State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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

March 22, 2011

The Honorable Joe Paskvan
Co-Chair, Senate Resources Committee
State Capitol Room 115
Juneau AK, 99801

The Honorable Thomas Wagoner
Co-Chair, Senate Resources Committee
State Capitol Room 427
Juneau AK, 99801

SUBJECT: Response #1 to Questions from SB 49 Bill Sectional Presentation in Senate Resources on March 11 and 14, 2011, and tax credits presentation on March 16, 2011.

Dear Co-Chairs Paskvan and Wagoner:

The purpose of this document is to respond to the follow-up questions raised by the Senate Resources Committee meeting during our presentation of the SB 49 bill introduction on March 11 and 14, 2011, and during our tax credits presentation on March 16, 2011. The requests/questions and responses follow. As noted in this document, there are a handful of remaining questions which we will provide answers to at a later date.

QUESTIONS FROM BILL INTRODUCTION PRESENTATION

1) **Discuss whether / how North Slope reserve additions recently reported by Conoco Phillips are included in our production forecast.**

   The Department of Revenue considers technically recoverable oil in the production forecast. Updated estimates of original oil in place (OOIP) and technically recoverable reserves are discussed with the individual operators on at least an annual basis and will be considered in future forecasts.

2) What is the forecasted production decline over the next decade?

The Department of Revenue's Fall 2010 production forecast, which includes producing, under development and under evaluation, projects an average decline rate of 2.1% per year from FY 2010 through FY 2020. The under evaluation portion is the most speculative and could greatly affect the production curve if it were not realized.

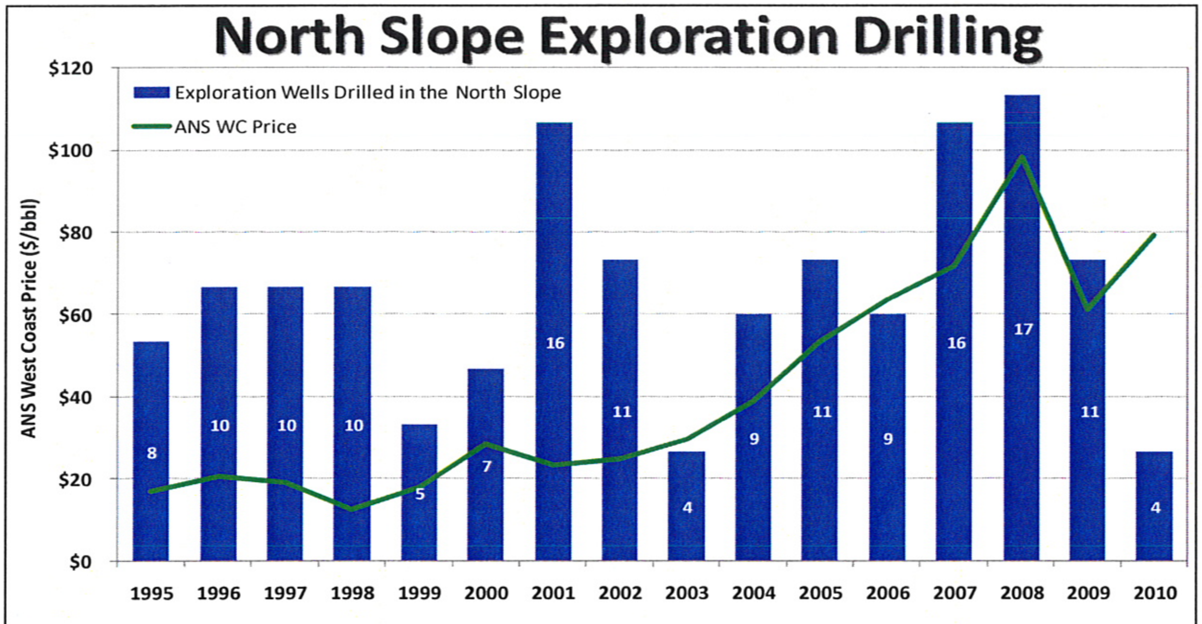
3) What part of the Department's production forecast comes from areas that are not currently unitized?

The vast majority of production in our forecast comes from areas that are currently unitized. Through FY 2020, the only production in our forecast that comes from an area that is not currently in a unit is a portion of the forecast production from the NPR-A. In general, production from areas that are not yet unitized does not have the level of certainty required to be included in our production forecast. In order to be included, a field must at least be "under evaluation," meaning it is a technically viable project where engineering, cost, risk and reward are all being actively evaluated. Most of the oil outside existing units does not yet meet these criteria.

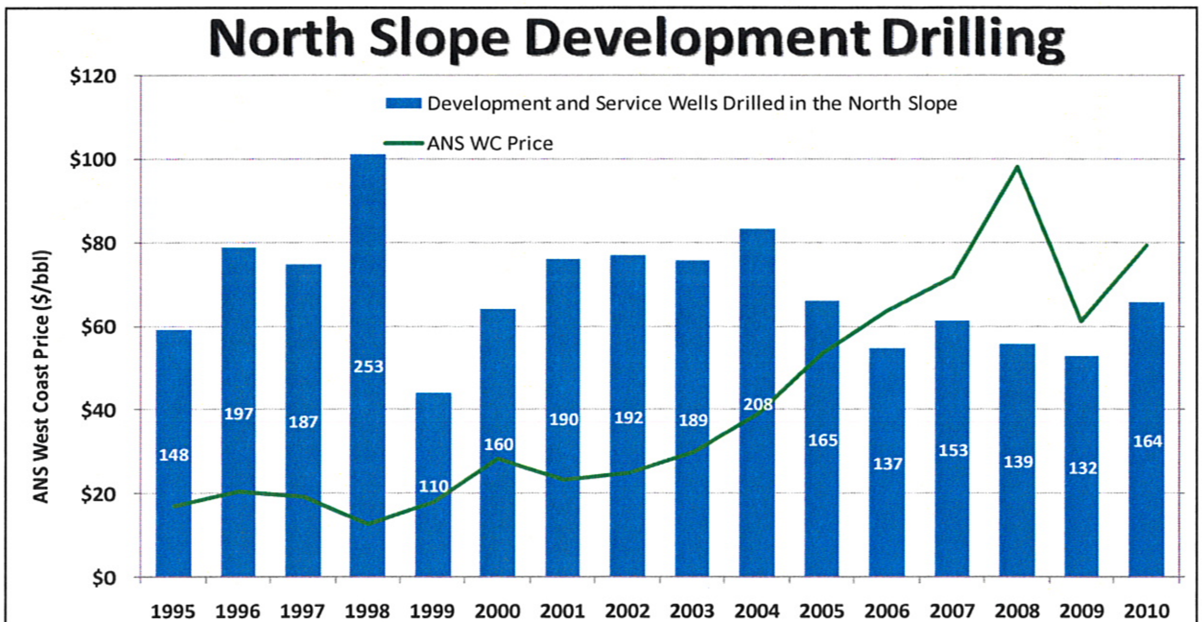
4) **Why was only one exploration well drilled in 2003?**

It has been brought to our attention that the drilling activity charts presented by the Department of Revenue on the basis of AOGCC data contained some inaccuracies. Corrected exploration and development drilling activity charts are included below.

Several factors may have contributed to the decline in exploration drilling in 2003, including the economic downturn at the beginning of that decade, merger and acquisition activity impacting companies active in Alaska, and changes in corporate strategy.



Source: Alaska Oil and Gas Conservation Commission



Source: Alaska Oil and Gas Conservation Commission

5) **Compare trends in the number of exploration and development wells drilled in Alaska, to trends in the U.S. or worldwide.**

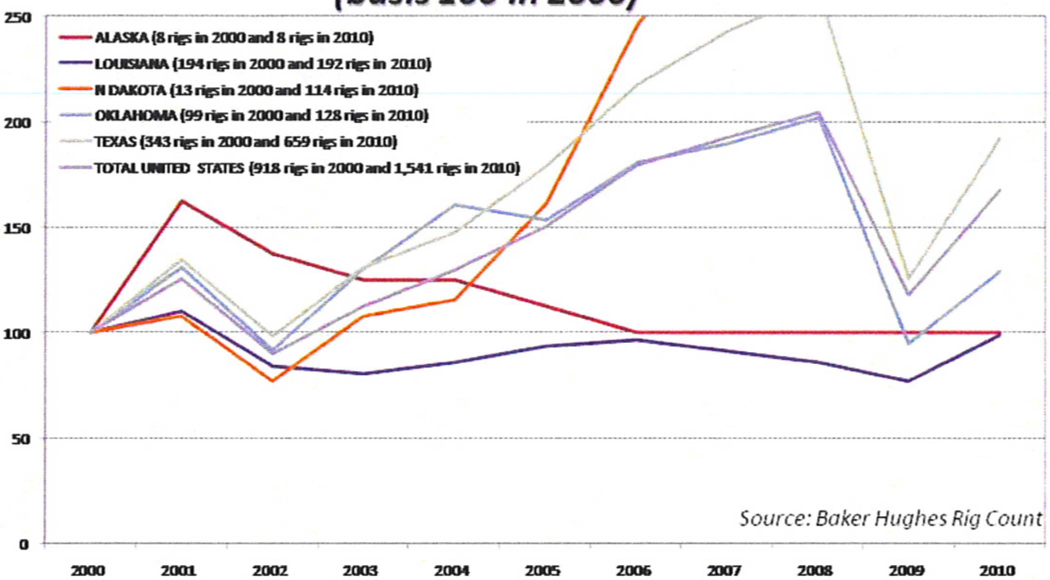
The number of active rigs can be used to compare oil and gas activity levels in various jurisdictions. The following charts show trends in rig counts in the United States, and internationally. These charts display the relative change in rig counts over the past decade using 2000 as a base year (the rig count for each series for any given year is represented relative to the rig count for that series in year 2000 – for example, if the rig count was to go from 8 in 2000 to 16 in 2010, this would be reflected in the chart by a line going from 100 in 2000 to 200 in 2010). These statistics include oil and gas rigs, active both onshore and offshore. No differentiation is made between exploration and development rigs in this context.

In summary, one can observe over the 2000 to 2010 period:

- A relatively flat rig count in Alaska
- The impacts of the recent recessions and of the "shale boom" in other US States
- Rig count in Europe remaining relatively stable
- Rig count in other areas, including the US, typically increasing by over 50%

Alaska and States with over 100 rigs in 2010

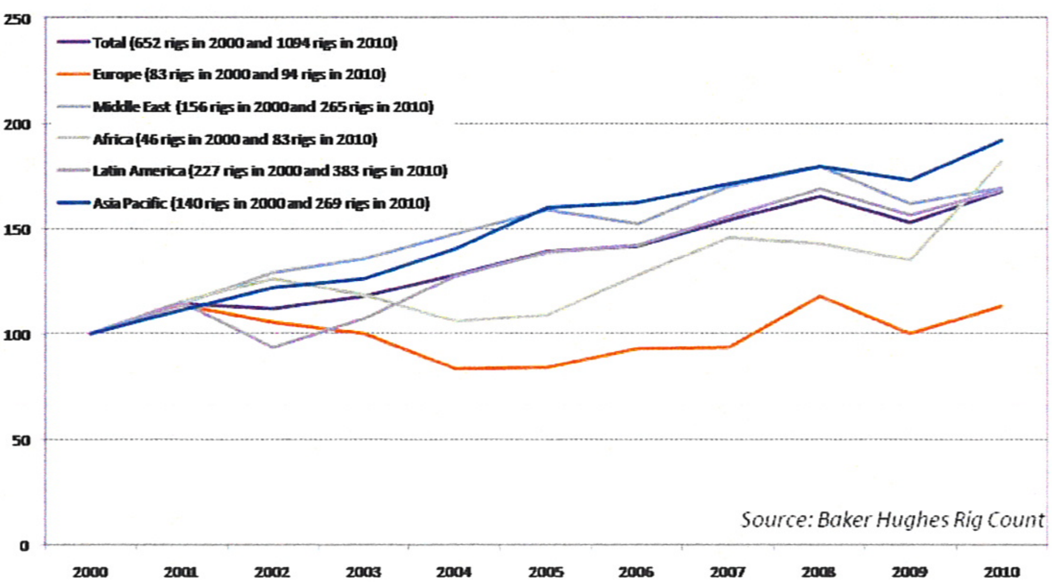
(basis 100 in 2000)



Notes: Includes oil and gas rigs (reflects impact of shale gas boom), as well as onshore and offshore (State + Federal). Selected States have over 100 active rigs in 2010 (except Alaska)

International Rig Counts

(basis 100 in 2000)



Notes: Includes oil and gas rigs, as well as onshore and offshore.

6) **Provide information about the "normal" number of development wells drilled in a mature oil field.**

The definition of an "elephant" oil field varies substantially in practical use, but typically refers to very large oil fields with total oil resources estimated in the hundreds of millions to billions of barrels. Prudhoe Bay is an "elephant" oil field with estimates from BP of more than 25 billion barrels of OOIP. More than 1,100 producing wells have been drilled in the Prudhoe Bay field as well as more than a hundred injection wells.

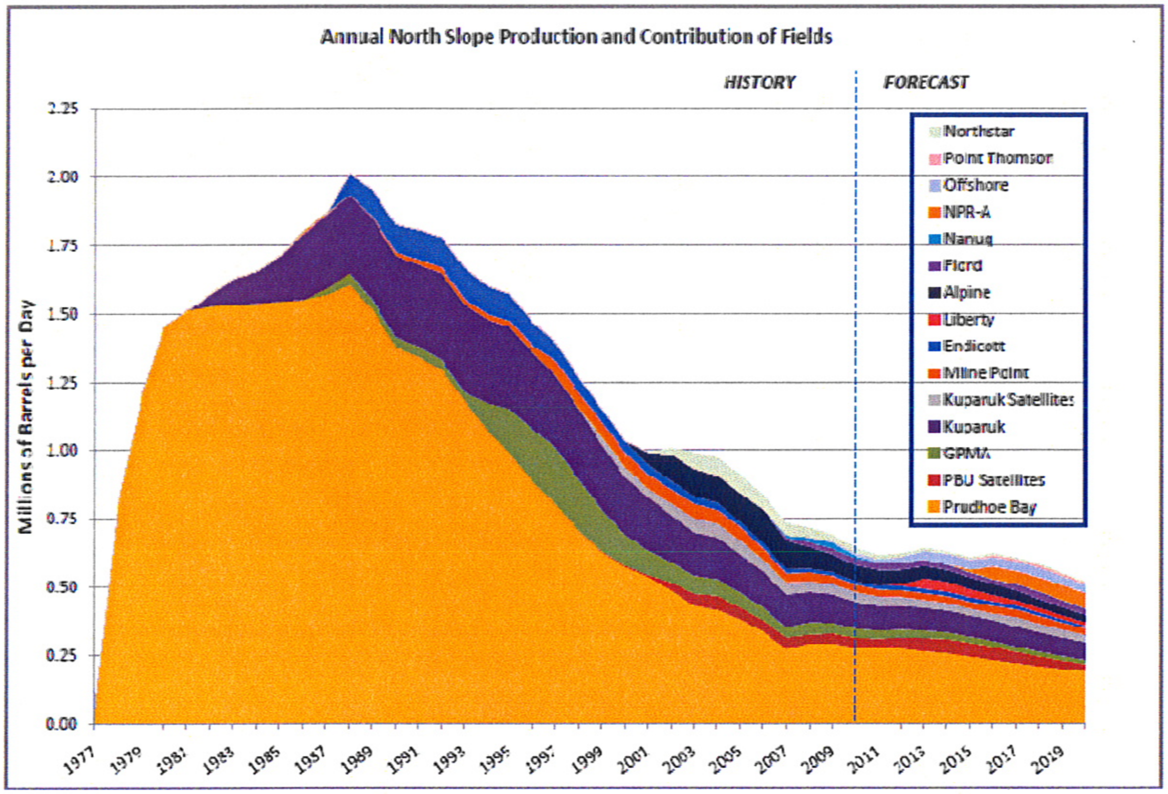
Unfortunately, it would be difficult to estimate a "normal" number of producing wells in a normal or hypothetical field as the development program will depend on the geology and the physical characteristics of the oil, among other factors. For example, looking at AOGCC data, Prudhoe Bay has seen an average of between 40 and 60 new producing "wells/penetrations" completed each year since 2000. While Kuparuk has seen an average of between 8 and 10 new producing "wells/penetrations" completed each year in that same time. In both cases, the productivity of the wells seem to be decreasing with time.

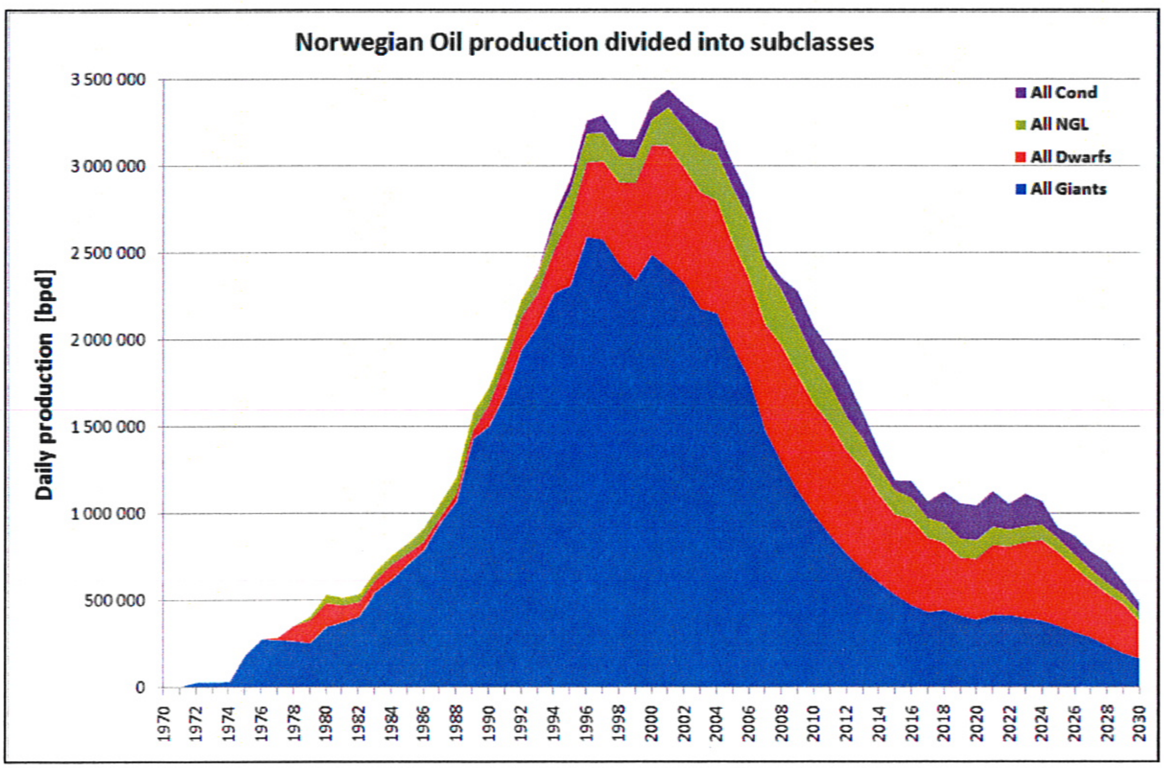
More public Prudhoe Bay statistics can be found at the following web address: http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_alaska_prudhoe_bay_fact_sheet.pdf

7) **Provide information about the pattern of natural decline in exploration of a mature oil basin, and how Alaska's mature basins compare. Also explain how a company would typically model investments in a mature oil basin.**

Following are graphs of the Alaska North Slope (ANS) and Norway's historical and forecasted production. Norway is not as mature as ANS. Norway's production peaked in 2000 at approximately 3.5MMBPD and is currently declining at an average rate of 13% ten years after peaking. ANS peaked in 1988 at 2.011MMBPD and is currently declining at a rate of 4.3%. For comparison, ten years after ANS peaked the decline rate was 9.1%.

Bob George of Gaffney, Cline and Associates testified before the committee on March 18, 2011. In his testimony, Mr. George addressed this question and explained that a company would typically assume a production path not unlike that of Alaska's in modeling investments in a mature oil basin, with a fast ramp up, a plateau period, and a period of decline. However Mr. George also noted that there are multiple opportunities in Alaska that could allow the state to return to growing production, including heavy oil, new discoveries, and increased development of known resources.


Annual North Slope Production and Contribution of Fields
HISTORY
FORECAST
Northstar
Point Thomson
Offshore
NPR-A
Nanuq
Fiord
Alpine
Liberty
Endicott
Milne Point
Kuparuk Satellites
Kuparuk
GPMA
PBU Satellites
Prudhoe Bay
Millions of Barrels per Day


Norwegian Oil production divided into subclasses
All Cond
All NGL
All Dwarfs
All Giants
Daily production [bpd]

8) Does the Department of Revenue have access to drilling plans and / or plans of development when preparing their production forecast, and how far out do those planning documents go?

Yes, the Department of Revenue has access to drilling plans and plans of development (PODs) when preparing the production forecast. In the near term, about one or two years out, the operators are usually very specific, sharing drilling schedules, budgets, production forecasts, etc. with us. In the time up to five years, some of the operators usually have a "plan" for future development that is somewhat less specific that may include anticipated wells, some budget information and perhaps anticipated production. Beyond five years, some of the operators will have a general plan that may just include the prospective field and a very general time estimate of the start of the field. The Department of Revenue does consider the Plans of Development submitted by the operators to the Department of Natural Resources.

9) **What would the revenue reductions have been each year since the passage of ACES, if the provisions of SB 49 had been in place instead?**

The following table provides the estimated impact of SB 49 using historical Department of Revenue models, which are set up to provide revenue forecasts by fiscal year. SB 49 as proposed would use calendar year prices to determine the average price for calculating progressivity and then allocate the revenue to fiscal years. This structural difference might cause the impacts to be slightly more in one year and less in the next, but the revenue impact should be the same over time.

Note also that this table does not reflect production level increases that would likely have been experienced had SB 49 been implemented during these years.

Production Tax Revenue under ACES and the Estimated Impact of HB 110/SB 49 on Production Tax Revenue in Prior Years*

(in $billions)

Year	Production Tax Revenue under ACES	Impact of Tax Rate Change	Impact of Well Lease Exp Credit	**Total Estimated Impact**	Estimated Production Tax Revenue under HB 110/SB 49
FY 2008	$6.81	-$2.06	-$0.30	**-$2.36**	$4.45
FY 2009	$3.10	-$0.99	-$0.30	**-$1.29**	$1.81
FY 2010	$2.86	-$0.60	-$0.30	**-$0.90**	$1.96

***Notes regarding this analysis**

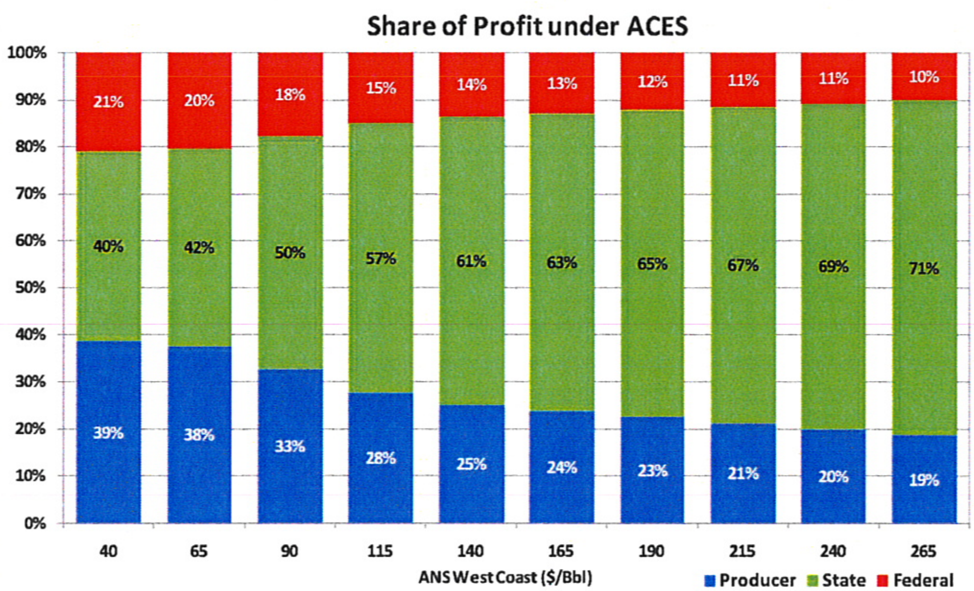
This analysis considers revenue impacts of only those provisions of HB 110 and SB 49 that can be reasonably quantified and that are not considered revenue neutral over time (such as the elimination of the credit split). Additionally, because historical models are maintained on a fiscal year basis, fiscal year inputs such as prices, production and costs were used for this analysis, even though annual tax calculations in HB 110 and SB 49 are based on calendar year inputs. For the well lease expenditure credit, we chose a median of the range of $200 to $400 million per year as stated in the fiscal note.
This analysis does not consider the likely production increases had HB 110/SB 49 been in effect.

10) Please provide the numbers, and assumptions, behind the profit share graph on slide 20 as presented.

The chart uses a range of possible ANS West Coast prices, with no change in costs across the range. The chart assumes production on state land. Following are the assumptions used in producing the chart. The chart as presented in committee is also included below.

Assumptions	Value	Unit
Transportation Costs	6.00	$/bbl
Royalty Rate	12.5%	
Upstream CAPEX	10.00	$/bbl
Upstream OPEX	10.00	$/bbl
Total Upstream Costs	**20.00**	**$/bbl**
Daily Production	600,000	Kbbl/d
Property Tax (% of CAPEX)	2.00%	

Share of total profit - ACES

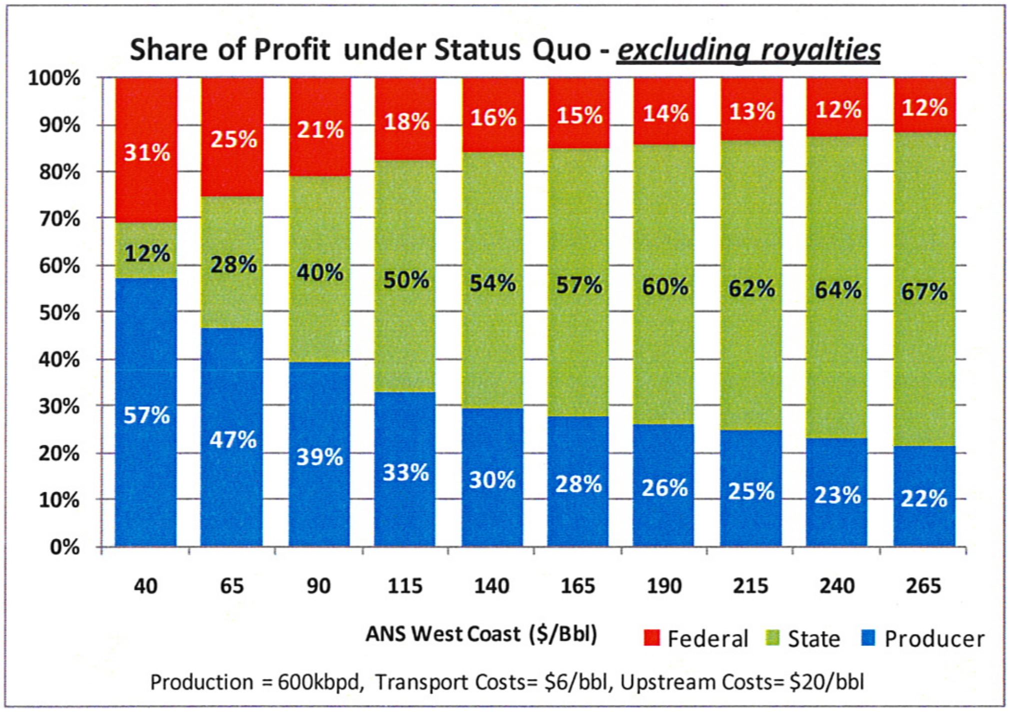


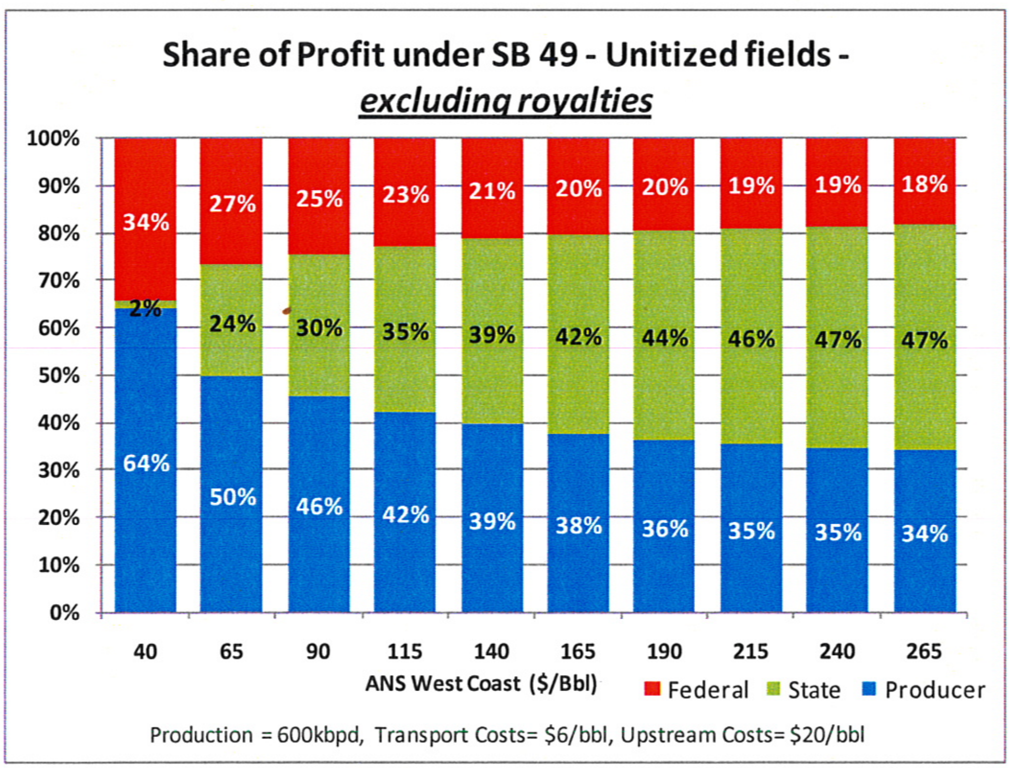
Production=600kbpd, Transport Costs=$6/bbl, Upstream Costs=$20/bbl

3/10/2011 20

11) Please reproduce the profit share graph on slide 20 without including state royalty.

The following charts show the distribution of profit (excluding royalty) at various oil prices, under both status quo and SB 49. Royalty is an integral part of the state's fiscal system and we maintain that it should be included in the analysis of distribution of profit.

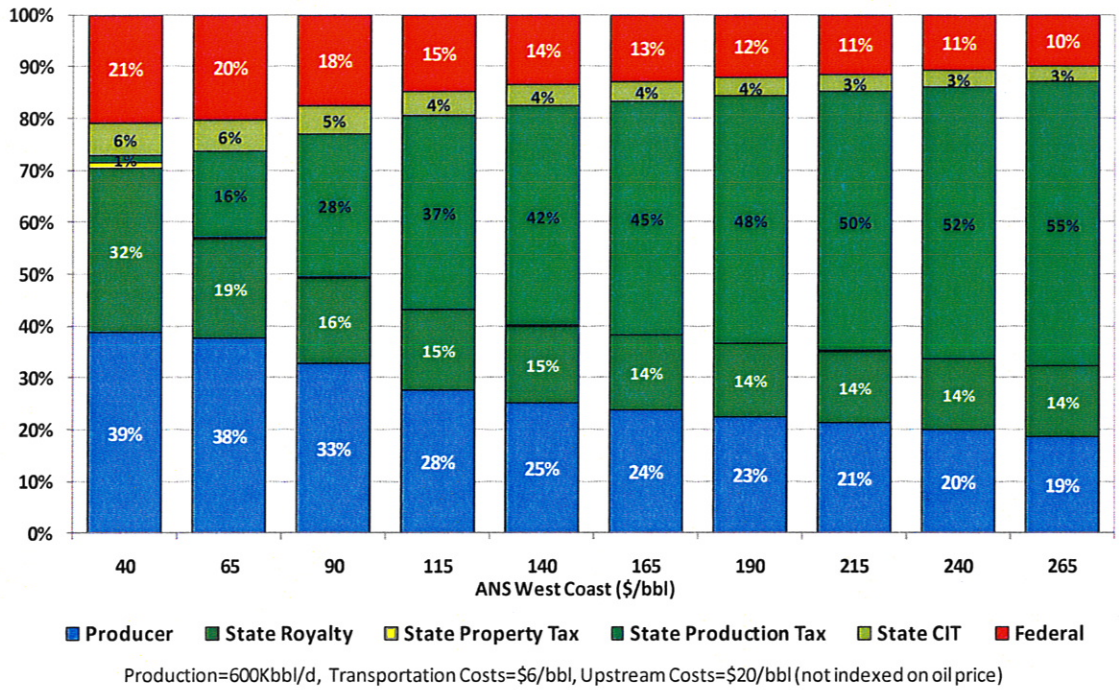




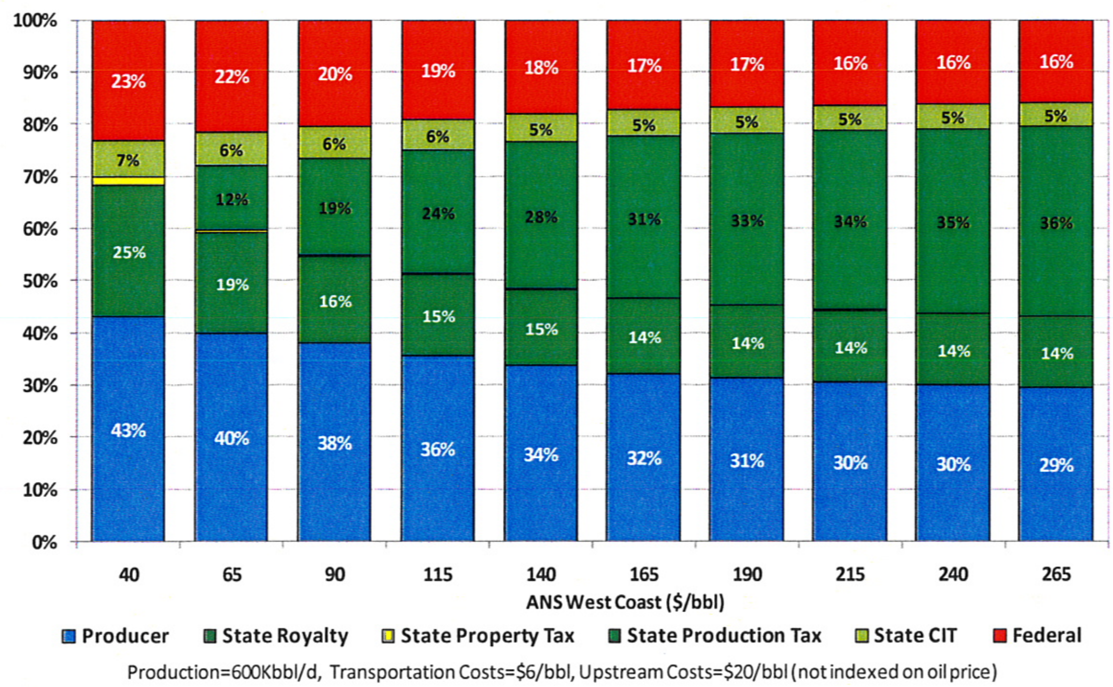
12) Please reproduce the profit share graph on slide 20, including royalty, with the state share broken down into the various components.

The following charts show the distribution of profit at various oil prices, including detailed breakdown of the components of state take, under both status quo and SB 49.

Share of Profit under Status Quo



Share of Profit under SB49 Unitized Fields



13) **Explain why the profit shares on the share graph on slide 20 and 21 are different than shares of gross value.**

Profit and gross value are two different numbers – one includes costs to produce oil and one does not. The concept of "profit" used in the "share of profit" slides represents the wellhead value of oil (which excludes transportation costs), less lease expenditures (operating and capital costs). The concept of "gross value at point of production" represents the value at the entry point into a common carrier pipeline (such as TAPS) and excludes only transportation costs.

14) **Provide the model used to produce the profit share graph on slide 20.**

The Department has prepared a one-year snapshot model designed to illustrate the impacts of SB49 on the state, federal and producer takes for a certain production rate, under fixed oil price and cost assumptions. Department staff are available to meet with interested legislators who wish to manipulate this model.

QUESTIONS FROM TAX CREDITS PRESENTATION

15) **What is the difference between an exploration well and a development well?**

Following are definitions of different types of wells, from the AOGCC:

- "Exploratory Well" means a well drilled to discover or to delineate a pool
- "Development Well" means a well drilled to a known productive pool
- "Service Well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production
- "Stratigraphic Test Well" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas

16) **Explain the difference between the $85.5 million in exploration credits for FY 2008 shown in today's presentation, and a lower number ($38.5 million) provided in an earlier presentation.**

The table used in the earlier presentation incorrectly excluded 3 applications for exploration credit claims totaling $47 million submitted and received during FY 2008. The data was omitted from a report obtained out of the database used to track credit applications. The error was discovered as we reconciled the eventual credits paid or refunded by the state to the applications received.

17) Will the Department be revising its estimate for credits taken in 2011 based on the recent announcement that Repsol will be investing in an exploration program on the North Slope?

The Department will not be revising the estimate for credits taken in FY 2011 based on Repsol's recent announcement about its North Slope investment plans. The Department may, however, revise estimates for FY 2012 and later years' expenditures and credits, pending further information gathered during our extensive fall forecasting process. As part of our fall forecast, we review plans of development, and we meet individually with oil and gas explorers and developers in order to gain a better understanding of their projects. This will also give us the opportunity to inquire about spending plans, and whether or not the projects will likely meet the criteria for credit under one of our exploration tax credits or other credits. Assuming company plans proceed as intended, we will likely incorporate these new estimates into our Fall 2011 forecast.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tang

Bruce Tangeman
Deputy Commissioner

OUTSTANDING QUESTIONS

The following questions remain from the Senate Resources hearings on March 11, 14, and 16, 2011. We are working on these questions and will respond at a future date.

1) **Provide the Department's previous forecasts for Prudhoe Bay production in 5-year increments (2010, 2005, 2000, etc)**

2) **Explain the concept of "duty to produce".**

3) **Can we look at a possible correlation between declines in exploration in 2003 and 2010, and the economic downturns in 2001 and 2008. Is Alaska's decline in exploration in those years similar to other states after removing gas exploration wells?**

4) **Provide information about companies that are working together on exploration wells shown in the exploration wells slide.**

5) **How do drilling agreements work when companies are working together? If one company pulls out of a project, is the project typically cancelled?**

6) **Compare royalty rates in Alaska with royalty rates in other states; that is, compare royalties paid in Alaska as an owner state to royalties paid to private land owners in Texas, North Dakota, etc.**

7) **Please show SB 49 compared to our revenue forecast in the "income statement" format for FY 2010, FY 2011, and FY 2012.**

8) **Please recast the fiscal note analysis using flat oil prices of $100, $110, and $120 instead of the Department's forecast oil prices.**

9) **Explain the difference between the $85.5 million in exploration credits for FY 2008 shown in today's presentation, and a lower number ($38.5 million) provided in an earlier presentation.**

10) **Provide a 5-year forecast for capital expenditures and the credits derived from those expenditures.**

11) **Provide a chart of effective tax rates under current law and SB 49 using forecasted transportation costs, lease expenditures, and credits for FY 2012.**

12) **Provide modeling to show whether the $1.1 billion in credits paid to explorers has led to any production.**

13) **Provide a breakout of the types of capital expenditures in as much detail as possible.**