State of Alaska
Department of Revenue

Commissioner Bryan Butcher

ANGDA ~ Tax ~ Treasury ~ ARMB ~ AMBBA ~ APFC ~ PFD ~ AHFC ~ CSSD ~ AMHTA
DOR

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Bill Thomas, Jr
State Capitol Room 505
Juneau AK, 99801

March 21, 2011

The Honorable Bill Stoltze
State Capitol Room 515
Juneau AK, 99801

SUBJECT: Response to Questions from House Finance Meetings on March 16, 17, and 18, 2011

Dear Representatives Thomas and Stoltze:

The purpose of this document is in response to the follow-up questions from the House Finance Committee meetings on March 16, 17, and 18, 2011. The requests/questions and responses follow.

(1) What would the price of oil need to be to balance the budget in FY 2030, assuming our forecasted level of production and the expected budget growth rate?

The Department forecasts revenue through FY 2020, so producing this analysis for FY 2030 requires us to make many simplifying assumptions.

- We use the FY 2030 production forecast of approximately 334,000 barrels per day.
- We hold lease expenditures and non-petroleum revenue constant at FY 2020 levels.
- We apply a 6% annual growth rate in expenditures to the FY 2012 baseline budget estimate of $5,466.2 million, resulting in an FY 2030 budget of $15,602 million.

Using this set of assumptions, an ANS price of approximately $245 per barrel would be needed to balance the budget in FY 2030. Note that this is a rough estimate and does not represent an official forecast for revenue, or spending.

(2) Has Point Thomson historically been included in the under evaluation category or did we change the classification due to litigation?

The production forecast by the Department of Revenue uses three levels of classification: currently producing, under development and under evaluation. Projects are not classified as "under development" until they are funded or awaiting project sanctioning in the very near future. Projects classified as "under development are described in the Fall 2010 Revenue Sources Book on page 40:

> It includes projects that may be in the design/construction phase, as well as development drilling and enhanced oil recovery (miscible or immiscible injection), projects currently funded or underway, but not included in the "currently producing" category. It also includes incremental oil expected from the long-term gas cap water injection project at Prudhoe Bay and Endicott, which is planned for 2012. Examples of production currently under development include: the Fiord, Nanuq, and Alpine West satellites at Alpine; the Borealis and Orion satellites at Prudhoe Bay; development drilling at Tarn, Liberty, Oooguruk and Nikaitchuq."

Using the standards listed above, production from Pt. Thomson was classified in the "under evaluation" prior to the initiation of litigation surrounding the leases at Pt. Thomson, and remains in the same category in the Fall 2010 Revenue Sources Book.

(3) Provide a chart showing our production forecast, compared to what it would be if the Department's historic error rate over the past 20 years was applied to the production forecast.

The DOR does not forecast production using a historical error rate. Twice per year, the department performs variance analyses to determine the reasons for the change in forecast versus actual. Multiple variables like project timing, unforeseen events, forecasting methodology, etc, produce annual variances. The forecast is a collaborative effort between the DOR, DNR, the producers, and the department's contracted petroleum engineers and are built on the best available information and set of circumstances known at the time. Narrative and analysis on the historical optimistic production forecasts and the variances may be found in the March 15, 2011 responses the House Finance Committee to questions raised on February 18, 2011.

(4) Provide a breakout of credits by type and by year, in the maximum detail possible.

Slides 7 and 10 of our March 17, 2011 presentation provide the amounts of each credit type, by year. The analysis is shown both for credits applied against tax liability, and for credit applications received from companies without a tax liability. The tables are included below and we have updated the information on credits applied for by companies without tax liability to reflect applications through March 17, 2011. While it may be possible to provide limited additional detail in regards to type of expenditures or area used, this would require a significant manual effort by the department because this information is not captured in any database.

Production Tax Credits Applied Against Tax Liability (Fiscal Year) ($ Millions)

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	2006	2007	2008	2009	2010*	2011*	Total
Capital Expenditure Credit	65	227	219	280	349	391	1,535
TIE Credits	33	138	73	0	0	0	243
Small Producer Credits	9	37	30	26	28	40	169
Exploration Credits	1	47	55	28	34	20	185
Totals	107	449	375	333	417	450	2,131

* Estimated

Production Tax Credits Under AS 43.55 Claimed by FY ($M)

Credit Type	Pre-2007	2007	2008	2009	2010	2011*	Total
Capital Expenditure - .023(a)		68.2	91.7	109.6	168.0	158.2	595.6
Net Operating Loss .023(b)		38.1	148.5	153.5	138.7	180.6	659.4
Well Lease Expenditure - .023(l)						6.7	6.7
Exploration -.025	48.3	44.9	85.5	56.6	99.5	2.4	337.2
Total	48.3	151.3	325.6	319.7	406.2	347.9	1598.9

* Applications received through March 17, 2011.

(5) Provide a model of a "typical" oil field, and show which credits would be received and in what amounts during exploration, development, and production.

The following table shows the tax credits relating to a hypothetical field. This is a simplified example, and is intended to be an illustration of how the tax credit system would work. The example is based on an assumption of $80 / barrel oil and $7 / barrel transportation costs.

The primary credits applicable to this example are:

- Exploration credit of up to 40% of eligible exploration expenditures.
- Capital credit of 20% of eligible expenditures for both development and ongoing capital.
- Net operating loss (NOL) credit of 25% of an annual loss.
- Small producer credit of $12 million per year, limited to tax liability after other credits.

Example of a Hypothetical Oil Field from Exploration to Production

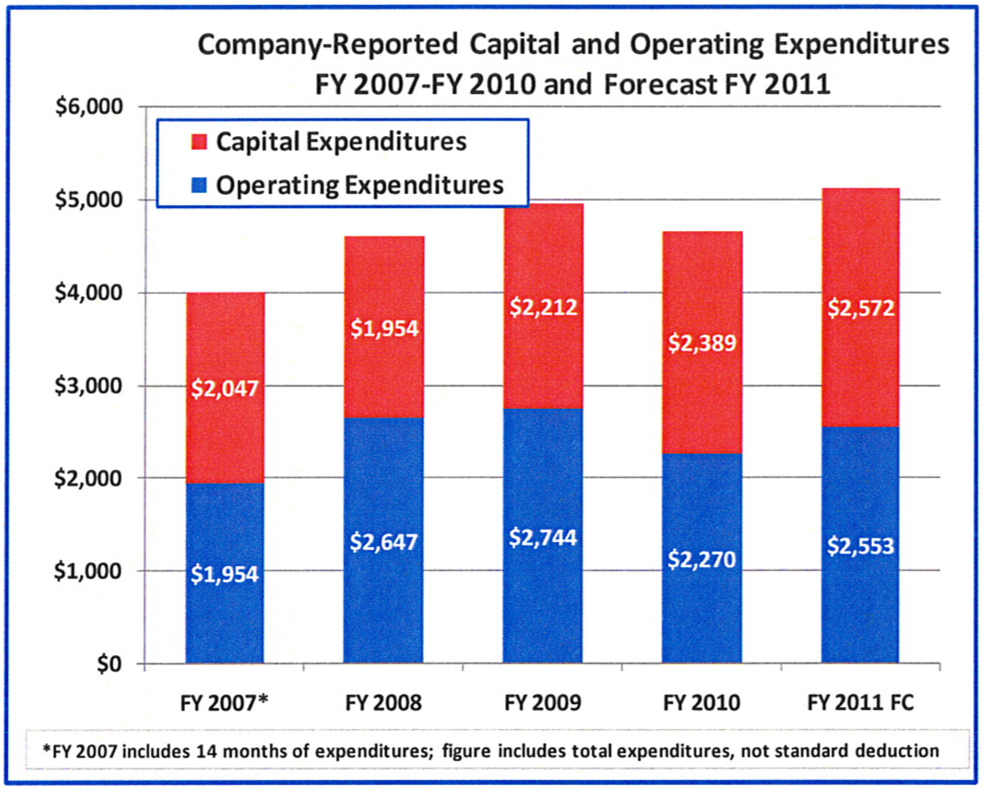
All amounts in $ millions (except production) - assumes $80 / barrel oil and $7 / barrel transportation

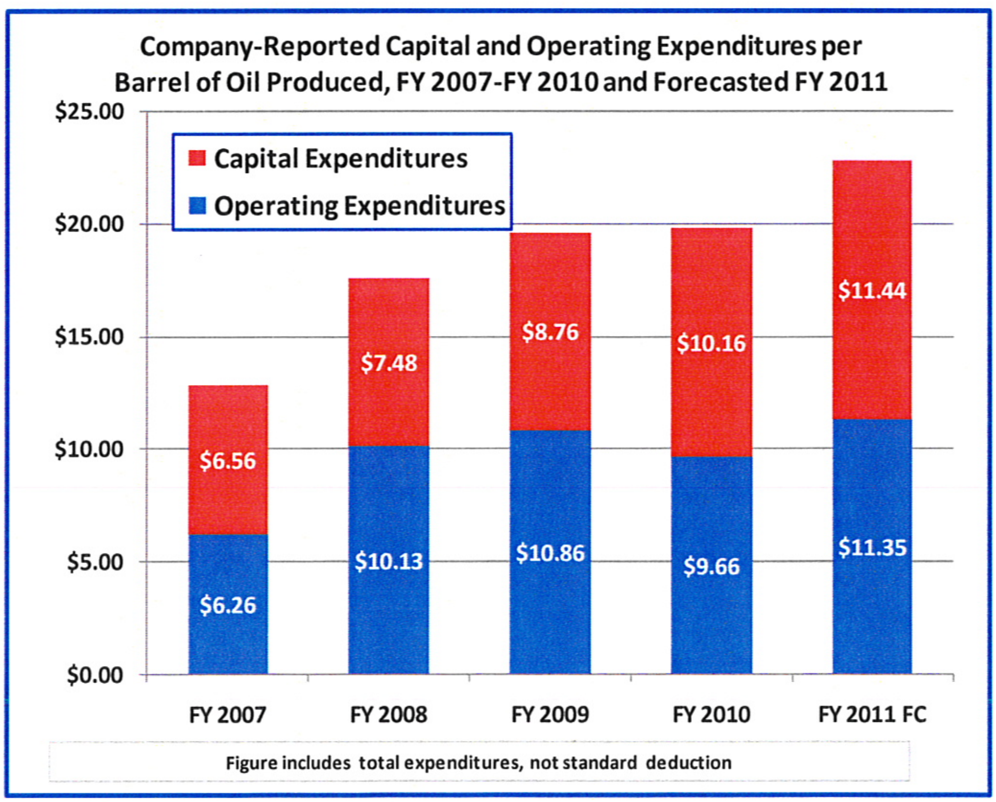
	EXPLORATION			DEVELOPMENT				TOTALS
	Year 1	Year 2	Year 3	Year 4	Year 6	Year 7	Year 8	Year 1- Year 8
Production - barrels per day	-	-	-	-	-	-	-	**Total Cost**
Capital Spending	$50.0	$50.0	$100.0	$50.0	$100.0	$300.0	$600.0	**to Develop:**
Operating Spending								**$1,250.0**
Gross Value	-$50.0	-$50.0	-$100.0	-$50.0	-$100.0	-$300.0	-$600.0	
Production Tax Value	-$50.0	-$50.0	-$100.0	-$50.0	-$100.0	-$300.0	-$600.0	**Total State**
Tax Before Credits - ACES	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	**Contribution:**
CREDITS								**$602.5**
Exploration Credit (40% of spend)	$20.0	$20.0	$40.0					
Capital Credit (20% of capex)				$10.0	$20.0	$60.0	$120.0	**Net Industry**
NOL Credit (25% of loss)	$12.5	$12.5	$25.0	$12.5	$25.0	$75.0	$150.0	**Investment:**
Total Credits	**$32.5**	**$32.5**	**$65.0**	**$22.5**	**$45.0**	**$135.0**	**$270.0**	**$647.5**
Total Paid to (Received From) State	**-$32.5**	**-$32.5**	**-$65.0**	**-$22.5**	**-$45.0**	**-$135.0**	**-$270.0**	

	PRODUCTION ***(continues into future beyond year 16)***							
	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
Production - barrels per day	20,000	40,000	40,000	40,000	40,000	37,000	33,000	30,000
Royalty Paid to State	$66.6	$133.2	$133.2	$133.2	$133.2	$123.2	$109.9	$99.9
Capital Spending	$321.9	$243.8	$100.0	$43.8	$43.8	$40.5	$36.1	$32.9
Operating Spending	$70.1	$56.9	$61.3	$67.9	$72.3	$72.9	$72.3	$70.6
Gross Value	$466.3	$932.6	$932.6	$932.6	$932.6	$862.6	$769.4	$699.4
Production Tax Value	$74.3	$631.8	$771.2	$820.9	$816.5	$749.2	$661.0	$596.0
PTV / bbl	$11.6	$49.5	$60.4	$64.3	$63.9	$63.4	$62.7	$62.2
ACES TAX RATE	25.0%	32.8%	37.1%	38.7%	38.6%	38.4%	38.1%	37.9%
Tax Before Credits - ACES	$18.6	$207.1	$286.5	$317.7	$314.9	$287.4	$251.7	$225.7
CREDITS								
Capital Credit (20% of capex)	$64.4	$48.8	$20.0	$8.8	$8.8	$8.1	$7.2	$6.6
NOL Credit (25% of loss)								
Small Producer Credit (Up to $12 mm)		$12.0	$12.0	$12.0	$12.0	$12.0	$12.0	$12.0
Total Credits	**$64.4**	**$60.8**	**$32.0**	**$20.8**	**$20.8**	**$20.1**	**$0.0**	**$18.6**
Total Prod Tax Paid to (Rec'd From) State	**-$45.8**	**$146.4**	**$254.5**	**$296.9**	**$294.1**	**$267.3**	**$251.7**	**$207.2**
Total Prod Tax and Royalty Paid to State	**$20.8**	**$279.6**	**$387.7**	**$430.2**	**$427.4**	**$390.5**	**$361.6**	**$307.1**

(6) Provide a history and forecast of total capital and operating expenses.

The following charts show historical and forecast capital and operating expenditures. The amounts are shown both in total and as a per-barrel calculation.





(7) How many taxpayers will there be available for audit for production tax this year, compared to 2006?

The requested information was included in the "Oil and Gas Production Tax Status Report to the Legislature" released on January 18, 2011. On page 11 of that publication, we reported the following:

"In 2006, the first year that filings were made under a net profits tax, there were 19 companies filing annual returns. In 2007, the number of companies filing production tax returns totaled 26, and in 2008, 36 companies filed annual production tax returns. The filing for 2009 increased only slightly from 2008, with 39 companies filing returns."

We will know the number of companies filing annual returns for 2010 after the due date for those returns, which is March 31, 2011.

(8) Have there been any applications for credits between January 4, 2011 and March 17, 2011?

As we indicated in committee, the vast majority of applications for exploration credits occur in the first half of the fiscal year. Since January 4, there have been $575,000 in claims for the exploration capital credit under AS 43.55.023(a)(2), and there have been no additional applications for the alternative credit for exploration under AS 43.55.025.

We have received 15 applications for credits since January 4, 2011, in the following amounts:

- AS 43.55.023(a)(1) Qualified Capital Expenditure Credits: $84,797,000
- AS 43.55.023(a)(2) Exploration Capital Credits: $575,000
- AS 43.55.023(b) NOL Carry Forward Credits: $180,359,000
- AS 43.55.023(l)(1) Well Lease Expenditure Credits: $834,000
- Total Applications for credits since January 4, 2011: $266,567,000

(9) Provide a figure showing the amount of exploration credits claimed through January 4 of Fiscal Years 2009, 2010, and 2011.

The vast majority of applications for the alternative tax credit for exploration under AS 43.55.025 are received in the first half of the fiscal year, and no applications have been received since January 4 this year. Therefore for this particular credit, comparing the total applications in FY 2009 and FY 2010 with the applications for the first half of FY 2011 provides a valid year-over-year comparison. The amounts of credit applications from companies without a tax liability for the alternative tax credit for exploration in the three years are as follows:

- FY 2009: $56.6 million
- FY 2010: $99.5 million
- FY 2011: $2.4 million (through March 17, 2011; we do not expect additional applications between March 17, 2011 and June 30, 2011)

(10) Provide a list of changes made to HB 110 in the House Resources committee, compared to the original proposal.

Following is a list of the amendments that were made to HB 110 in House Resources

House Resources meeting February 25, 2010, amendments passed:

#1: Qualification for 15% tax rate for new fields, Section 6 of CSHB 110

- In the original bill, the 25 % base tax rate applied to oil and gas produced from a lease or property that as of December 31, 2010 was or had previously been within a unit or in commercial production. The December 2010 date was changed to December 2008. Under the CS for HB 110, the 25 % base tax rate applies to oil and gas produced from a lease or property containing land that on December 31, 2008, was within a unit or in commercial production. For other oil and gas, the base rate is 15%. Annual progressivity applies to all production.

#2: Extends the sunset for non-transferable tax credits to 2021

- Adds two new sections 18 and 20, to amend AS 43.55.024(b) and (d) to extend the sunset date from 2016 to 2021. Change effective July 1, 2011. .

#3: Raises small producer credit under AS 43.55.024(c).

- Adds a new section 19 to increase the maximum allowable for the small producer tax credit from $12 million to $15 million per calendar year.
- Effective date is July 1, 2011, but DOR recommends changing to a future date, such as January 1, 2012, for production after December 31, 2011.

4: Extends the sunset from 2016 to 2021 for AS 43.55.025

- New sections 22 and 23 amend AS 43.55.025 (b) and (k) to extend the sunset date for exploration tax credits and certain seismic expenditures from 2016 to 2021.
- Effective July 1, 2011.

5: Tax credit certificates may be used in one year, AS 43.55.023.

- Section 11 and 12 were amended to make the change to the tax credit certificate rules retroactive to January 1, 2011.

#6: New North Slope credit of 30%

- Sections 21 and 24 amend AS 43.55.025 to add sub-section (a)(6) and a new section (n). This would add a new 30% credit for North Slope expenditures incurred outside a unit, or within a unit formed after June 30, 2008 if the expenditures are incurred before the later of the date four years after the unit is formed or the first exploration well is drilled on a lease or property within the unit.
- Effective January 1, 2012, to expenditures incurred after December 31, 2011

#7: Publication of tax credit information

- New section 28 amends 43.55.890 to clarify that the Department of Revenue may publish detailed aggregated information on tax credits.
- Effective date of 12/31/2011.

House Resources meeting February 28, 2010, amendments passed:

#15: Statute of limitations stays at 6 years

- Deleted former section 19 that would have amended AS 43.55.075 to reduce the six year statute of limitations to four years.

#25: Tax credit under 43.55.023(p) for percentage of wages and compensation attributable to Alaska residents.

- Section 17 adds a new tax credit to AS 43.55.023 to allow a credit against taxes levied under AS 43.55.011(e) for the percentage of total wages and compensation attributable to Alaska residents that exceeds total wages and compensation paid by the producer.
- Effective date is January 1, 2012, applicable to expenditures after December 31, 2010.

(11) Provide the names of persons that the Department of Revenue Commissioner and Deputy Commissioner met with to discuss possible changes to the oil and gas production tax and when those meetings were held.

The Department is currently working on this response.

(12) What was the reduction in oil production and revenue from the temporary shutdown of TAPS in January 2011?

From January 1-7, average North Slope production was approximately 634,623 barrels per day. If this average rate had continued for all of January, we estimate that ANS royalties would have been $190 million and ANS production tax would have been $360 million, for a total of $550 million.

The actual average North Slope production for January was approximately 471,665 barrels per day. We estimate that ANS royalties were $150 million and ANS production tax was $200 million, for a total of $350 million.

The difference between these two calculations is $200 million. This is a high level, estimated difference based on analysis using our DOR forecast model with two different assumptions for average daily production.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tang

Bruce Tangeman
Deputy Commissioner