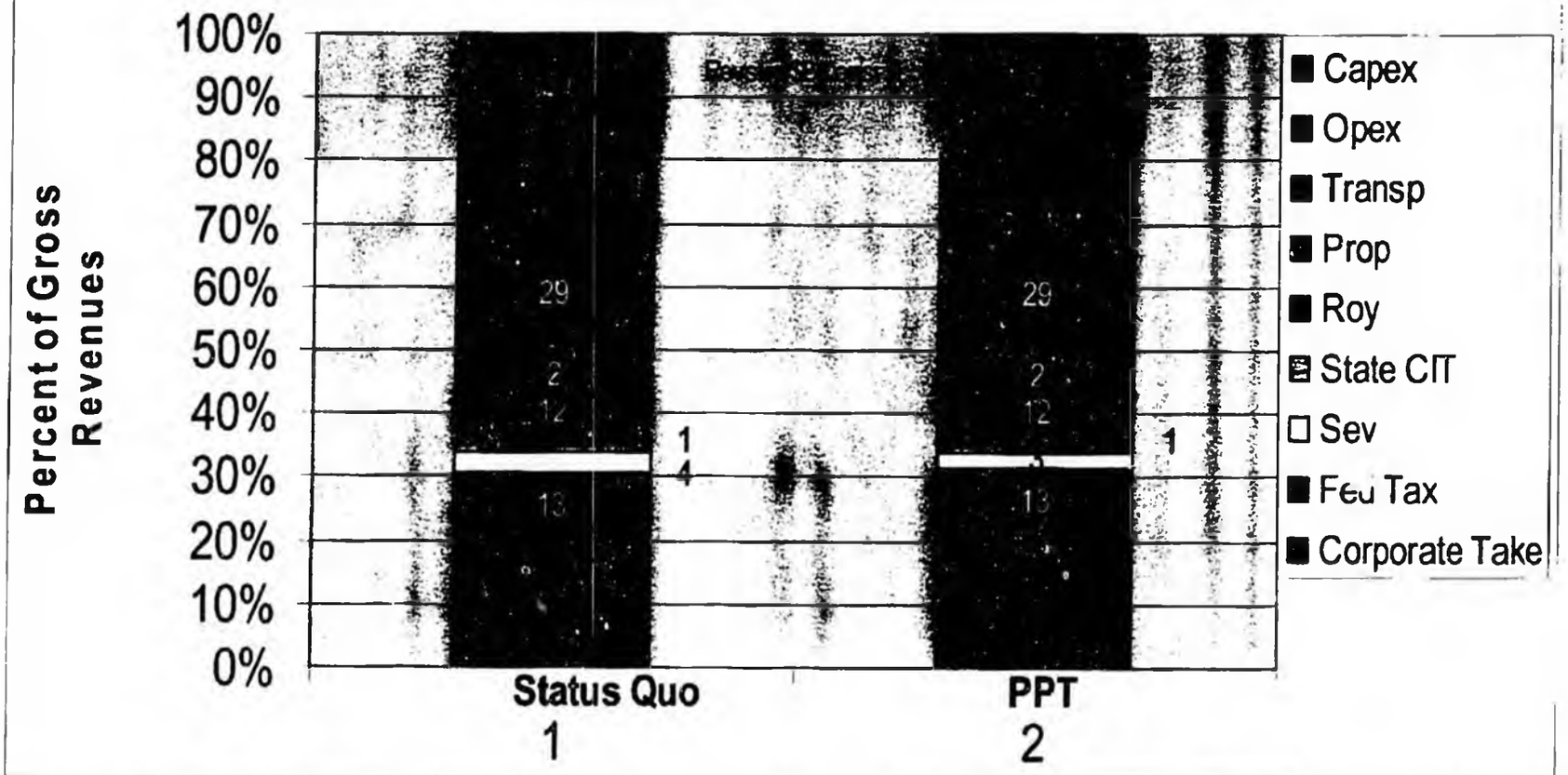
Department of Revenue

Question 72(b)
Price Corp Take @ 20% = $24.50/bbl ANS
Total Cumulative Revenues = $121 Billion (2005 Dollars)
20% Tax/20% Credit
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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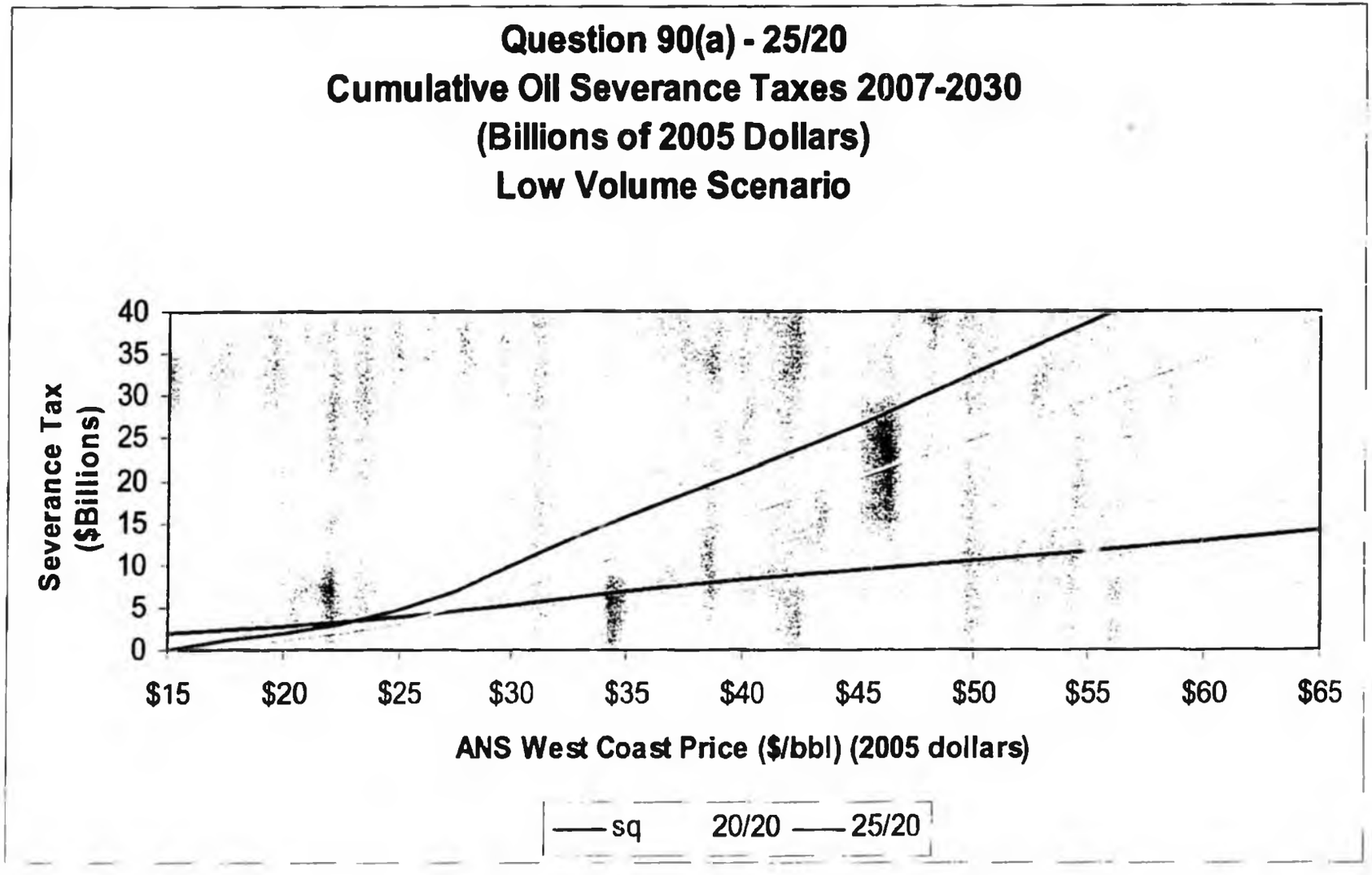

Alaska Department of Revenue, Tax Division
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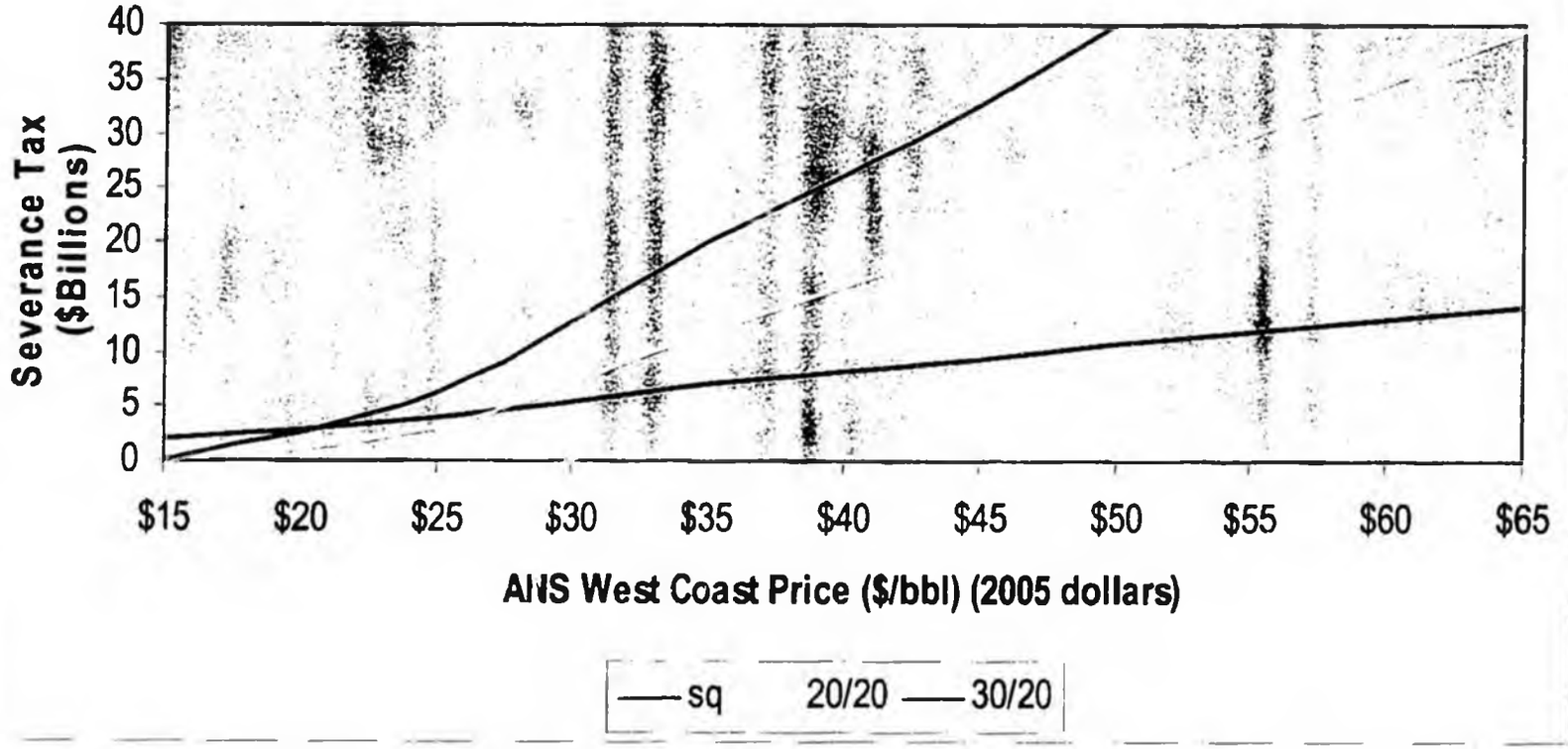
Question 90(b) - 30/20
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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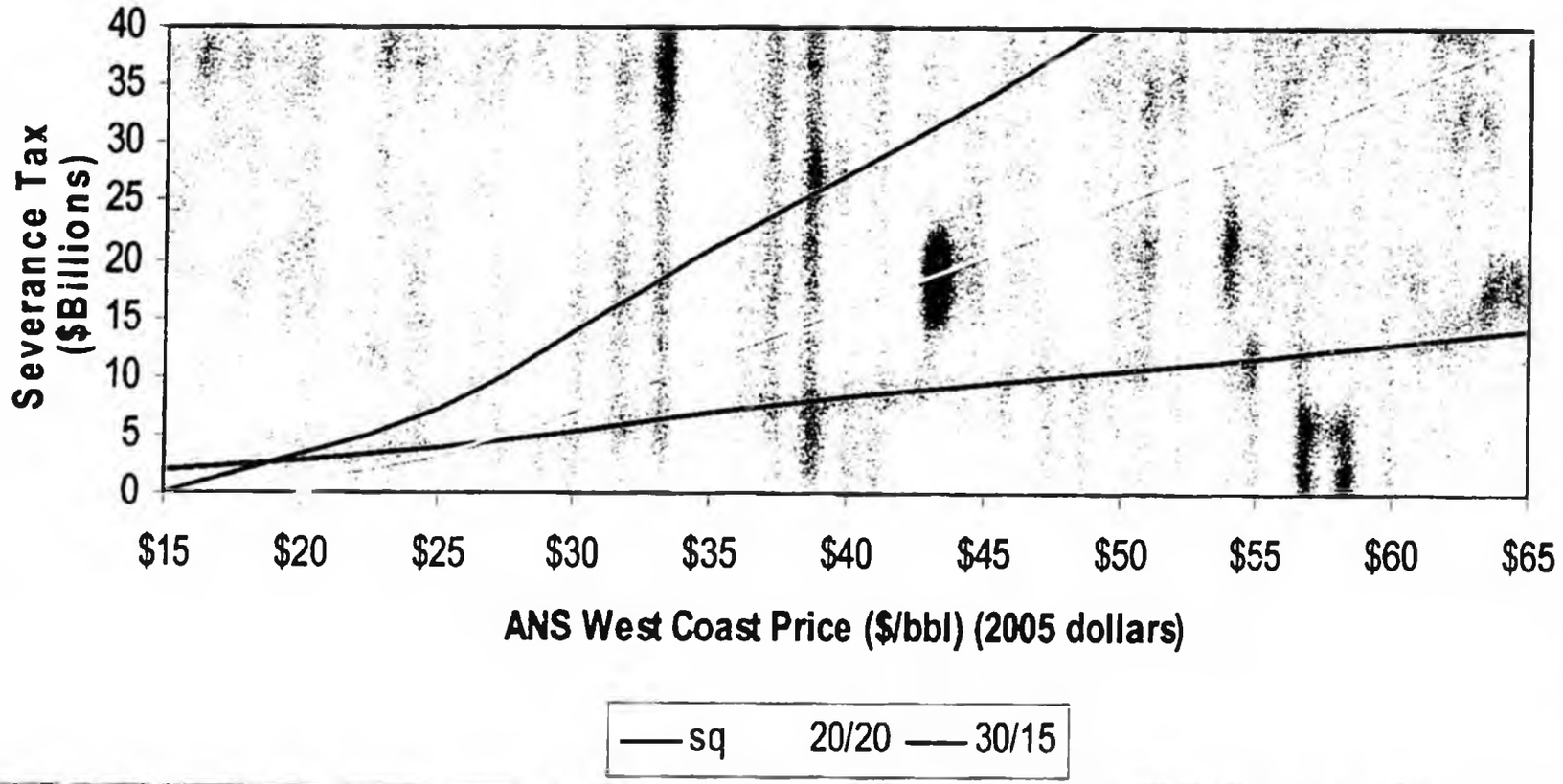
Question 90(c) - 30/15
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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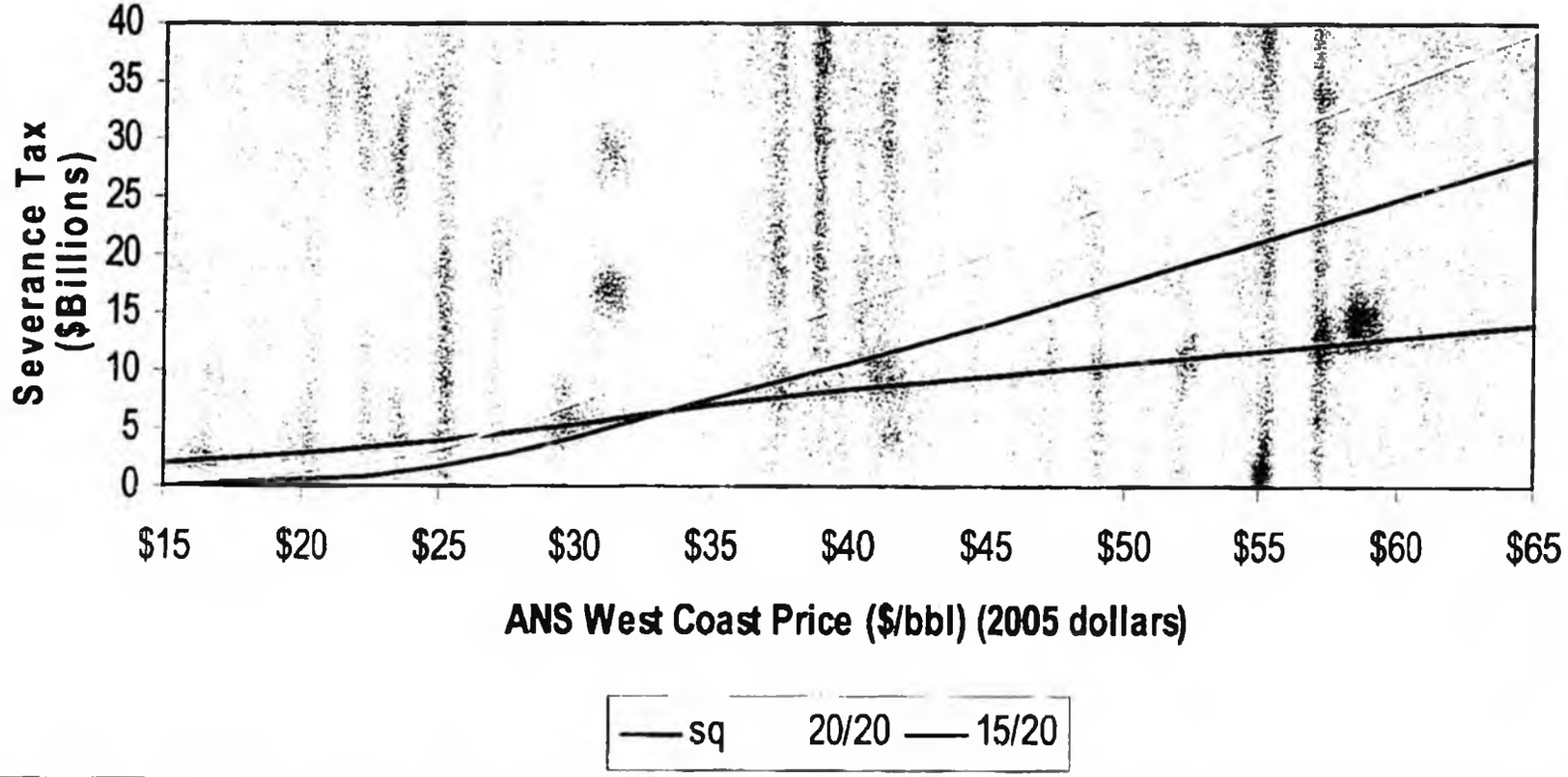
Question 90(d) - 15/20
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)

Low Volume Scenario



Alaska Department of Revenue, Tax Division
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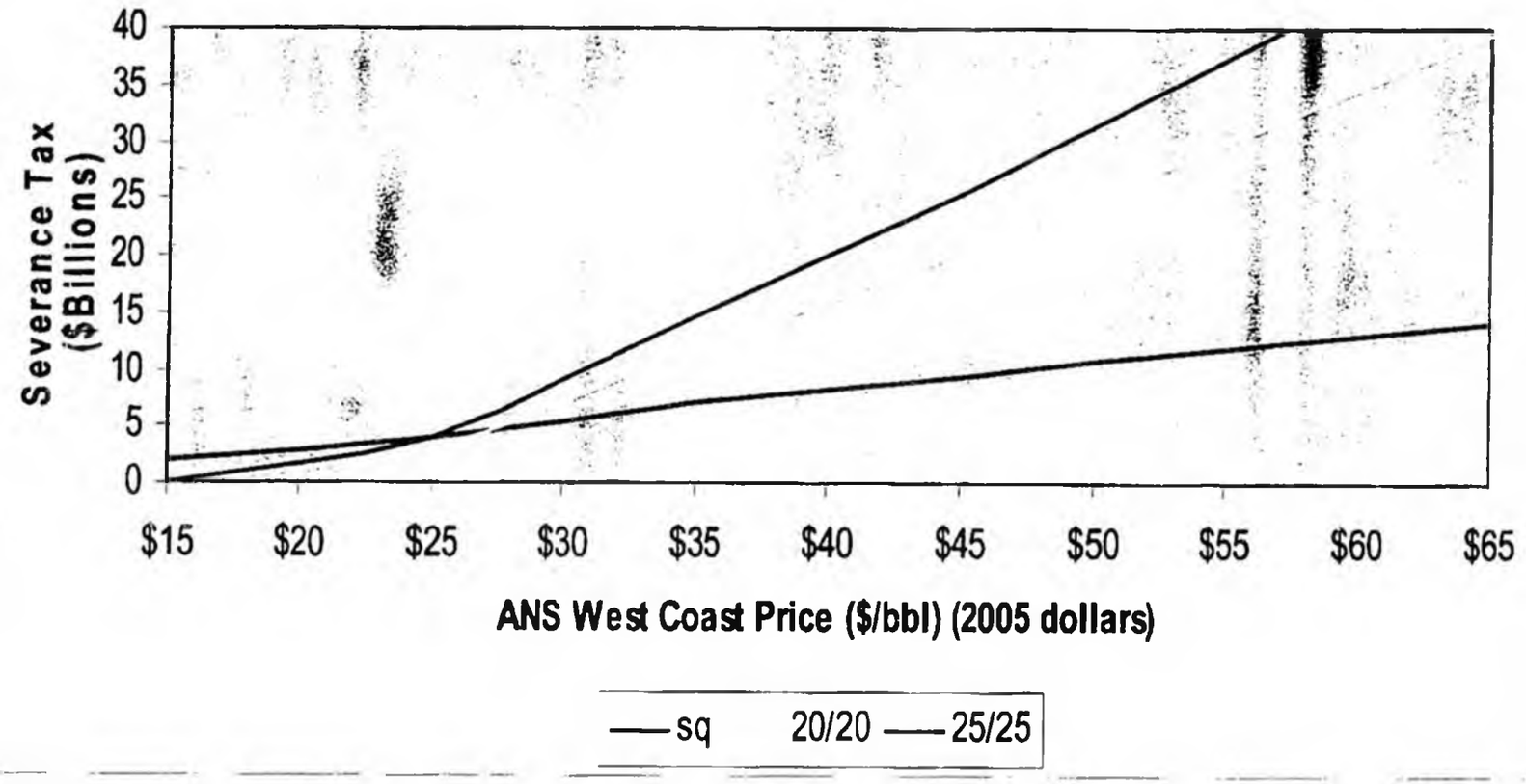
Question 90(e) - 25/25
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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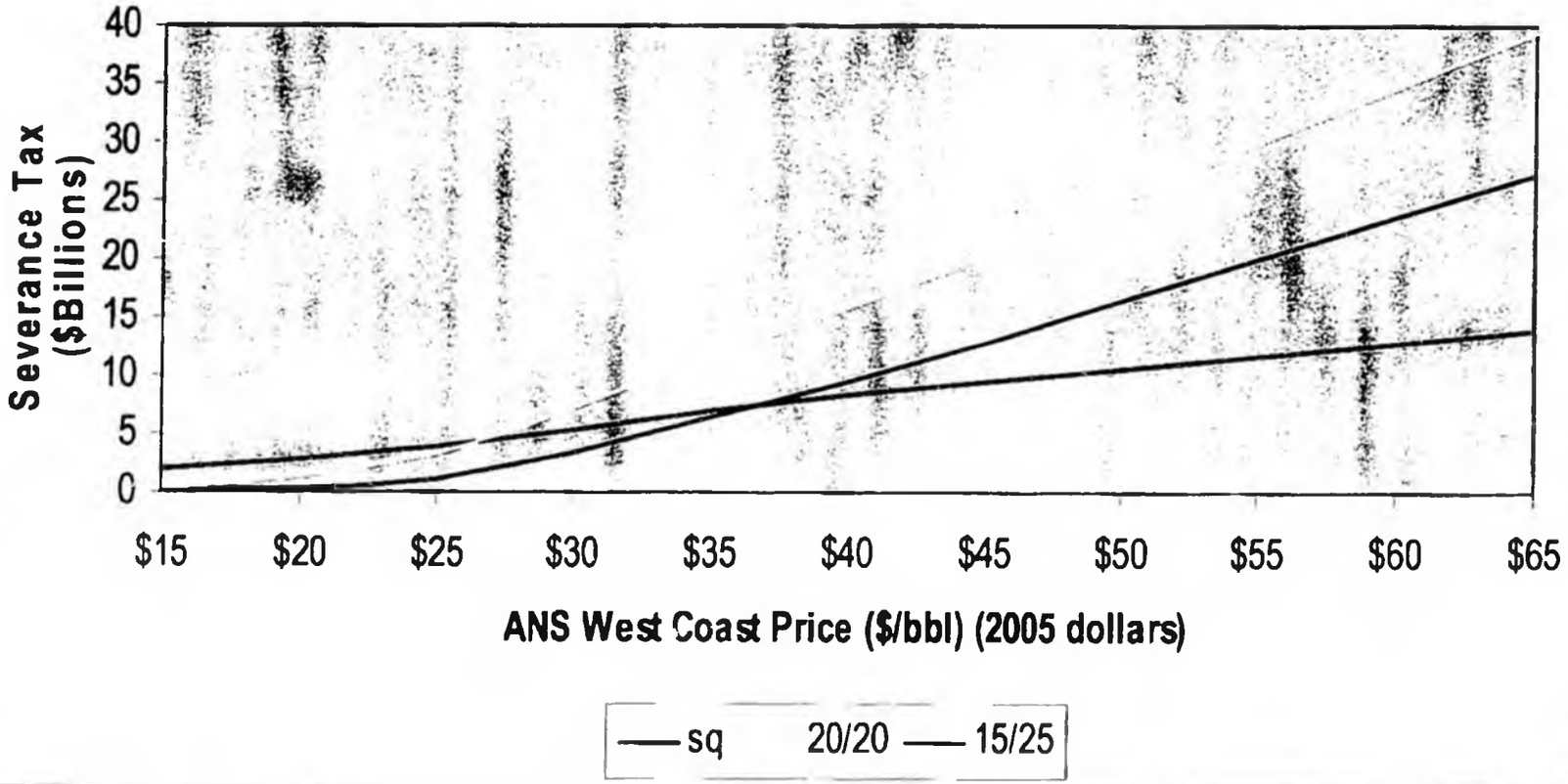
Question 90(f) - 15/25
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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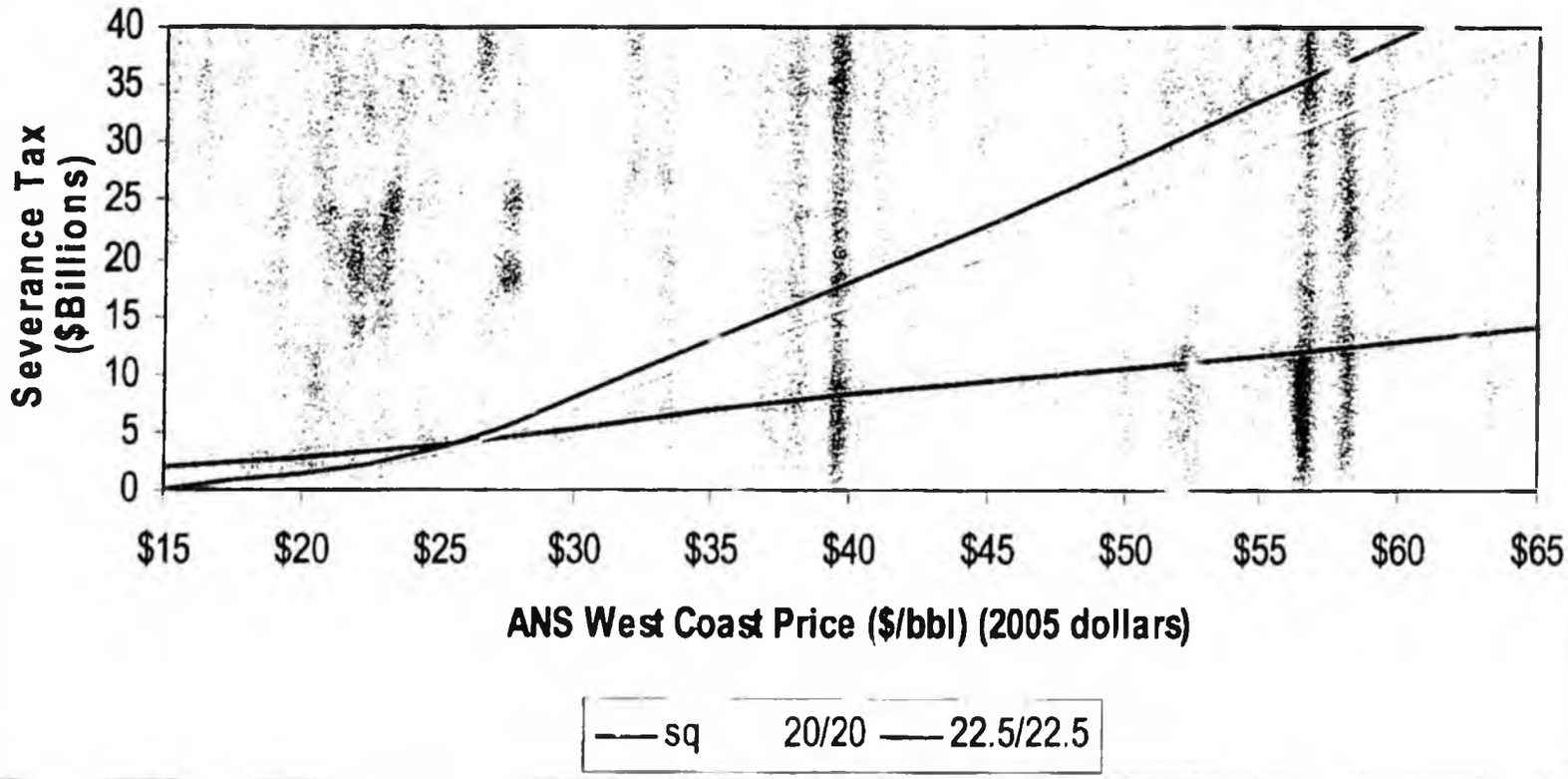
Question 90(g) - 22.5/22.5
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
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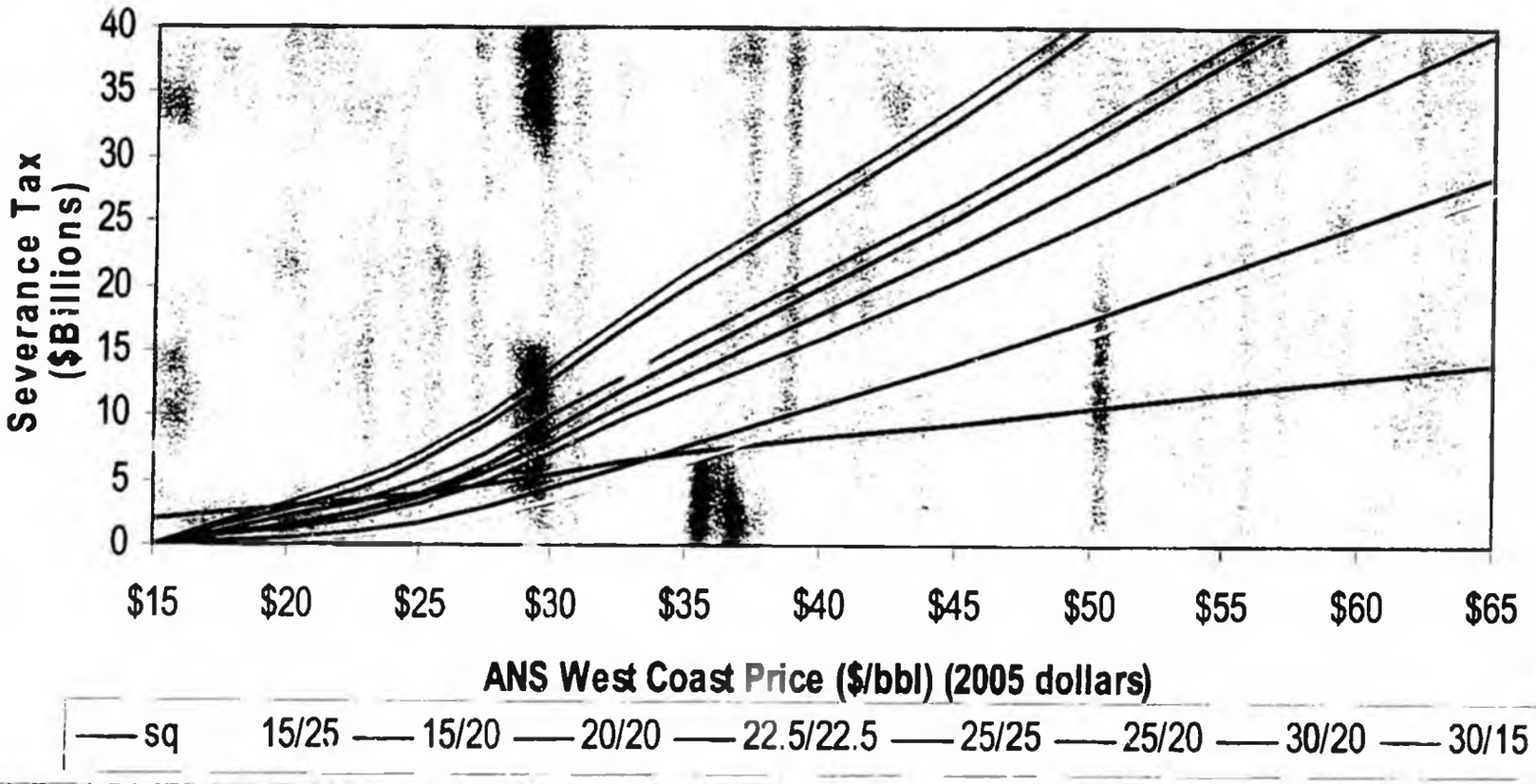
Question 90(h)
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 90(i) - Cumulative Severance Tax Revenues, Low Volume Scenario, No Gasline (in Millions of Dollars)			
Tax Rate/Credit Rate	$20/bbl	$40/bbl	$60/bbl
Status Quo	2,959	8,211	12,870
PPT 20/20	498	16,456	34,649
PPT 25/20	1,041	21,782	44,521
PPT 30/20	1,614	27,107	54,393
PPT 30/15	2,133	28,317	55,603
PPT 15/20	43	11,134	24,777
PPT 25/25	622	20,572	43,311
PPT 15/25	-	9,930	23,567
PPT 22.5/22.5	560	18,515	38,980
PPT 19/20	399	15,393	32,674
PPT 20/19	580	16,700	34,891
PPT 20/21	424	16,216	34,407
PPT 21/20	605	17,523	36,623

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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