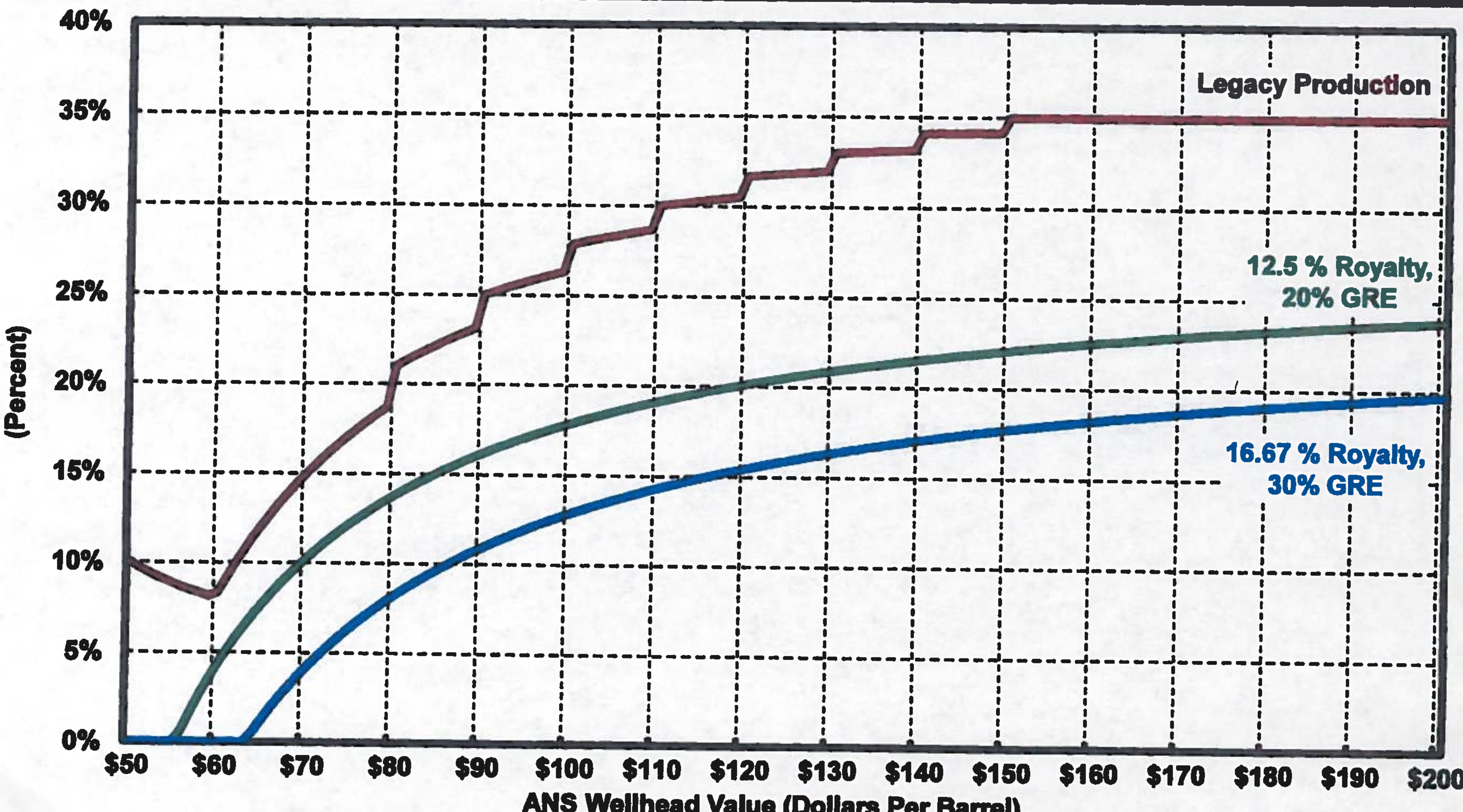
Attachment 1

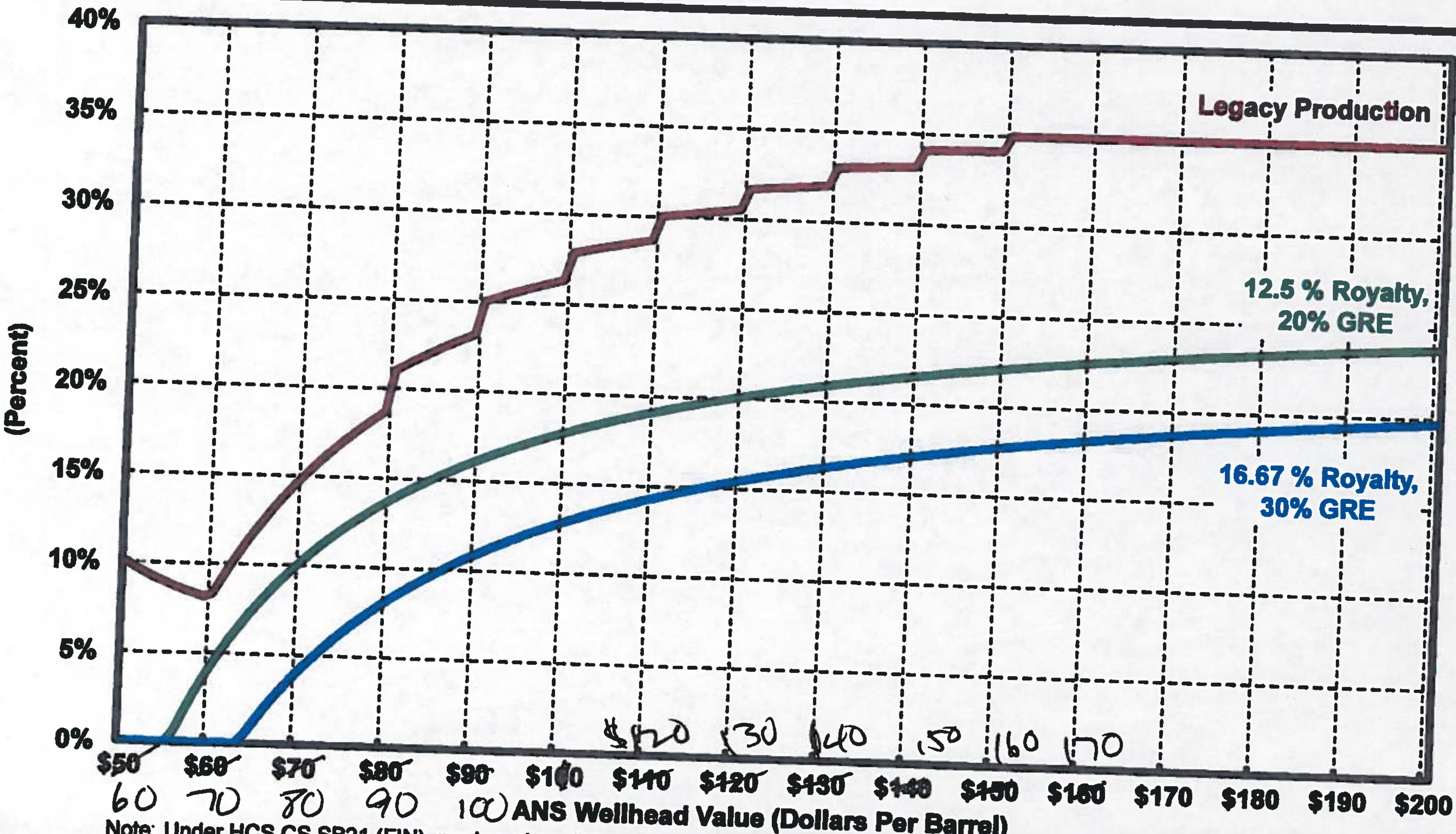
Effective Net Tax Rates Under HCS CS SB21 (FIN)



Note: Under HCS CS SB21 (FIN), per barrel credit is equal to $8/Bbl at wellhead prices below $80/bbl, diminishing to $0/Bbl at a wellhead price of $150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above $25/Bbl for non-GRE barrels.

Actual Rates (Doesn't reach 35% until $160/bbl)

Effective Net Tax Rates Under HCS CS SB21 (FIN)



Note: Under HCS CS SB21 (FIN), per barrel credit is equal to $8/Bbl at wellhead prices below $80/bbl, diminishing to $0/Bbl at a wellhead price of $150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above $25/Bbl for non-GRE barrels.

Attachment 2

Vol. 18, No. 10 Week of March 10, 2013
Providing coverage of Alaska and northern Canada's oil and gas industry

Sending AK tech abroad

ConocoPhillips is using technology to increase production in Alaska, Outside

Eric Lidji

For Petroleum News

ConocoPhillips plans to spend some $2.5 billion in Alaska over the next five years using a collection of drilling technologies to mitigate declining production on the North Slope.

The largest producer in Alaska believes it can get some 35,000 barrels per day of incremental production from its three legacy North Slope oil fields by using 4-D seismic, coiled-tubing drilling and casing drilling to lower development costs and access additional resources, but as with any discussion of investments, the company insists it could do more if Alaska policymakers would make the fiscal regime more "competitive."

The 35,000 barrels per day would stem production declines in Alaska to some 3 percent per year by 2017, ConocoPhillips' Executive Vice President of Exploration and Production Matthew Fox said during the company's annual analyst day on Feb. 28. And, Fox noted, if ConocoPhillips brings the Alpine West/CD-5 satellite into production as scheduled in the 2015-16 timeframe, the annual decline could drop to some 2 percent.

The goal of the $2.5 billion program is to use newly perfected techniques to suck additional oil out of Prudhoe Bay, Kuparuk River and Alpine, but with tax changes "we can see additional opportunities that we could take advantage of to grow production in Alaska and to grow production through the Trans-Alaska Pipeline System," Fox said.

A pair of techniques

The program involves two techniques "honed" in Alaska.

Attachment 3

2013 Spring

Revenue Forecast

State of Alaska
Department of Revenue
Tax Division

Attachment 4, Page 1

A-7 Crude Oil Production

(Figure C-2b in Fall 2012 RSB)
(thousand barrels per day)

FY	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Prudhoe Bay [1]	254.7	244.1	243.9	240.3	228.8	218.1	207.8	197.0	186.9	177.3
PBU Satellites [2]	45.1	44.4	41.6	38.9	36.3	33.1	30.5	27.9	25.8	23.8
GPMA [3]	26.6	25.5	23.4	21.1	19.2	17.6	16.4	15.3	14.3	13.4
Kuparuk	85.8	84.8	82.8	79.0	75.5	71.7	68.3	65.0	61.3	56.2
Kuparuk Satellites [4]	24.8	23.5	21.9	21.8	20.7	18.6	16.4	14.7	13.2	12.0
Endicott [5]	10.4	10.1	10.8	10.5	8.8	7.6	6.8	6.1	5.5	5.0
Alpine [6]	66.7	64.3	60.3	60.5	55.5	47.2	40.1	34.4	29.8	26.0
Offshore [7]	24.2	30.0	28.0	26.2	24.2	21.8	19.8	18.0	16.4	15.1
NPR-A	0.0	0.0	0.0	0.0	0.0	0.1	9.8	11.2	7.5	5.1
Point Thomson	0.0	0.0	0.0	1.5	8.0	7.4	6.8	9.9	11.5	10.7
Total ANS	538.5	526.6	512.8	499.7	476.9	443.3	422.4	399.4	372.3	344.5
Cook Inlet	10.4	9.6	8.9	8.3	7.7	7.2	6.7	6.3	5.9	5.6
Total Alaska	548.7	536.2	521.6	508.0	484.5	450.4	429.1	405.8	378.3	350.1

[1] Includes NGLs from Central Gas Facility shipped to TAPS.
[2] Aurora, Borealis, Midnight Sun, Orion, Polaris, Milne Point, Sag River, Schrader Bluff, Ugnu
[3] Lisburne, Niakuk, Point McIntyre, Raven, West Beach, West Niakuk
[4] Meltwater, NEWS, Tabasco, Tarn, West Sak
[5] Endicott, Minke, Sag Delta, Eider, Badami
[6] Alpine, Fiord, Nanuq, Qannik, Mustang (after 2016)
[7] Northstar, Oooguruk, Nikaitchuq, Liberty (delayed)

Attachment 4, Page 2

A-2 Petroleum Revenue
(Figure A-5b in Fall 2012 RSB)
($ million)

FY	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Unrestricted Petroleum Revenue										
Petroleum Corporate Income Tax	500.3	543.5	623.6	633.6	643.0	651.9	660.5	668.2	675.8	683.0
Oil and Gas Production Tax	4,378.3	3,589.0	3,298.5	3,751.7	4,033.1	3,646.2	3,403.1	3,194.6	3,011.9	2,809.7
Oil and Gas Hazardous Release	7.7	6.7	6.5	6.4	6.1	5.6	5.4	5.1	4.7	4.4
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum Property Tax	111.6	99.3	95.3	92.0	89.1	86.9	83.7	81.7	79.1	76.5
Oil & Gas Royalties	1,853.1	1,847.3	1,839.3	1,845.9	1,748.3	1,629.9	1,554.7	1,471.9	1,392.4	1,313.2
Bonuses, Rents & Interest	17.8	8.0	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Total Unrestricted Petroleum Revenue	6,868.8	6,093.8	5,876.2	6,342.0	6,532.6	6,032.8	5,700.1	5,494.4	5,176.9	4,899.7
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	4.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Royalties to AK Permanent Fund	766.4	798.8	793.4	796.5	751.2	694.9	652.0	618.5	579.4	542.5
Royalties to Public School Fund	13.3	13.3	13.3	13.3	12.6	11.7	11.1	10.6	10.0	9.4
CBRF Deposits	284.6	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Total Restricted Petroleum Revenue	1,069.1	836.0	830.6	833.8	787.7	730.6	686.9	652.9	613.3	575.8
Total Petroleum Revenue	7,937.9	6,929.8	6,706.8	7,175.8	7,320.3	6,763.4	6,387.0	6,147.3	5,790.2	5,475.5

Attachment 4, Page 3

Attachment 5, Page 1

[illegible]

FY (mmbls/day)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Prudhoe Bay	230.6	257.9	230.3	220.7	212.1	202.4	192.0	179.3	166.1	153.5
PBU Satellites[1]	45.1	41.9	41.3	38.2	36.8	35.0	31.1	28.0	25.5	23.1
GPMA[2]	26.5	22.8	21.1	19.4	17.8	16.5	15.4	14.3	13.4	12.5
Kuparuk	83.3	77.0	78.1	79.0	72.7	67.5	62.9	58.4	53.9	48.8
Kuparuk Satellites[3]	24.1	25.3	25.8	24.1	24.6	22.4	20.0	18.1	16.3	14.5
Endicott[4]	11.0	10.4	9.2	8.3	7.6	7.0	5.8	5.0	4.3	3.8
Alpine[5]	56.8	50.6	49.1	54.7	49.7	41.9	35.8	30.4	26.0	22.4
Offshore[6]	30.8	32.4	31.2	29.6	27.5	24.8	22.4	20.4	18.7	17.2
NPR-A	-	-	-	-	2.6	4.2	3.3	2.5	4.4	4.4
Point Thomson	-	-	1.6	8.7	8.0	7.4	10.8	12.5	11.8	12.7
Total Alaska North Slope	508.2	498.4	487.6	482.7	459.5	429.1	399.6	368.8	340.1	312.9
Cook Inlet	13.5	11.6	10.4	9.5	8.8	8.1	7.6	7.1	6.6	6.2
Total Alaska	521.7	510.0	498.1	492.2	468.3	437.2	407.2	375.9	346.8	319.1

[1] Aurora, Borealis, Midnight Sun, Orion, Polaris, Milne Point, Sag River, Schrader Bluff, Ugnu
[2] Lisburne, Niakuk, Point McIntyre, Raven, West Beach, West Niakuk
[3] Meltwater, NEWS, Tabasco, Tarn, West Sak
[4] Endicott, Minke, Sag Delta, Eider, Badami
[5] Alpine, Fiord, Nanuq, Qannik, Mustang (after 2016)
[6] Northstar, Oooguruk, Nikaitchuq, Liberty (delayed)

FALL 2013 Sourcebook

Attachment 5, Page 2

FY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($ millions)									
Unrestricted Petroleum Revenue										
Petroleum Property Tax	99.6	97.4	99.2	101.1	102.5	103.4	103.9	103.9	103.6	103.1
Petroleum Corporate Income Tax	463.8	463.7	460.8	465.4	456.1	441.9	424.2	400.0	382.1	361.0
Oil and Gas Production Tax	2,091.6	1,703.2	1,796.0	2,141.0	2,268.3	2,320.3	2,106.3	1,891.8	2,059.0	1,654.2
Oil and Gas Hazardous Release	8.1	8.0	7.8	7.7	7.4	6.9	6.4	5.9	5.4	5.0
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Royalties-Net[1]	1,685.9	1,652.4	1,648.4	1,656.9	1,636.1	1,603.7	1,485.1	1,390.8	1,372.2	1,246.7
Bonuses, Rents & Interest-Net[1][2]	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unrestricted Petroleum Revenue	**4,359.5**	**3,955.0**	**4,022.6**	**4,382.5**	**4,480.8**	**4,486.5**	**4,136.2**	**3,802.8**	**3,932.7**	**3,380.4**
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Royalties to AK Permanent Fund	724.3	706.6	703.2	707.3	703.1	688.7	632.1	584.3	582.9	528.9
Royalties to Public School Fund	12.2	11.9	11.9	11.9	11.8	11.6	10.7	10.0	9.9	9.0
CBRF Deposits	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Restricted Petroleum Revenue	**760.1**	**742.1**	**738.6**	**742.8**	**738.5**	**723.8**	**666.3**	**617.9**	**616.3**	**561.5**
Total Petroleum Revenue	**5,119.5**	**4,677.1**	**4,761.3**	**5,125.3**	**5,219.3**	**5,210.3**	**4,802.5**	**4,420.7**	**4,549.0**	**3,941.8**

(1) Royalties, bonuses, rents and interest rate are net of Permanent Fund Contribution and (CBRF) deposits.

(2) This category is primarily composed of petroleum revenue.

(3) The cumulative Unrestricted General Fund petroleum revenue is based on revenue beginning in FY 1959.

Attachment 5, Page 3

Fall 2013 forecast, General Fund spending capped at $5.6 billion through FY2024

Oil Price & Production	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24
Fall 2013 forecast ANS West Coast ($/bbl.)	$105.68	$105.06	$107.69	$110.38	$115.40	$121.19	$122.43	$123.67	$133.00	$131.85	$135.15
Fall 2013 forecast (Total ANS production State + Federal ths. bbl./day)	508.2	498.4	487.6	482.7	459.5	429.1	399.6	368.8	340.1	312.9	285.6
Revenue vs. Spending ($millions)											
General Fund Revenues[1]	$4,984.9	$4,532.0	$4,609.5	$4,980.6	$5,105.0	$5,135.4	$4,810.0	$4,502.5	$4,653.6	$4,129.4	$4,006.1
General Fund Expenses	$6,914.6	$5,640.9	$5,600.0	$5,600.0	$5,600.0	$5,600.0	$5,600.0	$5,600.0	$5,600.0	$5,600.0	$5,600.0
Budget Surplus/Shortfall	$1,949.7	$1,108.9	$990.5	$619.4	$495.0	$464.6	$790.0	$1,097.5	$946.4	$1,470.6	$1,593.9
Reserve Balances ($millions)											
CBRF Main Account Balance End of Year	$5,885.3	$2,941.4	$3,003.9	$3,076.3	$2,723.9	$2,337.1	$1,617.6	$570.4	$0.0	$0.0	$0.0
CBRF Subaccount Balance End of Year	$6,363.9	$6,755.1	$7,170.3	$7,611.0	$8,078.9	$8,575.4	$9,102.6	$9,662.1	$9,937.0	$9,049.3	$7,959.7
CBRF Total	$12,249.2	$9,696.5	$10,174.3	$10,687.3	$10,802.8	$10,912.6	$10,720.1	$10,232.4	$9,937.0	$9,049.3	$7,959.7
Statutory Budget Reserve Balance yr. end	$2,783.4	$1,674.5	$684.0	$64.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TOTAL RESERVES	$15,032.6	$11,371.0	$10,858.3	$10,752.0	$10,802.8	$10,912.6	$10,720.1	$10,232.4	$9,937.0	$9,049.3	$7,959.7

1. FY2014 number includes $4,930.0 GF Unrestricted Revenue forecast, plus $34.9 reappropriated and/or carried forward from FY2013 for total of $4,984.9

Appropriations projections in the plan do not represent a commitment by the Administration to propose spending or generate revenue at a particular level in FY2014, FY2015 or any future year. The 10-year forecast shows that unanticipated budget shortfalls during the 10-year period could be filled primarily through the use of reserve funds; however, other fiscal tools including spending reductions would likely be used in addition to, or in lieu of, reserve funds.

The plan will be revisited as conditions warrant.

Attachment 6

HOUSE FINANCE COMMITTEE
January 24, 2013
1:31 p.m.

1:31:58 PM

CALL TO ORDER

Co-Chair Austerman called the House Finance Committee meeting to order at 1:31 p.m.

MEMBERS PRESENT

Representative Alan Austerman, Co-Chair
Representative Bill Stoltze, Co-Chair
Representative Bryce Edgmon
Representative Les Gara
Representative David Guttenberg
Representative Lindsey Holmes
Representative Cathy Munoz
Representative Steve Thompson
Representative Tammie Wilson

MEMBERS ABSENT

Representative Mark Neuman, Vice-Chair
Representative Mia Costello

ALSO PRESENT

Michael Hanley, Commissioner, Department of Education and Early Development; Mark Lewis, Director, Administrative Services, Department of Education and Early Development; Bryan Butcher, Commissioner, Department Of Revenue; Dan Stickel, Assistant Chief Economist, Tax Division, Department of Revenue; Bruce Tangeman, Deputy Commissioner, Tax Division, Department of Revenue; William Barron, Director, Division of Oil and Gas, Department of Natural Resources; Angela Rodell, Deputy Commissioner, Treasury Division, Department of Revenue.

SUMMARY

FY 14 GOVERNOR'S BUDGET OVERVIEW:

Department of Education and Early Development

Attachment 7, Page 1

provided risk profile boundaries. Slide 15 showed a longer-term view of the refined model applied over time [1978 to 2022].

3:19:01 PM

Mr. Barron addressed that the real difference [between the original and refined methods] was how the departments looked at new oil. He pointed to a graph that illustrated the new oil share of total production on slide 16 [2012 through 2021]; the blue bar represented the 2011 forecast. The blue bars increased and then began to flatten out at approximately 40 percent to 45 percent of the total production. The red bars represented the 2012 forecast and were derived by using a risk model relative to under evaluation and under development tranches; out-year risk was factored in with projects that were not yet online.

Mr. Barron stressed that any good modeler would look back in history to determine how accurate the model would have been. He pointed to a spider diagram on slide 17 titled "Testing the Refined Method." The red line showed the original forecast error from 2001 to 2010. The blue line used the refined method and showed a significant reduction in overall error. He emphasized that the refined model took away approximately 50 percent of the error. He communicated that DNR had been asked to come up with a method that was more reasonable, more prudent, and more practical in terms of the out-year forecasting for the under development and under evaluation process.

Mr. Tangeman stated that the presentation and the DOR Revenue Sources Book were not meant to be "doom and gloom" scenarios. The goal had been to set a more realistic baseline for decision makers while recognizing the tremendous up-side of the state's resources. He stated that the forecast had historically dealt with what is possible compared to what is probable and had always been overly optimistic. He pointed out that chapter 4 of the Revenue Sources Book provided additional detail on the issue.

3:22:19 PM

Mr. Tangeman addressed potential concern about what ratings agencies would think of the state's process. He shared that Commissioner Butcher and Deputy Commissioner Rodell had met with the ratings agencies in late 2012 and had received

Attachment 7, Page 2

positive feedback on the department's process. He read a brief quote from the Standard and Poor's rating agency:

> The state's Department of Revenue has a good track record forecasting year ahead prices and production levels. A bigger issue for the state is measuring the long-term rate of oil production decline. Since peaking in 1988 the average annual rate of decline in production has been around 5.5 percent; however, the state's long-term forecast has consistently projected a long-term rate of annual decline in oil production of just 2.5 percent or lower. As a result the state's long-term forecast has tended to overestimate actual production levels. With its fall 2012 forecast the Department of Revenue has revised the methodology used to develop its longer-term production forecasts. The new approach applies risk factors to discount the projected oil production from oil fields that are still under development or in the evaluation stage. Previously production estimates in the forecast from such fields were not adjusted downward to account for their higher level of uncertainty.

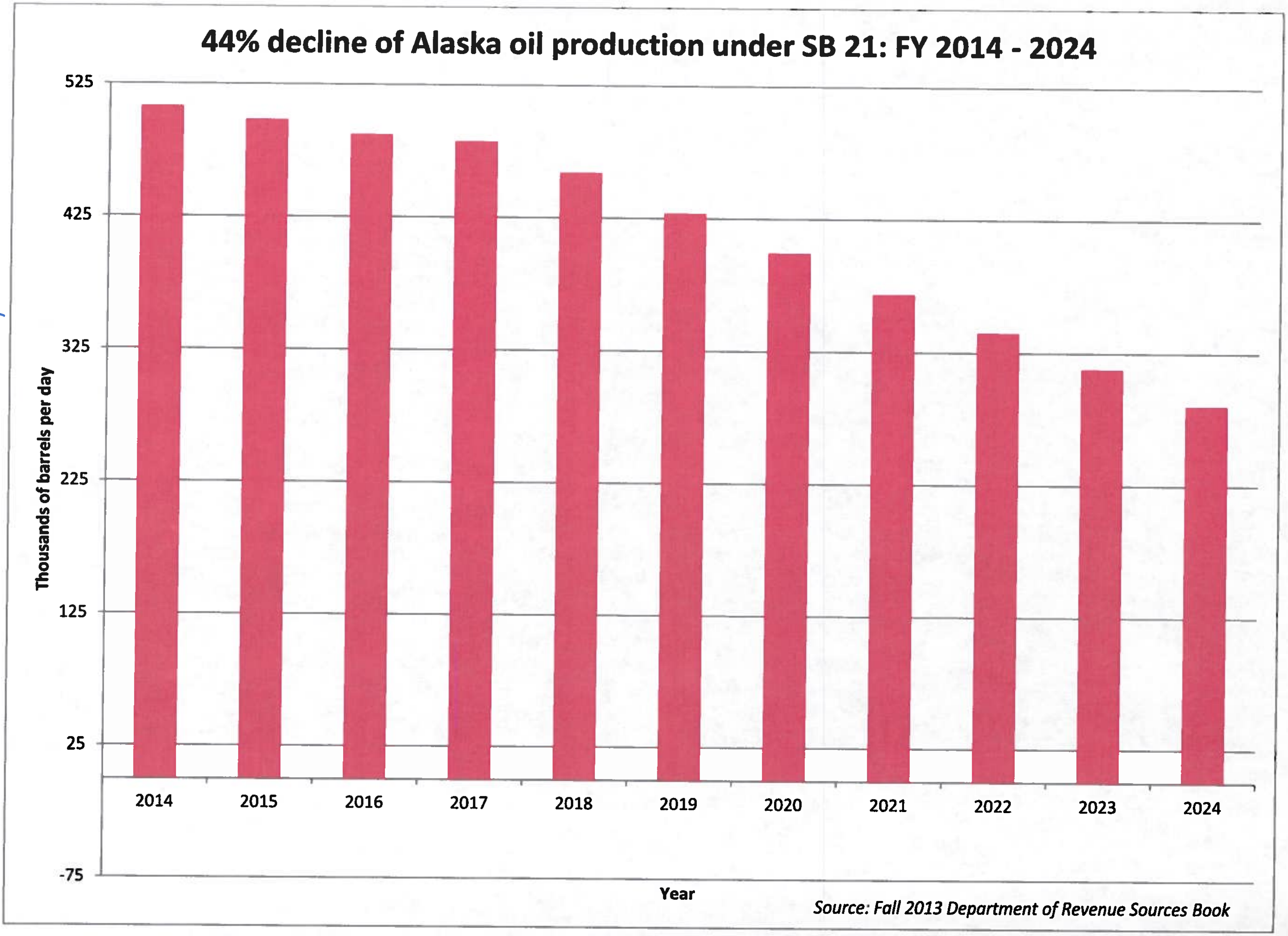
Mr. Tangeman elaborated that there were many items a rating agency took into account. Price and production were both very critical and DOR had received great feedback that it was headed in the right direction with its production forecasting.

Representative Guttenberg wondered whether an independent entity had been called upon to weigh in on the departments' approach to the forecasting method. He observed that during his time working for the legislature, price forecasters had admitted that they were always wrong. He recalled a legislative class that had been given in the past on mega projects; it had shown the ranges of projects that failed, succeeded, were over budget, and other. He believed the departments' work to increase forecasting accuracy was positive.

Mr. Barron replied that outside source had not been used; therefore, the confidence intervals had been established independently of the scenario plan. The Oil and Gas Division had reached out to some of its colleagues in the industry to ask if the approaches were reasonable; he relayed that the answer had been yes. He stated that the way assessment numbers had been generated could be

Attachment 7, Page 3

Attachment 8



FISCAL NOTE ANALYSIS #14

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. HCS CSSB 21(FIN)

Analysis Continued

Differences in General Fund Unrestricted Revenue under Proposed Bill from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impacts from the change in tax rates, per barrel allowance and gross revenue exclusions only and do not attempt to quantify impacts of other parts of the bill, such as the removal of the credit split, or the impact on the long-range budget from the elimination of QCE credits or changes to NOL credits. Values are generated from a scenario model and may vary slightly from other models.

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$225	-$150	-$200	-$325	-$275	-$400
$100	-$275	-$250	-$325	-$475	-$375	-$450
$120	-$575	-$800	-$925	-$1,125	-$925	-$925

All additional production scenarios below compare additional production under the proposed bill to ACES without the additional production.

Additional Production Scenario A

Forecasted production plus 50 million barrel field developed by a New Entrant

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$225	-$150	-$200	-$325	-$275	-$375
$100	-$275	-$250	-$325	-$475	-$375	-$425
$120	-$575	-$800	-$925	-$1,100	-$900	-$900

Assumes field outside of a current unit and subject to 30% gross revenue exclusion, first oil in 2017 and peak production of 10,000 barrels per day in 2019. Total development cost of $500 million.

Additional Production Scenario B

With addition of 4 oil rigs to legacy fields drilling from 2014-2019

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$175	$50	$125	$50	$225	$25
$100	-$200	$25	$75	$0	$225	$50
$120	-$475	-$425	-$400	-$475	-$125	-$250

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be $20 million. None of this oil is assumed to qualify for the GRE under the provisions of this bill.

Additional Production Scenario C

With new well pad and 4 additional rigs in legacy fields, plus new 10,000 bopd field starting in 2017

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$275	$0	$175	$300	$950	$725
$100	-$300	$0	$200	$350	$1,100	$925
$120	-$525	-$350	-$125	$125	$1,100	$925

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2014 at total development costs of $5 billion, none of which is assumed to qualify for the GRE. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new field.

(Revised 1/15/2013 OMB)

Attachment 9

ADN.com

Next Story >

House panel votes to turn Knik Arm bridge over to AHFC

Differing forecasts of Slope production decline are key factor in oil tax debate

Published: April 12, 2013

By LISA DEMER — ldemer@adn.com

ANCHORAGE — No one disputes that oil production is declining on Alaska's North Slope but sharp disagreement over projections of the future rate of decline is boiling up in the legislative fight over Gov. Sean Parnell's proposal for massive tax cuts.

The state's oil production forecast is one of the most important facts in the argument over how much tax revenue the state would give up under Parnell's plan.

Estimates of future production and future prices drive any analysis of the cost of the tax measure, Senate Bill 21. The more oil that goes into the pipeline, and the higher the price of that oil, the more money the state treasury loses with a lower tax rate.

Parnell and the Republican majorities in the Legislature are pushing for tax cuts to induce oil companies to invest millions of dollars to increase Alaska production, which has been slowly declining for many years.

Rep. Les Gara, a Democrat from Anchorage who sits on the House Finance Committee, on Thursday released a new analysis -- done at his request by the state Department of Revenue -- showing that the governor's proposed tax cuts could cost the state $1.6 billion to more than $3 billion a year. That analysis assumes high oil prices and a relatively modest production decline of 3 percent a year.

The Parnell administration's current official forecasts assume lower prices and steeper production declines, which leads it to project smaller revenue losses if the tax cuts become law.

It's politically advantageous for proponents of tax cuts to show less overall future revenue, so they can show less lost revenue. For opponents of the tax cuts, their argument is strengthened if revenue projections are as high as possible, which which results in much greater estimated tax losses.

A ConocoPhillips executive told investors in February that by 2017 the company could slow the decline in oil production on the North Slope to 3 percent a year, or maybe lower, by using new technology, according to a report in Petroleum News. ConocoPhillips is Alaska's biggest oil producer and one of three major oil companies with leases on the North Slope.

The state's latest forecast predicts an annual production decline of 4.6 percent in 2017 and 7 percent the year after that.

"There's no way the department's estimate of 7 percent decline in those out years makes any sense," Gara said. "They only did it to try and lower the loss" so that the governor's tax cuts don't look as severe.

The issue has lurked since last year when Parnell administration officials alerted some legislators of plans to change how they forecast oil production.

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For years the state has overestimated production by including expected production from planned projects that were either slow to develop or never did, Bruce Tangeman, the state's deputy revenue commissioner, said Thursday. The department's new approach is more conservative. The farther into the future the projection, the less oil from new production the state includes in its official forecast, he said.

The Revenue Department estimates that under a maximum 35 percent profits tax, similar to what's now before the House, starting in 2017 the state would lose revenues of $815 million to $1 billion a year, compared to the current tax system, the Palin-era measure known as Alaska's Clear and Equitable Share. ACES was passed in 2007 to replace a corruption-tainted measure.

Using the 3 percent decline figure argued by Gara, and under the state's current price forecast, the tax cuts will cost $25 million to $125 million a year more than the Parnell administration projects for 2017-19. The revenue department says it doesn't agree with the projections done for Gara. But if they're wrong and more oil is produced, it said, the department will adjust its forecast.

Revenue officials are familiar with ConocoPhillip's projections, Tangeman said.

"Those numbers are incorporated into our forecast," he said. "There is no smoking gun. There is nothing that (Rep. Gara) has overturned or uncovered."

The state predicts oil prices between $109 and $118 a barrel through 2019.

If those assumptions about the price are too low, the hit to state revenues grows much bigger. At $120 a barrel, the state would lose roughly $1.6 billion a year under the governor's tax bill. If prices top $150 a barrel, the annual loss could exceed $3 billion, the analysis for Gara says. Tangeman said that unlike its production forecast, the department's price forecasts have been accurate.

Sen. Bill Wielechowski, an Anchorage Democrat who serves on the Senate Resources Committee, said he and Sen. Johnny Ellis were briefed in December about the change in forecasting by Tangeman, Revenue Commissioner Bryan Butcher and Mike Pawlowski, the department's oil tax adviser.

"I was very suspicious right from the moment I heard it," Wielechowski said. "It just seems awfully coincidental that the month before session, when we're about to engage in this historic oil tax debate, the numbers change in such a way that (the new forecast) lowers (the cost to the state) by over a billion dollars, probably a billion and a half dollars."

Last year, a different version of the governor's oil tax cuts, using the previous forecasting approach, projected a revenue loss of nearly $2 billion a year.

If oil development projects are stalling, Wielechowski said, the state should push to find out what is going wrong.

On Wednesday, 560,167 barrels of oil were produced on the North Slope, according to the revenue department. Under its new "risk-adjusted" forecast, it projects an average of 538,300 barrels a day this budget year and 476,900 barrels a day by 2017.

If the oil tax bill passes, and production exceeds the forecast, it may be impossible to tell whether that was the result of the tax cut or a lowball forecast, Wielechowski said.

North Slope production peaked 25 years ago with more than 2 million barrels of oil a day, and has been on a fairly steady decline since.

Reach Lisa Demer at ldemer@adn.com or 257-4390.

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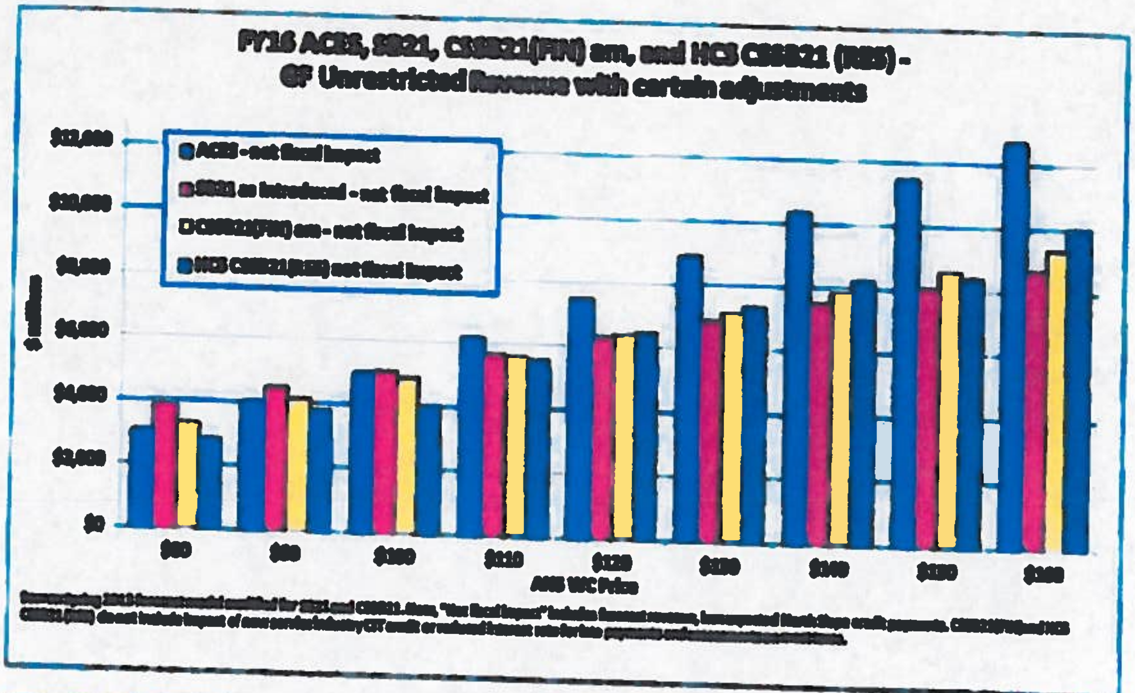

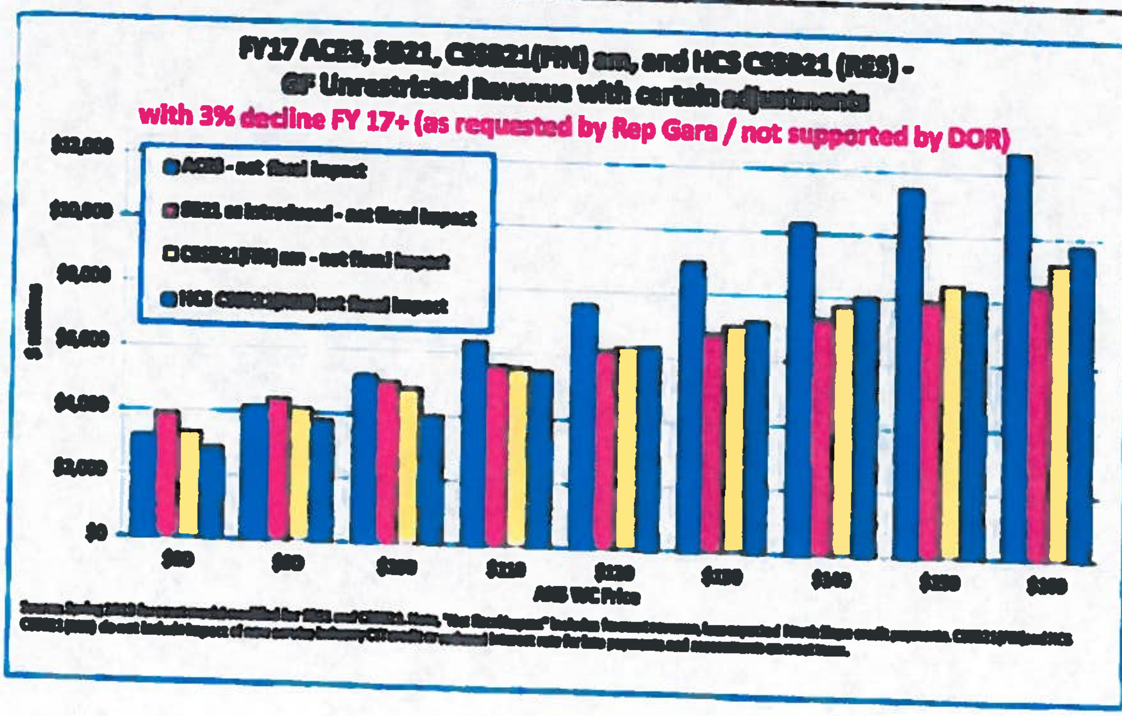

Attachment II

2

ELF Near 0% Tax Fields

Field	Rank Among U.S. 100 Largest Fields	Annual Production (barrels)	FY '06 Production Tax Rate
Kuparuk	**2nd** largest in U.S.	51,100,000	0.81 %
Milne Point (Milne Point Unit)	**13th** largest in U.S.	9,490,000	0 %
Endicott (Duck Island Unit)	**27th** largest in U.S.	8,395,000	0 %
West Sak (Heavy oil) (Kuparuk River Unit)	**39th** largest in U.S.	10,950,000	0.075 %
Tarn (Kuparuk River Unit)	**67th** largest in U.S.	8,030,000	0.0004 %
Niakuk (Lisburne Prod. Unit)	**93rd** largest in U.S.	2,920,000	0 %
Meltwater (Kuparuk River Unit)	**94th** largest in U.S.	4,015,000	0 %

** Prudhoe Bay aggregated fields included Polaris (57th), Orion (83rd), Borealis (44th) and Pt. McIntyre (28th)

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Table 2: Effective Production Tax Rates, by North Slope Field, FY 2006

Field	Nominal Rate (AS § 43.55.011)	Economic Limit Factor (Annual Average)	Effective Rate (Annual Average)
Prudhoe Bay Unit	15%	0.85646275	12.8469%
Lisburne	15%	0	0
Niakuk	15%	0	0
West Beach	15%	0	0
North Prudhoe Bay	15%	0	0
Kuparuk	15%	0.0036615	0.0549%
Tarn	15%	0.00025325	0.0038%
Tabasco	15%	0	0
Meltwater	12.25%	0	0
West Sak	15%	0	0
Milne Point	15%	0	0
Schrader Bluff	15%	0	0
Sag River	15%	0	0
Endicott	15%	0	0
Sag Delta	15%	0	0
Eider	15%	0	0
Badami	15%	0	0
Alpine*	13.85%	0.856458917	11.8620%
Northstar	12.25%	0.72241975	8.8496%

NOTES: In January 2005, the Department of Revenue aggregated seven fields in the Prudhoe Bay Unit (PBU). Fields aggregated with Prudhoe Bay are Aurora, Borealis, Orion, Polaris, Midnight Sun, and Pt. McIntyre. Analysis performed under 2005 PBU ELF Aggregation regulations.

*Alpine's nominal tax rate was 12.25% until December 2005, when it became 15%.

Amendments filed in the future may change data shown here.

SOURCE: Jennifer Duval, petroleum economist, Tax Division, Department of Revenue, 907.269.1025.

We hope this information is helpful. If you have questions or need additional information, please let us know.

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Attachment 13

Low Taxes, Same Production Declines

ACES passed November 2007

- 5.78 percent decline from 1998-2007
- 8.72 percent decline from 2004-2007

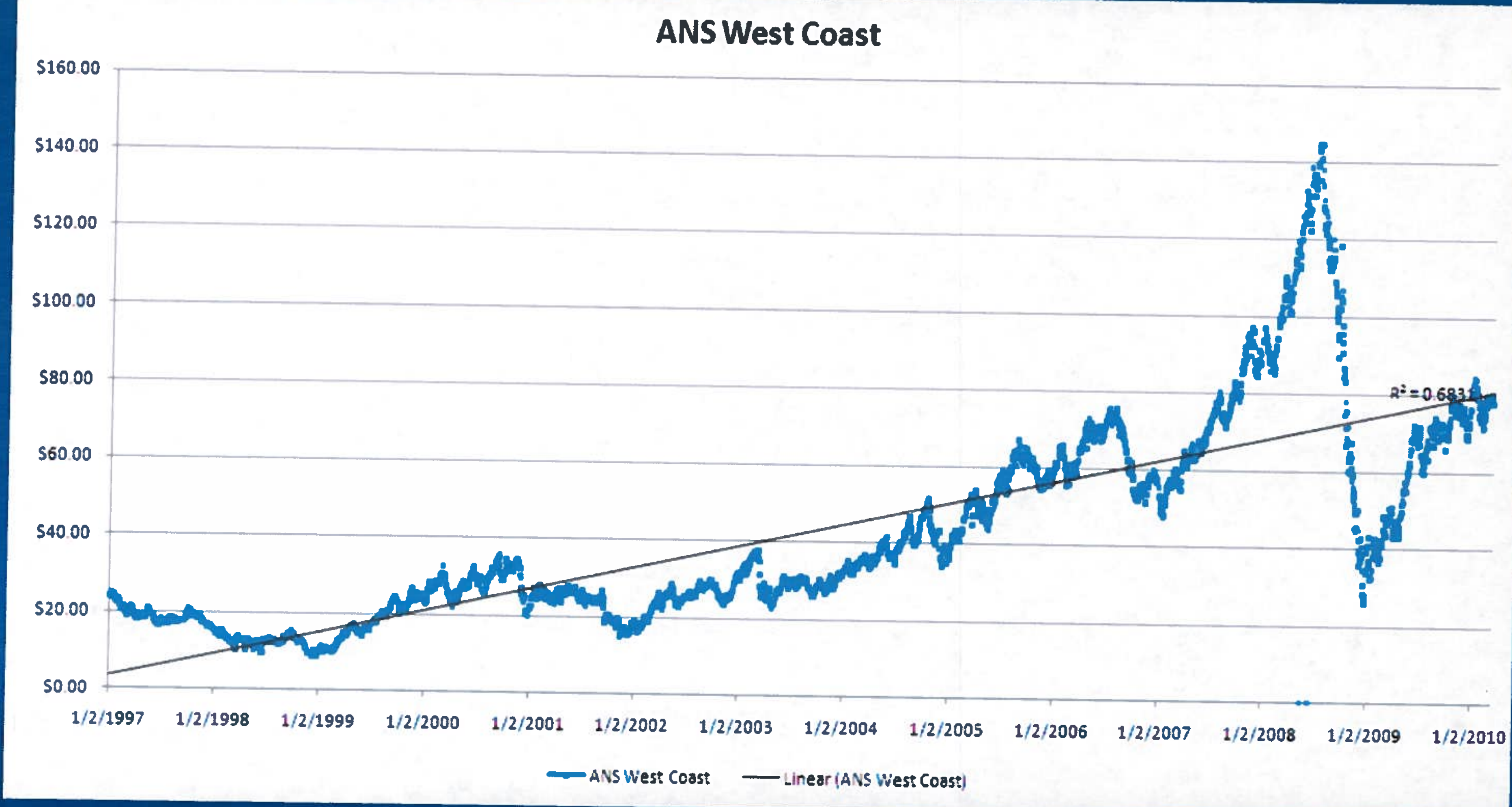
Total North Slope Production, FY 98– FY 07

(million barrels per day)

fy 1998	fy 1999	fy 2000	fy 2001	fy 2002	fy 2003	fy 2004	fy 2005	fy 2006	fy 2007
1.279	1.170	1.033	0.993	1.010	0.991	0.974	0.911	0.840	0.740

SOURCES: "Production C-2a: Crude Oil Production –History," *Revenue Sources Book*, Fall 2007, Fall 2008, Fall 2009, Tax Division, Department of Revenue.

Production Fell With Low Taxes and Vastly Increasing Oil Prices



Attachment 14

March 14, 2013
Senate Finance Committee
Testimony on Senate Bill 21

6:19:17 PM: Scott Jepsen, VP of External Affairs, ConocoPhillips: It has been brought to our attention that there has been some confusion with regard to a presentation that ConocoPhillips conducted on February 18th. In that presentation our Executive Vice-President for Exploration Matt Fox talked about some development activities that we foresee over the next five years dealing with primarily drilling. The thrust of Matt's presentation was to talk about the role that technology is currently playing in our efforts to develop our legacy assets of the North Slope. I think some may have misinterpreted his comments to mean this is a new initiative, and that this is something incremental above and beyond our base plan and I want to make it clear that it is not the case. The activities that Matt described are part of our base plan, it's a subset of what we expect to spend over the next five years. In fact, over the last five years we've been spending about $500 million a year on the same sorts of activities. So what Matt talked about was $2.5 billion over the next five years, which is on pace with the historical investment we've made.

6:25:06 PM: Senator Meyer to Bob Heinrich with ConocoPhillips: You had mentioned that there is more opportunity if the tax climate allows the opportunity to exist. It looks like the question would be if we have reached that point where we have a climate that would spur additional investment and hopefully production.

6:25:37 PM: Bob Heinrich with ConocoPhillips: With the current bill, while it is an improvement over ACES, and we are pleased to see that, the way we currently see it is we will have to look at our projects on a project by project basis because of the structure we can't across the board say that the opportunity slate...some projects will be approved and some because of the loss of the tax credit structure may not improve under the current structure.

6:27:00 PM: Scott Jeffson, VP of External Affairs, ConocoPhillips: At this point we are not in a place where we could say how much we would do differently if this bill was passed.

6:29:30 PM: Senator Click Bishop: Thanks for your testimony Mr. Jeffson. I just gotta tell you that we have worked very hard doing some heavy lifting here. We've moved the needle on the base rate almost seven percentage points down, and it's a tough lift for some of us. I understand the position that you're in but you need to understand the position that I'm in with my constituents and the people of Alaska and...I thought I was missing a slide. I thought there was gonna be a page four with a check-off on the increased activity box to say the least. Thank you.

6:36:30 PM: Damian Bilbao, Head of Finance for BP Alaska: The CS [for SB21] does provide some good steps forward to making Alaska more competitive, but we don't feel that it goes far enough to attract the type of meaningful investment that's required to make the future look different from the last six or seven years.

6:40:30 PM: Dan Seckers with ExxonMobil: We believe the committee substitute is a remarkable improvement over ACES. But we believe the base rate is still too high and does not make Alaska attractive enough.

Attachment 15

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