

HB

247

<TARGET><BILL>HB 247</BILL><SUBJECT>HB
247</SUBJECT><COMM>HFIN29</COMM></TARGET>

HOUSE COMMITTEE REPORT

(11)

Date Referred to Committee: March 23, 2016

FURTHER REFERRALS:

Date of Committee Action: 4-8-2016

The FINANCE Committee considered:

HB 247

HOUSE BILL NO. 247

"An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

Recommends it be replaced with [] HCS or [X] CS for HB 247 (FIN)
 For Senate Bills with new title: [] Technical Title [] New Title: HCR _____ [] Same Title [X] New Title

- [] attach amendments
- [] add new referral to _____ Committee
- [] Letter of Intent _____ Committee

- List of Abbrev for Depts.:
- ADM
 - AJS
 - CED
 - COR
 - EED
 - DEC
 - DFG
 - GOV
 - DHS
 - LWF
 - LAW
 - LEG
 - MVA
 - DNR
 - DPS
 - REV
 - DOT
 - UA

NEW FISCAL NOTES				
*FN# is assigned by Chief Clerk's Office				
*FN#	List by Dept(s):	Fiscal	Indet.	Zero
	DNR			X
	REV	X		

PREVIOUS FISCAL NOTES				
FN#	List by Dept(s):	Fiscal	Indet.	Zero

Signing with recommendations	Printed Last Name	DP	DNP	NR	AM
	SALLIE			X	
	Wilson		X		
	Williams		X		X
	Gattis		X		X
	Edgmon				X
	McInerz				X
Chair:	NEUMAN			X	
Chair:	Thompson	X			

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB247CS(FIN)-DNR-DOG-4-8-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: House Finance

Department: Department of Natural Resources
Appropriation: Oil & Gas
Allocation: Oil & Gas
OMB Component Number: 439

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017	Included in	Out-Year Cost Estimates				
	Appropriation Requested	Governor's FY2017 Request	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES	FY 2017	FY 2017					
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None							
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues							
---------------------------	--	--	--	--	--	--	--

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 (separate supplemental appropriation required)
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 (separate capital appropriation required)
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No
If yes, by what date are the regulations to be adopted, amended or repealed? N/A

Why this fiscal note differs from previous version:

Revised in response to Committee Substitute. No numbers or analysis were changed.

Prepared By: <u>Corri Feige, Director</u>	Phone: <u>(907)269-8775</u>
Division: <u>Division of Oil & Gas</u>	Date: <u>04/01/2016 12:00 AM</u>
Approved By: <u>Marty Rutherford, Acting Commissioner</u>	Date: <u>04/01/16</u>
Agency: <u>Department of Natural Resources</u>	

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. CSHB 247(FIN)

Analysis

No fiscal impact.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB247CS(FIN)-DOR-TAX-04-08-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: House Finance Committee

Department: Department of Revenue
Appropriation: Taxation and Treasury
Allocation: Tax Division
OMB Component Number: 2476

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits								
Miscellaneous								
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None								
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time								
Part-time								
Temporary								

Change in Revenues	20,000.0	90,000.0	90,000.0	95,000.0	145,000.0	210,000.0
---------------------------	----------	----------	----------	----------	-----------	-----------

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 1,200.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? **yes**
If yes, by what date are the regulations to be adopted, amended or repealed? **01/01/17**

Why this fiscal note differs from previous version:

Revised to conform to changes in the Finance Committee Substitute. Also revised to include as a new baseline scenario the Final Spring 2016 Revenue Forecast. This document only includes the revenue raising numbers, with any program expenditure savings being captured in the companion FUNDCAP fiscal note offered by the Finance Committee.

Prepared By: <u>Ken Alper, Director</u>	Phone: <u>(907)465-8221</u>
Division: <u>Tax Division</u>	Date: <u>04/08/2016 10:00 PM</u>
Approved By: <u>Jerry Burnett</u>	Date: <u>04/08/16</u>
Agency: <u>Department of Revenue</u>	

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. CS HB247(FIN)

Analysis

Bill Background

This legislation is a comprehensive attempt to reform and reduce the cost of Alaska's current program of providing direct tax credit rebates and other advantages to oil and gas companies. Various credits have been added to statute since 2003, with state repurchase beginning in 2007. Through the end of FY 2016, about \$8 billion in tax credits will be received by companies. This includes both credits used against tax liability and credits repurchased by the state; it also includes activity on both the North Slope and other areas of the state.

A substantial number of companies rely on these credits to support and subsidize their Alaska operations. For work done in 2015, in many cases the state is paying 55%-65% of the cost of a project during the development phase, and up to 85% of exploration costs. These large numbers result from "stacking" multiple credits. With the transition towards a system based mostly on operating loss credits, and the repeal or reduction of the expenditure credits that are stacked with those loss credits, the state's contribution towards many projects will be reduced roughly by half.

There are several themes, or goals, of this legislation as originally introduced. These include:

- * Reduce the state's annual cash outlay
- * Protect Net Operating Loss credits especially for exploration activity
- * Limit repurchases to companies who need the support
- * Strengthen the minimum tax and prevent abuses to the system
- * Be more open and transparent
- * Honor and pay credits earned to date and through any transition period.

To address the final bullet point, above, this legislation envisions a fund capitalization appropriation to cover any tax credits earned through the effective date. Savings due to reductions in future appropriations needed to repurchase tax credits will be captured in the separate fund capitalization fiscal note.

Summary of Fiscal Impact

With the revisions proposed in the Finance Committee substitute, we anticipate additional revenue of \$90 to \$210 million per year over the time period contained in the fiscal note, with a smaller number in FY17 due to the mid-year effective date. Of this, the majority will be due to the strengthening of the so-called minimum tax "floor," preventing certain credits from being used to reduce tax payments at low oil prices. Revenue will be saved through reduced operating budget expenditures. Other revenues will come from certain production moving from the lower "new oil" regime to the higher "legacy oil" regime after five years of production. The current "tax cap" on Cook Inlet production is also repealed. A small indeterminate amount would come from the restoration of compound interest and an increase in the interest rate for assessed delinquent taxes.

Implementation Cost

The changes anticipated in this bill will require somewhat substantial reprogramming of the Tax Revenue Management System and Revenue Online tax portal. We have received a preliminary estimate from the software developer, which allows us to reduce our one-time cost to about \$1,200,000 to accomplish these changes. We do not anticipate any additional costs to administer the tax program.

There will also be a need for substantial amendments to existing regulations to fully implement the changes.

Analysis Continued**Detail of Specific Provisions****1) Repeal of certain credits and closing of loopholes**

The Finance committee substitute reduces the Cook Inlet Well Lease Expenditure Credit (AS 43.55.023(l)) from 40% to 30% in 2017 and 20% in 2018. This credit, and the 20% Qualified Capital Expenditure Credit (AS 43.55.023(a)) are repealed in 2022 in anticipation of the sunset of the remaining "Cook Inlet Tax Caps" and a new tax regime for Cook Inlet. Also in 2017, the Carried Forward Annual Loss (or "New Operating Loss," AS 43.55.023(b)) credit is reduced from 25% to 10% for Cook Inlet. Higher credit levels are retained in the so-called "middle earth" areas.

The net effect of these changes will be to reduce state contribution for new Cook Inlet projects from the current 45-65% range to 25% beginning in 2018. Companies who do not have an operating loss will remain eligible to receive the Capital and Well credits. This would continue to provide cash support to potentially profitable companies who, due to existing tax caps, effectively pay no production taxes.

The bill also eliminates a loophole that enables companies who have production of "new oil" on the North Slope but also claim a net operating loss. With the changes, companies will no longer be able to use a Gross Value Reduction to increase the size of a net operating loss credit. Current law can result in situations where the credit received can be greater than 100% of a company's actual loss. It also eliminates another loophole that has been used by municipal utilities who also own oil or gas production. If a portion of that production is sold to an outside party, the proposed change ensures that these entities are only able to deduct or claim a pro-rated portion of their lease expenditures for the purpose of applying for credits.

2) Deferral or loss of eligibility for credit repurchase

Currently any company with less than 50,000 bbl / day of production in Alaska is eligible to have tax credit certificates repurchased by the state without limit, subject to appropriation. This legislation adds an additional restriction to repurchase, so that no single company can receive more than \$100 million per year in state cash repurchases. Although this would not have any impact based on currently forecasted activity, it provides an element of protection from large "outlier" projects that could otherwise result in multibillion dollar state credit liability in advance of production.

3) Other changes

In the CS, the "gross value reduction" for new oil only applies for the first five years of production, and is lost on 1/1/21 for fields currently receiving that reduction. The Cook Inlet tax cap on oil, which is tied to the 2005 "ELF" rate of 0%, is repealed on 1/1/17.

Additionally, the bill restores quarterly compound interest for delinquent taxes, underpayments, and tax assessments. Current statute has included simple interest since 2014, which is believed to be an inadvertent amendment made in SB21. The interest rate is increased from 3% above the federal discount rate to 5% above.

There is a small extension to a Frontier Areas exploration credit to enable wells in-process on 7/1/17 to be completed under the program before it sunsets. The committee substitute also repeals several older and currently unused exploration incentive credit programs, and authorizes the Department of Revenue to use credit certificates to offset a company's other obligations to the state prior to repurchase. It also establishes a legislative working group to review the state's tax structure for Cook Inlet and other areas outside the North Slope, to provide recommendations to the legislature for consideration in 2017.

Analysis Continued

Fiscal Detail of CSHB247(FIN)\F (Revenue and Budget Impacts)

Provisions in CSHB 247(FIN) \ F and their Estimated Fiscal Impact as compared to Spring 2016 Forecast (\$millions) - FORECAST PRICE¹

Note: this table attempts to value the impact of each of the items independently, except where noted. In some cases, the total value of several impacts will not equal the sum of the individual impact values.

Brief Description of Provision - Includes only provisions anticipated to have a direct fiscal impact	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
1. The rate for net operating loss credits for Cook Inlet is changed to 10% for companies with a previous credit and zero for other companies.	\$0	\$0	\$0	\$0	\$0	\$0
2. The rate for QCE credits for Cook Inlet is changed to 10%; the rate for well lease exp credits for Cook Inlet is changed to 30% on 1/1/17 and then 20% on 1/1/18	\$0	\$0	\$0	\$0	\$0	\$10-\$20
3. The tax limitation for Cook Inlet oil is repealed effective 1/1/17.	\$0-\$10	\$0-\$10	\$0-\$10	\$5-\$15	\$10-\$20	\$15-\$25
4. For North Slope, certain tax credits cannot reduce liability below 2% of GVPP effective 1/1/17.	\$10-\$20	\$70-\$100	\$70-\$100	\$70-\$100	\$100-\$150	\$100-\$150
5. The interest rate on delinquent taxes is changed to 5% above the Fed Res Discount rate, compounded quarterly	Indeterminate					
6. The GVR cannot be used to create or increase a net operating loss	\$0	\$0	\$0	\$0	\$0	\$5-\$15
7. GVR-eligible production qualifies for the GVR for a period of 5 years or until 1/1/21.	\$0	\$0	\$0	\$0	\$0-\$10	\$30-\$50
8. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax	Indeterminate					
Total Revenue Impact	\$10-\$30	\$70-\$110	\$70-\$110	\$75-\$115	\$110-\$180	\$160-\$260
Budget impact of change in net operating loss credits for Cook Inlet (provision 1 above)	\$0	\$0-\$10	\$10-\$20	\$10-\$20	\$10-\$20	\$10-\$20
Budget impact of change in QCE/WLE credits for Cook Inlet (provision 2 above)	\$0	\$15-\$25	\$15-\$25	\$15-\$25	\$45-\$60	\$45-\$60
Budget impact of not allowing certain credits to reduce North Slope below 2% of GVPP (provision 4 above)	\$0	\$0	\$0	\$0	\$0-\$10	\$0-\$10
Budget impact of limiting refunds to \$100 million per company/per project per year (only shifts timing of refunds)	Confidential due to limited use - net neutral as impact shifted to later years					
The GVR cannot be used to create or increase a net operating loss (provision 6 above)	0	\$10-\$20	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10
Budget impact of exploration credit extension for well spudded by 7/1/16	(\$5)-\$0	(\$5)-\$0	\$0	\$0	\$0	\$0
Budget impact of GVR applying to fields for a period of 5 years (provision 7 above)	\$0	\$0	\$0	\$0	\$0	\$0
Total Budget Impact	(\$5)-\$0	\$20-\$55	\$45-\$75	\$40-\$70	\$60-\$105	\$55-\$100
Total Fiscal Impact - does not include revenue impacts from potential changes in investment²	\$5-\$30	\$90-\$165	\$115-\$185	\$115-\$185	\$170-\$285	\$215-\$360
Non-refundable carry-forward credits balance at fiscal year end - current law ³	\$618	\$751	\$732	\$585	\$265	\$136
Non-refundable carry-forward credits balance at fiscal year end - proposed ³	\$676	\$941	\$1,065	\$1,055	\$957	\$923
Change in year-end balance due to bill	\$58	\$190	\$333	\$470	\$692	\$787

¹The impacts listed are based on production and prices as forecasted in DOR's Spring 2016 revenue forecast. The forecasted oil prices are between \$38.89 and \$61.64.

²NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts.

NOTE: The fiscal impact of this bill is an estimate based on the Spring 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

CS FOR HOUSE BILL NO. 247(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-NINTH LEGISLATURE - SECOND SESSION

BY THE HOUSE FINANCE COMMITTEE

Offered:

Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to interest applicable to delinquent tax; relating to the oil and gas
2 production tax, tax payments, and credits; relating to the minimum oil and gas
3 production tax; relating to refunds for the gas storage facility tax credit, the liquefied
4 natural gas storage facility tax credit, and the qualified in-state oil refinery
5 infrastructure expenditures tax credit; relating to the assessment of an oil and gas
6 production tax imposed; relating to oil and gas lease expenditures and production tax
7 credits for municipal entities; relating to a bond or cash deposit required for an oil or
8 gas business; establishing a legislative working group to study the tax structure for oil
9 and gas produced south of 68 degrees North latitude; and providing for an effective
10 date."

11 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

12 * Section 1. AS 38.05.036(a) is amended to read:

1 (a) The department may conduct audits regarding royalty and net profits under
2 oil and gas contracts, agreements, or leases under this chapter and regarding costs
3 related to exploration licenses entered into under AS 38.05.131 - 38.05.134 and
4 exploration incentive credits under this chapter [OR UNDER AS 41.09]. For purposes
5 of an audit under this section,

6 (1) the department may examine the books, papers, records, or
7 memoranda of a person regarding matters related to the audit; and

8 (2) the records and premises where a business is conducted shall be
9 open at all reasonable times for inspection by the department.

10 * **Sec. 2.** AS 38.05.036(b) is amended to read:

11 (b) The Department of Revenue may obtain from the department information
12 relating to royalty and net profits payments and to exploration incentive credits under
13 this chapter [OR UNDER AS 41.09], whether or not that information is confidential.
14 The Department of Revenue may use the information in carrying out its functions and
15 responsibilities under AS 43, and shall hold that information confidential to the extent
16 required by an agreement with the department or by AS 38.05.035(a)(8) [,
17 AS 41.09.010(d),] or AS 43.05.230.

18 * **Sec. 3.** AS 38.05.036(c) is amended to read:

19 (c) The department may obtain from the Department of Revenue all
20 information obtained under AS 43 relating to royalty and net profits and to exploration
21 incentive credits. The department may use the information for purposes of carrying out
22 its responsibilities and functions under this chapter [AND AS 41.09]. Information
23 made available to the department that was obtained under AS 43 is confidential and
24 subject to the provisions of AS 43.05.230.

25 * **Sec. 4.** AS 38.05.036(f) is amended to read:

26 (f) Except as otherwise provided in this section or in connection with official
27 investigations or proceedings of the department, it is unlawful for a current or former
28 officer, employee, or agent of the state to divulge information obtained by the
29 department as a result of an audit under this section that is required by an agreement
30 with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)] to be kept
31 confidential.

1 * **Sec. 5.** AS 38.05.036(g) is amended to read:

2 (g) Nothing in this section prohibits the publication of statistics in a manner
3 that maintains the confidentiality of information to the extent required by an
4 agreement with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)].

5 * **Sec. 6.** AS 43.05.225 is amended to read:

6 **Sec. 43.05.225. Interest.** Unless otherwise provided,

7 (1) a delinquent tax under this title,

8 (A) before January 1, 2014, bears interest in each calendar
9 quarter at the rate of five percentage points above the annual rate charged
10 member banks for advances by the 12th Federal Reserve District as of the first
11 day of that calendar quarter, or at the annual rate of 11 percent, whichever is
12 greater, compounded quarterly as of the last day of that quarter; [OR]

13 (B) on and after January 1, 2014, and before January 1, 2017,
14 bears interest in each calendar quarter at the rate of three percentage points
15 above the annual rate charged member banks for advances by the 12th Federal
16 Reserve District as of the first day of that calendar quarter;

17 (C) on and after January 1, 2017, bears interest

18 (i) for the first four years after a tax becomes
19 delinquent, in each calendar quarter at the rate of five percentage
20 points above the annual rate charged member banks for advances
21 by the 12th Federal Reserve District as of the first day of that
22 calendar quarter, compounded quarterly as of the last day of that
23 quarter; and

24 (ii) after the first four years after a tax becomes
25 delinquent, in each calendar quarter at a rate of five percentage
26 points above the annual rate charged member banks for advances
27 by the 12th Federal Reserve District as of the first day of that
28 calendar quarter;

29 (2) the interest rate is 12 percent a year for

30 (A) delinquent fees payable under AS 05.15.095(c); and

31 (B) unclaimed property that is not timely paid or delivered, as

1 allowed by AS 34.45.470(a).

2 * **Sec. 7.** AS 43.20.046(e) is amended to read:

3 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
4 may use available money in the oil and gas tax credit fund established in AS 43.55.028
5 to make the refund applied for under (d) of this section in whole or in part if the
6 department finds that, [(1) THE CLAIMANT DOES NOT HAVE AN
7 OUTSTANDING LIABILITY TO THE STATE FOR UNPAID DELINQUENT
8 TAXES UNDER THIS TITLE; AND (2)] after application of all available tax credits,
9 the claimant's total tax liability under this chapter for the calendar year in which the
10 claim is made is zero. [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX"
11 MEANS AN AMOUNT OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED
12 AN ASSESSMENT THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS
13 NOT BEEN FINALLY RESOLVED IN THE TAXPAYER'S FAVOR.]

14 * **Sec. 8.** AS 43.20.047(e) is amended to read:

15 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
16 may use money available in the oil and gas tax credit fund established in AS 43.55.028
17 to make a refund or payment under (d) of this section in whole or in part if the
18 department finds that, [(1) THE CLAIMANT DOES NOT HAVE AN
19 OUTSTANDING LIABILITY TO THE STATE FOR UNPAID DELINQUENT
20 TAXES UNDER THIS TITLE; AND (2)] after application of all available tax credits,
21 the claimant's total tax liability under this chapter for the calendar year in which the
22 claim is made is zero. [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX"
23 MEANS AN AMOUNT OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED
24 AN ASSESSMENT THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS
25 NOT BEEN FINALLY RESOLVED IN THE TAXPAYER'S FAVOR.]

26 * **Sec. 9.** AS 43.20.053(e) is amended to read:

27 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
28 may use money available in the oil and gas tax credit fund established in AS 43.55.028
29 to make a refund or payment under (d) of this section in whole or in part if the
30 department finds that,

31 [(1) THE CLAIMANT DOES NOT HAVE AN OUTSTANDING

1 LIABILITY TO THE STATE FOR UNPAID DELINQUENT TAXES UNDER THIS
2 TITLE; AND

3 (2)] after application of all available tax credits, the claimant's total tax
4 liability under this chapter for the calendar year in which the claim is made is zero.

5 * **Sec. 10.** AS 43.55.011(f) is amended to read:

6 (f) The levy of tax under (e) of this section for

7 (1) oil and gas produced before **January 1, 2017** [JANUARY 1,
8 2022], from leases or properties that include land north of 68 degrees North latitude,
9 other than gas subject to (o) of this section, may not be less than

10 (A) four percent of the gross value at the point of production
11 when the average price per barrel for Alaska North Slope crude oil for sale on
12 the United States West Coast during the calendar year for which the tax is due
13 is more than \$25;

14 (B) three percent of the gross value at the point of production
15 when the average price per barrel for Alaska North Slope crude oil for sale on
16 the United States West Coast during the calendar year for which the tax is due
17 is over \$20 but not over \$25;

18 (C) two percent of the gross value at the point of production
19 when the average price per barrel for Alaska North Slope crude oil for sale on
20 the United States West Coast during the calendar year for which the tax is due
21 is over \$17.50 but not over \$20;

22 (D) one percent of the gross value at the point of production
23 when the average price per barrel for Alaska North Slope crude oil for sale on
24 the United States West Coast during the calendar year for which the tax is due
25 is over \$15 but not over \$17.50; or

26 (E) zero percent of the gross value at the point of production
27 when the average price per barrel for Alaska North Slope crude oil for sale on
28 the United States West Coast during the calendar year for which the tax is due
29 is \$15 or less; [AND]

30 (2) oil **and gas** produced on and after **January 1, 2017, and before**
31 January 1, 2022, from leases or properties that include land north of 68 degrees North

1 latitude, other than gas subject to (o) of this section, may not be less than [(A)] four
2 percent of the gross value at the point of production, except that a credit authorized
3 under this chapter may reduce the tax under this subsection to less than four
4 percent, but not to less than two percent of the gross value at the point of
5 production;

6 (3) oil produced on and after January 1, 2022, from leases or
7 properties that include land north of 68 degrees North latitude may not be less
8 than four percent of the gross value at the point of production, except that a
9 credit authorized under this chapter may reduce the tax under this subsection to
10 less than four percent, but not to less than two percent of the gross value at the
11 point of production [WHEN THE AVERAGE PRICE PER BARREL FOR
12 ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED STATES
13 WEST COAST DURING THE CALENDAR YEAR FOR WHICH THE TAX IS
14 DUE IS MORE THAN \$25;

15 (B) THREE PERCENT OF THE GROSS VALUE AT THE
16 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
17 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
18 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
19 THE TAX IS DUE IS OVER \$20 BUT NOT OVER \$25;

20 (C) TWO PERCENT OF THE GROSS VALUE AT THE
21 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
22 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
23 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
24 THE TAX IS DUE IS OVER \$17.50 BUT NOT OVER \$20;

25 (D) ONE PERCENT OF THE GROSS VALUE AT THE
26 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
27 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
28 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
29 THE TAX IS DUE IS OVER \$15 BUT NOT OVER \$17.50; OR

30 (E) ZERO PERCENT OF THE GROSS VALUE AT THE
31 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL

1 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
2 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
3 THE TAX IS DUE IS \$15 OR LESS].

4 * **Sec. 11.** AS 43.55.011(m) is amended to read:

5 (m) Notwithstanding any contrary provision of [AS 38.05.180(i),
6 AS 41.09.010,] AS 43.55.024 [,] or 43.55.025, the department shall provide by
7 regulation a method to ensure that, for a calendar year for which a producer's tax
8 liability is limited by (j), (k), or (o) of this section, tax credits based on a lease
9 expenditure incurred before January 1, 2011, that are otherwise available under
10 [AS 38.05.180(i), AS 41.09.010,] AS 43.55.024 [,] or 43.55.025 and allocated to gas
11 subject to the limitations in (j), (k), and (o) of this section are accounted for as though
12 the credits had been applied first against a tax liability calculated without regard to the
13 limitations under (j), (k), and (o) of this section so as to reduce the tax liability to the
14 maximum amount provided for under (j) or (o) of this section for the production of gas
15 or (k) of this section for the production of oil. The regulation must provide for a
16 reasonable method to allocate tax credits to gas subject to (j) and (o) of this section.
17 Only the amount of a tax credit remaining after the accounting provided for under this
18 subsection may be used for a later calendar year, transferred to another person, or
19 applied against a tax levied on the production of oil or gas not subject to (j), (k), or (o)
20 of this section to the extent otherwise allowed.

21 * **Sec. 12.** AS 43.55.019(e) is amended to read:

22 (e) The credit under this section may not reduce a person's tax liability **for the**
23 **calendar year** under AS 43.55.011(e) to below **the amount calculated under**
24 **AS 43.55.011(f)** [ZERO FOR ANY TAX YEAR]. An unused credit or portion of a
25 credit not used under this section for a tax year may not be sold, traded, transferred, or
26 applied in a subsequent tax year.

27 * **Sec. 13.** AS 43.55.020(a) is amended to read:

28 (a) For a calendar year, a producer subject to tax under AS 43.55.011 shall pay
29 the tax as follows:

30 (1) for oil and gas produced before January 1, 2014, an installment
31 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied

1 as allowed by law, is due for each month of the calendar year on the last day of the
2 following month; except as otherwise provided under (2) of this subsection, the
3 amount of the installment payment is the sum of the following amounts, less 1/12 of
4 the tax credits that are allowed by law to be applied against the tax levied by
5 AS 43.55.011(e) for the calendar year, but the amount of the installment payment may
6 not be less than zero:

7 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
8 produced from leases or properties in the state outside the Cook Inlet
9 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),
10 the greater of

11 (i) zero; or

12 (ii) the sum of 25 percent and the tax rate calculated for
13 the month under AS 43.55.011(g) multiplied by the remainder obtained
14 by subtracting 1/12 of the producer's adjusted lease expenditures for the
15 calendar year of production under AS 43.55.165 and 43.55.170 that are
16 deductible for the oil and gas under AS 43.55.160 from the gross value
17 at the point of production of the oil and gas produced from the leases or
18 properties during the month for which the installment payment is
19 calculated;

20 (B) for oil and gas produced from leases or properties subject
21 to AS 43.55.011(f), the greatest of

22 (i) zero;

23 (ii) zero percent, one percent, two percent, three
24 percent, or four percent, as applicable, of the gross value at the point of
25 production of the oil and gas produced from the leases or properties
26 during the month for which the installment payment is calculated; or

27 (iii) the sum of 25 percent and the tax rate calculated for
28 the month under AS 43.55.011(g) multiplied by the remainder obtained
29 by subtracting 1/12 of the producer's adjusted lease expenditures for the
30 calendar year of production under AS 43.55.165 and 43.55.170 that are
31 deductible for the oil and gas under AS 43.55.160 from the gross value

1 at the point of production of the oil and gas produced from those leases
2 or properties during the month for which the installment payment is
3 calculated;

4 (C) for oil or gas subject to AS 43.55.011(j), (k), or (o), for
5 each lease or property, the greater of

6 (i) zero; or

7 (ii) the sum of 25 percent and the tax rate calculated for
8 the month under AS 43.55.011(g) multiplied by the remainder obtained
9 by subtracting 1/12 of the producer's adjusted lease expenditures for the
10 calendar year of production under AS 43.55.165 and 43.55.170 that are
11 deductible under AS 43.55.160 for the oil or gas, respectively,
12 produced from the lease or property from the gross value at the point of
13 production of the oil or gas, respectively, produced from the lease or
14 property during the month for which the installment payment is
15 calculated;

16 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

17 (i) the sum of 25 percent and the tax rate calculated for
18 the month under AS 43.55.011(g) multiplied by the remainder obtained
19 by subtracting 1/12 of the producer's adjusted lease expenditures for the
20 calendar year of production under AS 43.55.165 and 43.55.170 that are
21 deductible for the oil and gas under AS 43.55.160 from the gross value
22 at the point of production of the oil and gas produced from the leases or
23 properties during the month for which the installment payment is
24 calculated, but not less than zero; or

25 (ii) four percent of the gross value at the point of
26 production of the oil and gas produced from the leases or properties
27 during the month, but not less than zero;

28 (2) an amount calculated under (1)(C) of this subsection for oil or gas
29 subject to AS 43.55.011(j), (k), or (o) may not exceed the product obtained by
30 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
31 applicable, for gas or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil, but

1 substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the
2 amount of taxable gas produced during the month for the amount of taxable gas
3 produced during the calendar year and substituting in as 43.55.011(k)(1)(A) or (2)(A),
4 as applicable, the amount of taxable oil produced during the month for the amount of
5 taxable oil produced during the calendar year;

6 (3) an installment payment of the estimated tax levied by
7 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
8 on the last day of the following month; the amount of the installment payment is the
9 sum of

10 (A) the applicable tax rate for oil provided under
11 AS 43.55.011(i), multiplied by the gross value at the point of production of the
12 oil taxable under AS 43.55.011(i) and produced from the lease or property
13 during the month; and

14 (B) the applicable tax rate for gas provided under
15 AS 43.55.011(i), multiplied by the gross value at the point of production of the
16 gas taxable under AS 43.55.011(i) and produced from the lease or property
17 during the month;

18 (4) any amount of tax levied by AS 43.55.011, net of any credits
19 applied as allowed by law, that exceeds the total of the amounts due as installment
20 payments of estimated tax is due on March 31 of the year following the calendar year
21 of production;

22 (5) for oil and gas produced on and after January 1, 2014, and before
23 January 1, 2022, an installment payment of the estimated tax levied by
24 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
25 month of the calendar year on the last day of the following month; except as otherwise
26 provided under (6) and (10) of this subsection, the amount of the installment payment
27 is the sum of the following amounts, less 1/12 of the tax credits that are allowed by
28 law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but
29 the amount of the installment payment may not be less than zero:

30 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
31 produced from leases or properties in the state outside the Cook Inlet

1 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),
2 the greater of

3 (i) zero; or

4 (ii) 35 percent multiplied by the remainder obtained by
5 subtracting 1/12 of the producer's adjusted lease expenditures for the
6 calendar year of production under AS 43.55.165 and 43.55.170 that are
7 deductible for the oil and gas under AS 43.55.160 from the gross value
8 at the point of production of the oil and gas produced from the leases or
9 properties during the month for which the installment payment is
10 calculated;

11 (B) for oil and gas produced from leases or properties subject
12 to AS 43.55.011(f), the greatest of

13 (i) zero;

14 (ii) zero percent, one percent, two percent, three
15 percent, or four percent, as applicable, of the gross value at the point of
16 production of the oil and gas produced from the leases or properties
17 during the month for which the installment payment is calculated; or

18 (iii) 35 percent multiplied by the remainder obtained by
19 subtracting 1/12 of the producer's adjusted lease expenditures for the
20 calendar year of production under AS 43.55.165 and 43.55.170 that are
21 deductible for the oil and gas under AS 43.55.160 from the gross value
22 at the point of production of the oil and gas produced from those leases
23 or properties during the month for which the installment payment is
24 calculated, except that, for the purposes of this calculation, a reduction
25 from the gross value at the point of production may apply for oil and
26 gas subject to AS 43.55.160(f) or (g);

27 (C) for oil or gas subject to AS 43.55.011(j), (k), or (o), for
28 each lease or property, the greater of

29 (i) zero; or

30 (ii) 35 percent multiplied by the remainder obtained by
31 subtracting 1/12 of the producer's adjusted lease expenditures for the

1 calendar year of production under AS 43.55.165 and 43.55.170 that are
2 deductible under AS 43.55.160 for the oil or gas, respectively,
3 produced from the lease or property from the gross value at the point of
4 production of the oil or gas, respectively, produced from the lease or
5 property during the month for which the installment payment is
6 calculated;

7 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

8 (i) 35 percent multiplied by the remainder obtained by
9 subtracting 1/12 of the producer's adjusted lease expenditures for the
10 calendar year of production under AS 43.55.165 and 43.55.170 that are
11 deductible for the oil and gas under AS 43.55.160 from the gross value
12 at the point of production of the oil and gas produced from the leases or
13 properties during the month for which the installment payment is
14 calculated, but not less than zero; or

15 (ii) four percent of the gross value at the point of
16 production of the oil and gas produced from the leases or properties
17 during the month, but not less than zero;

18 (6) an amount calculated under (5)(C) of this subsection for oil or gas
19 subject to AS 43.55.011(j), (k), or (o) may not exceed the product obtained by
20 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
21 applicable, for gas or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil, but
22 substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the
23 amount of taxable gas produced during the month for the amount of taxable gas
24 produced during the calendar year and substituting in AS 43.55.011(k)(1)(A) or
25 (2)(A), as applicable, the amount of taxable oil produced during the month for the
26 amount of taxable oil produced during the calendar year;

27 (7) for oil and gas produced on or after January 1, 2022, an installment
28 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
29 as allowed by law, is due for each month of the calendar year on the last day of the
30 following month; except as provided in (10) of this subsection, the amount of the
31 installment payment is the sum of the following amounts, less 1/12 of the tax credits

1 that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the
2 calendar year, but the amount of the installment payment may not be less than zero:

3 (A) for oil produced from leases or properties that include land
4 north of 68 degrees North latitude, the greatest of

5 (i) zero;

6 (ii) zero percent, one percent, two percent, three
7 percent, or four percent, as applicable, of the gross value at the point of
8 production of the oil produced from the leases or properties during the
9 month for which the installment payment is calculated; or

10 (iii) 35 percent multiplied by the remainder obtained by
11 subtracting 1/12 of the producer's adjusted lease expenditures for the
12 calendar year of production under AS 43.55.165 and 43.55.170 that are
13 deductible for the oil under AS 43.55.160(h)(1) from the gross value at
14 the point of production of the oil produced from those leases or
15 properties during the month for which the installment payment is
16 calculated, except that, for the purposes of this calculation, a reduction
17 from the gross value at the point of production may apply for oil
18 subject to AS 43.55.160(f) or 43.55.160(f) and (g);

19 (B) for oil produced before or during the last calendar year
20 under AS 43.55.024(b) for which the producer could take a tax credit under
21 AS 43.55.024(a), from leases or properties in the state outside the Cook Inlet
22 sedimentary basin, no part of which is north of 68 degrees North latitude, other
23 than leases or properties subject to AS 43.55.011(p), the greater of

24 (i) zero; or

25 (ii) 35 percent multiplied by the remainder obtained by
26 subtracting 1/12 of the producer's adjusted lease expenditures for the
27 calendar year of production under AS 43.55.165 and 43.55.170 that are
28 deductible for the oil under AS 43.55.160(h)(2) from the gross value at
29 the point of production of the oil produced from the leases or properties
30 during the month for which the installment payment is calculated;

31 (C) for oil and gas produced from leases or properties subject

1 to AS 43.55.011(p), except as otherwise provided under (8) of this subsection,
2 the sum of

3 (i) 35 percent multiplied by the remainder obtained by
4 subtracting 1/12 of the producer's adjusted lease expenditures for the
5 calendar year of production under AS 43.55.165 and 43.55.170 that are
6 deductible for the oil under AS 43.55.160(h)(3) from the gross value at
7 the point of production of the oil produced from the leases or properties
8 during the month for which the installment payment is calculated, but
9 not less than zero; and

10 (ii) 13 percent of the gross value at the point of
11 production of the gas produced from the leases or properties during the
12 month, but not less than zero;

13 (D) for oil produced from leases or properties in the state, no
14 part of which is north of 68 degrees North latitude, other than leases or
15 properties subject to (B) or (C) of this paragraph, the greater of

16 (i) zero; or

17 (ii) 35 percent multiplied by the remainder obtained by
18 subtracting 1/12 of the producer's adjusted lease expenditures for the
19 calendar year of production under AS 43.55.165 and 43.55.170 that are
20 deductible for the oil under AS 43.55.160(h)(4) from the gross value at
21 the point of production of the oil produced from the leases or properties
22 during the month for which the installment payment is calculated;

23 (E) for gas produced from each lease or property in the state,
24 other than a lease or property subject to AS 43.55.011(p), 13 percent of the
25 gross value at the point of production of the gas produced from the lease or
26 property during the month for which the installment payment is calculated, but
27 not less than zero;

28 (8) an amount calculated under (7)(C) of this subsection may not
29 exceed four percent of the gross value at the point of production of the oil and gas
30 produced from leases or properties subject to AS 43.55.011(p) during the month for
31 which the installment payment is calculated;

1 (9) for purposes of the calculation under (1)(B)(ii), (5)(B)(ii), and
 2 (7)(A)(ii) of this subsection, the applicable percentage of the gross value at the point
 3 of production is determined under AS 43.55.011(f) [AS 43.55.011(f)(1) OR (2)] but
 4 substituting the phrase "month for which the installment payment is calculated" in
 5 [AS 43.55.011(f)(1) AND (2)] for the phrase "calendar year for which the tax is due";

6 (10) after December 31, 2016, for the purposes of a calculation
 7 under (5)(B)(ii) or (7)(A)(ii) of this subsection, a credit under this chapter may
 8 not be applied to reduce an installment payment to less than the applicable
 9 percentage under AS 43.55.011(f). ["

10 * **Sec. 14.** AS 43.55.023(a) is amended to read:

11 (a) A producer or explorer may take a tax credit for a qualified capital
 12 expenditure as follows:

13 (1) notwithstanding that a qualified capital expenditure may be a
 14 deductible lease expenditure for purposes of calculating the production tax value of oil
 15 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
 16 [AS 38.05.180(i), AS 41.09.010,] AS 43.20.043 [,] or AS 43.55.025, a producer or
 17 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
 18 against a tax levied by AS 43.55.011(e) in the amount of 10 [20] percent of that
 19 expenditure;

20 (2) a producer or explorer may take a credit for a qualified capital
 21 expenditure incurred in connection with geological or geophysical exploration or in
 22 connection with an exploration well only if the producer or explorer

23 (A) agrees, in writing, to the applicable provisions of
 24 AS 43.55.025(f)(2); and

25 (B) submits to the Department of Natural Resources all data
 26 that would be required to be submitted under AS 43.55.025(f)(2);

27 (3) a credit for a qualified capital expenditure incurred to explore for,
 28 develop, or produce oil or gas deposits located north of 68 degrees North latitude may
 29 be taken only if the expenditure is incurred before January 1, 2014.

30 * **Sec. 15.** AS 43.55.023(b) is amended to read:

31 (b) Before January 1, 2014, a producer or explorer may elect to take a tax

1 credit in the amount of 25 percent of a carried-forward annual loss. For lease
2 expenditures incurred on and after January 1, 2014, and before January 1, 2016, to
3 explore for, develop, or produce oil or gas deposits located north of 68 degrees North
4 latitude, a producer or explorer may elect to take a tax credit in the amount of 45
5 percent of a carried-forward annual loss. For lease expenditures incurred on and after
6 January 1, 2016, to explore for, develop, or produce oil or gas deposits located north
7 of 68 degrees North latitude, a producer or explorer may elect to take a tax credit in
8 the amount of 35 percent of a carried-forward annual loss. For lease expenditures
9 incurred on or after January 1, 2014, and before January 1, 2017, to explore for,
10 develop, or produce oil or gas deposits located south of 68 degrees North latitude, a
11 producer or explorer may elect to take a tax credit in the amount of 25 percent of a
12 carried-forward annual loss. For lease expenditures incurred after December 31,
13 2016, to explore for, develop, or produce oil or gas deposits located south of 68
14 degrees North latitude and outside of the Cook Inlet sedimentary basin, a
15 producer or explorer may elect to take a tax credit in the amount of 25 percent of
16 a carried-forward annual loss. For lease expenditures incurred after
17 December 31, 2016, to explore for, develop, or produce oil or gas deposits located
18 in the Cook Inlet sedimentary basin, a producer or explorer may elect to take a
19 credit in the amount of 10 percent of a carried-forward annual loss. A credit under
20 this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes
21 of this subsection,

22 (1) a carried-forward annual loss is the amount of a producer's or
23 explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a
24 previous calendar year that was not deductible in calculating production tax values for
25 that calendar year under AS 43.55.160;

26 (2) for lease expenditures incurred on or after January 1, 2017,
27 any reduction under AS 43.55.160(f) or (g) is added back to the calculation of
28 production tax values for that calendar year under AS 43.55.160 for the
29 determination of a carried-forward annual loss.

30 * Sec. 16. AS 43.55.023(c) is amended to read:

31 (c) A credit or portion of a credit under this section may not be used to reduce

1 a person's tax liability under AS 43.55.011(e) for any calendar year below the amount
2 calculated under AS 43.55.011(f) [ZERO], and any unused credit or portion of a
3 credit not used under this subsection may be applied in a later calendar year.

4 * **Sec. 17.** AS 43.55.023(d) is amended to read:

5 (d) A person that is entitled to take a tax credit under this section that wishes
6 to transfer the unused credit to another person or obtain a cash payment under
7 AS 43.55.028 may apply to the department for a transferable tax credit certificate. An
8 application under this subsection must be in a form prescribed by the department and
9 must include supporting information and documentation that the department
10 reasonably requires. The department shall grant or deny an application, or grant an
11 application as to a lesser amount than that claimed and deny it as to the excess, not
12 later than 120 days after the latest of (1) March 31 of the year following the calendar
13 year in which the [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward
14 annual loss for which the credit is claimed was incurred; (2) the date the statement
15 required under AS 43.55.030(a) or (e) was filed for the calendar year in which the
16 [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward annual loss for which
17 the credit is claimed was incurred; or (3) the date the application was received by the
18 department. If, based on the information then available to it, the department is
19 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
20 the applicant a transferable tax credit certificate for the amount of the credit. A
21 certificate issued under this subsection does not expire.

22 * **Sec. 18.** AS 43.55.023(e) is amended to read:

23 (e) A person to which a transferable tax credit certificate is issued under (d) of
24 this section may transfer the certificate to another person, and a transferee may further
25 transfer the certificate. Subject to the limitations set out in former (a) of this section
26 and (b) - (d) [(a) - (d)] of this section, and notwithstanding any action the department
27 may take with respect to the applicant under (g) of this section, the owner of a
28 certificate may apply the credit or a portion of the credit shown on the certificate only
29 against a tax levied by AS 43.55.011(e). However, a credit shown on a transferable tax
30 credit certificate may not be applied to reduce a transferee's total tax liability under
31 AS 43.55.011(e) for oil and gas produced during a calendar year to less than 80

1 percent of the tax that would otherwise be due without applying that credit. Any
2 portion of a credit not used under this subsection may be applied in a later period.

3 * **Sec. 19.** AS 43.55.023(I) is amended to read:

4 (I) A producer or explorer may apply for a tax credit for a well lease
5 expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE]
6 after June 30, 2010, as follows:

7 (1) notwithstanding that a well lease expenditure incurred in the state
8 [SOUTH OF 68 DEGREES NORTH LATITUDE] may be a deductible lease
9 expenditure for purposes of calculating the production tax value of oil and gas under
10 AS 43.55.160(a), unless a credit for that expenditure is taken under (a) of this section,
11 [AS 38.05.180(i), AS 41.09.010,] AS 43.20.043, or AS 43.55.025, a producer or
12 explorer that incurs a well lease expenditure in the state [SOUTH OF 68 DEGREES
13 NORTH LATITUDE] may elect to apply a tax credit against a tax levied by
14 AS 43.55.011(e) in the amount of

15 (A) 40 percent of that expenditure incurred south of 68
16 degrees North latitude before January 1, 2017;

17 (B) 30 percent of that expenditure incurred south of 68
18 degrees North latitude after December 31, 2016, and before January 1,
19 2018;

20 (C) 20 percent of that expenditure incurred inside the Cook
21 Inlet sedimentary basin after December 31, 2017;

22 (D) 30 percent of that expenditure incurred outside the
23 Cook Inlet sedimentary basin and south of 68 degrees North latitude after
24 December 31, 2017, and before January 1, 2019 [; A TAX CREDIT
25 UNDER THIS PARAGRAPH MAY BE APPLIED FOR A SINGLE
26 CALENDAR YEAR];

27 (2) a producer or explorer may take a credit for a well lease
28 expenditure incurred in the state south of 68 degrees North latitude in connection with
29 geological or geophysical exploration or in connection with an exploration well only if
30 the producer or explorer

31 (A) agrees, in writing, to the applicable provisions of

1 AS 43.55.025(f)(2); and

2 (B) submits to the Department of Natural Resources all data
3 that would be required to be submitted under AS 43.55.025(f)(2).

4 * **Sec. 20.** AS 43.55.024(f) is amended to read:

5 (f) A tax credit authorized by (a) of this section may not be applied to reduce a
6 producer's tax liability for any calendar year under AS 43.55.011(e) on oil and gas
7 produced from leases or properties outside the Cook Inlet sedimentary basin, no part
8 of which is north of 68 degrees North latitude, below **the amount calculated under**
9 **AS 43.55.011(f)** [ZERO].

10 * **Sec. 21.** AS 43.55.024(g) is amended to read:

11 (g) A tax credit authorized by (c) of this section may not be applied to reduce
12 a producer's tax liability for any calendar year under AS 43.55.011(e) below **the**
13 **amount calculated under AS 43.55.011(f)** [ZERO].

14 * **Sec. 22.** AS 43.55.024(i) is amended to read:

15 (i) A producer may apply against the producer's tax liability for the calendar
16 year under AS 43.55.011(e) a tax credit of \$5 for each barrel of oil taxable under
17 AS 43.55.011(e) that meets one or more of the criteria in AS 43.55.160(f) or (g) and
18 that is produced during a calendar year after December 31, 2013. A tax credit
19 authorized by this subsection may not reduce a producer's tax liability for a calendar
20 year under AS 43.55.011(e) below **the amount calculated under AS 43.55.011(f)**
21 [ZERO].

22 * **Sec. 23.** AS 43.55.024(j) is amended to read:

23 (j) A producer may apply against the producer's tax liability for the calendar
24 year under AS 43.55.011(e) a tax credit in the amount specified in this subsection for
25 each barrel of oil taxable under AS 43.55.011(e) that does not meet any of the criteria
26 in AS 43.55.160(f) or (g) and that is produced during a calendar year after
27 December 31, 2013, from leases or properties north of 68 degrees North latitude.
28 **Notwithstanding AS 43.55.011(f)(2) and (3), a** [A] tax credit under this subsection
29 may not reduce a producer's tax liability for a calendar year under AS 43.55.011(e)
30 below **four percent of the gross value at the point of production for oil produced**
31 **on and after January 1, 2017** [THE AMOUNT CALCULATED UNDER

1 AS 43.55.011(f)]. The amount of the tax credit for a barrel of taxable oil subject to this
2 subsection produced during a month of the calendar year is

3 (1) \$8 for each barrel of taxable oil if the average gross value at the
4 point of production for the month is less than \$80 a barrel;

5 (2) \$7 for each barrel of taxable oil if the average gross value at the
6 point of production for the month is greater than or equal to \$80 a barrel, but less than
7 \$90 a barrel;

8 (3) \$6 for each barrel of taxable oil if the average gross value at the
9 point of production for the month is greater than or equal to \$90 a barrel, but less than
10 \$100 a barrel;

11 (4) \$5 for each barrel of taxable oil if the average gross value at the
12 point of production for the month is greater than or equal to \$100 a barrel, but less
13 than \$110 a barrel;

14 (5) \$4 for each barrel of taxable oil if the average gross value at the
15 point of production for the month is greater than or equal to \$110 a barrel, but less
16 than \$120 a barrel;

17 (6) \$3 for each barrel of taxable oil if the average gross value at the
18 point of production for the month is greater than or equal to \$120 a barrel, but less
19 than \$130 a barrel;

20 (7) \$2 for each barrel of taxable oil if the average gross value at the
21 point of production for the month is greater than or equal to \$130 a barrel, but less
22 than \$140 a barrel;

23 (8) \$1 for each barrel of taxable oil if the average gross value at the
24 point of production for the month is greater than or equal to \$140 a barrel, but less
25 than \$150 a barrel;

26 (9) zero if the average gross value at the point of production for the
27 month is greater than or equal to \$150 a barrel.

28 * **Sec. 24.** AS 43.55.025(m) is amended to read:

29 (m) The persons that drill the first four exploration wells in the state and
30 within the areas described in (o) of this section on state lands, private lands, or federal
31 onshore lands for the purpose of discovering oil or gas that penetrate and evaluate a

1 prospect in a basin described in (o) of this section are eligible for a credit under (a)(6)
2 of this section. A credit under this subsection may not be taken for more than two
3 exploration wells in a single area described in (o)(1) - (6) of this section. Exploration
4 expenditures eligible for the credit in this subsection must be incurred for work
5 performed after June 1, 2012, and before July 1, 2016, **except that expenditures to**
6 **complete an exploration well that was spudded but not completed before July 1,**
7 **2016, are eligible for the credit under this subsection.** A person planning to drill an
8 exploration well on private land and to apply for a credit under this subsection shall
9 obtain written consent from the owner of the oil and gas interest for the full public
10 release of all well data after the expiration of the confidentiality period applicable to
11 information collected under (f) of this section. The written consent of the owner of the
12 oil and gas interest must be submitted to the commissioner of natural resources before
13 approval of the proposed exploration well. In addition to the requirements in (c)(1),
14 (c)(2)(A), and (c)(2)(C) of this section and submission of the written consent of the
15 owner of the oil and gas interest, a person planning to drill an exploration well shall
16 obtain approval from the commissioner of natural resources before the well is
17 spudded. The commissioner of natural resources shall make a written determination
18 approving or rejecting an exploration well within 60 days after receiving the request
19 for approval or as soon as is practicable thereafter. Before approving the exploration
20 well, the commissioner of natural resources shall consider the following: the location
21 of the well; the proximity to a community in need of a local energy source; the
22 proximity of existing infrastructure; the experience and safety record of the explorer in
23 conducting operations in remote or roadless areas; the projected cost schedule;
24 whether seismic mapping and seismic data sufficiently identify a particular trap for
25 exploration; whether the targeted and planned depth and range are designed to
26 penetrate and fully evaluate the hydrocarbon potential of the proposed prospect and
27 reach the level below which economic hydrocarbon reservoirs are likely to be found,
28 or reach 12,000 feet or more true vertical depth; and whether the exploration plan
29 provides for a full evaluation of the wellbore below surface casing to the depth of the
30 well. Whether the exploration well for which a credit is requested under this
31 subsection is located within an area and a basin described under (o) of this section

1 shall be determined by the commissioner of natural resources and reported to the
 2 commissioner. A taxpayer that obtains a credit under this subsection may not claim a
 3 tax credit under AS 43.55.023 or another provision in this section for the same
 4 exploration expenditure.

5 * **Sec. 25.** AS 43.55.025 is amended by adding a new subsection to read:

6 (q) A credit or portion of a credit under this section may not be used to reduce
 7 a person's tax liability under AS 43.55.011(e) for any calendar year below the amount
 8 calculated under AS 43.55.011(f).

9 * **Sec. 26.** AS 43.55.028(e) is amended to read:

10 (e) The department, on the written application of a person to whom a
 11 transferable tax credit certificate has been issued under AS 43.55.023(d) or former
 12 AS 43.55.023(m) or to whom a production tax credit certificate has been issued under
 13 AS 43.55.025(f), may use available money in the oil and gas tax credit fund to
 14 purchase, in whole or in part, the certificate. **The department may not purchase a**
 15 **total of more than \$100,000,000 in tax credit certificates from a person in a**
 16 **calendar year. Before purchasing a certificate or part of a certificate, [IF] the**
 17 department **shall find** [FINDS] that

18 (1) the calendar year of the purchase is not earlier than the first
 19 calendar year for which the credit shown on the certificate would otherwise be allowed
 20 to be applied against a tax;

21 (2) the **application is not the result of the division of a single entity**
 22 **into multiple entities that would reasonably be expected to apply as a single entity**
 23 **if the \$100,000,000 limitation in this subsection did not exist** [APPLICANT DOES
 24 NOT HAVE AN OUTSTANDING LIABILITY TO THE STATE FOR UNPAID
 25 DELINQUENT TAXES UNDER THIS TITLE];

26 (3) the applicant's total tax liability under AS 43.55.011(e), after
 27 application of all available tax credits, for the calendar year in which the application is
 28 made is zero;

29 (4) the applicant's average daily production of oil and gas taxable
 30 under AS 43.55.011(e) during the calendar year preceding the calendar year in which
 31 the application is made was not more than 50,000 BTU equivalent barrels; and

1 (5) the purchase is consistent with this section and regulations adopted
2 under this section.

3 * **Sec. 27.** AS 43.55.028 is amended by adding a new subsection to read:

4 (j) If an applicant or claimant has an outstanding liability to the state directly
5 related to the applicant's or claimant's oil or gas exploration, development, or
6 production and the department has not previously reduced the amount paid to that
7 applicant or claimant for a certificate or refund because of that outstanding liability,
8 the department may purchase only that portion of a certificate or pay only that portion
9 of a refund that exceeds the outstanding liability. With the applicant's or claimant's
10 consent, the department may apply the amount by which the department reduced its
11 purchase of a certificate or payment for a refund because of an outstanding liability to
12 satisfy the outstanding liability. Satisfaction of an outstanding liability under this
13 subsection does not affect the applicant's ability to contest that liability. The
14 department may enter into contracts or agreements with another department to which
15 the outstanding liability is owed. In this subsection, "outstanding liability" means an
16 amount of tax, interest, penalty, fee, rental, royalty, or other charge for which the state
17 has issued a demand for payment that has not been paid when due and, if contested,
18 has not been finally resolved against the state.

19 * **Sec. 28.** AS 43.55.029(a) is amended to read:

20 (a) An explorer or producer that has applied for a production tax credit under
21 former AS 43.55.023(a) [, (b),] or (l) or under AS 43.55.023(b) or 43.55.025(a) may
22 make a present assignment of the production tax credit certificate expected to be
23 issued by the department to a third-party assignee. The assignment may be made either
24 at the time the application is filed with the department or not later than 30 days after
25 the date of filing with the department. Once a notice of assignment in compliance with
26 this section is filed with the department, the assignment is irrevocable and cannot be
27 modified by the explorer or producer without the written consent of the assignee
28 named in the assignment. If a production tax credit certificate is issued to the explorer
29 or producer, the notice of assignment remains effective and shall be filed with the
30 department by the explorer or producer together with any application for the
31 department to purchase the certificate under AS 43.55.028(e).

1 * **Sec. 29.** AS 43.55.030(a) is amended to read:

2 (a) A producer that produces oil or gas from a lease or property in the state
3 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)
4 for that oil or gas, shall file with the department on March 31 of the following year a
5 statement, under oath, in a form prescribed by the department, giving, with other
6 information required, the following:

7 (1) a description of each lease or property from which oil or gas was
8 produced, by name, legal description, lease number, or accounting codes assigned by
9 the department;

10 (2) the names of the producer and, if different, the person paying the
11 tax, if any;

12 (3) the gross amount of oil and the gross amount of gas produced from
13 each lease or property, separately identifying the gross amount of gas produced from
14 each oil and gas lease to which an effective election under AS 43.55.014(a) applies,
15 the amount of gas delivered to the state under AS 43.55.014(b), and the percentage of
16 the gross amount of oil and gas owned by the producer;

17 (4) the gross value at the point of production of the oil and of the gas
18 produced from each lease or property owned by the producer and the costs of
19 transportation of the oil and gas;

20 (5) the name of the first purchaser and the price received for the oil and
21 for the gas, unless relieved from this requirement in whole or in part by the
22 department;

23 (6) the producer's qualified capital expenditures, [AS DEFINED IN
24 AS 43.55.023,] other lease expenditures under AS 43.55.165, and adjustments or other
25 payments or credits under AS 43.55.170;

26 (7) the production tax values of the oil and gas under AS 43.55.160(a)
27 or of the oil under AS 43.55.160(h), as applicable;

28 (8) any claims for tax credits to be applied; and

29 (9) calculations showing the amounts, if any, that were or are due
30 under AS 43.55.020(a) and interest on any underpayment or overpayment.

31 * **Sec. 30.** AS 43.55.030(e) is amended to read:

1 (e) An explorer or producer that incurs a lease expenditure under
 2 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
 3 year but does not produce oil or gas from a lease or property in the state during the
 4 calendar year shall file with the department, on March 31 of the following year, a
 5 statement, under oath, in a form prescribed by the department, giving, with other
 6 information required, the following:

7 (1) the explorer's or producer's qualified capital expenditures, [AS
 8 DEFINED IN AS 43.55.023,] other lease expenditures under AS 43.55.165, and
 9 adjustments or other payments or credits under AS 43.55.170; and

10 (2) if the explorer or producer receives a payment or credit under
 11 AS 43.55.170, calculations showing whether the explorer or producer is liable for a
 12 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount.

13 * **Sec. 31.** AS 43.55.160(f) is amended to read:

14 (f) On and after January 1, 2014, in the calculation of an annual production tax
 15 value of a producer under (a)(1)(A) or (h)(1) of this section, the gross value at the
 16 point of production of oil or gas produced from a lease or property north of 68 degrees
 17 North latitude meeting one or more of the following criteria is reduced by 20 percent:
 18 (1) the oil or gas is produced from a lease or property that does not contain a lease that
 19 was within a unit on January 1, 2003; (2) the oil or gas is produced from a
 20 participating area established after December 31, 2011, that is within a unit formed
 21 under AS 38.05.180(p) before January 1, 2003, if the participating area does not
 22 contain a reservoir that had previously been in a participating area established before
 23 December 31, 2011; (3) the oil or gas is produced from acreage that was added to an
 24 existing participating area by the Department of Natural Resources on and after
 25 January 1, 2014, and the producer demonstrates to the department that the volume of
 26 oil or gas produced is from acreage added to an existing participating area. This
 27 subsection does not apply to gas produced before 2022 that is used in the state or to
 28 gas produced on and after January 1, 2022. **For oil or gas first produced after**
 29 **December 31, 2016, the reduction under this subsection shall apply to oil or gas**
 30 **produced from a lease or property for the first five years after the**
 31 **commencement of production in commercial quantities of oil or gas from that**

1 lease or property. For oil or gas first produced before January 1, 2017, the
 2 reduction under this subsection for a lease or property shall expire January 1,
 3 2021. A reduction under this subsection may not reduce the gross value at the point of
 4 production below zero. In this subsection, "participating area" means a reservoir or
 5 portion of a reservoir producing or contributing to production as approved by the
 6 Department of Natural Resources.

7 * **Sec. 32.** AS 43.55.160(g) is amended to read:

8 (g) On and after January 1, 2014, in addition to the reduction under (f) of this
 9 section, in the calculation of an annual production tax value of a producer under
 10 (a)(1)(A) or (h)(1) of this section, the gross value at the point of production of oil or
 11 gas produced from a lease or property north of 68 degrees North latitude that does not
 12 contain a lease that was within a unit on January 1, 2003, is reduced by 10 percent if
 13 the oil or gas is produced from a unit made up solely of leases that have a royalty
 14 share of more than 12.5 percent in amount or value of the production removed or sold
 15 from the lease as determined under AS 38.05.180(f). This subsection does not apply if
 16 the royalty obligation for one or more of the leases in the unit has been reduced to 12.5
 17 percent or less under AS 38.05.180(j) for all or part of the calendar year for which the
 18 annual production tax value is calculated. This subsection does not apply to gas
 19 produced before 2022 that is used in the state or to gas produced on and after
 20 January 1, 2022. For oil or gas first produced after December 31, 2016, the
 21 reduction under this subsection shall apply to oil or gas produced from a lease or
 22 property for the first five years after the commencement of production in
 23 commercial quantities of oil or gas from that lease or property. For oil or gas first
 24 produced before January 1, 2017, the reduction under this subsection for a lease
 25 or property shall expire January 1, 2021. A reduction under this subsection may not
 26 reduce the gross value at the point of production below zero.

27 * **Sec. 33.** AS 43.55.165(a) is amended to read:

28 (a) For [EXCEPT AS PROVIDED IN (j) AND (k) OF THIS SECTION,
 29 FOR] purposes of this chapter, a producer's lease expenditures for a calendar year are
 30 (1) costs, other than items listed in (e) of this section, that are
 31 (A) incurred by the producer during the calendar year after

1 March 31, 2006, to explore for, develop, or produce oil or gas deposits located
 2 within the producer's leases or properties in the state or, in the case of land in
 3 which the producer does not own an operating right, operating interest, or
 4 working interest, to explore for oil or gas deposits within other land in the
 5 state; and

6 (B) allowed by the department by regulation, based on the
 7 department's determination that the costs satisfy the following three
 8 requirements:

9 (i) the costs must be incurred upstream of the point of
 10 production of oil and gas;

11 (ii) the costs must be ordinary and necessary costs of
 12 exploring for, developing, or producing, as applicable, oil or gas
 13 deposits; and

14 (iii) the costs must be direct costs of exploring for,
 15 developing, or producing, as applicable, oil or gas deposits; and

16 (2) a reasonable allowance for that calendar year, as determined under
 17 regulations adopted by the department, for overhead expenses that are directly related
 18 to exploring for, developing, or producing, as applicable, the oil or gas deposits.

19 * **Sec. 34.** AS 43.55.165(e) is amended to read:

20 (e) For purposes of this section, lease expenditures do not include

21 (1) depreciation, depletion, or amortization;

22 (2) oil or gas royalty payments, production payments, lease profit
 23 shares, or other payments or distributions of a share of oil or gas production, profit, or
 24 revenue, except that a producer's lease expenditures applicable to oil and gas produced
 25 from a lease issued under AS 38.05.180(f)(3)(B), (D), or (E) include the share of net
 26 profit paid to the state under that lease;

27 (3) taxes based on or measured by net income;

28 (4) interest or other financing charges or costs of raising equity or debt
 29 capital;

30 (5) acquisition costs for a lease or property or exploration license;

31 (6) costs arising from fraud, wilful misconduct, gross negligence,

1 violation of law, or failure to comply with an obligation under a lease, permit, or
2 license issued by the state or federal government;

3 (7) fines or penalties imposed by law;

4 (8) costs of arbitration, litigation, or other dispute resolution activities
5 that involve the state or concern the rights or obligations among owners of interests in,
6 or rights to production from, one or more leases or properties or a unit;

7 (9) costs incurred in organizing a partnership, joint venture, or other
8 business entity or arrangement;

9 (10) amounts paid to indemnify the state; the exclusion provided by
10 this paragraph does not apply to the costs of obtaining insurance or a surety bond from
11 a third-party insurer or surety;

12 (11) surcharges levied under AS 43.55.201 or 43.55.300;

13 (12) an expenditure otherwise deductible under (b) of this section that
14 is a result of an internal transfer, a transaction with an affiliate, or a transaction
15 between related parties, or is otherwise not an arm's length transaction, unless the
16 producer establishes to the satisfaction of the department that the amount of the
17 expenditure does not exceed the fair market value of the expenditure;

18 (13) an expenditure incurred to purchase an interest in any corporation,
19 partnership, limited liability company, business trust, or any other business entity,
20 whether or not the transaction is treated as an asset sale for federal income tax
21 purposes;

22 (14) a tax levied under AS 43.55.011 or 43.55.014;

23 (15) costs incurred for dismantlement, removal, surrender, or
24 abandonment of a facility, pipeline, well pad, platform, or other structure, or for the
25 restoration of a lease, field, unit, area, tract of land, body of water, or right-of-way in
26 conjunction with dismantlement, removal, surrender, or abandonment; a cost is not
27 excluded under this paragraph if the dismantlement, removal, surrender, or
28 abandonment for which the cost is incurred is undertaken for the purpose of replacing,
29 renovating, or improving the facility, pipeline, well pad, platform, or other structure;

30 (16) costs incurred for containment, control, cleanup, or removal in
31 connection with any unpermitted release of oil or a hazardous substance and any

1 liability for damages imposed on the producer or explorer for that unpermitted release;
2 this paragraph does not apply to the cost of developing and maintaining an oil
3 discharge prevention and contingency plan under AS 46.04.030;

4 (17) costs incurred to satisfy a work commitment under an exploration
5 license under AS 38.05.132;

6 (18) that portion of expenditures, that would otherwise be qualified
7 capital expenditures, [AS DEFINED IN AS 43.55.023,] incurred during a calendar
8 year that are less than the product of \$0.30 multiplied by the total taxable production
9 from each lease or property, in BTU equivalent barrels, during that calendar year,
10 except that, when a portion of a calendar year is subject to this provision, the
11 expenditures and volumes shall be prorated within that calendar year;

12 (19) costs incurred for repair, replacement, or deferred maintenance of
13 a facility, a pipeline, a structure, or equipment, other than a well, that results in or is
14 undertaken in response to a failure, problem, or event that results in an unscheduled
15 interruption of, or reduction in the rate of, oil or gas production; or costs incurred for
16 repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or
17 equipment, other than a well, that is undertaken in response to, or is otherwise
18 associated with, an unpermitted release of a hazardous substance or of gas; however,
19 costs under this paragraph that would otherwise constitute lease expenditures under (a)
20 and (b) of this section may be treated as lease expenditures if the department
21 determines that the repair or replacement is solely necessitated by an act of war, by an
22 unanticipated grave natural disaster or other natural phenomenon of an exceptional,
23 inevitable, and irresistible character, the effects of which could not have been
24 prevented or avoided by the exercise of due care or foresight, or by an intentional or
25 negligent act or omission of a third party, other than a party or its agents in privity of
26 contract with, or employed by, the producer or an operator acting for the producer, but
27 only if the producer or operator, as applicable, exercised due care in operating and
28 maintaining the facility, pipeline, structure, or equipment, and took reasonable
29 precautions against the act or omission of the third party and against the consequences
30 of the act or omission; in this paragraph,

31 (A) "costs incurred for repair, replacement, or deferred

1 maintenance of a facility, a pipeline, a structure, or equipment" includes costs
 2 to dismantle and remove the facility, pipeline, structure, or equipment that is
 3 being replaced;

4 (B) "hazardous substance" has the meaning given in
 5 AS 46.03.826;

6 (C) "replacement" includes renovation or improvement;

7 (20) costs incurred to construct, acquire, or operate a refinery or crude
 8 oil topping plant, regardless of whether the products of the refinery or topping plant
 9 are used in oil or gas exploration, development, or production operations; however, if
 10 a producer owns a refinery or crude oil topping plant that is located on or near the
 11 premises of the producer's lease or property in the state and that processes the
 12 producer's oil produced from that lease or property into a product that the producer
 13 uses in the operation of the lease or property in drilling for or producing oil or gas, the
 14 producer's lease expenditures include the amount calculated by subtracting from the
 15 fair market value of the product used the prevailing value, as determined under
 16 AS 43.55.020(f), of the oil that is processed;

17 (21) costs of lobbying, public relations, public relations advertising, or
 18 policy advocacy.

19 * **Sec. 35.** AS 43.55.165(f) is amended to read:

20 (f) For purposes of AS 43.55.023(b) [AS 43.55.023(a) AND (b)] and only as
 21 to expenditures incurred to explore for an oil or gas deposit located within land in
 22 which an explorer does not own a working interest, the term "producer" in this section
 23 includes "explorer."

24 * **Sec. 36.** AS 43.55.170(c) is amended to read:

25 (c) For purposes of AS 43.55.023(b) [AS 43.55.023(a) AND (b)] and only as
 26 to expenditures incurred to explore for an oil or gas deposit located within land in
 27 which an explorer does not own a working interest, the term "producer" in this section
 28 includes "explorer."

29 * **Sec. 37.** AS 43.55.890 is amended to read:

30 **Sec. 43.55.890. Disclosure of tax information.** Notwithstanding any contrary
 31 provision of AS 40.25.100, and regardless of whether the information is considered

1 under AS 43.05.230(e) to constitute statistics classified to prevent the identification of
 2 particular returns or reports, the department may publish the following information
 3 under this chapter, if aggregated among three or more producers or explorers, showing
 4 by month or calendar year and by lease or property, unit, or area of the state:

- 5 (1) the amount of oil or gas production;
 6 (2) the amount of taxes levied under this chapter or paid under this
 7 chapter;
 8 (3) the effective tax rates under this chapter;
 9 (4) the gross value of oil or gas at the point of production;
 10 (5) the transportation costs for oil or gas;
 11 (6) qualified capital expenditures [, AS DEFINED IN AS 43.55.023];
 12 (7) exploration expenditures under AS 43.55.025;
 13 (8) production tax values of oil or gas under AS 43.55.160;
 14 (9) lease expenditures under AS 43.55.165;
 15 (10) adjustments to lease expenditures under AS 43.55.170;
 16 (11) tax credits applicable or potentially applicable against taxes levied
 17 by this chapter.

18 * **Sec. 38.** AS 43.55.895(b) is amended to read:

- 19 (b) A municipal entity subject to taxation because of this section
 20 **(1)** is eligible for [ALL] tax credits **proportionate to its production**
 21 **taxable under AS 43.55.011(e); and**
 22 **(2)** **shall allocate its lease expenditures in proportion to its**
 23 **production taxable under AS 43.55.011(e)** [UNDER THIS CHAPTER TO THE
 24 SAME EXTENT AS ANY OTHER PRODUCER].

25 * **Sec. 39.** AS 43.55.900 is amended by adding a new paragraph to read:

26 (26) "qualified capital expenditure"

27 (A) means, except as otherwise provided in (B) of this
 28 paragraph, an expenditure that is a lease expenditure under AS 43.55.165 and
 29 is

- 30 (i) incurred for geological or geophysical exploration;
 31 (ii) treated as a capitalized expenditure under 26 U.S.C.

1 (Internal Revenue Code), as amended, regardless of elections made
 2 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
 3 treated as a capitalized expenditure for federal income tax reporting
 4 purposes by the person incurring the expenditure; or

5 (iii) treated as a capitalized expenditure under 26 U.S.C.
 6 (Internal Revenue Code), as amended, regardless of elections made
 7 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
 8 eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal
 9 Revenue Code), as amended;

10 (B) does not include an expenditure incurred to acquire an asset
 11 the cost of previously acquiring which was a lease expenditure under
 12 AS 43.55.165 or would have been a lease expenditure under AS 43.55.165 if it
 13 had been incurred after March 31, 2006, or that has previously been placed in
 14 service in the state; an expenditure to acquire an asset is not excluded under
 15 this subparagraph if not more than an immaterial portion of the asset meets a
 16 description under this subparagraph; for purposes of this subparagraph, "asset"
 17 includes geological, geophysical, and well data and interpretations.

18 * **Sec. 40.** AS 43.70 is amended by adding new sections to read:

19 **Sec. 43.70.025. Bond or cash deposit required for an oil or gas business.** (a)

20 At the time of applying for a license under this chapter, an applicant engaged in the
 21 business of oil or gas exploration, development, or production shall file a surety bond
 22 in the amount of \$250,000 running to the state, conditioned upon the applicant's
 23 promise to pay all

24 (1) taxes and contributions due the state and political subdivisions;

25 (2) persons furnishing labor or material or renting or supplying
 26 equipment to the applicant; and

27 (3) amounts that may be adjudged against the applicant because of
 28 negligent or improper work or breach of contract while engaged in the business of oil
 29 or gas exploration, development, or production.

30 (b) In lieu of the surety bond required under this section, the applicant may
 31 file with the commissioner a cash deposit or other negotiable security acceptable to the

1 commissioner in the amount of \$250,000.

2 (c) The bond required by this section remains in effect until cancelled by
3 action of the surety, the principal, or if the commissioner finds that the business is
4 producing oil or gas in commercial quantities, by the commissioner.

5 **Sec. 43.70.028. Claims against an oil or gas business.** (a) A person having a
6 claim against a person required to file a surety bond under AS 43.70.025 because of
7 the failure to pay a liability described in AS 43.70.025(a) may bring suit upon the
8 bond. A copy of the complaint shall be served by registered or certified mail on the
9 commissioner at the time suit is filed, and the commissioner shall maintain a record,
10 available for public inspection, of all suits commenced. This service on the
11 commissioner shall constitute service on the surety, and the commissioner shall
12 transmit the complaint or a copy of it to the surety within 72 hours after it is received.
13 The surety on the bond is not liable in an aggregate amount in excess of that named in
14 the bond, but if claims pending at any one time exceed the amount of the bond, the
15 claims shall be satisfied from the bond in the following order:

- 16 (1) labor, including employee benefits;
17 (2) taxes and contributions due the state, city, and borough, in that
18 order;
19 (3) material and equipment;
20 (4) claims for negligent or improper work or breach of contract;
21 (5) repair of public facilities.

22 (b) If a judgment is entered against a cash deposit, the commissioner, upon
23 receipt of a certified copy of a final judgment, shall pay the judgment from the amount
24 of the deposit in accordance with the priorities set out in (a) of this section.

25 (c) An action described in (a) of this section may not be commenced on the
26 bond more than three years after the bond's cancellation.

27 * **Sec. 41.** AS 38.05.180(i); AS 41.09.010, 41.09.020, 41.09.030, 41.09.090; and
28 AS 43.20.053(j)(4) are repealed January 1, 2017.

29 * **Sec. 42.** AS 43.55.023(a), 43.55.023(I), 43.55.023(n), 43.55.023(o), 43.55.028(i),
30 43.55.075(d)(1), 43.55.165(j), and 43.55.165(k) are repealed January 1, 2022.

31 * **Sec. 43.** The uncodified law of the State of Alaska is amended by adding a new section to

1 read:

2 LEGISLATIVE WORKING GROUP. (a) A legislative working group is established
3 to analyze the Cook Inlet fiscal regime for oil and gas, review the state's tax structure and
4 rates on oil and gas produced south of 68 degrees North latitude, recommend changes to the
5 legislature for consideration during the First Regular Session of the Thirtieth Alaska State
6 Legislature, and develop terms for a comprehensive fiscal regime for the area south of 68
7 degrees North latitude including,

8 (1) a tax structure that accounts for the unique circumstances for each oil and
9 gas producing area south of 68 degrees North latitude;

10 (2) incentives for the exploration, development, and production of oil and gas
11 south of 68 degrees North latitude;

12 (3) consideration of the competitiveness of the area to attract new oil and gas
13 development;

14 (4) consideration of the unique market considerations of the Cook Inlet
15 sedimentary basin and the need to support energy supply security for communities in
16 Southcentral Alaska;

17 (5) alternative means of state support for the exploration, development, and
18 production of oil and gas in this area, including through the Alaska Industrial Export and
19 Development Authority;

20 (6) analysis of whether refundable state tax credits are still necessary for a
21 new regime;

22 (7) evaluation of the need for disclosure of some confidential information to
23 help legislators shape policy, including an evaluation of the associated state and federal
24 constitutional issues related to statutory waivers of taxpayer confidentiality.

25 (b) The working group consists of

26 (1) two co-chairs, one of whom is a member of the house appointed by the
27 speaker of the house of representatives, and one of whom is a member of the senate appointed
28 by the president of the senate; and

29 (2) members appointed by the co-chairs; members must be legislators and
30 must include members of the majority and minority caucuses.

31 (c) The co-chairs of the working group may form an advisory group to the working

1 group, composed of members who are not legislators and who have expertise and skills to
2 assist in the review and development of a new plan for the tax structure and rates on oil and
3 gas produced south of 68 degrees North latitude. The members of an advisory group may
4 include commissioners or employees of state departments, members of the oil and gas
5 industry or trade associations, and economists.

6 (d) The working group is to be supported by legislative consultants under contract
7 through the Legislative Budget and Audit Committee.

8 * **Sec. 44.** The uncodified law of the State of Alaska is amended by adding a new section to
9 read:

10 APPLICABILITY. Sections 7 - 9, 26, and 27 of this Act apply to a refund or payment
11 applied for on or after January 1, 2017.

12 * **Sec. 45.** The uncodified law of the State of Alaska is amended by adding a new section to
13 read:

14 TRANSITION: QUALIFIED CAPITAL EXPENDITURES AND WELL LEASE
15 EXPENDITURES. (a) Notwithstanding the repeal of AS 43.55.023(a), (l), (n), and (o) by sec.
16 42 of this Act, and the amendments to AS 43.55.023(d) and (e), 43.55.029(a), 43.55.165(f),
17 and 43.55.170(c) by secs. 17, 18, 28, 35, and 36 of this Act, a taxpayer who incurs

18 (1) a qualified capital expenditure before the effective date of sec. 42 of this
19 Act that qualifies for a qualified capital expenditure credit under AS 43.55.023(a) may apply
20 for a credit or transferable tax credit certificate under AS 43.55.023 and assign the tax credit
21 under AS 43.55.029, as those sections read on the day before the effective date of sec. 42 of
22 this Act;

23 (2) a well lease expenditure before the effective date of sec. 42 of this Act that
24 qualifies for a well lease expenditure credit under AS 43.55.023(l) may apply for a credit or
25 transferable tax credit certificate under AS 43.55.023 and assign the tax credit under
26 AS 43.55.029, as those sections read on the day before the effective date of sec. 42 of this
27 Act.

28 (b) The Department of Revenue may continue to apply and enforce AS 43.55.023 and
29 43.55.029, as those sections read on the day before the effective date of sec. 42 of this Act, for
30 qualified capital expenditures and well lease expenditures incurred before the effective date of
31 sec. 42 of this Act.

1 * **Sec. 46.** The uncodified law of the State of Alaska is amended by adding a new section to
2 read:

3 TRANSITION: LEASE EXPENDITURES FOR A CALENDAR YEAR AFTER
4 2006 AND BEFORE 2010. Notwithstanding AS 43.55.165(a), as amended by sec. 33 of this
5 Act, and the repeal of AS 43.55.165(j) and (k) by sec. 42 of this Act, AS 43.55.165(j) and (k)
6 apply to a producer's total lease expenditures for a calendar year after 2006 and before 2010
7 under AS 43.55.165, as that section read on the day before the effective date of sec. 42 of this
8 Act.

9 * **Sec. 47.** The uncodified law of the State of Alaska is amended by adding a new section to
10 read:

11 TRANSITION: REGULATIONS. The Department of Revenue and the Department of
12 Natural Resources may adopt regulations necessary to implement the changes made by this
13 Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not
14 before the effective date of the law implemented by the regulation. The Department of
15 Revenue shall adopt regulations governing the use of tax credits under AS 43.55 for a
16 calendar year for which the applicable tax credit provisions of AS 43.55 differ as between
17 parts of the year as a result of this Act.

18 * **Sec. 48.** The uncodified law of the State of Alaska is amended by adding a new section to
19 read:

20 TRANSITION: RETROACTIVITY OF REGULATIONS. Notwithstanding any
21 contrary provision of AS 44.62.240,

22 (1) if the Department of Revenue expressly designates in a regulation that the
23 regulation applies retroactively, a regulation adopted by the Department of Revenue to
24 implement, interpret, make specific, or otherwise carry out this Act may apply retroactively to
25 the effective date of the law implemented by the regulation;

26 (2) if the Department of Natural Resources expressly designates in the
27 regulation that the regulation applies retroactively, a regulation adopted by the Department of
28 Natural Resources to implement, interpret, make specific, or otherwise carry out the statutory
29 amendments in this Act affecting the administration of oil and gas leases issued under
30 AS 38.05.180(f)(3)(B), (D), or (E), to the extent the regulation relates to the treatment of oil
31 and gas production taxes in determining net profits under those leases, may apply

1 retroactively to the effective date of the law implemented by the regulation.

2 * **Sec. 49.** Sections 24, 43, and 47 of this Act take effect immediately under
3 AS 01.10.070(c).

4 * **Sec. 50.** Sections 17, 18, 28 - 30, 33 - 37, 39, 42, 45, and 46 of this Act take effect
5 January 1, 2022.

6 * **Sec. 51.** Except as provided in secs. 49 and 50 of this Act, this Act takes effect January 1,
7 2017.

Permit added as cosponsor
Wilson added as cosponsor

①

29-GH2609\F.41
Nauman/Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVE THOMPSON

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 1, line 3:
- 2 Delete "repealing a maximum production tax on certain oil;"
- 3
- 4 Page 5, lines 5 - 26:
- 5 Delete all material.
- 6
- 7 Renumber the following bill sections accordingly.
- 8
- 9 Page 7, line 30:
- 10 Delete "[, (k),]"
- 11 Insert ", (k),"
- 12
- 13 Page 8, line 2:
- 14 Delete "[, (k),]"
- 15 Insert ", (k),"
- 16
- 17 Page 8, line 4:
- 18 Delete "[, (k),]"
- 19 Insert ", (k),"
- 20
- 21 Page 8, line 6:
- 22 Delete "[OR (k) OF THIS SECTION FOR THE PRODUCTION OF OIL]"
- 23 Insert "or (k) of this section for the production of oil"

PASSED

Y	N
7	4

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

Page 8, line 11:

Delete "[, (k),]"
Insert ", (k),"

Page 9, line 26:

Delete "[OIL OR]"
Insert "oil or"
Delete "[, (k),]"
Insert ", (k),"

Page 10, line 20:

Delete "[, (k),]"
Insert ", (k),"

Page 10, lines 22 - 23:

Delete "[OR SET OUT IN AS 43.55.011(k)(1) OR (2), AS APPLICABLE, FOR OIL,]"
Insert "or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil,"

Page 10, lines 25 - 28:

Delete "[AND SUBSTITUTING IN AS 43.55.011(k)(1)(A) OR (2)(A), AS APPLICABLE, THE AMOUNT OF TAXABLE OIL PRODUCED DURING THE MONTH FOR THE AMOUNT OF TAXABLE OIL PRODUCED DURING THE CALENDAR YEAR]"
Insert "and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of taxable oil produced during the month for the amount of taxable oil produced during the calendar year"

Page 12, line 19:

Delete "[OIL OR]"

- 1 Insert "oil or"
- 2 Delete "[, (k),]"
- 3 Insert ", (k),"
- 4
- 5 Page 12, line 25:
- 6 Delete "[OIL OR]"
- 7 Insert "oil or"
- 8
- 9 Page 12, lines 25 - 26:
- 10 Delete "[, RESPECTIVELY,]"
- 11 Insert ", respectively,"
- 12
- 13 Page 12, line 27:
- 14 Delete "[OIL OR]"
- 15 Insert "oil or"
- 16
- 17 Page 12, lines 27 - 28:
- 18 Delete "[, RESPECTIVELY,]"
- 19 Insert ", respectively,"
- 20
- 21 Page 13, line 10:
- 22 Delete "[OIL OR]"
- 23 Insert "oil or"
- 24
- 25 Page 13, line 11:
- 26 Delete "[, (k),]"
- 27 Insert ", (k),"
- 28
- 29 Page 13, lines 13 - 14:
- 30 Delete "[OR SET OUT IN AS 43.55.011(k)(1) OR (2), AS APPLICABLE, FOR
- 31 OIL,]"

1 Insert "or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil,"

2

3 Page 13, lines 16 - 19:

4 Delete "[AND SUBSTITUTING IN AS 43.55.011(k)(1)(A) OR (2)(A), AS
5 APPLICABLE, THE AMOUNT OF TAXABLE OIL PRODUCED DURING THE MONTH
6 FOR THE AMOUNT OF TAXABLE OIL PRODUCED DURING THE CALENDAR
7 YEAR]"

8 Insert "and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount
9 of taxable oil produced during the month for the amount of taxable oil produced during the
10 calendar year"

11

12 Page 25, lines 2 - 22:

13 Delete all material.

14

15 Renumber the following bill sections accordingly.

16

17 Page 33, line 5:

18 Delete "AS 43.20.053(j)(4); and AS 43.55.011(k)"

19 Insert "and AS 43.22.053(j)(4)"

20

21 Page 34, line 18:

22 Delete "26, and 27"

23 Insert "25, and 26"

24

25 Page 34, lines 23 - 24:

26 Delete "sec. 43"

27 Insert "sec. 41"

28

29 Page 34, line 25:

30 Delete "secs. 18, 19, 28, 36, and 37"

31 Insert "secs. 17, 18, 27, 34, and 35"

- 1
- 2 Page 34, line 26:
 - 3 Delete "sec. 43"
 - 4 Insert "sec. 41"
 - 5
- 6 Page 34, line 29:
 - 7 Delete "sec. 43"
 - 8 Insert "sec. 41"
 - 9
- 10 Page 34, line 31:
 - 11 Delete "sec. 43"
 - 12 Insert "sec. 41"
 - 13
- 14 Page 35, line 3:
 - 15 Delete "sec. 43"
 - 16 Insert "sec. 41"
 - 17
- 18 Page 35, line 6:
 - 19 Delete "sec. 43"
 - 20 Insert "sec. 41"
 - 21
- 22 Page 35, line 8:
 - 23 Delete "sec. 43"
 - 24 Insert "sec. 41"
 - 25
- 26 Page 35, line 12:
 - 27 Delete "sec. 34"
 - 28 Insert "sec. 32"
 - 29
- 30 Page 34, line 13:
 - 31 Delete "sec. 43"

1 Insert "sec. 41"

2

3 Page 35, line 15:

4 Delete "sec. 43"

5 Insert "sec. 41"

6

7 Page 36, line 10:

8 Delete "Sections 24, 44, and 48"

9 Insert "Sections 23, 42, and 46"

10

11 Page 36, line 12:

12 Delete "Sections 18, 19, 28 - 30, 34 - 38, 40, 43, 46, and 47"

13 Insert "Sections 17, 18, 27 - 29, 32 - 36, 38, 41, 44, and 45"

14

15 Page 36, line 14:

16 Delete "secs. 50 and 51"

17 Insert "secs. 48 and 49"

STP - M
MN - 0

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

PASSED

Y | N
7 | 4

DATE: 4-8-2016

Amendment: # 1

MEMBER

Favor

Oppose

MEMBER	Favor	Oppose
REP. KAWASAKI		X
REP. MUNOZ		X
REP. PRUITT	X	
REP. SADDLER	X	
REP. WILSON	X	
REP. EDGMON	X	
REP. GARA		X
REP. GATTIS	X	
REP. GUTTENBERG		X
REP. NEUMAN	X	
REP. THOMPSON	X	

YEA 7 NAY 4

2

PASSED

29-GH2609\F.25
Nauman/Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVE THOMPSON

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 17, lines 12 - 14:
- 2 Delete "if the producer or explorer had, before January 1, 2017, taken a credit
- 3 under this subsection for an expenditure incurred in the Cook Inlet sedimentary basin"

NO OBJECTIONS

4

Passed
NO OBJECTIONS

29-GH2609\F.22
Nauman/Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVE THOMPSON

TO: CSHB 247(FIN), Draft Version "F"

1 Page 32, line 28, through page 33, line 3:

2 Delete all material and insert:

3 ** Sec. 41. AS 43.70 is amended by adding new sections to read:

4 **Sec. 43.70.025. Bond or cash deposit required for an oil or gas business. (a)**

5 At the time of applying for a license under this chapter, an applicant engaged in the
6 business of oil or gas exploration, development, or production shall file a surety bond
7 in the amount of \$250,000 running to the state, conditioned upon the applicant's
8 promise to pay all

9 (1) taxes and contributions due the state and political subdivisions;

10 (2) persons furnishing labor or material or renting or supplying
11 equipment to the applicant; and

12 (3) amounts that may be adjudged against the applicant because of
13 negligent or improper work or breach of contract while engaged in the business of oil
14 or gas exploration, development, or production.

15 (b) In lieu of the surety bond required under this section, the applicant may
16 file with the commissioner a cash deposit or other negotiable security acceptable to the
17 commissioner in the amount of \$250,000.

18 (c) The bond required by this section remains in effect until cancelled by
19 action of the surety, the principal, or if the commissioner finds that the business is
20 producing oil or gas in commercial quantities, by the commissioner.

21 **Sec. 43.70.028. Claims against an oil or gas business. (a)** A person having a
22 claim against a person required to file a surety bond under this section because of the
23 failure to pay a liability described in AS 43.70.025(a) may bring suit upon the bond. A

1 copy of the complaint shall be served by registered or certified mail on the
2 commissioner at the time suit is filed, and the commissioner shall maintain a record,
3 available for public inspection, of all suits commenced. This service on the
4 commissioner shall constitute service on the surety, and the commissioner shall
5 transmit the complaint or a copy of it to the surety within 72 hours after it is received.
6 The surety on the bond is not liable in an aggregate amount in excess of that named in
7 the bond, but if claims pending at any one time exceed the amount of the bond, the
8 claims shall be satisfied from the bond in the following order:

- 9 (1) labor, including employee benefits;
10 (2) taxes and contributions due the state, city, and borough, in that
11 order;
12 (3) material and equipment;
13 (4) claims for negligent or improper work or breach of contract;
14 (5) repair of public facilities.

15 (b) If a judgment is entered against a cash deposit, the commissioner, upon
16 receipt of a certified copy of a final judgment, shall pay the judgment from the amount
17 of the deposit in accordance with the priorities set out in (a) of this section.

18 (c) An action described in (a) of this section may not be commenced on the
19 bond more than three years after the bond's cancellation."

Failed
Y | N
3 | 8

5

29-GH2609F.30
Nauman/Shutts
4/7/16

AMENDMENT

GATTIS

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 26, line 9:
 - 2 Delete "lease or property"
 - 3 Insert "well"
 - 4 Delete "five"
 - 5 Insert "10"
 - 6
- 7 Page 26, line 11:
 - 8 Delete "lease or property"
 - 9 Insert "well"
 - 10
- 11 Page 26, line 12:
 - 12 Delete "lease or property"
 - 13 Insert "well"
 - 14
- 15 Page 26, line 13:
 - 16 Delete "2021"
 - 17 Insert "2026"
 - 18
- 19 Page 26, line 31, through page 27, line 1:
 - 20 Delete "lease or property"
 - 21 Insert "well"
 - 22
- 23 Page 27, line 1:

1 Delete "five"

2 Insert "10"

3

4 Page 27, line 2:

5 Delete "lease or property"

6 Insert "well"

7

8 Page 27, lines 3 - 4:

9 Delete "lease or property"

10 Insert "well"

11

12 Page 27, line 4:

13 Delete "2021"

14 Insert "2026"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y	N
3	8

DATE: 4.8.2016

Amendment: #5

MEMBER

Favor

Oppose

REP. MUNOZ		X
REP. PRUITT	X	
REP. SADDLER		X
REP. WILSON	X	
REP. EDGMON		X
REP. GARA		X
REP. GATTIS	X	
REP. GUTTENBERG		X
REP. KAWASAKI		X
REP. THOMPSON		X
REP. NEUMAN		X

YEA 3 NAY 8

6

Withdrew

29-GH2609\F.28
Nauman/Shutts
4/7/16

AMENDMENT

GATTIS

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

1 Page 5, following line 4:

2 Insert a new bill section to read:

3 **"* Sec. 10.** AS 43.55 is amended by adding a new section to read:

4 **Sec. 43.55.008. Tax relief.** The tax and the accrual of credits under this
5 chapter shall be suspended by the department if a taxpayer subject to tax under this
6 chapter demonstrates that the taxpayer has paid over 105 percent of the amount of the
7 taxpayer's income attributable to the state in state and federal taxes during the calendar
8 year. The department shall adopt regulations to implement this section."
9

10 Renumber the following bill sections accordingly.

11

12 Page 34, line 18:

13 Delete "26, and 27"

14 Insert "27, and 28"

15

16 Page 34, lines 23 - 24:

17 Delete "sec. 43"

18 Insert "sec. 44"

19

20 Page 34, line 25:

21 Delete "secs. 18, 19, 28, 36, and 37"

22 Insert "secs. 19, 20, 29, 37, and 38"

23

- 1 Page 34, line 26:
- 2 Delete "sec. 43"
- 3 Insert "sec. 44"
- 4
- 5 Page 34, line 29:
- 6 Delete "sec. 43"
- 7 Insert "sec. 44"
- 8
- 9 Page 34, line 31:
- 10 Delete "sec. 43"
- 11 Insert "sec. 44"
- 12
- 13 Page 35, line 3:
- 14 Delete "sec. 43"
- 15 Insert "sec. 44"
- 16
- 17 Page 35, line 6:
- 18 Delete "sec. 43"
- 19 Insert "sec. 44"
- 20
- 21 Page 35, line 8:
- 22 Delete "sec. 43"
- 23 Insert "sec. 44"
- 24
- 25 Page 35, line 12:
- 26 Delete "sec. 34"
- 27 Insert "sec. 35"
- 28
- 29 Page 35 line 13:
- 30 Delete "sec. 43"
- 31 Insert "sec. 44"

1

2 Page 35, line 15:

3 Delete "sec. 43"

4 Insert "sec. 44"

5

6 Page 36, line 10:

7 Delete "Sections 24, 44, and 48"

8 Insert "Sections 25, 45, and 49"

9

10 Page 36, line 12:

11 Delete "Sections 18, 19, 28 - 30, 34 - 38, 40, 43, 46, and 47"

12 Insert "Sections 19, 20, 29 - 31, 35 - 39, 41, 44, 47, and 48"

13

14 Page 36, line 14:

15 Delete "secs. 50 and 51"

16 Insert "secs. 51 and 52"

Failed

Y/N
3/8

Pritt, Gathis, Wilson

7

29-GH2609F.33
Nauman/Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 16, line 11:
- 2 Delete "10 [20]"
- 3 Insert "20"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed
 Y/N
 3/8

DATE: 4.8.2016

Amendment: #7

MEMBER

Favor

Oppose

REP. PRUITT	X	.
REP. SADDLER	.	X
REP. WILSON	X	.
REP. EDGMON	.	X
REP. GARA	.	X
REP. GATTIS	X	.
REP. GUTTENBERG	.	X
REP. KAWASAKI	.	X
REP. MUNOZ	.	X
REP. NEUMAN	.	X
REP. THOMPSON	.	X

YEA 3 NAY 8

Failed

Y	N
3	8

AMENDMENT

Wilson, Gattis, Prui

8

29-GH2609F.32
Shutts
4/7/16

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 26, line 9:
- 2 Delete "five"
- 3 Insert "15"
- 4
- 5 Page 26, line 13:
- 6 Delete "2021"
- 7 Insert "2032"
- 8
- 9 Page 27, line 1:
- 10 Delete "five"
- 11 Insert "15"
- 12
- 13 Page 27, line 4:
- 14 Delete "2021"
- 15 Insert "2032"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y	N
3	8

DATE: 4.8.2016

Amendment: #8

MEMBER

Favor

Oppose

REP. SADDLER		X
REP. WILSON	X	
REP. EDGMON		X
REP. GARA		X
REP. GATTIS	X	
REP. GUTTENBERG		X
REP. KAWASAKI		X
REP. MUNOZ		X
REP. PRUITT	X	
REP. THOMPSON		X
REP. NEUMAN		X

YEA 3 NAY 8

Failed
Y | N
5 | 6

Pruitt, Wilson, Gattis
⑨
29-GH2609\F.31
Nauman/Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 33, following line 5:
- 2 Insert a new bill section to read:
- 3 "* **Sec. 43.** AS 43.55.023(l), 43.55.023(n), and 43.55.023(o) are repealed January 1, 2019."
- 4
- 5 Renumber the following bill sections accordingly.
- 6
- 7 Page 33, line 6:
- 8 Delete "43.55.023(l), 43.55.023(n), 43.55.023(o),"
- 9
- 10 Page 34, lines 22 - 23:
- 11 Delete "AND WELL LEASE EXPENDITURES"
- 12
- 13 Page 34, lines 23 - 24 :
- 14 Delete ", (l), (n), and (o) by sec. 43"
- 15 Insert "by sec. 44"
- 16
- 17 Page 34, line 24:
- 18 Delete "43.55.029(a),"
- 19
- 20 Page 34, line 25:
- 21 Delete "28,"
- 22
- 23 Page 34, line 26:

- 1 Delete "(1)"
- 2 Delete "sec. 43"
- 3 Insert "sec. 44"
- 4
- 5 Page 34, line 29:
 - 6 Delete "sec. 43"
 - 7 Insert "sec. 44"
 - 8
- 9 Page 34, line 30:
 - 10 Delete ";
 - 11 Insert "."
 - 12
- 13 Page 34, line 31, through page 35, line 4:
 - 14 Delete all material.
 - 15
- 16 Page 35, lines 5 - 6:
 - 17 Delete "AS 43.55.023 and 43.55.029, as those sections"
 - 18 Insert "AS 43.55.023(a) as that"
 - 19
- 20 Page 35, line 6:
 - 21 Delete "sec. 43"
 - 22 Insert "sec. 44"
 - 23
- 24 Page 35, line 7:
 - 25 Delete "and well lease expenditures"
 - 26
- 27 Page 35, line 8:
 - 28 Delete "sec. 43"
 - 29 Insert "sec. 44"
 - 30
- 31 Page 35, following line 8:

1 Insert a new bill section to read:

2 **"* Sec. 48.** The uncodified law of the State of Alaska is amended by adding a new section to
3 read:

4 TRANSITION: WELL LEASE EXPENDITURES. (a) Notwithstanding the repeal of
5 AS 43.55.023(l), (n), and (o) by sec. 43 of this Act, and the amendments to AS 43.55.029(a)
6 by sec. 28 of this Act, a taxpayer who incurs a well lease expenditure before the effective date
7 of sec. 43 of this Act that qualifies for a well lease expenditure credit under AS 43.55.023(l)
8 may apply for a credit or transferable tax credit certificate under AS 43.55.023 and assign the
9 tax credit under AS 43.55.029, as those sections read on the day before the effective date of
10 sec. 43 of this Act.

11 (b) The Department of Revenue may continue to apply and enforce AS 43.55.023(l)
12 and 43.55.029, as those sections read on the day before the effective date of sec. 43 of this
13 Act, for well lease expenditures incurred before the effective date of sec. 43 of this Act."

14

15 Renumber the following bill sections accordingly.

16

17 Page 35, line 15:

18 Delete "sec. 43"

19 Insert "sec. 44"

20

21 Page 36, following line 11:

22 Insert a new bill section to read:

23 **"* Sec. 53.** Sections 28, 40, 43, and 48 of this Act take effect January 1, 2019."

24

25 Renumber the following bill sections accordingly.

26

27 Page 36, line 12:

28 Delete "28"

29 Insert "29"

30 Delete "40, 43, 46, and 47"

31 Insert "44, 47, and 49"

1

2 Page 36, line 14:

3 Delete "secs. 50 and 51"

4 Insert "secs. 52 - 54"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

4	N
5	6

DATE: 4/8/2016

Amendment: #9

MEMBER

Favor

Oppose

REP. WILSON	X	
REP. EDGMON		X
REP. GARA		X
REP. GATTIS	X	
REP. GUTTENBERG		X
REP. KAWASAKI	X	
REP. MUNOZ	X	X
REP. PRUITT	X	
REP. SADDLER		X
REP. NEUMAN		X
REP. THOMPSON		X

YEA 5 NAY 6

Failed
Y | N
4 | 7

Pruitt, Wilson, Gattis
10

29-GH2609\F.35
Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

1 Page 17, lines 5 - 9:

2 Delete "For lease expenditures incurred after December 31, 2016, to explore for,
3 develop, or produce oil or gas deposits located south of 68 degrees North latitude and
4 outside of the Cook Inlet sedimentary basin, a producer or explorer may elect to take a
5 tax credit in the amount of 25 percent of a carried-forward annual loss."

6

7 Page 17, lines 9 - 10:

8 Delete "after December 31, 2016"
9 Insert "on or after January 1, 2017"

10

11 Page 17, line 11:

12 Delete "in the Cook Inlet sedimentary basin"
13 Insert "south of 68 degrees North latitude"

14

15 Page 17, lines 12 - 14:

16 Delete ", if the producer or explorer had, before January 1, 2017, taken a credit
17 under this subsection for an expenditure incurred in the Cook Inlet sedimentary basin"

18

19 Page 18, line 31:

20 Delete "[SOUTH OF 68 DEGREES NORTH LATITUDE]"
21 Insert "south of 68 degrees North latitude"

22

23 Page 19, line 3:

1 Delete "[SOUTH OF 68 DEGREES NORTH LATITUDE]"

2 Insert "south of 68 degrees North latitude"

3

4 Page 19, lines 7 - 8:

5 Delete "[SOUTH OF 68 DEGREES NORTH LATITUDE]"

6 Insert "south of 68 degrees North latitude"

7

8 Page 19, lines 10 - 11:

9 Delete "south of 68 degrees North latitude"

10

11 Page 19, lines 12 - 13:

12 Delete "south of 68 degrees North latitude after December 31, 2016"

13 Insert "on or after January 1, 2017"

14

15 Page 19, lines 15 - 19:

16 Delete "(C) 20 percent of that expenditure incurred inside the Cook Inlet
17 sedimentary basin after December 31, 2017;

18 (D) 30 percent of that expenditure incurred outside the
19 Cook Inlet sedimentary basin and south of 68 degrees North latitude after
20 December 31, 2017, and before January 1, 2019"

21 Insert "(C) 20 percent of that expenditure incurred on or after January 1, 2018"

22

23 Page 20, line 17, through page 21, line 24:

24 Delete all material.

25

26 Renumber the following bill sections accordingly.

27

28 Page 34, line 18:

29 Delete "26, and 27"

30 Insert "25, and 26"

31

1 Page 34, lines 23 - 24:

2 Delete "sec. 43"

3 Insert "sec. 42"

4

5 Page 34, line 25:

6 Delete "28, 36, and 37"

7 Insert "27, 35, and 36"

8

9 Page 34, line 26:

10 Delete "sec. 43"

11 Insert "sec. 42"

12

13 Page 34, line 29:

14 Delete "sec. 43"

15 Insert "sec. 42"

16

17 Page 34, line 31:

18 Delete "sec. 43"

19 Insert "sec. 42"

20

21 Page 35, line 3:

22 Delete "sec. 43"

23 Insert "sec. 42"

24

25 Page 35, line 6:

26 Delete "sec. 43"

27 Insert "sec. 42"

28

29 Page 35, line 8:

30 Delete "sec. 43"

31 Insert "sec. 42"

- 1
- 2 Page 35, line 12:
 - 3 Delete "sec. 34"
 - 4 Insert "sec. 33"
 - 5
- 6 Page 35, line 13:
 - 7 Delete "sec. 43"
 - 8 Insert "sec. 42"
 - 9
- 10 Page 35, line 15:
 - 11 Delete "sec. 43"
 - 12 Insert "sec. 42"
 - 13
- 14 Page 36, line 10:
 - 15 Delete "Sections 24, 44, and 48"
 - 16 Insert "Sections 43 and 47"
 - 17
- 18 Page 36, line 12:
 - 19 Delete "28 - 30, 34 - 38, 40, 43, 46, and 47"
 - 20 Insert "27 - 29, 33 - 37, 39, 42, 45, and 46"
 - 21
- 22 Page 36, line 14:
 - 23 Delete "secs. 50 and 51"
 - 24 Insert "secs. 49 and 50"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y	N
4	7

DATE: 4-8-16

Amendment: #10

MEMBER

Favor

Oppose

REP. EDGMON		X
REP. GARA	X	
REP. GATTIS	X	
REP. GUTTENBERG		X
REP. KAWASAKI		X
REP. MUNOZ		X
REP. PRUITT	X	
REP. SADDLER		X
REP. WILSON	X	
REP. NEUMAN		X
REP. THOMPSON		X

YEA 4 NAY 7

Failed
4 | N

3 | 8

(11)

Wilson
Pruitt
Gattis

29-GH2609\F.37
Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 1, lines 2 - 3:
- 2 Delete "~~relating to the minimum oil and gas production tax;~~"
- 3
- 4 Page 5, line 27, through page 7, line 25:
- 5 Delete all material.
- 6
- 7 Renumber the following bill sections accordingly.
- 8
- 9 Page 8, lines 12 - 17:
- 10 Delete all material.
- 11
- 12 Renumber the following bill sections accordingly.
- 13
- 14 Page 11, line 18:
- 15 Delete "and (10)"
- 16
- 17 Page 13, line 23:
- 18 Delete "except as provided in (10) of this subsection,"
- 19
- 20 Page 15, line 27:
- 21 Delete "AS 43.55.011(f) [AS 43.55.011(f)(1) OR (2)]"
- 22 Insert "AS 43.55.011(f)(1) or (2)"
- 23

1 Page 15, line 29:

2 Delete "'."'

3 Insert "'."

4

5 Page 15, line 30, through page 16, line 2:

6 Delete all material.

7

8 Page 17, lines 25 - 29:

9 Delete all material.

10

11 Renumber the following bill sections accordingly.

12

13 Page 19, line 30, through page 20, line 16:

14 Delete all material.

15

16 Page 21, lines 25 - 28:

17 Delete all material.

18

19 Renumber the following bill sections accordingly.

20

21 Page 34, line 18:

22 Delete "26, and 27"

23 Insert "20, and 21"

24

25 Page 34, lines 23 - 24:

26 Delete "sec. 43"

27 Insert "sec. 37"

28

29 Page 34, line 25:

30 Delete "secs. 18, 19, 28, 36, and 37"

31 Insert "secs. 15, 16, 22, 30, and 31"

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

Page 34, line 26:

Delete "sec. 43"

Insert "sec. 37"

Page 34, line 29:

Delete "sec. 43"

Insert "sec. 37"

Page 34, line 31:

Delete "sec. 43"

Insert "sec. 37"

Page 35, line 3:

Delete "sec. 43"

Insert "sec. 37"

Page 35, line 6:

Delete "sec. 43"

Insert "sec. 37"

Page 35, line 8:

Delete "sec. 43"

Insert "sec. 37"

Page 35, line 12:

Delete "sec. 34"

Insert "sec. 28"

Page 35, line 13:

Delete "sec. 43"

- 1 Insert "sec. 37"
- 2
- 3 Page 35, line 15:
- 4 Delete "sec. 43"
- 5 Insert "sec. 37"
- 6
- 7 Page 36, line 10:
- 8 Delete "Sections 24, 44, and 48"
- 9 Insert "Sections 18, 38, and 42"
- 10
- 11 Page 36, line 12:
- 12 Delete "Sections 18, 19, 28 - 30, 34 - 38, 40, 43, 46, and 47"
- 13 Insert "Sections 15, 16, 22 - 24, 28 - 32, 34, 37, 40, and 41"
- 14
- 15 Page 36, line 14:
- 16 Delete "secs. 50 and 51"
- 17 Insert "secs. 44 and 45"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y	N
3	8

DATE: 04-08-16

Amendment: # 11

MEMBER

Favor

Oppose

REP. GARA		X
REP. GATTIS	X	
REP. GUTTENBERG		X
REP. KAWASAKI		X
REP. MUNOZ		X
REP. PRUITT	X	
REP. SADDLER		X
REP. WILSON	X	
REP. EDGMON		X
REP. THOMPSON		X
REP. NEUMAN		X

YEA 3 NAY 8

Failed

Y	N
5	6

12

Wilson
Gatts
Pruitt

29-GH2609\F.40
Nauman/Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

1 Page 3, line 18:

2 Delete "(i)"

3

4 Page 3, lines 23 - 28:

5 Delete "and

6

7

8

9

10

11

12

(ii) after the first four years after a tax becomes delinquent, in each calendar quarter at a rate of five percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter"

Insert "no interest shall accrue after the first four years after a tax becomes delinquent"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y	N
5	6

DATE: 4-8-16

Amendment: #12

MEMBER

Favor

Oppose

REP. GATTIS	X	
REP. GUTTENBERG		X
REP. KAWASAKI		X
REP. MUNOZ	X	
REP. PRUITT	X	
REP. SADDLER	X	
REP. WILSON	X	
REP. EDGMON		X
REP. GARA		X
REP. NEUMAN		X
REP. THOMPSON		X

YEA 5 NAY 6

Failed
4/N
3/8

(13)

29-GH2609 F.39
Nauman/Shutts
4/7/16

AMENDMENT

Car
Guttenberg
Kawasaki

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 16, line 30, following "January 1, 2016,":
- 2 Insert "and before January 1, 2017,"
- 3
- 4 Page 17, line 1, following "loss.":
- 5 Insert "For lease expenditures incurred after December 31, 2017, to explore for,
- 6 develop, or produce oil or gas deposits located north of 68 degrees North latitude, a
- 7 producer or explorer may elect to take a tax credit in the amount of 20 percent of a
- 8 carried-forward annual loss."

Amendment TO Amendment #1
20% TO 25%

OFFERED BY ~~MUNOZ~~ GARA

VOTE TALLY — FAILED

4/N
5/6

Table 4-3: ANS Oil & Gas Production Tax Data Summary

	(\$ millions)		
	History	Forecast	
	FY 2015	FY 2016	FY 2017
North Slope Price and Production			
Price of ANS WC (in \$/barrel)	72.58	39.99	38.89
Transit Costs & Other (in \$/barrel)	9.74	10.50	10.86
ANS Wellhead (in \$/barrel)	62.83	29.49	28.03
North Slope Production			
Total ANS Production (in mbbls/day)	500.7	520.2	507.1
Royalty and federal (in mbbls/day) ⁽¹⁾	66.2	66.3	62.0
Taxable Barrels (in mbbls/day)	434.5	453.9	445.2
North Slope Lease Expenditures⁽²⁾⁽³⁾			
Total North Slope Lease Expenditures (in \$ millions)			
Operating Expenditures [OPEX]	3,438.8	3,235.2	3,075.9
Capital Expenditures [CAPEX]	3,992.0	3,315.1	2,970.3
Total North Slope Expenditures	7,430.8	6,550.3	6,046.2
Deductible North Slope Lease Expenditures (in \$ millions)			
Operating Expenditures [OPEX]	3,318.6	2,471.9	2,422.7
Capital Expenditures [CAPEX]	3,595.8	2,248.9	2,040.0
Deductible North Slope Expenditures	6,914.4	4,720.8	4,462.6
State Production Tax Revenue⁽⁴⁾			
Tax Revenue (in \$ millions)	389.7	153.4	67.9
Production Tax Collected per Taxable Barrel	2.5	0.9	0.4
Statewide Production Tax Credits⁽²⁾⁽⁵⁾			
Credits Used against Tax Liability (in \$ millions)	664.0	70.0	135.0
Credits for Potential Purchase (in \$ millions)	628.0	500.0	775.0

⁽¹⁾ Royalty and federal barrels represent the department's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and other untaxed barrels.

⁽²⁾ Lease expenditures and credits used against tax liability for FY 2015 were prepared using unaudited company-reported estimates.

⁽³⁾ Expenditure data for FY 2016 and FY 2017 are compiled from company submitted expenditure forecast estimates and other documentation as provided to the DOR. Expenditures shown here are shown in two ways: (1) total estimated allowable expenditures for all companies on the North Slope; and (2) estimated "deductible expenditures" defined for purposes of this analysis as the amount of total allowable expenditures for each company that does not exceed their gross value at point of production. Note that for producers with a net operating loss, only a portion of expenditures will be counted in the "deductible expenditures" category.

⁽⁴⁾ Production tax is calculated on a company specific basis, therefore the aggregated data reported here will not generate the total tax revenue shown. For an illustration of the tax calculation, see Appendix E in the 2015 Fall Revenue Sources Book.

⁽⁵⁾ Production tax credits shown include all production tax credits and all areas of the state. Assumptions for the \$12 million credits for small Alaska producers are included in the table. Per-taxable-barrel credits for oil not eligible for the gross value reduction may not reduce a producer's liability below the minimum tax; that limitation is reflected in these estimates.

Table A-3b: Petroleum Revenue Forecast

	(\$ millions)									
FY	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Unrestricted Petroleum Revenue										
Petroleum Property Tax	133.9	118.3	118.5	117.3	116.5	114.9	113.2	111.4	109.4	107.4
Petroleum Corporate Income Tax	0.0	30.0	105.0	135.0	165.0	195.0	190.0	185.0	180.0	175.0
Oil and Gas Production Tax	144.8	59.4	15.7	10.7	12.5	32.5	109.9	217.3	212.0	275.2
Oil and Gas Hazardous Release	8.6	8.4	8.2	8.1	7.7	7.0	6.5	6.0	5.5	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⁾	501.0	475.6	527.3	588.7	624.4	645.1	609.5	573.4	536.9	500.9
Bonuses, Rents & Interest-Net ⁽¹⁾⁽²⁾	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
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	801.1	704.7	787.5	872.7	938.9	1,007.5	1,042.0	1,105.9	1,056.7	1,076.4
Cumulative Unrestricted Petroleum Revenue ⁽³⁾	115,851	116,556	117,343	118,216	119,155	120,162	121,204	122,310	123,367	124,443
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	4.3	4.3	4.3	6.5	8.6	7.3	6.2	5.5	5.1	4.9
Royalties to AK Permanent Fund	224.4	214.4	238.8	274.7	291.8	294.4	273.9	255.1	237.6	220.9
Royalties to Public School Fund	3.7	3.6	3.9	4.4	4.7	4.8	4.5	4.2	4.0	3.7
CBRF Deposits	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Restricted Petroleum Revenue	332.4	322.3	347.0	385.6	405.1	406.5	384.6	364.9	346.7	329.5
Total Petroleum Revenue	1,133.5	1,026.9	1,134.5	1,258.3	1,344.0	1,414.0	1,426.5	1,470.7	1,403.4	1,405.9

⁽¹⁾ Net of Permanent Fund Contribution and CBRF deposits.

⁽²⁾ Primarily composed of petroleum revenue.

⁽³⁾ Based on revenue beginning in FY 1959.

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed
 Y | N
 3 | 8

DATE: 4-8-16

Amendment: #13

MEMBER

Favor

Oppose

REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. THOMPSON		X
REP. NEUMAN		X

YEA 3 NAY 8

Amend TO Amend # 13

conceptual amendment GARA

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y/N
5/6

DATE: 4-8-16

Amendment: NO # 13A

20% TO 25% NOL

MEMBER

Favor

Oppose

Amend TO Amend: #13A

REP. KAWASAKI	X	
REP. MUNOZ	X	
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON	X	
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. NEUMAN		X
REP. THOMPSON		X

YEA 5 NAY 6

Y/N
5/6

14

29-GH2609\F.19
Shutts
4/6/16

Gara
Guttenberg
Kawasaki

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 19, lines 12 - 14:
- 2 Delete all material.
- 3
- 4 Reletter the following subparagraphs accordingly.
- 5
- 6 Page 19, line 15:
- 7 Delete "20"
- 8 Insert "10"
- 9
- 10 Page 19, line 16:
- 11 Delete "2017"
- 12 Insert "2016"
- 13
- 14 Page 19, line 19:
- 15 Delete "2017"
- 16 Insert "2016"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Y/N
5/6

DATE: 4-8-16

Amendment: #14

MEMBER

Favor

Oppose

REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON	X	
REP. EDGMON	X	
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. THOMPSON		X
REP. NEUMAN		X

YEA 5 NAY 6

4/N
3 | 8
Failed

15

29-GH2609/F.21
Shutts
4/6/16

AMENDMENT

GARA
GUTTENBERG
Kawasaki

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

- 1 Page 22, line 4:
- 2 Delete "\$100,000,000"
- 3 Insert "\$25,000,000"
- 4
- 5 Page 22, line 12:
- 6 Delete "\$100,000,000"
- 7 Insert "\$25,000,000"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed

Y	N
3	8

DATE: 4.8.16

Amendment: # 15

MEMBER

Favor

Oppose

REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. NEUMAN		X
REP. THOMPSON		X

YEA 3 NAY 8

Failed
Y/N
3/8

16

29-GH2609\F.4
Shutts
4/6/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVES KAWASAKI,

TO: CSHB 247(FIN), Draft Version "F"

GARA, AND GUTTENBERG

1 Page 17, line 5:

2 Delete "For"

3 Insert "Subject to the limitations in (q) of this section, for"

4

5 Page 17, line 9:

6 Delete "For"

7 Insert "Subject to the limitations in (q) of this section, for"

8

9 Page 19, following line 29:

10 Insert a new bill section to read:

11 **** Sec. 21.** AS 43.55.023 is amended by adding new subsections to read:

12 (q) In a single calendar year, the department may not grant a credit accrued
13 under (b) of this section against the taxes due under this chapter and a cash payment
14 under AS 43.55.028 resulting from a credit under (b) of this section if the credit or
15 payment, or the sum of the credit and payment, exceeds

16 (1) \$50,000,000 for each person;

17 (2) \$200,000,000 for each unit.

18 (r) If the total application of credits accrued under (b) of this section against
19 taxes due under this chapter and applications for cash payments under AS 43.55.028
20 resulting from a credit under (b) of this section exceed \$200,000,000 for each unit, the
21 department shall prorate the application of credits accrued under (b) of this section
22 against taxes due under this chapter and applications for cash payments under
23 AS 43.55.028 resulting from a credit under (b) of this section by ownership interest in

1 the unit."

2

3 Renumber the following bill sections accordingly.

4

5 Page 21, following line 28:

6 Insert a new bill section to read:

7 "* Sec. 27. AS 43.55.028(a) is amended to read:

8 (a) The oil and gas tax credit fund is established as a separate fund of the state.

9 The purpose of the fund is to purchase transferable tax credit certificates issued under

10 AS 43.55.023 and production tax credit certificates issued under AS 43.55.025 and to

11 pay refunds and payments claimed under AS 43.20.046, 43.20.047, or 43.20.053. A

12 **purchase of a transferable tax credit certificate issued under AS 43.55.023 is**

13 **subject to the limitations in AS 43.55.023(g).**"

14

15 Renumber the following bill sections accordingly.

16

17 Page 34, line 18:

18 Delete "26, and 27"

19 Insert "28, and 29"

20

21 Page 34, lines 23 - 24:

22 Delete "sec. 43"

23 Insert "sec. 45"

24

25 Page 34, line 25:

26 Delete "28, 36, and 37"

27 Insert "30, 38, and 39"

28

29 Page 34, line 26:

30 Delete "sec. 43"

31 Insert "sec. 45"

1

2 Page 34, line 29:

3 Delete "sec. 43"

4 Insert "sec. 45"

5

6 Page 34, line 31:

7 Delete "sec. 43"

8 Insert "sec. 45"

9

10 Page 35, line 3:

11 Delete "sec. 43"

12 Insert "sec. 45"

13

14 Page 35, line 6:

15 Delete "sec. 43"

16 Insert "sec. 45"

17

18 Page 35, line 8:

19 Delete "sec. 43"

20 Insert "sec. 45"

21

22 Page 35, line 12:

23 Delete "sec. 34"

24 Insert "sec. 36"

25

26 Page 35, line 13:

27 Delete "sec. 43"

28 Insert "sec. 45"

29

30 Page 35, line 15:

31 Delete "sec. 43"

1 Insert "sec. 45"

2

3 Page 36, line 10:

4 Delete "Sections 24, 44, and 48"

5 Insert "Sections 25, 46, and 50"

6

7 Page 36, line 12:

8 Delete "28 - 30, 34 - 38, 40, 43, 46, and 47"

9 Insert "30 - 32, 36 - 40, 42, 45, 48, and 49"

10

11 Page 36, line 14:

12 Delete "secs. 50 and 51"

13 Insert "secs. 52 and 53"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Failed
 Y | N
 3 | 8

DATE: 04.08.2016

Amendment: #16

MEMBER

Favor

Oppose

REP. SADDLER		X
REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. THOMPSON		X
REP. NEUMAN		X

YEA 3 NAY 8

4 | N
3 | 8
Fairleaf

17

29-GH2609/F.42
Nauman/Shutts
4/8/16

AMENDMENT

Gene
Guttenberg
Kawasaki

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

1 Page 6, line 21, through page 7, line 25:

2 Delete all material and insert:

3 "(2) oil and gas produced on and after January 1, 2017, but before
4 January 1, 2022, from leases or properties that include land north of 68 degrees
5 North latitude,

6 (A) by a producer that does not qualify under (B) of this
7 paragraph, may not be less than

8 (i) 10 percent of the gross value at the point of
9 production when the average price per barrel for Alaska North
10 Slope crude oil for sale on the United States West Coast during the
11 calendar year for which the tax is due is more than \$85;

12 (ii) nine percent of the gross value at the point of
13 production when the average price per barrel for Alaska North
14 Slope crude oil for sale on the United States West Coast during the
15 calendar year for which the tax is due is over \$80 but not over \$85;

16 (iii) eight percent of the gross value at the point of
17 production when the average price per barrel for Alaska North
18 Slope crude oil for sale on the United States West Coast during the
19 calendar year for which the tax is due is over \$75 but not over \$80;

20 (iv) seven percent of the gross value at the point of
21 production when the average price per barrel for Alaska North
22 Slope crude oil for sale on the United States West Coast during the
23 calendar year for which the tax is due is over \$70 but not over \$75;

1 (v) six percent of the gross value at the point of
2 production when the average price per barrel for Alaska North
3 Slope crude oil for sale on the United States West Coast during the
4 calendar year for which the tax is due is over \$65 but not over \$70;

5 (vi) five percent of the gross value at the point of
6 production when the average price per barrel for Alaska North
7 Slope crude oil for sale on the United States West Coast during the
8 calendar year for which the tax is due is over \$60 but not over \$65;

9 or

10 (vii) four percent of the gross value at the point of
11 production when the average price per barrel for Alaska North
12 Slope crude oil for sale on the United States West Coast during the
13 calendar year for which the tax is due is \$60 or less; or

14 (B) by a producer that produces less than an average of
15 ^{35,000}
15 ~~30,000~~ barrels of oil a day, in total, from leases or properties located north
16 of 68 degrees North latitude and that produces oil or gas that qualifies for
17 a reduction in the gross value of the point of production under
18 AS 43.55.160(f) may not be less than

19 (i) 10 percent of the gross value at the point of
20 production when the average price per barrel for Alaska North
21 Slope crude oil for sale on the United States West Coast during the
22 calendar year for which the tax is due is more than \$100;

23 (ii) nine percent of the gross value at the point of
24 production when the average price per barrel for Alaska North
25 Slope crude oil for sale on the United States West Coast during the
26 calendar year for which the tax is due is over \$95 but not over
27 \$100;

28 (iii) eight percent of the gross value at the point of
29 production when the average price per barrel for Alaska North
30 Slope crude oil for sale on the United States West Coast during the
31 calendar year for which the tax is due is over \$90 but not over \$95;

1 (iv) seven percent of the gross value at the point of
 2 production when the average price per barrel for Alaska North
 3 Slope crude oil for sale on the United States West Coast during the
 4 calendar year for which the tax is due is over \$85 but not over \$90;

5 (v) six percent of the gross value at the point of
 6 production when the average price per barrel for Alaska North
 7 Slope crude oil for sale on the United States West Coast during the
 8 calendar year for which the tax is due is over \$80 but not over \$85;

9 (vi) five percent of the gross value at the point of
 10 production when the average price per barrel for Alaska North
 11 Slope crude oil for sale on the United States West Coast during the
 12 calendar year for which the tax is due is over \$75 but not over \$80;

13 or

14 (vii) four percent of the gross value at the point of
 15 production when the average price per barrel for Alaska North
 16 Slope crude oil for sale on the United States West Coast during the
 17 calendar year for which the tax is due is \$75 or less; and

18 (3) oil produced on and after January 1, 2022, from leases or properties
 19 that include land north of 68 degrees North latitude,

20 (A) by a producer that does not qualify under (B) of this
 21 paragraph, may not be less than

22 (i) 10 [(A) FOUR] percent of the gross value at the
 23 point of production when the average price per barrel for Alaska North
 24 Slope crude oil for sale on the United States West Coast during the
 25 calendar year for which the tax is due is more than \$85 [\$25];

26 (ii) nine [(B) THREE] percent of the gross value at the
 27 point of production when the average price per barrel for Alaska North
 28 Slope crude oil for sale on the United States West Coast during the
 29 calendar year for which the tax is due is over \$80 [\$20] but not over
 30 \$85 [\$25];

31 (iii) eight [(C) TWO] percent of the gross value at the

1 point of production when the average price per barrel for Alaska North
 2 Slope crude oil for sale on the United States West Coast during the
 3 calendar year for which the tax is due is over \$75 [\$17.50] but not over
 4 \$80 [\$20];

5 (iv) seven [(D) ONE] percent of the gross value at the
 6 point of production when the average price per barrel for Alaska North
 7 Slope crude oil for sale on the United States West Coast during the
 8 calendar year for which the tax is due is over \$70 [\$15] but not over
 9 \$75;

10 (v) six percent of the gross value at the point of
 11 production when the average price per barrel for Alaska North
 12 Slope crude oil for sale on the United States West Coast during the
 13 calendar year for which the tax is due is over \$65 but not over \$70;

14 (vi) five percent of the gross value at the point of
 15 production when the average price per barrel for Alaska North
 16 Slope crude oil for sale on the United States West Coast during the
 17 calendar year for which the tax is due is over \$60 but not over \$65
 18 [\$17.50]; or

19 (vii) four [(E) ZERO] percent of the gross value at the
 20 point of production when the average price per barrel for Alaska North
 21 Slope crude oil for sale on the United States West Coast during the
 22 calendar year for which the tax is due is \$60 [\$15] or less; or

23 (B) by a producer that produces less than an average of
 24 ^{35,000}~~30,000~~ barrels of oil a day, in total, from leases or properties located north
 25 of 68 degrees North latitude and that produces oil that qualifies for a
 26 reduction in the gross value of the point of production under
 27 AS 43.55.160(f) may not be less than

28 (i) 10 percent of the gross value at the point of
 29 production when the average price per barrel for Alaska North
 30 Slope crude oil for sale on the United States West Coast during the
 31 calendar year for which the tax is due is more than \$100;

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

(ii) nine percent of the gross value at the point of production when the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year for which the tax is due is over \$95 but not over \$100;

(iii) eight percent of the gross value at the point of production when the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year for which the tax is due is over \$90 but not over \$95;

(iv) seven percent of the gross value at the point of production when the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year for which the tax is due is over \$85 but not over \$90;

(v) six percent of the gross value at the point of production when the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year for which the tax is due is over \$80 but not over \$85;

(vi) five percent of the gross value at the point of production when the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year for which the tax is due is over \$75 but not over \$80;

or

(vii) four percent of the gross value at the point of production when the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year for which the tax is due is \$75 or less."

Page 12, lines 6 - 7:

Delete "zero percent, one percent, two percent, three percent, or four percent, as applicable,"

Insert "the [ZERO PERCENT, ONE PERCENT, TWO PERCENT, THREE

1 PERCENT, OR FOUR] percent [, AS] applicable under AS 43.55.011(f) [,]"

2

3 Page 13, lines 30 - 31:

4 Delete "zero percent, one percent, two percent, three percent, or four percent, as
5 applicable,"

6 Insert "the [ZERO PERCENT, ONE PERCENT, TWO PERCENT, THREE
7 PERCENT, OR FOUR] percent [, AS] applicable under AS 43.55.011(f) [,]"

Minimum Tax threshold - Base Tax and Minimum Tax using Current Assumptions*	
West Coast Price (\$/tax bbl)	\$76
Transportation (\$/tax bbl)	<u>-\$10</u>
Wellhead Value (\$/tax bbl)	\$66
Lease Expenditures (\$/tax bbl)	<u>-\$36</u>
Net Value (\$/tax bbl)	\$30
Base Tax Rate (%)	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$10.50
Sliding Scale Credit per-Tax-Barrel (\$/tax bbl)	<u>-\$8</u>
Base Production Tax after credits (\$/tax bbl)	\$2.50
Minimum Tax Rate (%)	4%
Wellhead Value (\$/tax bbl)	x <u>\$66</u>
Minimum Tax (\$/tax bbl)	\$2.64

Greater of base production tax after credits and minimum tax

*Current assumptions include transport costs of \$10 per barrel and deductible lease expenditures of \$36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160. The effective tax rates in this table are calculated by dividing the production tax after credits by the production tax value.

Note that in the illustration above, some but not the entirety of sliding scale per-taxable-barrel credits can be used. Because the minimum tax is 14 cents higher per barrel than the base production tax after credits, and the sliding scale credit cannot reduce the tax liability below the minimum tax, this means that the sliding scale credit is reduced by 14 cents per barrel, from \$8 to \$7.86 per barrel. Under these assumptions, at prices greater than \$76 per barrel, producers are able to take their entire sliding scale credit without going below the minimum tax. The exact price will vary depending on specific economics for different fields and producers

Using the same assumptions for transportation costs and lease expenditures, non-GVR fields lose the entire \$8 per-taxable-barrel credit at oil prices of \$50.62 per barrel and lower. At this price, the base tax before credits equals the minimum tax. This is illustrated in the calculation below. The exact price will vary depending on specific economics for different fields and producers.

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Y | N
 3 | 8
 Failed

DATE: 04-8-2016

Amendment: #17

MEMBER

Favor

Oppose

REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. NEUMAN		X
REP. THOMPSON		X

YEA 3

NAY 8

Y | N
3 | 8

18

29-GH2609\F.2
Nauman
4/6/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVES KAWASAKI,

TO: CSHB 247(FIN), Draft Version "F"

GARA, AND GUTTENBERG

1 Page 6, line 23:

2 Delete "[A] four"

3 Insert "five [(A) FOUR]"

4

5 Page 6, lines 24 - 27:

6 Delete ", except that a credit authorized under this chapter may reduce the tax

7 under this subsection to less than four percent, but not to less than two percent of the

8 gross value at the point of production"

9

10 Page 6, line 30:

11 Delete "four"

12 Insert "five"

13

14 Page 6, line 30, through page 7, line 2:

15 Delete ", except that a credit authorized under this chapter may reduce the tax

16 under this subsection to less than four percent, but not to less than two percent of the

17 gross value at the point of production"

18

19 Page 34, line 18, following "APPLICABILITY.":

20 Insert "(a)"

21

22 Page 34, following line 19:

23 Insert a new subsection to read:

1 "(b) The limitations on the use of tax credits added in AS 43.55.019(e), as amended
2 by sec. 13 of this Act, AS 43.55.020(a), as amended by sec. 14 of this Act, AS 43.55.023(c),
3 as amended by sec. 17 of this Act, AS 43.55.024(f), as amended by sec. 21 of this Act,
4 AS 43.55.024(g), as amended by sec. 22 of this Act, and AS 43.55.025(q), added by sec. 25 of
5 this Act, apply to credits applied to reduce a tax liability for a tax year starting on or after the
6 effective date of secs. 13, 14, 17, 21, 22, and 25 of this Act."

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

$\frac{4}{3} | N$ failed

DATE: 4-8-2016

Amendment: #18

MEMBER

Favor

Oppose

REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. NEUMAN		X
REP. THOMPSON		X

YEA 3 NAY 8

CONCEPTUAL Amend 18A

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

Y | N
5 | 6
Failed

DATE: 4-8-2016

Amendment: #18A - conceptual Amend
4% hard FLOOR

MEMBER

Favor

Oppose

REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
R. MUNOZ	X	
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON	X	
REP. THOMPSON		X
REP. NEUMAN		X

YEA 5 NAY 6

Y | N

19

29-GH2609\F.38
Shutts
4/7/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVE GUTTENBERG

TO: CSHB 247(FIN), Draft Version "F"

GARA KAWASAKI

1 Page 3, following line 4:

2 Insert a new bill section to read:

3 **"* Sec. 6.** AS 40.25.100(a) is amended to read:

4 (a) Information in the possession of the Department of Revenue that discloses
5 the particulars of the business or affairs of a taxpayer or other person, including
6 information under AS 38.05.020(b)(11) that is subject to a confidentiality agreement
7 under AS 38.05.020(b)(12), is not a matter of public record, except as provided in
8 AS 43.05.230(i) - (m) [AS 43.05.230(i) OR (k)] or for purposes of investigation and
9 law enforcement. The information shall be kept confidential except when its
10 production is required in an official investigation, administrative adjudication under
11 AS 43.05.405 - 43.05.499, or court proceeding. These restrictions do not prohibit the
12 publication of statistics presented in a manner that prevents the identification of
13 particular reports and items, prohibit the publication of tax lists showing the names of
14 taxpayers who are delinquent and relevant information that may assist in the collection
15 of delinquent taxes, or prohibit the publication of records, proceedings, and decisions
16 under AS 43.05.405 - 43.05.499."

17

18 Renumber the following bill sections accordingly.

19

20 Page 4, following line 1:

21 Insert a new bill section to read:

22 **"* Sec. 8.** AS 43.05.230 is amended by adding new subsections to read:

23 (l) The following information for persons claiming a credit under AS 43.55 or

1 applying to the department for the purchase of a transferable tax credit certificate
2 under AS 43.55.028 is public:

3 (1) the name of each person

4 (A) claiming a credit under AS 43.55;

5 (B) from whom the department purchases a transferable tax
6 credit certificate under AS 43.55.028; and

7 (2) the amount of each

8 (A) credit under AS 43.55 claimed by the person in the
9 calendar year, except for the credit in AS 43.55.024(j); and

10 (B) transferable tax credit certificate purchased from the person
11 under AS 43.55.028.

12 (m) A person may not claim a credit under AS 43.55 or apply to the
13 department for the purchase of a transferable tax credit certificate under AS 43.55.028
14 unless the person has signed an agreement with the department acknowledging the
15 application of (l) of this section."

16
17 Renumber the following bill sections accordingly.

18
19 Page 34, line 18:

20 Delete "Sections 7 - 9, 26, and 27"

21 Insert "Sections 9 - 11, 28, and 29"

22
23 Page 34, lines 23 - 24:

24 Delete "sec. 43"

25 Insert "sec. 45"

26
27 Page 34, line 25:

28 Delete "secs. 18, 19, 28, 36, and 37"

29 Insert "secs. 20, 21, 30, 38, and 39"

30
31 Page 34, line 26:

- 1 Delete "sec. 43"
- 2 Insert "sec. 45"
- 3
- 4 Page 34, line 29:
- 5 Delete "sec. 43"
- 6 Insert "sec. 45"
- 7
- 8 Page 34, line 31:
- 9 Delete "sec. 43"
- 10 Insert "sec. 45"
- 11
- 12 Page 35, line 3:
- 13 Delete "sec. 43"
- 14 Insert "sec. 45"
- 15
- 16 Page 35, line 6:
- 17 Delete "sec. 43"
- 18 Insert "sec. 45"
- 19
- 20 Page 35, line 8:
- 21 Delete "sec. 43"
- 22 Insert "sec. 45"
- 23
- 24 Page 35, line 12:
- 25 Delete "sec. 34"
- 26 Insert "sec. 36"
- 27
- 28 Page 35, line 13:
- 29 Delete "sec. 43"
- 30 Insert "sec. 45"
- 31

- 1 Page 35, line 15:
- 2 Delete "sec. 43"
- 3 Insert "sec. 45"
- 4
- 5 Page 36, line 10:
- 6 Delete "Sections 24, 44, and 48"
- 7 Insert "Sections 26, 46, and 50"
- 8
- 9 Page 36, line 12:
- 10 Delete "Sections 18, 19, 28 - 30, 34 - 38, 40, 43, 46, and 47"
- 11 Insert "Sections 20, 21, 30 - 32, 36 - 40, 42, 45, 48, and 49"
- 12
- 13 Page 36, line 14:
- 14 Delete "secs. 50 and 51"
- 15 Insert "secs. 52 and 53"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

$\frac{4}{3} / \frac{N}{8}$ Failed

DATE: 4-8-16

Amendment: # 19

MEMBER

Favor

Oppose

REP. GATTIS		X
REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. NEUMAN		X
REP. THOMPSON		X

YEA 3 NAY 8

Y/N
3/8
FAILED

20

29-GH2609\F.11
Nauman/Shutts
4/6/16

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVES KAWASAKI,

TO: CSHB 247(FIN), Draft Version "F"

GARA, AND GUTTENBERG

1 Page 1, line 1, following "tax;":

2 Insert "relating to confidential tax information in the possession of the
3 Department of Revenue;"

4
5 Page 4, following line 1:

6 Insert new bill sections to read:

7 "* Sec. 7. AS 43.05.230(f) is amended to read:

8 (f) A wilful violation of the provisions of this section or of a condition
9 imposed under AS 43.55.040(1)(B) is punishable by a fine of not more than \$5,000, or
10 by imprisonment for not more than two years, or by both. The penalty under this
11 subsection may be in addition to, and not in place of, an applicable criminal
12 sanction under state or federal law.

13 * Sec. 8. AS 43.05.230 is amended by adding a new subsection to read:

14 (l) The department may disclose confidential tax information, documents, or
15 other materials related to a credit for oil and gas investment, exploration, production,
16 delivery, storage, or use against a tax imposed under AS 43.20 or AS 43.55 to a
17 legislator, an agent of a legislator or a legislative committee, or a contractor of a
18 legislator or a legislative committee if

19 (1) the information is disclosed during an executive session of a
20 committee hearing or an executive session of a meeting of one house of the legislature
21 as a committee of the whole;

22 (2) only legislators, agents, and contractors complying with the
23 remainder of this subsection are in attendance at the committee meeting;

1 (3) written information, documents, or other materials are clearly
2 labeled as confidential tax information;

3 (4) the legislator, agent, or contractor has executed an agreement with
4 the department

5 (A) that acknowledges that tax information, documents, and
6 materials received under this subsection are confidential by law;

7 (B) that acknowledges that it is illegal to publicly disclose
8 confidential tax information, documents, or materials received under this
9 subsection unless the information is otherwise publicly available; and

10 (C) in which the legislator, agent, or contractor agrees not to

11 (i) disclose the information received during the meeting
12 or the contents of documents or materials viewed during a committee
13 meeting under this section; and

14 (ii) remove any written information, documents, or
15 materials from the physical location of the committee meeting."
16

17 Renumber the following bill sections accordingly.

18
19 Page 34, line 18:

20 Delete "Sections 7 - 9, 26, and 27"

21 Insert "Sections 9 - 11, 28, and 29"

22
23 Page 34, lines 23 - 24:

24 Delete "sec. 43"

25 Insert "sec. 45"

26
27 Page 34, line 25:

28 Delete "secs. 18, 19, 28, 36, and 37"

29 Insert "secs. 20, 21, 30, 38, and 39"

30
31 Page 34, line 26:

1 Delete "sec. 43"

2 Insert "sec. 45"

3

4 Page 34, line 29:

5 Delete "sec. 43"

6 Insert "sec. 45"

7

8 Page 34, line 31:

9 Delete "sec. 43"

10 Insert "sec. 45"

11

12 Page 35, line 3:

13 Delete "sec. 43"

14 Insert "sec. 45"

15

16 Page 35, line 6:

17 Delete "sec. 43"

18 Insert "sec. 45"

19

20 Page 35, line 8:

21 Delete "sec. 43"

22 Insert "sec. 45"

23

24 Page 35, line 12:

25 Delete "sec. 34"

26 Insert "sec. 36"

27

28 Page 34, line 13:

29 Delete "sec. 43"

30 Insert "sec. 45"

31

1 Page 35, line 15:

2 Delete "sec. 43"

3 Insert "sec. 45"

4

5 Page 36, line 10:

6 Delete "Sections 24, 44, and 48"

7 Insert "Sections 26, 46, and 50"

8

9 Page 36, line 12:

10 Delete "Sections 18, 19, 28 - 30, 34 - 38, 40, 43, 46, and 47"

11 Insert "Sections 20, 21, 30 - 32, 36 - 40, 42, 45, 48, and 49"

12

13 Page 36, line 14:

14 Delete "secs. 50 and 51"

15 Insert "secs. 52 and 53"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

$$\begin{array}{c|c} 4 & N \\ \hline 3 & 8 \end{array}$$
 FAILED

DATE: 4-8-2016

Amendment: #20

MEMBER

Favor

Oppose

REP. GUTTENBERG	X	
REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. THOMPSON		X
REP. NEUMAN		X

YEA 3 NAY 8

Y | N
3 | 8

FAILED

21

29-GH2609\F.23
Shutts
4/7/16

Gara Sutterbe
Lawasch

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 247(FIN), Draft Version "F"

1 Page 19, following line 29:

2 Insert a new bill section to read:

3 **** Sec. 21.** AS 43.55.023 is amended by adding a new subsection to read:

4 (q) Notwithstanding that a qualified capital expenditure and a well lease
5 expenditure may be a deductible lease expenditure for purposes of calculating the
6 production tax value of oil, gas, or oil and gas under AS 43.55.160(a), a producer or
7 explorer may not apply against the taxes due under this chapter a credit under this
8 section for an expenditure incurred in the Cook Inlet sedimentary basin in the same tax
9 year that a producer or explorer applies another credit under this section for an
10 expenditure incurred in the Cook Inlet sedimentary basin."

11

12 Renumber the following bill sections accordingly.

13

14 Page 34, line 18:

15 Delete "26, and 27"

16 Insert "27, and 28"

17

18 Page 34, lines 23 - 24:

19 Delete "sec. 43"

20 Insert "sec. 44"

21

22 Page 34, line 25:

23 Delete "28, 36, and 37"

- 1 Insert "29, 37, and 38"
- 2
- 3 Page 34, line 26:
- 4 Delete "sec. 43"
- 5 Insert "sec. 44"
- 6
- 7 Page 34, line 29:
- 8 Delete "sec. 43"
- 9 Insert "sec. 44"
- 10
- 11 Page 34, line 31:
- 12 Delete "sec. 43"
- 13 Insert "sec. 44"
- 14
- 15 Page 35, line 3:
- 16 Delete "sec. 43"
- 17 Insert "sec. 44"
- 18
- 19 Page 35, line 6:
- 20 Delete "sec. 43"
- 21 Insert "sec. 44"
- 22
- 23 Page 35, line 8:
- 24 Delete "sec. 43"
- 25 Insert "sec. 44"
- 26
- 27 Page 35, line 12:
- 28 Delete "sec. 34"
- 29 Insert "sec. 35"
- 30
- 31 Page 35, line 13:

- 1 Delete "sec. 43"
- 2 Insert "sec. 44"
- 3
- 4 Page 35, line 15:
 - 5 Delete "sec. 43"
 - 6 Insert "sec. 44"
 - 7
- 8 Page 36, line 10:
 - 9 Delete "Sections 24, 44, and 48"
 - 10 Insert "Sections 25, 45, and 49"
 - 11
- 12 Page 36, line 12:
 - 13 Delete "28 - 30, 34 - 38, 40, 43, 46, and 47"
 - 14 Insert "29 - 31, 35 - 39, 41, 44, 47, and 48"
 - 15
- 16 Page 36, line 14:
 - 17 Delete "secs. 50 and 51"
 - 18 Insert "secs. 51 and 52"

2016 HOUSE FINANCE COMMITTEE VOTE SHEET

4	N
3	8

 FAILED

DATE: 4-8-2016

Amendment: # 21

MEMBER

Favor

Oppose

REP. KAWASAKI	X	
REP. MUNOZ		X
REP. PRUITT		X
REP. SADDLER		X
REP. WILSON		X
REP. EDGMON		X
REP. GARA	X	
REP. GATTIS		X
REP. GUTTENBERG	X	
REP. NEUMAN		X
REP. THOMPSON		X

YEA 3 NAY 8

Passed
No OBJECTIONS

29-GH2609F



Conceptual AMENDMENT # 22

OFFERED IN THE HOUSE

BY Thompson

TO: CSHB 247(FIN)

- 1 Page 6, line 25, following "chapter":
- 2 Insert ", excluding a credit under AS 43.55.024(j),"
- 3
- 4 Page 6, line 31, following "chapter":
- 5 Insert ", excluding a credit under AS 43.55.024(j),"

*Adopted
4/6/16*

29-GH2609\F
Nauman/Shutts
4/6/16

CS FOR HOUSE BILL NO. 247(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-NINTH LEGISLATURE - SECOND SESSION

BY THE HOUSE FINANCE COMMITTEE

Offered:

Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to interest applicable to delinquent tax; relating to the oil and gas
2 production tax, tax payments, and credits; relating to the minimum oil and gas
3 production tax; repealing a maximum production tax on certain oil; relating to refunds
4 for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit,
5 and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to
6 the assessment of an oil and gas production tax imposed; relating to oil and gas lease
7 expenditures and production tax credits for municipal entities; relating to a business
8 license for an oil or gas business; establishing a legislative working group to study the
9 tax structure for oil and gas produced south of 68 degrees North latitude; and providing
10 for an effective date."

11 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

12 * Section 1. AS 38.05.036(a) is amended to read:

1 (a) The department may conduct audits regarding royalty and net profits under
2 oil and gas contracts, agreements, or leases under this chapter and regarding costs
3 related to exploration licenses entered into under AS 38.05.131 - 38.05.134 and
4 exploration incentive credits under this chapter [OR UNDER AS 41.09]. For purposes
5 of an audit under this section,

6 (1) the department may examine the books, papers, records, or
7 memoranda of a person regarding matters related to the audit; and

8 (2) the records and premises where a business is conducted shall be
9 open at all reasonable times for inspection by the department.

10 * **Sec. 2.** AS 38.05.036(b) is amended to read:

11 (b) The Department of Revenue may obtain from the department information
12 relating to royalty and net profits payments and to exploration incentive credits under
13 this chapter [OR UNDER AS 41.09], whether or not that information is confidential.
14 The Department of Revenue may use the information in carrying out its functions and
15 responsibilities under AS 43, and shall hold that information confidential to the extent
16 required by an agreement with the department or by AS 38.05.035(a)(8) [,
17 AS 41.09.010(d),] or AS 43.05.230.

18 * **Sec. 3.** AS 38.05.036(c) is amended to read:

19 (c) The department may obtain from the Department of Revenue all
20 information obtained under AS 43 relating to royalty and net profits and to exploration
21 incentive credits. The department may use the information for purposes of carrying out
22 its responsibilities and functions under this chapter [AND AS 41.09]. Information
23 made available to the department that was obtained under AS 43 is confidential and
24 subject to the provisions of AS 43.05.230.

25 * **Sec. 4.** AS 38.05.036(f) is amended to read:

26 (f) Except as otherwise provided in this section or in connection with official
27 investigations or proceedings of the department, it is unlawful for a current or former
28 officer, employee, or agent of the state to divulge information obtained by the
29 department as a result of an audit under this section that is required by an agreement
30 with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)] to be kept
31 confidential.

1 * **Sec. 5.** AS 38.05.036(g) is amended to read:

2 (g) Nothing in this section prohibits the publication of statistics in a manner
3 that maintains the confidentiality of information to the extent required by an
4 agreement with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)].

5 * **Sec. 6.** AS 43.05.225 is amended to read:

6 **Sec. 43.05.225. Interest.** Unless otherwise provided,

7 (1) a delinquent tax under this title,

8 (A) before January 1, 2014, bears interest in each calendar
9 quarter at the rate of five percentage points above the annual rate charged
10 member banks for advances by the 12th Federal Reserve District as of the first
11 day of that calendar quarter, or at the annual rate of 11 percent, whichever is
12 greater, compounded quarterly as of the last day of that quarter; [OR]

13 (B) on and after January 1, 2014, and before January 1, 2017,
14 bears interest in each calendar quarter at the rate of three percentage points
15 above the annual rate charged member banks for advances by the 12th Federal
16 Reserve District as of the first day of that calendar quarter;

17 (C) on and after January 1, 2017, bears interest

18 (i) for the first four years after a tax becomes
19 delinquent, in each calendar quarter at the rate of five percentage
20 points above the annual rate charged member banks for advances
21 by the 12th Federal Reserve District as of the first day of that
22 calendar quarter, compounded quarterly as of the last day of that
23 quarter; and

24 (ii) after the first four years after a tax becomes
25 delinquent, in each calendar quarter at a rate of five percentage
26 points above the annual rate charged member banks for advances
27 by the 12th Federal Reserve District as of the first day of that
28 calendar quarter;

29 (2) the interest rate is 12 percent a year for

30 (A) delinquent fees payable under AS 05.15.095(c); and

31 (B) unclaimed property that is not timely paid or delivered, as

1 allowed by AS 34.45.470(a).

2 * **Sec. 7.** AS 43.20.046(e) is amended to read:

3 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
4 may use available money in the oil and gas tax credit fund established in AS 43.55.028
5 to make the refund applied for under (d) of this section in whole or in part if the
6 department finds that, [(1) THE CLAIMANT DOES NOT HAVE AN
7 OUTSTANDING LIABILITY TO THE STATE FOR UNPAID DELINQUENT
8 TAXES UNDER THIS TITLE; AND (2)] after application of all available tax credits,
9 the claimant's total tax liability under this chapter for the calendar year in which the
10 claim is made is zero. [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX"
11 MEANS AN AMOUNT OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED
12 AN ASSESSMENT THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS
13 NOT BEEN FINALLY RESOLVED IN THE TAXPAYER'S FAVOR.]

14 * **Sec. 8.** AS 43.20.047(e) is amended to read:

15 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
16 may use money available in the oil and gas tax credit fund established in AS 43.55.028
17 to make a refund or payment under (d) of this section in whole or in part if the
18 department finds that, [(1) THE CLAIMANT DOES NOT HAVE AN
19 OUTSTANDING LIABILITY TO THE STATE FOR UNPAID DELINQUENT
20 TAXES UNDER THIS TITLE; AND (2)] after application of all available tax credits,
21 the claimant's total tax liability under this chapter for the calendar year in which the
22 claim is made is zero. [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX"
23 MEANS AN AMOUNT OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED
24 AN ASSESSMENT THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS
25 NOT BEEN FINALLY RESOLVED IN THE TAXPAYER'S FAVOR.]

26 * **Sec. 9.** AS 43.20.053(e) is amended to read:

27 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
28 may use money available in the oil and gas tax credit fund established in AS 43.55.028
29 to make a refund or payment under (d) of this section in whole or in part if the
30 department finds that,

31 [(1) THE CLAIMANT DOES NOT HAVE AN OUTSTANDING

1 LIABILITY TO THE STATE FOR UNPAID DELINQUENT TAXES UNDER THIS
2 TITLE; AND

3 (2)] after application of all available tax credits, the claimant's total tax
4 liability under this chapter for the calendar year in which the claim is made is zero.

5 * **Sec. 10.** AS 43.55.011(e) is amended to read:

6 (e) There is levied on the producer of oil or gas a tax for all oil and gas
7 produced each calendar year from each lease or property in the state, less any oil and
8 gas the ownership or right to which is exempt from taxation or constitutes a
9 landowner's royalty interest or for which a tax is levied by AS 43.55.014. Except as
10 otherwise provided under (f), (j), [(k),] (o), and (p) of this section, for oil and gas
11 produced

12 (1) before January 1, 2014, the tax is equal to the sum of

13 (A) the annual production tax value of the taxable oil and gas
14 as calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

15 (B) the sum, over all months of the calendar year, of the tax
16 amounts determined under (g) of this section;

17 (2) on and after January 1, 2014, and before January 1, 2022, the tax is
18 equal to the annual production tax value of the taxable oil and gas as calculated under
19 AS 43.55.160(a)(1) multiplied by 35 percent;

20 (3) on and after January 1, 2022, the tax for

21 (A) oil is equal to the annual production tax value of the
22 taxable oil as calculated under AS 43.55.160(h) multiplied by 35 percent;

23 (B) gas is equal to 13 percent of the gross value at the point of
24 production of the taxable gas; if the gross value at the point of production of
25 gas produced from a lease or property is less than zero, that gross value at the
26 point of production is considered zero for purposes of this subparagraph.

27 * **Sec. 11.** AS 43.55.011(f) is amended to read:

28 (f) The levy of tax under (e) of this section for

29 (1) oil and gas produced before January 1, 2017 [JANUARY 1,
30 2022], from leases or properties that include land north of 68 degrees North latitude,
31 other than gas subject to (o) of this section, may not be less than

1 (A) four percent of the gross value at the point of production
2 when the average price per barrel for Alaska North Slope crude oil for sale on
3 the United States West Coast during the calendar year for which the tax is due
4 is more than \$25;

5 (B) three percent of the gross value at the point of production
6 when the average price per barrel for Alaska North Slope crude oil for sale on
7 the United States West Coast during the calendar year for which the tax is due
8 is over \$20 but not over \$25;

9 (C) two percent of the gross value at the point of production
10 when the average price per barrel for Alaska North Slope crude oil for sale on
11 the United States West Coast during the calendar year for which the tax is due
12 is over \$17.50 but not over \$20;

13 (D) one percent of the gross value at the point of production
14 when the average price per barrel for Alaska North Slope crude oil for sale on
15 the United States West Coast during the calendar year for which the tax is due
16 is over \$15 but not over \$17.50; or

17 (E) zero percent of the gross value at the point of production
18 when the average price per barrel for Alaska North Slope crude oil for sale on
19 the United States West Coast during the calendar year for which the tax is due
20 is \$15 or less; [AND]

21 (2) oil and gas produced on and after January 1, 2017, and before
22 January 1, 2022, from leases or properties that include land north of 68 degrees North
23 latitude, other than gas subject to (o) of this section, may not be less than [(A)] four
24 percent of the gross value at the point of production, except that a credit authorized
25 under this chapter may reduce the tax under this subsection to less than four
26 percent, but not to less than two percent of the gross value at the point of
27 production;

28 (3) oil produced on and after January 1, 2022, from leases or
29 properties that include land north of 68 degrees North latitude may not be less
30 than four percent of the gross value at the point of production, except that a
31 credit authorized under this chapter may reduce the tax under this subsection to

1 **less than four percent, but not to less than two percent of the gross value at the**
2 **point of production** [WHEN THE AVERAGE PRICE PER BARREL FOR
3 ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED STATES
4 WEST COAST DURING THE CALENDAR YEAR FOR WHICH THE TAX IS
5 DUE IS MORE THAN \$25;

6 (B) THREE PERCENT OF THE GROSS VALUE AT THE
7 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
8 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
9 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
10 THE TAX IS DUE IS OVER \$20 BUT NOT OVER \$25;

11 (C) TWO PERCENT OF THE GROSS VALUE AT THE
12 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
13 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
14 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
15 THE TAX IS DUE IS OVER \$17.50 BUT NOT OVER \$20;

16 (D) ONE PERCENT OF THE GROSS VALUE AT THE
17 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
18 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
19 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
20 THE TAX IS DUE IS OVER \$15 BUT NOT OVER \$17.50; OR

21 (E) ZERO PERCENT OF THE GROSS VALUE AT THE
22 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
23 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
24 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
25 THE TAX IS DUE IS \$15 OR LESS].

26 * **Sec. 12.** AS 43.55.011(m) is amended to read:

27 (m) Notwithstanding any contrary provision of [AS 38.05.180(i),
28 AS 41.09.010,] AS 43.55.024 [,] or 43.55.025, the department shall provide by
29 regulation a method to ensure that, for a calendar year for which a producer's tax
30 liability is limited by (j) [, (k),] or (o) of this section, tax credits based on a lease
31 expenditure incurred before January 1, 2011, that are otherwise available under

1 [AS 38.05.180(i), AS 41.09.010,] AS 43.55.024 [,] or 43.55.025 and allocated to gas
2 subject to the limitations in (j) [, (k),] and (o) of this section are accounted for as
3 though the credits had been applied first against a tax liability calculated without
4 regard to the limitations under (j) [, (k),] and (o) of this section so as to reduce the tax
5 liability to the maximum amount provided for under (j) or (o) of this section for the
6 production of gas [OR (k) OF THIS SECTION FOR THE PRODUCTION OF OIL].
7 The regulation must provide for a reasonable method to allocate tax credits to gas
8 subject to (j) and (o) of this section. Only the amount of a tax credit remaining after
9 the accounting provided for under this subsection may be used for a later calendar
10 year, transferred to another person, or applied against a tax levied on the production of
11 oil or gas not subject to (j) [, (k),] or (o) of this section to the extent otherwise allowed.

12 * **Sec. 13.** AS 43.55.019(e) is amended to read:

13 (e) The credit under this section may not reduce a person's tax liability **for the**
14 **calendar year** under AS 43.55.011(e) to below **the amount calculated under**
15 **AS 43.55.011(f)** [ZERO FOR ANY TAX YEAR]. An unused credit or portion of a
16 credit not used under this section for a tax year may not be sold, traded, transferred, or
17 applied in a subsequent tax year.

18 * **Sec. 14.** AS 43.55.020(a) is amended to read:

19 (a) For a calendar year, a producer subject to tax under AS 43.55.011 shall pay
20 the tax as follows:

21 (1) for oil and gas produced before January 1, 2014, an installment
22 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
23 as allowed by law, is due for each month of the calendar year on the last day of the
24 following month; except as otherwise provided under (2) of this subsection, the
25 amount of the installment payment is the sum of the following amounts, less 1/12 of
26 the tax credits that are allowed by law to be applied against the tax levied by
27 AS 43.55.011(e) for the calendar year, but the amount of the installment payment may
28 not be less than zero:

29 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
30 produced from leases or properties in the state outside the Cook Inlet
31 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

the greater of

(i) zero; or

(ii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

(B) for oil and gas produced from leases or properties subject to AS 43.55.011(f), the greatest of

(i) zero;

(ii) zero percent, one percent, two percent, three percent, or four percent, as applicable, of the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated; or

(iii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated;

(C) for [OIL OR] gas subject to AS 43.55.011(j) [, (k),] or (o), for each lease or property, the greater of

(i) zero; or

(ii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the

1 calendar year of production under AS 43.55.165 and 43.55.170 that are
2 deductible under AS 43.55.160 for the oil or gas, respectively,
3 produced from the lease or property from the gross value at the point of
4 production of the oil or gas, respectively, produced from the lease or
5 property during the month for which the installment payment is
6 calculated;

7 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

8 (i) the sum of 25 percent and the tax rate calculated for
9 the month under AS 43.55.011(g) multiplied by the remainder obtained
10 by subtracting 1/12 of the producer's adjusted lease expenditures for the
11 calendar year of production under AS 43.55.165 and 43.55.170 that are
12 deductible for the oil and gas under AS 43.55.160 from the gross value
13 at the point of production of the oil and gas produced from the leases or
14 properties during the month for which the installment payment is
15 calculated, but not less than zero; or

16 (ii) four percent of the gross value at the point of
17 production of the oil and gas produced from the leases or properties
18 during the month, but not less than zero;

19 (2) an amount calculated under (1)(C) of this subsection for [OIL OR]
20 gas subject to AS 43.55.011(j) [, (k),] or (o) may not exceed the product obtained by
21 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
22 applicable, for gas [OR SET OUT IN AS 43.55.011(k)(1) OR (2), AS APPLICABLE,
23 FOR OIL,] but substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as
24 applicable, the amount of taxable gas produced during the month for the amount of
25 taxable gas produced during the calendar year [AND SUBSTITUTING IN
26 AS 43.55.011(k)(1)(A) OR (2)(A), AS APPLICABLE, THE AMOUNT OF
27 TAXABLE OIL PRODUCED DURING THE MONTH FOR THE AMOUNT OF
28 TAXABLE OIL PRODUCED DURING THE CALENDAR YEAR];

29 (3) an installment payment of the estimated tax levied by
30 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
31 on the last day of the following month; the amount of the installment payment is the

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

sum of

(A) the applicable tax rate for oil provided under AS 43.55.011(i), multiplied by the gross value at the point of production of the oil taxable under AS 43.55.011(i) and produced from the lease or property during the month; and

(B) the applicable tax rate for gas provided under AS 43.55.011(i), multiplied by the gross value at the point of production of the gas taxable under AS 43.55.011(i) and produced from the lease or property during the month;

(4) any amount of tax levied by AS 43.55.011, net of any credits applied as allowed by law, that exceeds the total of the amounts due as installment payments of estimated tax is due on March 31 of the year following the calendar year of production;

(5) for oil and gas produced on and after January 1, 2014, and before January 1, 2022, an installment payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each month of the calendar year on the last day of the following month; except as otherwise provided under (6) and (10) of this subsection, the amount of the installment payment is the sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount of the installment payment may not be less than zero:

(A) for oil and gas not subject to AS 43.55.011(o) or (p) produced from leases or properties in the state outside the Cook Inlet sedimentary basin, other than leases or properties subject to AS 43.55.011(f), the greater of

(i) zero; or

(ii) 35 percent multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or

1 properties during the month for which the installment payment is
2 calculated;

3 (B) for oil and gas produced from leases or properties subject
4 to AS 43.55.011(f), the greatest of

5 (i) zero;

6 (ii) zero percent, one percent, two percent, three
7 percent, or four percent, as applicable, of the gross value at the point of
8 production of the oil and gas produced from the leases or properties
9 during the month for which the installment payment is calculated; or

10 (iii) 35 percent multiplied by the remainder obtained by
11 subtracting 1/12 of the producer's adjusted lease expenditures for the
12 calendar year of production under AS 43.55.165 and 43.55.170 that are
13 deductible for the oil and gas under AS 43.55.160 from the gross value
14 at the point of production of the oil and gas produced from those leases
15 or properties during the month for which the installment payment is
16 calculated, except that, for the purposes of this calculation, a reduction
17 from the gross value at the point of production may apply for oil and
18 gas subject to AS 43.55.160(f) or (g);

19 (C) for [OIL OR] gas subject to AS 43.55.011(j) [, (k),] or (o),
20 for each lease or property, the greater of

21 (i) zero; or

22 (ii) 35 percent multiplied by the remainder obtained by
23 subtracting 1/12 of the producer's adjusted lease expenditures for the
24 calendar year of production under AS 43.55.165 and 43.55.170 that are
25 deductible under AS 43.55.160 for the [OIL OR] gas [,
26 RESPECTIVELY,] produced from the lease or property from the gross
27 value at the point of production of the [OIL OR] gas [,
28 RESPECTIVELY,] produced from the lease or property during the
29 month for which the installment payment is calculated;

30 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

31 (i) 35 percent multiplied by the remainder obtained by

1 subtracting 1/12 of the producer's adjusted lease expenditures for the
2 calendar year of production under AS 43.55.165 and 43.55.170 that are
3 deductible for the oil and gas under AS 43.55.160 from the gross value
4 at the point of production of the oil and gas produced from the leases or
5 properties during the month for which the installment payment is
6 calculated, but not less than zero; or

7 (ii) four percent of the gross value at the point of
8 production of the oil and gas produced from the leases or properties
9 during the month, but not less than zero;

10 (6) an amount calculated under (5)(C) of this subsection for [OIL OR]
11 gas subject to AS 43.55.011(j) [, (k),] or (o) may not exceed the product obtained by
12 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
13 applicable, for gas [OR SET OUT IN AS 43.55.011(k)(1) OR (2), AS APPLICABLE,
14 FOR OIL,] but substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as
15 applicable, the amount of taxable gas produced during the month for the amount of
16 taxable gas produced during the calendar year [AND SUBSTITUTING IN
17 AS 43.55.011(k)(1)(A) OR (2)(A), AS APPLICABLE, THE AMOUNT OF
18 TAXABLE OIL PRODUCED DURING THE MONTH FOR THE AMOUNT OF
19 TAXABLE OIL PRODUCED DURING THE CALENDAR YEAR];

20 (7) for oil and gas produced on or after January 1, 2022, an installment
21 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
22 as allowed by law, is due for each month of the calendar year on the last day of the
23 following month; **except as provided in (10) of this subsection,** the amount of the
24 installment payment is the sum of the following amounts, less 1/12 of the tax credits
25 that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the
26 calendar year, but the amount of the installment payment may not be less than zero:

27 (A) for oil produced from leases or properties that include land
28 north of 68 degrees North latitude, the greatest of

29 (i) zero;

30 (ii) zero percent, one percent, two percent, three
31 percent, or four percent, as applicable, of the gross value at the point of

1 production of the oil produced from the leases or properties during the
2 month for which the installment payment is calculated; or

3 (iii) 35 percent multiplied by the remainder obtained by
4 subtracting 1/12 of the producer's adjusted lease expenditures for the
5 calendar year of production under AS 43.55.165 and 43.55.170 that are
6 deductible for the oil under AS 43.55.160(h)(1) from the gross value at
7 the point of production of the oil produced from those leases or
8 properties during the month for which the installment payment is
9 calculated, except that, for the purposes of this calculation, a reduction
10 from the gross value at the point of production may apply for oil
11 subject to AS 43.55.160(f) or 43.55.160(f) and (g);

12 (B) for oil produced before or during the last calendar year
13 under AS 43.55.024(b) for which the producer could take a tax credit under
14 AS 43.55.024(a), from leases or properties in the state outside the Cook Inlet
15 sedimentary basin, no part of which is north of 68 degrees North latitude, other
16 than leases or properties subject to AS 43.55.011(p), the greater of

17 (i) zero; or

18 (ii) 35 percent multiplied by the remainder obtained by
19 subtracting 1/12 of the producer's adjusted lease expenditures for the
20 calendar year of production under AS 43.55.165 and 43.55.170 that are
21 deductible for the oil under AS 43.55.160(h)(2) from the gross value at
22 the point of production of the oil produced from the leases or properties
23 during the month for which the installment payment is calculated;

24 (C) for oil and gas produced from leases or properties subject
25 to AS 43.55.011(p), except as otherwise provided under (8) of this subsection,
26 the sum of

27 (i) 35 percent multiplied by the remainder obtained by
28 subtracting 1/12 of the producer's adjusted lease expenditures for the
29 calendar year of production under AS 43.55.165 and 43.55.170 that are
30 deductible for the oil under AS 43.55.160(h)(3) from the gross value at
31 the point of production of the oil produced from the leases or properties

1 during the month for which the installment payment is calculated, but
2 not less than zero; and

3 (ii) 13 percent of the gross value at the point of
4 production of the gas produced from the leases or properties during the
5 month, but not less than zero;

6 (D) for oil produced from leases or properties in the state, no
7 part of which is north of 68 degrees North latitude, other than leases or
8 properties subject to (B) or (C) of this paragraph, the greater of

9 (i) zero; or

10 (ii) 35 percent multiplied by the remainder obtained by
11 subtracting 1/12 of the producer's adjusted lease expenditures for the
12 calendar year of production under AS 43.55.165 and 43.55.170 that are
13 deductible for the oil under AS 43.55.160(h)(4) from the gross value at
14 the point of production of the oil produced from the leases or properties
15 during the month for which the installment payment is calculated;

16 (E) for gas produced from each lease or property in the state,
17 other than a lease or property subject to AS 43.55.011(p), 13 percent of the
18 gross value at the point of production of the gas produced from the lease or
19 property during the month for which the installment payment is calculated, but
20 not less than zero;

21 (8) an amount calculated under (7)(C) of this subsection may not
22 exceed four percent of the gross value at the point of production of the oil and gas
23 produced from leases or properties subject to AS 43.55.011(p) during the month for
24 which the installment payment is calculated;

25 (9) for purposes of the calculation under (1)(B)(ii), (5)(B)(ii), and
26 (7)(A)(ii) of this subsection, the applicable percentage of the gross value at the point
27 of production is determined under AS 43.55.011(f) [AS 43.55.011(f)(1) OR (2)] but
28 substituting the phrase "month for which the installment payment is calculated" in
29 [AS 43.55.011(f)(1) AND (2)] for the phrase "calendar year for which the tax is due";

30 (10) after December 31, 2016, for the purposes of a calculation
31 under (5)(B)(ii) or (7)(A)(ii) of this subsection, a credit under this chapter may

1 not be applied to reduce an installment payment to less than the applicable
2 percentage under AS 43.55.011(f). [""]

3 * **Sec. 15.** AS 43.55.023(a) is amended to read:

4 (a) A producer or explorer may take a tax credit for a qualified capital
5 expenditure as follows:

6 (1) notwithstanding that a qualified capital expenditure may be a
7 deductible lease expenditure for purposes of calculating the production tax value of oil
8 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
9 [AS 38.05.180(i), AS 41.09.010,] AS 43.20.043 [,] or AS 43.55.025, a producer or
10 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
11 against a tax levied by AS 43.55.011(e) in the amount of 10 [20] percent of that
12 expenditure;

13 (2) a producer or explorer may take a credit for a qualified capital
14 expenditure incurred in connection with geological or geophysical exploration or in
15 connection with an exploration well only if the producer or explorer

16 (A) agrees, in writing, to the applicable provisions of
17 AS 43.55.025(f)(2); and

18 (B) submits to the Department of Natural Resources all data
19 that would be required to be submitted under AS 43.55.025(f)(2);

20 (3) a credit for a qualified capital expenditure incurred to explore for,
21 develop, or produce oil or gas deposits located north of 68 degrees North latitude may
22 be taken only if the expenditure is incurred before January 1, 2014.

23 * **Sec. 16.** AS 43.55.023(b) is amended to read:

24 (b) Before January 1, 2014, a producer or explorer may elect to take a tax
25 credit in the amount of 25 percent of a carried-forward annual loss. For lease
26 expenditures incurred on and after January 1, 2014, and before January 1, 2016, to
27 explore for, develop, or produce oil or gas deposits located north of 68 degrees North
28 latitude, a producer or explorer may elect to take a tax credit in the amount of 45
29 percent of a carried-forward annual loss. For lease expenditures incurred on and after
30 January 1, 2016, to explore for, develop, or produce oil or gas deposits located north
31 of 68 degrees North latitude, a producer or explorer may elect to take a tax credit in

1 the amount of 35 percent of a carried-forward annual loss. For lease expenditures
2 incurred on or after January 1, 2014, and before January 1, 2017, to explore for,
3 develop, or produce oil or gas deposits located south of 68 degrees North latitude, a
4 producer or explorer may elect to take a tax credit in the amount of 25 percent of a
5 carried-forward annual loss. For lease expenditures incurred after December 31,
6 2016, to explore for, develop, or produce oil or gas deposits located south of 68
7 degrees North latitude and outside of the Cook Inlet sedimentary basin, a
8 producer or explorer may elect to take a tax credit in the amount of 25 percent of
9 a carried-forward annual loss. For lease expenditures incurred after
10 December 31, 2016, to explore for, develop, or produce oil or gas deposits located
11 in the Cook Inlet sedimentary basin, a producer or explorer may elect to take a
12 credit in the amount of 10 percent of a carried-forward annual loss, if the
13 producer or explorer had, before January 1, 2017, taken a credit under this
14 subsection for an expenditure incurred in the Cook Inlet sedimentary basin. A
15 credit under this subsection may be applied against a tax levied by AS 43.55.011(e).
16 For purposes of this subsection,

17 (1) a carried-forward annual loss is the amount of a producer's or
18 explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a
19 previous calendar year that was not deductible in calculating production tax values for
20 that calendar year under AS 43.55.160;

21 (2) for lease expenditures incurred on or after January 1, 2017,
22 any reduction under AS 43.55.160(f) or (g) is added back to the calculation of
23 production tax values for that calendar year under AS 43.55.160 for the
24 determination of a carried-forward annual loss.

25 * Sec. 17. AS 43.55.023(c) is amended to read:

26 (c) A credit or portion of a credit under this section may not be used to reduce
27 a person's tax liability under AS 43.55.011(e) for any calendar year below the amount
28 calculated under AS 43.55.011(f) [ZERO], and any unused credit or portion of a
29 credit not used under this subsection may be applied in a later calendar year.

30 * Sec. 18. AS 43.55.023(d) is amended to read:

31 (d) A person that is entitled to take a tax credit under this section that wishes

1 to transfer the unused credit to another person or obtain a cash payment under
2 AS 43.55.028 may apply to the department for a transferable tax credit certificate. An
3 application under this subsection must be in a form prescribed by the department and
4 must include supporting information and documentation that the department
5 reasonably requires. The department shall grant or deny an application, or grant an
6 application as to a lesser amount than that claimed and deny it as to the excess, not
7 later than 120 days after the latest of (1) March 31 of the year following the calendar
8 year in which the [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward
9 annual loss for which the credit is claimed was incurred; (2) the date the statement
10 required under AS 43.55.030(a) or (e) was filed for the calendar year in which the
11 [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward annual loss for which
12 the credit is claimed was incurred; or (3) the date the application was received by the
13 department. If, based on the information then available to it, the department is
14 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
15 the applicant a transferable tax credit certificate for the amount of the credit. A
16 certificate issued under this subsection does not expire.

17 * **Sec. 19.** AS 43.55.023(e) is amended to read:

18 (e) A person to which a transferable tax credit certificate is issued under (d) of
19 this section may transfer the certificate to another person, and a transferee may further
20 transfer the certificate. Subject to the limitations set out in **former (a) of this section**
21 **and (b) - (d)** [(a) - (d)] of this section, and notwithstanding any action the department
22 may take with respect to the applicant under (g) of this section, the owner of a
23 certificate may apply the credit or a portion of the credit shown on the certificate only
24 against a tax levied by AS 43.55.011(e). However, a credit shown on a transferable tax
25 credit certificate may not be applied to reduce a transferee's total tax liability under
26 AS 43.55.011(e) for oil and gas produced during a calendar year to less than 80
27 percent of the tax that would otherwise be due without applying that credit. Any
28 portion of a credit not used under this subsection may be applied in a later period.

29 * **Sec. 20.** AS 43.55.023(l) is amended to read:

30 (l) A producer or explorer may apply for a tax credit for a well lease
31 expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE]

1 after June 30, 2010, as follows:

2 (1) notwithstanding that a well lease expenditure incurred in the state
3 [SOUTH OF 68 DEGREES NORTH LATITUDE] may be a deductible lease
4 expenditure for purposes of calculating the production tax value of oil and gas under
5 AS 43.55.160(a), unless a credit for that expenditure is taken under (a) of this section,
6 [AS 38.05.180(i), AS 41.09.010,] AS 43.20.043, or AS 43.55.025, a producer or
7 explorer that incurs a well lease expenditure in the state [SOUTH OF 68 DEGREES
8 NORTH LATITUDE] may elect to apply a tax credit against a tax levied by
9 AS 43.55.011(e) in the amount of

10 (A) 40 percent of that expenditure incurred south of 68
11 degrees North latitude before January 1, 2017;

12 (B) 30 percent of that expenditure incurred south of 68
13 degrees North latitude after December 31, 2016, and before January 1,
14 2018;

15 (C) 20 percent of that expenditure incurred inside the Cook
16 Inlet sedimentary basin after December 31, 2017;

17 (D) 30 percent of that expenditure incurred outside the
18 Cook Inlet sedimentary basin and south of 68 degrees North latitude after
19 December 31, 2017, and before January 1, 2019 [; A TAX CREDIT
20 UNDER THIS PARAGRAPH MAY BE APPLIED FOR A SINGLE
21 CALENDAR YEAR];

22 (2) a producer or explorer may take a credit for a well lease
23 expenditure incurred in the state south of 68 degrees North latitude in connection with
24 geological or geophysical exploration or in connection with an exploration well only if
25 the producer or explorer

26 (A) agrees, in writing, to the applicable provisions of
27 AS 43.55.025(f)(2); and

28 (B) submits to the Department of Natural Resources all data
29 that would be required to be submitted under AS 43.55.025(f)(2).

30 * **Sec. 21.** AS 43.55.024(f) is amended to read:

31 (f) A tax credit authorized by (a) of this section may not be applied to reduce a

1 producer's tax liability for any calendar year under AS 43.55.011(e) on oil and gas
2 produced from leases or properties outside the Cook Inlet sedimentary basin, no part
3 of which is north of 68 degrees North latitude, below **the amount calculated under**
4 **AS 43.55.011(f)** [ZERO].

5 * **Sec. 22.** AS 43.55.024(g) is amended to read:

6 (g) A tax credit authorized by (c) of this section may not be applied to reduce
7 a producer's tax liability for any calendar year under AS 43.55.011(e) below **the**
8 **amount calculated under AS 43.55.011(f)** [ZERO].

9 * **Sec. 23.** AS 43.55.024(i) is amended to read:

10 (i) A producer may apply against the producer's tax liability for the calendar
11 year under AS 43.55.011(e) a tax credit of \$5 for each barrel of oil taxable under
12 AS 43.55.011(e) that meets one or more of the criteria in AS 43.55.160(f) or (g) and
13 that is produced during a calendar year after December 31, 2013. A tax credit
14 authorized by this subsection may not reduce a producer's tax liability for a calendar
15 year under AS 43.55.011(e) below **the amount calculated under AS 43.55.011(f)**
16 [ZERO].

17 * **Sec. 24.** AS 43.55.025(m) is amended to read:

18 (m) The persons that drill the first four exploration wells in the state and
19 within the areas described in (o) of this section on state lands, private lands, or federal
20 onshore lands for the purpose of discovering oil or gas that penetrate and evaluate a
21 prospect in a basin described in (o) of this section are eligible for a credit under (a)(6)
22 of this section. A credit under this subsection may not be taken for more than two
23 exploration wells in a single area described in (o)(1) - (6) of this section. Exploration
24 expenditures eligible for the credit in this subsection must be incurred for work
25 performed after June 1, 2012, and before July 1, 2016, **except that expenditures to**
26 **complete an exploration well that was spudded but not completed before July 1,**
27 **2016, are eligible for the credit under this subsection.** A person planning to drill an
28 exploration well on private land and to apply for a credit under this subsection shall
29 obtain written consent from the owner of the oil and gas interest for the full public
30 release of all well data after the expiration of the confidentiality period applicable to
31 information collected under (f) of this section. The written consent of the owner of the

1 oil and gas interest must be submitted to the commissioner of natural resources before
2 approval of the proposed exploration well. In addition to the requirements in (c)(1),
3 (c)(2)(A), and (c)(2)(C) of this section and submission of the written consent of the
4 owner of the oil and gas interest, a person planning to drill an exploration well shall
5 obtain approval from the commissioner of natural resources before the well is
6 spudded. The commissioner of natural resources shall make a written determination
7 approving or rejecting an exploration well within 60 days after receiving the request
8 for approval or as soon as is practicable thereafter. Before approving the exploration
9 well, the commissioner of natural resources shall consider the following: the location
10 of the well; the proximity to a community in need of a local energy source; the
11 proximity of existing infrastructure; the experience and safety record of the explorer in
12 conducting operations in remote or roadless areas; the projected cost schedule;
13 whether seismic mapping and seismic data sufficiently identify a particular trap for
14 exploration; whether the targeted and planned depth and range are designed to
15 penetrate and fully evaluate the hydrocarbon potential of the proposed prospect and
16 reach the level below which economic hydrocarbon reservoirs are likely to be found,
17 or reach 12,000 feet or more true vertical depth; and whether the exploration plan
18 provides for a full evaluation of the wellbore below surface casing to the depth of the
19 well. Whether the exploration well for which a credit is requested under this
20 subsection is located within an area and a basin described under (o) of this section
21 shall be determined by the commissioner of natural resources and reported to the
22 commissioner. A taxpayer that obtains a credit under this subsection may not claim a
23 tax credit under AS 43.55.023 or another provision in this section for the same
24 exploration expenditure.

25 * **Sec. 25.** AS 43.55.025 is amended by adding a new subsection to read:

26 (q) A credit or portion of a credit under this section may not be used to reduce
27 a person's tax liability under AS 43.55.011(e) for any calendar year below the amount
28 calculated under AS 43.55.011(f).

29 * **Sec. 26.** AS 43.55.028(e) is amended to read:

30 (e) The department, on the written application of a person to whom a
31 transferable tax credit certificate has been issued under AS 43.55.023(d) or former

1 AS 43.55.023(m) or to whom a production tax credit certificate has been issued under
2 AS 43.55.025(f), may use available money in the oil and gas tax credit fund to
3 purchase, in whole or in part, the certificate. **The department may not purchase a**
4 **total of more than \$100,000,000 in tax credit certificates from a person in a**
5 **calendar year. Before purchasing a certificate or part of a certificate,** [IF] the
6 department **shall find** [FINDS] that

7 (1) the calendar year of the purchase is not earlier than the first
8 calendar year for which the credit shown on the certificate would otherwise be allowed
9 to be applied against a tax;

10 (2) the **application is not the result of the division of a single entity**
11 **into multiple entities that would reasonably be expected to apply as a single entity**
12 **if the \$100,000,000 limitation in this subsection did not exist** [APPLICANT DOES
13 NOT HAVE AN OUTSTANDING LIABILITY TO THE STATE FOR UNPAID
14 DELINQUENT TAXES UNDER THIS TITLE];

15 (3) the applicant's total tax liability under AS 43.55.011(e), after
16 application of all available tax credits, for the calendar year in which the application is
17 made is zero;

18 (4) the applicant's average daily production of oil and gas taxable
19 under AS 43.55.011(e) during the calendar year preceding the calendar year in which
20 the application is made was not more than 50,000 BTU equivalent barrels; and

21 (5) the purchase is consistent with this section and regulations adopted
22 under this section.

23 * **Sec. 27.** AS 43.55.028 is amended by adding a new subsection to read:

24 (j) If an applicant or claimant has an outstanding liability to the state directly
25 related to the applicant's or claimant's oil or gas exploration, development, or
26 production and the department has not previously reduced the amount paid to that
27 applicant or claimant for a certificate or refund because of that outstanding liability,
28 the department may purchase only that portion of a certificate or pay only that portion
29 of a refund that exceeds the outstanding liability. With the applicant's or claimant's
30 consent, the department may apply the amount by which the department reduced its
31 purchase of a certificate or payment for a refund because of an outstanding liability to

1 satisfy the outstanding liability. Satisfaction of an outstanding liability under this
2 subsection does not affect the applicant's ability to contest that liability. The
3 department may enter into contracts or agreements with another department to which
4 the outstanding liability is owed. In this subsection, "outstanding liability" means an
5 amount of tax, interest, penalty, fee, rental, royalty, or other charge for which the state
6 has issued a demand for payment that has not been paid when due and, if contested,
7 has not been finally resolved against the state.

8 * **Sec. 28.** AS 43.55.029(a) is amended to read:

9 (a) An explorer or producer that has applied for a production tax credit under
10 former AS 43.55.023(a) [, (b),] or (l) or under AS 43.55.023(b) or 43.55.025(a) may
11 make a present assignment of the production tax credit certificate expected to be
12 issued by the department to a third-party assignee. The assignment may be made either
13 at the time the application is filed with the department or not later than 30 days after
14 the date of filing with the department. Once a notice of assignment in compliance with
15 this section is filed with the department, the assignment is irrevocable and cannot be
16 modified by the explorer or producer without the written consent of the assignee
17 named in the assignment. If a production tax credit certificate is issued to the explorer
18 or producer, the notice of assignment remains effective and shall be filed with the
19 department by the explorer or producer together with any application for the
20 department to purchase the certificate under AS 43.55.028(e).

21 * **Sec. 29.** AS 43.55.030(a) is amended to read:

22 (a) A producer that produces oil or gas from a lease or property in the state
23 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)
24 for that oil or gas, shall file with the department on March 31 of the following year a
25 statement, under oath, in a form prescribed by the department, giving, with other
26 information required, the following:

27 (1) a description of each lease or property from which oil or gas was
28 produced, by name, legal description, lease number, or accounting codes assigned by
29 the department;

30 (2) the names of the producer and, if different, the person paying the
31 tax, if any;

1 (3) the gross amount of oil and the gross amount of gas produced from
2 each lease or property, separately identifying the gross amount of gas produced from
3 each oil and gas lease to which an effective election under AS 43.55.014(a) applies,
4 the amount of gas delivered to the state under AS 43.55.014(b), and the percentage of
5 the gross amount of oil and gas owned by the producer;

6 (4) the gross value at the point of production of the oil and of the gas
7 produced from each lease or property owned by the producer and the costs of
8 transportation of the oil and gas;

9 (5) the name of the first purchaser and the price received for the oil and
10 for the gas, unless relieved from this requirement in whole or in part by the
11 department;

12 (6) the producer's qualified capital expenditures, [AS DEFINED IN
13 AS 43.55.023,] other lease expenditures under AS 43.55.165, and adjustments or other
14 payments or credits under AS 43.55.170;

15 (7) the production tax values of the oil and gas under AS 43.55.160(a)
16 or of the oil under AS 43.55.160(h), as applicable;

17 (8) any claims for tax credits to be applied; and

18 (9) calculations showing the amounts, if any, that were or are due
19 under AS 43.55.020(a) and interest on any underpayment or overpayment.

20 * **Sec. 30.** AS 43.55.030(e) is amended to read:

21 (e) An explorer or producer that incurs a lease expenditure under
22 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
23 year but does not produce oil or gas from a lease or property in the state during the
24 calendar year shall file with the department, on March 31 of the following year, a
25 statement, under oath, in a form prescribed by the department, giving, with other
26 information required, the following:

27 (1) the explorer's or producer's qualified capital expenditures, [AS
28 DEFINED IN AS 43.55.023,] other lease expenditures under AS 43.55.165, and
29 adjustments or other payments or credits under AS 43.55.170; and

30 (2) if the explorer or producer receives a payment or credit under
31 AS 43.55.170, calculations showing whether the explorer or producer is liable for a

1 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount.

2 * **Sec. 31.** AS 43.55.160(e) is amended to read:

3 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
4 would otherwise be deductible by a producer in a calendar year but whose deduction
5 would cause an annual production tax value calculated under (a)(1) or (h) of this
6 section of taxable oil or gas produced during the calendar year to be less than zero
7 may be used to establish a carried-forward annual loss under AS 43.55.023(b).
8 However, the department shall provide by regulation a method to ensure that, for a
9 period for which a producer's tax liability is limited by AS 43.55.011(j), [(k),] (o), or
10 (p), **or former AS 43.55.011(k)**, any adjusted lease expenditures under AS 43.55.165
11 and 43.55.170 that would otherwise be deductible by a producer for that period but
12 whose deduction would cause a production tax value calculated under (a)(1)(C), (D),
13 (E), or (F), or (h)(3) of this section to be less than zero are accounted for as though the
14 adjusted lease expenditures had first been used as deductions in calculating the
15 production tax values of oil or gas subject to any of the limitations under
16 AS 43.55.011(j), [(k),] (o), or (p) **or former AS 43.55.011(k)** that have positive
17 production tax values so as to reduce the tax liability calculated without regard to the
18 limitation to the maximum amount provided for under the applicable provision of
19 AS 43.55.011(j), [(k),] (o), or (p) **or former AS 43.55.011(k)**. Only the amount of
20 those adjusted lease expenditures remaining after the accounting provided for under
21 this subsection may be used to establish a carried-forward annual loss under
22 AS 43.55.023(b). In this subsection, "producer" includes "explorer."

23 * **Sec. 32.** AS 43.55.160(f) is amended to read:

24 (f) On and after January 1, 2014, in the calculation of an annual production tax
25 value of a producer under (a)(1)(A) or (h)(1) of this section, the gross value at the
26 point of production of oil or gas produced from a lease or property north of 68 degrees
27 North latitude meeting one or more of the following criteria is reduced by 20 percent:
28 (1) the oil or gas is produced from a lease or property that does not contain a lease that
29 was within a unit on January 1, 2003; (2) the oil or gas is produced from a
30 participating area established after December 31, 2011, that is within a unit formed
31 under AS 38.05.180(p) before January 1, 2003, if the participating area does not

1 contain a reservoir that had previously been in a participating area established before
2 December 31, 2011; (3) the oil or gas is produced from acreage that was added to an
3 existing participating area by the Department of Natural Resources on and after
4 January 1, 2014, and the producer demonstrates to the department that the volume of
5 oil or gas produced is from acreage added to an existing participating area. This
6 subsection does not apply to gas produced before 2022 that is used in the state or to
7 gas produced on and after January 1, 2022. **For oil or gas first produced after**
8 **December 31, 2016, the reduction under this subsection shall apply to oil or gas**
9 **produced from a lease or property for the first five years after the**
10 **commencement of production in commercial quantities of oil or gas from that**
11 **lease or property. For oil or gas first produced before January 1, 2017, the**
12 **reduction under this subsection for a lease or property shall expire January 1,**
13 **2021.** A reduction under this subsection may not reduce the gross value at the point of
14 production below zero. In this subsection, "participating area" means a reservoir or
15 portion of a reservoir producing or contributing to production as approved by the
16 Department of Natural Resources.

17 * **Sec. 33.** AS 43.55.160(g) is amended to read:

18 (g) On and after January 1, 2014, in addition to the reduction under (f) of this
19 section, in the calculation of an annual production tax value of a producer under
20 (a)(1)(A) or (h)(1) of this section, the gross value at the point of production of oil or
21 gas produced from a lease or property north of 68 degrees North latitude that does not
22 contain a lease that was within a unit on January 1, 2003, is reduced by 10 percent if
23 the oil or gas is produced from a unit made up solely of leases that have a royalty
24 share of more than 12.5 percent in amount or value of the production removed or sold
25 from the lease as determined under AS 38.05.180(f). This subsection does not apply if
26 the royalty obligation for one or more of the leases in the unit has been reduced to 12.5
27 percent or less under AS 38.05.180(j) for all or part of the calendar year for which the
28 annual production tax value is calculated. This subsection does not apply to gas
29 produced before 2022 that is used in the state or to gas produced on and after
30 January 1, 2022. **For oil or gas first produced after December 31, 2016, the**
31 **reduction under this subsection shall apply to oil or gas produced from a lease or**

1 property for the first five years after the commencement of production in
2 commercial quantities of oil or gas from that lease or property. For oil or gas first
3 produced before January 1, 2017, the reduction under this subsection for a lease
4 or property shall expire January 1, 2021. A reduction under this subsection may not
5 reduce the gross value at the point of production below zero.

6 * **Sec. 34.** AS 43.55.165(a) is amended to read:

7 (a) **For** [EXCEPT AS PROVIDED IN (j) AND (k) OF THIS SECTION,
8 FOR] purposes of this chapter, a producer's lease expenditures for a calendar year are

9 (1) costs, other than items listed in (e) of this section, that are

10 (A) incurred by the producer during the calendar year after
11 March 31, 2006, to explore for, develop, or produce oil or gas deposits located
12 within the producer's leases or properties in the state or, in the case of land in
13 which the producer does not own an operating right, operating interest, or
14 working interest, to explore for oil or gas deposits within other land in the
15 state; and

16 (B) allowed by the department by regulation, based on the
17 department's determination that the costs satisfy the following three
18 requirements:

19 (i) the costs must be incurred upstream of the point of
20 production of oil and gas;

21 (ii) the costs must be ordinary and necessary costs of
22 exploring for, developing, or producing, as applicable, oil or gas
23 deposits; and

24 (iii) the costs must be direct costs of exploring for,
25 developing, or producing, as applicable, oil or gas deposits; and

26 (2) a reasonable allowance for that calendar year, as determined under
27 regulations adopted by the department, for overhead expenses that are directly related
28 to exploring for, developing, or producing, as applicable, the oil or gas deposits.

29 * **Sec. 35.** AS 43.55.165(e) is amended to read:

30 (e) For purposes of this section, lease expenditures do not include

31 (1) depreciation, depletion, or amortization;

1 (2) oil or gas royalty payments, production payments, lease profit
2 shares, or other payments or distributions of a share of oil or gas production, profit, or
3 revenue, except that a producer's lease expenditures applicable to oil and gas produced
4 from a lease issued under AS 38.05.180(f)(3)(B), (D), or (E) include the share of net
5 profit paid to the state under that lease;

6 (3) taxes based on or measured by net income;

7 (4) interest or other financing charges or costs of raising equity or debt
8 capital;

9 (5) acquisition costs for a lease or property or exploration license;

10 (6) costs arising from fraud, wilful misconduct, gross negligence,
11 violation of law, or failure to comply with an obligation under a lease, permit, or
12 license issued by the state or federal government;

13 (7) fines or penalties imposed by law;

14 (8) costs of arbitration, litigation, or other dispute resolution activities
15 that involve the state or concern the rights or obligations among owners of interests in,
16 or rights to production from, one or more leases or properties or a unit;

17 (9) costs incurred in organizing a partnership, joint venture, or other
18 business entity or arrangement;

19 (10) amounts paid to indemnify the state; the exclusion provided by
20 this paragraph does not apply to the costs of obtaining insurance or a surety bond from
21 a third-party insurer or surety;

22 (11) surcharges levied under AS 43.55.201 or 43.55.300;

23 (12) an expenditure otherwise deductible under (b) of this section that
24 is a result of an internal transfer, a transaction with an affiliate, or a transaction
25 between related parties, or is otherwise not an arm's length transaction, unless the
26 producer establishes to the satisfaction of the department that the amount of the
27 expenditure does not exceed the fair market value of the expenditure;

28 (13) an expenditure incurred to purchase an interest in any corporation,
29 partnership, limited liability company, business trust, or any other business entity,
30 whether or not the transaction is treated as an asset sale for federal income tax
31 purposes;

1 (14) a tax levied under AS 43.55.011 or 43.55.014;

2 (15) costs incurred for dismantlement, removal, surrender, or
3 abandonment of a facility, pipeline, well pad, platform, or other structure, or for the
4 restoration of a lease, field, unit, area, tract of land, body of water, or right-of-way in
5 conjunction with dismantlement, removal, surrender, or abandonment; a cost is not
6 excluded under this paragraph if the dismantlement, removal, surrender, or
7 abandonment for which the cost is incurred is undertaken for the purpose of replacing,
8 renovating, or improving the facility, pipeline, well pad, platform, or other structure;

9 (16) costs incurred for containment, control, cleanup, or removal in
10 connection with any unpermitted release of oil or a hazardous substance and any
11 liability for damages imposed on the producer or explorer for that unpermitted release;
12 this paragraph does not apply to the cost of developing and maintaining an oil
13 discharge prevention and contingency plan under AS 46.04.030;

14 (17) costs incurred to satisfy a work commitment under an exploration
15 license under AS 38.05.132;

16 (18) that portion of expenditures, that would otherwise be qualified
17 capital expenditures, [AS DEFINED IN AS 43.55.023,] incurred during a calendar
18 year that are less than the product of \$0.30 multiplied by the total taxable production
19 from each lease or property, in BTU equivalent barrels, during that calendar year,
20 except that, when a portion of a calendar year is subject to this provision, the
21 expenditures and volumes shall be prorated within that calendar year;

22 (19) costs incurred for repair, replacement, or deferred maintenance of
23 a facility, a pipeline, a structure, or equipment, other than a well, that results in or is
24 undertaken in response to a failure, problem, or event that results in an unscheduled
25 interruption of, or reduction in the rate of, oil or gas production; or costs incurred for
26 repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or
27 equipment, other than a well, that is undertaken in response to, or is otherwise
28 associated with, an unpermitted release of a hazardous substance or of gas; however,
29 costs under this paragraph that would otherwise constitute lease expenditures under (a)
30 and (b) of this section may be treated as lease expenditures if the department
31 determines that the repair or replacement is solely necessitated by an act of war, by an

1 unanticipated grave natural disaster or other natural phenomenon of an exceptional,
2 inevitable, and irresistible character, the effects of which could not have been
3 prevented or avoided by the exercise of due care or foresight, or by an intentional or
4 negligent act or omission of a third party, other than a party or its agents in privity of
5 contract with, or employed by, the producer or an operator acting for the producer, but
6 only if the producer or operator, as applicable, exercised due care in operating and
7 maintaining the facility, pipeline, structure, or equipment, and took reasonable
8 precautions against the act or omission of the third party and against the consequences
9 of the act or omission; in this paragraph,

10 (A) "costs incurred for repair, replacement, or deferred
11 maintenance of a facility, a pipeline, a structure, or equipment" includes costs
12 to dismantle and remove the facility, pipeline, structure, or equipment that is
13 being replaced;

14 (B) "hazardous substance" has the meaning given in
15 AS 46.03.826;

16 (C) "replacement" includes renovation or improvement;

17 (20) costs incurred to construct, acquire, or operate a refinery or crude
18 oil topping plant, regardless of whether the products of the refinery or topping plant
19 are used in oil or gas exploration, development, or production operations; however, if
20 a producer owns a refinery or crude oil topping plant that is located on or near the
21 premises of the producer's lease or property in the state and that processes the
22 producer's oil produced from that lease or property into a product that the producer
23 uses in the operation of the lease or property in drilling for or producing oil or gas, the
24 producer's lease expenditures include the amount calculated by subtracting from the
25 fair market value of the product used the prevailing value, as determined under
26 AS 43.55.020(f), of the oil that is processed;

27 (21) costs of lobbying, public relations, public relations advertising, or
28 policy advocacy.

29 * **Sec. 36.** AS 43.55.165(f) is amended to read:

30 (f) For purposes of AS 43.55.023(b) [AS 43.55.023(a) AND (b)] and only as
31 to expenditures incurred to explore for an oil or gas deposit located within land in

1 which an explorer does not own a working interest, the term "producer" in this section
2 includes "explorer."

3 * **Sec. 37.** AS 43.55.170(c) is amended to read:

4 (c) For purposes of **AS 43.55.023(b)** [AS 43.55.023(a) AND (b)] and only as
5 to expenditures incurred to explore for an oil or gas deposit located within land in
6 which an explorer does not own a working interest, the term "producer" in this section
7 includes "explorer."

8 * **Sec. 38.** AS 43.55.890 is amended to read:

9 **Sec. 43.55.890. Disclosure of tax information.** Notwithstanding any contrary
10 provision of AS 40.25.100, and regardless of whether the information is considered
11 under AS 43.05.230(e) to constitute statistics classified to prevent the identification of
12 particular returns or reports, the department may publish the following information
13 under this chapter, if aggregated among three or more producers or explorers, showing
14 by month or calendar year and by lease or property, unit, or area of the state:

- 15 (1) the amount of oil or gas production;
- 16 (2) the amount of taxes levied under this chapter or paid under this
17 chapter;
- 18 (3) the effective tax rates under this chapter;
- 19 (4) the gross value of oil or gas at the point of production;
- 20 (5) the transportation costs for oil or gas;
- 21 (6) qualified capital expenditures [, AS DEFINED IN AS 43.55.023];
- 22 (7) exploration expenditures under AS 43.55.025;
- 23 (8) production tax values of oil or gas under AS 43.55.160;
- 24 (9) lease expenditures under AS 43.55.165;
- 25 (10) adjustments to lease expenditures under AS 43.55.170;
- 26 (11) tax credits applicable or potentially applicable against taxes levied

27 by this chapter.

28 * **Sec. 39.** AS 43.55.895(b) is amended to read:

29 (b) A municipal entity subject to taxation because of this section

30 **(1)** is eligible for [ALL] tax credits **proportionate to its production**
31 **taxable under AS 43.55.011(e); and**

1 (2) shall allocate its lease expenditures in proportion to its
2 production taxable under AS 43.55.011(e) [UNDER THIS CHAPTER TO THE
3 SAME EXTENT AS ANY OTHER PRODUCER].

4 * **Sec. 40.** AS 43.55.900 is amended by adding a new paragraph to read:

5 (26) "qualified capital expenditure"

6 (A) means, except as otherwise provided in (B) of this
7 paragraph, an expenditure that is a lease expenditure under AS 43.55.165 and
8 is

9 (i) incurred for geological or geophysical exploration;

10 (ii) treated as a capitalized expenditure under 26 U.S.C.
11 (Internal Revenue Code), as amended, regardless of elections made
12 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
13 treated as a capitalized expenditure for federal income tax reporting
14 purposes by the person incurring the expenditure; or

15 (iii) treated as a capitalized expenditure under 26 U.S.C.
16 (Internal Revenue Code), as amended, regardless of elections made
17 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
18 eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal
19 Revenue Code), as amended;

20 (B) does not include an expenditure incurred to acquire an asset
21 the cost of previously acquiring which was a lease expenditure under
22 AS 43.55.165 or would have been a lease expenditure under AS 43.55.165 if it
23 had been incurred after March 31, 2006, or that has previously been placed in
24 service in the state; an expenditure to acquire an asset is not excluded under
25 this subparagraph if not more than an immaterial portion of the asset meets a
26 description under this subparagraph; for purposes of this subparagraph, "asset"
27 includes geological, geophysical, and well data and interpretations.

28 * **Sec. 41.** AS 43.70.020 is amended by adding a new subsection to read:

29 (g) A person whose business engages in oil or gas exploration or development
30 must, in addition to filing the regular application required by this section, file with the
31 commissioner a surety bond of \$250,000 running to unsecured creditors licensed in the

1 state before being entitled to a license under this chapter. The commissioner shall
2 waive the surety bond requirement under this subsection if the business produces oil or
3 gas in commercial quantities.

4 * **Sec. 42.** AS 38.05.180(i); AS 41.09.010, 41.09.020, 41.09.030, 41.09.090;
5 AS 43.20.053(j)(4); and AS 43.55.011(k) are repealed January 1, 2017.

6 * **Sec. 43.** AS 43.55.023(a), 43.55.023(l), 43.55.023(n), 43.55.023(o), 43.55.028(i),
7 43.55.075(d)(1), 43.55.165(j), and 43.55.165(k) are repealed January 1, 2022.

8 * **Sec. 44.** The uncodified law of the State of Alaska is amended by adding a new section to
9 read:

10 LEGISLATIVE WORKING GROUP. (a) A legislative working group is established
11 to analyze the Cook Inlet fiscal regime for oil and gas, review the state's tax structure and
12 rates on oil and gas produced south of 68 degrees North latitude, recommend changes to the
13 legislature for consideration during the First Regular Session of the Thirtieth Alaska State
14 Legislature, and develop terms for a comprehensive fiscal regime for the area south of 68
15 degrees North latitude including,

16 (1) a tax structure that accounts for the unique circumstances for each oil and
17 gas producing area south of 68 degrees North latitude;

18 (2) incentives for the exploration, development, and production of oil and gas
19 south of 68 degrees North latitude;

20 (3) consideration of the competitiveness of the area to attract new oil and gas
21 development;

22 (4) consideration of the unique market considerations of the Cook Inlet
23 sedimentary basin and the need to support energy supply security for communities in
24 Southcentral Alaska;

25 (5) alternative means of state support for the exploration, development, and
26 production of oil and gas in this area, including through the Alaska Industrial Export and
27 Development Authority;

28 (6) analysis of whether refundable state tax credits are still necessary for a
29 new regime;

30 (7) evaluation of the need for disclosure of some confidential information to
31 help legislators shape policy, including an evaluation of the associated state and federal

1 constitutional issues related to statutory waivers of taxpayer confidentiality.

2 (b) The working group consists of

3 (1) two co-chairs, one of whom is a member of the house appointed by the
4 speaker of the house of representatives, and one of whom is a member of the senate appointed
5 by the president of the senate; and

6 (2) members appointed by the co-chairs; members must be legislators and
7 must include members of the majority and minority caucuses.

8 (c) The co-chairs of the working group may form an advisory group to the working
9 group, composed of members who are not legislators and who have expertise and skills to
10 assist in the review and development of a new plan for the tax structure and rates on oil and
11 gas produced south of 68 degrees North latitude. The members of an advisory group may
12 include commissioners or employees of state departments, members of the oil and gas
13 industry or trade associations, and economists.

14 (d) The working group is to be supported by legislative consultants under contract
15 through the Legislative Budget and Audit Committee.

16 * **Sec. 45.** The uncodified law of the State of Alaska is amended by adding a new section to
17 read:

18 **APPLICABILITY.** Sections 7 - 9, 26, and 27 of this Act apply to a refund or payment
19 applied for on or after January 1, 2017.

20 * **Sec. 46.** The uncodified law of the State of Alaska is amended by adding a new section to
21 read:

22 **TRANSITION: QUALIFIED CAPITAL EXPENDITURES AND WELL LEASE**
23 **EXPENDITURES.** (a) Notwithstanding the repeal of AS 43.55.023(a), (l), (n), and (o) by sec.
24 43 of this Act, and the amendments to AS 43.55.023(d) and (e), 43.55.029(a), 43.55.165(f),
25 and 43.55.170(c) by secs. 18, 19, 28, 36, and 37 of this Act, a taxpayer who incurs

26 (1) a qualified capital expenditure before the effective date of sec. 43 of this
27 Act that qualifies for a qualified capital expenditure credit under AS 43.55.023(a) may apply
28 for a credit or transferable tax credit certificate under AS 43.55.023 and assign the tax credit
29 under AS 43.55.029, as those sections read on the day before the effective date of sec. 43 of
30 this Act;

31 (2) a well lease expenditure before the effective date of sec. 43 of this Act that

1 qualifies for a well lease expenditure credit under AS 43.55.023(l) may apply for a credit or
2 transferable tax credit certificate under AS 43.55.023 and assign the tax credit under
3 AS 43.55.029, as those sections read on the day before the effective date of sec. 43 of this
4 Act.

5 (b) The Department of Revenue may continue to apply and enforce AS 43.55.023 and
6 43.55.029, as those sections read on the day before the effective date of sec. 43 of this Act, for
7 qualified capital expenditures and well lease expenditures incurred before the effective date of
8 sec. 43 of this Act.

9 * **Sec. 47.** The uncodified law of the State of Alaska is amended by adding a new section to
10 read:

11 TRANSITION: LEASE EXPENDITURES FOR A CALENDAR YEAR AFTER
12 2006 AND BEFORE 2010. Notwithstanding AS 43.55.165(a), as amended by sec. 34 of this
13 Act, and the repeal of AS 43.55.165(j) and (k) by sec. 43 of this Act, AS 43.55.165(j) and (k)
14 apply to a producer's total lease expenditures for a calendar year after 2006 and before 2010
15 under AS 43.55.165, as that section read on the day before the effective date of sec. 43 of this
16 Act.

17 * **Sec. 48.** The uncodified law of the State of Alaska is amended by adding a new section to
18 read:

19 TRANSITION: REGULATIONS. The Department of Revenue and the Department of
20 Natural Resources may adopt regulations necessary to implement the changes made by this
21 Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not
22 before the effective date of the law implemented by the regulation. The Department of
23 Revenue shall adopt regulations governing the use of tax credits under AS 43.55 for a
24 calendar year for which the applicable tax credit provisions of AS 43.55 differ as between
25 parts of the year as a result of this Act.

26 * **Sec. 49.** The uncodified law of the State of Alaska is amended by adding a new section to
27 read:

28 TRANSITION: RETROACTIVITY OF REGULATIONS. Notwithstanding any
29 contrary provision of AS 44.62.240,

30 (1) if the Department of Revenue expressly designates in a regulation that the
31 regulation applies retroactively, a regulation adopted by the Department of Revenue to

1 implement, interpret, make specific, or otherwise carry out this Act may apply retroactively to
2 the effective date of the law implemented by the regulation;

3 (2) if the Department of Natural Resources expressly designates in the
4 regulation that the regulation applies retroactively, a regulation adopted by the Department of
5 Natural Resources to implement, interpret, make specific, or otherwise carry out the statutory
6 amendments in this Act affecting the administration of oil and gas leases issued under
7 AS 38.05.180(f)(3)(B), (D), or (E), to the extent the regulation relates to the treatment of oil
8 and gas production taxes in determining net profits under those leases, may apply
9 retroactively to the effective date of the law implemented by the regulation.

10 * **Sec. 50.** Sections 24, 44, and 48 of this Act take effect immediately under
11 AS 01.10.070(c).

12 * **Sec. 51.** Sections 18, 19, 28 - 30, 34 - 38, 40, 43, 46, and 47 of this Act take effect
13 January 1, 2022.

14 * **Sec. 52.** Except as provided in secs. 50 and 51 of this Act, this Act takes effect January 1,
15 2017.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB 247(HFIN) Fund Cap 4-8-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: House

Department: Fund Capitalization
Appropriation: Fund Capitalization (no approps out)
Allocation: Oil and Gas Tax Credit Fund
OMB Component Number: 2894

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits	800,000.0	73,425.0						
Miscellaneous								
Total Operating	800,000.0	73,425.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

1001 CBR Fund	800,000.0	73,425.0						
Total	800,000.0	73,425.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time								
Part-time								
Temporary								

Change in Revenues								
---------------------------	--	--	--	--	--	--	--	--

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? **Yes**
If yes, by what date are the regulations to be adopted, amended or repealed? **01/01/17**

Why this fiscal note differs from previous version:

This revised fiscal note appropriates \$800,000.0 from the Constitutional Budget Reserve to the Oil & Gas Tax Credit Fund. This appropriation requires a supermajority vote in each body.

WITHDRAWN

Prepared By: Representative Neuman Phone: (907)465-2679
House Finance Committee Date: 04/08/2016
Representative Thompson
House Finance Committee

Fiscal Detail of CSHB247(FIN)\F (Revenue and Budget Impacts)

Provisions in CSHB 247(FIN) \ F and their Estimated Fiscal Impact as compared to Spring 2016 Forecast (\$millions) - FORECAST PRICE¹

Note regarding this table: this table attempts to value the impact of each of the items independently, except where noted. In some cases, the total value of several impacts will not equal the sum of the

Brief Description of Provision - Includes only provisions anticipated to have a direct fiscal im	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
1. The rate for net operating loss credits for Cook Inlet is changed to 10% for companies with a previous credit and zero for other companies.	\$0	\$0	\$0	\$0	\$0	\$0
2. The rate for QCE credits for Cook Inlet is changed to 10%; the rate for well lease exp credits for Cook Inlet is changed to 30% on 1/1/17 and then 20% on 1/1/18	\$0	\$0	\$0	\$0	\$0	\$10-\$20
3. The tax limitation for Cook Inlet oil is repealed effective 1/1/17.	\$0-\$10	\$0-\$10	\$0-\$10	\$5-\$15	\$10-\$20	\$15-\$25
4. For North Slope, certain tax credits cannot reduce liability below 2% of GVPP effective 1/1/17.	\$10-\$20	\$70-\$100	\$70-\$100	\$70-\$100	\$100-\$150	\$100-\$150
5. The interest rate on delinquent taxes is changed to 5% above the Fed Res Discount rate, compounded	Indeterminate					
6. The GVR cannot be used to create or increase a net operating loss	\$0	\$0	\$0	\$0	\$0	\$5-\$15
7. GVR-eligible production qualifies for the GVR for a period of 5 years or until 1/1/21.	\$0	\$0	\$0	\$0	\$0-\$10	\$30-\$50
8. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax	Indeterminate					
Total Revenue Impact	\$10-\$30	\$70-\$110	\$70-\$110	\$75-\$115	\$110-\$180	\$160-\$260
Budget impact of change in net operating loss credits for Cook Inlet (provision 1 above)	\$0	\$0-\$10	\$10-\$20	\$10-\$20	\$10-\$20	\$10-\$20
Budget impact of change in QCE/WLE credits for Cook Inlet (provision 2 above)	\$0	\$15-\$25	\$15-\$25	\$15-\$25	\$45-\$60	\$45-\$60
Budget impact of not allowing certain credits to reduce North Slope below 2% of GVPP (provision 4 above)	\$0	\$0	\$0	\$0	\$0-\$10	\$0-\$10
Budget impact of limiting refunds to \$100 million per company/per project per year (only shifts timing of refunds)	Confidential due to limited use - net neutral as impact shifted to later years					
The GVR cannot be used to create or increase a net operating loss (provision 6 above)	0	\$10-\$20	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10
Budget impact of exploration credit extension for well spudded by 7/1/16	(\$5)-\$0	(\$5)-\$0	\$0	\$0	\$0	\$0
Budget impact of GVR applying to fields for a period of 5 years (provision 7 above)	\$0	\$0	\$0	\$0	\$0	\$0
Total Budget Impact	(\$5)-\$0	\$20-\$55	\$45-\$75	\$40-\$70	\$60-\$105	\$55-\$100
Total Fiscal Impact - does not include revenue impacts from potential changes in investment²	\$5-\$30	\$90-\$165	\$115-\$185	\$115-\$185	\$170-\$285	\$215-\$360
Non-refundable carry-forward credits balance at fiscal year end - current law ³	\$618	\$751	\$732	\$585	\$265	\$136
Non-refundable carry-forward credits balance at fiscal year end - proposed ³	\$676	\$941	\$1,065	\$1,055	\$957	\$923
Change in year-end balance due to bill	\$58	\$190	\$333	\$470	\$692	\$787

¹The impacts listed are based on production and prices as forecasted in DOR's Spring 2016 revenue forecast. The forecasted oil prices are between \$38.89 and \$61.64. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts.

NOTE: The fiscal impact of this bill is an estimate based on the Spring 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
 Fiscal Note Number: _____
 () Publish Date: _____

Identifier: HB247CS(RES)-DNR-DOG-4-1-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: House Resources

Department: Department of Natural Resources
 Appropriation: Oil & Gas
 Allocation: Oil & Gas
 OMB Component Number: 439

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017	Included in	Out-Year Cost Estimates				
	Appropriation Requested	Governor's FY2017 Request	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES	FY 2017	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None							
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues							
---------------------------	--	--	--	--	--	--	--

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 (separate supplemental appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No
 If yes, by what date are the regulations to be adopted, amended or repealed? N/A

Why this fiscal note differs from previous version:

Revised in response to Committee Substitute.

Prepared By: Corri Feige, Director	Phone: (907)269-8775
Division: Division of Oil & Gas	Date: 04/01/2016 12:00 AM
Approved By: Marty Rutherford, Acting Commissioner	Date: 04/01/16
Agency: Department of Natural Resources	

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. CSHB 247

Analysis

No fiscal impact.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB 247(HFIN) Fund Cap 4-8-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: House

Department: Fund Capitalization
Appropriation: Fund Capitalization (no approps out)
Allocation: Oil and Gas Tax Credit Fund
OMB Component Number: 2894

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates				
			FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES	FY 2017	FY 2017					
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits	800,000.0	73,425.0					
Miscellaneous							
Total Operating	800,000.0	73,425.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

1001 CBR Fund	800,000.0	73,425.0					
Total	800,000.0	73,425.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues							
---------------------------	--	--	--	--	--	--	--

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? Yes
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

This revised fiscal note appropriates \$800,000.0 from the Constitutional Budget Reserve to the Oil & Gas Tax Credit Fund. This appropriation requires a supermajority vote in each body.

Prepared By: Representative Neuman
House Finance Committee
Representative Thompson
House Finance Committee

Phone: (907)465-2679
Date: 04/08/2016

Fiscal Detail of CSHB247(FIN)\F (Revenue and Budget Impacts)

Provisions in CSHB 247(FIN) \ F and their Estimated Fiscal Impact as compared to Spring 2016 Forecast (\$millions) - FORECAST PRICE¹

Note regarding this table: this table attempts to value the impact of each of the items independently, except where noted. In some cases, the total value of several impacts will not equal the sum of the

Brief Description of Provision - Includes only provisions anticipated to have a direct fiscal im	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
1. The rate for net operating loss credits for Cook Inlet is changed to 10% for companies with a previous credit and zero for other companies.	\$0	\$0	\$0	\$0	\$0	\$0
2. The rate for QCE credits for Cook Inlet is changed to 10%; the rate for well lease exp credits for Cook Inlet is changed to 30% on 1/1/17 and then 20% on 1/1/18	\$0	\$0	\$0	\$0	\$0	\$10-\$20
3. The tax limitation for Cook Inlet oil is repealed effective 1/1/17.	\$0-\$10	\$0-\$10	\$0-\$10	\$5-\$15	\$10-\$20	\$15-\$25
4. For North Slope, certain tax credits cannot reduce liability below 2% of GVPP effective 1/1/17.	\$10-\$20	\$70-\$100	\$70-\$100	\$70-\$100	\$100-\$150	\$100-\$150
5. The interest rate on delinquent taxes is changed to 5% above the Fed Res Discount rate, compounded	Indeterminate					
6. The GVR cannot be used to create or increase a net operating loss	\$0	\$0	\$0	\$0	\$0	\$5-\$15
7. GVR-eligible production qualifies for the GVR for a period of 5 years or until 1/1/21.	\$0	\$0	\$0	\$0	\$0-\$10	\$30-\$50
8. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax	Indeterminate					
Total Revenue Impact	\$10-\$30	\$70-\$110	\$70-\$110	\$75-\$115	\$110-\$180	\$160-\$260
Budget impact of change in net operating loss credits for Cook Inlet (provision 1 above)	\$0	\$0-\$10	\$10-\$20	\$10-\$20	\$10-\$20	\$10-\$20
Budget impact of change in QCE/WLE credits for Cook Inlet (provision 2 above)	\$0	\$15-\$25	\$15-\$25	\$15-\$25	\$45-\$60	\$45-\$60
Budget impact of not allowing certain credits to reduce North Slope below 2% of GVPP (provision 4 above)	\$0	\$0	\$0	\$0	\$0-\$10	\$0-\$10
Budget impact of limiting refunds to \$100 million per company/per project per year (only shifts timing of refunds)	Confidential due to limited use - net neutral as impact shifted to later years					
The GVR cannot be used to create or increase a net operating loss (provision 6 above)	0	\$10-\$20	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10
Budget impact of exploration credit extension for well spudded by 7/1/16	(\$5)-\$0	(\$5)-\$0	\$0	\$0	\$0	\$0
Budget impact of GVR applying to fields for a period of 5 years (provision 7 above)	\$0	\$0	\$0	\$0	\$0	\$0
Total Budget Impact	(\$5)-\$0	\$20-\$55	\$45-\$75	\$40-\$70	\$60-\$105	\$55-\$100
Total Fiscal Impact - does not include revenue impacts from potential changes in investment²	\$5-\$30	\$90-\$165	\$115-\$185	\$115-\$185	\$170-\$285	\$215-\$360
Non-refundable carry-forward credits balance at fiscal year end - current law ³	\$618	\$751	\$732	\$585	\$265	\$136
Non-refundable carry-forward credits balance at fiscal year end - proposed ³	\$676	\$941	\$1,065	\$1,055	\$957	\$923
Change in year-end balance due to bill	\$58	\$190	\$333	\$470	\$692	\$787

¹The impacts listed are based on production and prices as forecasted in DOR's Spring 2016 revenue forecast. The forecasted oil prices are between \$38.89 and \$61.64. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts.

NOTE: The fiscal impact of this bill is an estimate based on the Spring 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB247-DOR-TAX-03-28-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: House Finance Committee

Department: Department of Revenue
Appropriation: Taxation and Treasury
Allocation: Tax Division
OMB Component Number: 2476

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017	Included in	Out-Year Cost Estimates				
	Appropriation Requested	Governor's FY2017 Request	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES	FY 2017	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits	(17,500.0)		(70,000.0)	(47,500.0)	(35,000.0)	(55,000.0)	(55,000.0)
Miscellaneous							
Total Operating	(17,500.0)	0.0	(70,000.0)	(47,500.0)	(35,000.0)	(55,000.0)	(55,000.0)

Fund Source (Operating Only)

1004 Gen Fund	(17,500.0)		(70,000.0)	(47,500.0)	(35,000.0)	(55,000.0)	(55,000.0)
Total	(17,500.0)	0.0	(70,000.0)	(47,500.0)	(35,000.0)	(55,000.0)	(55,000.0)

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues	***		***	***	***	***	***
---------------------------	-----	--	-----	-----	-----	-----	-----

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 (separate supplemental appropriation required)
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 1,200.0 (separate capital appropriation required)
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

Revised to conform to changes in the Resources Committee Substitute. Also revised to include as a new baseline scenario the Spring 2016 Preliminary Revenue Forecast. Analysis methodology has also changed, to include more "granular" modeling of each individual bill component.

Prepared By: Ken Alper, Director
Division: Tax Division
Approved By: Jerry Burnett, Deputy Commissioner
Agency: Department of Revenue

Phone: (907)465-8221
Date: 03/28/2016 04:00 PM
Date: 03/29/16

**Fiscal Detail of HB247 Resources Committee Substitute
(Revenue and Budget Impacts)**

Provisions in CSHB247(RES) and their Estimated Fiscal Impact as compared to Spring 2016 Forecast (\$millions) - FORECAST PRICE¹

Note regarding this table: this table attempts to value the impact of each of the items independently, except where noted. In some cases, the total value of several impacts will not equal the sum of the individual impact values.

Brief Description of Provision - Includes only provisions anticipated to have a direct fiscal impact	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
1. The GVR cannot be used to create or increase a net operating loss (REVENUE IMPACT)	\$0	\$0	\$0	\$0	\$0	\$5-\$15
2. The well lease expenditure credit is reduced from 40% to 30% on 1/1/17, to 20% on 1/1/18	\$0	\$0	\$0	\$0	\$0	\$5-\$15
3. For non-North Slope, the net operating loss credit is reduced from 25% to 10% of the carried-forward loss	\$0	\$0	\$0	\$0	\$0	\$0
4. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax						Indeterminate
5. The State may withhold payment of a credit refund to companies with an outstanding liability to the State						Indeterminate
6. The interest rate on delinquent taxes from simple interest to interest compounded quarterly						Indeterminate
Total Revenue Impact	\$0	\$0	\$0	\$0	\$0	\$10 to \$30
The GVR cannot be used to create or increase a net operating loss (BUDGET IMPACT)	\$5-\$10	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10	\$0-\$10
Budget impact of reduction of well lease expenditure credit (provision 3 above)	\$0-\$5	\$15-\$25	\$10-\$20	\$10-\$20	\$35-\$45	\$35-\$45
Budget impact of reduction in net operating loss credit for non-North Slope (provision 4 above)	\$5-\$10	\$20-\$30	\$10-\$15	\$5-\$15	\$5-\$15	\$5-\$15
Budget impact of limitation of cash refunds for credits to \$200 million per company per year	\$0	\$0	\$0	\$0	\$0	\$0
Total Budget Impact	\$10 to \$25	\$55 to \$85	\$35 to \$60	\$20 to \$50	\$40 to \$70	\$40 to \$70
Total Fiscal Impact (does not include revenue impacts from potential changes in investment)²	\$10 to \$25	\$55 to \$85	\$35 to \$60	\$20 to \$50	\$40 to \$70	\$50 to \$100
Non-refundable carry-forward credits balance at fiscal year end - current law ³	632	766	747	600	284	151
Non-refundable carry-forward credits balance at fiscal year end - proposed ³	627	746	708	548	269	146
Net change in carry-forward credits due to bill	-5	-15	-19	-13	37	10

¹The impacts listed are based on production and prices as forecasted in our Spring 2016 revenue forecast. The forecasted oil prices are between \$38.89 and \$61.64. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²NOTE: "Total Fiscal Impact" includes best estimates combining both revenue and operating budget impacts.

³These rows include estimates of carried-forward credits for previous calendar years, plus estimates of credits that will be earned on activity through June 30 of the fiscal year.

NOTE: The fiscal impact of this bill is an estimate based on the preliminary Spring 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

Analysis Continued

**Fiscal Detail of HB247 As Originally Proposed
(Revenue and Budget Impacts)**

Provisions in HB 247 and their Estimated Fiscal Impact as compared to preliminary Spring 2016 Forecast (\$millions) - FORECAST PRICE¹

Note regarding this table: this table attempts to value the impact of each of the items independently, except where noted. In some cases, the total value of several impacts will not equal the sum of the individual

Brief Description of Provision - Includes only provisions anticipated to have a direct fiscal impact	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
1a. Minimum tax cannot be reduced by net operating loss credit	\$100	\$150	\$170	\$185	\$190	\$150
1b. Minimum tax cannot be reduced by small producer credit	\$10	\$5	\$5	\$5	\$5	\$5
1c. Minimum tax cannot be reduced by per-taxable-barrel credits applicable to GVR-eligible production	\$15	\$25	\$40	\$40	\$20	\$20
1d. Minimum tax cannot be reduced by the alternative credit for exploration credit	\$0	\$0	\$0	\$0	\$0	\$0
2. Minimum tax change from multiple percentages to a flat 5% of GVPP combined with 1a-1d above	\$175	\$235	\$265	\$280	\$270	\$215
3. Qualified capital expenditure credits and well lease expenditure credits are repealed	\$10-\$15	\$10-\$15	\$10-\$15	\$10-\$15	\$10-\$15	\$30-\$40
4. No true-up of sliding scale per-taxable-barrel credits on annual return	No impact at forecast price - could benefit State under volatile prices					
5. The GVR cannot be used to create or increase a net operating loss (REVENUE IMPACT ONLY)	\$0	\$0	\$0	\$0	\$0	\$5-\$15
6. Credits expire 10 years after they are earned	\$0	\$0	\$0	\$0	\$0	\$0
7. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax	Indeterminate					
8. The gross value at the point of production cannot be less than zero	\$0	\$0	\$0	\$0	\$0	\$0
9. The interest rate on delinquent taxes is changed to 7% above the Fed Res Discount rate, compounded quart	Indeterminate					
Total Revenue Impact	\$185 to \$190	\$245 to \$250	\$275 to \$280	\$290 to \$295	\$280 to \$285	\$250 to \$270
The GVR cannot be used to create or increase a net operating loss (BUDGET IMPACT ONLY)	\$10-\$20	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10	\$0-\$10
Budget impact of repeal of qualified capital and well lease expenditure credits (provision 3 above)	\$35	\$65	\$45	\$50	\$85	\$90
Budget impact of limiting refunds to \$25 million per company per year (only shifts timing of refunds)	\$500	\$50	\$0	(\$100)	(\$10)	(\$10)
Budget impact of limiting refunds by the percentage of a company's Alaska resident hire	Indeterminate					
Budget impact of limiting refunds to companies with no outstanding liability to the State	Indeterminate					
Budget impact of limiting refunds to companies with annual gross revenues of <\$10 billion ²	\$40-\$60	\$40-\$60	\$40-\$60	\$20-\$40	\$20-\$40	\$20-\$40
Total Budget Impact	\$585 to \$615	\$175 to \$205	\$100 to \$130	\$-25 to \$5	\$95 to \$125	\$100 to \$130
Total Fiscal Impact - does not include revenue impacts from potential changes in investment³	\$770 to \$805	\$420 to \$455	\$375 to \$410	\$265 to \$300	\$375 to \$410	\$350 to \$400
Non-refundable carry-forward credits balance at fiscal year end - current law ⁴	632	766	747	600	284	151
Non-refundable carry-forward credits balance at fiscal year end - proposed ⁴	1225	1513	1585	1536	1490	1500
Net change in carry-forward credits due to bill	593	154	91	98	270	143

¹The impacts listed are based on production and prices as forecasted in DOR's preliminary Spring 2016 revenue forecast. The forecasted oil prices are between \$38.89 and \$61.64. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Estimates shown for this provision are incremental to the budget impact of limiting refunds to \$25 million per company per year. As a standalone provision, these estimates would be much higher, especially in the first year.

³NOTE: "Total Fiscal Impact" includes best estimates combining both revenue and operating budget impacts.

⁴These rows include estimates of carried-forward credits for previous calendar years, plus estimates of credits that will be earned on activity through June 30 of the fiscal year.

NOTE: The fiscal impact of this bill is an estimate based on the preliminary Spring 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. CS HB247(RES)II

Analysis Continued

Bill Background

This legislation is a comprehensive attempt to reform and reduce the cost of Alaska's current program of providing direct tax credit rebates and other advantages to oil and gas companies. Various credits have been added to statute since 2003, with state repurchase beginning in 2007. Through the end of FY 2016, about \$8 billion in tax credits will be received by companies. This includes both credits used against tax liability and credits repurchased by the state; it also includes activity on both the North Slope and other areas of the state.

A substantial number of companies rely on these credits to support and subsidize their Alaska operations. Currently, in many cases the state is paying 55%-65% of the cost of a project during the development phase, and up to 85% of exploration costs. These large numbers result from "stacking" multiple credits. With the transition towards a system based mostly on operating loss credits, and the repeal or reduction of the expenditure credits that are stacked with those loss credits, the state's contribution towards many projects will be reduced roughly by half.

There are several themes, or goals, of this legislation as originally introduced. These include:

- * Reduce the state's annual cash outlay
- * Protect Net Operating Loss credits especially for exploration activity
- * Limit repurchases to companies who need the support
- * Strengthen the minimum tax and prevent abuses to the system
- * Be more open and transparent
- * Honor and pay credits earned to date and through any transition period.

To address the final bullet point, above, this legislation envisions a fund capitalization appropriation to cover any tax credits earned through the effective date. As originally introduced, this would have covered the last of the credits that would have been paid in FY 2016 if not for the \$500 million limit established by the governor's line-item veto, all estimated credits that would be paid in FY 2017, and credits earned in the first part of calendar year 2016 before the effective date of the bill. The transition funds will total nearly \$1 billion. This appropriation was described in earlier versions of this fiscal note, but was not passed on from the prior committee.

Summary of Fiscal Impact

An earlier version of this fiscal note described DOR's estimate for this legislation as originally introduced. In order to provide an "apples to apples" comparison given the transition to the Spring revenue forecast, we have also re-modeled the governor's original bill using the new more detailed methodology.

With the revisions proposed in the committee substitute, we anticipate a fiscal impact of \$35-\$70 million per year over the time period contained in the fiscal note, with a smaller number in FY17 due to the mid-year effective date. Of this, nearly all will be saved through reduced operating budget expenditures. Only a small indeterminate amount would come from increased revenues, due to the restoration of compound interest for assessed delinquent taxes.

The savings occur because some tax credit certificates would be smaller or would no longer be earned due to the repeal and reduction of certain specific credits as well as the closing of certain loopholes.

Implementation Cost

The changes anticipated in this bill will require somewhat substantial reprogramming of the Tax Revenue Management System and Revenue Online tax portal. We have received a preliminary estimate from the software developer, which allows us to reduce our one-time cost to about \$1,200,000 to accomplish these changes. We do not anticipate any additional costs to administer the tax program.

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. CS HB247(RES)II

Analysis Continued

Detail of Specific Provisions

1) Repeal of certain credits and closing of loopholes

The committee substitute reduces the Well Lease Expenditure Credit (AS 43.55.023(l)) from 40% to 30% in 2017 and 20% in 2018. This credit, and the 20% Qualified Capital Expenditure Credit (AS 43.55.023(a)) are repealed in 2022 in anticipation of the sunset of the existing "Cook Inlet Tax Caps" and a new tax regime for Cook Inlet. Also in 2017, the Carried Forward Annual Loss (or "New Operating Loss," AS 43.55.023(b)) credit is reduced from 25% to 10% for areas outside the North Slope.

The net effect of these changes will be to reduce state contribution for new projects from the current 45-65% range to 30% beginning in 2018. Companies who do not have an operating loss will remain eligible to receive the Capital and Well credits. This would continue to provide cash support to potentially profitable companies who, due to existing tax caps, effectively pay no production taxes.

The bill also eliminates a loophole that enables companies who have production of "new oil" on the North Slope but also claim a net operating loss. With the changes, companies will no longer be able to use a Gross Value Reduction to increase the size of a net operating loss credit. Current law can result in situations where the credit received can be greater than 100% of a company's actual loss.

It also eliminates another loophole that has been used by municipal utilities who also own oil or gas production. If a portion of that production is sold to an outside party, the proposed change ensures that these entities are only able to deduct or claim a pro-rated portion of their lease expenditures for the purpose of applying for credits.

2) Deferral or loss of eligibility for credit repurchase

Currently any company with less than 50,000 bbl / day of production in Alaska is eligible to have tax credit certificates repurchased by the state without limit, subject to appropriation. This legislation adds an additional restriction to repurchase, so that no single company can receive more than \$200 million per year in state cash repurchases. Although this would not have any impact based on currently forecasted activity, it provides an element of protection from very large "outlier" projects that could otherwise result in multibillion dollar state credit liability in advance of production.

3) Other changes

Additionally, the bill restores quarterly compound interest for delinquent taxes, underpayments, and tax assessments. Current statute has included simple interest since 2014, which is believed to be an inadvertent amendment made in SB21.

The committee substitute also repeals several older and currently unused exploration incentive credit programs, and authorizes the Department of Revenue to use credit certificates to offset a company's other obligations to the state prior to repurchase. It also establishes a legislative working group to review the state's tax structure for Cook Inlet and other areas outside the North Slope, to provide recommendations to the legislature for consideration in 2017.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version:	CSHB 247(RES)
Fiscal Note Number:	4
(H) Publish Date:	3/23/2016

Identifier: CS HB 247(RES) 3-22-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: House Resources Committee

Department: Fund Capitalization
Appropriation: Fund Capitalization (no approps out)
Allocation: Oil and Gas Tax Credit Fund
OMB Component Number: 2894

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below.

(Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates				
			FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES	FY 2017	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Personal Services	***	***	***	***	***	***	***
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	***	***	***	***	***	***	***

Fund Source (Operating Only)

None								
Total	***	***	***	***	***	***	***	***

Positions

Full-time	***	***	***	***	***	***	***	***
Part-time	***	***	***	***	***	***	***	***
Temporary	***	***	***	***	***	***	***	***

Change in Revenues	***	***	***	***	***	***	***	***
---------------------------	------------	------------	------------	------------	------------	------------	------------	------------

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 (separate supplemental appropriation required)
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 (separate capital appropriation required)
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? Yes
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

The House Resources Committee deleted the \$926.6 appropriation and adopted an indeterminate fiscal note. The updated fiscal note is one page.

Prepared By: Representative Nageak
House Resources Committee
Representative Talerico
House Resources Committee
Phone: (907)465-3473
Date: 03/22/2016

29-GH2609\AF
Nauman/Shutts
3/23/16

CS FOR HOUSE BILL NO. 247(~~RES~~FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-NINTH LEGISLATURE - SECOND SESSION

BY THE HOUSE ~~RESOURCES~~FINANCE COMMITTEE

Offered:
Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to interest applicable to delinquent tax; relating to the oil and gas
2 production tax, tax payments, and credits; relating to the minimum oil and gas
3 production tax; repealing a maximum production tax on certain oil; relating to refunds
4 for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit,
5 and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to
6 the assessment of an oil and gas production tax imposed; relating to oil and gas lease
7 expenditures and production tax credits for municipal entities; relating to a business
8 license for an oil or gas business; establishing a legislative working group to study the
9 tax structure for oil and gas produced south of 68 degrees North latitude; and providing
10 for an effective date."

11 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

12 * Section 1. AS 38.05.036(a) is amended to read:

1 (a) The department may conduct audits regarding royalty and net profits under
2 oil and gas contracts, agreements, or leases under this chapter and regarding costs
3 related to exploration licenses entered into under AS 38.05.131 - 38.05.134 and
4 exploration incentive credits under this chapter [OR UNDER AS 41.09]. For purposes
5 of an audit under this section,

6 (1) the department may examine the books, papers, records, or
7 memoranda of a person regarding matters related to the audit; and

8 (2) the records and premises where a business is conducted shall be
9 open at all reasonable times for inspection by the department.

10 * **Sec. 2.** AS 38.05.036(b) is amended to read:

11 (b) The Department of Revenue may obtain from the department information
12 relating to royalty and net profits payments and to exploration incentive credits under
13 this chapter [OR UNDER AS 41.09], whether or not that information is confidential.
14 The Department of Revenue may use the information in carrying out its functions and
15 responsibilities under AS 43, and shall hold that information confidential to the extent
16 required by an agreement with the department or by AS 38.05.035(a)(8) [,
17 AS 41.09.010(d),] or AS 43.05.230.

18 * **Sec. 3.** AS 38.05.036(c) is amended to read:

19 (c) The department may obtain from the Department of Revenue all
20 information obtained under AS 43 relating to royalty and net profits and to exploration
21 incentive credits. The department may use the information for purposes of carrying out
22 its responsibilities and functions under this chapter [AND AS 41.09]. Information
23 made available to the department that was obtained under AS 43 is confidential and
24 subject to the provisions of AS 43.05.230.

25 * **Sec. 4.** AS 38.05.036(f) is amended to read:

26 (f) Except as otherwise provided in this section or in connection with official
27 investigations or proceedings of the department, it is unlawful for a current or former
28 officer, employee, or agent of the state to divulge information obtained by the
29 department as a result of an audit under this section that is required by an agreement
30 with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)] to be kept
31 confidential.

1 * **Sec. 5.** AS 38.05.036(g) is amended to read:

2 (g) Nothing in this section prohibits the publication of statistics in a manner
3 that maintains the confidentiality of information to the extent required by an
4 agreement with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)].

5 * **Sec. 6.** AS 43.05.225 is amended to read:

6 **Sec. 43.05.225. Interest.** Unless otherwise provided,

7 (1) a delinquent tax under this title,

8 (A) before January 1, 2014, bears interest in each calendar
9 quarter at the rate of five percentage points above the annual rate charged
10 member banks for advances by the 12th Federal Reserve District as of the first
11 day of that calendar quarter, or at the annual rate of 11 percent, whichever is
12 greater, compounded quarterly as of the last day of that quarter; [OR]

13 (B) on and after January 1, 2014, and before January 1, 2017,
14 bears interest in each calendar quarter at the rate of three percentage points
15 above the annual rate charged member banks for advances by the 12th Federal
16 Reserve District as of the first day of that calendar quarter;

17 (C) on and after January 1, 2017, bears interest

18 (i) for the first four years after a tax becomes
19 delinquent, in each calendar quarter at the rate of ~~three~~five
20 percentage points above the annual rate charged member banks
21 for advances by the 12th Federal Reserve District as of the first day
22 of that calendar quarter, compounded quarterly as of the last day
23 of that quarter; and

24 (ii) after the first four years after a tax becomes
25 delinquent, in each calendar quarter at a rate of five percentage
26 points above the annual rate charged member banks for advances
27 by the 12th Federal Reserve District as of the first day of that
28 calendar quarter;

29 (2) the interest rate is 12 percent a year for

30 (A) delinquent fees payable under AS 05.15.095(c); and

31 (B) unclaimed property that is not timely paid or delivered, as

1 allowed by AS 34.45.470(a).

2 * **Sec. 7.** AS 43.20.046(e) is amended to read:

3 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
4 may use available money in the oil and gas tax credit fund established in AS 43.55.028
5 to make the refund applied for under (d) of this section in whole or in part if the
6 department finds that, [(1) THE CLAIMANT DOES NOT HAVE AN
7 OUTSTANDING LIABILITY TO THE STATE FOR UNPAID DELINQUENT
8 TAXES UNDER THIS TITLE; AND (2)] after application of all available tax credits,
9 the claimant's total tax liability under this chapter for the calendar year in which the
10 claim is made is zero. [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX"
11 MEANS AN AMOUNT OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED
12 AN ASSESSMENT THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS
13 NOT BEEN FINALLY RESOLVED IN THE TAXPAYER'S FAVOR.]

14 * **Sec. 8.** AS 43.20.047(e) is amended to read:

15 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
16 may use money available in the oil and gas tax credit fund established in AS 43.55.028
17 to make a refund or payment under (d) of this section in whole or in part if the
18 department finds that, [(1) THE CLAIMANT DOES NOT HAVE AN
19 OUTSTANDING LIABILITY TO THE STATE FOR UNPAID DELINQUENT
20 TAXES UNDER THIS TITLE; AND (2)] after application of all available tax credits,
21 the claimant's total tax liability under this chapter for the calendar year in which the
22 claim is made is zero. [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX"
23 MEANS AN AMOUNT OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED
24 AN ASSESSMENT THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS
25 NOT BEEN FINALLY RESOLVED IN THE TAXPAYER'S FAVOR.]

26 * **Sec. 9.** AS 43.20.053(e) is amended to read:

27 (e) **Subject to the requirements in AS 43.55.028(j), the** [THE] department
28 may use money available in the oil and gas tax credit fund established in AS 43.55.028
29 to make a refund or payment under (d) of this section in whole or in part if the
30 department finds that,

31 [(1) THE CLAIMANT DOES NOT HAVE AN OUTSTANDING

1 LIABILITY TO THE STATE FOR UNPAID DELINQUENT TAXES UNDER THIS
2 TITLE; AND

3 (2)] after application of all available tax credits, the claimant's total tax
4 liability under this chapter for the calendar year in which the claim is made is zero.

5 * **Sec. 10.** AS 43.55.011(~~me~~) is amended to read:

6 (e) There is levied on the producer of oil or gas a tax for all oil and gas
7 produced each calendar year from each lease or property in the state, less any oil and
8 gas the ownership or right to which is exempt from taxation or constitutes a
9 landowner's royalty interest or for which a tax is levied by AS 43.55.014. Except as
10 otherwise provided under (f), (j), [(k),] (o), and (p) of this section, for oil and gas
11 produced

12 (1) before January 1, 2014, the tax is equal to the sum of

13 (A) the annual production tax value of the taxable oil and gas
14 as calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

15 (B) the sum, over all months of the calendar year, of the tax
16 amounts determined under (g) of this section;

17 (2) on and after January 1, 2014, and before January 1, 2022, the tax is
18 equal to the annual production tax value of the taxable oil and gas as calculated under
19 AS 43.55.160(a)(1) multiplied by 35 percent;

20 (3) on and after January 1, 2022, the tax for

21 (A) oil is equal to the annual production tax value of the
22 taxable oil as calculated under AS 43.55.160(h) multiplied by 35 percent;

23 (B) gas is equal to 13 percent of the gross value at the point of
24 production of the taxable gas; if the gross value at the point of production of
25 gas produced from a lease or property is less than zero, that gross value at the
26 point of production is considered zero for purposes of this subparagraph.

27 * **Sec. 11.** AS 43.55.011(f) is amended to read:

28 (f) The levy of tax under (e) of this section for

29 (1) oil and gas produced before **January 1, 2017** [JANUARY 1,
30 2022], from leases or properties that include land north of 68 degrees North latitude,
31 other than gas subject to (o) of this section, may not be less than

1 (A) four percent of the gross value at the point of production
2 when the average price per barrel for Alaska North Slope crude oil for sale on
3 the United States West Coast during the calendar year for which the tax is due
4 is more than \$25;

5 (B) three percent of the gross value at the point of production
6 when the average price per barrel for Alaska North Slope crude oil for sale on
7 the United States West Coast during the calendar year for which the tax is due
8 is over \$20 but not over \$25;

9 (C) two percent of the gross value at the point of production
10 when the average price per barrel for Alaska North Slope crude oil for sale on
11 the United States West Coast during the calendar year for which the tax is due
12 is over \$17.50 but not over \$20;

13 (D) one percent of the gross value at the point of production
14 when the average price per barrel for Alaska North Slope crude oil for sale on
15 the United States West Coast during the calendar year for which the tax is due
16 is over \$15 but not over \$17.50; or

17 (E) zero percent of the gross value at the point of production
18 when the average price per barrel for Alaska North Slope crude oil for sale on
19 the United States West Coast during the calendar year for which the tax is due
20 is \$15 or less; [AND]

21 (2) oil and gas produced on and after January 1, 2017, and before
22 January 1, 2022, from leases or properties that include land north of 68 degrees North
23 latitude, other than gas subject to (o) of this section, may not be less than [(A)] four
24 percent of the gross value at the point of production, except that a credit authorized
25 under this chapter may reduce the tax under this subsection to less than four
26 percent, but not to less than two percent of the gross value at the point of
27 production;

28 (3) oil produced on and after January 1, 2022, from leases or
29 properties that include land north of 68 degrees North latitude may not be less
30 than four percent of the gross value at the point of production, except that a
31 credit authorized under this chapter may reduce the tax under this subsection to

1 less than four percent, but not to less than two percent of the gross value at the
 2 point of production [WHEN THE AVERAGE PRICE PER BARREL FOR
 3 ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED STATES
 4 WEST COAST DURING THE CALENDAR YEAR FOR WHICH THE TAX IS
 5 DUE IS MORE THAN \$25;

6 (B) THREE PERCENT OF THE GROSS VALUE AT THE
 7 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
 8 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
 9 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
 10 THE TAX IS DUE IS OVER \$20 BUT NOT OVER \$25;

11 (C) TWO PERCENT OF THE GROSS VALUE AT THE
 12 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
 13 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
 14 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
 15 THE TAX IS DUE IS OVER \$17.50 BUT NOT OVER \$20;

16 (D) ONE PERCENT OF THE GROSS VALUE AT THE
 17 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
 18 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
 19 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
 20 THE TAX IS DUE IS OVER \$15 BUT NOT OVER \$17.50; OR

21 (E) ZERO PERCENT OF THE GROSS VALUE AT THE
 22 POINT OF PRODUCTION WHEN THE AVERAGE PRICE PER BARREL
 23 FOR ALASKA NORTH SLOPE CRUDE OIL FOR SALE ON THE UNITED
 24 STATES WEST COAST DURING THE CALENDAR YEAR FOR WHICH
 25 THE TAX IS DUE IS \$15 OR LESS].

26 * Sec. 12. AS 43.55.011(m) is amended to read:

27 (m) Notwithstanding any contrary provision of [AS 38.05.180(i),
 28 AS 41.09.010,] AS 43.55.024 [,] or 43.55.025, the department shall provide by
 29 regulation a method to ensure that, for a calendar year for which a producer's tax
 30 liability is limited by ~~(j);~~ [,] ~~(k);~~ [,] or (o) of this section, tax credits based on a lease
 31 expenditure incurred before January 1, 2011, that are otherwise available under

1 [AS 38.05.180(i), AS 41.09.010,] AS 43.55.024 [,] or 43.55.025 and allocated to gas
2 subject to the limitations in ~~(j);~~ [,] ~~(k);~~ [,] and (o) of this section are accounted for as
3 though the credits had been applied first against a tax liability calculated without
4 regard to the limitations under ~~(j);~~ [,] ~~(k);~~ [,] and (o) of this section so as to reduce the
5 tax liability to the maximum amount provided for under (j) or (o) of this section for
6 the production of gas ~~or (k) of this section for the production of oil.~~ [OR (k) OF THIS
7 SECTION FOR THE PRODUCTION OF OIL]. The regulation must provide for a
8 reasonable method to allocate tax credits to gas subject to (j) and (o) of this section.
9 Only the amount of a tax credit remaining after the accounting provided for under this
10 subsection may be used for a later calendar year, transferred to another person, or
11 applied against a tax levied on the production of oil or gas not subject to ~~(j);~~ [,] ~~(k);~~ [,]
12 or (o) of this section to the extent otherwise allowed.

13 * **Sec. ~~13~~ 13.** AS 43.55.019(e) is amended to read:

14 (e) The credit under this section may not reduce a person's tax liability for the
15 calendar year under AS 43.55.011(e) to below the amount calculated under
16 AS 43.55.011(f) [ZERO FOR ANY TAX YEAR]. An unused credit or portion of a
17 credit not used under this section for a tax year may not be sold, traded, transferred, or
18 applied in a subsequent tax year.

19 * **Sec. 14.** AS 43.55.020(a) is amended to read:

20 (a) For a calendar year, a producer subject to tax under AS 43.55.011 shall pay
21 the tax as follows:

22 (1) for oil and gas produced before January 1, 2014, an installment
23 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
24 as allowed by law, is due for each month of the calendar year on the last day of the
25 following month; except as otherwise provided under (2) of this subsection, the
26 amount of the installment payment is the sum of the following amounts, less 1/12 of
27 the tax credits that are allowed by law to be applied against the tax levied by
28 AS 43.55.011(e) for the calendar year, but the amount of the installment payment may
29 not be less than zero:

30 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
31 produced from leases or properties in the state outside the Cook Inlet

1 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),
2 the greater of

3 (i) zero; or

4 (ii) the sum of 25 percent and the tax rate calculated for
5 the month under AS 43.55.011(g) multiplied by the remainder obtained
6 by subtracting 1/12 of the producer's adjusted lease expenditures for the
7 calendar year of production under AS 43.55.165 and 43.55.170 that are
8 deductible for the oil and gas under AS 43.55.160 from the gross value
9 at the point of production of the oil and gas produced from the leases or
10 properties during the month for which the installment payment is
11 calculated;

12 (B) for oil and gas produced from leases or properties subject
13 to AS 43.55.011(f), the greatest of

14 (i) zero;

15 (ii) zero percent, one percent, two percent, three
16 percent, or four percent, as applicable, of the gross value at the point of
17 production of the oil and gas produced from the leases or properties
18 during the month for which the installment payment is calculated; or

19 (iii) the sum of 25 percent and the tax rate calculated for
20 the month under AS 43.55.011(g) multiplied by the remainder obtained
21 by subtracting 1/12 of the producer's adjusted lease expenditures for the
22 calendar year of production under AS 43.55.165 and 43.55.170 that are
23 deductible for the oil and gas under AS 43.55.160 from the gross value
24 at the point of production of the oil and gas produced from those leases
25 or properties during the month for which the installment payment is
26 calculated;

27 (C) for [OIL OR] gas subject to AS 43.55.011(j) [, (k),] or (o),
28 for each lease or property, the greater of

29 (i) zero; or

30 (ii) the sum of 25 percent and the tax rate calculated for
31 the month under AS 43.55.011(g) multiplied by the remainder obtained

1 by subtracting 1/12 of the producer's adjusted lease expenditures for the
2 calendar year of production under AS 43.55.165 and 43.55.170 that are
3 deductible under AS 43.55.160 for the oil or gas, respectively,
4 produced from the lease or property from the gross value at the point of
5 production of the oil or gas, respectively, produced from the lease or
6 property during the month for which the installment payment is
7 calculated;

8 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

9 (i) the sum of 25 percent and the tax rate calculated for
10 the month under AS 43.55.011(g) multiplied by the remainder obtained
11 by subtracting 1/12 of the producer's adjusted lease expenditures for the
12 calendar year of production under AS 43.55.165 and 43.55.170 that are
13 deductible for the oil and gas under AS 43.55.160 from the gross value
14 at the point of production of the oil and gas produced from the leases or
15 properties during the month for which the installment payment is
16 calculated, but not less than zero; or

17 (ii) four percent of the gross value at the point of
18 production of the oil and gas produced from the leases or properties
19 during the month, but not less than zero;

20 (2) an amount calculated under (1)(C) of this subsection for [OIL OR]
21 gas subject to AS 43.55.011(j) [, (k),] or (o) may not exceed the product obtained by
22 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
23 applicable, for gas [OR SET OUT IN AS 43.55.011(k)(1) OR (2), AS APPLICABLE,
24 FOR OIL,] but substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as
25 applicable, the amount of taxable gas produced during the month for the amount of
26 taxable gas produced during the calendar year [AND SUBSTITUTING IN
27 AS 43.55.011(k)(1)(A) OR (2)(A), AS APPLICABLE, THE AMOUNT OF
28 TAXABLE OIL PRODUCED DURING THE MONTH FOR THE AMOUNT OF
29 TAXABLE OIL PRODUCED DURING THE CALENDAR YEAR];

30 (3) an installment payment of the estimated tax levied by
31 AS 43.55.011(i) for each lease or property is due for each month of the calendar year

1 on the last day of the following month; the amount of the installment payment is the
2 sum of

3 (A) the applicable tax rate for oil provided under
4 AS 43.55.011(i), multiplied by the gross value at the point of production of the
5 oil taxable under AS 43.55.011(i) and produced from the lease or property
6 during the month; and

7 (B) the applicable tax rate for gas provided under
8 AS 43.55.011(i), multiplied by the gross value at the point of production of the
9 gas taxable under AS 43.55.011(i) and produced from the lease or property
10 during the month;

11 (4) any amount of tax levied by AS 43.55.011, net of any credits
12 applied as allowed by law, that exceeds the total of the amounts due as installment
13 payments of estimated tax is due on March 31 of the year following the calendar year
14 of production;

15 (5) for oil and gas produced on and after January 1, 2014, and before
16 January 1, 2022, an installment payment of the estimated tax levied by
17 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
18 month of the calendar year on the last day of the following month; except as otherwise
19 provided under (6) and (10) of this subsection, the amount of the installment payment
20 is the sum of the following amounts, less 1/12 of the tax credits that are allowed by
21 law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but
22 the amount of the installment payment may not be less than zero:

23 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
24 produced from leases or properties in the state outside the Cook Inlet
25 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),
26 the greater of

27 (i) zero; or

28 (ii) 35 percent multiplied by the remainder obtained by
29 subtracting 1/12 of the producer's adjusted lease expenditures for the
30 calendar year of production under AS 43.55.165 and 43.55.170 that are
31 deductible for the oil and gas under AS 43.55.160 from the gross value

1 at the point of production of the oil and gas produced from the leases or
2 properties during the month for which the installment payment is
3 calculated;

4 (B) for oil and gas produced from leases or properties subject
5 to AS 43.55.011(f), the greatest of

6 (i) zero;

7 (ii) zero percent, one percent, two percent, three
8 percent, or four percent, as applicable, of the gross value at the point of
9 production of the oil and gas produced from the leases or properties
10 during the month for which the installment payment is calculated; or

11 (iii) 35 percent multiplied by the remainder obtained by
12 subtracting 1/12 of the producer's adjusted lease expenditures for the
13 calendar year of production under AS 43.55.165 and 43.55.170 that are
14 deductible for the oil and gas under AS 43.55.160 from the gross value
15 at the point of production of the oil and gas produced from those leases
16 or properties during the month for which the installment payment is
17 calculated, except that, for the purposes of this calculation, a reduction
18 from the gross value at the point of production may apply for oil and
19 gas subject to AS 43.55.160(f) or (g);

20 (C) for [OIL OR] gas subject to AS 43.55.011(j) [, (k),] or (o),
21 for each lease or property, the greater of

22 (i) zero; or

23 (ii) 35 percent multiplied by the remainder obtained by
24 subtracting 1/12 of the producer's adjusted lease expenditures for the
25 calendar year of production under AS 43.55.165 and 43.55.170 that are
26 deductible under AS 43.55.160 for the [OIL OR] gas [,
27 RESPECTIVELY,] produced from the lease or property from the gross
28 value at the point of production of the [OIL OR] gas [,
29 RESPECTIVELY,] produced from the lease or property during the
30 month for which the installment payment is calculated;

31 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

1 (i) 35 percent multiplied by the remainder obtained by
2 subtracting 1/12 of the producer's adjusted lease expenditures for the
3 calendar year of production under AS 43.55.165 and 43.55.170 that are
4 deductible for the oil and gas under AS 43.55.160 from the gross value
5 at the point of production of the oil and gas produced from the leases or
6 properties during the month for which the installment payment is
7 calculated, but not less than zero; or

8 (ii) four percent of the gross value at the point of
9 production of the oil and gas produced from the leases or properties
10 during the month, but not less than zero;

11 (6) an amount calculated under (5)(C) of this subsection for [OIL OR
12 gas subject to AS 43.55.011(j) [, (k),] or (o) may not exceed the product obtained by
13 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
14 applicable, for gas [OR SET OUT IN AS 43.55.011(k)(1) OR (2), AS APPLICABLE,
15 FOR OIL,] but substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as
16 applicable, the amount of taxable gas produced during the month for the amount of
17 taxable gas produced during the calendar year [AND SUBSTITUTING IN
18 AS 43.55.011(k)(1)(A) OR (2)(A), AS APPLICABLE, THE AMOUNT OF
19 TAXABLE OIL PRODUCED DURING THE MONTH FOR THE AMOUNT OF
20 TAXABLE OIL PRODUCED DURING THE CALENDAR YEAR];

21 (7) for oil and gas produced on or after January 1, 2022, an installment
22 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
23 as allowed by law, is due for each month of the calendar year on the last day of the
24 following month; **except as provided in (10) of this subsection,** the amount of the
25 installment payment is the sum of the following amounts, less 1/12 of the tax credits
26 that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the
27 calendar year, but the amount of the installment payment may not be less than zero;

28 (A) for oil produced from leases or properties that include land
29 north of 68 degrees North latitude, the greatest of

30 (i) zero;

31 (ii) zero percent, one percent, two percent, three

1 percent, or four percent, as applicable, of the gross value at the point of
2 production of the oil produced from the leases or properties during the
3 month for which the installment payment is calculated; or

4 (iii) 35 percent multiplied by the remainder obtained by
5 subtracting 1/12 of the producer's adjusted lease expenditures for the
6 calendar year of production under AS 43.55.165 and 43.55.170 that are
7 deductible for the oil under AS 43.55.160(h)(1) from the gross value at
8 the point of production of the oil produced from those leases or
9 properties during the month for which the installment payment is
10 calculated, except that, for the purposes of this calculation, a reduction
11 from the gross value at the point of production may apply for oil
12 subject to AS 43.55.160(f) or 43.55.160(f) and (g);

13 (B) for oil produced before or during the last calendar year
14 under AS 43.55.024(b) for which the producer could take a tax credit under
15 AS 43.55.024(a), from leases or properties in the state outside the Cook Inlet
16 sedimentary basin, no part of which is north of 68 degrees North latitude, other
17 than leases or properties subject to AS 43.55.011(p), the greater of

18 (i) zero; or

19 (ii) 35 percent multiplied by the remainder obtained by
20 subtracting 1/12 of the producer's adjusted lease expenditures for the
21 calendar year of production under AS 43.55.165 and 43.55.170 that are
22 deductible for the oil under AS 43.55.160(h)(2) from the gross value at
23 the point of production of the oil produced from the leases or properties
24 during the month for which the installment payment is calculated;

25 (C) for oil and gas produced from leases or properties subject
26 to AS 43.55.011(p), except as otherwise provided under (8) of this subsection,
27 the sum of

28 (i) 35 percent multiplied by the remainder obtained by
29 subtracting 1/12 of the producer's adjusted lease expenditures for the
30 calendar year of production under AS 43.55.165 and 43.55.170 that are
31 deductible for the oil under AS 43.55.160(h)(3) from the gross value at

1 the point of production of the oil produced from the leases or properties
2 during the month for which the installment payment is calculated, but
3 not less than zero; and

4 (ii) 13 percent of the gross value at the point of
5 production of the gas produced from the leases or properties during the
6 month, but not less than zero;

7 (D) for oil produced from leases or properties in the state, no
8 part of which is north of 68 degrees North latitude, other than leases or
9 properties subject to (B) or (C) of this paragraph, the greater of

10 (i) zero; or

11 (ii) 35 percent multiplied by the remainder obtained by
12 subtracting 1/12 of the producer's adjusted lease expenditures for the
13 calendar year of production under AS 43.55.165 and 43.55.170 that are
14 deductible for the oil under AS 43.55.160(h)(4) from the gross value at
15 the point of production of the oil produced from the leases or properties
16 during the month for which the installment payment is calculated;

17 (E) for gas produced from each lease or property in the state,
18 other than a lease or property subject to AS 43.55.011(p), 13 percent of the
19 gross value at the point of production of the gas produced from the lease or
20 property during the month for which the installment payment is calculated, but
21 not less than zero;

22 (8) an amount calculated under (7)(C) of this subsection may not
23 exceed four percent of the gross value at the point of production of the oil and gas
24 produced from leases or properties subject to AS 43.55.011(p) during the month for
25 which the installment payment is calculated;

26 (9) for purposes of the calculation under (1)(B)(ii), (5)(B)(ii), and
27 (7)(A)(ii) of this subsection, the applicable percentage of the gross value at the point
28 of production is determined under AS 43.55.011(f) [AS 43.55.011(f)(1) OR (2)] but
29 substituting the phrase "month for which the installment payment is calculated" in
30 [AS 43.55.011(f)(1) AND (2)] for the phrase "calendar year for which the tax is due";

31 (10) after December 31, 2016, for the purposes of a calculation

1 under (5)(B)(ii) or (7)(A)(ii) of this subsection, a credit under this chapter may
2 not be applied to reduce an installment payment to less than the applicable
3 percentage under AS 43.55.011(f). ["

4 * Sec. 15. AS 43.55.023(a) is amended to read:

5 (a) A producer or explorer may take a tax credit for a qualified capital
6 expenditure as follows:

7 (1) notwithstanding that a qualified capital expenditure may be a
8 deductible lease expenditure for purposes of calculating the production tax value of oil
9 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
10 [AS 38.05.180(i), AS 41.09.010,] AS 43.20.043 [,] or AS 43.55.025, a producer or
11 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
12 against a tax levied by AS 43.55.011(e) in the amount of 10 [20] percent of that
13 expenditure;

14 (2) a producer or explorer may take a credit for a qualified capital
15 expenditure incurred in connection with geological or geophysical exploration or in
16 connection with an exploration well only if the producer or explorer

17 (A) agrees, in writing, to the applicable provisions of
18 AS 43.55.025(f)(2); and

19 (B) submits to the Department of Natural Resources all data
20 that would be required to be submitted under AS 43.55.025(f)(2);

21 (3) a credit for a qualified capital expenditure incurred to explore for,
22 develop, or produce oil or gas deposits located north of 68 degrees North latitude may
23 be taken only if the expenditure is incurred before January 1, 2014.

24 * Sec. ~~12~~16. AS 43.55.023(b) is amended to read:

25 (b) Before January 1, 2014, a producer or explorer may elect to take a tax
26 credit in the amount of 25 percent of a carried-forward annual loss. For lease
27 expenditures incurred on and after January 1, 2014, and before January 1, 2016, to
28 explore for, develop, or produce oil or gas deposits located north of 68 degrees North
29 latitude, a producer or explorer may elect to take a tax credit in the amount of 45
30 percent of a carried-forward annual loss. For lease expenditures incurred on and after
31 January 1, 2016, to explore for, develop, or produce oil or gas deposits located north

1 of 68 degrees North latitude, a producer or explorer may elect to take a tax credit in
2 the amount of 35 percent of a carried-forward annual loss. For lease expenditures
3 incurred on or after January 1, 2014, **and before January 1, 2017**, to explore for,
4 develop, or produce oil or gas deposits located south of 68 degrees North latitude, a
5 producer or explorer may elect to take a tax credit in the amount of 25 percent of a
6 carried-forward annual loss. ~~For lease expenditures incurred on or after January 1,~~
7 ~~2017~~December 31, 2016, to explore for, develop, or produce oil or gas deposits
8 located south of 68 degrees North latitude and outside of the Cook Inlet
9 sedimentary basin, a producer or explorer may elect to take a tax credit in the
10 amount of 25 percent of a carried-forward annual loss. For lease expenditures
11 incurred after December 31, 2016, to explore for, develop, or produce oil or gas
12 deposits located in the Cook Inlet sedimentary basin, a producer or explorer may
13 elect to take a credit in the amount of 10 percent of a carried-forward annual
14 loss, if the producer or explorer had, before January 1, 2017, taken a credit
15 under this subsection for an expenditure incurred in the Cook Inlet sedimentary
16 basin. A credit under this subsection may be applied against a tax levied by
17 AS 43.55.011(e). For purposes of this subsection,

18 (1) a carried-forward annual loss is the amount of a producer's or
19 explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a
20 previous calendar year that was not deductible in calculating production tax values for
21 that calendar year under AS 43.55.160;

22 (2) for lease expenditures incurred on or after January 1, 2017,
23 any reduction under AS 43.55.160(f) or (g) is added back to the calculation of
24 production tax values for that calendar year under AS 43.55.160 for the
25 determination of a carried-forward annual loss.

26 * ~~Sec. 13~~17. AS 43.55.023(c) is amended to read:

27 (c) A credit or portion of a credit under this section may not be used to reduce
28 a person's tax liability under AS 43.55.011(e) for any calendar year below the amount
29 calculated under AS 43.55.011(f) [ZERO], and any unused credit or portion of a
30 credit not used under this subsection may be applied in a later calendar year.

31 * Sec. 18. AS 43.55.023(d) is amended to read:

1 (d) A person that is entitled to take a tax credit under this section that wishes
2 to transfer the unused credit to another person or obtain a cash payment under
3 AS 43.55.028 may apply to the department for a transferable tax credit certificate. An
4 application under this subsection must be in a form prescribed by the department and
5 must include supporting information and documentation that the department
6 reasonably requires. The department shall grant or deny an application, or grant an
7 application as to a lesser amount than that claimed and deny it as to the excess, not
8 later than 120 days after the latest of (1) March 31 of the year following the calendar
9 year in which the [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward
10 annual loss for which the credit is claimed was incurred; (2) the date the statement
11 required under AS 43.55.030(a) or (e) was filed for the calendar year in which the
12 [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward annual loss for which
13 the credit is claimed was incurred; or (3) the date the application was received by the
14 department. If, based on the information then available to it, the department is
15 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
16 the applicant a transferable tax credit certificate for the amount of the credit. A
17 certificate issued under this subsection does not expire.

18 * **Sec. 1419.** AS 43.55.023(e) is amended to read:

19 (e) A person to which a transferable tax credit certificate is issued under (d) of
20 this section may transfer the certificate to another person, and a transferee may further
21 transfer the certificate. Subject to the limitations set out in **former (a) of this section**
22 **and (b) - (d)** [(a) - (d)] of this section, and notwithstanding any action the department
23 may take with respect to the applicant under (g) of this section, the owner of a
24 certificate may apply the credit or a portion of the credit shown on the certificate only
25 against a tax levied by AS 43.55.011(e). However, a credit shown on a transferable tax
26 credit certificate may not be applied to reduce a transferee's total tax liability under
27 AS 43.55.011(e) for oil and gas produced during a calendar year to less than 80
28 percent of the tax that would otherwise be due without applying that credit. Any
29 portion of a credit not used under this subsection may be applied in a later period.

30 * **Sec. 1520.** AS 43.55.023(l) is amended to read:

31 (l) A producer or explorer may apply for a tax credit for a well lease

1 expenditure incurred in the state ~~south of 68 degrees North latitude~~[SOUTH OF 68
2 DEGREES NORTH LATITUDE] after June 30, 2010, as follows:

3 (1) notwithstanding that a well lease expenditure incurred in the state
4 ~~south of 68 degrees North latitude~~[SOUTH OF 68 DEGREES NORTH LATITUDE]
5 may be a deductible lease expenditure for purposes of calculating the production tax
6 value of oil and gas under AS 43.55.160(a), unless a credit for that expenditure is
7 taken under (a) of this section, [AS 38.05.180(i), AS 41.09.010,] AS 43.20.043, or
8 AS 43.55.025, a producer or explorer that incurs a well lease expenditure in the state
9 ~~south of~~[SOUTH OF 68 degrees North latitudeDEGREES NORTH LATITUDE] may
10 elect to apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of

11 (A) 40 percent of that expenditure incurred south of 68
12 degrees North latitude before January 1, 2017;

13 (B) 30 percent of that expenditure incurred ~~on or~~south of
14 68 degrees North latitude after ~~January 1, 2017~~December 31, 2016, and
15 before January 1, 2018;

16 (C) 20 percent of that expenditure incurred ~~on or~~inside the
17 Cook Inlet sedimentary basin after ~~January 1, 2018~~December 31, 2017;

18 (D) 30 percent of that expenditure incurred outside the
19 Cook Inlet sedimentary basin and south of 68 degrees North latitude after
20 December 31, 2017, and before January 1, 2019 [; A TAX CREDIT
21 UNDER THIS PARAGRAPH MAY BE APPLIED FOR A SINGLE
22 CALENDAR YEAR];

23 (2) a producer or explorer may take a credit for a well lease
24 expenditure incurred in the state south of 68 degrees North latitude in connection with
25 geological or geophysical exploration or in connection with an exploration well only if
26 the producer or explorer

27 (A) agrees, in writing, to the applicable provisions of
28 AS 43.55.025(f)(2); and

29 (B) submits to the Department of Natural Resources all data
30 that would be required to be submitted under AS 43.55.025(f)(2).

31 * **Sec. 1621.** AS 43.55.024(f) is amended to read:

1 (f) A tax credit authorized by (a) of this section may not be applied to reduce a
2 producer's tax liability for any calendar year under AS 43.55.011(e) on oil and gas
3 produced from leases or properties outside the Cook Inlet sedimentary basin, no part
4 of which is north of 68 degrees North latitude, below **the amount calculated under**
5 **AS 43.55.011(f) [ZERO].**

6 * Sec. 22. AS 43.55.024(g) is amended to read:

7 (g) A tax credit authorized by (c) of this section may not be applied to reduce
8 a producer's tax liability for any calendar year under AS 43.55.011(e) below **the**
9 **amount calculated under AS 43.55.011(f) [ZERO].**

10 * Sec. 23. AS 43.55.024(i) is amended to read:

11 (i) A producer may apply against the producer's tax liability for the calendar
12 year under AS 43.55.011(e) a tax credit of \$5 for each barrel of oil taxable under
13 AS 43.55.011(e) that meets one or more of the criteria in AS 43.55.160(f) or (g) and
14 that is produced during a calendar year after December 31, 2013. A tax credit
15 authorized by this subsection may not reduce a producer's tax liability for a calendar
16 year under AS 43.55.011(e) below **the amount calculated under AS 43.55.011(f)**
17 **[ZERO].**

18 * Sec. 24. AS 43.55.025(m) is amended to read:

19 (m) The persons that drill the first four exploration wells in the state and
20 within the areas described in (o) of this section on state lands, private lands, or federal
21 onshore lands for the purpose of discovering oil or gas that penetrate and evaluate a
22 prospect in a basin described in (o) of this section are eligible for a credit under (a)(6)
23 of this section. A credit under this subsection may not be taken for more than two
24 exploration wells in a single area described in (o)(1) - (6) of this section. Exploration
25 expenditures eligible for the credit in this subsection must be incurred for work
26 performed after June 1, 2012, and before July 1, 2016, **except that expenditures to**
27 **complete an exploration well that was spudded but not completed before July 1,**
28 **2016, are eligible for the credit under this subsection.** A person planning to drill an
29 exploration well on private land and to apply for a credit under this subsection shall
30 obtain written consent from the owner of the oil and gas interest for the full public
31 release of all well data after the expiration of the confidentiality period applicable to

1 information collected under (f) of this section. The written consent of the owner of the
2 oil and gas interest must be submitted to the commissioner of natural resources before
3 approval of the proposed exploration well. In addition to the requirements in (c)(1),
4 (c)(2)(A), and (c)(2)(C) of this section and submission of the written consent of the
5 owner of the oil and gas interest, a person planning to drill an exploration well shall
6 obtain approval from the commissioner of natural resources before the well is
7 spudded. The commissioner of natural resources shall make a written determination
8 approving or rejecting an exploration well within 60 days after receiving the request
9 for approval or as soon as is practicable thereafter. Before approving the exploration
10 well, the commissioner of natural resources shall consider the following: the location
11 of the well; the proximity to a community in need of a local energy source; the
12 proximity of existing infrastructure; the experience and safety record of the explorer in
13 conducting operations in remote or roadless areas; the projected cost schedule;
14 whether seismic mapping and seismic data sufficiently identify a particular trap for
15 exploration; whether the targeted and planned depth and range are designed to
16 penetrate and fully evaluate the hydrocarbon potential of the proposed prospect and
17 reach the level below which economic hydrocarbon reservoirs are likely to be found,
18 or reach 12,000 feet or more true vertical depth; and whether the exploration plan
19 provides for a full evaluation of the wellbore below surface casing to the depth of the
20 well. Whether the exploration well for which a credit is requested under this
21 subsection is located within an area and a basin described under (o) of this section
22 shall be determined by the commissioner of natural resources and reported to the
23 commissioner. A taxpayer that obtains a credit under this subsection may not claim a
24 tax credit under AS 43.55.023 or another provision in this section for the same
25 exploration expenditure.

26 * Sec. 25. AS 43.55.025 is amended by adding a new subsection to read:

27 (q) A credit or portion of a credit under this section may not be used to reduce
28 a person's tax liability under AS 43.55.011(e) for any calendar year below the amount
29 calculated under AS 43.55.011(f).

30 * Sec. 26. AS 43.55.028(e) is amended to read:

31 (e) The department, on the written application of a person to whom a

1 transferable tax credit certificate has been issued under AS 43.55.023(d) or former
2 AS 43.55.023(m) or to whom a production tax credit certificate has been issued under
3 AS 43.55.025(f), may use available money in the oil and gas tax credit fund to
4 purchase, in whole or in part, the certificate. **The department may not purchase a**
5 **total of more than \$200100,000,000 in tax credit certificates from a person in a**
6 **calendar year. Before purchasing a certificate or part of a certificate,** [IF] the
7 department **shall find** [FINDS] that

8 (1) the calendar year of the purchase is not earlier than the first
9 calendar year for which the credit shown on the certificate would otherwise be allowed
10 to be applied against a tax;

11 (2) the **application is not the result of the division of a single entity**
12 **into multiple entities that would reasonably be expected to apply as a single entity**
13 **if the \$200100,000,000 limitation in this subsection did not exist** [APPLICANT
14 DOES NOT HAVE AN OUTSTANDING LIABILITY TO THE STATE FOR
15 UNPAID DELINQUENT TAXES UNDER THIS TITLE];

16 (3) the applicant's total tax liability under AS 43.55.011(e), after
17 application of all available tax credits, for the calendar year in which the application is
18 made is zero;

19 (4) the applicant's average daily production of oil and gas taxable
20 under AS 43.55.011(e) during the calendar year preceding the calendar year in which
21 the application is made was not more than 50,000 BTU equivalent barrels; and

22 (5) the purchase is consistent with this section and regulations adopted
23 under this section.

24 * **Sec. 1727.** AS 43.55.028 is amended by adding a new subsection to read:

25 (j) If an applicant or claimant has an outstanding liability to the state directly
26 related to the applicant's or claimant's oil or gas exploration, development, or
27 production and the department has not previously reduced the amount paid to that
28 applicant or claimant for a certificate or refund because of that outstanding liability,
29 the department may purchase only that portion of a certificate or pay only that portion
30 of a refund that exceeds the outstanding liability. With the applicant's or claimant's
31 consent, the department may apply the amount by which the department reduced its

1 purchase of a certificate or payment for a refund because of an outstanding liability to
2 satisfy the outstanding liability. Satisfaction of an outstanding liability under this
3 subsection does not affect the applicant's ability to contest that liability. The
4 department may enter into contracts or agreements with another department to which
5 the outstanding liability is owed. In this subsection, "outstanding liability" means an
6 amount of tax, interest, penalty, fee, rental, royalty, or other charge for which the state
7 has issued a demand for payment that has not been paid when due and, if contested,
8 has not been finally resolved against the state.

9 * **Sec. 1828.** AS 43.55.029(a) is amended to read:

10 (a) An explorer or producer that has applied for a production tax credit under
11 **former** AS 43.55.023(a) [, (b),] or (l) **or under AS 43.55.023(b)** or 43.55.025(a) may
12 make a present assignment of the production tax credit certificate expected to be
13 issued by the department to a third-party assignee. The assignment may be made either
14 at the time the application is filed with the department or not later than 30 days after
15 the date of filing with the department. Once a notice of assignment in compliance with
16 this section is filed with the department, the assignment is irrevocable and cannot be
17 modified by the explorer or producer without the written consent of the assignee
18 named in the assignment. If a production tax credit certificate is issued to the explorer
19 or producer, the notice of assignment remains effective and shall be filed with the
20 department by the explorer or producer together with any application for the
21 department to purchase the certificate under AS 43.55.028(e).

22 * **Sec. 1929.** AS 43.55.030(a) is amended to read:

23 (a) A producer that produces oil or gas from a lease or property in the state
24 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)
25 for that oil or gas, shall file with the department on March 31 of the following year a
26 statement, under oath, in a form prescribed by the department, giving, with other
27 information required, the following:

28 (1) a description of each lease or property from which oil or gas was
29 produced, by name, legal description, lease number, or accounting codes assigned by
30 the department;

31 (2) the names of the producer and, if different, the person paying the

1 tax, if any;

2 (3) the gross amount of oil and the gross amount of gas produced from
3 each lease or property, separately identifying the gross amount of gas produced from
4 each oil and gas lease to which an effective election under AS 43.55.014(a) applies,
5 the amount of gas delivered to the state under AS 43.55.014(b), and the percentage of
6 the gross amount of oil and gas owned by the producer;

7 (4) the gross value at the point of production of the oil and of the gas
8 produced from each lease or property owned by the producer and the costs of
9 transportation of the oil and gas;

10 (5) the name of the first purchaser and the price received for the oil and
11 for the gas, unless relieved from this requirement in whole or in part by the
12 department;

13 (6) the producer's qualified capital expenditures, [AS DEFINED IN
14 AS 43.55.023,] other lease expenditures under AS 43.55.165, and adjustments or other
15 payments or credits under AS 43.55.170;

16 (7) the production tax values of the oil and gas under AS 43.55.160(a)
17 or of the oil under AS 43.55.160(h), as applicable;

18 (8) any claims for tax credits to be applied; and

19 (9) calculations showing the amounts, if any, that were or are due
20 under AS 43.55.020(a) and interest on any underpayment or overpayment.

21 * **Sec. 2030.** AS 43.55.030(e) is amended to read:

22 (e) An explorer or producer that incurs a lease expenditure under
23 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
24 year but does not produce oil or gas from a lease or property in the state during the
25 calendar year shall file with the department, on March 31 of the following year, a
26 statement, under oath, in a form prescribed by the department, giving, with other
27 information required, the following:

28 (1) the explorer's or producer's qualified capital expenditures, [AS
29 DEFINED IN AS 43.55.023,] other lease expenditures under AS 43.55.165, and
30 adjustments or other payments or credits under AS 43.55.170; and

31 (2) if the explorer or producer receives a payment or credit under

1 AS 43.55.170, calculations showing whether the explorer or producer is liable for a
2 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount.

3 * **Sec. 2131.** AS 43.55.160(e) is amended to read:

4 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
5 would otherwise be deductible by a producer in a calendar year but whose deduction
6 would cause an annual production tax value calculated under (a)(1) or (h) of this
7 section of taxable oil or gas produced during the calendar year to be less than zero
8 may be used to establish a carried-forward annual loss under AS 43.55.023(b).
9 However, the department shall provide by regulation a method to ensure that, for a
10 period for which a producer's tax liability is limited by AS 43.55.011(j), [(k),] (o), or
11 (p), or former AS 43.55.011(k), any adjusted lease expenditures under AS 43.55.165
12 and 43.55.170 that would otherwise be deductible by a producer for that period but
13 whose deduction would cause a production tax value calculated under (a)(1)(C), (D),
14 (E), or (F), or (h)(3) of this section to be less than zero are accounted for as though the
15 adjusted lease expenditures had first been used as deductions in calculating the
16 production tax values of oil or gas subject to any of the limitations under
17 AS 43.55.011(j), [(k),] (o), or (p) or former AS 43.55.011(k) that have positive
18 production tax values so as to reduce the tax liability calculated without regard to the
19 limitation to the maximum amount provided for under the applicable provision of
20 AS 43.55.011(j), [(k),] (o), or (p) or former AS 43.55.011(k). Only the amount of
21 those adjusted lease expenditures remaining after the accounting provided for under
22 this subsection may be used to establish a carried-forward annual loss under
23 AS 43.55.023(b). In this subsection, "producer" includes "explorer."

24 * **Sec. 32.** AS 43.55.160(f) is amended to read:

25 (f) On and after January 1, 2014, in the calculation of an annual production tax
26 value of a producer under (a)(1)(A) or (h)(1) of this section, the gross value at the
27 point of production of oil or gas produced from a lease or property north of 68 degrees
28 North latitude meeting one or more of the following criteria is reduced by 20 percent:
29 (1) the oil or gas is produced from a lease or property that does not contain a lease that
30 was within a unit on January 1, 2003; (2) the oil or gas is produced from a
31 participating area established after December 31, 2011, that is within a unit formed

1 under AS 38.05.180(p) before January 1, 2003, if the participating area does not
2 contain a reservoir that had previously been in a participating area established before
3 December 31, 2011; (3) the oil or gas is produced from acreage that was added to an
4 existing participating area by the Department of Natural Resources on and after
5 January 1, 2014, and the producer demonstrates to the department that the volume of
6 oil or gas produced is from acreage added to an existing participating area. This
7 subsection does not apply to gas produced before 2022 that is used in the state or to
8 gas produced on and after January 1, 2022. For oil or gas first produced after
9 December 31, 2016, the reduction under this subsection shall apply to oil or gas
10 produced from a lease or property for the first five years after the
11 commencement of production in commercial quantities of oil or gas from that
12 lease or property. For oil or gas first produced before January 1, 2017, the
13 reduction under this subsection for a lease or property shall expire January 1,
14 2021. A reduction under this subsection may not reduce the gross value at the point of
15 production below zero. In this subsection, "participating area" means a reservoir or
16 portion of a reservoir producing or contributing to production as approved by the
17 Department of Natural Resources.

18 * Sec. 33. AS 43.55.160(g) is amended to read:

19 (g) On and after January 1, 2014, in addition to the reduction under (f) of this
20 section, in the calculation of an annual production tax value of a producer under
21 (a)(1)(A) or (h)(1) of this section, the gross value at the point of production of oil or
22 gas produced from a lease or property north of 68 degrees North latitude that does not
23 contain a lease that was within a unit on January 1, 2003, is reduced by 10 percent if
24 the oil or gas is produced from a unit made up solely of leases that have a royalty
25 share of more than 12.5 percent in amount or value of the production removed or sold
26 from the lease as determined under AS 38.05.180(f). This subsection does not apply if
27 the royalty obligation for one or more of the leases in the unit has been reduced to 12.5
28 percent or less under AS 38.05.180(j) for all or part of the calendar year for which the
29 annual production tax value is calculated. This subsection does not apply to gas
30 produced before 2022 that is used in the state or to gas produced on and after
31 January 1, 2022. For oil or gas first produced after December 31, 2016, the

1 reduction under this subsection shall apply to oil or gas produced from a lease or
2 property for the first five years after the commencement of production in
3 commercial quantities of oil or gas from that lease or property. For oil or gas first
4 produced before January 1, 2017, the reduction under this subsection for a lease
5 or property shall expire January 1, 2021. A reduction under this subsection may not
6 reduce the gross value at the point of production below zero.

7 * Sec. 34. AS 43.55.165(a) is amended to read:

8 (a) **For** [EXCEPT AS PROVIDED IN (j) AND (k) OF THIS SECTION,
9 FOR] purposes of this chapter, a producer's lease expenditures for a calendar year are

10 (1) costs, other than items listed in (e) of this section, that are

11 (A) incurred by the producer during the calendar year after
12 March 31, 2006, to explore for, develop, or produce oil or gas deposits located
13 within the producer's leases or properties in the state or, in the case of land in
14 which the producer does not own an operating right, operating interest, or
15 working interest, to explore for oil or gas deposits within other land in the
16 state; and

17 (B) allowed by the department by regulation, based on the
18 department's determination that the costs satisfy the following three
19 requirements:

20 (i) the costs must be incurred upstream of the point of
21 production of oil and gas;

22 (ii) the costs must be ordinary and necessary costs of
23 exploring for, developing, or producing, as applicable, oil or gas
24 deposits; and

25 (iii) the costs must be direct costs of exploring for,
26 developing, or producing, as applicable, oil or gas deposits; and

27 (2) a reasonable allowance for that calendar year, as determined under
28 regulations adopted by the department, for overhead expenses that are directly related
29 to exploring for, developing, or producing, as applicable, the oil or gas deposits.

30 * Sec. 2235. AS 43.55.165(e) is amended to read:

31 (e) For purposes of this section, lease expenditures do not include

- 1 (1) depreciation, depletion, or amortization;
- 2 (2) oil or gas royalty payments, production payments, lease profit
- 3 shares, or other payments or distributions of a share of oil or gas production, profit, or
- 4 revenue, except that a producer's lease expenditures applicable to oil and gas produced
- 5 from a lease issued under AS 38.05.180(f)(3)(B), (D), or (E) include the share of net
- 6 profit paid to the state under that lease;
- 7 (3) taxes based on or measured by net income;
- 8 (4) interest or other financing charges or costs of raising equity or debt
- 9 capital;
- 10 (5) acquisition costs for a lease or property or exploration license;
- 11 (6) costs arising from fraud, wilful misconduct, gross negligence,
- 12 violation of law, or failure to comply with an obligation under a lease, permit, or
- 13 license issued by the state or federal government;
- 14 (7) fines or penalties imposed by law;
- 15 (8) costs of arbitration, litigation, or other dispute resolution activities
- 16 that involve the state or concern the rights or obligations among owners of interests in,
- 17 or rights to production from, one or more leases or properties or a unit;
- 18 (9) costs incurred in organizing a partnership, joint venture, or other
- 19 business entity or arrangement;
- 20 (10) amounts paid to indemnify the state; the exclusion provided by
- 21 this paragraph does not apply to the costs of obtaining insurance or a surety bond from
- 22 a third-party insurer or surety;
- 23 (11) surcharges levied under AS 43.55.201 or 43.55.300;
- 24 (12) an expenditure otherwise deductible under (b) of this section that
- 25 is a result of an internal transfer, a transaction with an affiliate, or a transaction
- 26 between related parties, or is otherwise not an arm's length transaction, unless the
- 27 producer establishes to the satisfaction of the department that the amount of the
- 28 expenditure does not exceed the fair market value of the expenditure;
- 29 (13) an expenditure incurred to purchase an interest in any corporation,
- 30 partnership, limited liability company, business trust, or any other business entity,
- 31 whether or not the transaction is treated as an asset sale for federal income tax

1 purposes;

2 (14) a tax levied under AS 43.55.011 or 43.55.014;

3 (15) costs incurred for dismantlement, removal, surrender, or
4 abandonment of a facility, pipeline, well pad, platform, or other structure, or for the
5 restoration of a lease, field, unit, area, tract of land, body of water, or right-of-way in
6 conjunction with dismantlement, removal, surrender, or abandonment; a cost is not
7 excluded under this paragraph if the dismantlement, removal, surrender, or
8 abandonment for which the cost is incurred is undertaken for the purpose of replacing,
9 renovating, or improving the facility, pipeline, well pad, platform, or other structure;

10 (16) costs incurred for containment, control, cleanup, or removal in
11 connection with any unpermitted release of oil or a hazardous substance and any
12 liability for damages imposed on the producer or explorer for that unpermitted release;
13 this paragraph does not apply to the cost of developing and maintaining an oil
14 discharge prevention and contingency plan under AS 46.04.030;

15 (17) costs incurred to satisfy a work commitment under an exploration
16 license under AS 38.05.132;

17 (18) that portion of expenditures, that would otherwise be qualified
18 capital expenditures, [AS DEFINED IN AS 43.55.023,] incurred during a calendar
19 year that are less than the product of \$0.30 multiplied by the total taxable production
20 from each lease or property, in BTU equivalent barrels, during that calendar year,
21 except that, when a portion of a calendar year is subject to this provision, the
22 expenditures and volumes shall be prorated within that calendar year;

23 (19) costs incurred for repair, replacement, or deferred maintenance of
24 a facility, a pipeline, a structure, or equipment, other than a well, that results in or is
25 undertaken in response to a failure, problem, or event that results in an unscheduled
26 interruption of, or reduction in the rate of, oil or gas production; or costs incurred for
27 repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or
28 equipment, other than a well, that is undertaken in response to, or is otherwise
29 associated with, an unpermitted release of a hazardous substance or of gas; however,
30 costs under this paragraph that would otherwise constitute lease expenditures under (a)
31 and (b) of this section may be treated as lease expenditures if the department

1 determines that the repair or replacement is solely necessitated by an act of war, by an
2 unanticipated grave natural disaster or other natural phenomenon of an exceptional,
3 inevitable, and irresistible character, the effects of which could not have been
4 prevented or avoided by the exercise of due care or foresight, or by an intentional or
5 negligent act or omission of a third party, other than a party or its agents in privity of
6 contract with, or employed by, the producer or an operator acting for the producer, but
7 only if the producer or operator, as applicable, exercised due care in operating and
8 maintaining the facility, pipeline, structure, or equipment, and took reasonable
9 precautions against the act or omission of the third party and against the consequences
10 of the act or omission; in this paragraph,

11 (A) "costs incurred for repair, replacement, or deferred
12 maintenance of a facility, a pipeline, a structure, or equipment" includes costs
13 to dismantle and remove the facility, pipeline, structure, or equipment that is
14 being replaced;

15 (B) "hazardous substance" has the meaning given in
16 AS 46.03.826;

17 (C) "replacement" includes renovation or improvement;

18 (20) costs incurred to construct, acquire, or operate a refinery or crude
19 oil topping plant, regardless of whether the products of the refinery or topping plant
20 are used in oil or gas exploration, development, or production operations; however, if
21 a producer owns a refinery or crude oil topping plant that is located on or near the
22 premises of the producer's lease or property in the state and that processes the
23 producer's oil produced from that lease or property into a product that the producer
24 uses in the operation of the lease or property in drilling for or producing oil or gas, the
25 producer's lease expenditures include the amount calculated by subtracting from the
26 fair market value of the product used the prevailing value, as determined under
27 AS 43.55.020(f), of the oil that is processed;

28 (21) costs of lobbying, public relations, public relations advertising, or
29 policy advocacy.

30 * **Sec. 2336.** AS 43.55.165(f) is amended to read:

31 (f) For purposes of AS 43.55.023(b) [AS 43.55.023(a) AND (b)] and only as

1 to expenditures incurred to explore for an oil or gas deposit located within land in
2 which an explorer does not own a working interest, the term "producer" in this section
3 includes "explorer."

4 * **Sec. 2437.** AS 43.55.170(c) is amended to read:

5 (c) For purposes of **AS 43.55.023(b)** [AS 43.55.023(a) AND (b)] and only as
6 to expenditures incurred to explore for an oil or gas deposit located within land in
7 which an explorer does not own a working interest, the term "producer" in this section
8 includes "explorer."

9 * **Sec. 2538.** AS 43.55.890 is amended to read:

10 **Sec. 43.55.890. Disclosure of tax information.** Notwithstanding any contrary
11 provision of AS 40.25.100, and regardless of whether the information is considered
12 under AS 43.05.230(e) to constitute statistics classified to prevent the identification of
13 particular returns or reports, the department may publish the following information
14 under this chapter, if aggregated among three or more producers or explorers, showing
15 by month or calendar year and by lease or property, unit, or area of the state:

- 16 (1) the amount of oil or gas production;
17 (2) the amount of taxes levied under this chapter or paid under this
18 chapter;
19 (3) the effective tax rates under this chapter;
20 (4) the gross value of oil or gas at the point of production;
21 (5) the transportation costs for oil or gas;
22 (6) qualified capital expenditures [, AS DEFINED IN AS 43.55.023];
23 (7) exploration expenditures under AS 43.55.025;
24 (8) production tax values of oil or gas under AS 43.55.160;
25 (9) lease expenditures under AS 43.55.165;
26 (10) adjustments to lease expenditures under AS 43.55.170;
27 (11) tax credits applicable or potentially applicable against taxes levied
28 by this chapter.

29 * **Sec. 2639.** AS 43.55.895(b) is amended to read:

30 (b) A municipal entity subject to taxation because of this section

31 **(1)** is eligible for [ALL] tax credits **proportionate to its production**

1 **taxable under AS 43.55.011(e); and**

2 **(2) shall allocate its lease expenditures in proportion to its**
3 **production taxable under AS 43.55.011(e)** [UNDER THIS CHAPTER TO THE
4 SAME EXTENT AS ANY OTHER PRODUCER].

5 * **Sec. ~~2740~~**. AS 43.55.900 is amended by adding a new paragraph to read:

6 (26) "qualified capital expenditure"

7 (A) means, except as otherwise provided in (B) of this
8 paragraph, an expenditure that is a lease expenditure under AS 43.55.165 and
9 is

10 (i) incurred for geological or geophysical exploration;

11 (ii) treated as a capitalized expenditure under 26 U.S.C.
12 (Internal Revenue Code), as amended, regardless of elections made
13 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
14 treated as a capitalized expenditure for federal income tax reporting
15 purposes by the person incurring the expenditure; or

16 (iii) treated as a capitalized expenditure under 26 U.S.C.
17 (Internal Revenue Code), as amended, regardless of elections made
18 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
19 eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal
20 Revenue Code), as amended;

21 (B) does not include an expenditure incurred to acquire an asset
22 the cost of previously acquiring which was a lease expenditure under
23 AS 43.55.165 or would have been a lease expenditure under AS 43.55.165 if it
24 had been incurred after March 31, 2006, or that has previously been placed in
25 service in the state; an expenditure to acquire an asset is not excluded under
26 this subparagraph if not more than an immaterial portion of the asset meets a
27 description under this subparagraph; for purposes of this subparagraph, "asset"
28 includes geological, geophysical, and well data and interpretations.

29 * **Sec. ~~2841~~**. AS 43.70.020 is amended by adding a new subsection to read:

30 (g) A person whose business engages in oil or gas exploration or development
31 must, in addition to filing the regular application required by this section, file with the

1 commissioner a surety bond of \$250,000 running to unsecured creditors licensed in the
2 state before being entitled to a license under this chapter. The commissioner shall
3 waive the surety bond requirement under this subsection if the business produces oil or
4 gas in commercial quantities.

5 * **Sec. ~~2942~~**. AS 38.05.180(i); AS 41.09.010, 41.09.020, 41.09.030, 41.09.090; ~~and~~
6 AS 43.20.053(j)(4); and AS 43.55.011(k) are repealed January 1, 2017.

7 * **Sec. ~~3043~~**. AS 43.55.023(a), 43.55.023(l), 43.55.023(n), 43.55.023(o), 43.55.028(i),
8 43.55.075(d)(1), 43.55.165(j), and 43.55.165(k) are repealed January 1, 2022.

9 * **Sec. ~~3144~~**. The uncodified law of the State of Alaska is amended by adding a new section
10 to read:

11 LEGISLATIVE WORKING GROUP. (a) A legislative working group is established
12 to analyze the Cook Inlet fiscal regime for oil and gas, review the state's tax structure and
13 rates on oil and gas produced south of 68 degrees North latitude, recommend changes to the
14 legislature for consideration during the First Regular Session of the Thirtieth Alaska State
15 Legislature, and develop terms for a comprehensive fiscal regime for the area south of 68
16 degrees North latitude including,

17 (1) a tax structure that accounts for the unique circumstances for each oil and
18 gas producing area south of 68 degrees North latitude;

19 (2) incentives for the exploration, development, and production of oil and gas
20 south of 68 degrees North latitude;

21 (3) consideration of the competitiveness of the area to attract new oil and gas
22 development;

23 (4) consideration of the unique market considerations of the Cook Inlet
24 sedimentary basin and the need to support energy supply security for communities in
25 Southcentral Alaska;

26 (5) alternative means of state support for the exploration, development, and
27 production of oil and gas in this area, including through the Alaska Industrial Export and
28 Development Authority;

29 (6) analysis of whether refundable state tax credits are still necessary for a
30 new regime;

31 (7) evaluation of the need for disclosure of some confidential information to

1 help legislators shape policy, including an evaluation of the associated state and federal
2 constitutional issues related to statutory waivers of taxpayer confidentiality.

3 (b) The working group consists of

4 (1) two co-chairs, one of whom is a member of the house appointed by the
5 speaker of the house of representatives, and one of whom is a member of the senate appointed
6 by the president of the senate; and

7 (2) members appointed by the co-chairs; members must be legislators and
8 must include members of the majority and minority caucuses.

9 (c) The co-chairs of the working group may form an advisory group to the working
10 group, composed of members who are not legislators and who have expertise and skills to
11 assist in the review and development of a new plan for the tax structure and rates on oil and
12 gas produced south of 68 degrees North latitude. The members of an advisory group may
13 include commissioners or employees of state departments, members of the oil and gas
14 industry or trade associations, and economists.

15 (d) The working group is to be supported by legislative consultants under contract
16 through the Legislative Budget and Audit Committee.

17 * **Sec. 3245**. The uncodified law of the State of Alaska is amended by adding a new section
18 to read:

19 APPLICABILITY. Sections 7 - 9, ~~1626~~, and ~~1727~~ of this Act apply to a refund or
20 payment applied for on or after January 1, 2017.

21 * **Sec. 3346**. The uncodified law of the State of Alaska is amended by adding a new section
22 to read:

23 TRANSITION: QUALIFIED CAPITAL EXPENDITURES AND WELL LEASE
24 EXPENDITURES. (a) Notwithstanding the repeal of AS 43.55.023(a), (l), (n), and (o) by sec.
25 ~~3043~~ of this Act, and the amendments to AS 43.55.023(d) and (e), 43.55.029(a), 43.55.165(f),
26 and 43.55.170(c) by secs. ~~13, 14, 18, 2319, 28, 36~~, and ~~2437~~ of this Act, a taxpayer who
27 incurs

28 (1) a qualified capital expenditure before the effective date of sec. ~~3043~~ of this
29 Act that qualifies for a qualified capital expenditure credit under AS 43.55.023(a) may apply
30 for a credit or transferable tax credit certificate under AS 43.55.023 and assign the tax credit
31 under AS 43.55.029, as those sections read on the day before the effective date of sec. ~~3043~~ of

1 this Act;

2 (2) a well lease expenditure before the effective date of sec. ~~3043~~ of this Act
3 that qualifies for a well lease expenditure credit under AS 43.55.023(I) may apply for a credit
4 or transferable tax credit certificate under AS 43.55.023 and assign the tax credit under
5 AS 43.55.029, as those sections read on the day before the effective date of sec. ~~3043~~ of this
6 Act.

7 (b) The Department of Revenue may continue to apply and enforce AS 43.55.023 and
8 43.55.029, as those sections read on the day before the effective date of sec. ~~3043~~ of this Act,
9 for qualified capital expenditures and well lease expenditures incurred before the effective
10 date of sec. ~~3043~~ of this Act.

11 * **Sec. ~~3447~~**. The uncodified law of the State of Alaska is amended by adding a new section
12 to read:

13 TRANSITION: LEASE EXPENDITURES FOR A CALENDAR YEAR AFTER
14 2006 AND BEFORE 2010. Notwithstanding AS 43.55.165(a), as amended by sec. ~~2134~~ of
15 this Act, and the repeal of AS 43.55.165(j) and (k) by sec. ~~3043~~ of this Act, AS 43.55.165(j)
16 and (k) apply to a producer's total lease expenditures for a calendar year after 2006 and before
17 2010 under AS 43.55.165, as that section read on the day before the effective date of sec.
18 ~~3043~~ of this Act.

19 * **Sec. ~~3548~~**. The uncodified law of the State of Alaska is amended by adding a new section
20 to read:

21 TRANSITION: REGULATIONS. The Department of Revenue and the Department of
22 Natural Resources may adopt regulations necessary to implement the changes made by this
23 Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not
24 before the effective date of the law implemented by the regulation. The Department of
25 Revenue shall adopt regulations governing the use of tax credits under AS 43.55 for a
26 calendar year for which the applicable tax credit provisions of AS 43.55 differ as between
27 parts of the year as a result of this Act.

28 * **Sec. ~~3649~~**. The uncodified law of the State of Alaska is amended by adding a new section
29 to read:

30 TRANSITION: RETROACTIVITY OF REGULATIONS. Notwithstanding any
31 contrary provision of AS 44.62.240,

1 (1) if the Department of Revenue expressly designates in a regulation that the
2 regulation applies retroactively, a regulation adopted by the Department of Revenue to
3 implement, interpret, make specific, or otherwise carry out this Act may apply retroactively to
4 the effective date of the law implemented by the regulation;

5 (2) if the Department of Natural Resources expressly designates in the
6 regulation that the regulation applies retroactively, a regulation adopted by the Department of
7 Natural Resources to implement, interpret, make specific, or otherwise carry out the statutory
8 amendments in this Act affecting the administration of oil and gas leases issued under
9 AS 38.05.180(f)(3)(B), (D), or (E), to the extent the regulation relates to the treatment of oil
10 and gas production taxes in determining net profits under those leases, may apply
11 retroactively to the effective date of the law implemented by the regulation.

12 * **Sec. 3750**. Sections ~~3424, 44,~~ and 3548 of this Act take effect immediately under
13 AS 01.10.070(c).

14 * **Sec. 3851**. Sections ~~13, 14, 18—25, 27,~~ 19, 28 - 30, 3334 - 38, 40, 43, 46, and 3447 of
15 this Act take effect January 1, 2022.

16 * **Sec. 3952**. Except as provided in secs. 3750 and 3851 of this Act, this Act takes effect
17 January 1, 2017.

4/6/16

DRAFT Prepared 4-6-16 by Department of Revenue

NOTE: The fiscal impact of this bill is an estimate based on the Spring 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

***DRAFT* Provisions in CSHB 247(FIN) and their Estimated Fiscal Impact as compared to Spring 2016 Forecast (\$millions) - FORECAST PRICE¹**

Note regarding this table: this table attempts to value the impact of each of the items independently, except where noted. In some cases, the total value of several impacts will not equal the sum of the individual impact values.

Brief Description of Provision - Includes only provisions anticipated to have a direct fiscal impact	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
1. The rate for net operating loss credits for Cook Inlet is changed to 10% for companies with a previous credit and zero for other companies.	\$0	\$0	\$0	\$0	\$0	\$0
2. The rate for QCE credits for Cook Inlet is changed to 10%; the rate for well lease exp credits for Cook Inlet is changed to 30% on 1/1/17 and then 20% on 1/1/18	\$0	\$0	\$0	\$0	\$0	\$10-\$20
3. The tax limitation for Cook Inlet oil is repealed effective 1/1/17.	\$0-\$10	\$0-\$10	\$0-\$10	\$5-\$15	\$10-\$20	\$15-\$25
4. For North Slope, some tax credits cannot reduce liability below 2% of GVPP effective 1/1/17.	\$10-\$20	\$70-\$100	\$70-\$100	\$70-\$100	\$70-\$100	\$60-\$90
5. The interest rate on delinquent taxes is changed to 5% above the Fed Res Discount rate, compounded quarterly	Indeterminate					
6. The GVR cannot be used to create or increase a net operating loss (REVENUE IMPACT ONLY)	\$0	\$0	\$0	\$0	\$0	\$5-\$15
7. GVR-eligible production qualifies for the GVR for a period of 5 years or until 1/1/21.	\$0	\$0	\$0	\$0	\$0	\$20-\$30
8. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax	Indeterminate					
Total Revenue Impact	\$10-\$30	\$70-\$110	\$70-\$110	\$75-\$115	\$80-\$120	\$110-\$180
Budget impact of change in net operating loss credits for Cook Inlet (provision 1 above)	\$0	\$10-\$20	\$20-\$30	\$10-\$20	\$10-\$20	\$10-\$20
Budget impact of change in QCE/WLE credits for Cook Inlet (provision 2 above)	\$0	\$15-\$25	\$20-\$30	\$20-\$30	\$45-\$65	\$45-\$65
Budget impact of not allowing some credits to reduce North Slope below 2% of GVPP (provision 4 above)	\$0	\$0	\$0	\$0	\$0-\$10	\$0-\$10
Budget impact of limiting refunds to \$100 million per company/per project per year (only shifts timing of refunds)	\$100 million cap has no impact after 1/1/17 under Spring 2016 forecast					
The GVR cannot be used to create or increase a net operating loss (BUDGET IMPACT ONLY)	0	\$10-\$20	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10
Budget impact of exploration credit extension for well spudded by 7/1/16	\$0-\$20	\$0-\$20	\$0	\$0	\$0	\$0
Budget impact of GVR applying to fields for a period of 5 years (provision 7 above)	\$0	\$0	\$0	\$0	\$0	\$0
Total Budget Impact	\$0-\$20	\$35-\$85	\$60-\$90	\$45-\$75	\$60-\$110	\$55-\$105
Total Fiscal Impact - does not include revenue impacts from potential changes in investment²	\$10-\$50	\$105-\$195	\$130-\$200	\$120-\$190	\$140-\$230	\$165-\$285

¹The impacts listed are based on production and prices as forecasted in DOR's Spring 2016 revenue forecast. The forecasted oil prices are between \$38.89 and \$61.64. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts.

ALASKA STATE LEGISLATURE

HOUSE FINANCE COMMITTEE

Representative Mark Neuman
Co-Chairman
(907) 465-2679
Rep.Mark.Neuman@akleg.gov

Alaska State Capitol Building- Rm 513



Representative Steve Thompson
Co-Chairman
(907) 465-3004
Rep.Steve.Thompson@akleg.gov

Alaska State Capitol Building- Rm 515

House Bill 247 explanation of changes version I (RES) to version F (FIN)

Title Changes to conform with changes in the bill.

Sec. 6. (Page 3, Lines 18-28) AS 43.05.225 – Interest Rate on delinquent taxes. Will now be compounded quarterly at 5% above the 12th Federal Reserve District for the first 4 years after the tax becomes delinquent and 5% annually, no compounding after the first 4 years.

Sec. 10 (Page 5, Lines 5-26) AS 43.55.011(e) Deletes reference to the Cook Inlet tax cap. Repealed in Sec. 42.

Sec. 11 (Page 5, Lines 6-26) AS 43.55.011(f) - Hardens the floor so that no credits can reduce the floor below 2% of the gross value at the point of production.

Sec. 12 (Page 8, Lines 6-7) AS 43.55.011(m) Takes out reference to old credits that are not being used and deletes a reference to the Cook Inlet tax cap.

Sec. 13. (Page 8, Line 13-18) AS 43.55.019(e) - Makes sure that the Education Tax Credit cannot take the floor.

Sec.14. (Page 15-16, Lines 1-3) AS 43.55.020(a) – Installment Payments - Conforming language regarding payment of taxes and the new floor. Addresses the Cook Inlet tax cap.

Sec. 15 (Page 16, Line 12) AS 43.55.023(a) - Qualified Capital Expenditures. Reduces the qualified capital expenditure credits from 20% to 10% starting on January 1, 2017.

Sec. 16 (Page 17, Lines 6-16) AS 43.55.023(b) - Net Operating Loss Credits. Keeps the Middle Earth carried-forward annual loss credits at 25%. Reduces the Cook Inlet Net Operating loss credits from 25% to 10% starting January 1, 2017, if the producer or explorer has not taken a credit prior to January 1, 2017 they are not eligible. The amount Cook Inlet NOLs are consistent with the House Resources version of the bill. Continues a 25% credit for Middle Earth after 2016.

Sec. 17 (Page 17, Lines 27-30) AS 43.55.023(c) – Conforming language to the floor.

Sec. 20 (Page 19 Lines 11-20) AS 43.55.023(l) – Well Lease Expenditure Credits. Reduces the Cook Inlet Well Lease Expenditure Credits from 40% to 30% on January 1, 2017, and to 20% on January 1, 2018. Middle Earth credits will reduce from 40% to 30% on January 1, 2017

Sec. 21-23 (Pages 19, Lines 31-17) AS 43.55.024(f) (g) (i) - Small Producer Credits. Conforms to the floor.

Sec. 24 (Page 20, Lines 26-28) AS 43.55.025(m) - Middle Earth Drilling Credits. States that the middle earth drilling credits are extended to complete an exploration well that has spudded but not completed before July 1, 2016.

Sec.25. (Page 21, Lines 26-29) AS 43.55.025 - Alternative Tax Credits for Oil and Gas Exploration. – Conforming language to the floor.

Sec. 26. (Page 22, Lines 5 and 13) AS 43.55.028(e) – Oil and Gas Tax Credit Fund Established; Cash Purchase of Tax Credit Certificates. States that the Department may not purchase more than \$100,000,000 in tax credits from a person in a calendar year. This is reduced from \$200,000,000 in the House Resources version of the bill.

Sec. 31. (Page 15, Lines 11, 17, and 20) AS 43.55.160(e) Conforming amendment regarding Cook Inlet Tax Cap on oil.

Secs. 32 and 33. (Pages 25-27, Lines 24 – 6) AS 43.55.160(f) (g) New Oil, Gross Value Reduction – For oil and gas first produced after December 31, 2016, the new oil reduction shall apply for the first five years after the commencement of production in commercial quantities. For oil and gas first produced prior to January 1, 2017, the reduction shall expire January 1, 2021.

ALASKA STATE LEGISLATURE

HOUSE FINANCE COMMITTEE

Representative Mark Neuman
Co-Chairman
(907) 465-2679
Rep.Mark.Neuman@akleg.gov



Representative Steve Thompson
Co-Chairman
(907) 465-3004
Rep.Steve.Thompson@akleg.gov

Alaska State Capitol Building- Rm 513

Alaska State Capitol Building- Rm 515

House Bill 247 explanation of changes version I (RES) to version F (FIN)

Title Changes to conform with changes in the bill.

Sec. 6. (Page 3, Lines 6- Page 4 Line 1) AS 43.05.225 – Interest Rate on delinquent taxes. Will now be compounded quarterly at 5% above the 12th Federal Reserve District for the first 4 years after the tax becomes delinquent and 5% annually, no compounding after the first 4 years.

Sec. 10 (Page 5, Lines 5-26) AS 43.55.011(e) Deletes reference to the Cook Inlet tax cap. Repealed in Sec. 42.

Sec. 11 (Page 5, Line 27- Page 7 Line 25) AS 43.55.011(f) - Hardens the floor so that no credits can reduce the floor below 2% of the gross value at the point of production.

Sec. 12 (Page 7, Line 26- Page 8 Line 11) AS 43.55.011(m) Takes out reference to old credits that are not being used and deletes a reference to the Cook Inlet tax cap.

Sec. 13. (Page 8, Lines 12-17) AS 43.55.019(e) - Makes sure that the Education Tax Credit cannot take the floor.

Sec.14. (Page 8, Lines 18- Page 16 Line 22) AS 43.55.020(a) – Installment Payments - Conforming language regarding payment of taxes and the new floor. Addresses the Cook Inlet tax cap.

Sec. 15 (Page 16, Lines 3-22) AS 43.55.023(a) - Qualified Capital Expenditures. Reduces the qualified capital expenditure credits from 20% to 10% starting on January 1, 2017.

Sec. 16 (Page 16, Line 23- Page 17 Line 24) AS 43.55.023(b) - Net Operating Loss Credits. Keeps the Middle Earth carried-forward annual loss credits at 25%. Reduces the Cook Inlet Net Operating loss credits from 25% to 10% starting January 1, 2017, if the producer or explorer has not taken a credit prior to January 1, 2017 they are not eligible. The amount Cook Inlet NOLs are consistent with the House Resources version of the bill. Continues a 25% credit for Middle Earth after 2016.

Sec. 17 (Page 17, Lines 25-29) AS 43.55.023(c) – Conforming language to the floor.

Sec. 20 (Page 18 Line 29 - Page 19 Line 29) AS 43.55.023(l) – Well Lease Expenditure Credits. Reduces the Cook Inlet Well Lease Expenditure Credits from 40% to 30% on January 1, 2017, and to 20% on January 1, 2018. Middle Earth credits will reduce from 40% to 30% on January 1, 2017

Sec. 21-23 (Page 19, Line 30- Page 20 Line 16) AS 43.55.024(f) (g) (i) - Small Producer Credits. Conforms to the floor.

Sec. 24 (Page 20, Lines 24- Page 21 Line 24) AS 43.55.025(m) - Middle Earth Drilling Credits. States that the middle earth drilling credits are extended to complete an exploration well that has spudded but not completed before July 1, 2016.

Sec.25. (Page 21, Line 25-28) AS 43.55.025 - Alternative Tax Credits for Oil and Gas Exploration. – Conforming language to the floor.

Sec. 26. (Page 21, Line 29- Page 22 Line 22) AS 43.55.028(e) – Oil and Gas Tax Credit Fund Established; Cash Purchase of Tax Credit Certificates. States that the Department may not purchase more than \$100,000,000 in tax credits from a person in a calendar year. This is reduced from \$200,000,000 in the House Resources version of the bill.

Sec. 31. (Page 25, Lines 2-22) AS 43.55.160(e) Conforming amendment regarding Cook Inlet Tax Cap on oil.

Secs. 32 and 33. (Page 25 Line 23 – Page 27 Line 5) AS 43.55.160(f) (g) New Oil, Gross Value Reduction – For oil and gas first produced after December 31, 2016, the new oil reduction shall apply for the first five years after the commencement of production in commercial quantities. For oil and gas first produced prior to January 1, 2017, the reduction shall expire January 1, 2021.



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
907.564.5111 or 907-463-5242

05 April, 2016

The Honorable Mark Neuman
Co-Chair House Finance Committee
Alaska State Legislature
State Capitol Room 505
Juneau, AK 99801-1182

The Honorable Steve Thompson
Co-Chair House Finance Committee
Alaska State Legislature
State Capitol Room 511
Juneau, AK 99801-1182

Dear Representatives Newman and Thompson:

During BP's HB 247 testimony before the House Finance Committee on April 1, Rep. David Guttenberg asked two questions. I'm requesting this response from BP be added to the testimony record on HB 247. Thank you for the opportunity to testify during the Alaska Legislative House Finance Committee's review of this bill.

Representative Guttenberg stated: *BP you are the managing partner in Prudhoe Bay and in TAPS. You must have conversations about minimum flow levels that yearly production increases are needed to maintain the facilities and the TAPS line. Do you have any idea what this is, if you can say? And what would the liabilities be if production didn't increase and something happens to a facility or TAPS?*

First, BP is committed to maintaining a safe and compliant business in Alaska that is sustainable. That means the safety of our people and our infrastructure remains the number one priority for BP.

Improving our cost base is critical to maintaining a sustainable business at Prudhoe Bay and the long-term viability of an Alaska LNG project. Over the past two years, there has been a 70% drop in oil price and in 2015 BPXA had a loss of \$194 million with taxes and royalties paid of ~\$263 million.

In today's low oil price environment, Prudhoe Bay's working interest owners must look closely at every investment decision. Please note that while the Prudhoe Bay Unit (PBU) is operated by BP, it is a minority owner at 26 percent with ExxonMobil and ConocoPhillips each owning 36 percent. BP was asked by the working interest owners to reduce the PBU rig fleet from five to two rigs over the next few months. Prudhoe Bay gross production in 2015 was 281,000 barrels of oil per day (BOPD), while in 2014 it produced 289,000 BOPD. This three percent decline is a significant accomplishment for a 40-year-old oilfield. Continued investment in Prudhoe Bay and the recent tax policy by the State of Alaska has been critical to maintaining production.

As we move along Alaska LNG's timeline towards FEED, the PBU oil business that underpins the project's gas supply must remain stable. The oil and gas come from the same reservoir, through the same wells, the same pipelines and same processing facilities. Maintaining economic operations of

the existing PBU facilities reduces risk to the Alaska LNG project. A successful Alaska LNG project depends on a healthy base oil business. First gas is still many years away and we need to enable Alaska LNG with a safe, compliant, sustainable base business for the long term. Increasing taxes will be an additional challenge to those missions, and affects the base business that supports Alaska LNG.

Alyeska Pipeline Company is the operator of TAPS and is responsible for operations, flow rates, and future plans. Your questions regarding TAPS minimum flow and daily operations are best answered by Alyeska Pipeline Company.

Sincerely,

A handwritten signature in black ink, appearing to be 'JR' with a long horizontal stroke extending to the right.

Joe Reese
Senior Managing Tax Counsel, Alaska
BP Exploration (Alaska), Inc.

NEW SUSTAINABLE

ALASKA

PLAN



Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform

HB 247

Department of Revenue

Initial Overview for House Finance Committee

March 24, 2016

History of Oil and Gas Production Tax Credits

FY 2007 thru 2015, \$7.4 Billion in Credits

North Slope

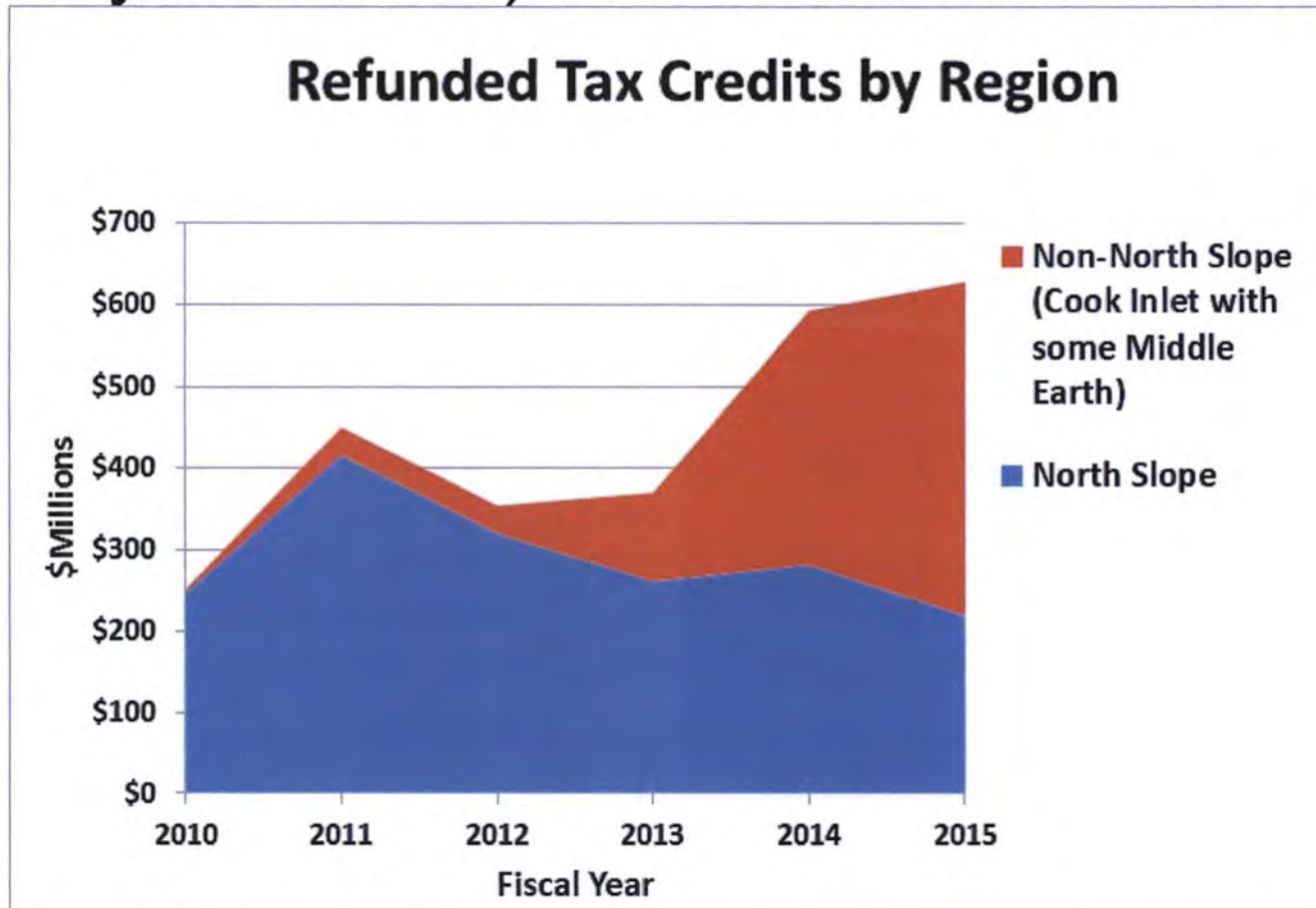
- \$4.3 billion credits against tax liability
 - Major producers; mostly 20% capital credit in ACES and per-taxable-barrel credit in SB21
- \$2.1 billion refunded credits
 - New producers and explorers developing new fields

Non-North Slope (Cook Inlet & Middle Earth)

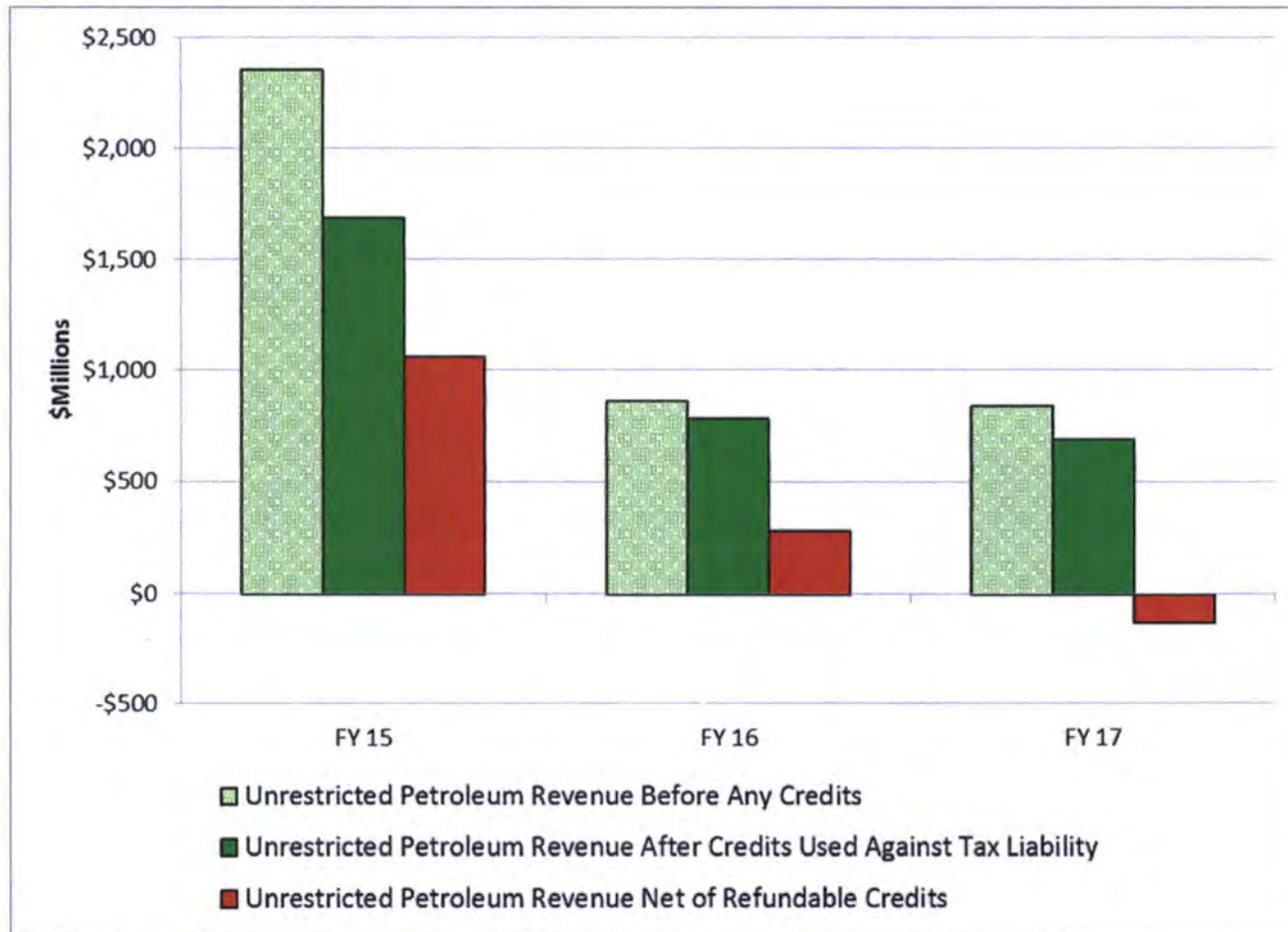
- \$100 million credits against tax liability
 - Another \$500 to \$800 million Cook Inlet tax reductions (through 2013) due to the tax cap still tied to ELF
- \$900 million refunded credits (most since 2013)

History of Oil and Gas Production Tax Credits

- Tremendous growth in non-North Slope (almost entirely Cook Inlet) refunded credits since FY10



Forecast of O&G Revenue and Tax Credits



*This graph shows net tax credits versus unrestricted petroleum revenue, which includes the petroleum property tax, petroleum CIT, production tax, oil and gas hazardous release surcharge, oil and gas conservation surcharge, rents, and petroleum royalties, bonuses, rents, and interest. Net tax credits include certain refinery credits under AS 43.20.

Source : Department of Revenue - PRELIMINARY Spring 2016 forecast

Work Done Since Last Session

- Governor's line-item veto capped FY16 spending at \$500 million
 - Temporary liquidity crisis; many meetings with industry and others to help reassure lenders
- Multiple presentations with history, current practice, and possible changes
 - Joint Resources in Kenai, June 17
 - Three "regional" presentations to Senate Working Group September through November
 - All presentations on BASIS; we're prepared to go through similar information for the committee
- Development of reform legislation including plan for transition from current system

Major Bill Themes

1. Reduce the state's annual cash outlay
2. Protect Net Operating Loss credits as a playing field leveler between legacy producers and newcomers
3. Limit repurchases
4. Strengthen the minimum tax
5. Be more open and transparent
6. Honor and pay credits earned to date and through any transition period

Major Bill Concepts in Governor's Proposal

- 1. Exploration Credits-** *sunset and transition*
- 2. Cook Inlet Drilling Credits-** *phase out while retaining operating loss credits*
- 3. Repurchase Limits-** *limit cash outlay*
- 4. Remove Exceptions / Loopholes**
- 5. Strengthen Minimum Tax-** *prevent certain credits from going below the floor, plus increase to 5%*
- 6. Other Provisions-** *technical cleanup, transparency, interest rate reform*

Content of Future Presentations

We provided five different presentations to the prior committee; all are on BASIS

- History and development of our credit system
- History and application of the minimum tax
- Various credits and how they have been used, which ones haven't been, and what is sunseting
- Detailed forecasts and scenario analysis
- Details and modeling of specific provisions
- Explanation of changes made in prior committee
- Life cycle modeling of typical new projects, with impact of legislation

NEW SUSTAINABLE

ALASKA

PLAN



Pulling Together to Build Our Future

Thank You!

Contact Information

Randall Hoffbeck
Commissioner
Department of Revenue
Randall.Hoffbeck@Alaska.gov
(907) 465-2300

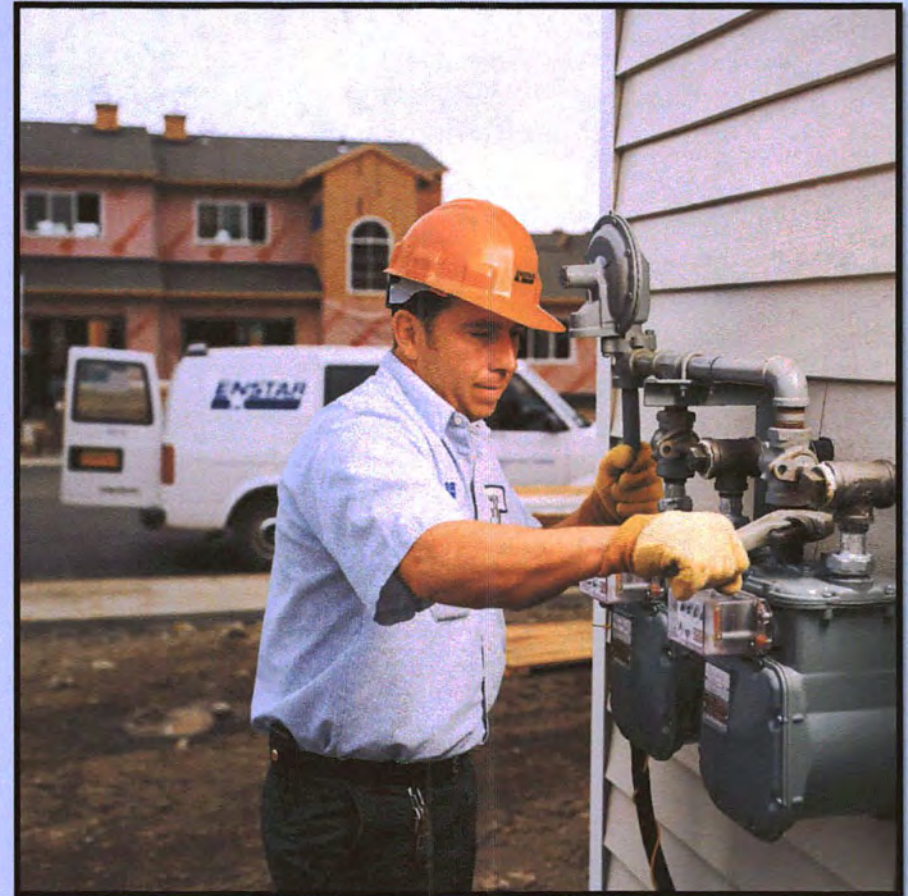
Ken Alper
Director, Tax Division
Department of Revenue
Ken.Alper@Alaska.gov
(907) 465-8221



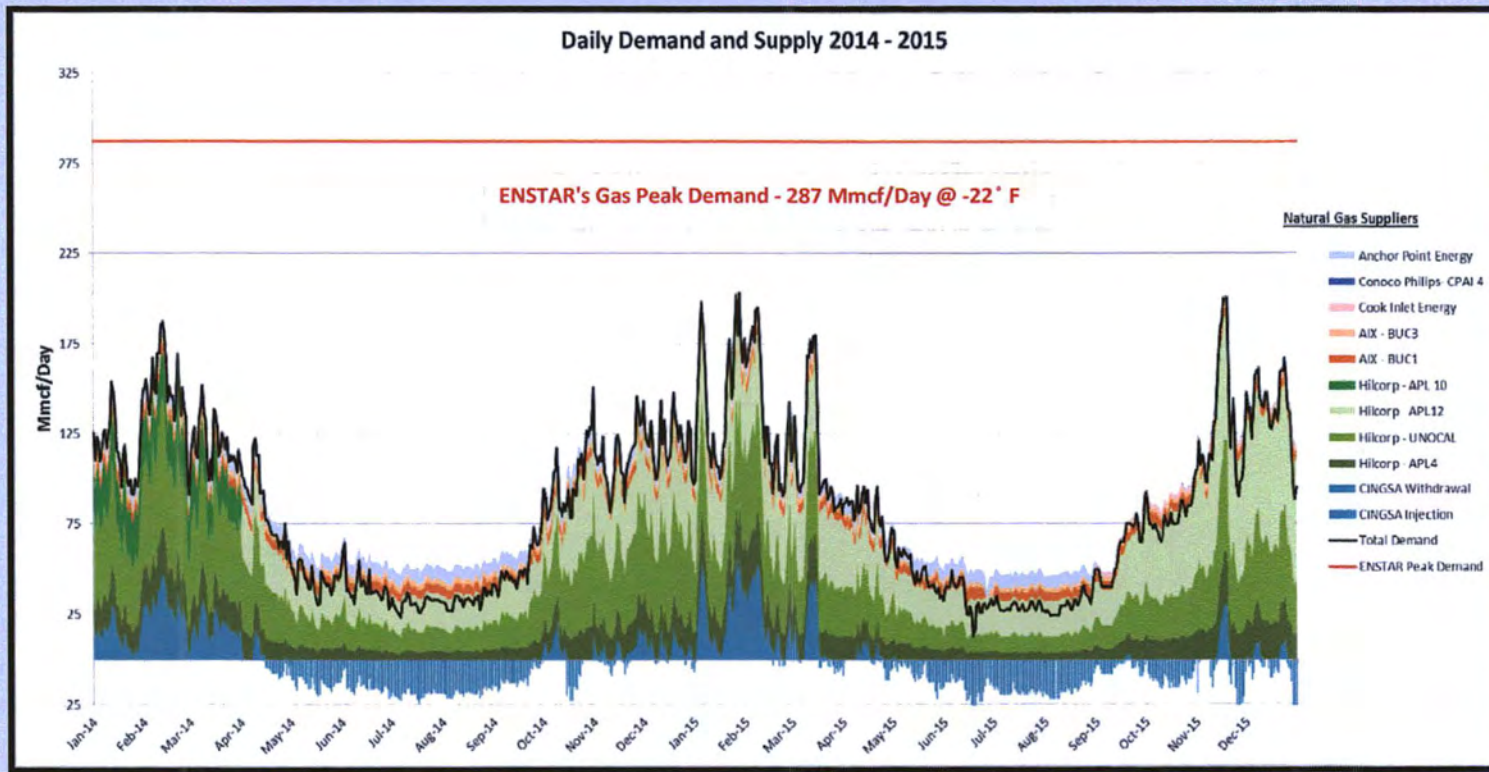
Presentation to the
House Finance Committee
April 5, 2016

Natural Gas Supply Needs

- 140,935 Customers
- Anchorage, Anchor Point, Big Lake, Girdwood, Homer, Houston, Kenai, Palmer, Soldotna, Wasilla, and Whittier
- 33 Bcf/year
- Peak deliverability 287 MMcf/day



Supply and Demand

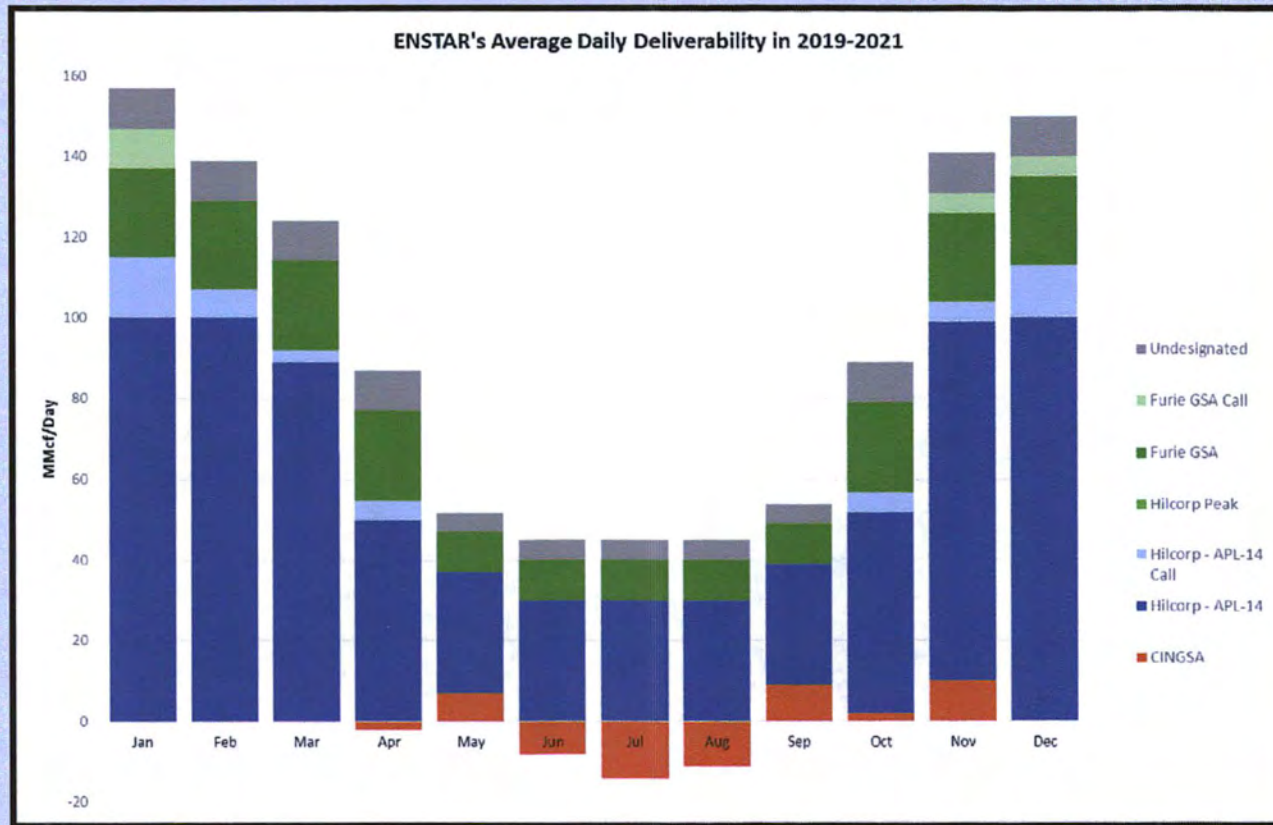


03/02/2016

House Resources Committee



Seasonal Average Deliverability

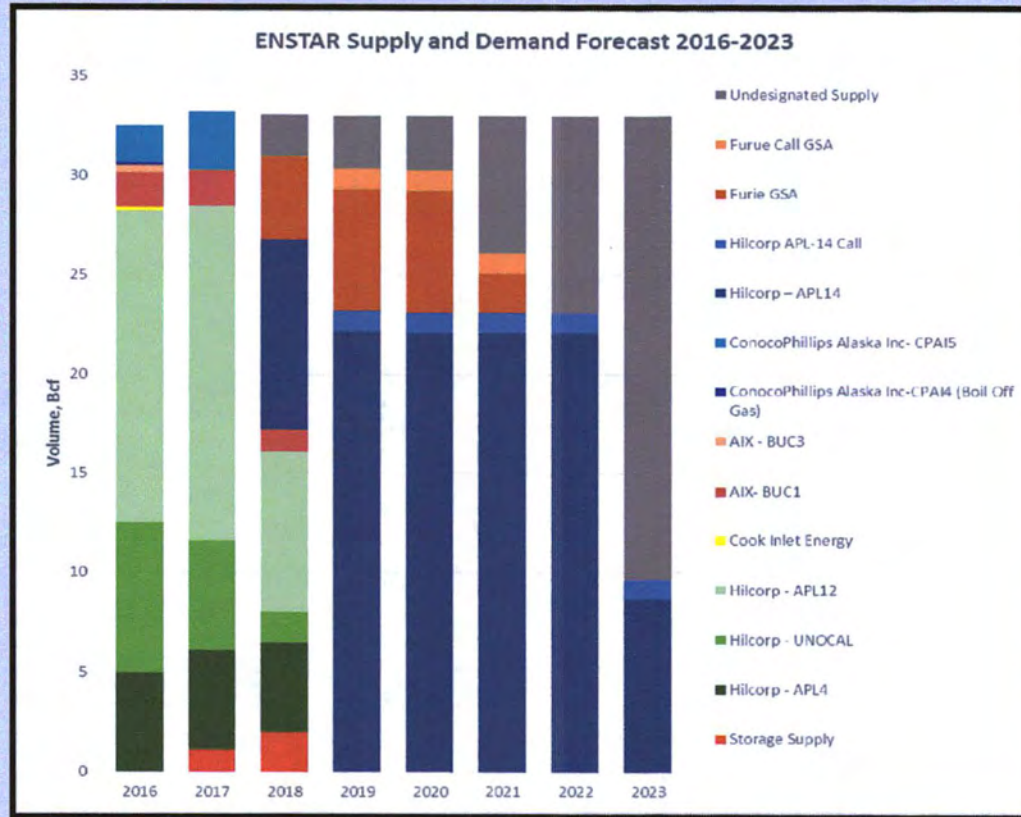


03/02/2016

House Resources Committee



Supply Contracts 2016-23



03/02/2016

House Resources Committee



(TA 280-4) APL-14 GSA

- APL-14 is a new agreement with Hilcorp signed on December 23 and filed February 29 with the RCA.
- Represents approximately 70% (110 Bcf) of ENSTAR's gas supply starting on April 1st 2018 - 2023.
- Approximately 22 Bcf/year.

GAS SALE AND PURCHASE AGREEMENT
BETWEEN
HILCORP ALASKA, LLC
AND
ALASKA PIPELINE COMPANY
APL-14
Effective Date: December 23, 2015
Delivery Commencement Date: April 1, 2018
Termination Date: March 31, 2023

NEW SUSTAINABLE

ALASKA

PLAN



Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform

CS HB247(RES)

Department of Revenue

Presentation to the House Finance Committee

March 31, 2016

What We'll Be Discussing

1. History and Development of Credits
2. Credits- What Worked, What Didn't?
3. Credit Cost in Perspective
4. Overview of the Tax & Credit Calculations
5. Bill Summary- What is in the CS?
6. Changes from Governor's to Resources Version
7. Fiscal Impact of Changes
8. Summary of Scenario Analysis and Life Cycle Modeling: Economics of Changes
9. Implementation

History and Development of Credits

History of Oil and Gas Production Tax Credits

- First “modern” Oil and Gas credit was the Alternative Credit for Exploration (AS 43.55.025) passed in 2003 while Alaska still had the “Economic Limit Factor” (ELF) Gross Tax
- Several added in 2006 with passage of the “Petroleum Production Tax” (PPT) and switch to net profits taxation. Included Cook Inlet tax caps as well as the first “state repurchase” provisions
- Credits substantially modified with passage of “Alaska’s Clear and Equitable Share” (ACES) in 2007; state repurchase made more open-ended
- Cook Inlet Recovery Act and related legislation in 2010
- Frontier Basin credits added in 2012
- SB 21 passed in 2013, dramatically changed North Slope credits, replacing “spending” with “production” focus

History of Oil and Gas Production Tax Credits

- Credits initially added to encourage certain desired behaviors, tied to anxiety over declining production and a need for new investment
- Later credits were added as core components / offsets of the net profits system
- At times credits were layered on top of each other, creating unanticipated circumstances
- Credits can either be used against tax liability, sold / transferred to a taxpayer, or cashed out (“repurchased”) by the state
- Per AS 43.55.028(e)(4), a company producing over 50,000 bbl / day can not have their credits repurchased by the state

History of Oil and Gas Production Tax Credits

Major Credits Available (current law):

- **.023(b) Net Operating Loss (25-45%)**
This is the main refundable credit on the North Slope and the largest statewide credit. “Stackable”
- **.024(i&j) Per-Taxable Barrel (\$0 to \$8)**
Only on North Slope
Only can be used against tax liability
- **.023(a&l) Capital and Well Expend (20-40%)**
Only outside North Slope, usually refunded
- **.025(var) Exploration Credit (30-40%)**
Expires 7/16 in North Slope and Cook Inlet
Extended in Interior / Frontier Areas until 2022
- **.024(c) Small Producer Credit (up to \$12 mil)**
Closed to new applicants in 5/16

Credits: What Worked, What Didn't?

Credits- What Worked, What Didn't?

Some Credits have Never Been Claimed

- Middle Earth “New Areas” \$6 million Credit
(AS 43.55.024(a); part of HB3001/PPT, 2006)
- Cook Inlet “Jack Up Rig” 100% Credit
(AS 43.55.025(m); part of SB309, 2010)
- Frontier Basin 80% Drilling Credit
(AS 43.55.025(n); part of SB23, 2012)

Companies did some of the activities incentivized by these, but were able to get better results from “stacking” other credits

All of these programs are sunseting in 2016

Credits- What Worked, What Didn't?

To-date cost of Sunsetting Credits

Exploration Credits (various) 2007-sunset

- North Slope Refunded: \$270 million
- North Slope Against Liability: \$190 million
- Non-North Slope Refunded: \$160 million
- Non-North Slope Against Liability: \$0

Small Producer Credits 2007-2016

- North Slope Against Liability: \$340 million
- Non-North Slope Against Liability: \$60 million
- (these cannot be refunded)

Total: slightly over \$1 billion

Credits- What Worked, What Didn't?

Credits Remaining if HB247 Passes

- **Carried-Forward Annual Loss Credit**
(also called “net operating loss”)
 - 35% on North Slope and 25% in Cook Inlet and elsewhere (non-NS reduced to 10% by H(RES))
- **Non-North Slope Drilling Credits**
 - “QCE” and “WLE” were repealed in governor’s bill; maintained at 20% in H(RES) version
- **Exploration Credits outside North Slope and Cook Inlet** (“middle earth exploration”)
 - 30-40% depending on location
 - Sunset January 1, 2022

Credits- What Worked, What Didn't?

Credits Remaining If HB247 Passes (contd.)

- **Cook Inlet Tax Caps**
 - Oil tax of zero, gas tax averages 17 cents / mcf
 - Sunset January 1, 2022
- **Middle Earth Tax Caps**
 - 4% of gross value (first seven years of production that begins before 2027)
- **LNG Storage Facility Credit**
 - Lesser of 50% of cost or \$15 million
- **Refinery Infrastructure Credit**
 - 40% of cost up to \$10 million / year per refinery, before 2020



Credit Cost in Perspective

Credit Cost in Perspective

FY 2007 thru 2016, \$8.0 Billion in Credits

North Slope

- \$4.4 billion credits against tax liability
 - Major producers; mostly 20% capital credit in ACES and per-taxable-barrel credit in SB21
- \$2.3 billion refunded credits
 - New producers and explorers developing new fields

Non-North Slope (Cook Inlet & Middle Earth)

- \$0.1 billion credits against tax liability
 - Another \$500 to \$800 million Cook Inlet tax reductions (through 2013) due to the tax cap still tied to ELF
- \$1.2 billion refunded credits (most since 2013)

Credit Cost in Perspective

Of the \$3.0 billion in state-refunded credits through the end of FY15:

- \$1.45 billion went to six North Slope projects that now have production
- \$650 million went to 13 North Slope projects that do not have any production. Some of these are abandoned, and some are in process
- \$450 million went to six non-North Slope projects that have production
- \$450 million went to eight non-North Slope projects that do not have any production

Credit Cost in Perspective

North Slope Refundable Credits

Of the \$1.45 billion that was spent between FY07-FY15 supporting six producing projects:

- Total production through end of FY15 is 38.5 million barrels
- Total credits = **\$37.30** / barrel
 - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were \$4.94 billion
 - Credit support was **29%** of lease expenditures

Credit Cost in Perspective

Cook Inlet Refundable Credits


Of the \$450 million that was spent between FY07-FY15 supporting six producing projects:

- Total production through end of FY15 is 55.9 million BOE (much of this was gas)
- Total credits = **\$7.80** / BOE or about **\$1.30** / mcf
 - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were \$1.09 billion
 - Credit support was **40%** of lease expenditures

Credit Cost in Perspective

Cook Inlet Tax Caps

- Estimated value to industry \$550-\$850 over the years 2007-2013
- Total Production Estimate
 - Gas: ~ 250 million cubic feet / day for seven years = 640 BCF of gas or 106 million BOE
 - Oil: ~ 10,000 barrels / day for seven years = 26 million BOE
 - Total Production = 132 BOE
- Using midpoint \$700 million estimate, value of caps = **\$5.30** / barrel or **\$0.88** / mcf



Overview of Tax and Credit Calculations

Overview of Tax and Credit Calculations

How the Production Tax Works at \$100 oil

Tax on a single barrel of taxable North Slope oil.

We currently have about 160 million taxable barrels / year

Market Price	\$100
<u>Transport Cost</u>	<u>\$10</u>
Gross Value	\$90
<u>Lease Expenditures</u>	<u>\$35</u>
Production Tax Value	\$55
Tax @ 35%	\$19.25
<u>Per-Barrel Credit</u>	<u>\$6.00</u>
Net Payment	\$13.25
Minimum Tax Gross x 4%	\$3.60
<u>Higher Of (Actual Tax)</u>	<u>\$13.25</u>
Approx. Annual Revenue	\$2.1 billion

Overview of Tax and Credit Calculations

At \$70 Oil, the “minimum tax” takes over

Market Price	\$70
<u>Transport Cost</u>	<u>\$10</u>
Gross Value	\$60
<u>Lease Expenditures</u>	<u>\$35</u>
Production Tax Value	\$25
Tax @ 35%	\$8.75
<u>Per-Barrel Credit</u>	<u>\$8.00</u>
Net Payment	\$0.75
Minimum Tax Gross x 4%	\$2.40
<u>Higher Of (Actual Tax)</u>	<u>\$2.40</u>
Approx. Annual Revenue	\$380 million

Overview of Tax and Credit Calculations

At \$40 Oil, producers have operating losses

Market Price	\$40
<u>Transport Cost</u>	<u>\$10</u>
Gross Value	\$30
<u>Lease Expenditures</u>	<u>\$35</u>
Production Tax Value	(\$5)
<i>Approx. Operating Loss</i>	<i>\$800 million</i>
Tax @ 35%	(\$1.75)
<u>Per-Barrel Credit</u>	<u>\$8.00</u>
Net Payment	(\$9.75)
Minimum Tax Gross x 4%	\$1.20
<u>Higher Of (Actual Tax)</u>	<u>\$1.20</u>
Approx. Annual Revenue	\$190 million
<i>Carried Forward Loss Credit 35%</i>	<i>\$280 million</i>

Overview of Tax and Credit Calculations

\$40 for second year means Operating Loss credits can be used to reduce payments below the minimum tax

	Year 1	Year 2
Market Price	\$40	\$40
Transport Cost	\$10	\$10
Gross Value	\$30	\$30
Lease Expenditures	\$35	\$35
Production Tax Value	(\$5)	(\$5)
Approx. Operating Loss	\$800 million	\$800 million
Tax @ 35%	(\$1.75)	(\$1.75)
Per-Barrel Credit	\$8.00	\$8.00
Net Payment	(\$9.75)	(\$9.75)
Minimum Tax Gross x 4%	\$1.20	\$1.20
Higher Of (Actual Tax)	\$1.20	\$1.20
Approx. Annual Revenue	\$190 million	\$190 million
Less Carried-Forward Loss Credit		(\$190 million)
Actual Tax Payment	\$190 million	\$0
Carried-Forward Loss Credit 35%	\$280 million	\$370 million

Overview of Tax and Credit Calculations

- This is just the “baseline” scenario, for legacy oil from the North Slope.
- Does not account for the fact that roughly 9% of production qualifies for the “Gross Value Reduction” new oil tax break
- Can also provide example calculations for North Slope GVR Eligible Production as well as Cook Inlet scenarios

Bill Summary:
What is in the H(RES) CS?

Bill Summary- What is in the H(RES) CS?

Exploration Credits

HB247 Proposed / Kept in CS

- Allowing the .025(a) “alt. credit for exploration” to expire on 7/1/16, for North Slope and Cook Inlet
 - 025(a) credits remain for “Middle Earth” until 2022
- Also allowing the “Jack up Rig” and “Frontier Basin” credits to expire at the same time
- Preemptively repeal other exploration credit programs that are not currently being used, in AS 38.05.180(i) and AS 41.09.

Bill Summary- What is in the H(RES) CS?

Cook Inlet Credits, Current Conditions

New Field Developer

- Currently receives a 25% Net Operating Loss (NOL) credit stacked with either the 20% Capital (QCE) or 40% Well (WLE) credit. Generally a weighted average of the two “spending / drilling” credits
- State typically refunds 50-60% of costs

Existing Producer

- Currently pays low to zero taxes due to Cook Inlet tax caps, yet is eligible for 20% Capital or 40% Well Lease Expenditure credits
- State typically refunds 25%-35% of costs

Bill Summary- What is in the H(RES) CS?

Cook Inlet Credits, Changes in CS

New Field Developer

- NOL (Loss) credit reduced from 25% to 10% in 2017
- WLE (Well) credit reduced to 30% in 2017 and 20% in 2018 (effectively repealing it)
- QCE (Capital) credit remains until 2022 (anticipating sunset of Cook Inlet tax caps)
- State will typically refund 35% of costs in 2017 and 30% in 2018 and beyond

Existing Producer

- Tax caps remain until 2022. Continuation of 20% QCE credit means state will continue to refund 20% of capital spending

CS sets path for broader Cook Inlet tax reform by 2022

Bill Summary- What is in the H(RES) CS?

Repurchase Limits

Changes in Committee Substitute

- Adds an annual “cap” on per-company credit repurchases of \$200 million
- Multiple partners in the same project can each claim \$200 million. However, a single company cannot artificially split themselves to multiply the benefit
- Cash flow protection in the case of a large “outlier” project such as proposed by Armstrong
 - Modeling showed annual credits from a similar project of up to \$800 million

Bill Summary- What is in the H(RES) CS?

Repurchase Limits (cont'd)

Historic Notes on large annual credits:

Over the 2007-2016 history of the tax credit program:

- There has only been **one** instance of a company who ever received **> \$200** million in a single year
- **Five** times ever when one company received between **\$100 - \$200** million in one year
- **11** times ever when one company received between **\$50 - \$100** million in one year

Bill Summary- What is in the H(RES) CS?

Remove Exceptions / Loopholes

CS retains two proposed changes to prevent artificially inflated net operating losses

- Can't use GVR (new oil value reduction) to increase the size of a Net Operating Loss (has led to credits greater than 100% of loss)
- If a municipal entity owns production and sells only a portion of that production to an outside party, only the pro-rata share of expenses can be deducted against revenue

Bill Summary- What is in the H(RES) CS?

Brief explanation of GVR / NOL Problem (Sec. 12; AS 43.55.23(b)(2))

- CSHB 247 would prohibit the gross value reduction (GVR) from being used to increase size of net operating loss and by extension, the NOL credit
- In the low oil price / low cost example shown on the next page, the net operating loss would be limited to the net value before GVR, which is \$6 per barrel instead of \$12 per barrel
- The resulting credit is 35% of the actual net operating loss, reducing the credit liability to the State by 50%. For a GVR-field producing 10,000 taxable barrels per day, the difference is \$7.6 million

Bill Summary- What is in the H(RES) CS?

Current law allows GVR to increase an NOL credit

**Example
showing
NOL due to
low prices**

20% GVR-Eligible Production increasing Size of Net Operating Loss and Proposed Change*		
	Current Law	Proposed Change
West Coast Price (\$/tax bbl)	\$40	\$40
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$30	\$30
Lease Expenditures (\$/tax bbl)	-\$36	-\$36
Net Value before GVR (\$/tax bbl)	-\$6	-\$6
Wellhead Value from above (\$/tax bbl)	\$30	\$30
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction (\$/tax bbl)	\$6	\$6
GVR-Adjusted Net Value (\$/tax bbl)	-\$12	-\$12
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$0.00	\$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	\$30	\$30
Minimum Tax (\$/tax bbl)	\$1.20	\$1.20
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$5	\$5
Production Tax after credits (\$/tax bbl)	\$0.00	\$0.00
Net Operating Loss for Credit (\$/tax bbl)	-\$12	-\$6
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit (\$/tax bbl)	\$4.20	\$2.10
NOL per barrel times 10,000 taxable b/d	\$15,330,000	\$7,665,000
Difference		\$7,665,000

*Current assumptions include transport costs of \$10 per barrel and deductible lease expenditures of \$36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160.

Bill Summary- What is in the H(RES) CS?

Brief explanation of Municipal Utility Problem (Sec. 26; AS 43.55.895(b))

If a municipal utility owns a portion of a gas field and uses all of the gas to generate its own power, this is not taxable

However, if a portion of that gas is sold to a third party, those sales are taxable.

Current law allows all lease expenditures to be used to offset the comparably small amount of sales, potentially generating large credits. HB247 proposes to limit the lease expenditure calculation to just the pro-rata share of the expenditures equal to the proportion of the gas that was sold

	Current Law	HB247 Proposal
Daily Volume Produced (mmcf)	20	20
Volume Used By Utility (untaxable)	18	18
Volume Sold to 3rd Parties (taxable)	2	2
Sales Price / mcf	\$8	\$8
Annual Revenue Subject to Tax (\$000)	\$5,840	\$5,840
Lease Expenditures per mcf produced	\$3	\$3
Annual Lease Expenditures (\$000)	\$21,900	\$21,900
Allowable Lease Expenditures	\$21,900	\$2,190
Operating Profit (Loss)	(\$16,060)	\$3,650
Operating Loss Credit @ 25%	\$4,015	n/a

Bill Summary- What is in the H(RES) CS?

Other Provisions

Interest Rate Reform

- Fixes a technical error in SB21 that prevents compound interest on underpayments and assessments.
Since 2014 we have collected only simple interest
- Interest rate remains 3% above federal discount rate

Bankruptcy & Debt Protection

- Credit certificates can be used to satisfy obligations to the state for the company's oil and gas business before repurchase
- Surety bond of \$250,000 for developers, to protect unsecured creditors in event of default

Changes from Governor's to Resources Version

Changes made in House Resources

- Kept and improved many of the technical fixes, including inadvertent “double dip” credit for new oil on the North Slope
- Reduced Cook Inlet credits, with different emphasis and delayed phase-out
- Increased repurchase “cap,” limiting its impact to just very large ‘outlier’ projects
- Removed all changes to minimum tax “floor,” transparency provisions, interest rate increase, and several smaller provisions
- New legislative working group to review tax regimes outside the North Slope

Changes made in House Resources

Cook Inlet Credits

Original proposal was to repeal 20% Capital (QCE) and 40% Well (WLE) credits on 7/1/16, while maintaining the 25% Operating Loss (NOL)

- Effectively, three substantial changes:
 1. Timing: CS phased in the changes over 18 months, taking full effect on 1/1/18
 2. Total: CS retained a 30% level of development support vs. 25% in original bill
 3. Applicability: CS maintained 20% credit support for producers who earn a profit, vs. no support in original version. Means additional companies will still qualify for cash credits

Changes made in House Resources

Repurchase Limits

Original proposal added four limits to repurchase:

- Per-company / per-year cap of \$25 million
- Large companies, with annual revenue over \$10 billion, are ineligible for credit repurchase
- Percentage of repurchase tied to percentage of Alaska resident hire
- 10-year carry forward sunset

Impact of Changes

- A large percentage of projected savings were in these provisions, although tighter repurchase limits would increase the total amount of “carried forward” credits that could offset future production

Changes made in House Resources

Strengthen Minimum Tax

CS eliminated- items that impact legacy producers:

- Can't use an operating loss credit, to reduce payments below the 4% floor
This was the largest "added revenue" component
- Prevent per-taxable-barrel credits earned in one month from being used against another month's taxes at true-up
- Increase in minimum tax from 4% to 5%

CS eliminated- items that impact new oil producers:

- Extend minimum tax to GVR-eligible "new" oil
- Not allow small producer credit to reduce tax payments below the floor



Fiscal Impact

Fiscal Impact

Summary of Fiscal Note with Bill Changes (updated for Prelim. Spring 2016 Revenue Forecast)

	FY17		FY18		FY19	
	HB247	CS HB247(RES)	HB247	CS HB247(RES)	HB247	CS HB247(RES)
Reduced Spending						
Credits Eliminated or Reduced						
North Slope	\$15	\$10	\$25	\$25	\$20	\$20
Cook Inlet / Mid Earth	\$35	\$10	\$65	\$45	\$45	\$30
Credits Deferred						
North Slope	\$275	\$0	\$50	\$0	\$25	\$0
Cook Inlet / Mid Earth	\$275	\$0	\$50	\$0	\$25	\$0
Budget Subtotal	\$600	\$20	\$190	\$70	\$115	\$50
Increased Revenue						
Floor "Hardening"	\$125	\$0	\$180	\$0	\$215	\$0
Floor Increase to 5%	\$50	\$0	\$55	\$0	\$50	\$0
CI Credit Repeal	\$10	\$0	\$10	\$0	\$10	\$0
Revenue Subtotal	\$185	\$0	\$245	\$0	\$275	\$0
Total Bill Impact	\$785	\$20	\$435	\$70	\$390	\$50

Fiscal Impact

Impact of Changes from Fall 15 to Preliminary Spring 16 Forecast

- Much lower prices for longer period means:
 - Larger company operating losses
 - Status quo, production tax goes to near zero as all of it is offset by NOL credits
 - Large carried-forward NOL's, \$630 million after FY17
- Refundable credit estimate for FY17 increases by \$200 mil
 - Larger company operating losses
 - Higher than expected work on exploration projects, before expected sunset this year (up to 85% on NS)

Fiscal Impact

In future years, our “status quo” credit forecast appears to decrease.

This can’t really be built into future budgets.

- Our credit forecast only includes “known” projects
- Most “new” projects would add to the amount of projected credits
- Credit projections use the same conservative methodology as DOR’s production forecast

Intro, Samples, and Summary of Scenario Analysis Model

Introduction to Scenario Analysis

- The Tax Division has developed a new model, looking at project life cycles
- Cash flow over the 30-40 year life of a project, for the state's production tax and credits, all state revenue, the producer's cash flow, and discounted (NPV)
- Scenarios Analyzed at \$40, \$60, \$80, and Fall Forecast oil price
- Status quo modeled vs. Governor's original bill
- Two full presentations on BASIS from previous committee

Introduction to Scenario Analysis

Fields Analyzed:

North Slope Scenarios:

- 50 million barrel North Slope Oil
- 750 million barrel North Slope Oil (20% GVR)

Cook Inlet Scenarios

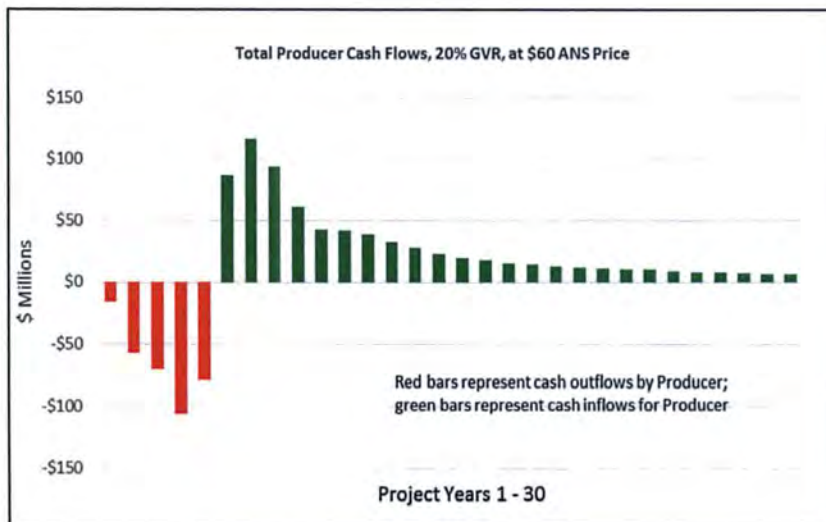
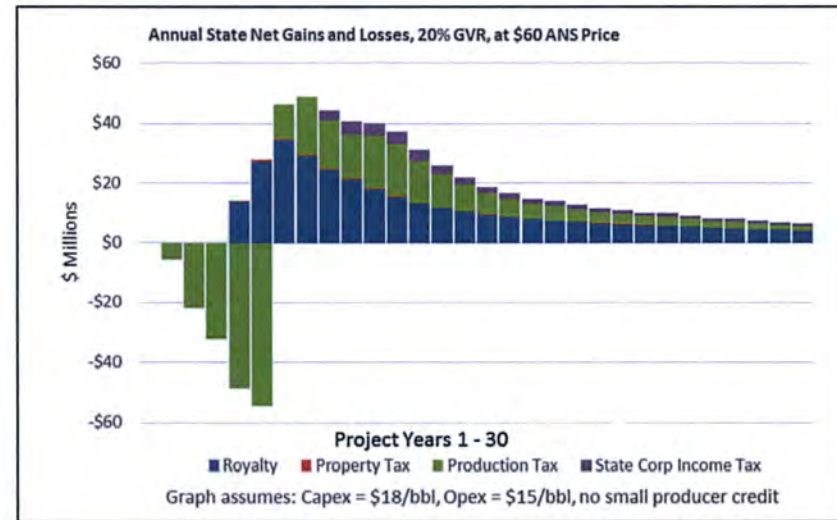
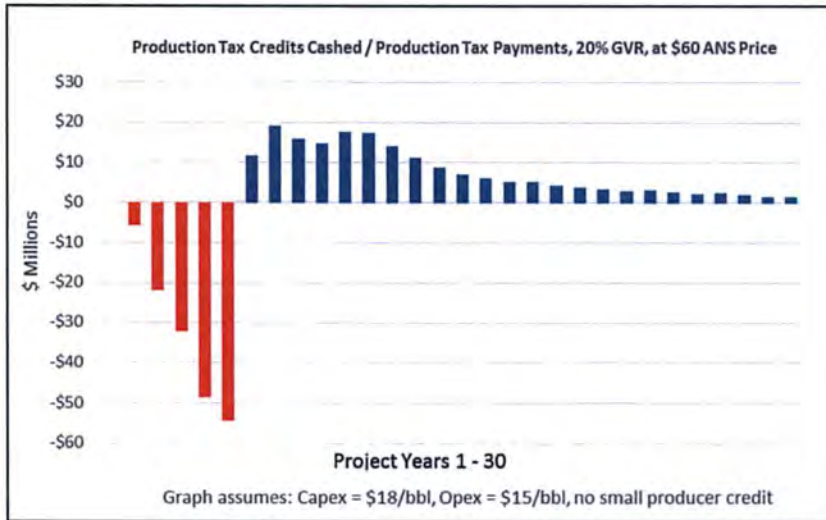
- 50 million barrel Cook Inlet Oil (with and without tax caps)

Supplemental Scenarios

- 750 million barrel North Slope Oil (30% GVR)
- 750 million barrel North Slope Oil (50% Private Royalty)
- 670 bcf Cook Inlet Gas
- 670 bcf Middle Earth Gas

Sample of Scenario Analysis

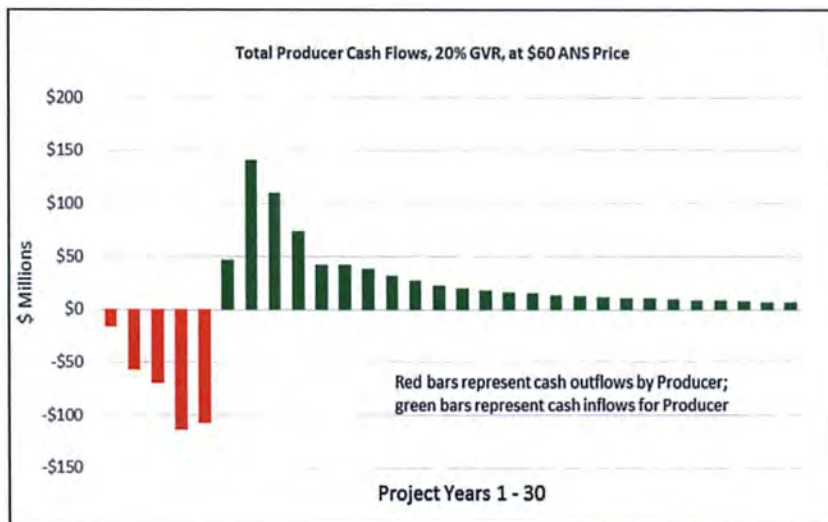
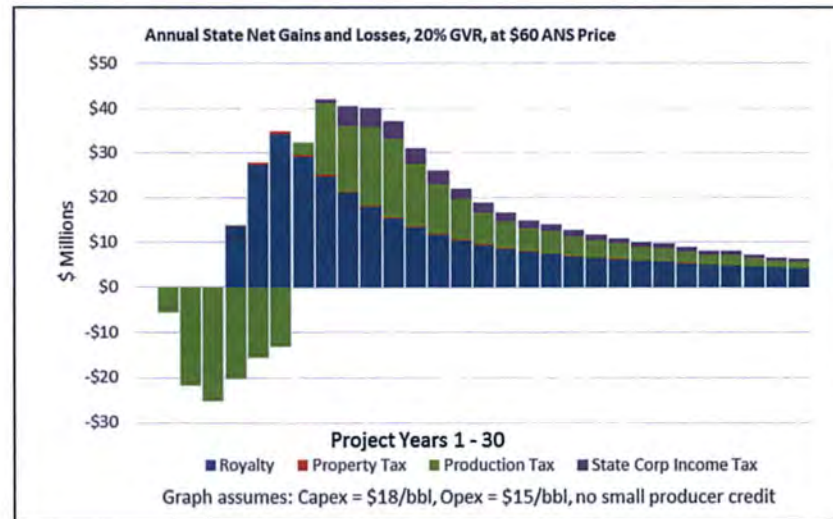
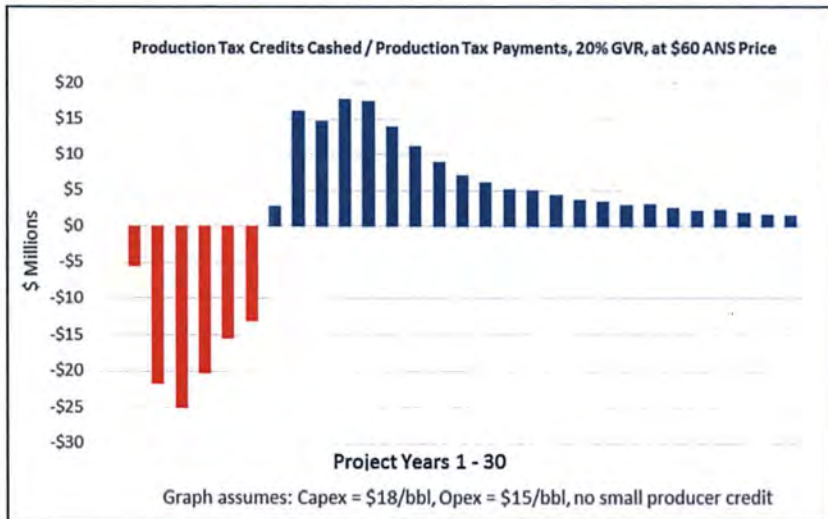
North Slope- 50 mmbo Status Quo, \$60/bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cashed	162
Production Tax Paid	183
Net Production Tax	21
Production Tax NPV 6.15%	-37
<hr/>	
Total Annual State Losses	121
Total Annual State Gains	501
Net State Gain (Loss)	380
State NPV 6.15%	136
<hr/>	
Total Producer Cash Out	327
Total Producer Cash In	731
Net Producer Cash Flow	404
Producer Cash NPV 6.15%	112

Sample of Scenario Analysis

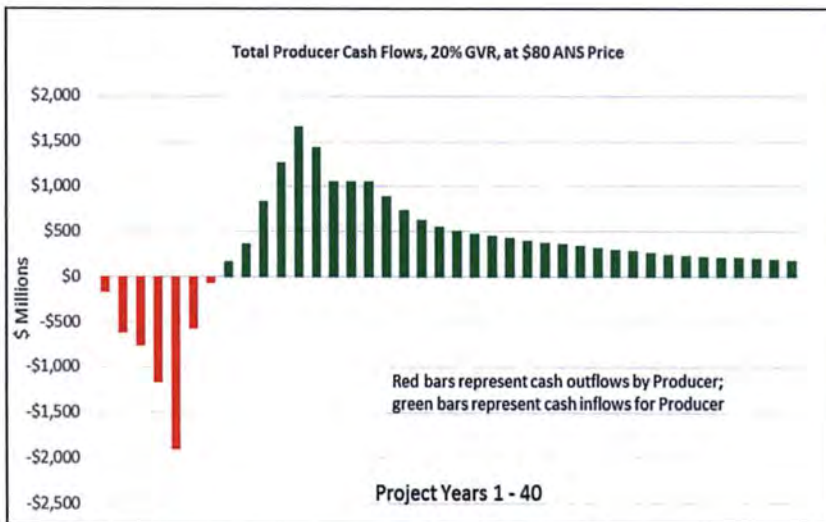
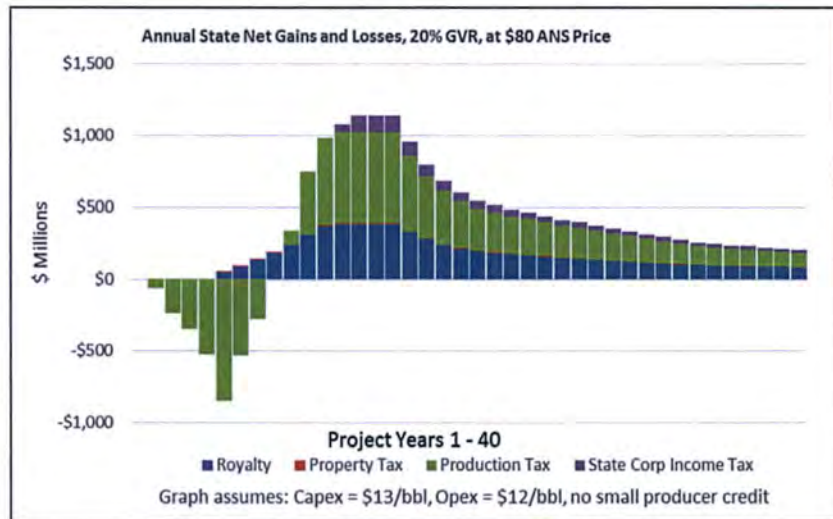
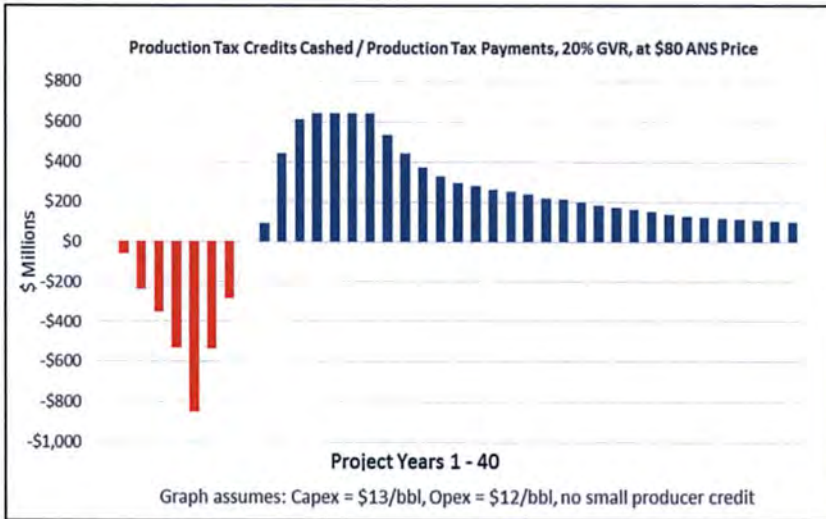
North Slope- 50 mmbo HB 247, \$60 / bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cashed	101
Production Tax Paid	155
Net Production Tax	54
Production Tax NPV 6.15%	-10
Total Annual State Losses	59
Total Annual State Gains	470
Net State Gain (Loss)	412
State NPV 6.15%	163
Total Producer Cash Out	362
Total Producer Cash In	746
Net Producer Cash Flow	384
Producer Cash NPV 6.15%	93

Sample of Scenario Analysis

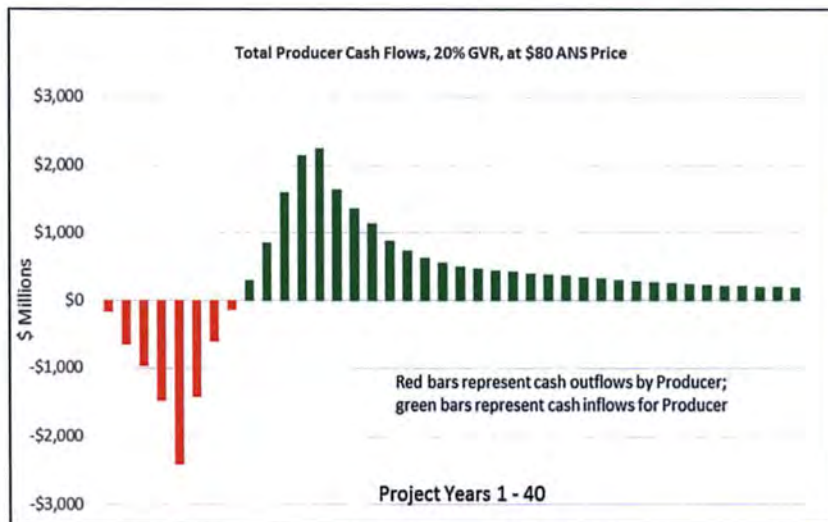
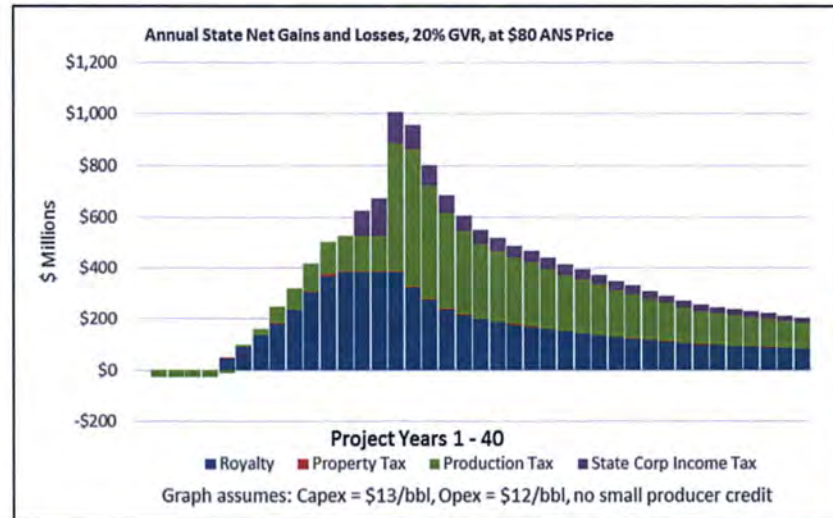
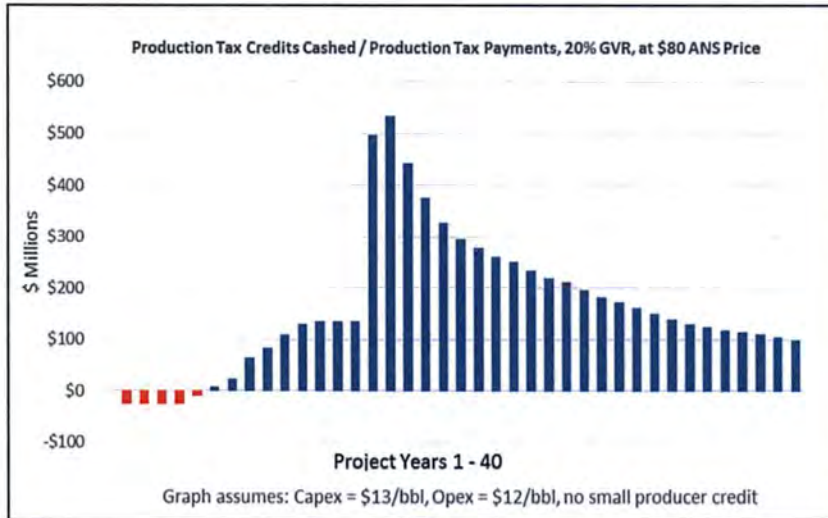
North Slope- 750 mmbo Status Quo, \$80/bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cashed	2,830
Production Tax Paid	8,923
Net Production Tax	6,093
Production Tax NPV 6.15%	869
Total Annual State Losses	2,553
Total Annual State Gains	16,623
Net State Gain (Loss)	14,069
State NPV 6.15%	3,527
Total Producer Cash Out	5,247
Total Producer Cash In	17,933
Net Producer Cash Flow	12,686
Producer Cash NPV 6.15%	2,216

Sample of Scenario Analysis

North Slope- 750 mmbo HB 247, \$80 / bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cashed	109
Production Tax Paid	6,533
Net Production Tax	6,424
Production Tax NPV 6.15%	1,743
Total Annual State Losses	100
Total Annual State Gains	14,479
Net State Gain (Loss)	14,379
State NPV 6.15%	4,388
Total Producer Cash Out	7,832
Total Producer Cash In	20,317
Net Producer Cash Flow	12,485
Producer Cash NPV 6.15%	1,415

Summary of Scenario Analysis

North Slope Scenarios

Field Size (million bbl)	Tax Regime	Producer Size (>\$10 billion revenue)	Oil Price	Credits Paid (\$millions)	Net Production Tax Paid (\$millions)	Production Tax NPV 6.15% (\$millions)	Net State Gain (Loss) (\$millions)	State NPV 6.15% (\$millions)	Producer Cash Flow (\$millions)	Producer NPV 6.15% (\$millions)
50	Status Quo	n/a	\$40	\$221	(\$217)	(\$153)	(\$24)	(\$58)	\$19	(\$99)
50	Status Quo	n/a	\$60	\$162	\$21	(\$37)	\$380	\$136	\$404	\$112
50	Status Quo	n/a	\$80	\$134	\$323	\$110	\$844	\$364	\$751	\$289
50	Status Quo	n/a	Fall 15 FC	\$155	\$183	\$40	\$629	\$255	\$588	\$203
50	HB 247	small	\$40	\$150	(\$116)	(\$95)	\$71	(\$1)	(\$71)	(\$155)
50	HB 247	small	\$60	\$101	\$54	(\$10)	\$412	\$163	\$384	\$93
50	HB 247	small	\$80	\$82	\$344	\$128	\$863	\$380	\$738	\$277
50	HB 247	small	Fall 15 FC	\$95	\$207	\$60	\$651	\$274	\$574	\$189
750	Status Quo	n/a	\$40	\$2,967	(\$2,738)	(\$2,047)	\$367	(\$1,016)	\$2,131	(\$1,768)
750	Status Quo	n/a	\$60	\$2,897	\$1,568	(\$642)	\$7,115	\$1,197	\$7,475	\$312
750	Status Quo	n/a	\$80	\$2,830	\$6,093	\$869	\$14,069	\$3,527	\$12,686	\$2,216
750	Status Quo	n/a	Fall 15 FC	\$2,864	\$4,135	\$206	\$11,069	\$2,509	\$10,458	\$1,401
750	HB 247	small	\$40	\$134	\$807	\$206	\$3,685	\$1,192	(\$39)	(\$3,744)
750	HB 247	small	\$60	\$116	\$2,867	\$749	\$8,331	\$2,553	\$6,686	(\$870)
750	HB 247	small	\$80	\$109	\$6,424	\$1,743	\$14,379	\$4,388	\$12,485	\$1,415
750	HB 247	small	Fall 15 FC	\$111	\$4,523	\$1,172	\$11,433	\$3,461	\$10,222	\$520
750	HB 247	large	\$40	\$0	\$982	\$337	\$3,860	\$1,322	(\$214)	(\$3,875)
750	HB 247	large	\$60	\$0	\$3,084	\$879	\$8,494	\$2,679	\$6,579	(\$974)
750	HB 247	large	\$80	\$0	\$6,424	\$1,806	\$14,379	\$4,451	\$12,485	\$1,355
750	HB 247	large	Fall 15 FC	\$0	\$4,683	\$1,303	\$11,596	\$3,587	\$10,116	\$417

Summary of Scenario Analysis

Cook Inlet Scenarios

Field Size (million bbl)	Tax Regime	Tax Caps Sunset?	Oil Price	Credits Paid (\$millions)	Net Production Tax Paid (\$millions)	Production Tax NPV 6.15% (\$millions)	Net State Gain (Loss) (\$millions)	State NPV 6.15% (\$millions)	Producer Cash Flow (\$millions)	Producer NPV 6.15% (\$millions)
50	Status Quo	yes	\$40	\$349	(\$177)	(\$192)	\$99	(\$59)	\$139	\$3
50	Status Quo	yes	\$60	\$337	\$128	(\$50)	\$579	\$167	\$527	\$202
50	Status Quo	yes	\$80	\$329	\$432	\$92	\$1,060	\$395	\$915	\$396
50	Status Quo	yes	Fall 15 FC	\$335	\$294	\$26	\$840	\$288	\$735	\$303
50	Status Quo	no	\$40	\$357	(\$357)	(\$275)	(\$70)	(\$137)	\$249	\$54
50	Status Quo	no	\$60	\$349	(\$349)	(\$269)	\$134	(\$37)	\$817	\$335
50	Status Quo	no	\$80	\$341	(\$341)	(\$263)	\$337	\$63	\$1,385	\$612
50	Status Quo	no	Fall 15 FC	\$347	(\$347)	(\$268)	\$241	\$14	\$1,124	\$481
50	HB 247	yes	\$40	\$120	\$38	(\$19)	\$300	\$108	\$9	(\$135)
50	HB 247	yes	\$60	\$104	\$343	\$121	\$780	\$331	\$397	\$80
50	HB 247	yes	\$80	\$89	\$647	\$263	\$1,261	\$557	\$784	\$278
50	HB 247	yes	Fall 15 FC	\$89	\$509	\$197	\$1,041	\$451	\$604	\$183
50	HB 247	no	\$40	\$142	(\$142)	(\$101)	\$131	\$29	\$118	(\$76)
50	HB 247	no	\$60	\$134	(\$134)	(\$97)	\$335	\$126	\$686	\$214
50	HB 247	no	\$80	\$126	(\$126)	(\$92)	\$538	\$225	\$1,254	\$494
50	HB 247	no	Fall 15 FC	\$132	(\$132)	(\$95)	\$442	\$177	\$994	\$362

Summary of Scenario Analysis

Supplemental North Slope Scenarios

<i>750 MM Barrel Field, 16.67% Royalty, 30% GVR; Assumes all Royalty paid to State</i>									
Tax Regime	Oil Price	Producer Size (>\$10 billion revenue)	Credits Paid (\$millions)	Net Production Tax Paid (\$millions)	Production Tax NPV 6.15% (\$millions)	Net State Gain (Loss) (\$millions)	State NPV 6.15% (\$millions)	Producer Cash Flow (\$millions)	Producer NPV 6.15% (\$millions)
Status Quo	\$40	n/a	\$2,982	(\$2,893)	(\$2,096)	\$1,097	(\$756)	\$1,656	(\$1,965)
Status Quo	\$60	n/a	\$2,905	\$1,178	(\$772)	\$8,210	\$1,578	\$6,764	\$48
Status Quo	\$80	n/a	\$2,841	\$5,472	\$656	\$15,532	\$4,030	\$11,735	\$1,879
Status Quo	Fall 2015 FC	n/a	\$2,874	\$3,623	\$35	\$12,383	\$2,964	\$9,604	\$1,092
Status Quo	\$80	Large	\$2,841	\$5,472	\$656	\$15,532	\$4,030	\$11,735	\$1,879
HB 247	\$40	n/a	\$136	\$761	\$190	\$4,574	\$1,496	(\$928)	(\$4,049)
HB 247	\$60	n/a	\$117	\$2,605	\$679	\$9,544	\$2,992	\$5,897	(\$1,179)
HB 247	\$80	n/a	\$110	\$5,818	\$1,557	\$15,855	\$4,918	\$11,525	\$1,052
HB 247	Fall 2015 FC	n/a	\$112	\$4,171	\$1,078	\$12,896	\$3,991	\$9,271	\$154
HB 247	\$80	Large	\$0	\$5,818	\$1,621	\$15,855	\$4,982	\$11,525	\$991
<i>750 MM Barrel Field, 50% Private Royalty (at 12.5%), 20% GVR; Assumes non-Private Royalty paid to State</i>									
Status Quo	\$40	n/a	\$2,963	(\$2,668)	(\$2,023)	(\$971)	(\$1,474)	\$2,089	(\$1,785)
Status Quo	\$60	n/a	\$2,892	\$1,685	(\$602)	\$4,886	\$433	\$7,404	\$286
Status Quo	\$80	n/a	\$2,823	\$6,256	\$925	\$10,947	\$2,458	\$12,587	\$2,181
Status Quo	Fall 2015 FC	n/a	\$2,858	\$4,278	\$255	\$8,331	\$1,572	\$10,371	\$1,370
Status Quo	\$80	Large	\$2,823	\$6,256	\$925	\$10,947	\$2,458	\$12,587	\$2,181
HB 247	\$40	n/a	\$131	\$878	\$230	\$2,351	\$735	(\$109)	(\$3,768)
HB 247	\$60	n/a	\$113	\$2,984	\$789	\$6,101	\$1,789	\$6,614	(\$896)
HB 247	\$80	n/a	\$108	\$6,588	\$1,799	\$11,257	\$3,319	\$12,385	\$1,379
HB 247	Fall 2015 FC	n/a	\$110	\$4,667	\$1,222	\$8,694	\$2,524	\$10,135	\$488
HB 247	\$80	Large	\$0	\$6,588	\$1,862	\$11,257	\$3,382	\$12,385	\$1,319

Summary of Scenario Analysis

Supplemental Cook Inlet and Middle Earth Scenarios

Geography	Tax Regime	Tax Caps Sunset?	Gas Price	Credits Paid (\$millions)	Net Production Tax Paid (\$millions)	Production Tax NPV 6.15% (\$millions)	Net State Gain (Loss) (\$millions)	State NPV 6.15% (\$millions)	Producer Cash Flow (\$millions)	Producer NPV 6.15% (\$millions)
Cook Inlet	Status Quo	yes	\$4.00	\$365	(\$262)	(\$264)	\$124	(\$67)	\$177	\$30
Cook Inlet	Status Quo	yes	\$6.00	\$360	\$105	(\$84)	\$709	\$226	\$663	\$292
Cook Inlet	Status Quo	yes	\$8.00	\$351	\$462	\$89	\$1,285	\$512	\$1,154	\$554
Cook Inlet	Status Quo	no	\$4.00	\$404	(\$367)	(\$315)	\$26	(\$114)	\$241	\$60
Cook Inlet	Status Quo	no	\$6.00	\$383	(\$336)	(\$297)	\$297	\$27	\$931	\$421
Cook Inlet	Status Quo	no	\$8.00	\$373	(\$326)	(\$290)	\$548	\$158	\$1,633	\$784
Cook Inlet	HB 247	yes	\$4.00	\$136	\$16	(\$35)	\$384	\$154	\$8	(\$148)
Cook Inlet	HB 247	yes	\$6.00	\$122	\$383	\$143	\$696	\$442	\$494	\$132
Cook Inlet	HB 247	yes	\$8.00	\$113	\$740	\$316	\$1,545	\$727	\$985	\$400
Cook Inlet	HB 247	no	\$4.00	\$144	(\$88)	(\$86)	\$286	\$106	\$72	(\$114)
Cook Inlet	HB 247	no	\$6.00	\$122	(\$58)	(\$69)	\$557	\$243	\$762	\$263
Cook Inlet	HB 247	no	\$8.00	\$113	(\$48)	(\$63)	\$809	\$373	\$1,464	\$630
Mid Earth	Status Quo	N/A	\$4.00	\$404	(\$281)	(\$277)	\$73	(\$95)	\$189	\$37
Mid Earth	Status Quo	N/A	\$6.00	\$383	(\$6)	(\$154)	\$573	\$144	\$731	\$334
Mid Earth	Status Quo	N/A	\$8.00	\$373	\$259	(\$37)	\$1,063	\$377	\$1,278	\$630
Mid Earth	HB 247	N/A	\$4.00	\$144	(\$3)	(\$47)	\$333	\$126	\$20	(\$139)
Mid Earth	HB 247	N/A	\$6.00	\$122	\$272	\$74	\$833	\$361	\$562	\$175
Mid Earth	HB 247	N/A	\$8.00	\$113	\$537	\$190	\$1,323	\$592	\$1,109	\$476



Implementation

Implementation

Transition

- Original bill was written with an effective date of 7/1/16 for nearly all changes
- CS moves most changes to 1/1/17, with the full repeal of the Well Lease Expenditure credit on 1/1/18
- The bill's original fiscal note included a fund capitalization for \$926,575.0 to the .028 fund. This is the difference between what is in the operating budget and \$1 billion.
- This would have covered all expected credit liability before the effective date.
- With the changes made in the CS, additional appropriation will be needed

Implementation

Connection to Fiscal Plan

- HB247 was introduced as one of 10 bills that comprised the governor's fiscal plan.
- All the bills taken together, with anticipated budget cuts, proposed a balanced budget by FY19
- The broader fiscal package, and the specific tax credit bill, are intended to add certainty to industry regarding what support the state can provide and how we're going to continue to pay for government
- Original bill also assumed companion "AIDEA Loan" bill to help with projects that lost funding with credit changes
 - HB246 would create a new "fourth fund" at AIDEA to concentrate on oil and gas development loans, for proven reserves
 - Envisioned \$200 million initial fund capitalization

Implementation

Administration

- The changes anticipated in this bill still require somewhat substantial reprogramming of the Tax Revenue Management System (TRMS) and Revenue Online (ROL) which allows a taxpayer to file a return online and update the current tax return forms
- We have received a preliminary estimate from the software developer, and currently assume a one-time cost of about \$1.2 million to accomplish this
- We do not anticipate any additional costs to administer the tax program
- There will also be a need for substantial amendments to existing regulations to fully implement the changes

NEW SUSTAINABLE

ALASKA

PLAN



Pulling Together to Build Our Future

Thank You!

Contact Information

Randall Hoffbeck
Commissioner
Department of Revenue
Randall.Hoffbeck@Alaska.gov
(907) 465-2300

Ken Alper
Director, Tax Division
Department of Revenue
Ken.Alper@Alaska.gov
(907) 465-8221



Hilcorp Alaska, LLC

Post Office Box 244027
Anchorage, AK 99524-4027

3800 Centerpoint Drive
Suite 1400
Anchorage, AK 99503

Phone: 907/777-8300
Fax: 907/777-8301

**Hilcorp Alaska, LLC Testimony
Committee Substitute House Bill 247
House Finance Committee
April 1, 2016**

For the record my name is Dave Wilkins, I'm the Senior Vice President for Hilcorp Alaska. Mr. Chairman and members of the committee thank you for the opportunity to address you today about CSHB 247. I have previously testified on HB247 at the House Resources Committee on March 1st of this year.

For those of you who aren't familiar with our company, Hilcorp is the largest privately-held oil and gas company in the United States. Headquartered in Houston, TX, Hilcorp has operations in the Gulf Coast of Texas and Louisiana, the Northeast United States, and Alaska's Cook Inlet and North Slope. Hilcorp was founded 1989 and has more than 1,400 full-time employees. Just over 500 of those employees support our operations here in Alaska and I'm proud to say that nearly 90% are Alaskan residents.

Here in Alaska we operate approximately 53,000 gross barrels of oil per day and 150 million cubic feet of gross gas per day from approximately 500 producing wells, for a total net production to Hilcorp of approximately 57,000 barrels of oil equivalent per day.

Hilcorp's assets are primarily (although not exclusively) older fields with extensive production histories, steady and

predictable performance that carry incredible opportunity for getting more oil and gas out of the ground safely and responsibly while extending production life through efficiency and thousands of smaller scale projects. We think the State needs to attract more companies like Hilcorp as fields and infrastructure continue to age.

That brings me to why I sit before you here today. Hilcorp's production in Alaska represents approximately 40% of what we produce company-wide, so our success here in Alaska is critical to Hilcorp's overall success.

I can say from Hilcorp's perspective, the credits in question have resulted in more investments here in Alaska, both on the North Slope and the Cook Inlet basins. Starting with the Cook Inlet area, it's no secret that Hilcorp has been a big part in reviving energy security in Southcentral Alaska.

During the past 4 years, we have invested over \$1 billion in projects and have drilled over 50 wells in the Cook Inlet Area. As a result of this investment and the increased production, we're sending more oil to be refined and used in Alaska. On the natural gas side, due to our significant investment over the past four years, we are now making gas supply commitments with local utilities into the year 2023. We stand by our commitment to serve Alaskan's energy needs first and are working to ensure a reliable and affordable energy source for Alaska's largest population hub.

As you're well aware, prior to Hilcorp's entry into Alaska, there was widespread concern of "brownouts" and that utilities would need to import natural gas to meet demand. I have

spoken to many who made electric generator purchases during this time expecting service interruptions.

Hilcorp's success certainly didn't come without challenges. Developing oil and natural gas in the Cook Inlet basin carries a very high cost of production coupled with decline rates that vary from 15-50% annually depending on the field. The simple fact is that if we are not spending money on projects that bring on new production we cannot curb these declines. So we believe it is in both our best interest and the state's best interest that we continue to spend dollars on trying to produce more oil and gas.

It's also no secret that Alaska's tax credit system and the Cook Inlet Recovery act were key drivers in bringing Hilcorp to Alaska and in our investments to date. Since 2012, Hilcorp has spent approximately \$3.2 Billion dollars in capital and acquisition costs here in the State of Alaska. Those investments were aimed at one primary goal – increasing oil & gas production. Since 2012, we have increased overall production by approximately 40%. A lot of people like to ask us how we do it, and the answer is simple. We have and continue to make significant investments; investments that were encouraged by the State's tax credit program and investment that did just what the credits were meant to do...Increase energy supply for Alaskans.

I would argue that our success has been meaningful to many, including the State. Increased production levels of oil and natural gas in the Cook Inlet basin has resulted in increased royalty rates, property taxes, jobs and more.

One example of this is looking at our Monopod offshore platform. In January 2012, right after Hilcorp took over operations, the realized oil price was approximately \$95 per barrel. Production was approximately 600 barrels of oil per day,

a marginal rate for an offshore platform that has a high operating cost. Because of this marginal rate and low profitability, the Monopod qualified for royalty relief under HB 185 passed in 2003.

The royalty rate was reduced to help maintain profitability for the platform so it would not be shut-in and/or permanently abandoned. As the royalty owner, the state's take from the Monopod at that time was approximately \$90,000 per month...again, when oil was about \$95 per barrel. Over the past 4 years, Hilcorp has done over 150 projects on the Monopod, most of which were smaller in scope, and has increased production to a current rate of approximately 3,000 barrels of oil per day.

Because of the increase in production, the state's royalty share is back up to the standard 12-1/2% and even with oil prices at \$35 per barrel, the state's royalty take from the Monopod has increased to approximately a half a million dollars per month. That's over a 5 times more in royalty dollars going to the state, despite oil prices declining more than 60%. Furthermore, and probably more important, our success at the Monopod has added 20+ years of production life and 8 million barrels of future oil production.

The Monopod is not an isolated anomaly. Since Hilcorp's entry into the Cook Inlet area in 2012, oil production has doubled, which has increased oil royalty to the state of over \$70 million. Furthermore, even though oil prices are lower this year, estimated oil royalties will be approximately \$10 million more this year than what they were right before Hilcorp's entry when oil prices were high. Hilcorp's success in increasing oil

production over the last 4 years also has increased future estimated oil production by 20-30 million barrels, meaning increased future royalties for the state.

I would offer, we need more results like this...more production. I will also offer that the state needs a system in place that is stable, predictable and incentivizes, not jeopardizes, continued investments. Hilcorp's Cook Inlet success is a really good example of the State putting good policy in place aimed at achieving a positive result and getting one.

I can tell you today that the credits Hilcorp EARNED were absolutely reinvested in the resource. Our current production rates prove it. We have managed to work our way above the 50K Barrel threshold both through acquisition and A LOT of hard work. Breaking the 50K per day mark means we can no longer cash in the very credits that this legislation proposes to take away. But other budding companies can, and Hilcorp is a company that always welcomes competition in the market. We want to help promote a healthy industry throughout the state. An active industry means additional service companies will be attracted to Alaska which creates competition and will help drive down costs.

A lot of the discussion regarding credits has involved the Cook Inlet basin, primarily because of the notable increase in production and activity that the existing tax structure intended to generate was wildly successful. Our success in Cook Inlet is what fueled Hilcorp's interest in expanding to the North... And we did just that in November of 2014 when we purchased three of BP's assets on the North Slope, Milne Point, Endicott and Northstar fields. When we took over operations, we were

producing approximately 36,000 gross barrels of oil per day from these three fields and now we produce approximately 37,000 gross barrels of oil per day.

After a year of working with these assets, I am so excited about the amount of opportunity up there. We have a comprehensive list of projects we can invest in...projects that will put more oil in the pipeline and support literally hundreds, if not thousands, of jobs for Alaskans. We currently have 1 drilling rig running on the slope and would like to pick up a 2nd rig by the end of the year.

BUT, in today's price environment and in the face of an uncertain state fiscal structure, it is to be determined what projects move forward and when. We have to be very thoughtful with every penny we spend. Investment budgets are shrinking and compete with other oil and gas producing areas throughout the world. I want Hilcorp's investment dollars to come to Alaska. We have to continue to work hard to build efficiencies and cut costs, while ensuring we do it safely and without causing harm to the environment. Cutting COSTS, not corners, is the only way we will survive the current downturn.

I know that we aren't the only ones faced with difficult decisions and realities during this challenging time. I also recognize the members of this committee and the legislature have much to consider about what is best for the state and our future. I ask you today to recognize that change creates uncertainty, and uncertainty deters investment and affects jobs. Investment, whether for exploration or development, is the only way to increase production and increased production is the only way we can help get out of this situation.

Over the past 30 years, I have worked in several other basins throughout the US, and I can say with confidence Alaska has changed its tax policy more in the last few years than other areas have in decades. I want to keep Alaskans working, I want to increase production but the company simply isn't going to continue to invest hundreds of millions of dollars in Alaska, especially in this price environment, when the fiscal structure continually changes.

So, in closing I'd just like to say again that the uncertainty we are currently facing threatens our ability to plan our investments and that the decisions you make today will impact the economics of the opportunities to increase tomorrow's production both in Cook Inlet and on the North Slope.

Thank you.



ALASKA STATE LEGISLATURE

HOUSE FINANCE COMMITTEE

State Capitol, Room 519

Rep. Mark Neuman, Co-Chair

Rep. Steve Thompson, Co-Chair

Monday, April 4, 2016

8:30 AM

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

Industry Testimony:
 Furie Operating Alaska
 Great Bear Petroleum
 BlueCrest Energy
 Ahtna

CSL

		Tentative no	If so calling in
Jim Mery	Doyon Senior Vice President Lands & Natural Resources		
Chris Cook	Ahtna Director of Finance	Yes	In person
Matt Block	General Counsel (available for questions)		
Bruce Webb David Elder	Furie Vice President CFO	Yes	In Person
Pat Galvin	Great Bear Chief Commercial Officer & General Counsel	-Yes	In person
Benjamin Johnson	BlueCrest Energy President/CEO	Yes	In Person



ALASKA STATE LEGISLATURE
HOUSE FINANCE COMMITTEE

State Capitol, Room 519

Rep. Mark Neuman, Co-Chair

Rep. Steve Thompson, Co-Chair

Monday, April 4, 2016

8:30 AM

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

Industry Testimony:

Furie Operating Alaska

Great Bear Petroleum

BlueCrest Energy

Ahtna

- 1.Strong Investment Value of Tax Credits
- 2.Cosmopolitan Unit Overview
- 3.Impact of HB 247 CS on BlueCrest

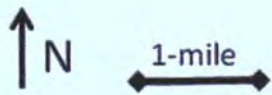


J. Benjamin Johnson
House Finance Committee Testimony
April 4, 2016

Cosmopolitan Project Area

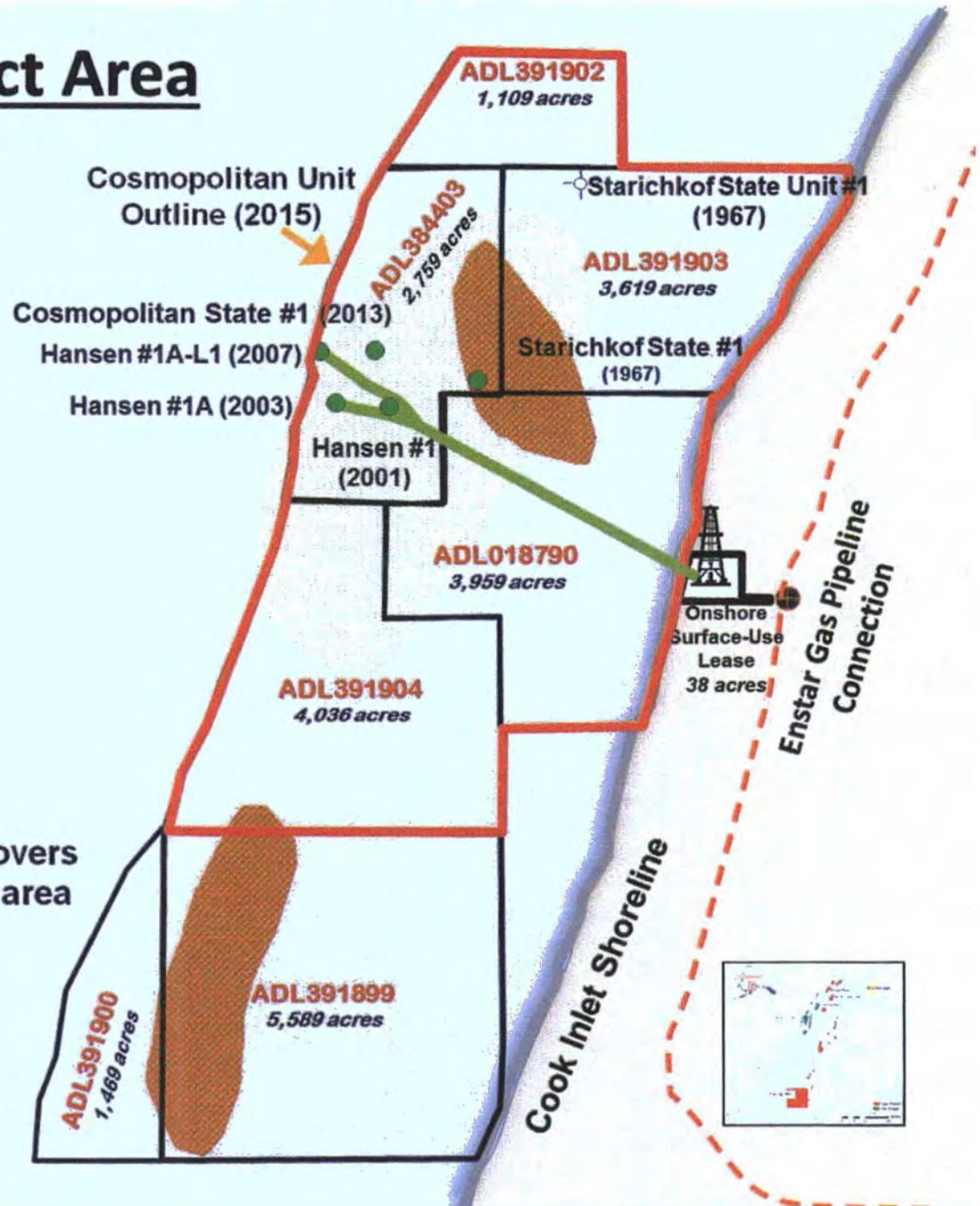
- 100% owned and operated by BlueCrest
- 7 State leases
- 22,540 acres offshore
- 38-acre onshore surface lease
- 6 wells drilled to date
- 6 known oil zones
- 6+ known gas zones
- 2 identified exploratory prospects

3-D Seismic covers entire Project area (2005)



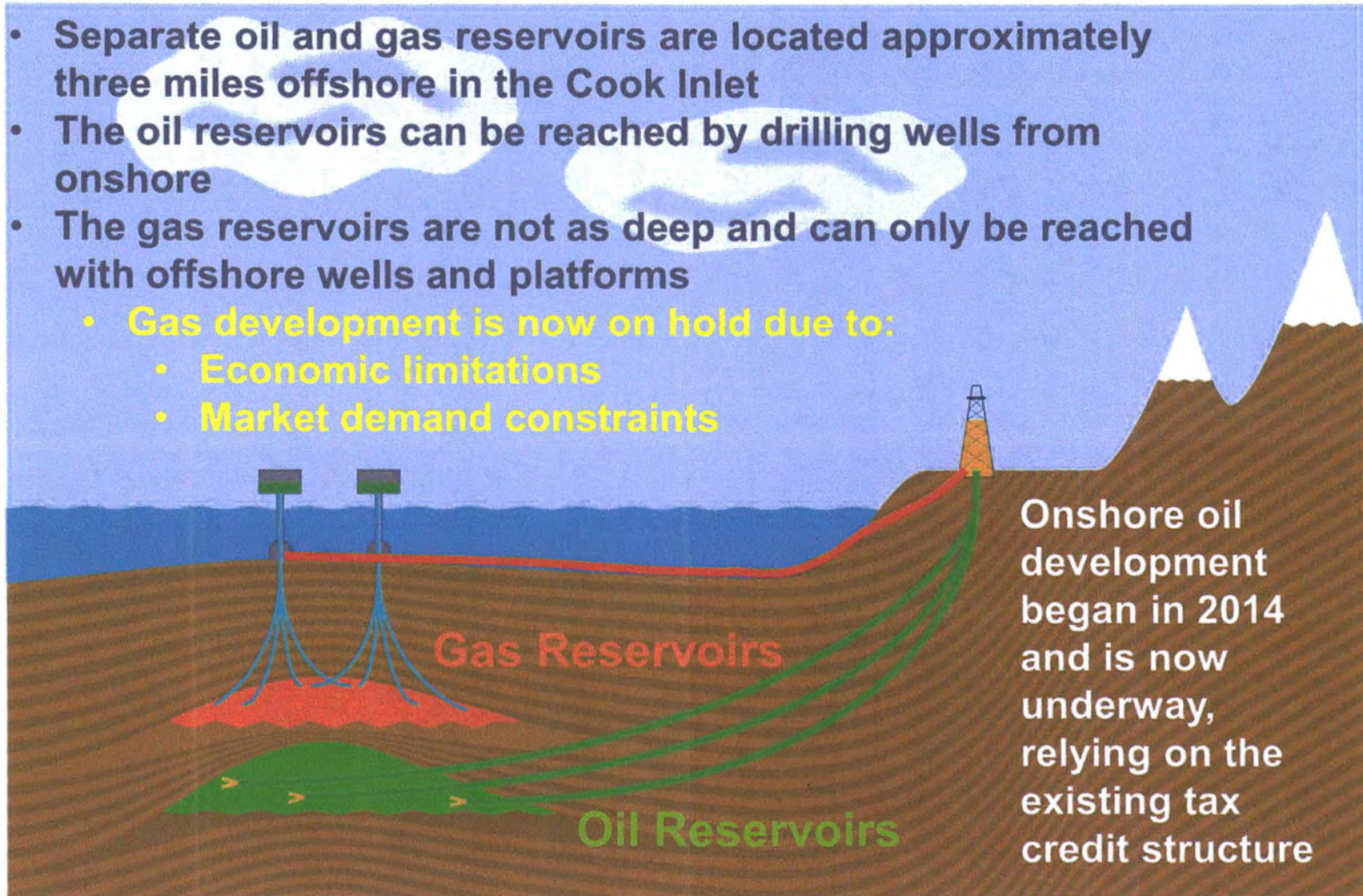
Approximate areal extent of known productive reservoirs

Approximate areal extent of identified exploratory prospects



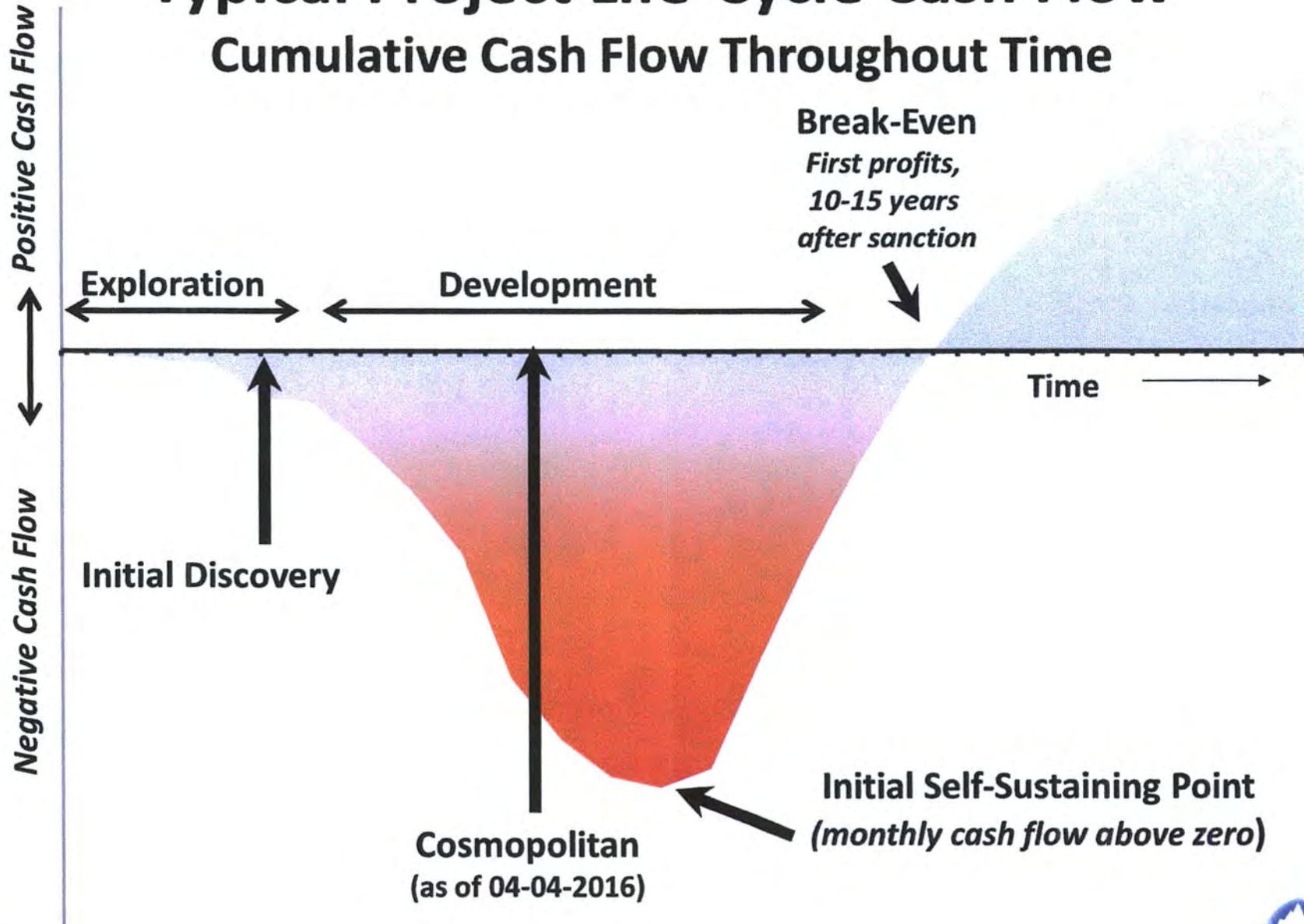
Cosmopolitan Unit Development Concept

- Separate oil and gas reservoirs are located approximately three miles offshore in the Cook Inlet
- The oil reservoirs can be reached by drilling wells from onshore
- The gas reservoirs are not as deep and can only be reached with offshore wells and platforms
 - Gas development is now on hold due to:
 - Economic limitations
 - Market demand constraints

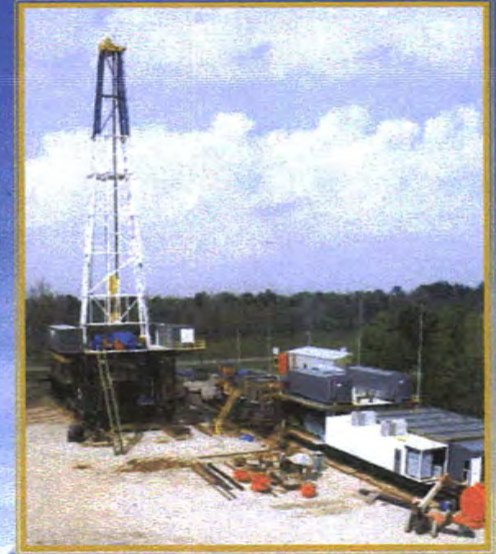
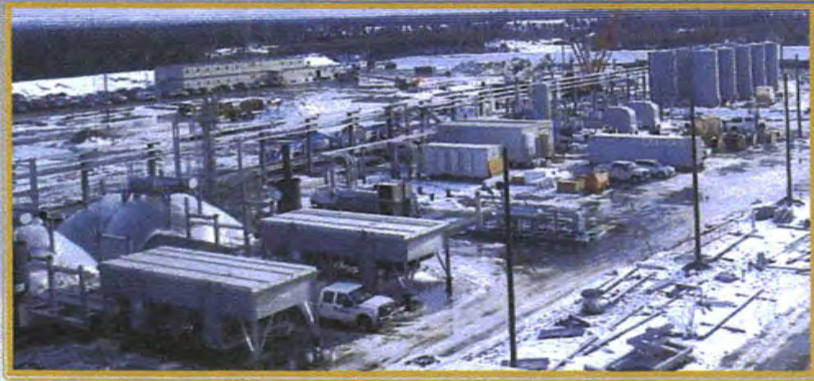


Typical Project Life-Cycle Cash Flow

Cumulative Cash Flow Throughout Time



Cosmopolitan Progress as of 04/04/2016

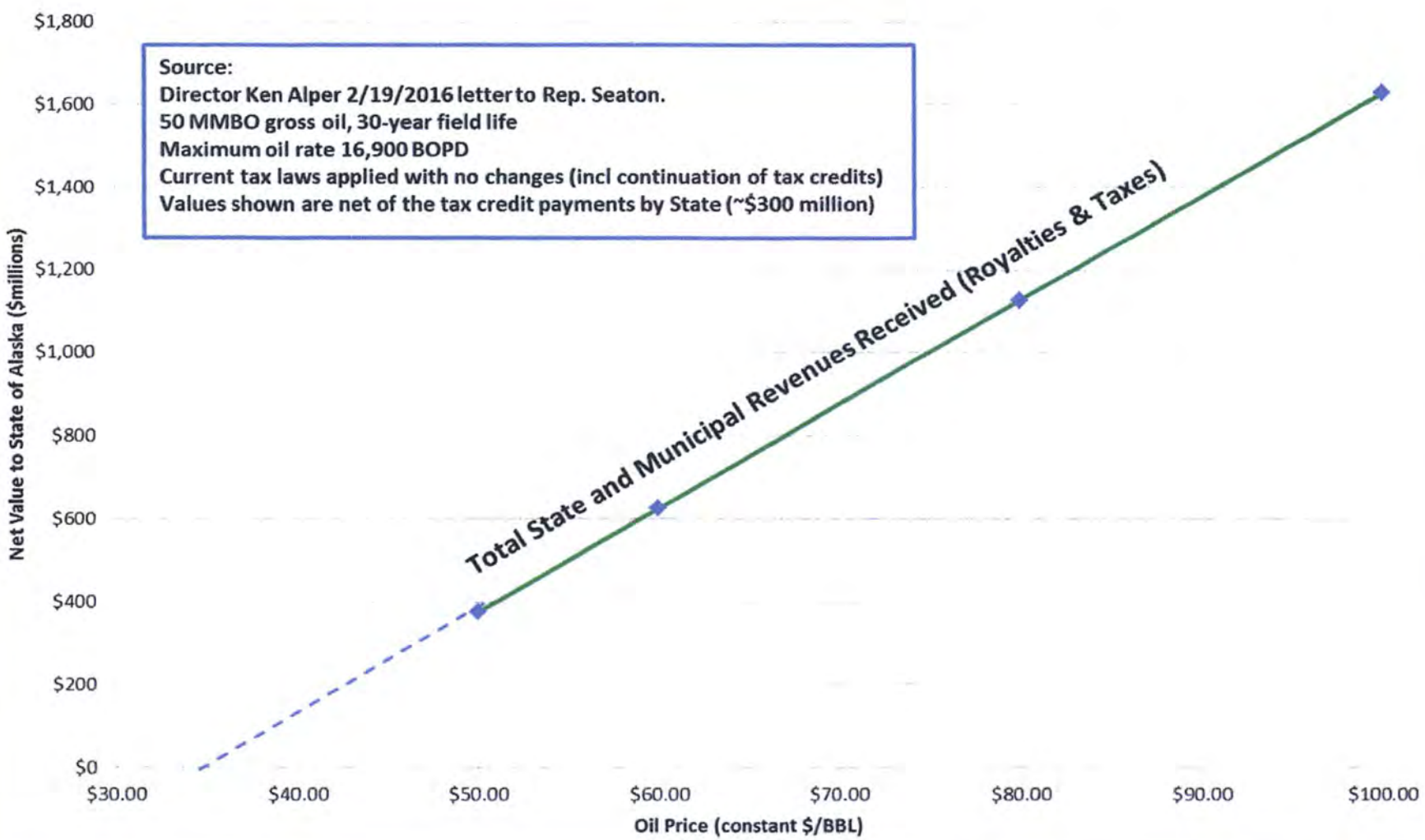




Tax credits for development of previously-discovered proven reserves are a solid, low-risk investment for Alaska.

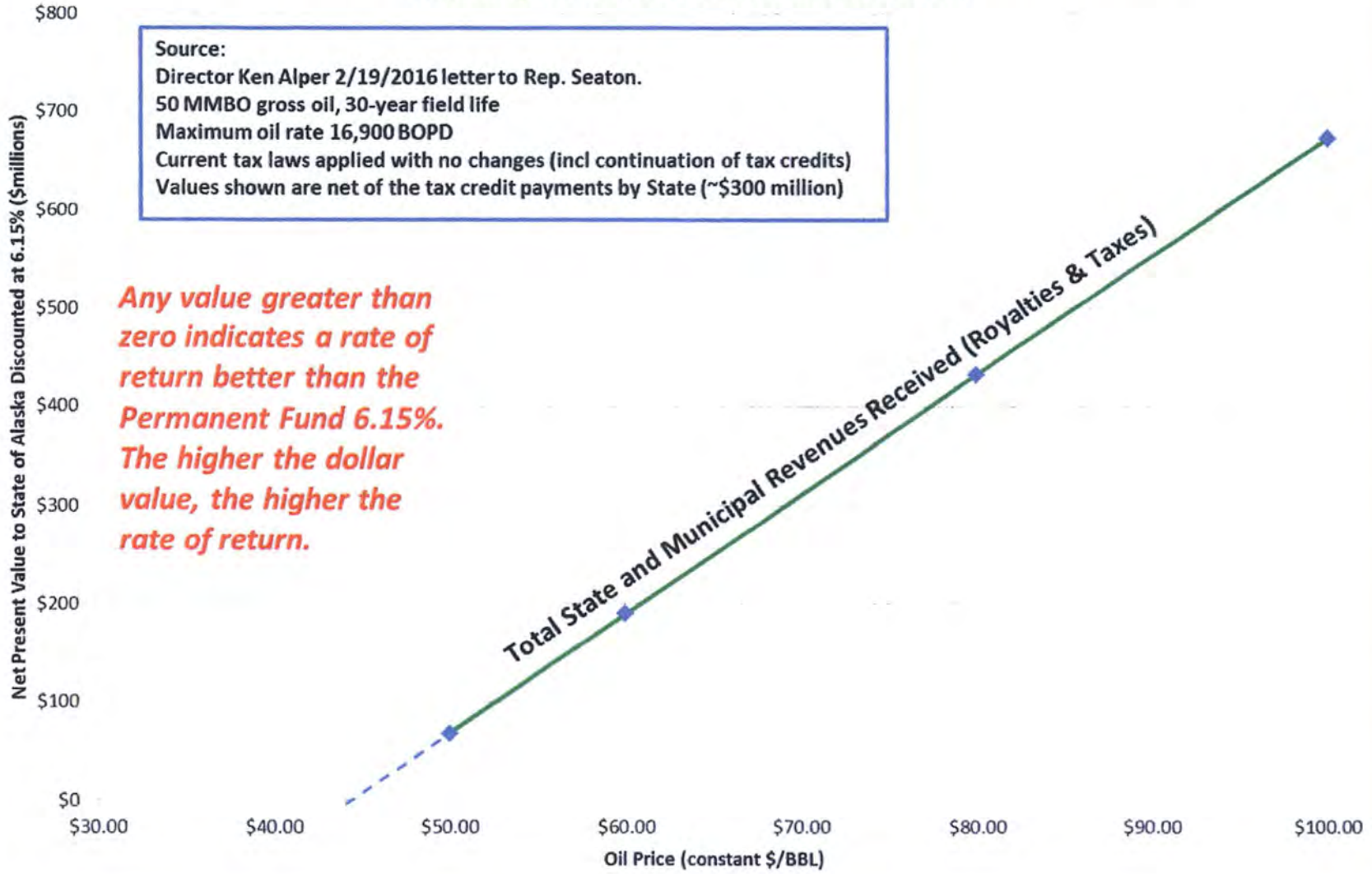
Summary of DOR Analysis, 2/19/2016: Example Cook Inlet Full Field Development

Net Cash Benefit to State from Continuation of Current Tax Credit Law at Various Oil Prices



**Summary of DOR Analysis Cook Inlet Oil Development 2/19/2016
Comparison to Permanent Fund NPV Return (6.15%) to State at Various Oil Prices
Assuming All Tax Credits are Continued In Full**

Source:
 Director Ken Alper 2/19/2016 letter to Rep. Seaton.
 50 MMBO gross oil, 30-year field life
 Maximum oil rate 16,900 BOPD
 Current tax laws applied with no changes (incl continuation of tax credits)
 Values shown are net of the tax credit payments by State (~\$300 million)



Continuation of 023(a) and 023(I) Credits

Continuation of the 023(a) and 023(I) credits is a good investment for the state.

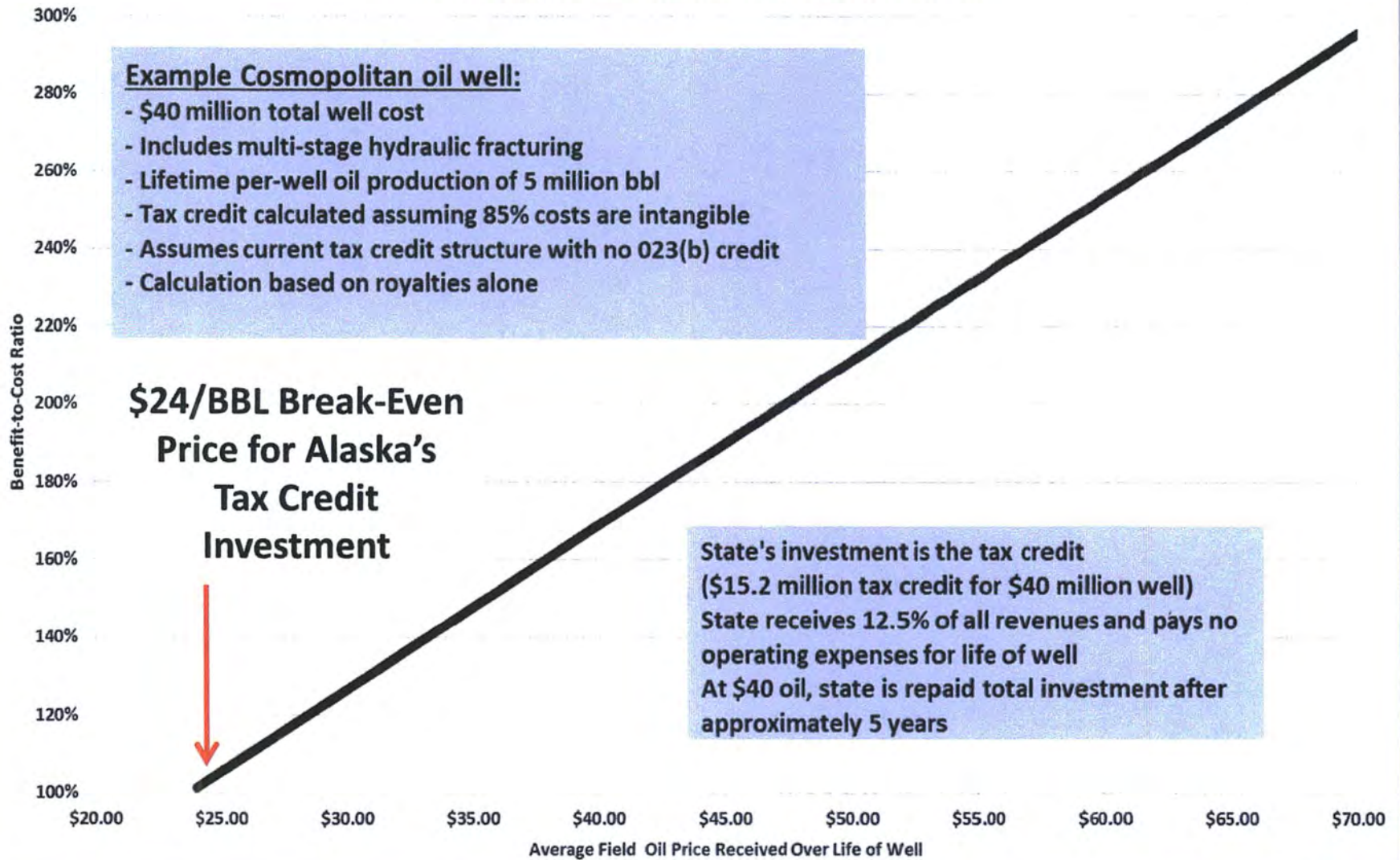
Termination of the 023(I) credits will result in a significant reduction of BlueCrest's ability to continue drilling at Cosmopolitan.

Continuation of the 023(I) credits facilitates Cosmopolitan continued drilling at ~\$10/BBL lower oil prices.

State's Investment Return From Individual New Cosmopolitan Well Royalties

State's Benefit-to-Cost Ratio versus Average Lease Oil Price

Assumes 023(a) and 023(l) Tax Credit Paid (total 38% of Well Cost)



Per-company limitations for cash payments:

- **Arbitrary**
- **Particularly disadvantages small companies like BlueCrest who have invested but do not yet have production**
- **BlueCrest has invested in good faith, based on the tax policy in existence when the investments were committed**
- **BlueCrest has financed the Cosmopolitan development assuming the credits would be paid on time**
- **The state is backing out on its prior commitment if previously-filed credits are not paid**
- **A strong disincentive for future investments**

Effective Date for Changes (July 1, 2016 – July 1, 2017)

BlueCrest has already contracted for work that will take place over the next year. Funding of that work was based on current tax laws/credits.

BlueCrest's funding plan for initial Cosmopolitan oil development

Total cost: \$525 million

Funding sources

Cash investment by shareholders:	\$200 million
AIDEA loan on drilling rig:	\$30 million
Development loan:	\$150 million
Tax credits received to date:	\$24 million
Tax credits for 2015-2016 spending under current law:	\$121 million



**When we are driving on
slippery icy roads, the most
dangerous thing we can do is
suddenly slam on the brakes!**



FRONTIER BASINS TAX CREDITS

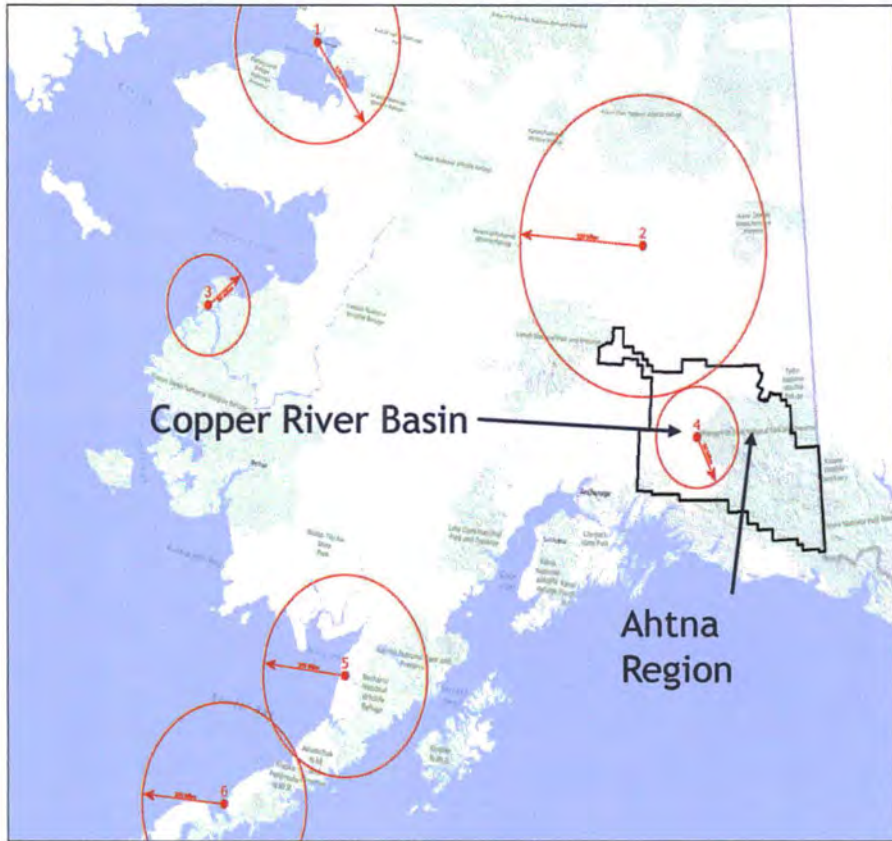
Presented to the Alaska House of Representatives
Finance Committee

April 4, 2016

1

Ahtna

FRONTIER BASINS EXPERIENCE



AS.43.55.025(a)(6) & (7) originally created in 2012 under HB 276 and merged with SB23

Intent of Legislature - incentivize oil and gas exploration in under explored Basins

Reduce the risk of development of local rural energy to Alaskans

Create local energy source for rural residents

Reduce or eliminate the Power Cost Equalization (PCE) subsidies

FRONTIER BASIN TAX CREDITS

- ▶ AS 43.55.025(a)(6) – The first two exploration wells drilled inside each of the six Frontier Basins receives 80% credit or up to \$25M of qualified expenditures
- ▶ AS 43.55.025(a)(7) – The first seismic project performed inside each of the six Frontier Basins receives 75% credit up to \$7.5M of qualified expenditures
- ▶ **Ahtna would not consider any exploration activities without tax credits**

Ahtna

SPECIFIC FRONTIER BASIN REGULATIONS

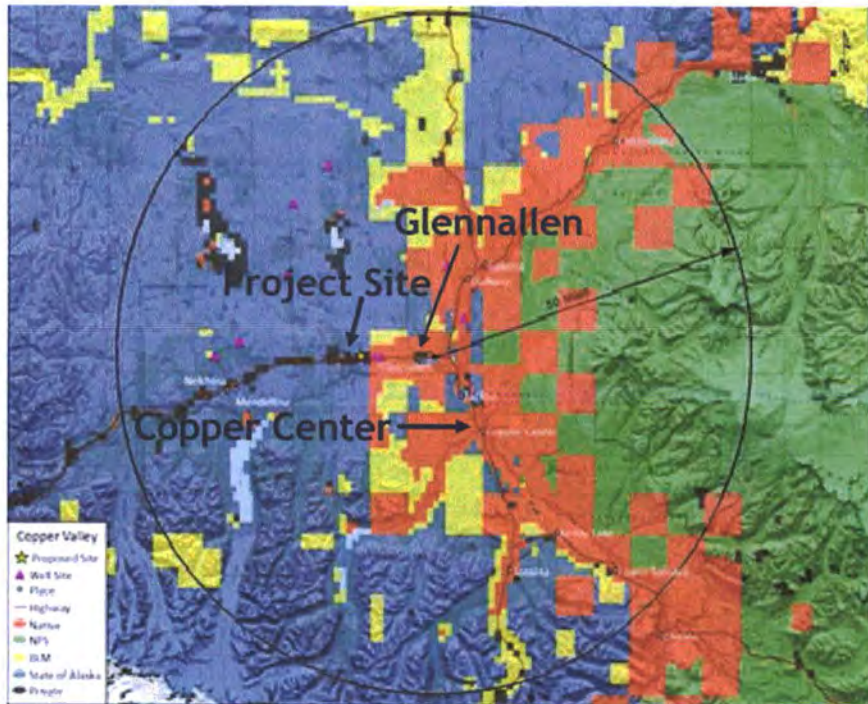
- ▶ ADNR-DOG pre-qualification approval for seismic and well
- ▶ Various well depth and set back from previous wells
- ▶ Submission of all data to ADNR prior to credit award
- ▶ Public data disclosure of all data after 2 years
- ▶ Must provide energy source for rural energy needs!
- ▶ The AS.43.55.025(a)(6) & (7) tax credits are not eligible for stacking

Ahtna

EXPLORATION PROGRAM HISTORY

- ▶ April 2012 Ahtna applies for SOA Exploration License
- ▶ May 2012 Legislature approves SB 23
- ▶ December 2013 Ahtna receives Tolsona Exploration License
- ▶ June 2014 receive ADNR Commissioner pre-qualification approval for seismic
- ▶ December 2014 completes 40-miles of 2D seismic over exploration area
- ▶ April 2015 completed reprocessing of seismic data identifying 12-sq. mile potential oil and gas trap
- ▶ May 2015 submit seismic data to ADNR-DOG
- ▶ September 2015 receive ADNR Commissioner pre-qualification approval of new well
- ▶ February 2016 – majority of permits approved
- ▶ March 2016 final stages of new well engineering and design

COPPER RIVER BASIN



- ✘ Proposed Tolsona well depth of 4,500' Vertical hole.
- ✘ Targeted structure is the Nelchina sandstone.
- ✘ 11 wells drilled in the basin since 1960's.
- ✘ Most recent well - drilled by Rutter in 2005-2008.
- ✘ Natural gas shows (approximately 94% methane).
- ✘ Tolsona #1 potential for a great local fuel source.

PURPOSE AND NEED FOR GAS IN COPPER RIVER BASIN

...To conduct exploration within the license area on a single natural gas well, Tolsona #1, with the potential to develop natural gas production for distribution to local residents and electric utilities...

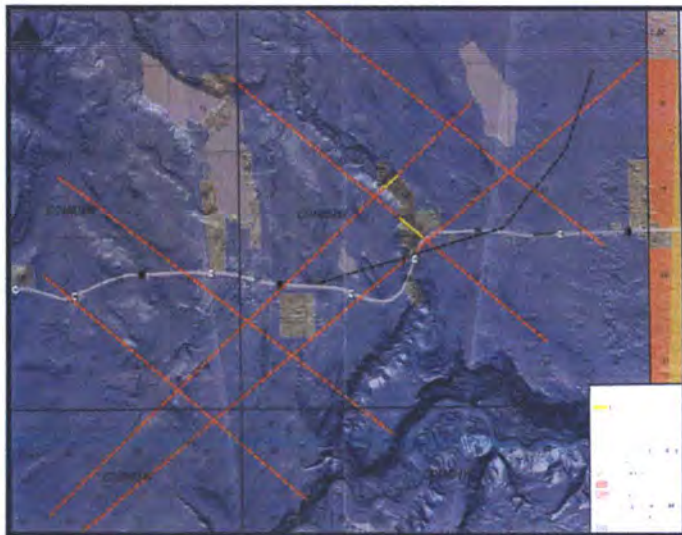
Community and Economic Development Benefits:

- ▶ Potential Opportunities for Local Employment
- ▶ Economical Benefits, Expanding Local Business
- ▶ Lowering High Energy Cost for Our Rural Economy
- ▶ Reducing Out-migration
- ▶ Building Infrastructure in the Region

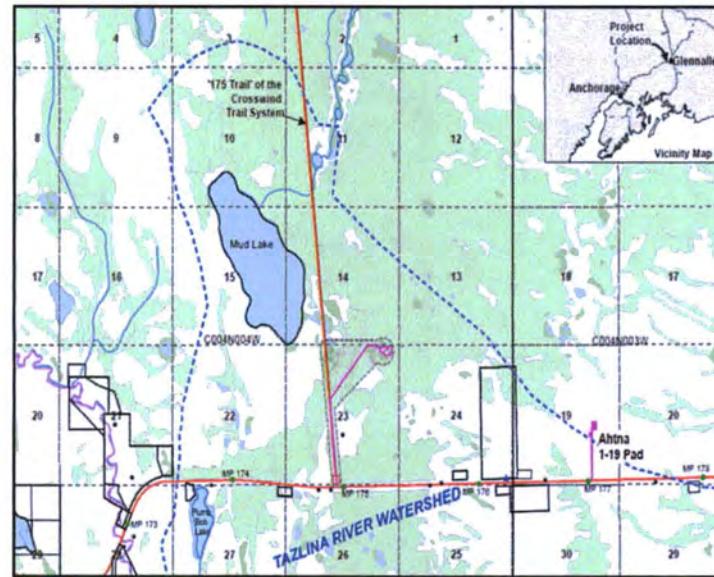
Project Overview

► Seismic

- Winter 2014/15
- 40 miles of new seismic
- Majority on State Land



► Current Location



- Exploration site on State land.
- Royalties/production tax to the State if successful.
- Improvement to public access & recreational area.

PROJECT TEAM

Ahtna, Inc.

Tolsona Exploration Oil and Gas, LLC

Ahtna Construction

HXR Drilling Services

Restoration Science & Engineering

Multiple Alaskan Companies

State, Local, Federal Agencies

ADNR

ADFG

USACE

ADOT

ADEC

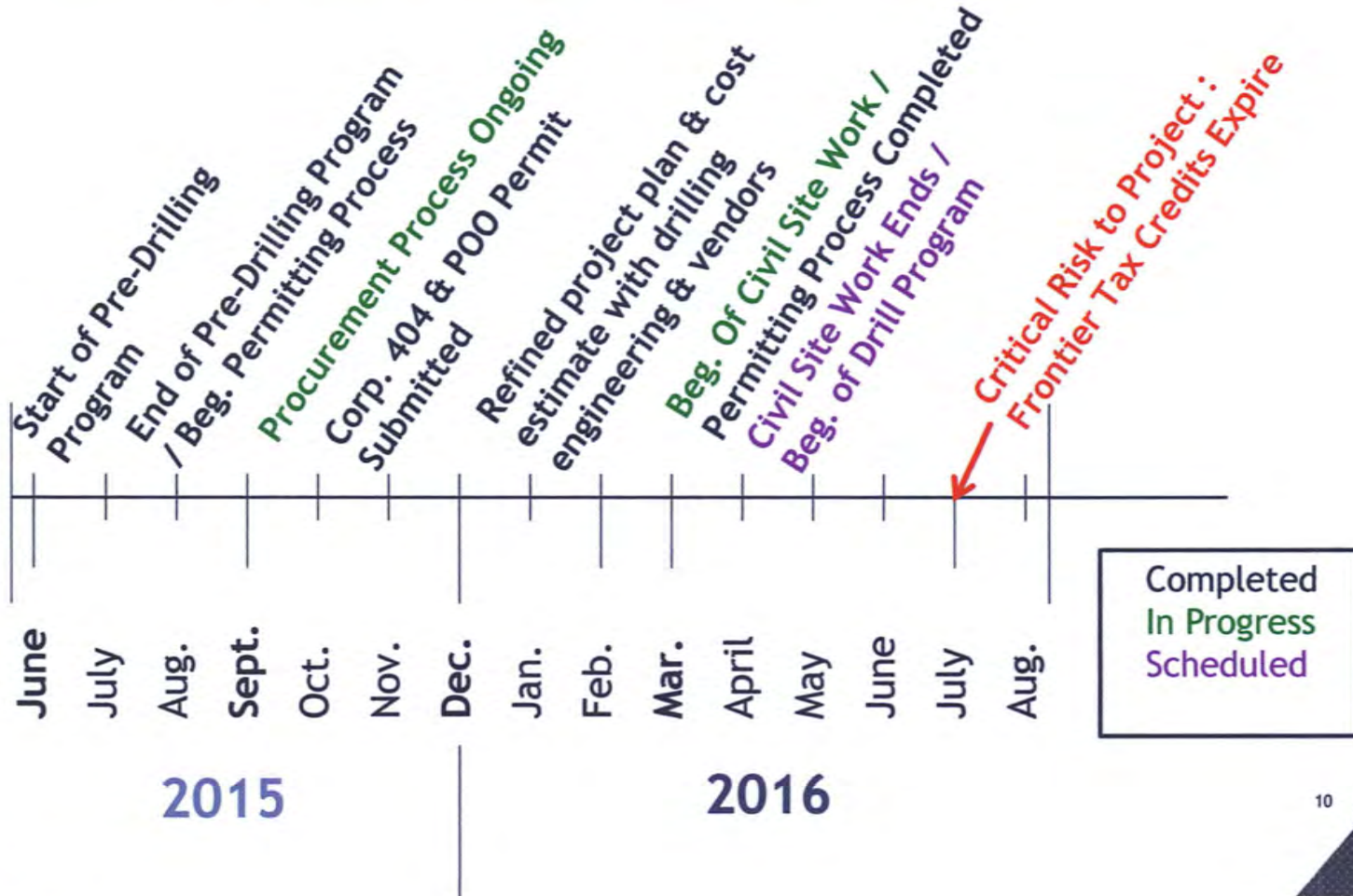
AOGCC

USFWS

USEPA

Tremendous agency support, as an example, DNR Division of Oil and Gas Director has visited the region and project site.

PROJECT SCHEDULE (Very tight)!



CONCLUSION

- ▶ **Our Request:** It is critical to our project that the Frontier Basin AS 43.55.025(a)(6) & (7) credits are extended from June 30th 2016 to a future date, we recommend 2022 to coincide with other credit expiration dates.
 - ▶ This will greatly help the Tolsona Project that is under way with a committed investment and a very tight schedule.
- ▶ Ahtna also supports the AS 43.55.023 and 025(a)(1-4) Middle Earth tax credits to be kept in place, as an incentive to the Frontier Basin exploration and development efforts by explorers who have taken the risk and committed investment based on these incentives.

THANK YOU TO OUR GOOD PARTNERS

- ▶ We would like to thank the members of this committee for the opportunity to share our experience. We would also like to thank the Alaska Legislature, Governor, Staff and the citizens of the State of Alaska for your support for developing an affordable energy source in our region.

Questions?

Contact Information

Chris Cook
Ahtna, Incorporated
Director of Finance
110 W. 38th Ave
Anchorage, AK 99503
907-868-8250
ccook@ahtna.net

BlueCrest testimony to House Finance Committee 4/4/2016



Slide 1

Good afternoon co-chairs Thompson and Neuman, and members of the Committee. Thank you for the opportunity to comment on this very important issue of proposed changes to Alaska's oil and gas tax laws.

For the record, my name is J. Benjamin Johnson, and I'm the president and CEO of BlueCrest Energy Inc. Although BlueCrest is based in Texas, we definitely have Alaskan roots. My family first moved to Anchor Point in the early 1950's. I grew up in Kenai and graduated from Kenai Central High. I worked my way through college on Cook Inlet platforms and at Prudhoe Bay. Then after college, I came back home to Alaska, doing some of the early engineering work for ARCO on Prudhoe Bay and Kuparuk. In total, BlueCrest senior management has over 40 years of collective experience working in Alaska's oil and gas industry.

Since BlueCrest only has operations in the Cook Inlet at this time, I will only speak to the issues particular to the Cook Inlet, with a specific focus on the following points:

First, I want to emphasize that, specifically with regard to what BlueCrest is doing in the Cook Inlet, the tax credit program is a very good investment for the State. And I want to strongly encourage you to consider that any changes made to the system (whatever they may be) need to be well-planned with regard to the long-term consequences and done in an orderly progression over time.

BlueCrest has not been involved in drilling "wildcat" exploratory wells. We have focused on low-risk development of previously-identified resources of oil and gas. In the process of delineating the field in 2013, we discovered several new oil and gas zones that added to the total reserves, but the underlying basis of the oil and gas accumulation was already known at that time. The bottom line is that the State's investment in development of known reserves has a much lower risk factor than support for higher-risk exploratory drilling.

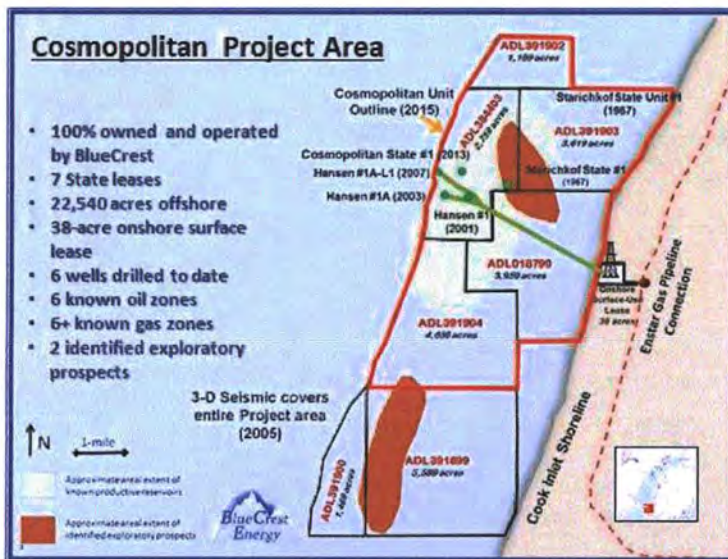
BlueCrest Energy was formed by a group of former major oil company executives, each of whom have extensive experience in developing and managing large oil and gas assets. Our original business plan was to find some oil and gas properties with already-identified reserves that could potentially be improved using our backgrounds and knowledge of

industry technology. We evaluated dozens of acquisition opportunities around the US (offshore California, Gulf of Mexico, Wyoming, Colorado, Texas, Louisiana and Alaska). Alaska's huge handicap was – and continues to be – that the exploration, development and operating costs in the State are at least three hundred percent of any other major hydrocarbon basin in the US. But we ultimately decided to invest in Alaska because, through the credit programs, the State was investing in itself, and that investment – the State's credits – somewhat offset the higher costs of drilling and development.

BlueCrest is in Alaska today directly as a result of the State's incentives programs. And it is the State's investment through the tax credits that has facilitated success in the Cosmopolitan Unit, which we are now moving into its first production. As I will demonstrate today, these credits will provide substantial future positive value to the State. I'm going to show you that the State's investments in the Cosmopolitan tax credits will provide high returns even at low oil prices. In fact, the tax credit investments under the current laws can actually provide higher rates of return to the State than the average investments in the Permanent Fund.

Second, I'd like to give you a quick overview of the Cosmopolitan Unit, or "Cosmo" as we call it. And I will show you the calculations made by both BlueCrest and the DOR showing the very favorable investment returns to the State as a result of the tax credits.

And finally, I will address the direct impact to BlueCrest of critical specific factors in HB247 and the CS.



Slide 2

The Cosmopolitan Unit is located about three miles offshore in the Cook Inlet, a few miles north of Anchor Point. All of the productive area in the unit is on State leases. We also have an onshore surface lease that contains the production facilities and the drill sites for drilling wells to the offshore leases. For the interest of time, I won't repeat my prior testimony to House Resources concerning the lengthy Cosmo history. But suffice it to say that the field was originally discovered in 1967. BlueCrest acquired the leases in 2012, and we are about to finally start-up the initial production this month. We drilled a very critical well in 2013 and gained new information that has allowed us to finally develop the field employing technology currently available today.

Cosmopolitan Unit Development Concept

- Separate oil and gas reservoirs are located approximately three miles offshore in the Cook Inlet
- The oil reservoirs can be reached by drilling wells from onshore
- The gas reservoirs are not as deep and can only be reached with offshore wells and platforms
 - Gas development is now on hold due to:
 - Economic limitations
 - Market demand constraints

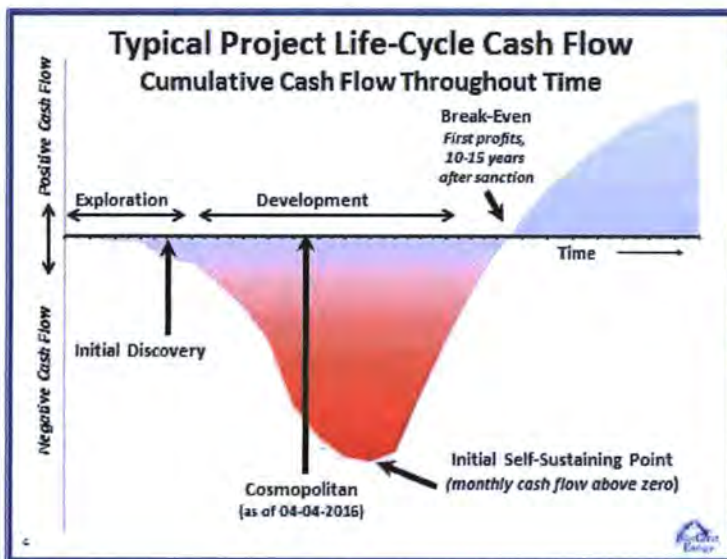
Onshore oil development began in 2014 and is now underway, relying on the existing tax credit structure

Slide 3

The Cosmopolitan Unit actually consists of two separate development projects. The oil zones are deep enough that they can all be reached from an onshore drill site, using a very powerful land-based drilling rig.

We are now proceeding with development of the oil zones from onshore, but the offshore gas development is on hold due to economic limitations on costs and confirmation of sufficient market demand. The Cosmopolitan gas zones are simply too shallow to make drilling from onshore a possibility. So the gas zones will need to be developed by drilling gas wells offshore with a jack-up rig and setting small dry-gas production platforms over the wells. The gas will then be piped through sub-sea pipelines from the platforms to the onshore oil production facility. This is, of course, quite expensive. The Cook Inlet gas market is quite unique, in that the limited current demand for the gas (without some larger user such as Agrium) does not facilitate development of large new gas field like Cosmopolitan to spend all the money to get it on production and then shut it in. It is important to understand that, although we know there is a large quantity of gas, it will take several years to get it developed. And we are faced with another particular challenge, in that the one currently available offshore rig we could use cannot afford to sit idle in the Cook Inlet for years into the future without being put to work now. Once that rig leaves, it may be very difficult (and will certainly be very expensive) to bring in another rig in the future.

But with regard to the oil development that we could start right away and given the success of our 2013 drilling program, we were then faced with the challenge of how to pay for development of the new field. Right now, BlueCrest is a small private company with a singular focus of developing the Cosmopolitan Unit. The members of our management team all have extensive technical and business experience in developing projects like this, but the potential costs far exceeded our personal financial capabilities. So we teamed with a group of oil industry investors who have much greater financial capabilities, and we very carefully created our plan with them for financing the development of Cosmopolitan.



Slide 4

Now I'd like to digress for just a minute to explain something that's really important to understand about oil and gas developments. This next chart figuratively shows the cumulative cash flow over time for a typical life cycle of a successful oil or gas development. When the curve goes down, it means that the company is spending more cash in a month than it is bringing in. When the curve is rising, it means that the company is receiving more revenues than it is spending. But as long as the curve is below the horizontal axis, it means that the company has cumulatively spent more money than it has received on the project. When the curve (hopefully) eventually goes above the axis, that's when the company finally begins to receive a return on its investment. There can be no profits whatsoever until the curve is above the axis. And prudent oil or gas developers will never begin such a project unless they believe that it will eventually provide enough future revenues to justify the large initial expenditures.

What is important to note about this chart is that the successful development of a new oil or gas field is a very long process and requires a lot of money to be spent before any profits can be generated. You can see that the very first stage is spending money to explore. At this stage, there is no assurance that anything will be found. The only way to know that an area will be productive is to spend lots of money to drill expensive wells, and then test them if it looks like there may be some potential. The vast majority of exploration prospects are, in fact, dry holes – the money spent will never be recovered. Just because you might drill a lot of wells does not guarantee you're going to discover anything.

But in the minority situation where the exploration process is successful, then the really huge cost of developing the field comes into play. In many other basins around the world, producers can just simply set up a tank and start flowing a new oil well into it with the produced gas either being flared or venting into the atmosphere. In Alaska, however, we have higher standards. BlueCrest takes a very strong stance on safety and protecting the environment, and it costs a lot of money to do it right. Before we can sell the first barrel of oil from a new well, we have to have a way to collect all the associated gas and water to make sure that nothing makes its way into the atmosphere or the environment. That means construction of drilling sites and sophisticated production facilities with the ability to safely handle everything that comes out of the wells. So you can see that, after the discoveries have already been made, this curve starts to go very negative. Whenever this curve goes lower, it means that we have had to come out of pocket to put more investment into the project. In our case with developing the Cosmopolitan oil zones, we expect that we will have to spend about \$525 million dollars before we can – hopefully – get to the point that we are finally generating enough money from sales of the oil to cover the monthly costs. It will have taken decades to get from the first exploratory well to the point where we don't have to keep spending more money than we are receiving.

Now, what a lot of people get confused with is this point at the bottom of the curve where it begins to turn up for the first time. That simply means that the project is finally paying out more money on a monthly basis than we are putting into it. But that DOES NOT mean that any profits have been made or that the project has broken even. No profits can be generated until the curve comes all the way back up to the zero point. The zero line here is the break-even point. Or, in other words, all of the investments over time have been repaid at that point but no profits have yet been generated.

To further complicate the issue is that we have to consider the fact that this curve represents development of a **successful** exploratory prospect. In fact, the vast majority (anywhere from 2/3 to 90%) of exploration projects do not find economic oil or gas. So, for the industry to survive, we have to at least be able to generate enough profits on the successful developments to pay for the losses on the exploration failures.



Slide 5

So let's talk more specifically about Cosmopolitan. Right now, we are just days away from the very first commercial production of oil that will begin with minor production from one of the old wells. Next, we have to bring in our new specialized drilling rig and start spending over \$40 million per well to bring on the new production that can finally start paying off the loans. And that can't happen until we have finished the drill sites and the production facilities, which will occur mostly in the second half of this year and the first half of 2017.

These photos show the progress we have made so far with the onshore Cosmo production facility after about two years of construction. The total site is 38 acres, and contains the drill sites for up to 20 wells and the facilities to process up to approximately 10,000 barrels per day of new oil production. The site includes a 50-person camp for housing our operations and drilling workers, and we are already connected into the Enstar gas line for sales of our gas into the Southcentral gas supply. We are also designed to allow expansion of this facility as needed to handle additional production increases in the future. Of course that's going to depend on the performance and number of new wells that we can drill. We are now almost complete in our construction process, and we are now running the final operational tests of all the components. We are on schedule for starting the first oil production later this month.

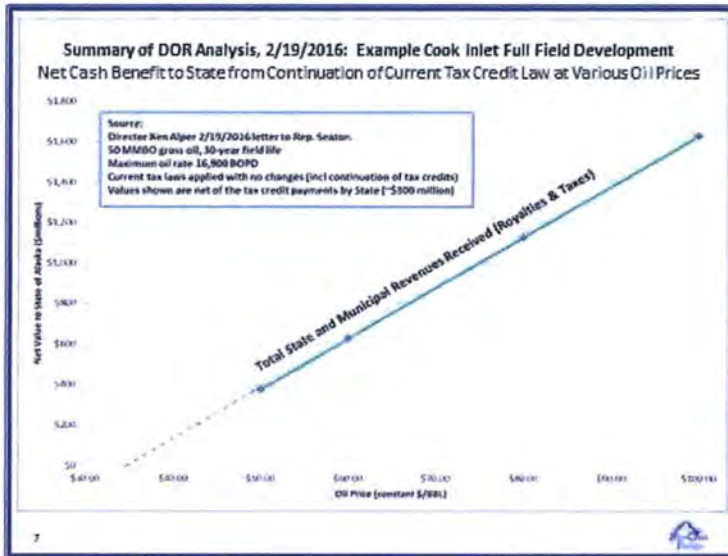
Tax credits for development of previously-discovered proven reserves are a solid, low-risk investment for Alaska.



Slide 6

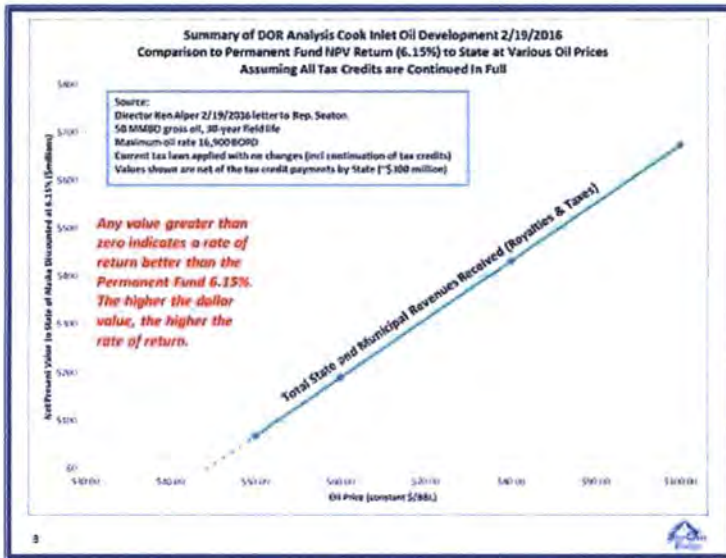
So let's look at what the tax credits from a successful development project like Cosmopolitan actually mean to Alaska. When the tax credits are used for development of new proven reserves in the State, they are – without question – a valuable low-risk **investment**. Speaking of the credits as a cost or a “give-away” completely ignores the substantial value that is received by the State. The tax credits make new projects work, and they bring new sources of long-term revenues to the State for decades into the future.

At Cosmo, we are sitting on a large proven resource of future oil and gas that now simply requires additional new investments to bring it to full production. On February 19, the DOR provided its analysis of the financial impact to the State on development of a new Cook Inlet oil field, assuming that no changes are ever made to the existing tax laws (including tax credits and production tax rates). DOR's analysis modeled an example Cook Inlet field that is somewhat more expensive and less productive than the actual Cosmopolitan oil development. So the DOR's calculations are, in fact, conservative. Their analysis assumed only 50 million barrels of ultimate oil recovery and a maximum oil producing rate of about 17,000 barrels per day, which would represent the low side of our future Cosmo expectations. The total capital costs it assumed were about \$600 million, and it assumed that the full tax credits, as currently written, would continue indefinitely into the future.



Slide 7

This chart is a summary of the calculations the DOR provided. It includes a summary of the total net benefit received by the State and municipalities, including taxes and royalties, as a function of various future oil prices. It shows that, if oil prices over the entire field life average only about \$35 per barrel, the State would break-even. In other words, the State would receive back 100% of its investments in the tax credits (unchanged from current law for many years into the future). At about \$47 per barrel average oil price, the State would receive back double the amount of its investment in the tax credits. And at about \$59 per barrel average oil price, the State would receive back triple its investment in the tax credits.



Slide 8

The DOR also provided their calculations showing the impact of the tax credits as a pure investment, with a head-to-head comparison to the investments by the Permanent Fund. According to the DOR, the Permanent Fund's September 2015 earnings were 6.15%. So if an alternative investment earned less than 6.15%, it would have a worse performance than the average investments in the Permanent Fund. On the other hand, if an alternative investment earned more than 6.15%, it would be a better investment than what the Permanent Fund had in place in September 2015.

This chart shows that, even in the case where there are never any changes to the tax system in the Cook Inlet (that is, all tax credits stay in place and there are no oil production taxes until 2022), the State's investment in those tax credits for the example field is still better than the average investment in the Permanent Fund as long as oil prices over the next 30 years average only \$44 per barrel.

Now I'd like to provide our additional comments on particular portions of the bill specific to BlueCrest and the Cosmopolitan Unit.

Continuation of 023(a) and 023(l) Credits

Continuation of the 023(a) and 023(l) credits is a good investment for the state.

Termination of the 023(l) credits will result in a significant reduction of BlueCrest's ability to continue drilling at Cosmopolitan.

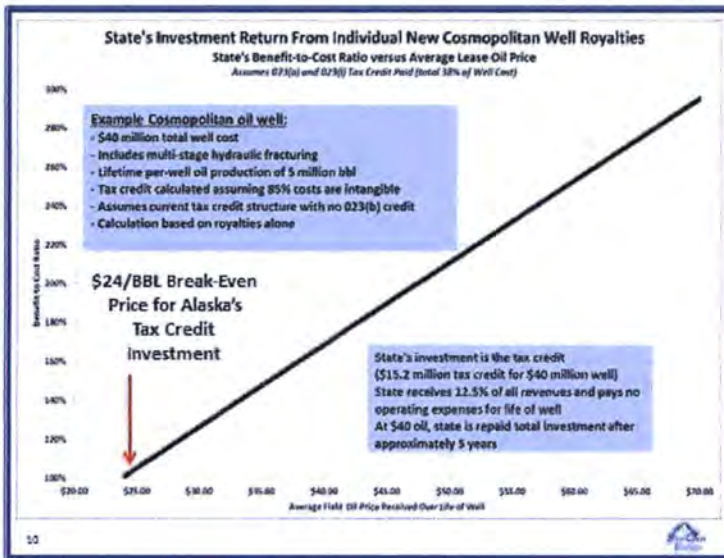
Continuation of the 023(l) credits facilitates Cosmopolitan continued drilling at ~\$10/BBL lower oil prices.

4



Slide 9

First of all, termination of the 023(a) and 023(l) credits would result in a significant reduction in our ability to continue making investments in the Cosmo oil wells, resulting in less future revenues to the State. The Governor's original bill completely eliminated the 023(l) (Well Lease Expenditure) credits, effective immediately. The House Resources CS temporarily retained the 023(l) credit but effectively scaled it down to 20% over two years from the current 40% and reduced the NOL credit from 25% to 10%.



Slide 10

We've done some interesting analyses of the value to the State in keeping both the 023(a) and 023(l) credits as they apply to Cosmopolitan. We looked at the effective return to the State using a simple and conservative calculation including only the incremental royalty for each single new Cosmopolitan oil well drilled. This calculation does not even include the production taxes that would be paid after 2022 nor does it include property taxes. The bottom line is that, in periods of low oil prices, the 023(a) and 023(l) credits allow us to continue drilling the Cosmopolitan oil wells at approximately \$10 lower oil prices than without the credits. This is likely to be an important factor in our 2017 capital program.

This next chart shows the calculated return on investment to the State (including ONLY the royalties) from the 023(a) and (l) credits. A 100% return on investment means that 100% of the tax credit would be repaid out of increased royalties over the life of the well at an average oil price of only \$24 per barrel. At \$40 per barrel, the total return would be about 170%, and at \$60 per barrel, the return would be about 250%. So you can see that these credits, at least for Cosmo, are likely to be a very good investment for the State.

Per-company limitations for cash payments:

- **Arbitrary**
- **Particularly disadvantages small companies like BlueCrest who have invested but do not yet have production**
- **BlueCrest has invested in good faith, based on the tax policy in existence when the investments were committed**
- **BlueCrest has financed the Cosmopolitan development assuming the credits would be paid on time**
- **The state is backing out on its prior commitment if previously-filed credits are not paid**
- **A strong disincentive for future investments**



Slide 11

Another factor in the original bill was setting a limitation in the amount of the credits that can be paid annually. While the CS provided for a larger limit (that probably would not negatively affect BlueCrest), it still does not recognize the differences in qualified investments made by different parties. If this limit is too low, it would be particularly damaging to small companies like BlueCrest who have already invested in good faith, based on the tax policy in existence when we entered into the commitments for our investments. We came to Alaska based on the credits. We invested our cash, and we have borrowed a lot of money and committed to spending a lot more – all based on the tax credits. And the timing of the receipt of those payments for the credits is paramount in our ability to make the payments on the loan used for making those investments.

Effective Date for Changes (July 1, 2016 – July 1, 2017)

BlueCrest has already contracted for work that will take place over the next year. Funding of that work was based on current tax laws/credits.

BlueCrest's funding plan for initial Cosmopolitan oil development

Total cost: \$525 million

Funding sources

Cash investment by shareholders:	\$200 million
AIDEA loan on drilling rig:	\$30 million
Development loan:	\$150 million
Tax credits received to date:	\$24 million
Tax credits for 2015-2016 spending under current law:	\$121 million

Slide 12

Most important of any of these provisions to BlueCrest is the timing of implementation of any changes, whatever they may be. It is now April, and the proposed changes in the original HB247 are supposed to take place on July 1. The CS moved that date back, which certainly helped but does not completely solve the problem.

BlueCrest has been very careful in its financial planning process. Before we ever started the oil development project, we made sure that we would have enough funds to allow us to complete construction of the onshore drill site, production facilities, bring in the most powerful drilling rig in Alaska, and to drill at least the first two new oil wells. We calculated that we would need approximately \$525 million to reach the point of self-sufficiency (where we no longer have to keep borrowing additional money to put into the project). And we expect that should happen in the first half of 2017. In order to make that work, our shareholders invested approximately \$200 million in cash. We have borrowed \$30 million from AIDEA for a loan on the drilling rig. We secured a \$150 million high-interest development loan. We have received \$24 million to date in tax credits. And the remaining \$121 million was to come from credits earned for 2015 and 2016 spending under the current tax laws. We have spent a lot of money to get to the point where we can now start drilling these new wells, but an abrupt termination of the tax credits on which we have based our entire financial planning would be devastating.

We have finally reached the point – by completing all this work and spending all this money– to where we will finally have our drill site and rig ready to drill in the second half of 2016 and the first quarter of 2017. We need the production from the first new wells to pay for the costs we have spent so far. Those drilling costs – at least through early 2017 – are all based upon the assumption that we will be able to obtain the credits under existing law for those investments. We have done all this work and spent all this money to date, and it seems only reasonable for us to be able to claim the existing credits for the spending that is the result of our investments made in good faith based on the expectation that the State would honor its share of the investments. We need to be able to be able to get to the finish line. If the date for changes in the original bill (just three months from now) was reinstated, we would not have the full funding for finishing the initial part of the project, although we have basically already committed those investments. Not paying the credits that were the basis for the investments we've made is like saying "you can spend the money for a new house, but now you just can't ever move into it."

**When we are driving on
slippery icy roads, the most
dangerous thing we can do is
suddenly slam on the brakes!**



Slide 13

In conclusion, I'd like to reemphasize the importance of phasing-into any changes over a reasonable time period. Everyone in this room today understands that when we are driving on slippery icy roads (like the State of Alaska and Alaska's oil and gas industry is faced with today), the most dangerous thing we can do is suddenly slam on the brakes.

We appreciate your careful consideration of these important issues that will have far-reaching implications into Alaska's future.

4/4/16



House Finance
HB 247
April 4, 2016

*Pat Galvin
Chief Commercial Officer
and General Counsel*

GREAT BEAR PETROLEUM – A QUICK HISTORY

A NORTH SLOPE EXPLORATION COMPANY

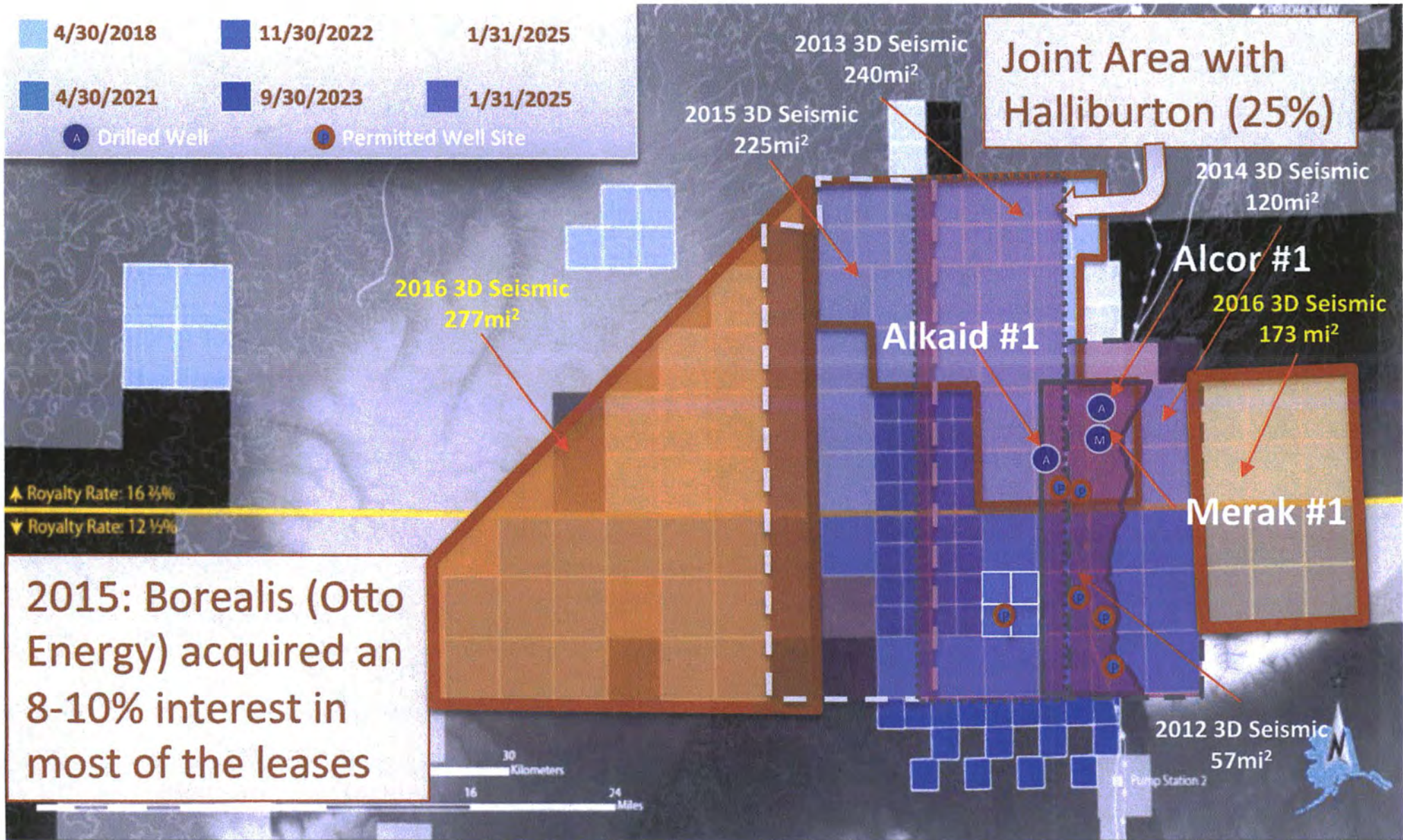
- Founded in 2010
- Focused exclusively on Alaska's North Slope
- Office and employees all in Anchorage
- Holder of 499,000 acres, Operator of 590,000 acres
- Acquired 500 square miles of 3D seismic
- Currently acquiring another 450 square miles
- Drilled 3 exploration wells

GREAT BEAR PETROLEUM – A QUICK HISTORY

FROM UNCONVENTIONAL TO CONVENTIONAL

- Original Target -> North Slope Shale Play (aka “source rock play”, aka “unconventional play”)
- Soon Faced an “Alaska Shale Play Catch-22”
 - Not economic without cost reductions
 - Costs reduction requires a critical mass of drilling activity, such as that generated by a shale play
- **Re-directed focus to extensive conventional prospectivity**
- Still believe a North Slope unconventional play can be economic following a conventional play build-out
- New Management Team – focus on performance - expanding technical capabilities

GREAT BEAR – LEASEHOLD POSITION AND ACTIVITIES (2012-PRESENT)



GREAT BEAR – IMMEDIATE WORK PLAN

HOW WE WILL REALIZE THE POTENTIAL

1. Complete our seismic program
2. Complete our prospect inventory
3. Execute a multi-year, multi-well exploration program
4. Secure cost-effective services by using the multi-well commitment



4 MYTHS ABOUT NORTH SLOPE EXPLORATION COMPANIES

- Exploration companies are “financed” by Alaska tax credits.
- Exploration companies don’t have “skin in the game”.
- Alaska could get the same level of exploration activity with lower exploration tax credits.
- Tax credit payments can be delayed with little impact to exploration companies.



TAX CREDIT FINANCING

BUSTING THE MYTH THAT EXPLORATION COMPANIES ARE “FINANCED” BY TAX CREDITS

- North Slope exploration company investors pay for employee salaries, oil and gas lease rentals, office rental, and other business expenses.
- Some expenditures (geologic work, permitting, etc.) qualify for tax credits (up to 75% reimbursement rate, dropping to flat 35% after June 30, 2016).
- An explorer can borrow against those expected tax credits, but has to have the remaining equity funding (plus financing costs) on hand at the time of the loan.
- At no time does a North Slope explorer “make money” on tax credits.



GREAT BEAR PROJECT SPENDING (2010 – PRESENT)

BUSTING THE MYTH THAT EXPLORATION COMPANIES DON'T HAVE "SKIN IN THE GAME"

- Total Gross Spend of Approximately \$220 Million
 - Approximately \$140M has been or will be reimbursed by State of Alaska
 - Net Operating Loss Credits (25% -> 45% -> 35%)
 - 40% Exploration Incentive Credit for Seismic
 - 30% Exploration Incentive Credit for Wells
- Great Bear Petroleum and Partners have spent approximately \$80M that will not be recovered through tax credits
 - As a result, Great Bear has been very prudent and deliberate in what activities we have conducted
- **Tax Credits bought valuable exploration data** - State now has extensive new data about its resources on the Great Bear leases



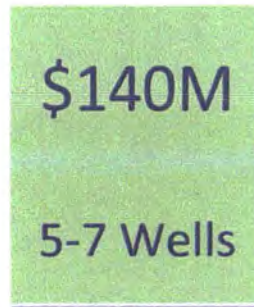
HOW TAX CREDITS DICTATE EXPLORATION DRILLING VOLUME

BUSTING THE MYTH THAT LOWER TAX CREDITS COULD STILL RESULT IN SAME EXPLORATION ACTIVITY



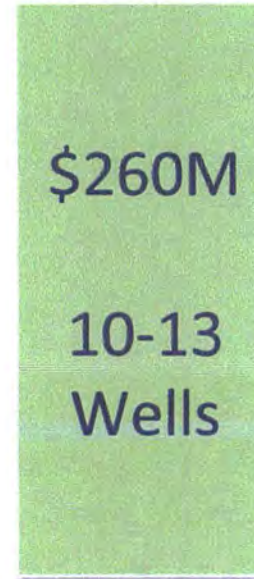
Exploration Company Has \$100M In Equity Capital to Spend on Exploration

35% Tax Credit Offered



Company will spend approximately \$140M in exploration activities

65% Tax Credit Offered



Company will spend approximately \$260M in exploration activities

By offering a higher tax credit, State generates more activity

IMPACT OF TAX CREDIT PAYMENT UNCERTAINTY

BUSTING THE MYTH THAT PAYMENTS CAN BE DELAYED WITHOUT IMPACT

- Delay in tax credit payments will result in increasing financing costs for explorers
 - Additional interest payments & higher interest rates
 - Less money goes into the ground – more goes to the banks
- Uncertainty or surprises in tax credit payments by the state causes financing sources to leave the market or freeze existing credit agreements
 - Makes tax credit financing far more expensive, or completely unavailable
 - Dramatically reduces the exploration activity that is bought by the tax credits

TAX CREDITS – KEEP WHAT IS WORKING

INERTIA/MOMENTUM ARE STRONG FORCES IN THE OIL & GAS INDUSTRY

- Alaska Has Emphasized North Slope Exploration in State Oil and Gas Policy for the Past 15 Years
 - Areawide Leasing Program
 - Exploration Incentive Credit (EIC) Program
 - Net Operating Loss Credits
 - Tax Credit Certificate Payments
 - Collateralization of Tax Credit Certificates
- It Took A While, But That Effort is Now Showing Success
 - Diversified Group of North Slope Explorers
 - Recent Discoveries
 - New Production Coming On-Line
- Elimination/Reduction of Credits Will Be Costly
 - Likely to Slow Down or Stop Exploration
 - Lower Likelihood of New Discoveries
- Getting Momentum Back Will Take A Long Time



SUMMARY

- Great Bear is a highly active North Slope explorer
- Great Bear's investment to date has been substantial and well spent
- Great Bear's pace and volume of future exploration activity will be directly related to tax credit program
- Risk is reduced, and likelihood of success is increased by more exploration
- Reducing exploration risk of Alaska's North Slope resources is a good investment for the State of Alaska
- The Exploration Incentive Credit Program ("025 Credits") is a valuable catalyst for North Slope exploration activities





FRONTIER BASINS TAX CREDITS

Presented to the Alaska House of Representatives
Finance Committee

April 4, 2016

1

Ahtna

FRONTIER BASINS EXPERIENCE



AS.43.55.025(a)(6) & (7) originally created in 2012 under HB 276 and merged with SB23

Intent of Legislature - incentivize oil and gas exploration in under explored Basins

Reduce the risk of development of local rural energy to Alaskans

Create local energy source for rural residents

Reduce or eliminate the Power Cost Equalization (PCE) subsidies

FRONTIER BASIN TAX CREDITS

- ▶ **AS 43.55.025(a)(6) – The first two exploration wells drilled inside each of the six Frontier Basins receives 80% credit or up to \$25M of qualified expenditures**
- ▶ **AS 43.55.025(a)(7) – The first seismic project performed inside each of the six Frontier Basins receives 75% credit up to \$7.5M of qualified expenditures**
- ▶ **Ahtna would not consider any exploration activities without tax credits**

Ahtna

SPECIFIC FRONTIER BASIN REGULATIONS

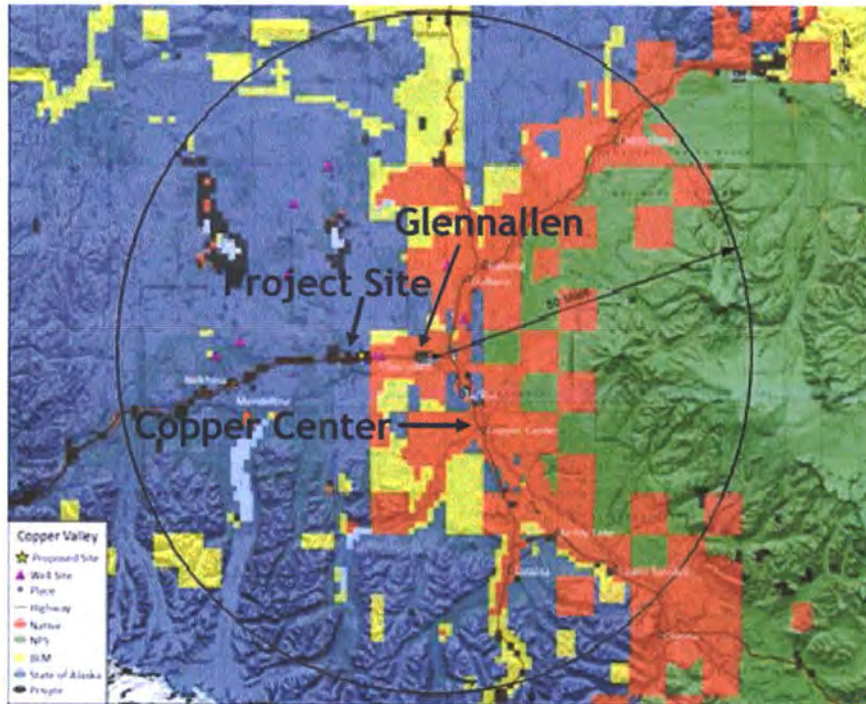
- ▶ ADNR-DOG pre-qualification approval for seismic and well
- ▶ Various well depth and set back from previous wells
- ▶ Submission of all data to ADNR prior to credit award
- ▶ Public data disclosure of all data after 2 years
- ▶ Must provide energy source for rural energy needs!
- ▶ The AS.43.55.025(a)(6) & (7) tax credits are not eligible for stacking

Ahtna

EXPLORATION PROGRAM HISTORY

- ▶ April 2012 Ahtna applies for SOA Exploration License
- ▶ May 2012 Legislature approves SB 23
- ▶ December 2013 Ahtna receives Tolsona Exploration License
- ▶ June 2014 receive ADNR Commissioner pre-qualification approval for seismic
- ▶ December 2014 completes 40-miles of 2D seismic over exploration area
- ▶ April 2015 completed reprocessing of seismic data identifying 12-sq. mile potential oil and gas trap
- ▶ May 2015 submit seismic data to ADNR-DOG
- ▶ September 2015 receive ADNR Commissioner pre-qualification approval of new well
- ▶ February 2016 – majority of permits approved
- ▶ March 2016 final stages of new well engineering and design

COPPER RIVER BASIN



- ✘ Proposed Tolsona well depth of 4,500' Vertical hole.
- ✘ Targeted structure is the Nelchina sandstone.
- ✘ 11 wells drilled in the basin since 1960's.
- ✘ Most recent well - drilled by Rutter in 2005-2008.
- ✘ Natural gas shows (approximately 94% methane).
- ✘ Tolsona #1 potential for a great local fuel source.

PURPOSE AND NEED FOR GAS IN COPPER RIVER BASIN

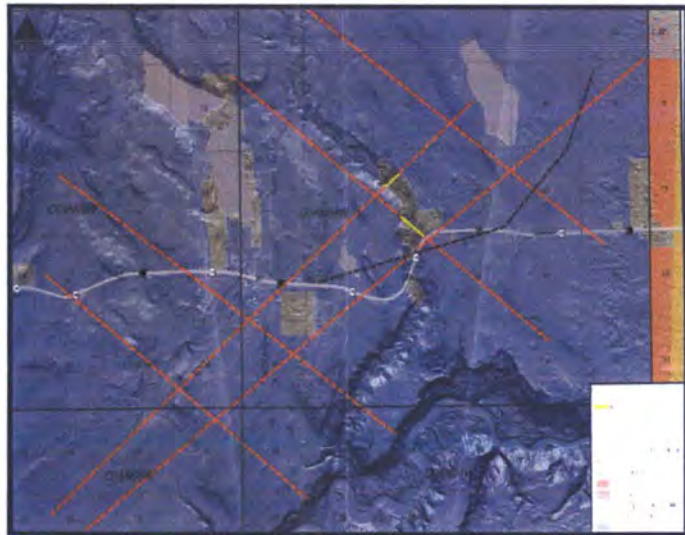
...To conduct exploration within the license area on a single natural gas well, Tolsona #1, with the potential to develop natural gas production for distribution to local residents and electric utilities...

Community and Economic Development Benefits:

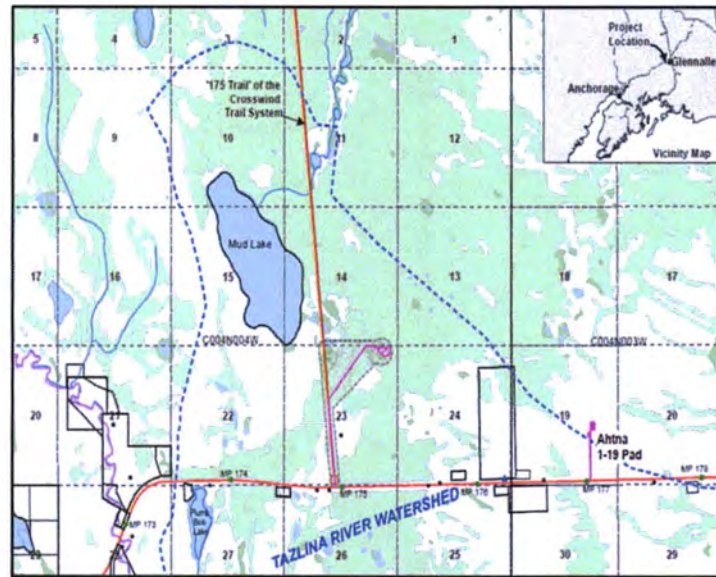
- ▶ Potential Opportunities for Local Employment
- ▶ Economical Benefits, Expanding Local Business
- ▶ Lowering High Energy Cost for Our Rural Economy
- ▶ Reducing Out-migration
- ▶ Building Infrastructure in the Region

Project Overview

- ▶ Seismic
 - ▶ Winter 2014/15
 - ▶ 40 miles of new seismic
 - ▶ Majority on State Land



▶ Current Location



- ▶ Exploration site on State land.
- ▶ Royalties/production tax to the State if successful.
- ▶ Improvement to public access & recreational area.

PROJECT TEAM

Ahtna, Inc.

Tolsona Exploration Oil and Gas, LLC

Ahtna Construction

HXR Drilling Services

Restoration Science & Engineering

Multiple Alaskan Companies

State, Local, Federal Agencies

ADNR ADFG

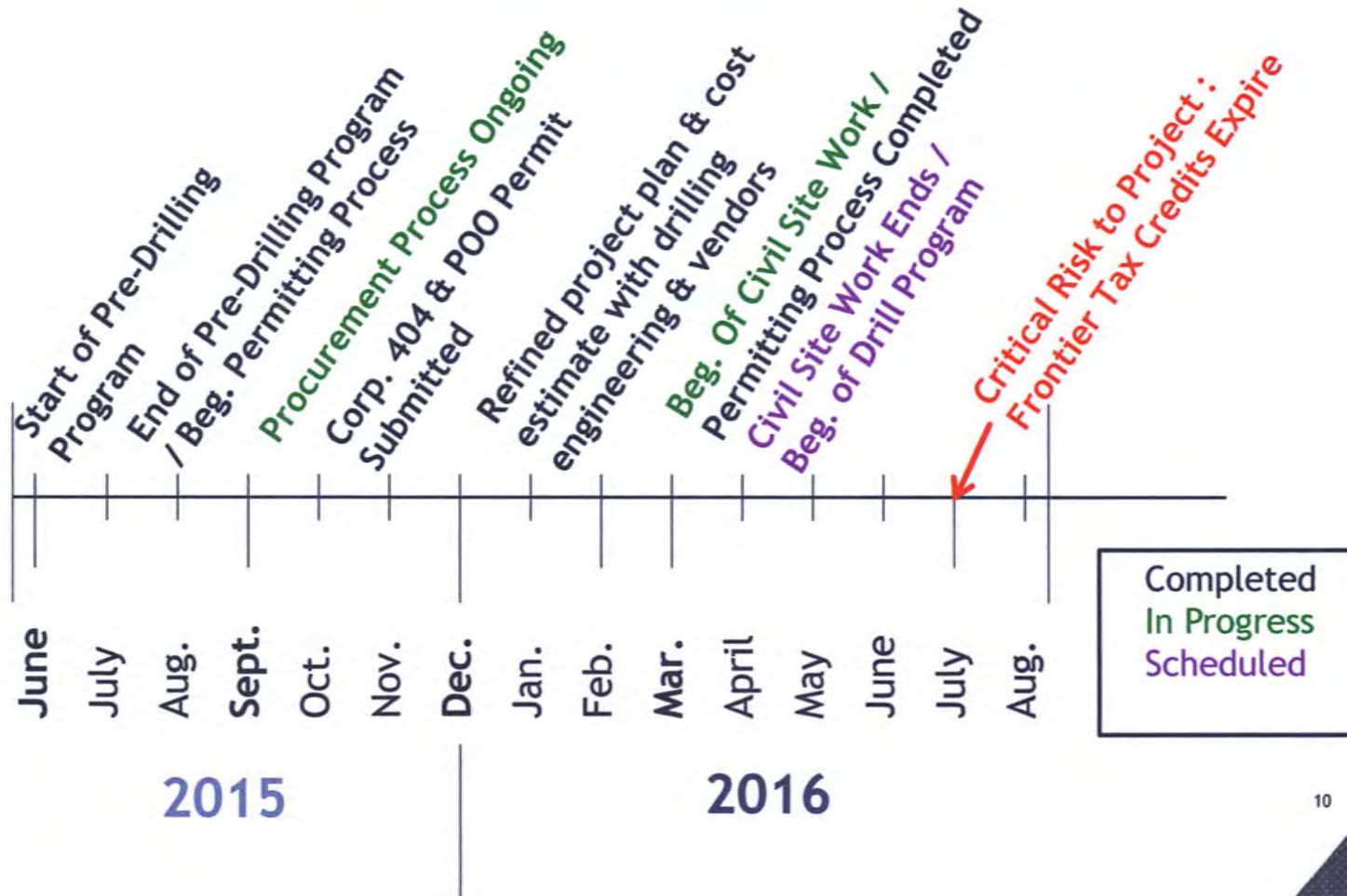
USACE ADOT

ADEC AOGCC

USFWS USEPA

Tremendous agency support, as an example, DNR Division of Oil and Gas Director has visited the region and project site.

PROJECT SCHEDULE (Very tight)!



CONCLUSION

- ▶ **Our Request:** It is critical to our project that the Frontier Basin AS 43.55.025(a)(6) & (7) credits are extended from June 30th 2016 to a future date, we recommend 2022 to coincide with other credit expiration dates.
 - ▶ This will greatly help the Tolsona Project that is under way with a committed investment and a very tight schedule.
- ▶ Ahtna also supports the AS 43.55.023 and 025(a)(1-4) Middle Earth tax credits to be kept in place, as an incentive to the Frontier Basin exploration and development efforts by explorers who have taken the risk and committed investment based on these incentives.

THANK YOU TO OUR GOOD PARTNERS

- ▶ We would like to thank the members of this committee for the opportunity to share our experience. We would also like to thank the Alaska Legislature, Governor, Staff and the citizens of the State of Alaska for your support for developing an affordable energy source in our region.

Questions?

Contact Information

Chris Cook
Ahtna, Incorporated
Director of Finance
110 W. 38th Ave
Anchorage, AK 99503
907-868-8250
ccook@ahtna.net

HB 247: KEY ISSUES & ASSESSMENT

Presentation to House Finance Committee
Juneau, Alaska > Friday, April 1, 2016

Janak Mayer, Chairman & Chief Technologist > janak.mayer@enalytica.com
(via teleconference) Nikos Tsafos, President & Chief Analyst > nikos.tsafos@enalytica.com

<http://enalytica.com>

AGENDA

HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

HB 247: SUMMARY OF KEY ISSUES

APPENDIX

Fiscal System Feature	Status Quo	HB 247 Proposed Change	Impact	HRES CS HB247
Per-Barrel Credit and Gross Minimum Tax	Tax liabilities assessed annually, smoothing impact of price volatility.	Calculate \$/bbl credit and Gross Minimum Tax interaction monthly.	State would have netted additional ~\$100mm in 2014 under this system.	Maintain status quo - tax liabilities assessed annually
Gross Value Reduction and Net Operating Loss Credit	Gross Value Reduction artificially reduces Production Tax Value, and NOL credit is based on PTV, so 35% NOL credit can be given on loss greater than actual loss - effectively more than 35% support for spending.	Assess NOL credit on actual loss (not including GVR), so NOL is for 35% of actual loss, and all producers have 35% support for spending.	Net impact is to reduce state support for all spending to 35%. Questions exist about whether >35% spending support for GVR oil was deliberate incentive or unintended consequence under SB21.	Adopt proposed fix to NOL calculation for GVR-eligible production
Gross Minimum Tax	4% rate, binding for legacy output if net value is positive. If net value is negative, NOL can reduce taxes below floor. "New," GVR-eligible production can take to zero due to \$5/bbl and small producer credit	Harden floor for all production: NOL credits can't take below floor for legacy, and NOL, small Producer and \$5/bbl can't take below floor for GVR-eligible production. Increase rate from 4% to 5%	State revenues rise at low oil prices. For many new fields, taxes rise from 0 to 5% at current prices. For legacy production, taxes rise at time when value is negative.	Maintain status quo - no further floor hardening

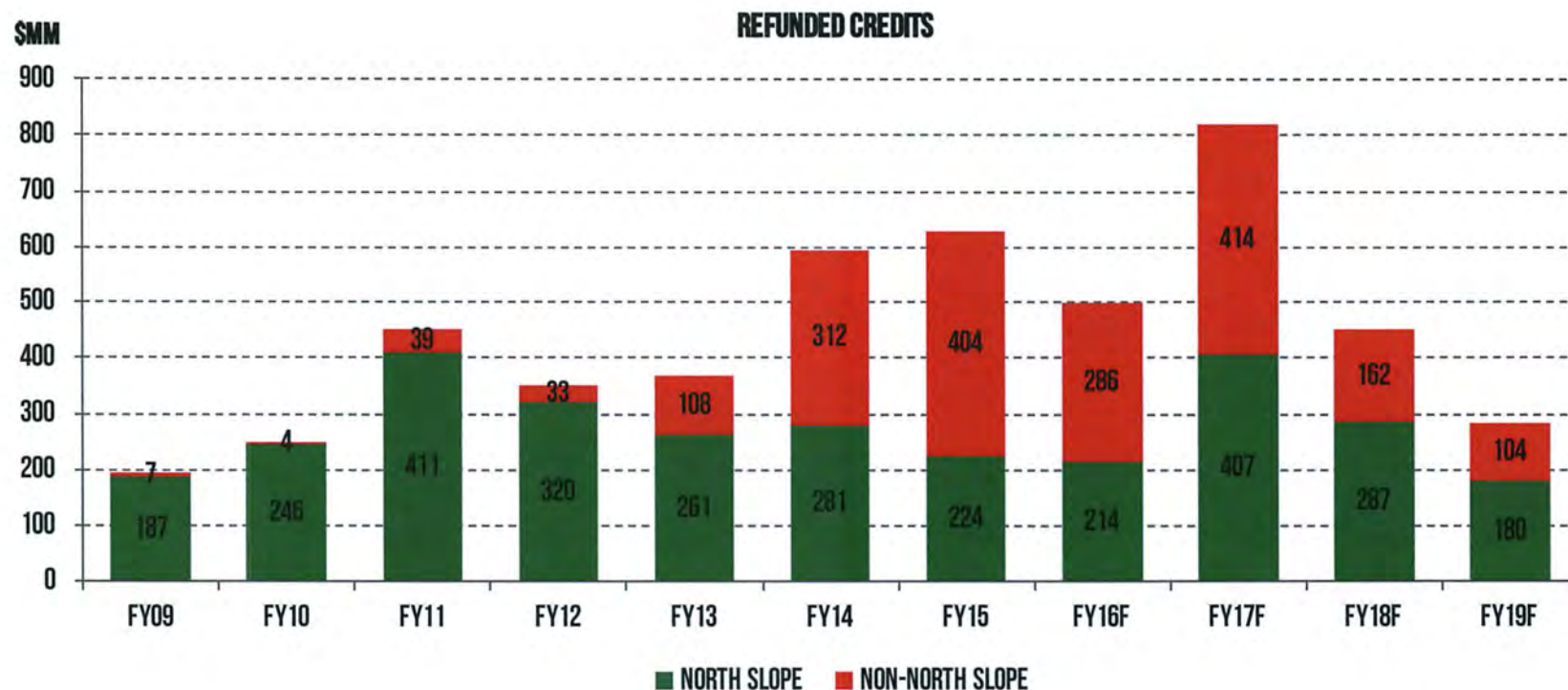
Fiscal System Feature	Status Quo	HB 247 Proposed Change	Impact	HRES CS HB247
Net Operating Loss credit reimbursement	Producers with >50 mb/d production must carry NOL forward, others can be reimbursed by the state	\$25mm per company annual limit on reimbursement. Companies with annual revenues > \$10bn must carry forward, regardless of production level.	Limit substantially increases capital needs for new developments; and if effective July 2016 would have major negative impact on developments underway. Raises hurdle/break-even price for projects by \$5 to \$15/bbl.	\$200mm per company annual limit on reimbursement.
Gross Value at Point of Production calculation	GVPP is calculated by subtracting transportation costs from sale price. If transportation costs for some production exceed price, GVPP is negative	GVPP cannot go below zero	Could limit deductibility of some transport costs. Particularly likely to be an issue at current prices if applied on a per-unit or per field basis.	Maintain status quo
Cook Inlet Tax Credits	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit; up to 65% gov't support for spending and minimal production tax	Repeal QCE and WLE credits effective July 1 2016, leaving only 25% NOL credit	Cook Inlet credit regime is clearly unsustainable in current environment; repeal in present year may have major impacts on capital commitments already made, and the viability of producers who have made those commitments	Reduce NOL credit to 10%, keep 20% QCE credit, reduce WLE credit to 20% by 2018

REFUNDED CREDITS REACHED NEW HIGH IN FY 2015

Refundable credits in FY 2015 reached \$628 mm, the highest point ever

In both 2014 and 2015, the majority of these credits went to non-North Slope producers

Under DOR's current forecast, credits will exceed \$1.3 billion across FY 2016 and FY 2017



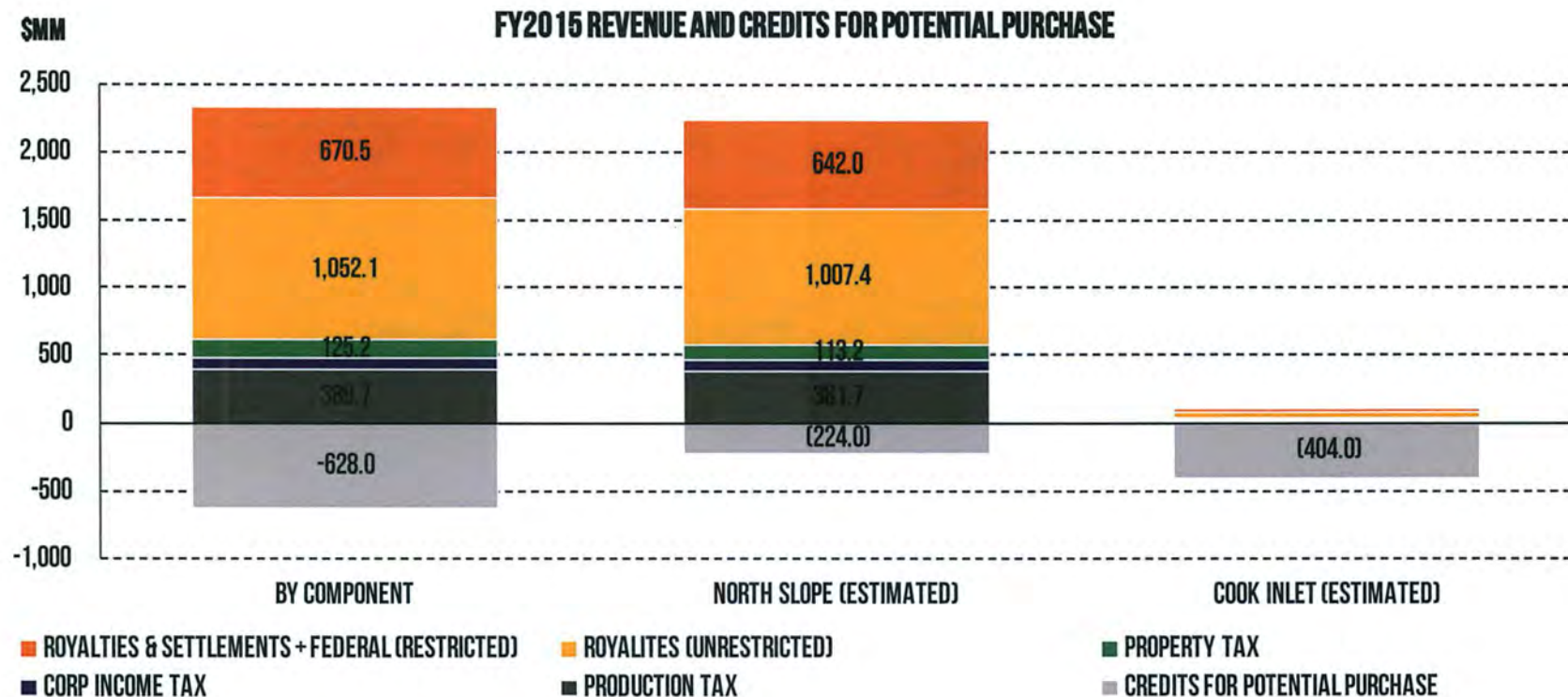
SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION

BIG DIFFERENCE BETWEEN NORTH SLOPE AND COOK INLET

The majority of refundable credits go to Cook Inlet producers

Cook Inlet production, however, generates limited direct revenue for the state

Credits on the North Slope are more limited but also a far smaller fraction of total value generated



SOURCE: ALASKA DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK; TAX DIVISION; ANALYTICA ESTIMATES

AGENDA

HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

HB 247: SUMMARY OF KEY ISSUES

APPENDIX

HARD TO BE BOTH NORWAY & N. DAKOTA AT SAME TIME

Gross taxes

Less volatile, shift risk to private sector

Simple and easy to administer

High/low government take at low/high prices

Disadvantages marginal investment

Net taxes

More volatile revenues for government

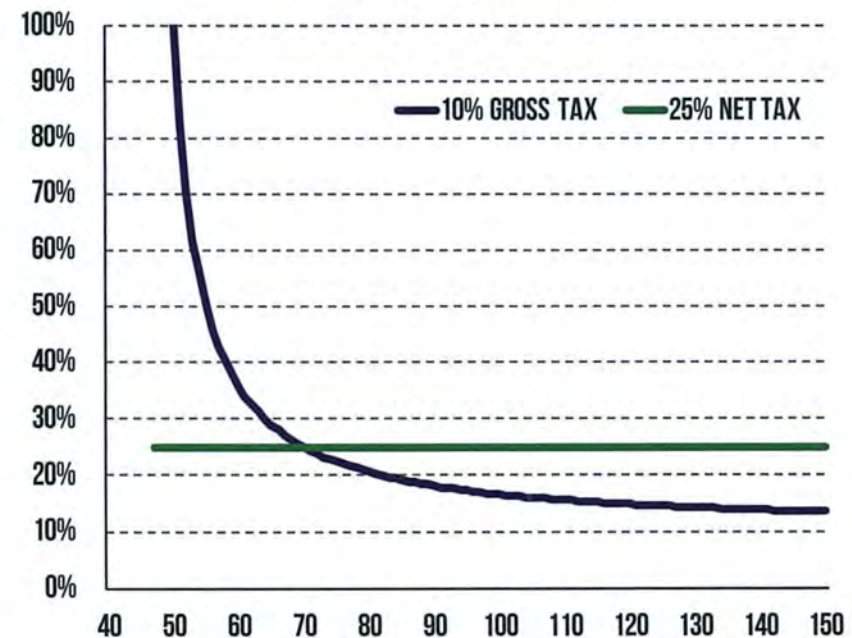
Harder to administer

Efficient—do not distort decision-making

Enable investment across commodity cycle

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	-6	14	34	54	74	94
10% GROSS TAX	3	5	7	9	11	13
% GROSS	10%	10%	10%	10%	10%	10%
% NET	#N/A	36%	21%	17%	15%	14%
25% NET TAX	-1.5	3.5	8.5	13.5	18.5	23.5
% GROSS	-5%	7%	12%	15%	17%	18%
% NET	25%	25%	25%	25%	25%	25%

EFFECTIVE TAX RATES



CASHFLOW TAXES: MORE EFFICIENT, MORE VOLATILE

Purpose of net tax is to **minimize distorting impact** on investment

Best achieved by making the state's fiscal cost/benefit as close as possible to **equity investor**

Results in **outflows** during development, **receipts** during production

HIGHLY SIMPLIFIED CASHFLOW AND INCOME EXAMPLE

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRODUCTION (THOUSAND BBLs)	-	-	-	1,000	1,000	900	810	729	656	590
ANS WC	60	60	60	60	60	60	60	60	60	60
TRANSPORT	10	10	10	10	10	10	10	10	10	10
GVPP/BBL	50	50	50	50	50	50	50	50	50	50
GVPP (\$THOUSANDS)	-	-	-	50,000	50,000	45,000	40,500	36,450	32,805	29,525
OPEX	-	-	-	18,000	18,000	16,200	14,580	13,122	11,810	10,629
CAPEX	20,286	60,857	33,809	20,286	-	-	-	-	-	-
PRE-TAX CASHFLOW	(20,286)	(60,857)	(33,809)	11,714	32,000	28,800	25,920	23,328	20,995	18,896
ASSET VALUE	-	-	-	135,238	108,190	86,552	69,242	55,393	44,315	35,452
DEPRECIATION	-	-	-	27,048	21,638	17,310	13,848	11,079	8,863	7,090
NET INCOME	-	-	-	4,952	10,362	11,490	12,072	12,249	12,132	11,805
25% CASHFLOW TAX	(5,071)	(15,214)	(8,452)	2,929	8,000	7,200	6,480	5,832	5,249	4,724
25% INCOME TAX	-	-	-	1,238	2,590	2,872	3,018	3,062	3,033	2,951

ALASKA'S PRODUCTION TAX: ORIGINS IN 2006 PROPOSAL

PPT **as proposed** by Dr Pedro van Meurs useful to understand core of system and evolution to date

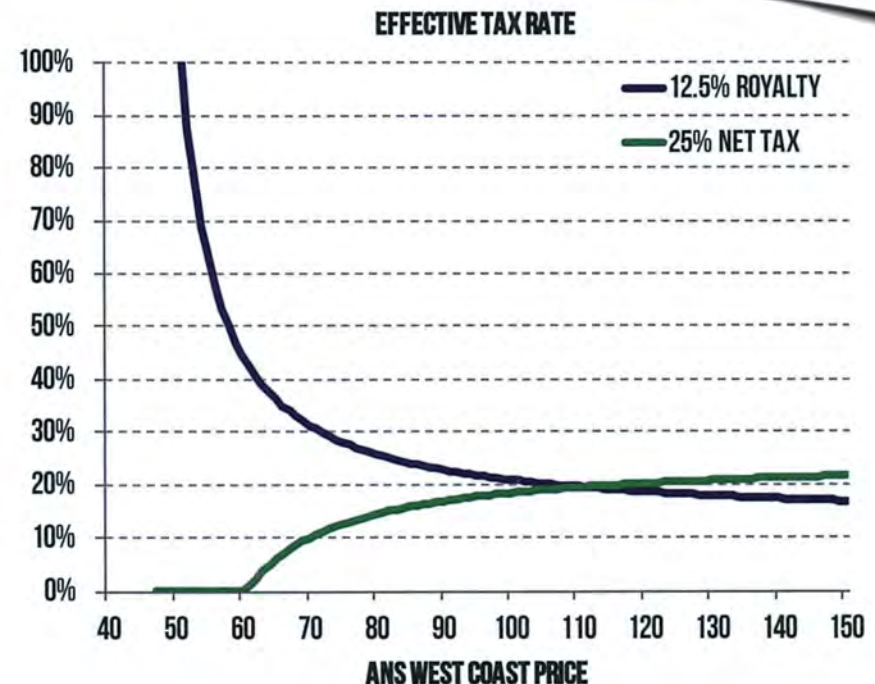
25% flat cashflow tax, 25% credit for net operating losses (NOLs), 20% capital credit

45% government support for spending for new and incumbent players alike

Statewide floor of zero (credits tradable rather than reimbursable)



ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
25% NET TAX	(1.5)	3.5	8.5	13.5	18.5	23.5
CAPITAL CREDIT	3.6	3.6	3.6	3.6	3.6	3.6
TAX AFTER CREDITS	(5.1)	(0.1)	4.9	9.9	14.9	19.9
% GROSS	-17%	0%	7%	11%	14%	15%
% NET	#N/	-1%	14%	18%	20%	21%



NOL CREDIT AIMS TO EQUALIZE TAX SYSTEM IMPACT

Incumbent can deduct spending against liability at marginal tax rate: **25% gov't spending support**

Aim for NOL credit to **ensure same impact for new developer** with no liability

Alternative is to **carry forward**: same cash impact over time, but disadvantages new developer economics

In original proposal, credits **not refundable but tradable**

Aim was for **new developers** to **sell to incumbent producers** at close to face value

In reality credits sold for much less than face value - much **value captured by incumbents**

As a result, credits **made refundable** by the treasury, to direct full value to new developers

HIGHLY SIMPLIFIED CASHFLOW AND INCOME EXAMPLE

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRODUCTION (THOUSAND BBLs)	-	-	-	1,000	1,000	900	810	729	656	590
ANS WC	60	60	60	60	60	60	60	60	60	60
TRANSPORT	10	10	10	10	10	10	10	10	10	10
GVPP/BBL	50	50	50	50	50	50	50	50	50	50
GVPP (\$THOUSANDS)	-	-	-	50,000	50,000	45,000	40,500	36,450	32,805	29,525
OPEX	-	-	-	18,000	18,000	16,200	14,580	13,122	11,810	10,629
CAPEX	20,286	60,857	33,809	20,286	-	-	-	-	-	-
PRE-TAX CASHFLOW	(20,286)	(60,857)	(33,809)	11,714	32,000	28,800	25,920	23,328	20,995	18,896
25% CASHFLOW TAX	(5,071)	(15,214)	(8,452)	2,929	8,000	7,200	6,480	5,832	5,249	4,724

ACES: STEEP PROGRESSIVITY, HIGH SPENDING SUPPORT

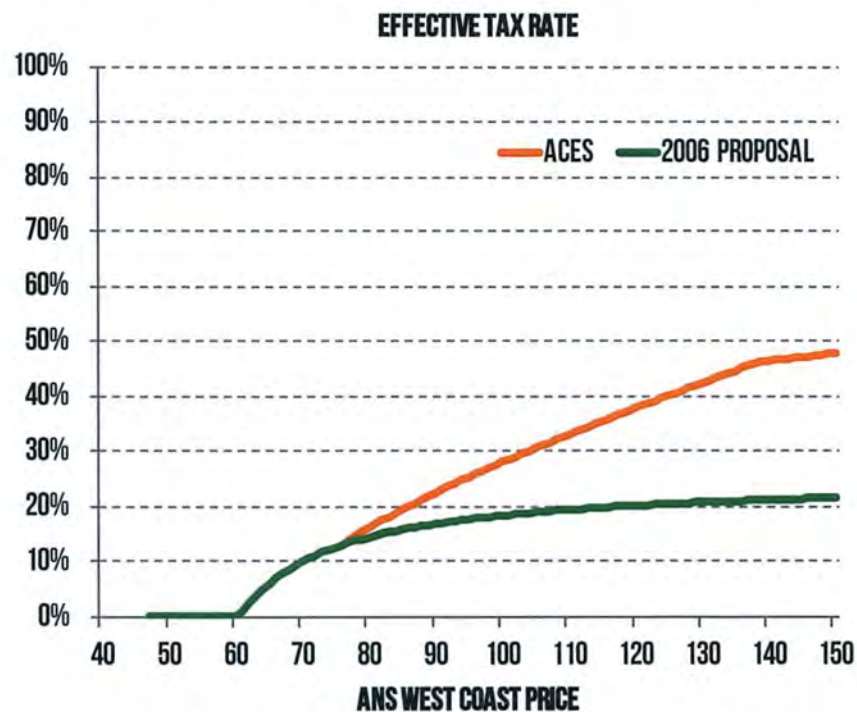
Tax rate 25% to 75% (variable with PTV/bbl), 20% capital credit, 40% exploration credit, 25% NOL credit

High progressivity: **high marginal tax rates** (up to 86%, higher at yet-unseen prices)

High marginal rates + credits = **very high state support for spending** (from 45% to over 100%)

With **high prices and low spending**, brought huge revenue; low prices and high spending **major risks**

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
NET TAX RATE	25%	25%	27%	35%	43%	50%
NET TAX CALC	-	3.5	9.0	18.7	31.5	47.1
4% GROSS FLOOR	1.2	2.0	2.8	3.6	4.4	5.2
TAX BEFORE CREDITS	1.2	3.5	9.0	18.7	31.5	47.1
NOL CREDIT	1.5	-	-	-	-	-
CAPITAL CREDIT	3.6	3.6	3.6	3.6	3.6	3.6
TAX AFTER CREDITS	(3.9)	(0.1)	5.4	15.1	27.9	43.5
% GROSS	-13%	0%	8%	17%	25%	33%
% NET	#N/A	-1%	16%	28%	38%	46%



SB21: PROTECT ON THE LOW END, GIVE BACK AT THE HIGH

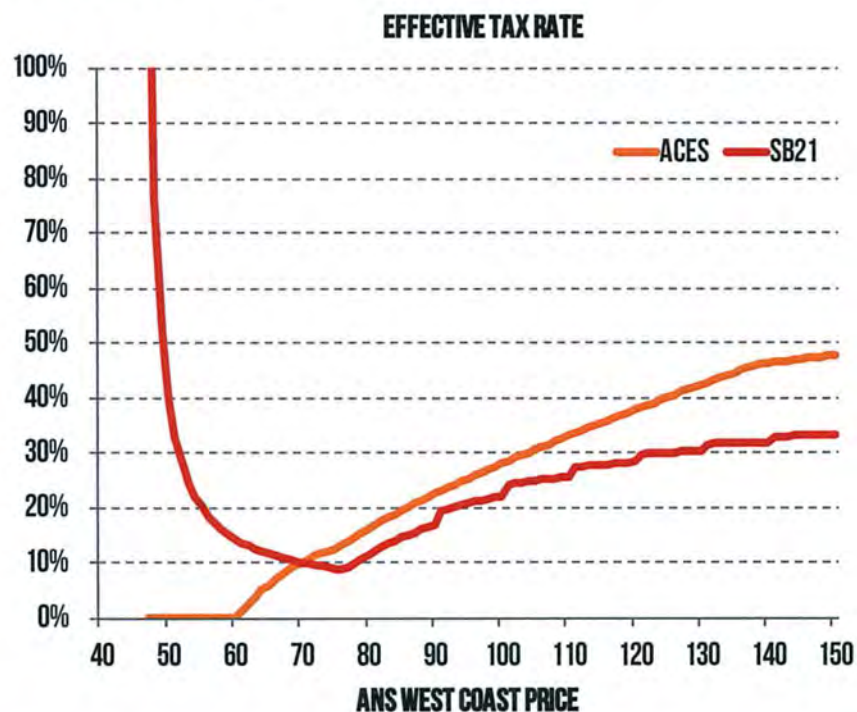
Tax rate 35%, \$0 to \$8 per-bbl credit, hardened gross floor, 35% NOL credit

Key aim was to **reduce state support for spending** and make predictable: **35% for everyone**

Reduced rates at high prices for competitiveness, but **4% gross floor binding** to protect at low end

Significantly reduced the risks brought by low prices and high spending

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
NET TAX RATE	35%	35%	35%	35%	35%	35%
NET TAX PRE \$/BBL	-	4.9	11.9	18.9	25.9	32.9
\$/BBL CREDIT	8.0	8.0	8.0	7.0	4.0	-
NET TAX CALC	(8.0)	(3.1)	3.9	11.9	21.9	32.9
4% GROSS FLOOR	1.2	2.0	2.8	3.6	4.4	5.2
TAX BEFORE NOL	1.2	2.0	3.9	11.9	21.9	32.9
NOL CREDIT	2.1	-	-	-	-	-
TAX AFTER CREDITS	(0.9)	2.0	3.9	11.9	21.9	32.9
% GROSS	-3%	4%	6%	13%	20%	25%
% NET	#N/A	14%	11%	22%	30%	35%



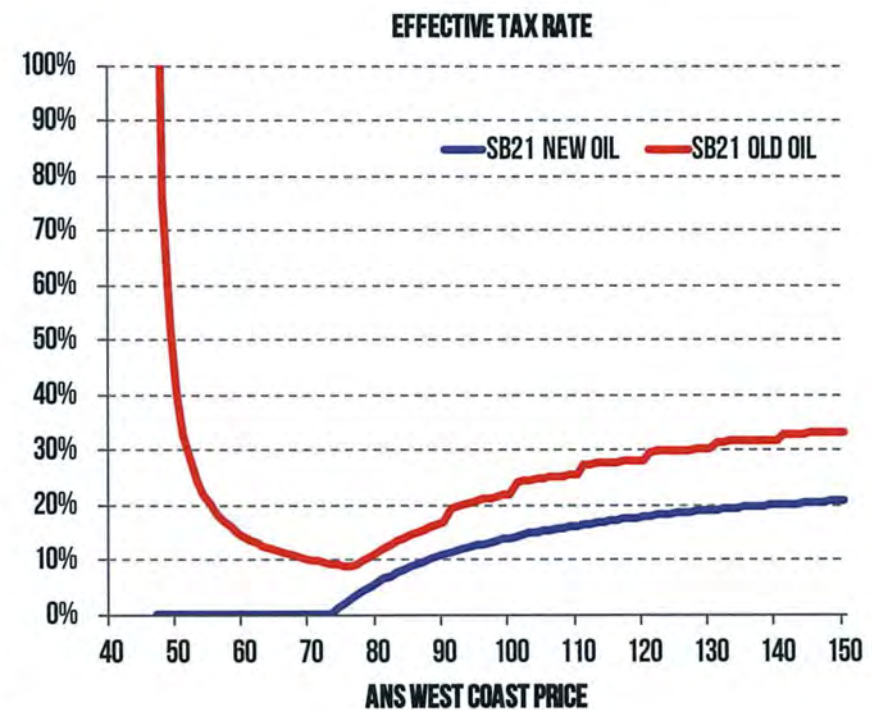
SB21: SPECIAL INCENTIVES FOR “NEW OIL”

Gross Value Reduction (GVR) - reduce GVPP by 20% or 10% for certain units / participating areas

Purpose of GVR - **reduce effective tax rates** for particular fields **without ring-fencing** costs

GVR-eligible production receives **fixed \$5/bbl credit**, not variable \$0-\$8/bbl, **no hard floor**

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP BEFORE GVR	30	50	70	90	110	130
GVPP AFTER GVR	24	40	56	72	88	104
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL BEFORE GVR	(6.0)	14.0	34.0	54.0	74.0	94.0
PTV/BBL	(12.0)	4.0	20.0	36.0	52.0	68.0
NET TAX RATE	35%	35%	35%	35%	35%	35%
NET TAX	-	1.4	7.0	12.6	18.2	23.8
4% GROSS FLOOR	1.0	1.6	2.2	2.9	3.5	4.2
\$/BBL CREDIT	5.0	5.0	5.0	5.0	5.0	5.0
TAX BEFORE NOL	(4.0)	(3.4)	2.0	7.6	13.2	18.8
NOL CREDIT	4.2	-	-	-	-	-
TAX AFTER CREDITS	(8.2)	(3.4)	2.0	7.6	13.2	18.8
% GROSS	-27%	-7%	3%	8%	12%	14%
% NET	#N/A	-24%	6%	14%	18%	20%



AGENDA

HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

HB 247: SUMMARY OF KEY ISSUES

APPENDIX

MONTHLY GROSS MIN CALCULATION: NEUTRAL OR TAX HIKE

Under volatility, **gross minimum** tax may apply to some months, while annual remains **net profit**-based

In 2014, gross minimum would have applied Nov & Dec, but not full-year⁺

Enforcing monthly gross minimum would have netted additional ~\$100mm⁺

	ANS WC	TRANSPORT	OPEX	CAPEX	PTV/BBL	35%*PTV/BBL	LESS \$8/BBL	4% OF GVPP	PROD TAX / BBL	LIABILITY \$MM
ANNUAL										
2014	97.74	10.42	19.30	20.29	47.73	16.71	8.71	3.49	8.71	1,440.32
MONTHLY										
JAN-2014	103.82	10.42	19.30	20.29	53.81	18.83	10.83	3.74	10.83	
FEB-2014	106.30	10.42	19.30	20.29	56.29	19.70	11.70	3.84	11.70	
MAR-2014	107.91	10.42	19.30	20.29	57.90	20.26	12.26	3.90	12.26	
APR-2014	107.36	10.42	19.30	20.29	57.35	20.07	12.07	3.88	12.07	
MAY-2014	108.06	10.42	19.30	20.29	58.05	20.32	12.32	3.91	12.32	
JUN-2014	110.76	10.42	19.30	20.29	60.75	21.26	13.26	4.01	13.26	
JUL-2014	107.63	10.42	19.30	20.29	57.62	20.17	12.17	3.89	12.17	
AUG-2014	101.78	10.42	19.30	20.29	51.77	18.12	10.12	3.65	10.12	
SEP-2014	96.05	10.42	19.30	20.29	46.04	16.12	8.12	3.43	8.12	
OCT-2014	84.91	10.42	19.30	20.29	34.90	12.21	4.21	2.98	4.21	
NOV-2014	77.41	10.42	19.30	20.29	27.40	9.59	1.59	2.68	2.68	
DEC-2014	60.90	10.42	19.30	20.29	10.89	3.81	(4.19)	2.02	2.02	
									9.31	1,540.94
INCREASE									0.61	100.62

⁺single-taxpayer, taxable-barrel-based approximation, FY2014 DOR RSB costs, assumes no taxable production GVR-eligible

GVR RAISES NOL CREDIT ABOVE 35% OF ACTUAL LOSS

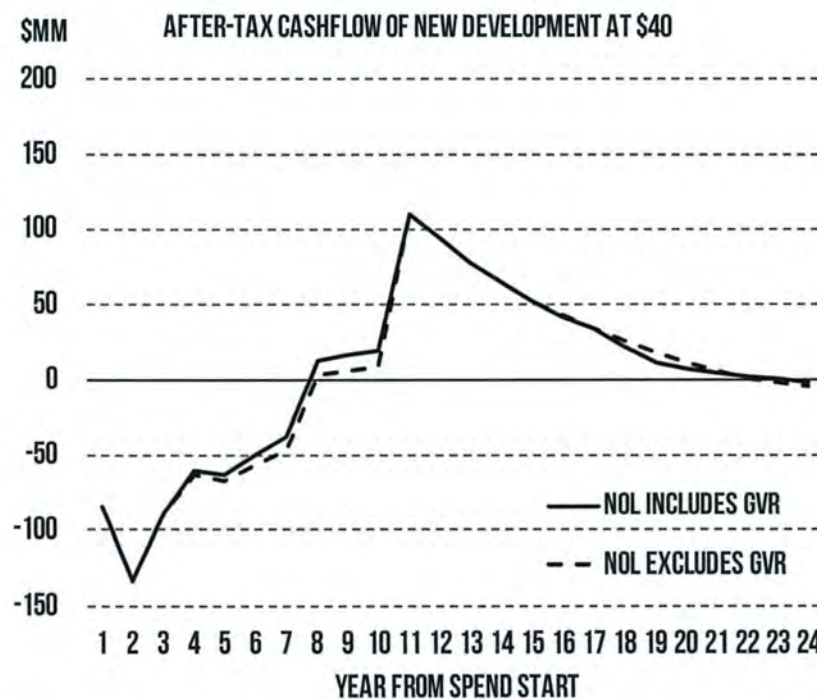
The purpose of the Gross Value Reduction (GVR) is to **lower the effective tax rate** on new production

One surprising and counter-intuitive effect is to **raise the effective rate of the NOL** credit

Issue after production from new development starts, but ongoing drilling costs mean NOL eligible

Exacerbated at low prices, but impact <\$10mm yr for 20mb/d new development

	SB 21 GVR	HB 247
ANS WC	40	40
TRANSPORT	10	10
GVPP BEFORE GVR	30	30
GVPP AFTER GVR	24	24
OPEX	18	18
CAPEX	18	18
PTV/BBL BEFORE GVR	(6.0)	(6.0)
PTV/BBL	(12.0)	(12.0)
NET TAX RATE	35%	35%
NET TAX	-	-
4% GROSS FLOOR	1.0	1.0
\$/BBL CREDIT	5.0	5.0
TAX BEFORE NOL	(4.0)	(4.0)
NOL CREDIT	4.2	2.1
TAX AFTER CREDITS	(8.2)	(6.1)
CREDIT % PTV (BEFORE)	-70%	-35%

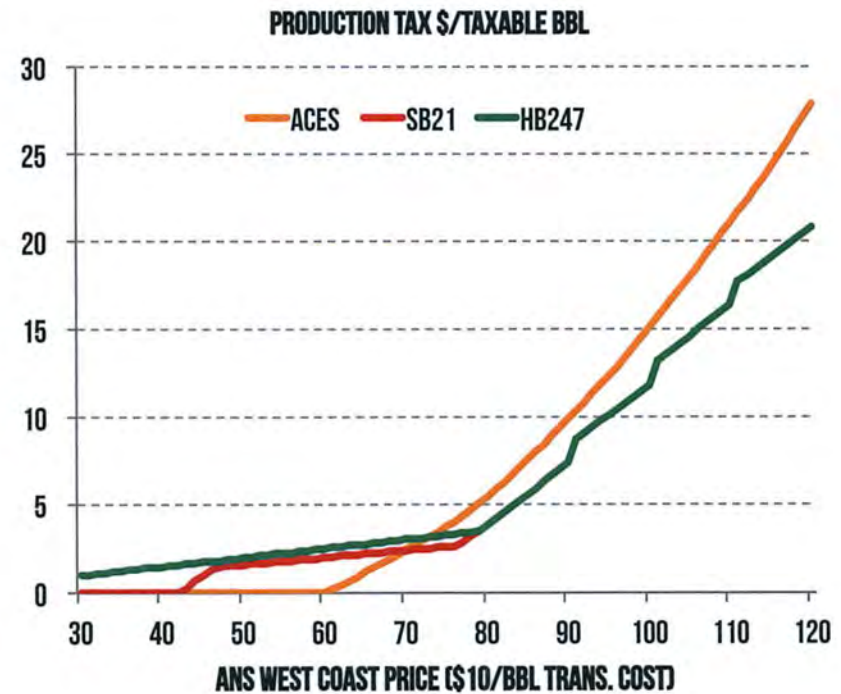
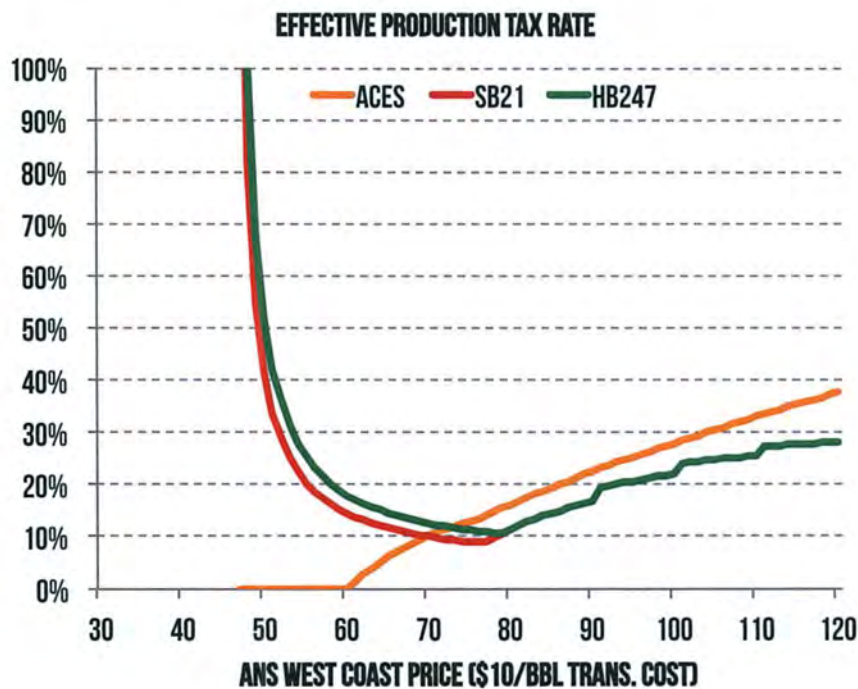


HARDER, HIGHER FLOOR RAISES TAXES ON LOSSES

Effective tax rate under ACES could fall to zero because capital credits were applied after gross floor
 SB21 applied a **hard gross floor** under \$/bbl credits - meaning skyrocketing net tax rate at low prices

Concern to **protect state at low prices** always valid

Competitive regimes **balance risk and reward** at low and high end

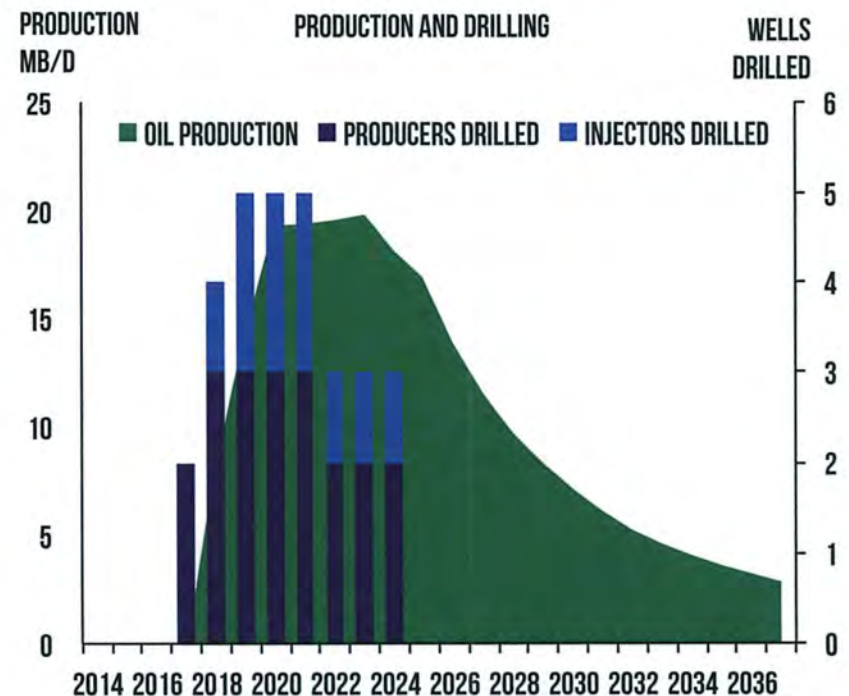
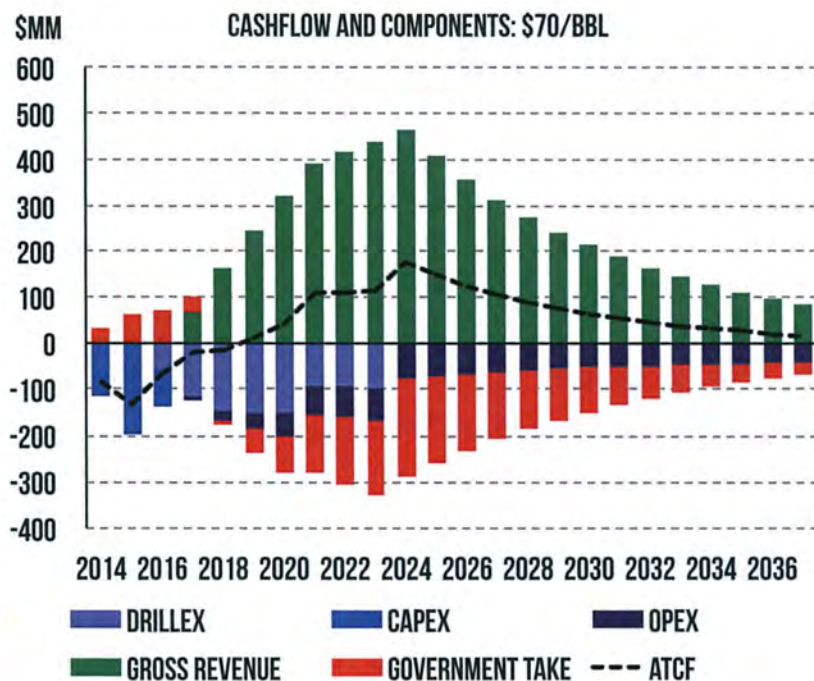


HOW DO CHANGES IMPACT NEW FIELD DEVELOPMENT?

To understand the cumulative impact of the proposed changes, we look at a **sample NS investment**

Cumulative CAPEX and drillex of \$1.3 billion; average annual OPEX of about \$15/bbl

Peak production of 20 mb/d; 30 wells (production and injection) drilled over 8 years



REFUND LIMITS BOOST CAPITAL NEEDS AND LOWER IRR

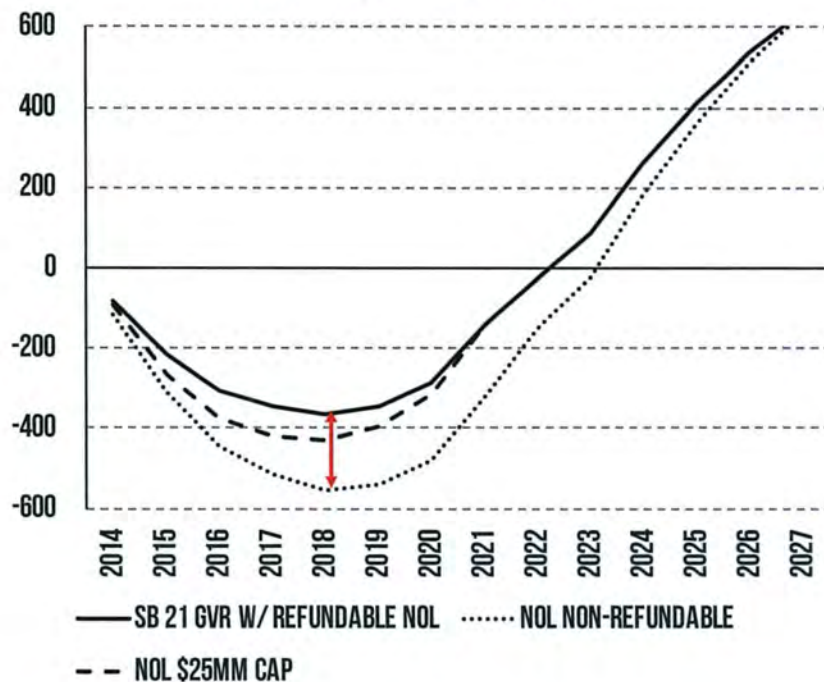
Refundable credit limit would **increase capital needs** by up to 50% (from \$350mm to \$400–\$550mm)

Application to projects currently under development could have **major adverse impacts**

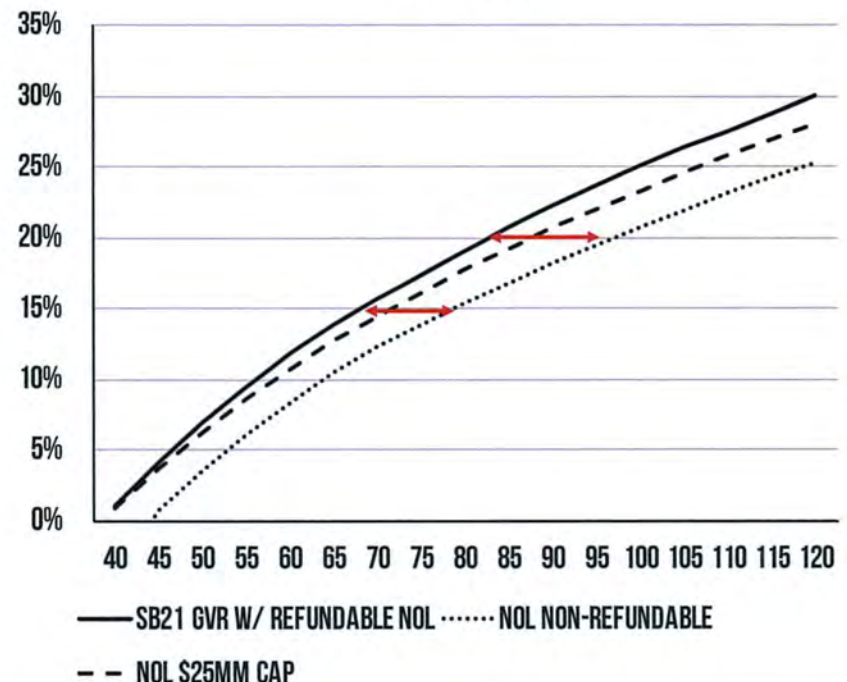
Near-Kuparak-sized new development could easily incur **>\$2bn in NOL credits** in development years

If per-company limit on refundability is the solution, what is the right level?

CUMULATIVE CASHFLOW (\$70/BBL)



IRR SENSITIVITY

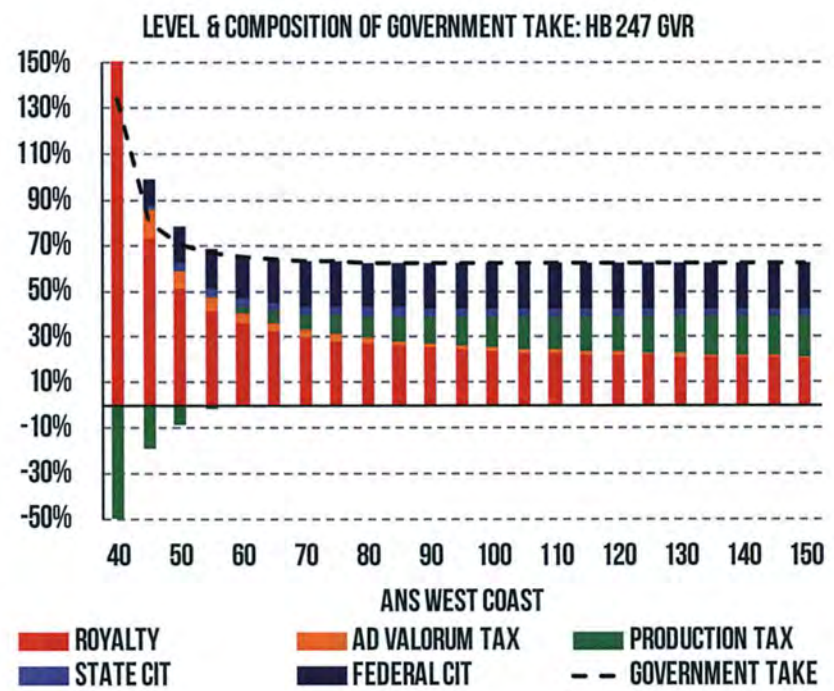
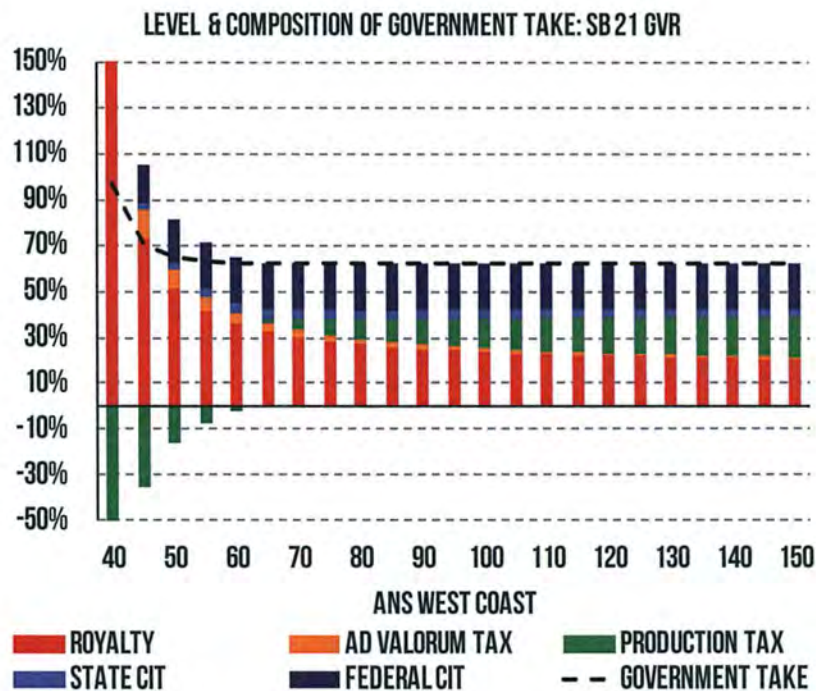


CHANGES MAKE REGRESSIVE SYSTEM EVEN MORE SO

State of Alaska making negative production tax in today's prices; but overall gov't take is still high

Cumulative impact of proposed changes would be to shift up government take in lower oil prices

In times of high investment / low prices (as in 2016), **effective government take exceeds 100%**



AGENDA

HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

HB 247: SUMMARY OF KEY ISSUES

APPENDIX

ACTIVITY HAS RESPONDED IN RECENT YEARS

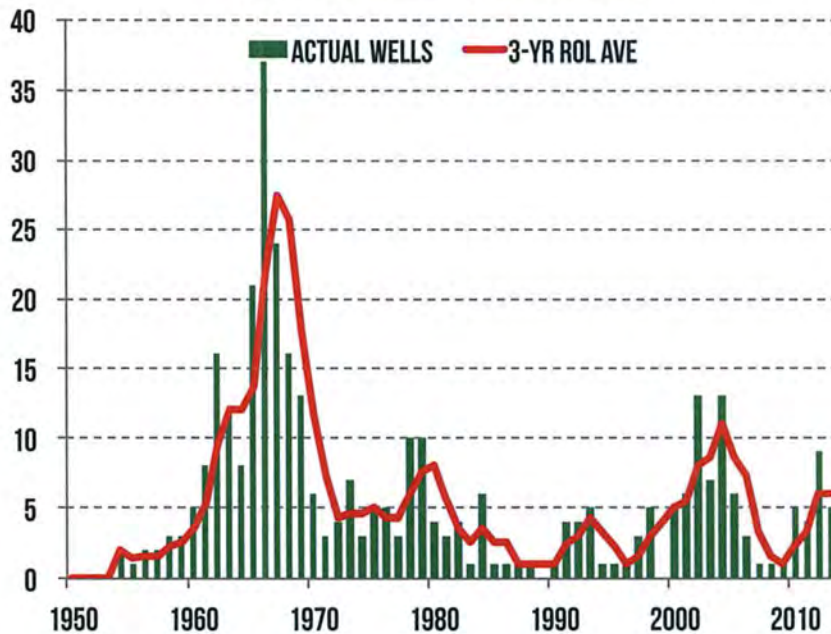
Exploration drilling in Cook Inlet has gone through several cycles since 1950s

Recent exploration activity (post 2010) on par with previous exploration peaks

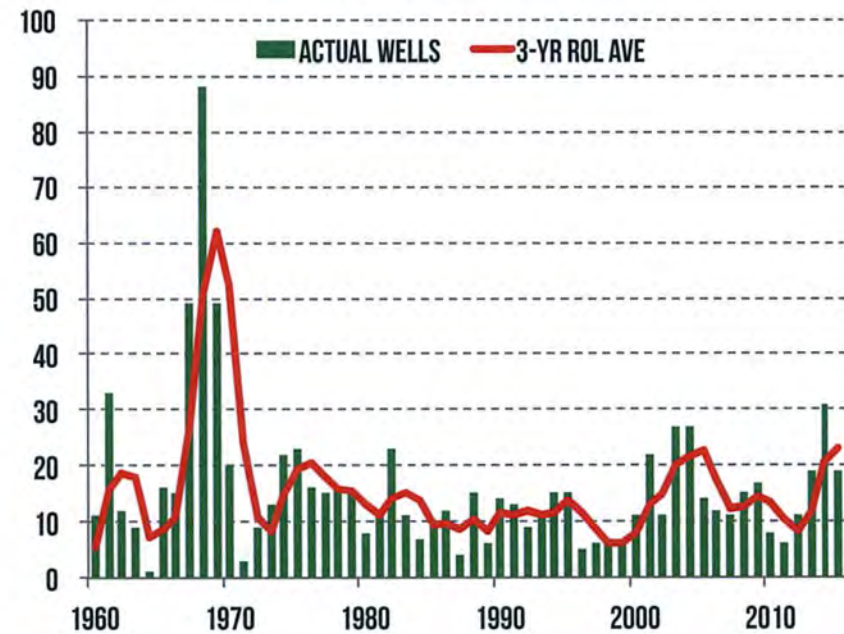
Development drilling has been more stable over the years

Recent growth placing three-year rolling average among highest in state's history

COOK INLET: EXPLORATORY WELLS SPUDDED



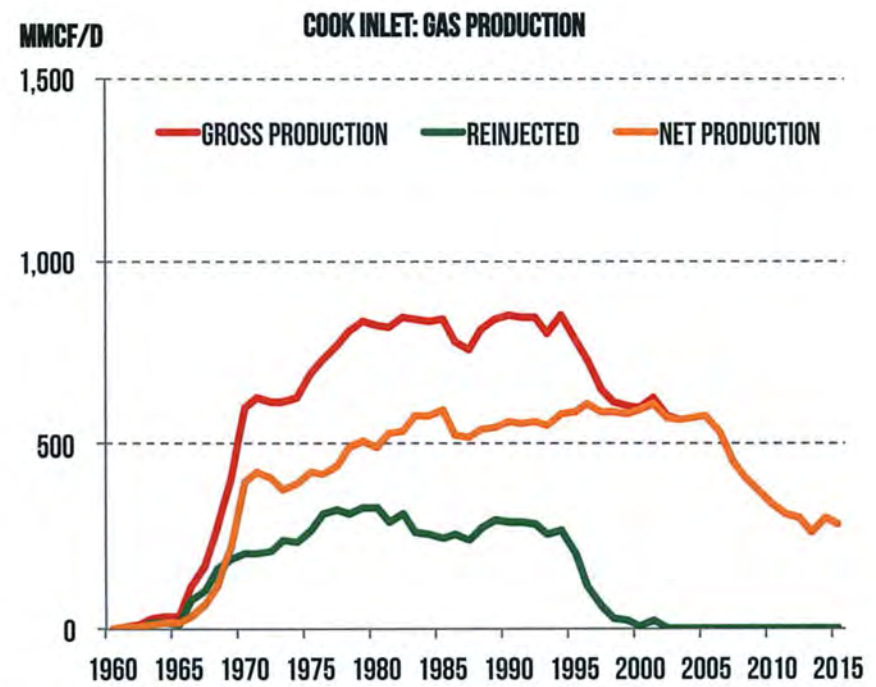
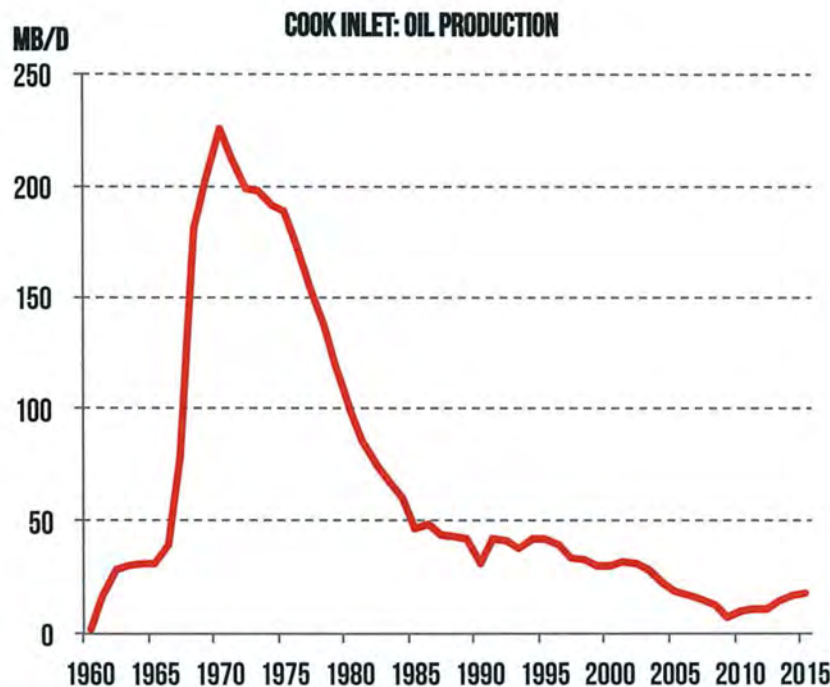
COOK INLET: WELLS BY YEAR OF FIRST OIL/GAS



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

COOK INLET OIL AND GAS PRODUCTION: BASIC FACTS

- Oil** Peak in 1970 at 226 mb/d; trough in 2009 at 7.5 mb/d; upturn post 2010 (+10.5 mb/d)
- Gross Gas** Peak in 1990 at 853 mmcf/d; big drops in 1994–1998 and 2005–2013; stable in 2014–15
- Net Gas** Peak in 1996; 1990s plateau from blowdown at Swanson River; fall post 2005, then stable



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

THE COOK INLET OIL AND GAS MARKET: A SCORECARD

What has happened to oil and gas production and activity in the Cook Inlet in recent years?

Oil production has risen from 7.5 mb/d in 2009 to almost 18 mb/d

Gas production has stabilized after years of steadier decline

How has the gas market adjusted in recent years?

Cook Inlet has undergone major transition in supply, demand, prices, competition and expectations

Some of these changes are typical in mature basins—others are unique to Cook Inlet

What's the outlook and how sensitive is the outlook to changes in oil/gas fiscal system?

DNR: 1,183 bcf in remaining 2P reserves; 1,600 bcf w/ Cosmopolitan and Kitchen Lights (ballpark)

Continued drilling at old fields plus Cosmopolitan and Kitchen Lights: current market well supplied

At current (gas) price levels, brownfield investment should be profitable under stricter fiscal regime

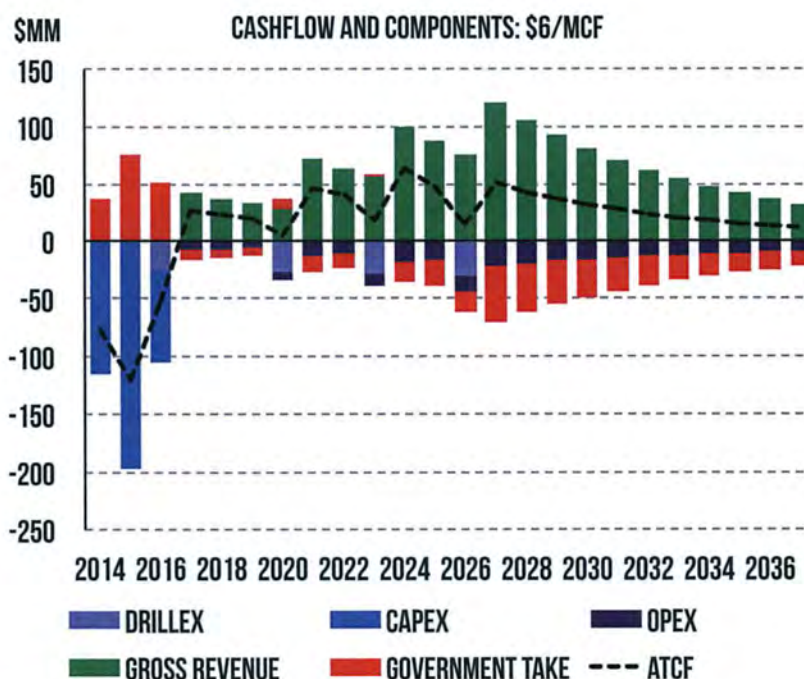
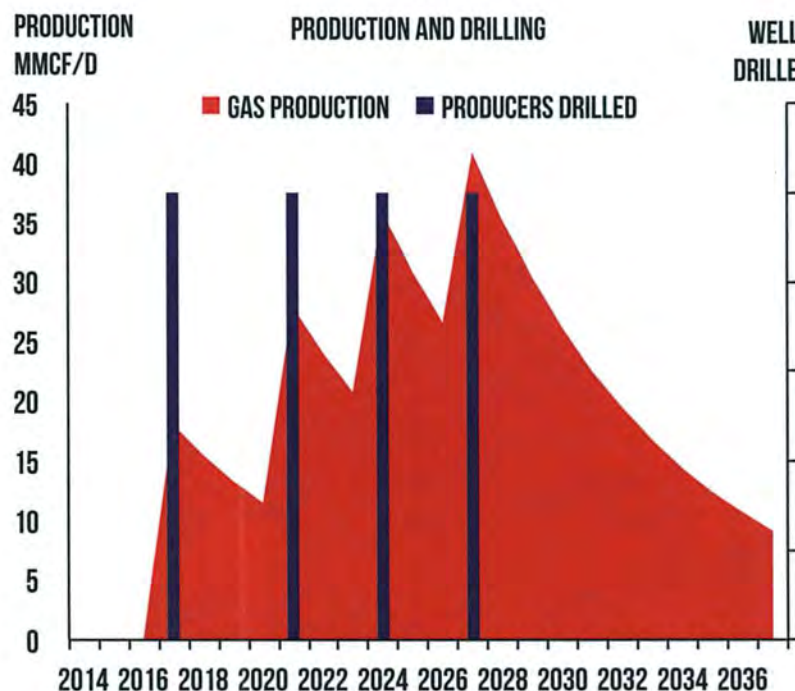
Credits more important for developing new resources, especially with demand constraints

Currently much uncertainty over future regime - setting a stable, sustainable system is paramount

PROJECT #1: MARKET CONSTRAINED (ASSUMPTIONS)

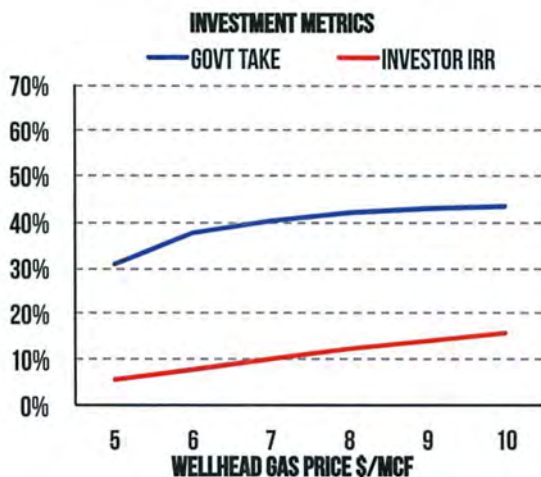
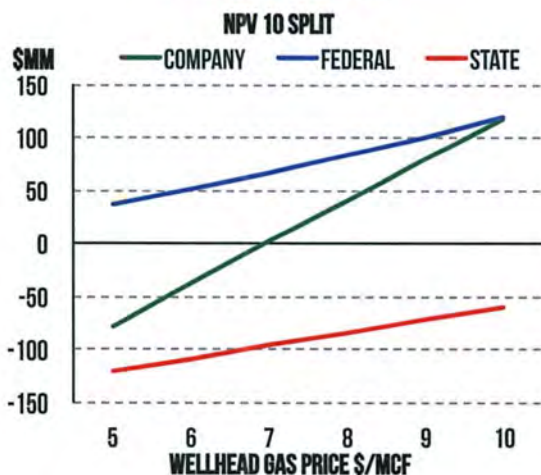
Large upfront investment but constrained gas market

Limited ability to sell gas: can only drill a well every few years

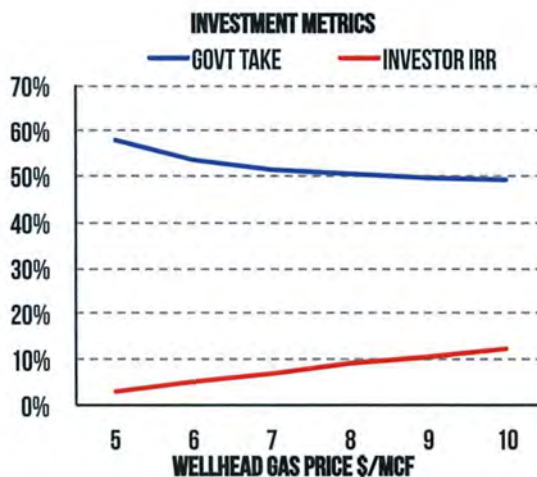
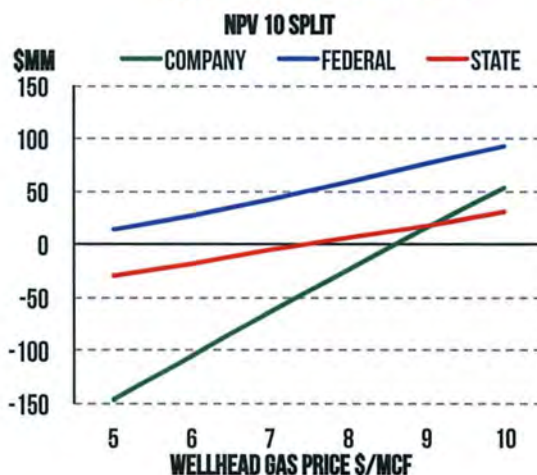


PROJECT #1: MARKET CONSTRAINED (RESULTS)

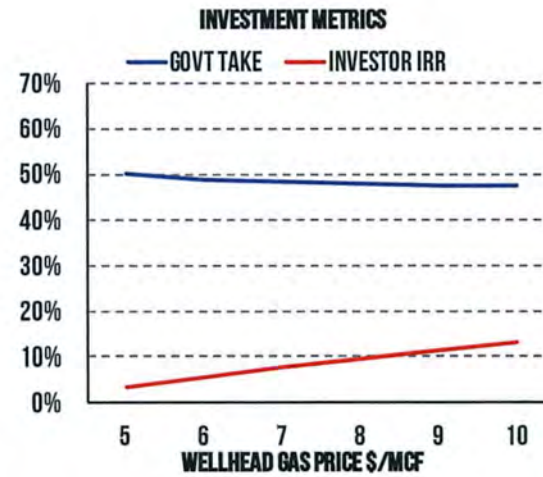
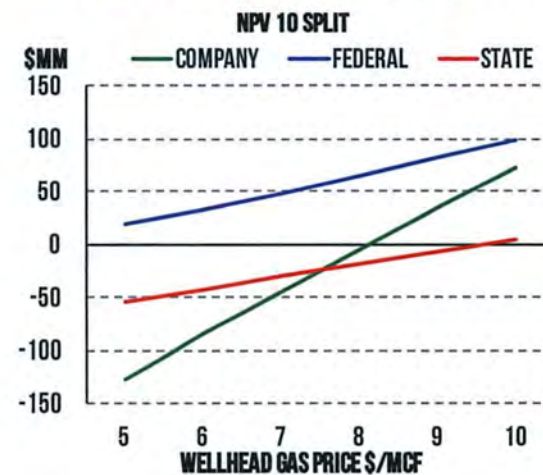
STATUS QUO



HB 247: NOL ONLY



CS HB247: 10% NOL. 20% CAP

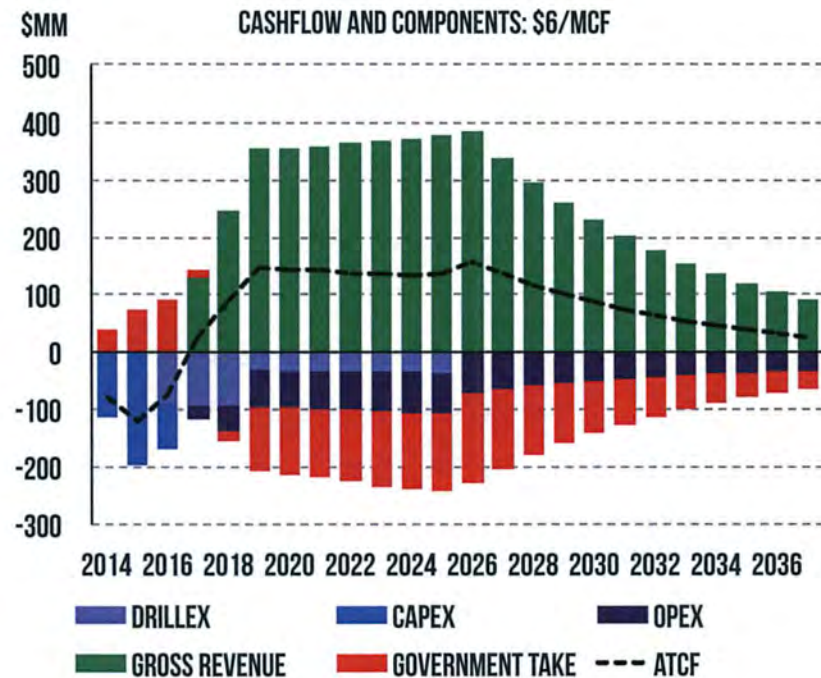
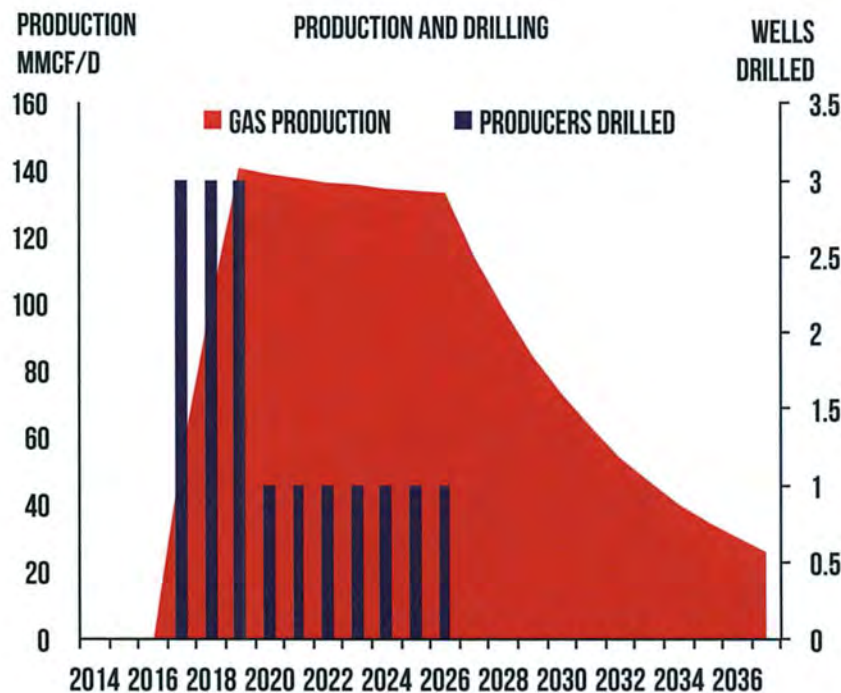


PROJECT #2: MARKET UN-CONSTRAINED (ASSUMPTIONS)

Large upfront investment but un-constrained gas market

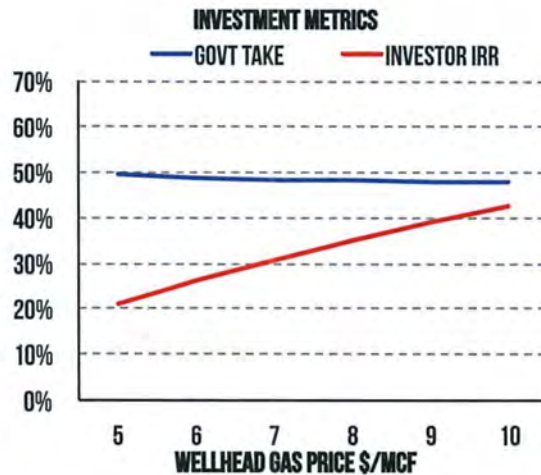
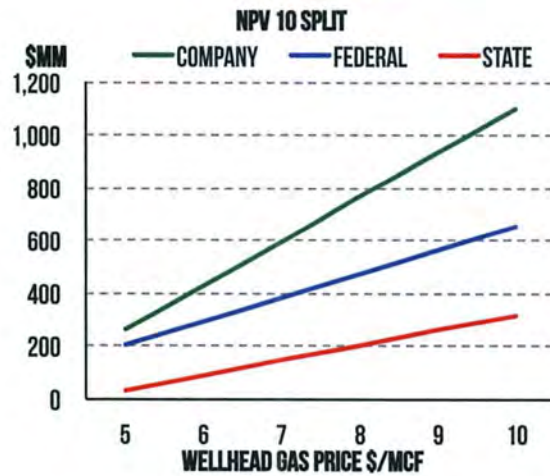
Continued drilling lead to a plateau of 130 mmcf/d

Scenario would require a step change in existing supply-demand dynamics in Cook Inlet

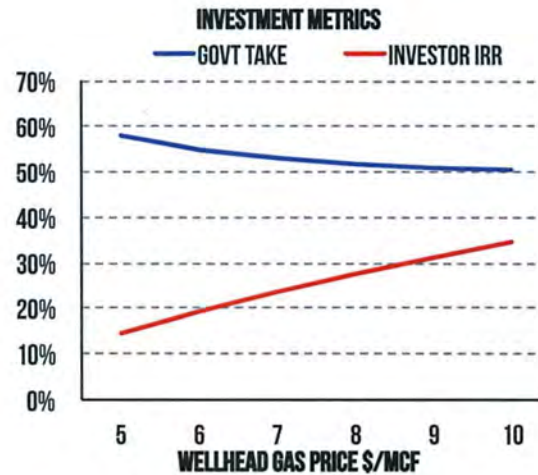
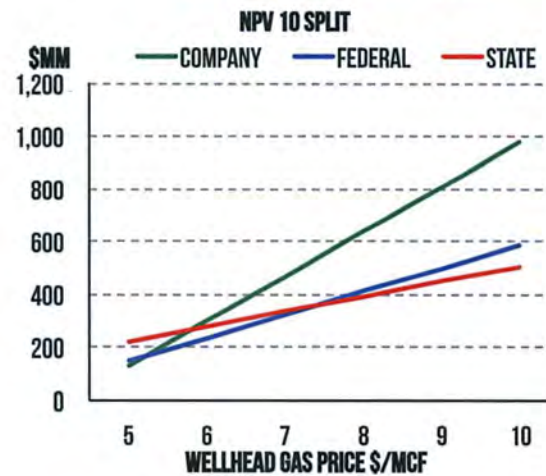


PROJECT #2: UN-CONSTRAINED (RESULTS)

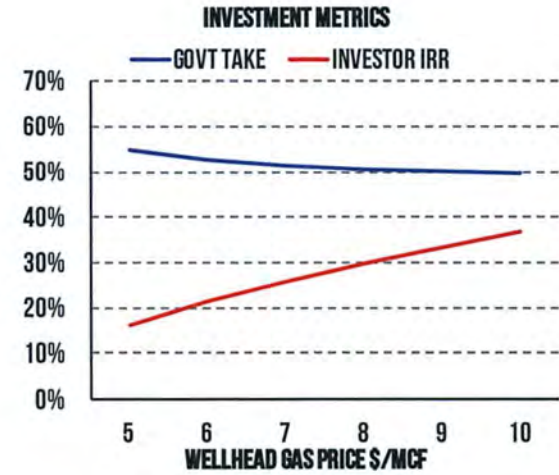
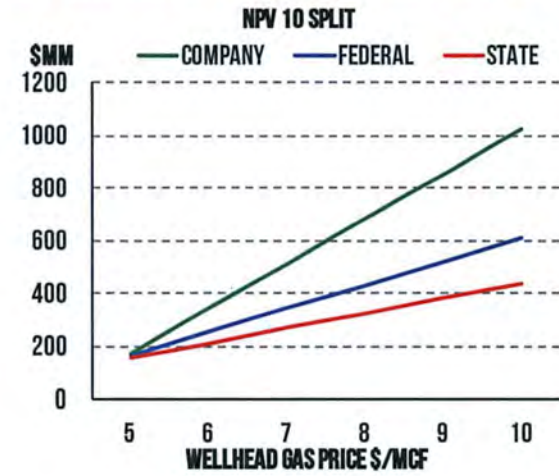
STATUS QUO



HB 247: NOL ONLY



CS HB247: 10% NOL. 20% CAP

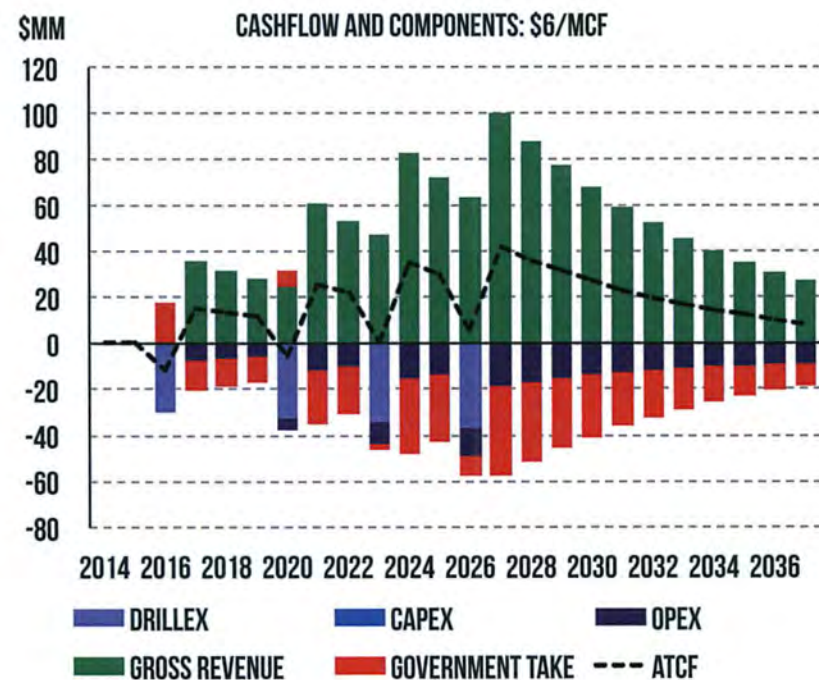
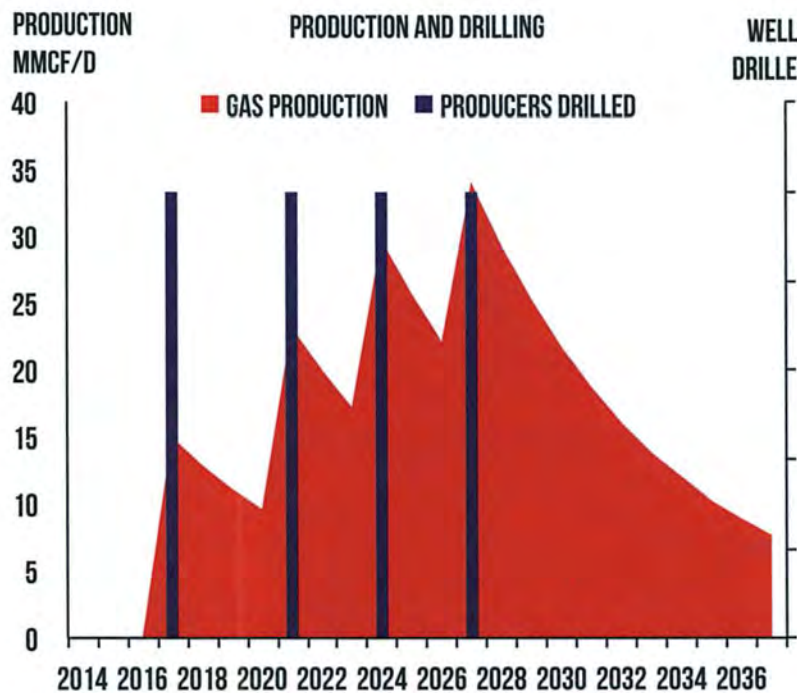


PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)

Drilling expenditures at existing production—smaller upfront investment

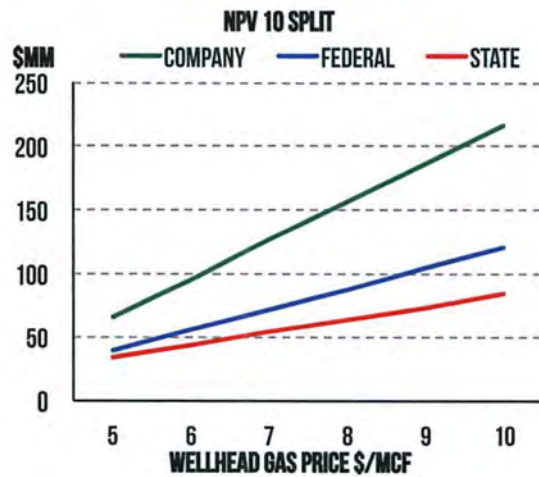
No market constrains assumed

This is a point-forward analysis—it ignores sunk, entry or acquisition costs

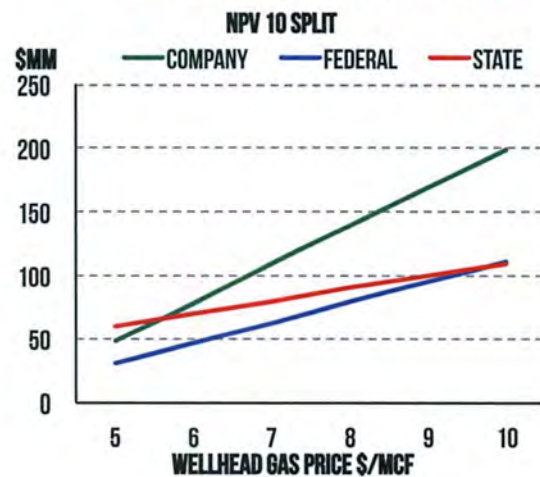


PROJECT #3: DRILLING EXISTING FIELD (RESULTS)

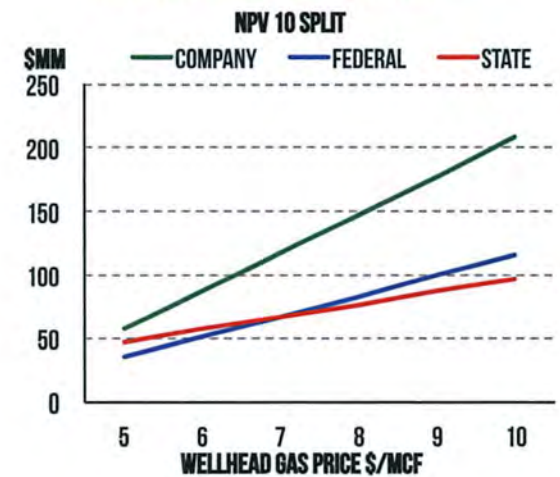
STATUS QUO



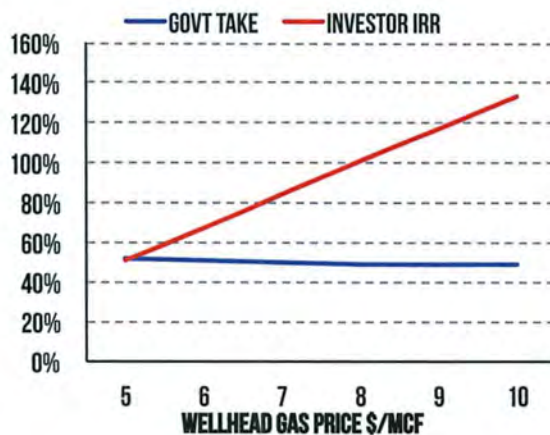
HB 247: NO CREDITS



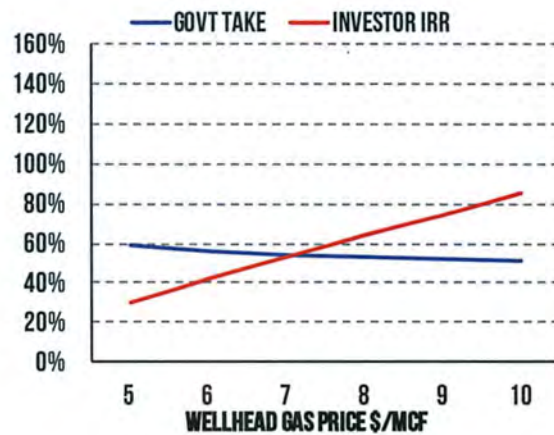
CS HB247: 20% CAP



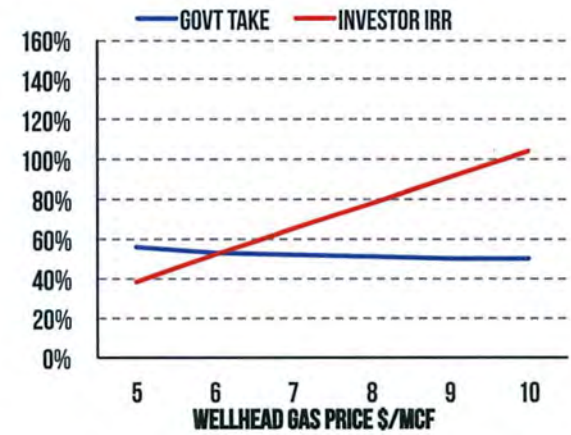
INVESTMENT METRICS



INVESTMENT METRICS



INVESTMENT METRICS



AGENDA

HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

HB 247: SUMMARY OF KEY ISSUES

APPENDIX

Fiscal System Feature	Status Quo	HB 247 Proposed Change	Impact	HRES CS HB247
Per-Barrel Credit and Gross Minimum Tax	Tax liabilities assessed annually, smoothing impact of price volatility.	Calculate \$/bbl credit and Gross Minimum Tax interaction monthly.	State would have netted additional ~\$100mm in 2014 under this system.	Maintain status quo - tax liabilities assessed annually
Gross Value Reduction and Net Operating Loss Credit	Gross Value Reduction artificially reduces Production Tax Value, and NOL credit is based on PTV, so 35% NOL credit can be given on loss greater than actual loss - effectively more than 35% support for spending.	Assess NOL credit on actual loss (not including GVR), so NOL is for 35% of actual loss, and all producers have 35% support for spending.	Net impact is to reduce state support for all spending to 35%. Questions exist about whether >35% spending support for GVR oil was deliberate incentive or unintended consequence under SB21.	Adopt proposed fix to NOL calculation for GVR-eligible production
Gross Minimum Tax	4% rate, binding for legacy output if net value is positive. If net value is negative, NOL can reduce taxes below floor. "New," GVR-eligible production can take to zero due to \$5/bbl and small producer credit	Harden floor for all production: NOL credits can't take below floor for legacy, and NOL, small Producer and \$5/bbl can't take below floor for GVR-eligible production. Increase rate from 4% to 5%	State revenues rise at low oil prices. For many new fields, taxes rise from 0 to 5% at current prices. For legacy production, taxes rise at time when value is negative.	Maintain status quo - no further floor hardening

Fiscal System Feature	Status Quo	HB 247 Proposed Change	Impact	HRES CS HB247
Net Operating Loss credit reimbursement	Producers with >50 mb/d production must carry NOL forward, others can be reimbursed by the state	\$25mm per company annual limit on reimbursement. Companies with annual revenues > \$10bn must carry forward, regardless of production level.	Limit substantially increases capital needs for new developments; and if effective July 2016 would have major negative impact on developments underway. Raises hurdle/break-even price for projects by \$5 to \$15/bbl.	\$200mm per company annual limit on reimbursement.
Gross Value at Point of Production calculation	GVPP is calculated by subtracting transportation costs from sale price. If transportation costs for some production exceed price, GVPP is negative	GVPP cannot go below zero	Could limit deductibility of some transport costs. Particularly likely to be an issue at current prices if applied on a per-unit or per field basis.	Maintain status quo
Cook Inlet Tax Credits	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit; up to 65% gov't support for spending and minimal production tax	Repeal QCE and WLE credits effective July 1 2016, leaving only 25% NOL credit	Cook Inlet credit regime is clearly unsustainable in current environment; repeal in present year may have major impacts on capital commitments already made, and the viability of producers who have made those commitments	Reduce NOL credit to 10%, keep 20% QCE credit, reduce WLE credit to 20% by 2018

AGENDA

HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

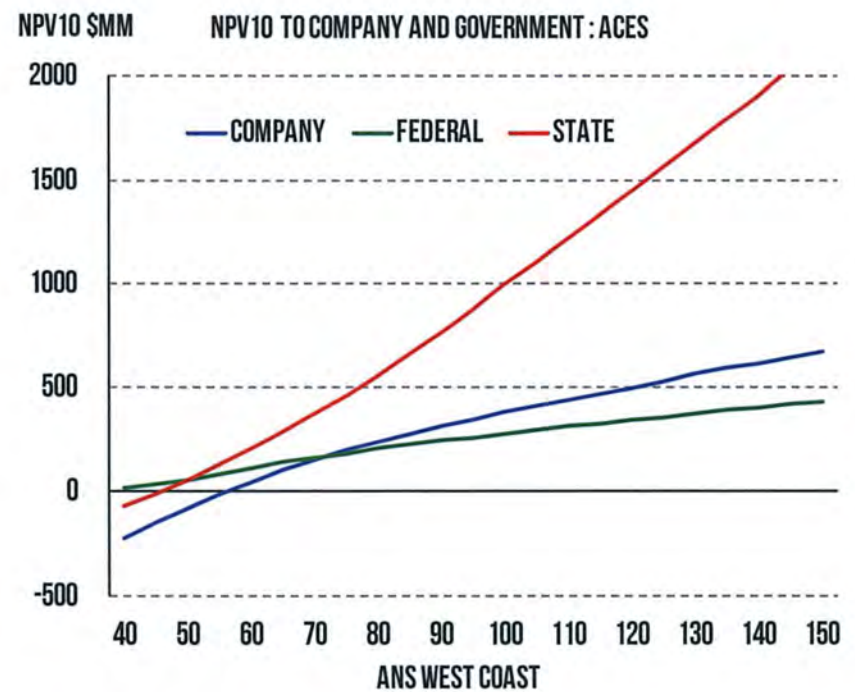
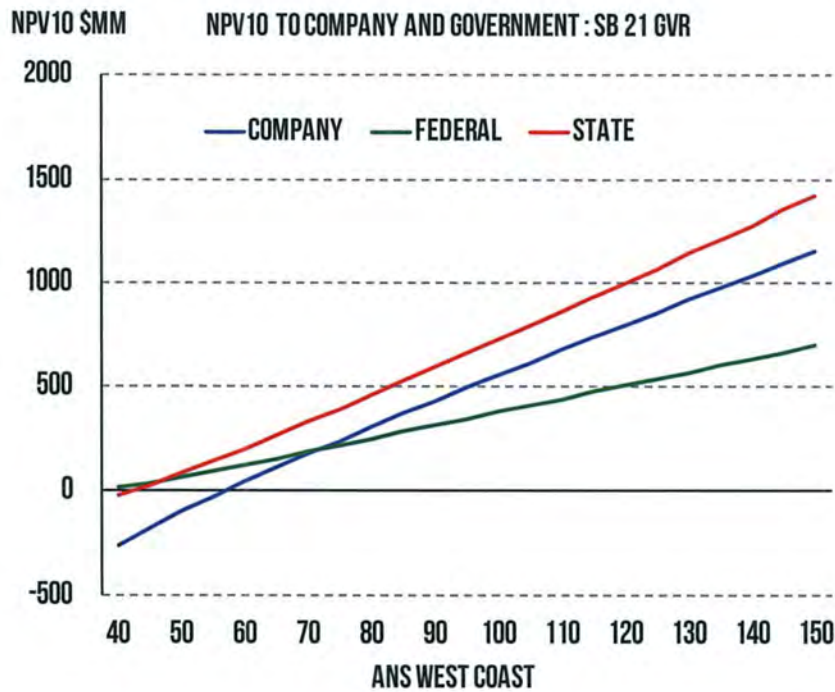
HB 247: SUMMARY OF KEY ISSUES

APPENDIX

SB21 WITH GVR MORE PROTECTIVE AT LOWER PRICES

Using sample NS investment, examining total value over lifecycle to all stakeholders at range of prices:

- SB21 GVR Split of total value between state and company relatively even over a wide range of prices
- SB21 GVR state NPV10 higher than that for company at all prices, and at low prices, higher than ACES



COOK INLET GAS HAS GONE THROUGH MAJOR TRANSITION

Old Cook Inlet Gas Market

Surplus gas exported (via LNG and Agrium)

Low wellhead prices

Market view is that gas is long

Gas produced by large, international players

Secure local supply via long-term contracts

Producers offered high seasonal flex

Seasonal flex coming largely from supply

New Cook Inlet Gas Market

Limited surplus; gas absorbed in local market

High wellhead prices

Market view is that gas is short

Gas produced by smaller, focused players

Shorter term sales contracts b/w producers, utilities

Mature fields have much more limited seasonal flex

Seasonal flex largely from storage and demand

GAS SUPPLY AND DEMAND DYNAMICS IN COOK INLET

Supply and resources

2015 production: 103 bcf

Estimated 2P reserves: 1,600 bcf (DNR, 2015)

Legacy fields: 1,183 bcf

Kitchen Lights/Cosmo: 417 bcf (ballpark)

Yet to find estimates are much higher

Existing + new fields should be enough for current demand 10+ years; demand upside needs more gas

Demand

2015 consumption around 100 bcf

In-state demand: 80-85 bcf/yr

Exports: 13–16 bcf (2014–2015)

AGDC 2030 forecast: 115 to 130 bcf/yr (ex. nitrogen)

Nitrogen demand upside: 28 bcf/yr per train (2 trains)

State support due to gas “shortage,” yet developers say they lack markets to develop new fields; why?

Maybe issue is timing (market covered by existing contracts, window opens later)

Or a natural negotiation process (buyers and sellers looking for the “right” pricing point)

Or different views about resource certainty, especially for developing new demand (Agrium)

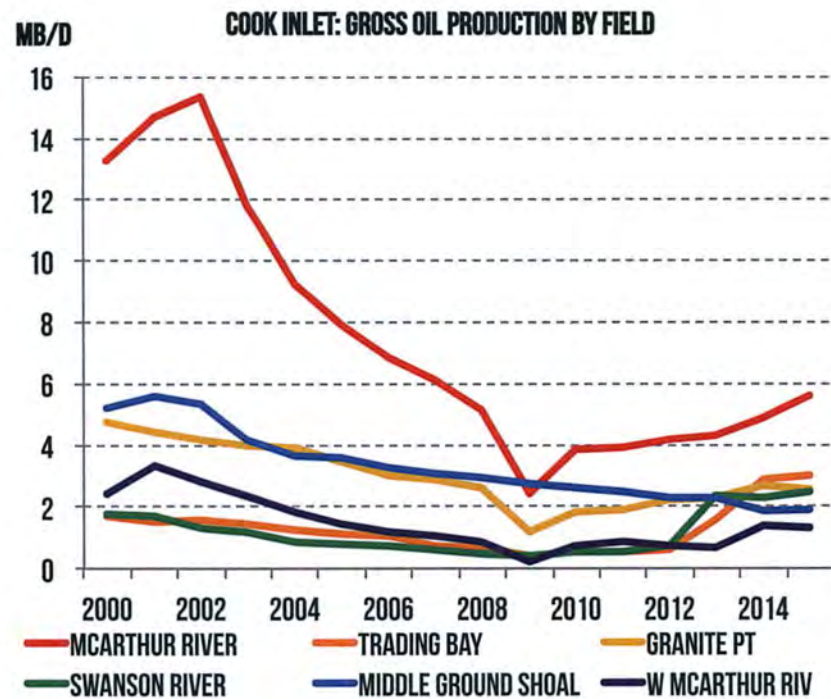
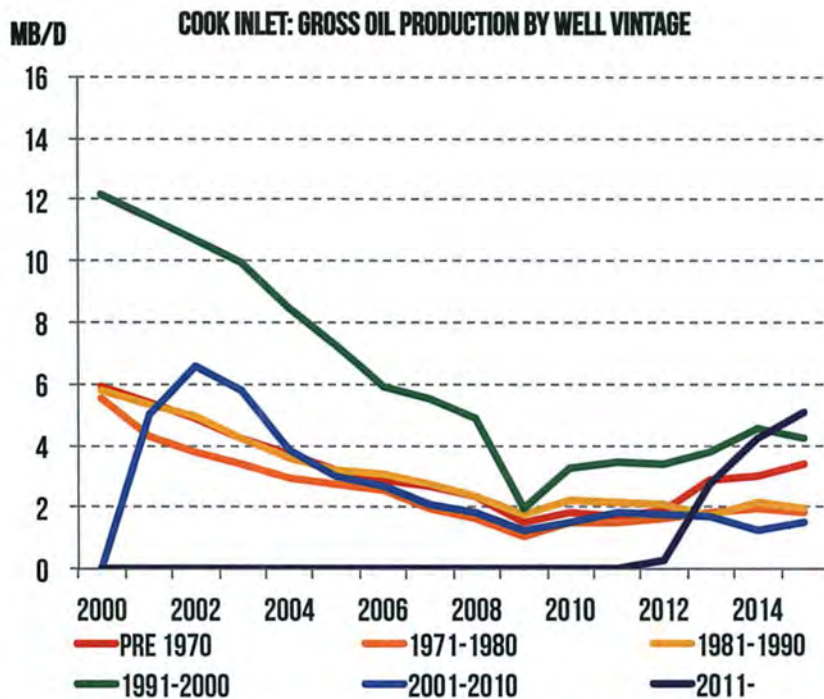
SOURCE: DEPARTMENT OF NATURAL RESOURCES; ALASKA OIL AND GAS CONSERVATION COMMISSION; ALASKA GASLINE DEVELOPMENT CORPORATION; MCDOWELL GROUP (NITROGEN DEMAND)

OIL UP FROM WORKOVERS, NEW WELLS IN EXISTING FIELDS

Production from old wells has risen, especially from wells drilled before 1970 and in 1990s

New wells drilled after 2011 have also added about 5 mb/d of production

Production is up in most fields; biggest gains from McArthur River field



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

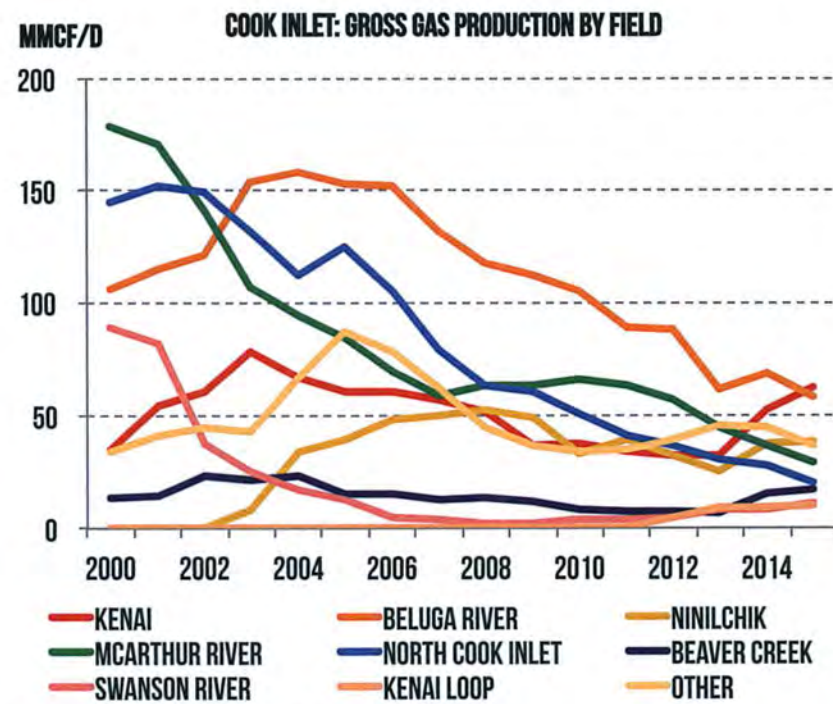
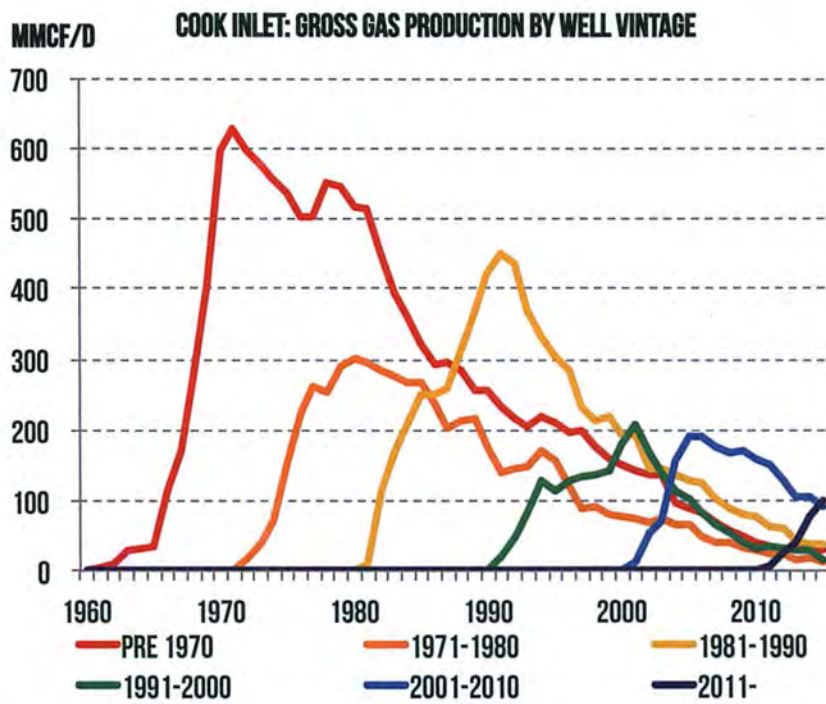
GAS FLATTENING FROM NEW WELLS IN EXISTING FIELDS

Wells drilled after 2011 have added about 100 mmcf/d of new production

Production from Beluga River, Ninilchik, and North Cook Inlet declined by 85.7 mmcf/d in 2011–2015

Growth from Kenai (+28 mmcf/d), Beaver Creek (+10), Kenai Loop (+9.7), and Swanson River (+7.3)

Only Kenai Loop is (major) new field (first gas in 2012); other growth from workovers and new wells



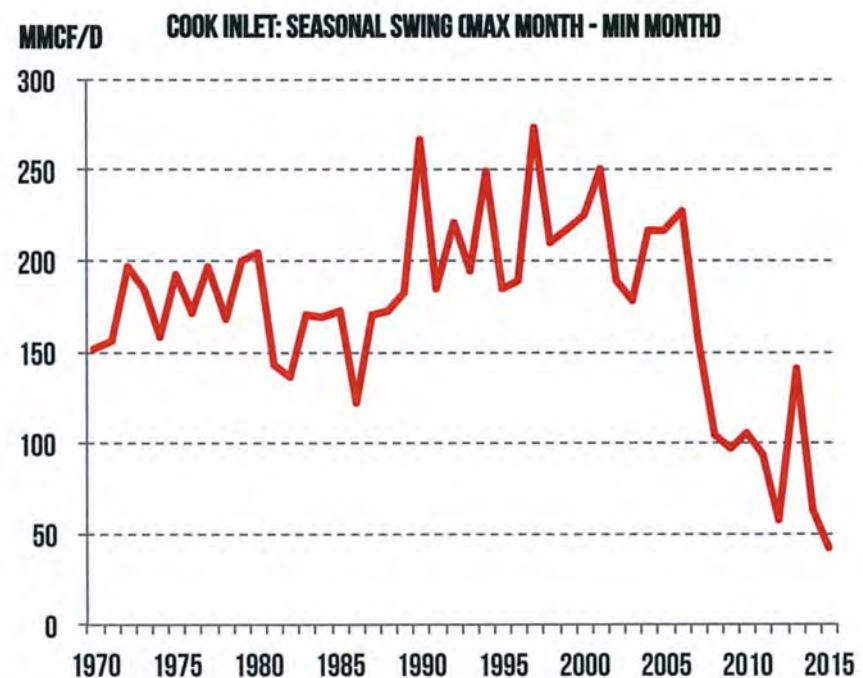
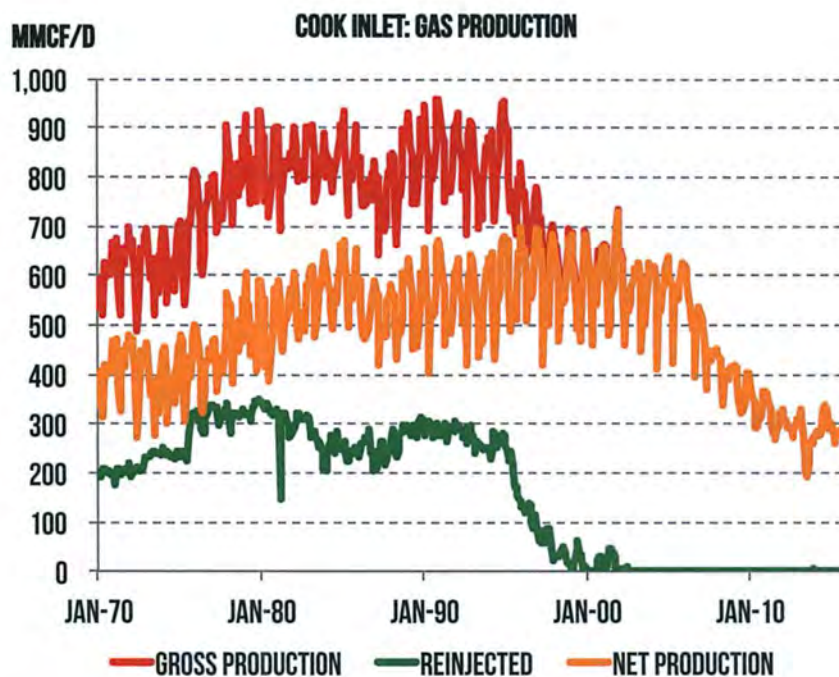
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

MATURE BASIN HAS **LIMITED SEASONAL** PRODUCTION FLEX

Historically, gas production in Cook Inlet has provided seasonal flex

As production has matured, that seasonality has gone away

Since 2006, we have seen the seasonal swing (max-min month) drop to below 100 mmcf/d



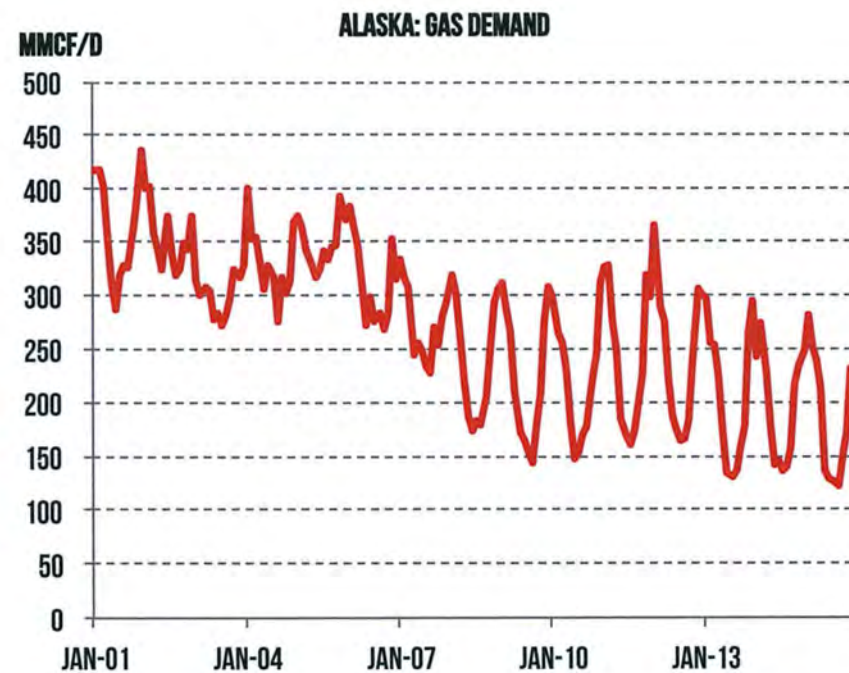
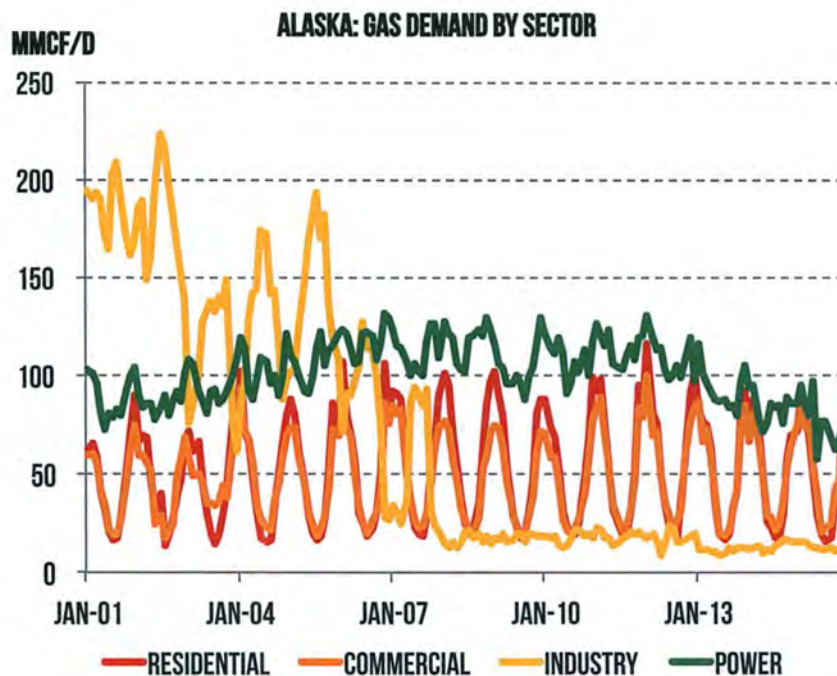
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

DEMAND HAS, MEANWHILE, BECOME MORE SEASONAL

Historically, gas production was either exported or consumed in industry (nitrogen)

Lower consumption in industry has made the demand profile more seasonal (lack of “base-load” demand)

In 2003–2005, industry consumption was flexible enough to serve a seasonal purpose



SOURCE: ENERGY INFORMATION ADMINISTRATION, ALASKA NATURAL GAS CONSUMPTION BY END USE

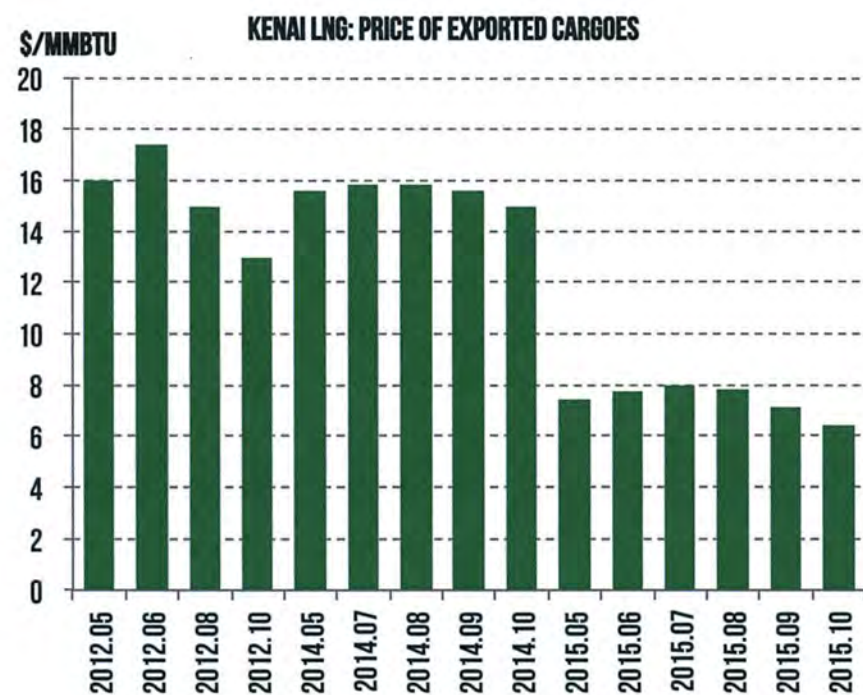
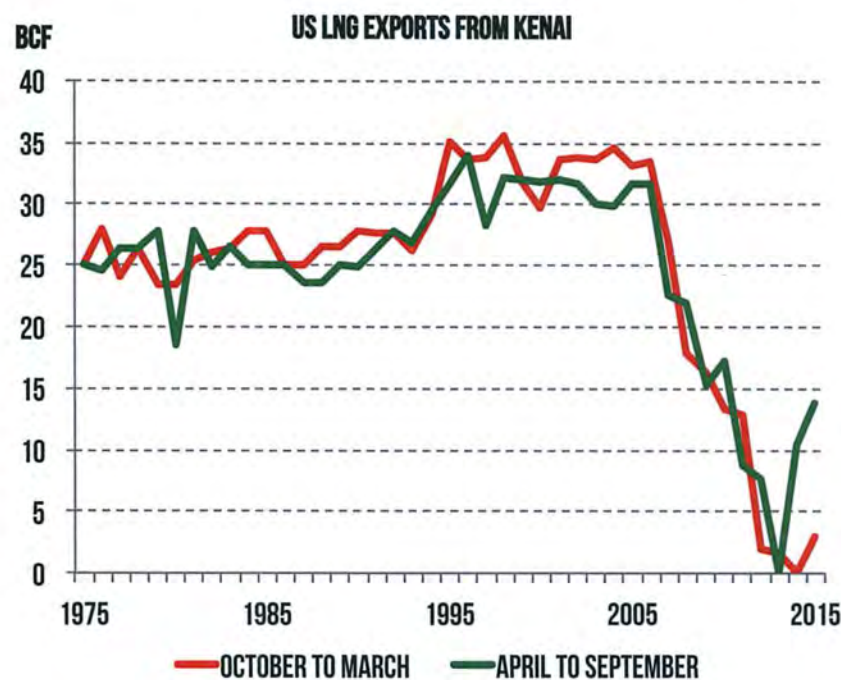
RECENTLY, EXPORTS HAVE OFFERED A SEASONAL OUTLET

Historically, LNG exports were not particularly seasonal: exports in winter and summer were similar

Since 2012, LNG exports have taken place largely in the summer

In 2014 and 2015, Kenai exported 13 and 16 bcf respectively, helping to support seasonal flexibility

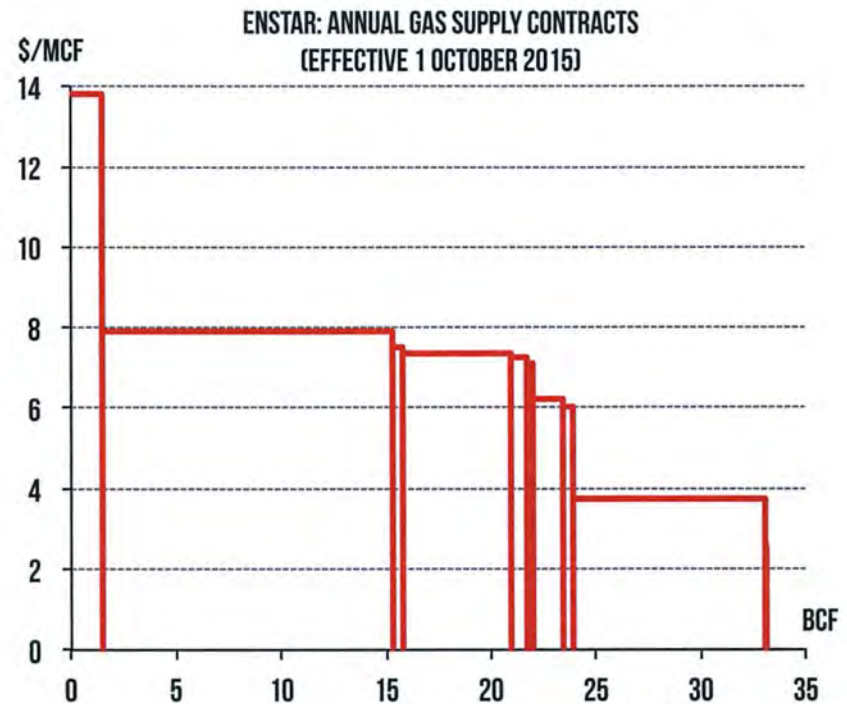
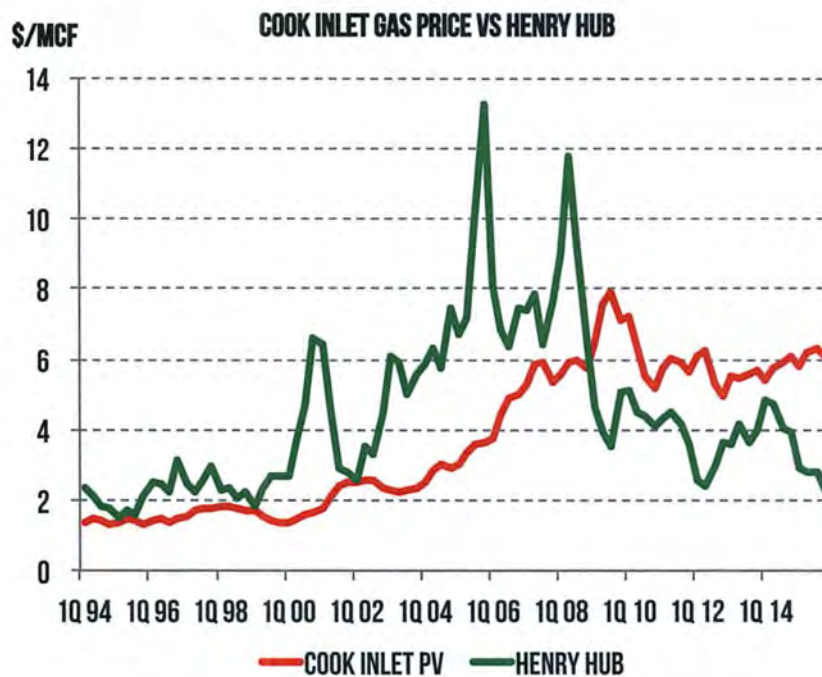
How will lower prices and ConocoPhillips' divestment of upstream in Cook Inlet impact this outlet?



SOURCE: ENERGY INFORMATION ADMINISTRATION

GAS PRICES HAVE RISEN CONSIDERABLY POST 2004

Historically, gas prices in Cook Inlet have been equal to or (more often) below Henry Hub
 Since 2004, there has been a steady rise in gas prices; since 2010, prices were between \$5 and \$6/mcf
 But there is considerable supply trading above this level, at \$8+ (and rising depending on contract)
 Other jurisdictions have found \$5-\$7/mcf is sufficient to produce most expensive gas (shale, deepwater)



SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION (COOK INLET PV); ENERGY INFORMATION ADMINISTRATION (HENRY HUB); ENSTAR, DETERMINATION OF GAS COST ADJUSTMENT

ConocoPhillips Alaska 2015 Results

2015 Full Year Reported Net Income \$4 Million
Net Cash Flow (\$100)+ Million

<u>Earnings</u>	<u>\$ Million</u>	<u>Cash Flow</u>	<u>\$ Million</u>
Revenue	3,206	Net Income	4
Less Expenses	3,273	Add Non-Cash Items:	
Income Taxes	<u>(71)</u>	Special Items	478
Net Income	4	Depreciation	680
Exclude Special Items	478	Less Capital Expenditures	<u>1,352</u>
Adjusted Earnings	482	Net Cash Flow	(100)+

House Finance Committee


CSHB247

Scott Jepsen, VP External Affairs

Paul Rusch, VP Finance

ConocoPhillips Alaska

April 1, 2016

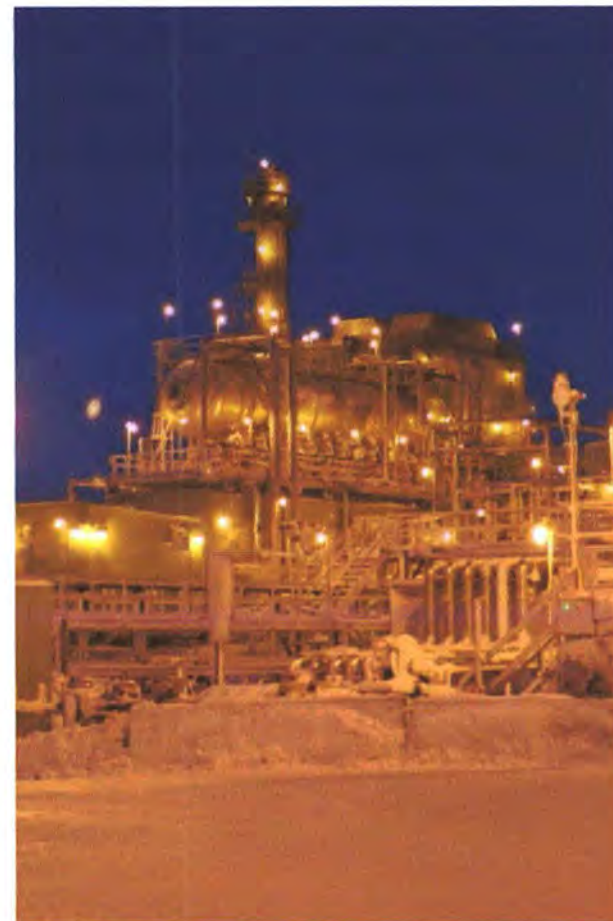
A decorative blue bar with a white diagonal cutout on the left side, located at the bottom right of the slide.

Agenda

- Look back since MAPA passed
- Economic Environment
- Key Concerns with Original HB247
- Observations

Activities Since Tax reform (MAPA) Passed

- **Added two rigs to the Kuparuk rig fleet**
 - Investment has decreased Kuparuk Unit decline
- **Two new-build rigs are on order – deliver 2016**
- **New Drill site at Kuparuk (DS 2S) – on stream October 12, 2015**
 - Estimated 8,000 BOPD peak production rate
 - About \$500 million gross cost to develop
 - 250+ construction jobs
- **Viscous oil expansion in Kuparuk (1H NEWS)**
 - About 8,000 BOPD gross, 100+ construction jobs
 - About \$450 million gross cost to develop
 - Under construction – first oil 2017
- **New development in NPRA (GMT1)**
 - Final investment decision made late 2015
 - About \$900 million gross cost to develop; peak gross rate ~30,000 BOPD
 - About 600-700 construction jobs
 - First oil 2018
- **Permitting underway for GMT2**
 - \$1+ billion gross investment
 - Will create 600-700 jobs
- **Active Exploration Program**
 - 2 wells drilled in 2014
 - Acquired GMT1 Seismic – 2015
 - Three wells in 2016 (NPRA)



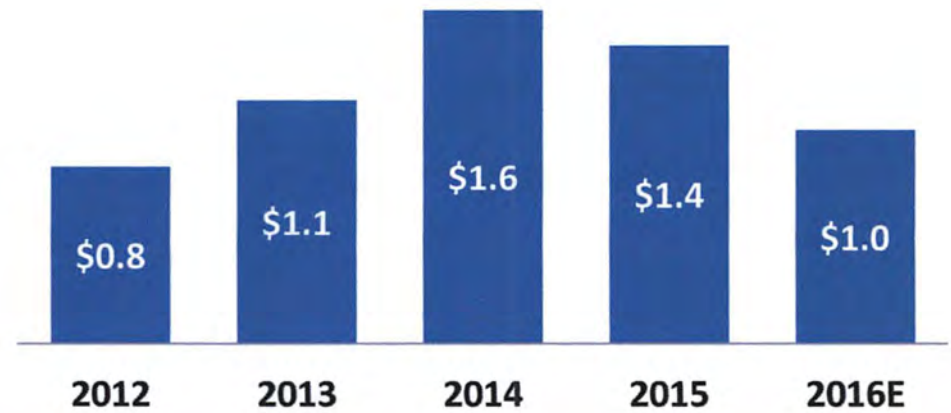
Capital Spending Trends

ConocoPhillips Capital Spend (\$B)



Total Company capital reduced 63% since 2014

ConocoPhillips Alaska Capital Spend (\$B)

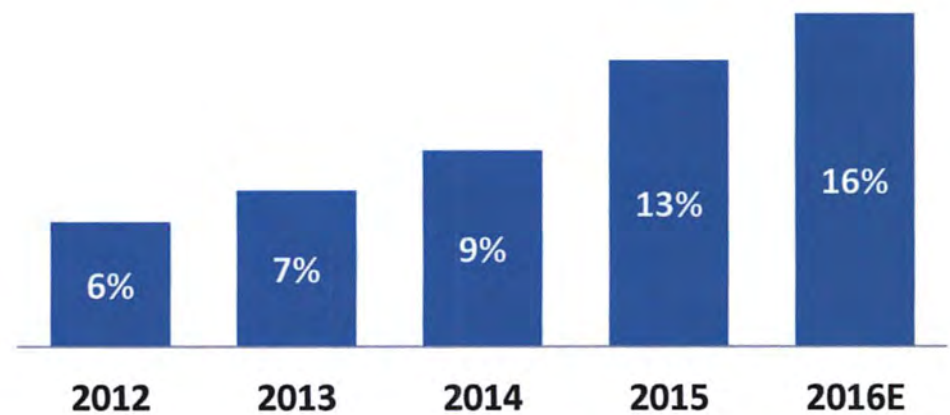


2016E Alaska capex ~ 25% higher than ACES years (~\$0.8 B/yr 2007-2012)

ANS WC Oil Prices (\$/bbl)

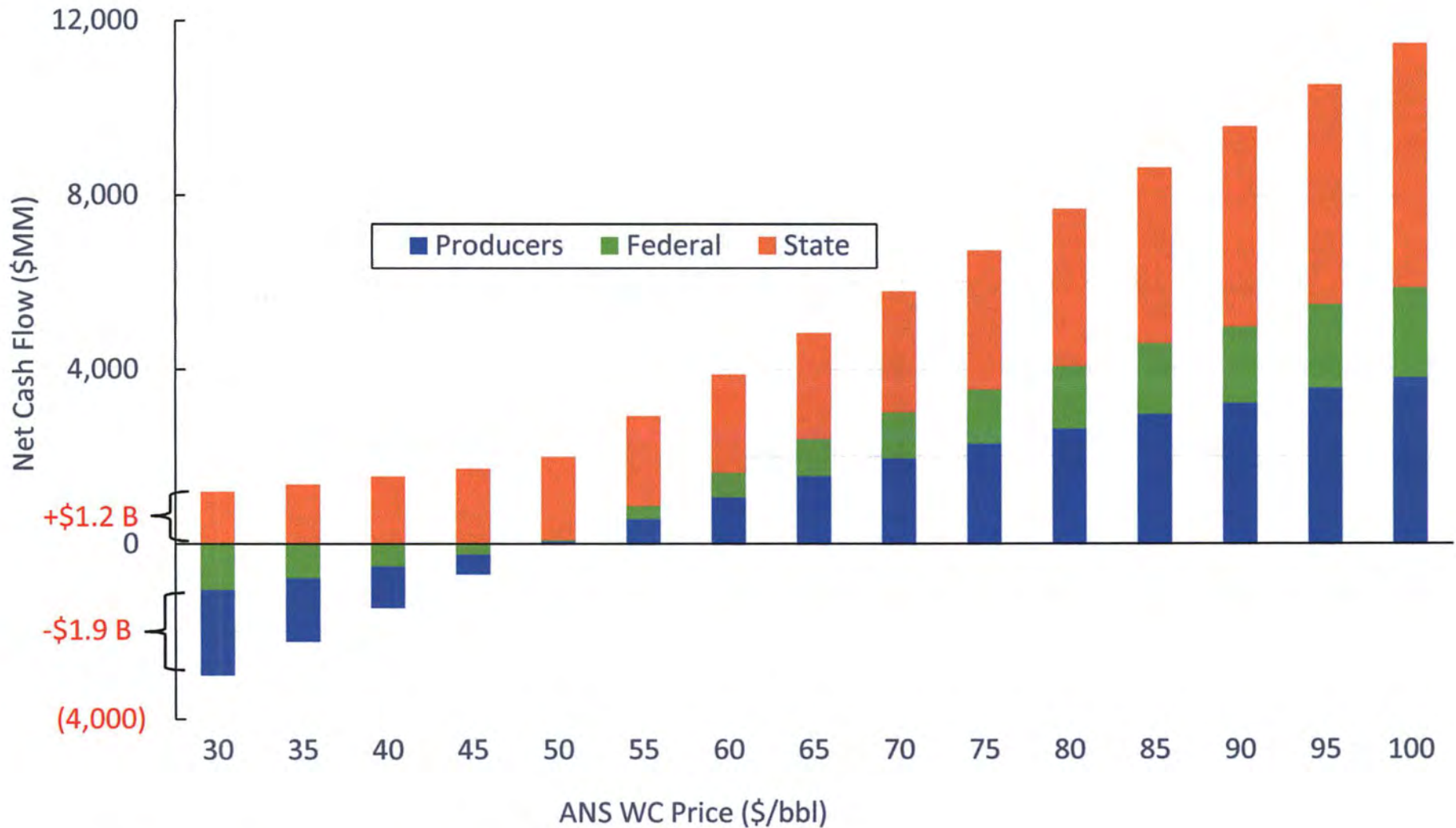


Alaska Capex as % of COP Total



North Slope Investors Negative at Current Pricing

2017 FY Cash Flow - Spring 2016 RSB assumptions



State share shown excludes tax credits other than production tax credits

Key Concerns with Original HB247

- Increase in minimum tax from 4% to 5%
 - 25% tax increase when industry in negative cash flow position
 - ConocoPhillips in excess of \$100 MM cash flow negative in 2015
- Hard minimum tax floor
 - Represents a potential tax increase when oil prices are low – moving in the wrong direction
- Increase interest rate on taxes due
 - Current tax system leads to uncertainty on final tax amount due until audits have been completed
 - Pace of completing audits and appeals (6+ years) leads to excessive interest charges
- Restricting use of per barrel credits to the month earned moves towards a monthly tax - intent was full year basis
- Confidentiality

Observations

- Significant changes in tax law would validate concerns regarding State's ability to implement a stable oil and gas fiscal policy
 - Only 19 months since SB21 ratified by voters
 - Long-term investment requires durable, reasonable fiscal framework
- CSHB247 an improvement over original bill
- Any changes that increase tax burden/costs will adversely impact ConocoPhillips current year and future investments

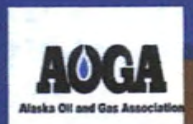


House Finance Committee

Kara Moriarty –President/CEO

April 1, 2016

OIL & GAS:
FUELING
ALASKA'S
ECONOMY



Oil & Gas Drives Alaska's Economy

- **1/3 all Alaska jobs (110,000 jobs) attributed to industry**
- **Every direct job = 20 more jobs**
- **Every dollar in wage = \$8 more**
- **85% of State's Unrestricted General Fund since statehood**
 - *No other industry even comes close*

Questions to ask when considering policy change

- *What effect will the policy have on overall oil and gas production in the state?*
- *Will the policy make Alaska more or less competitive on a global scale?*
- *Will the policy provide stability to the industry and the State of Alaska?*
- *Will the policy provide predictability to companies looking to make huge investment decisions?*

More Production? Competitive? Stable? Predictable?

Alaska Oil and Gas Tax Policy Changed 5 times in a decade

- **February 2005 – March 31, 2006: Aggregated ELF – Decision that altered gross production tax**
- **April 1, 2006 – July 2007: Petroleum Production Tax (PPT)**
- **July 2007 – 2013: Alaska's Clear and Equitable Share (ACES) ***
- **2010: Cook Inlet Recovery Act**
- **2014 – present: SB 21 & SB 138**
- **2016: HB 247/SB 130 – Governor Walker's Proposal**

* Some provisions of ACES made retroactive to enactment of PPT, others to 1/1/2007

No other region considers oil/gas changes more than Alaska.

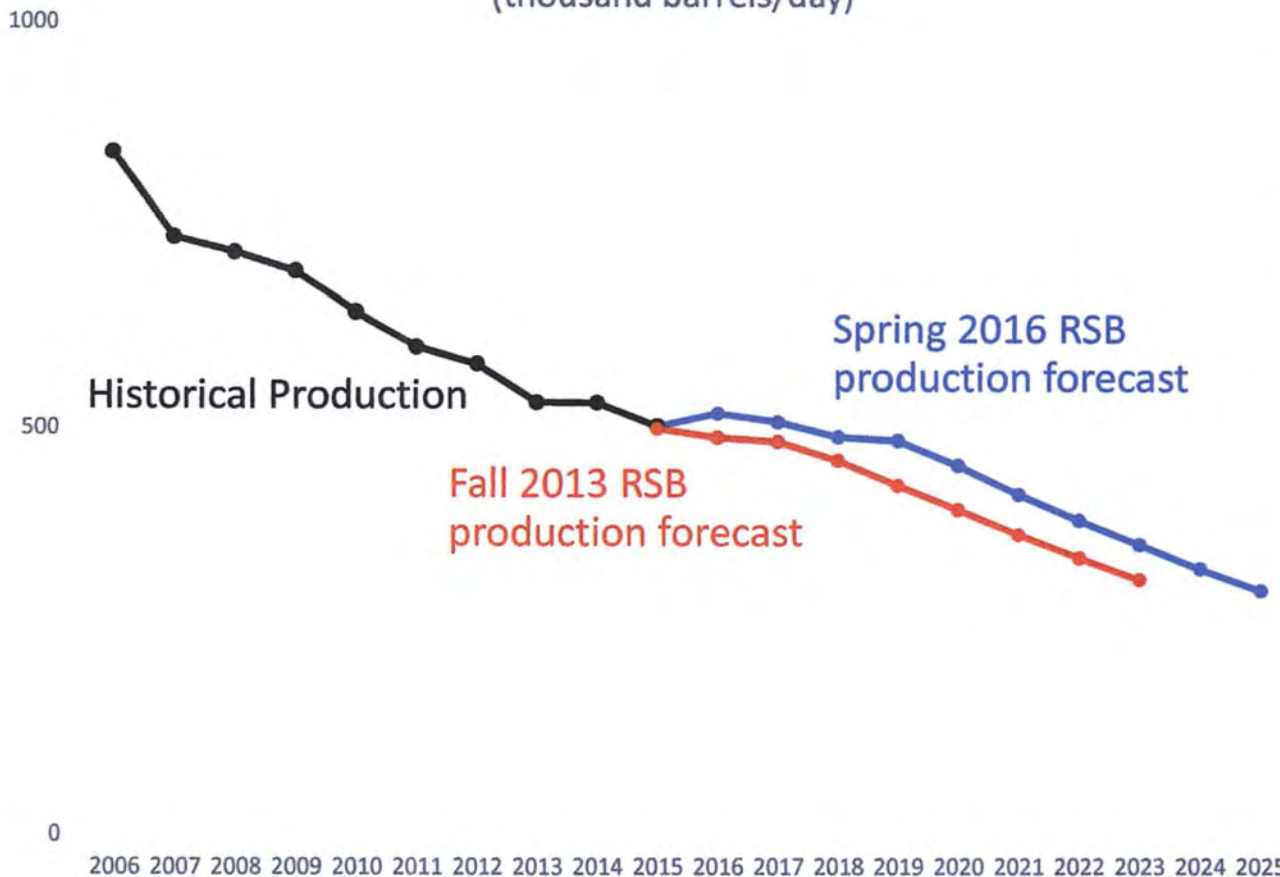
OIL & GAS:
FUELING
ALASKA'S
ECONOMY

AOGA
Alaska Oil and Gas Association

If DOR forecasts hold for FY 2016, production will increase for the first time since 2002

TAPS Throughput Historical & Forecasted

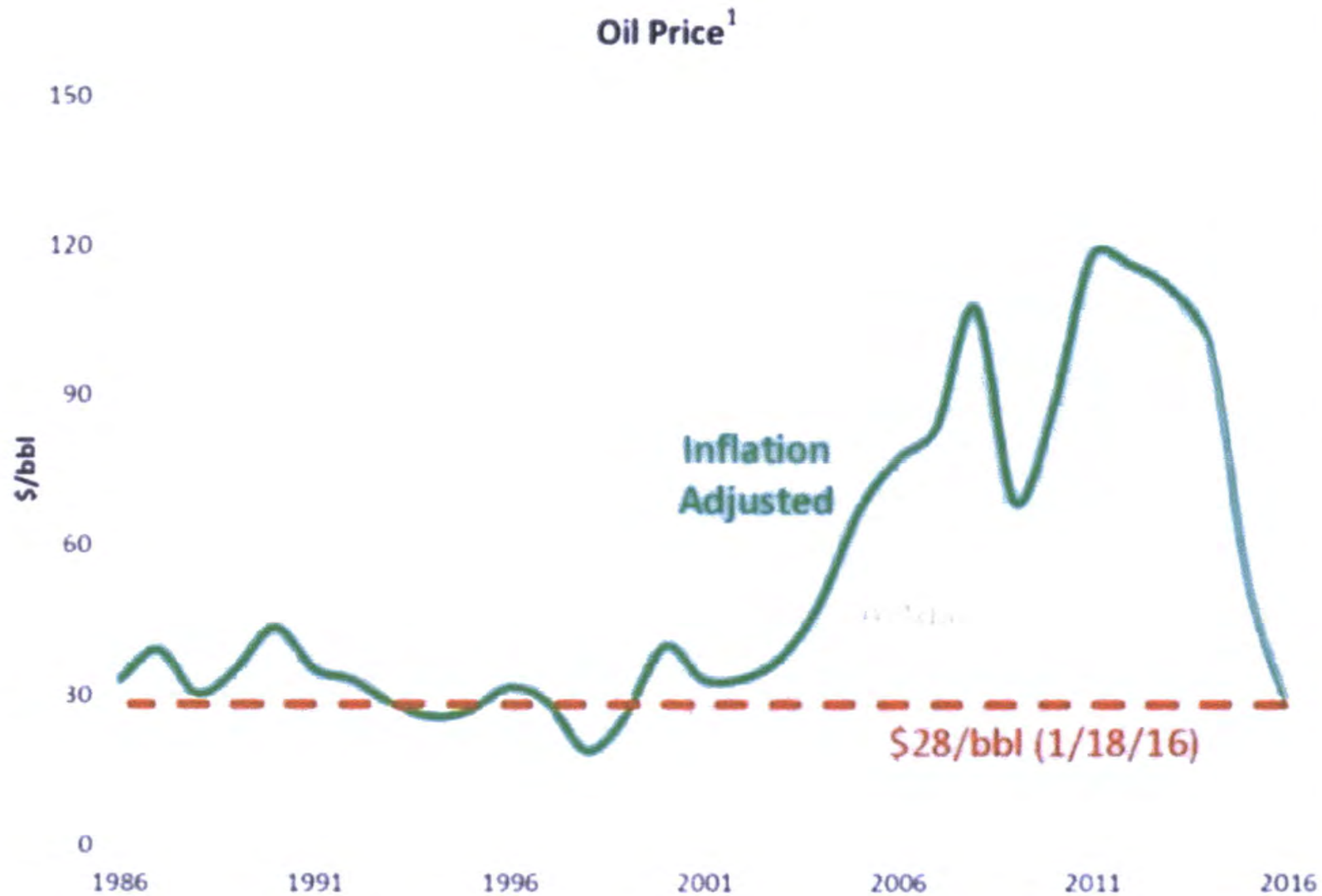
(thousand barrels/day)



Year	Fall 2013 Forecast	Spring 2016 Forecast
2016	487.6	517.7
2017	482.7	507.1
2018	459.5	488.8
2019	429.1	484.4
2020	399.6	454.1
2021	368.8	418.6
2022	340.1	387.1
2023	312.9	356.8
2024		327.0
2025		300.0

Source: DOR Spring 2016 RSB

Unprecedented Low Oil Price

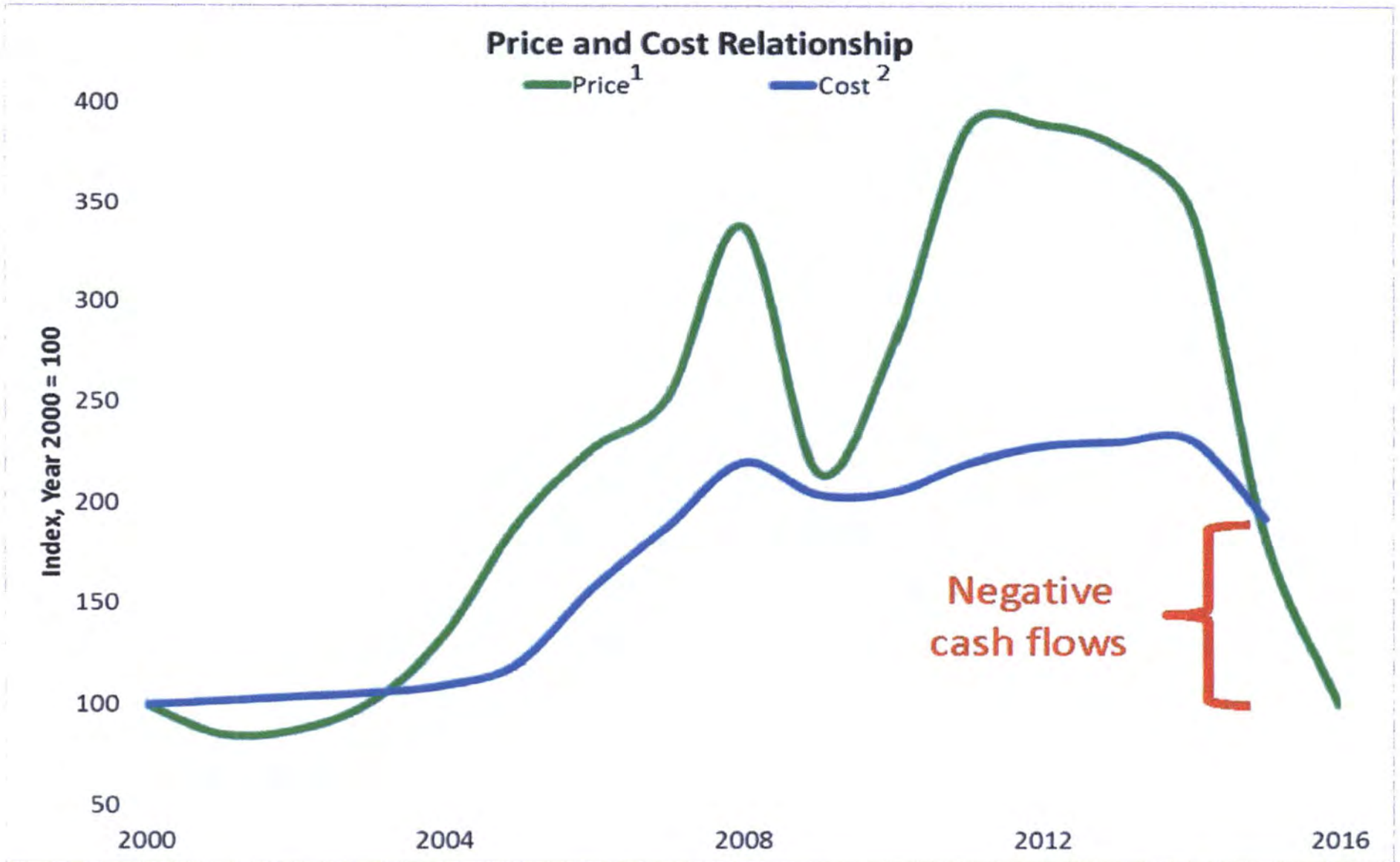


Source: Cost: Upstream Capital Cost Index (IHS/CERA)

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

AOGA
Alaska Oil and Gas Association

Companies Have Negative Cash Flow



At current prices, industry has *negative cash flow before tax*

Estimate Average March 2016 ANS Price	\$38.11
Transportation Costs	(\$10.51)
Total Operating Expenditures	(\$19.59)
Total Capital Expenditures	(\$20.07)
Total Average Cost Per Barrel Before Tax	(\$50.17)

Source: DOR Spring 2016 Forecast, March 2016

More Production? Competitive? Stable? Predictable?

Administration Goal is to Raise Money

“The motivation to go down this path to look at credits was the budget. The motivation was not to go in and redefine oil and gas taxes in the State of Alaska.”

DOR Commissioner Hoffbeck – 2/10/16

“It is a tax increase. I don’t think we are attempting to disguise that.”

Tax Director Alper – 2/12/16

More Production? Competitive? Stable? Predictable?

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

AOGA
Alaska Oil and Gas Association

Specific Concerns with CSHB 247

- *Interest rates increase - compounding interest (Sec. 6)*
- *Outstanding liability set limits on credits (Sec. 7-9)*
- *Net Operating Loss tax credits lose value for new oil (Sec. 12)*
- *Key Cook Inlet credits eliminated (Sec. 13-15 & Sec. 29)*
- *New work group creates instability (Sec. 31)*
- *Retroactivity of Regulations concerning (Sec. 36)*

More Production? Competitive? Stable? Predictable?

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

AOGA
Alaska Oil and Gas Association

Any change will have a negative impact on industry

***“OIL PATCH GOING THROUGH ‘PURE HELL’, BUT DOESN’T
LOOK TO D.C. FOR SALVATION.” – Politico, 2/26/16***

"Look at the number of layoffs we've had in this industry. If that had happened in Detroit, think of the hue and cry in Washington,"
American Petroleum Institute CEO Jack Gerard

**AOGA is not asking for assistance from the state
of Alaska in this down turn.**

Do No Harm

More Production? Competitive? Stable? Predictable?

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

AOGA
Alaska Oil and Gas Association

House Finance CS HB 247 (RES) Testimony

April 1, 2016

J. Patrick Foley
Senior Vice President, Alaska Operations

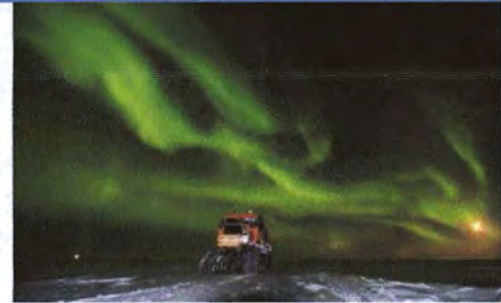


Caelus Energy Alaska: Key Facts & Information

- ❖ Privately-held E&P company focused exclusively on Alaska's NS
- ❖ \$2Bn capital investment in Alaska since 2002
- ❖ ~\$300MM 2016 capital budget
- ❖ Total Alaska workforce is equivalent to over 600 full-time positions
 - ~70 full-time Alaska employees
 - Nearly 400 contractors on the North Slope today
- ❖ Operational Highlights & Accomplishments:
 - 23MMBO gross cumulative production since 2008
 - 4MMBO gross annual production 2015
 - 2015 best safety record, 0.65 OSHA recordable injury rate
 - Longest Oooguruk well length to date: 23,209'MD (ODS N-7i)
- ❖ Direct Financial Benefits to the State:
 - \$67 MM paid in royalties to the State of Alaska
 - \$60 MM paid to the State of Alaska / NSB in property taxes
- ❖ Proven & Potential Reserves:
 - ~85 MMBO remaining at ODS
 - ~100 MMBO remaining at Nuna
- ❖ 350,000 undeveloped State of Alaska leases on the North Slope



North Slope Exploration & Development Program



Smith Bay Exploration Tulimanig

Oooguruk Unit (ODS / OTP)

Nuna Drill Site

Eastern ANS Exploration Acreage

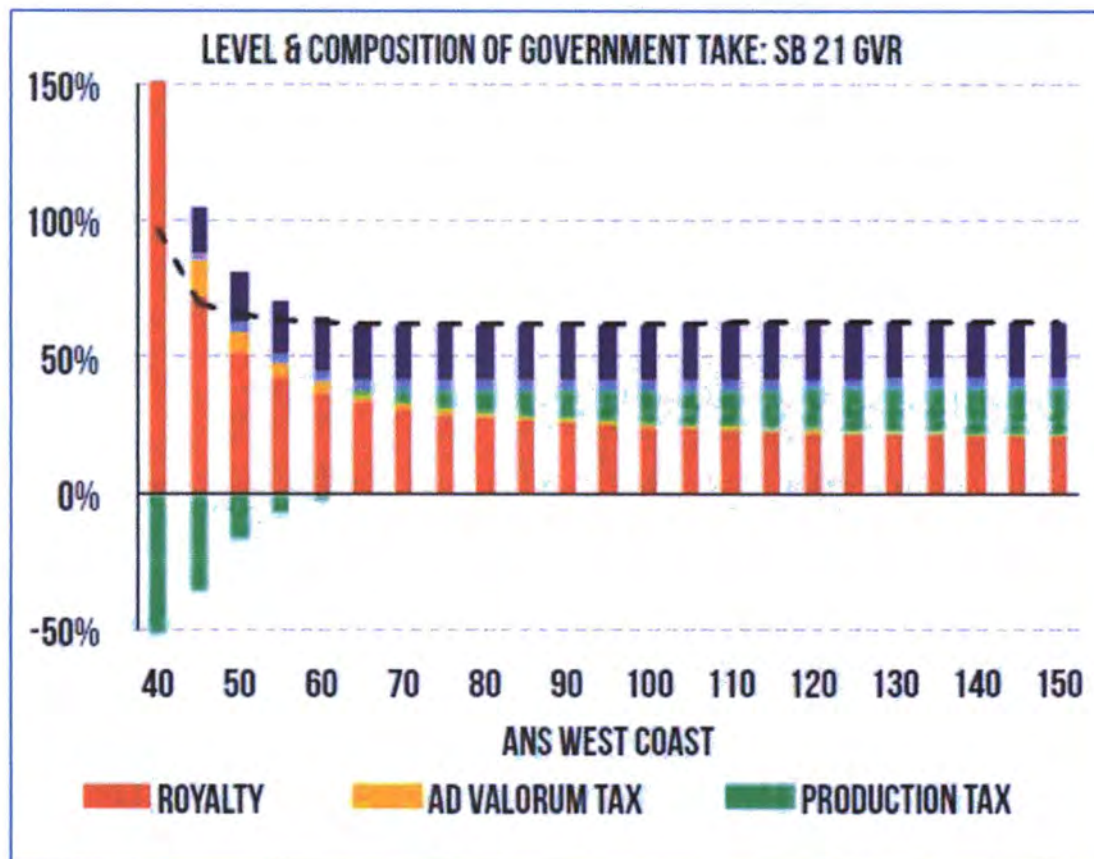


2015 3D Seismic Program

Proprietary Acquisition & Processing

Licensing and Re-processing

World Class Resources?	Yes
Access to Substantial Leasehold of Interest?	Yes
Access to G&G Data and Information	Yes
Expert Contractor Community?	Yes
Hospitable Regulatory Environment?	Yes
Access to Existing Infrastructure?	Yes
Favorable Logistics?	No – remote, harsh conditions, seasonal limitations
Favorable Fiscal Regime?	Yes, under SB21. No, under proposed system changes
Stable Fiscal Regime?	No, 5 significant changes in a decade
Lender & Equity Provider's Confidence?	Historically low participation & experience Confidence in stability is low Apollo has backed Caelus Other equity providers are “watching” Bank of America committed but spooked by change ING backed out when changes began Wells Fargo disengaged when changes began

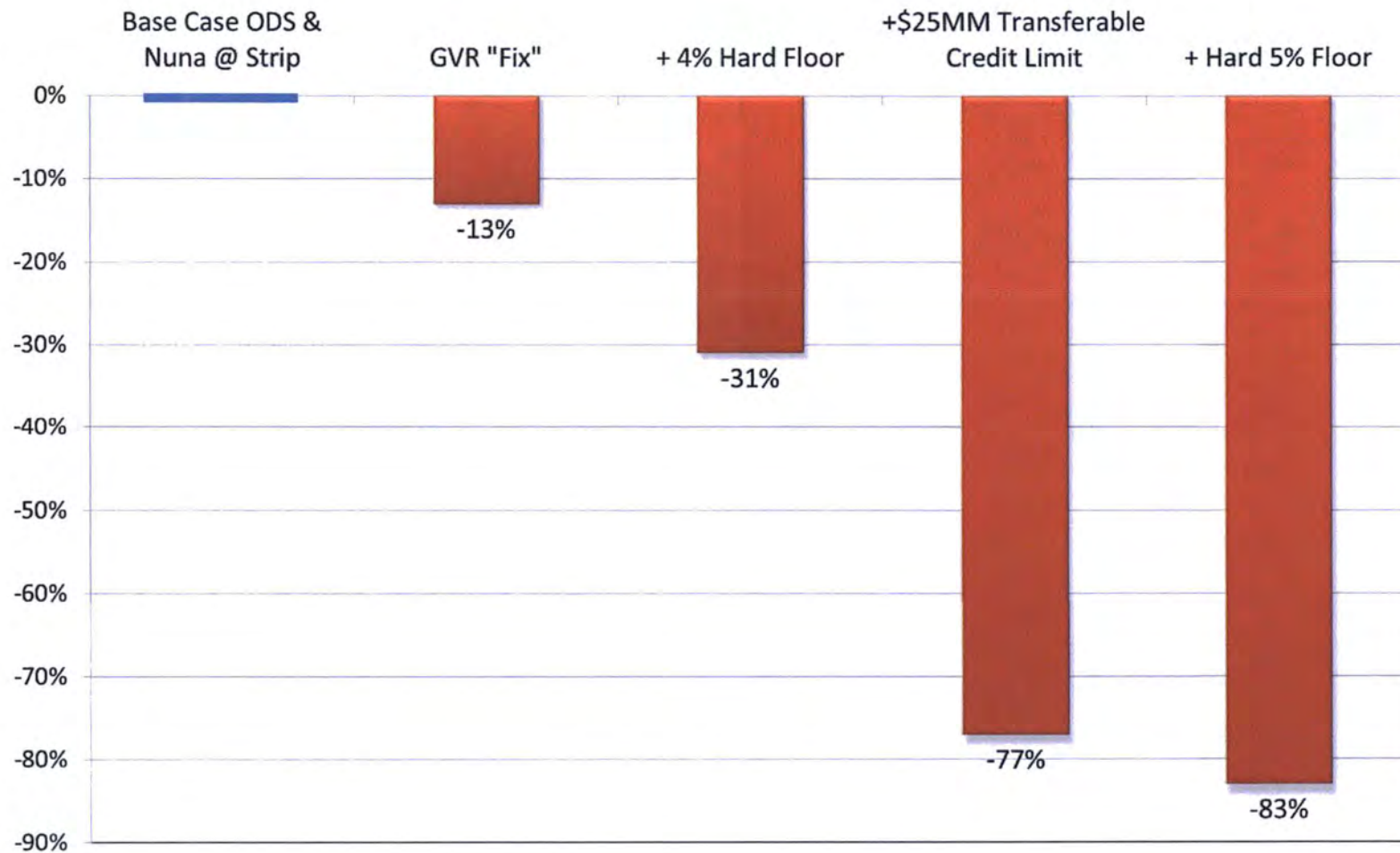


“At \$40 per barrel and below, (the government) is taking so much value, when there is not value to take”

~Janak Mayer, enalytica,
House Resources Committee
Feb. 25, 2016

Felt like the rug was pulled from under us when the change conversation began

Percentage Change in Life-Cycle Project Net Present Value



First oil Late 2018 IF Prices recover & confidence in favorable / stable fiscal terms exist

- ❖ Caelus holds 100% interest
- ❖ 100+ MMBO 2P reserves
- ❖ 20,000 to 25,000 BOPD peak production in 2021

Economically Benefits Alaska

- ❖ 300 FTE contractor construction jobs for two years
- ❖ 300 FTE contractor drilling jobs for 4 to 5 years
- ❖ \$1.75 Bn in future payments to the State of Alaska
 - ~ \$900MM in future royalty payments*
 - ~ \$500 MM in future NPSL payments*
 - > \$250 MM in future production tax payments*
 - ~ \$100 MM in future Ad Valorem taxes
- ❖ <\$250MM in future NOL cash payments from the State of Alaska

* Values are undiscounted based upon a Flat \$70/bbl Brent Price Assumption



❖ Alaska has Great Resource Potential

- Alaska needs more exploration & production companies to fully develop its petroleum resources
- SB 21 is a balanced system that is working for Alaska

❖ CS HB 247(RES) :

- > 40 hrs. of examination: experts, industry, public
- Better than original version, but not perfect
- Represents yet another change in oil tax law
 - > Instability > Uncertainty

❖ Recommendations

- **NO U-Turn!**
 - Limits on capital credits limits investment
 - Hard floor: taking value when no value to take
- Thoughtful policy considerations:
 - Will policy increase production?



Thank you



Dallas

8401 North Central Expressway, Suite 400
Dallas, TX 75209

Main: +1 (214) 368.6050

Fax: +1 (214) 234.0270

Anchorage

3700 Centerpoint Dr., Suite 500
Anchorage, AK 99503

Main: +1 (907) 277-2700

Fax: +1 (907) 343-2190

Fiscal Impact of Cook Inlet Production Tax Limitations, 2007-2013

This analysis provides estimates of the amount of production tax revenue that could have been collected under the ACES production tax regime in Cook Inlet, but that was not collected due to the Cook Inlet tax limitations in place for calendar years (CY) 2007 through 2013. The estimates provided in this analysis are approximations, provided in ranges to reflect several assumptions made in the calculations and to reflect a level of uncertainty as to the completeness of the data.

Oil and gas production tax changes enacted with the Petroleum Profits Tax (PPT) in 2006 and with Alaska's Clear and Equitable Share (ACES) in 2007 contained provisions limiting the production tax for oil and gas produced in Cook Inlet. These provisions generally limited the production tax to the lower of the tax calculated under PPT and later ACES, and the tax calculated under the ELF tax regime as it existed in the year prior to April 1, 2006. These limitations went through several changes in the years since PPT's passage, with the largest changes occurring with the Cook Inlet Recovery Act in 2010. The Cook Inlet Recovery Act eliminated certain ring-fencing provisions, and provided additional credits for Cook Inlet, which in turn increased and the value of Cook Inlet credits by allowing more of them to be used elsewhere and/or be redeemed for cash from the State.

Due to the numerous changes in law from year to year, we calculated these estimates to the best of our ability using primarily annual estimates of tax liabilities and credits, without regard to certain specific credit provisions and details about taxing jurisdictions specific to Cook Inlet. Data and reporting inconsistencies also hampered our confidence in the estimates. To reflect this uncertainty, we have provided the production tax estimates in terms of ranges of revenue.

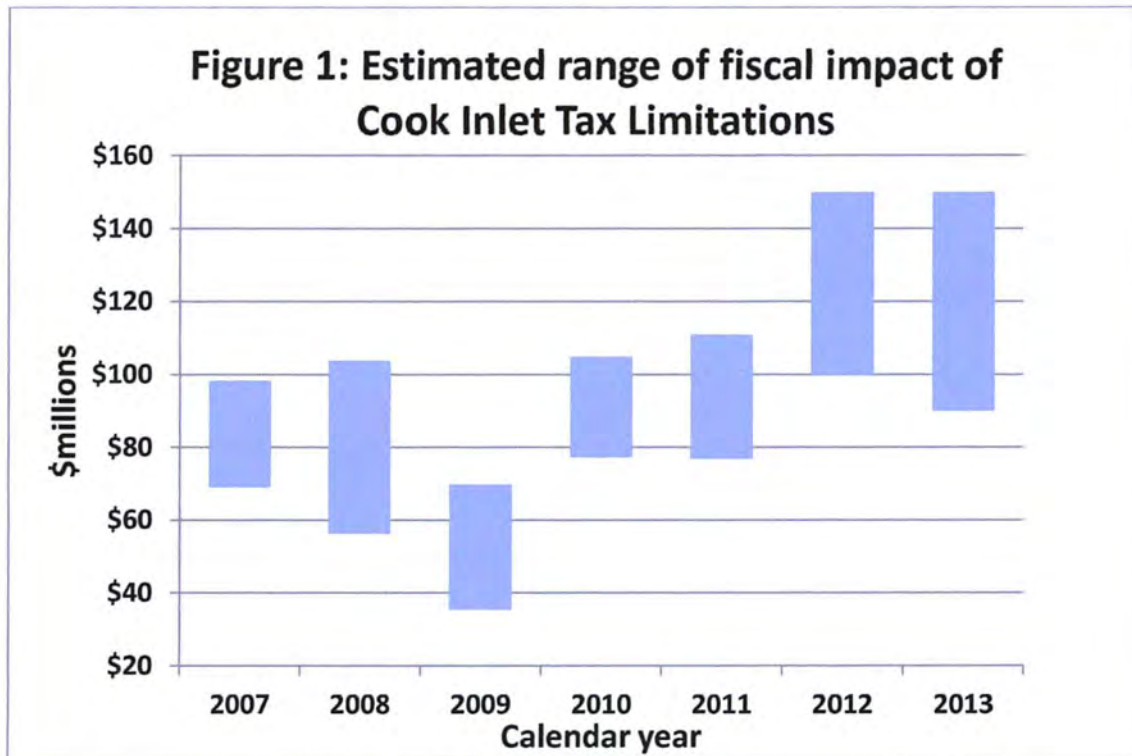
It is important to note that while Cook Inlet producers enjoy very low tax rates under the ELF production tax limitations, if taxed under ACES, many of these same producers would have their entire production tax liability eliminated by the small producer credit under AS 43.55.024(c). The small producer credit, worth \$12 million each year, is a use-or-lose credit that most Cook Inlet producers earn each year. Because the tax liability of many of these small producers, even under ACES, is less than \$12 million, most of them are unable to take full advantage of the credit. Further, in any given year, up to one half of the producers in Cook Inlet spend more in oil and/or gas lease expenditures than they take in revenues. These producers qualify for net operating losses under the production tax credit system.

In the seven years that this analysis covers, the number of companies reporting that they are exploring for and/or producing oil or gas in Non-North Slope areas of the state increased significantly, from 7 companies in 2007 to 21 companies in 2013. The increase in the number of companies with activity in Non-North Slope areas is shown in the table below.¹

¹ For purposes of public reporting the Department of Revenue combines Cook Inlet figures with those from other Non-North Slope areas in so-called "middle earth." The primary reason for this is the relatively small number of companies and projects in the middle earth area, which could not be reported separately due to confidentiality restrictions. Therefore, to ensure complete statewide data, we combine these few middle earth companies with the much larger Cook Inlet data set. Since there is no commercial oil or gas production in "middle earth," all production and production tax liabilities in this analysis are from Cook Inlet producers.

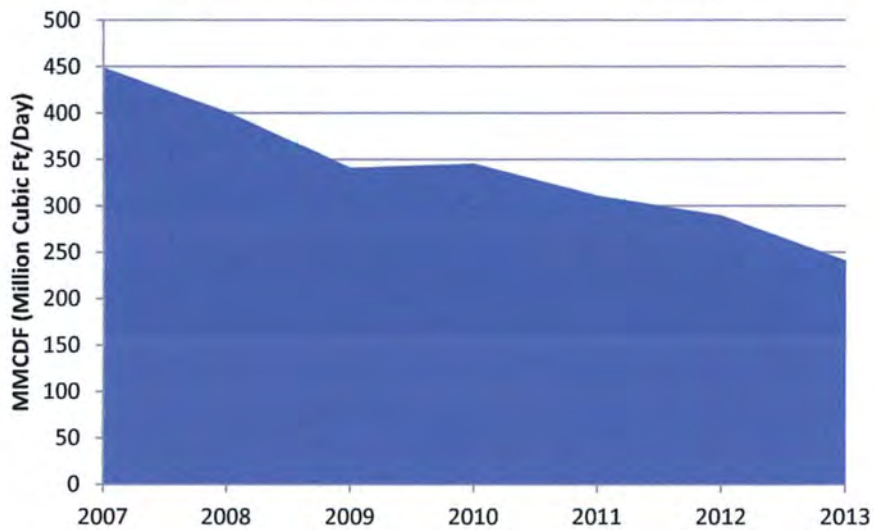
Companies Reporting Production and Companies Receiving Refunded Credits in Non-North Slope Areas of Alaska							
Calendar Year	2007	2008	2009	2010	2011	2012	2013
Count of Producers reporting production in Cook Inlet	7	7	8	9	13	14	13
Count of Companies Receiving Refunded Credits in Non-North Slope	0	0	1	8	12	13	17
Count of Total Non-North Slope Companies	7	7	9	16	18	18	21

Figure 1 below illustrates ranges of estimated foregone revenue of Cook Inlet companies. Unrealized production tax revenue dipped from 2007 to 2009, due primarily to lower oil and gas prices, then steadily began increasing, growing even more in 2012 and 2013. The total fiscal impact of these limitations over the seven years analyzed is estimated to be between \$550 million and \$800 million.



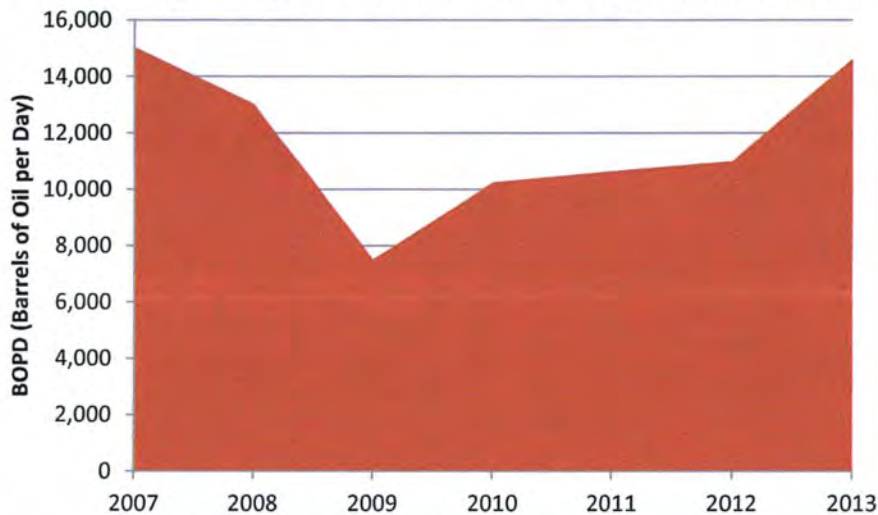
The results in Figure 1 can be partially explained by commodity prices and partially explained by production volumes. Oil prices varied from the \$60 per barrel range in 2007 to over \$100 per barrel in 2008, to lows of \$40 per barrel in 2009. The lower values contribute to lower tax liabilities in 2009. With regard to production volumes, although Cook Inlet gas production has been declining since 2008 (see Figure 2), Cook Inlet oil production almost doubled from lows of 7,500 barrels per day in 2009 to close to 15,000 barrels per day in 2013 (see Figure 3). During this time, capital lease expenditures for Non-North Slope more than tripled from around \$120 million in CY 2010 to close to \$400 million in CY 2012, and increased further to close to \$500 million in CY 2013. Refunded credits to Non-North Slope companies increased from around \$15 million in CY 2010 to around \$94 million in CY 2012, then doubling to around

Figure 2: Cook Inlet Gas Production, 2007-2013



Source: Department of Natural Resources, Oil and Gas Division

Figure 3: Cook Inlet Oil Production, 2007-2013



Source: Department of Natural Resources, Oil and Gas Division

\$191 million in CY 2013.

Because many Cook Inlet companies do not incur a tax liability, or their tax liability is eliminated by non-refundable credits, any remaining credits are generally cashed out by the State. The table below shows the amount of credits that were earned by oil and gas activity in Non-North Slope areas of the state that were redeemed for cash from the State treasury. Note the significant increase beginning in CY 2011, for a total of over \$300 million over the seven years. Refunded credits for Non-North Slope activity in CY 2014 are even higher, estimated to be in excess of \$300 million.

Historical Refunded Credits in Non-North Slope							
(\$millions)	CY 07	CY 08	CY 09	CY 10	CY 11	CY 12	CY 13
Non- North Slope Refunded Credits							
Credits under AS 43.55.023 ¹	0	0	*	*	34	*	*
Credits under AS 43.55.025 ²	0	0	*	*	3	*	*
Credits under AS 43.20 ³	0	0	0	0	0	0	15
Total Non-NS Refunded Credits	0	0	*	15	36	94	191

***An asterisk indicates that a number is confidential.

¹Credits under AS 43.55.023 include the Qualified capital expenditure, the Carried-forward annual loss, and the Well lease expenditure Credit.

²Credits under AS 43.55.025 include the Alternative Credit for Exploration, the Frontier Basin Credit, and for Cook Inlet only, the Cook Inlet Jack-up Rig Credit

³Credits under AS 43.20 include the Gas Exploration and Development Credit, Gas Storage Facility Credit, the In-State Gas Refinery Credit, and the LNG Storage Facility Credit.

Tax Credits Available by Year

Tax Era	ELF			PPT	ACES			ACES + HB280			SB21					
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
North Slope- Against Liability																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	45%	45%	35%	35%	35%	35%
Transitional Investment Expenditure (clawback)				20%	20%	20%										
Small Producer Credit (maximum)				\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%					
Per-Taxable Barrel											\$0-\$8	\$0-\$8	\$0-\$8	\$0-\$8	\$0-\$8	\$0-\$8
North Slope- Refundable																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	45%	45%	35%	35%	35%	35%
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%					
Non-North Slope- Against Liability																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Small Producer Credit (maximum)				\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Well Lease Expenditure								40%	40%	40%	40%	40%	40%	40%	40%	40%
Non-North Slope- Refundable																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Exploration (middle earth)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%
Exploration (jack-up rig)								80-100%	80-100%	80-100%	80-100%	80-100%	80-100%	80-100%		
Exploration (frontier area)										75-80%	75-80%	75-80%	75-80%			
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Well Lease Expenditure								40%	40%	40%	40%	40%	40%	40%	40%	40%
Gas Storage Facility (maximum)											\$15mil		\$15mil			
Refinery Improvement (maximum)													\$30mil	\$30mil	\$30mil	\$30mil

Tax Credits Available by Year

Tax Era	ELF			PPT	ACES			ACES + CIRA			SB21					
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
North Slope- Against Liability																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	45%	45%	35%	35%	35%	35%
Transitional Investment Expenditure (clawback)				20%	20%	20%										
Small Producer Credit (maximum)				\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%					
Per-Taxable Barrel											\$0-\$8	\$0-\$8	\$0-\$8	\$0-\$8	\$0-\$8	\$0-\$8
North Slope- Refundable																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	45%	45%	35%	35%	35%	35%
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%					
Non-North Slope- Against Liability																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Small Producer Credit (maximum)				\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil	\$12mil
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Well Lease Expenditure								40%	40%	40%	40%	40%	40%	40%	40%	40%
Non-North Slope- Refundable																
Exploration (traditional)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%		
Exploration (middle earth)	20-40%	20-40%	20-40%	20-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%	30-40%
Exploration (jack-up rig)								80-100%	80-100%	80-100%	80-100%	80-100%	80-100%	80-100%		
Exploration (frontier area)										75-80%	75-80%	75-80%	75-80%	75-80%		
Carry-Forward Annual Loss (NOL)				20%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Qualified Capital Expenditure				20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Well Lease Expenditure								40%	40%	40%	40%	40%	40%	40%	40%	40%
Gas Storage Facility (maximum)											\$15mil			\$15mil		
Refinery Improvement (maximum per company)												\$10mil	\$10mil	\$10mil	\$10mil	\$10mil



ALASKA STATE LEGISLATURE
HOUSE FINANCE COMMITTEE

State Capitol, Room 519

Rep. Mark Neuman, Co-Chair

Rep. Steve Thompson, Co-Chair

Thursday, March 31, 2016

5:00 PM

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

Department of Revenue

Testifying in Person:

RH . Randall Hoffbeck, Commissioner, Department of Revenue
KA Ken Alper, Director, Tax Division, Department of Revenue

Department of Natural Resources

Presenting in person:

7D Paul Decker, Petroleum Geologist, Division of Oil and Gas

via teleconference:

CF Corri Feige, Director, Division of Oil and Gas

3/31/16

Table of Tax Credits under AS 43.55 - The Alaska Oil and Gas Production Tax and Comparison to Proposed Changes in HB 247

Below is a table relating to credits under AS 43.55, the Oil and Gas Production Tax, for the State of Alaska. This is intended as an informational guide only. The State of Alaska makes no warranty, expressed or implied, of the accuracy of this. To be certain of the current statutes and regulations, refer to the official printed version of the statutes and regulations. This information only relates to credits in effect on January 1, 2016.

Credits under AS 43.55

Statute for Credit	Credits that May be Issued as Certificates and Submitted to the State for Cash Purchase								Credits that may only be used to offset a tax liability					
	AS 43.55.023(b)	AS 43.55.023(a)(1)	AS 43.55.023(a)(2)	AS 43.55.023(f)(1)	AS 43.55.023(f)(2)	AS 43.55.025(a)(1-4)	AS 43.55.025(a)(5)	AS 43.55.025(a)(6) & (7)	AS 43.55.019	AS 43.55.024(a)	AS 43.55.024(c)	AS 43.55.024(i)	AS 43.55.024(j)	AS 38.05.180(i) / AS 41.09.010
Informal Title	Carried-Forward Annual Loss Credit; NOL Credit	Qualified Capital Expenditures (QCE) Credit	Qualified Capital Expenditures (QCE) Credit for Exploration	Well Lease Expenditure (WLE) Credit	Well Lease Expenditure (WLE) Credit for Exploration	Alternative Credit for Exploration	Exploration - Jack-up Rig	Exploration - Frontier Basins	Education Credit	New Area Development ("Middle Earth") Credit	Small Producer Credit	Credit on GVR Oil	Sliding Scale Credit	(DNR) Exploration Incentive Credits
Initial and Most Recent Effective Date(s)	4/1/2006, amended 7/1/2007 & 1/1/2014	4/1/2006, amended 7/1/2007, 1/1/2013 & 1/1/2014		7/1/2010		9/9/2003, amended 7/1/2008 & 1/1/2013	5/10/2010	1/1/2013	1987, amended 1/1/2011	4/1/2006	4/1/2006	1/1/2014	1/1/2014	
Expiration Date	No expiration	North Slope QCEs expire on 12/31/2013		No expiration		7/1/2016 for projects in North Slope and Cook Inlet; 1/1/2022 for "Middle Earth"	7/1/2016	7/1/2016	Changes 1/1/2021, no expiration	If started before 5/1/16, after 9th calendar year of production	If started before 5/1/16, after 9th calendar year of production	No expiration	No expiration	
Credit Percentage / Amount	North Slope 35%; rest of state 25%	20%		40%		30% or 40% (pre-7/1/08 20% or 40%)	80%, 90%, or 100% (up to \$20, \$22.5 or \$25 million)	80% (up to \$25 million) for wells; 75% (up to \$7.5 million) for seismic	Max of \$5,000,000	\$6,000,000	\$12,000,000	\$5 per bbl	\$0-\$8 per bbl	N/A
Description	Calculated for each segment by taking 25% or 35% of excess lease expenditures.	A QCE must be a lease expenditure and treated as a capitalized cost under 26 IRC. .	A QCE must be a lease expenditure and related to exploration.	A WLE must be a lease expenditure, QCE, and an Intangible Drilling and Development Cost (IDC)	A WLE must be a lease expenditure, QCE, and an Intangible Drilling and Development Cost (IDC) related to exploration	Costs directly related to drilling an exploration well or performing a seismic shoot; amount depends on location	For the first 3 unaffiliated wells drilled by the same jack-up rig in Cook Inlet pre-Tertiary zone	The first two qualified exploration wells and the first seismic project in each basin	A part of cash donations to qualified educational institutes or foundations	For production south of 68 degrees North latitude and outside of Cook Inlet	Full credit if the taxpayer produces less than 50,000 BTU equiv. barrels. Prorated between 50,000-100,000 BTU equiv. barrels	\$5 per barrel, based on oil produced that meets one of the criteria for "new oil"	Sliding scale of \$0-\$8, based on average monthly gross value, for oil that does not meet the criteria for "new oil"	DNR administers this credit, two statutes depend on state land vs. non-state land
DNR Data Requirements	No	No	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No	
Location Requirements	No	Effective 1/1/2014, no QCEs on North Slope		Must be south of 68 degrees North latitude		Some have distance requirements from other wells and units	Yes - must be a jack-up rig in Cook Inlet	Yes - six basins defined in AS 43.55.025(o)	No	Outside North Slope and Cook Inlet	No	Must be north of 68 degrees North latitude (North Slope)		N/A
Regulations**	15 AAC 55.310-320 and 15 AAC 55.250-260	15 AAC 55.310-320 and 15 AAC 55.250-260		15 AAC 55.310-320 and 15 AAC 55.250-260		15 AAC 55.350-360			None	15 AAC 55.335			15 AAC 55.520(f)	
Combinations	May be "stacked" with credits under AS 43.55.023(a), (f), or 025(a)	Same expenditures may also qualify for credit under AS 43.55.023(b)				None of the expenditures included in this credit may receive a credit under any other section of this chapter			Credit may be in addition to all other credits	Not for specific expenditures - credit may be in addition to all other credits			N/A	
Uses of Credit	Applied directly to tax or issued as a certificate. The certificate may be transferred to another company, applied against tax liability, or "cashed" out with the State under AS 43.55.028								Applied directly to tax at 1/12 each month and may not be carried forward or transferred			Applied to tax at actual amount earned each month. Can't be carried forward or transferred	Applied against royalty, rental payments, or tax liability	

Proposed Changes to Credits in HB 247

See below	These credit are repealed	Cannot reduce tax liability below the minimum tax under AS 43.55.011(f), retroactive to 1/1/16. (Sec. 17, 19, and 44)	No change	Credits cannot reduce tax liability below the minimum tax under AS 43.55.011(f), retroactive to 1/1/16. (Sec. 17(b) and 19)	This credit is repealed
				The Per-Taxable-Credits are monthly calculations instead of annual. (Sec. 17(c))	

Changes to Carried-Forward Annual Loss (NOL) Credit

- 1) If a company producing at a loss is producing oil that qualifies as "new oil" that is eligible for the Gross Value Reduction (GVR), the GVR is added back into the production tax value calculation for determining the NOL credit. (Sec. 18)
- 2) Any unused portion of this credit can only be used up to the 10th calendar year after the carried-forward annual lost was incurred. (Sec 19)
- 3) Applies the current DNR seismic and well data sharing requirements currently mandated for exploration credits (Sec. 22)

Proposed Changes (General for All Credits)

General Changes

- 1) The name of each company claiming credits, the aggregate amount of credits in a calendar year, and the general description of the activities which generated the credit will be public information. (Sec. 8)
- 2) Companies with a non-tardy liability to the state cannot receive a cash refund for a credit from the state; it must be applied towards that liability

Changes Impacting Repurchase of Certificates

- 1) Companies can only receive \$25 million in cashed out credits annually.
- 2) Only companies whose gross revenues in the previous year were less than \$10 billion can get a cash refund for a credit
- 3) The state will only repurchase a percentage of a credit certificate equal to the percentage of a company's Alaska resident hire in the previous calendar year. (Sec. 9, 10, 11, 26, 27, & 39)

3/31/16

Assumptions for Revenue Estimates	Price of Oil	\$50
	Transport Cost	\$10
	Volume in BBL / Day	10,000
	Royalty Rate	12.50%

Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land

Revised 3/12/16 by Dan Stickel

Land status	Revenue component				Royalty or Tax on Pvt. Royalty (revenue in \$millions)
	Production tax / credits	Royalty	Corporate Income Tax	Property Tax	
Offshore beyond 6 miles - Federal OCS	Do not apply	Federal royalties applies; zero shared back to state (in Alaska; other states do receive shared royalties)	Not included in apportionment factor	Does not apply	\$ -
Offshore 3-6 miles - Federal OCS 8(g) area	Do not apply	Federal royalties applies; 27% shared back to state with no restrictions	Not included in apportionment factor	Does not apply	\$ 4.9
State lands	All credits available; tax applies to all taxable production	State royalty applies	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 18.3
NPR-A - federal owned	All credits available; tax applies to all taxable production	Federal royalty applies; 50% of royalties are shared back to state but must be used for benefit of local communities	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 9.1
ANWR	All credits available; tax applies to all taxable production	Federal royalty applies; 90% shared back to state with no restrictions (under current law)	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 16.4
Other federal land	All credits available; tax applies to all taxable production	Federal royalties applies; 90% shared back to state with no restrictions	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 16.4
Private land (including Alaska Native Corporation)	All credits available; tax applies to all taxable production	Privately negotiated royalty applies; not shared with state. However state levies 5% (oil) or 1.667% (gas) gross tax on the value of private landowner royalty interest as part of production tax	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 0.9

Notes:

Offshore submerged lands in the 0-3 miles category treated same as similar onshore land.

Title: PRELIMINARY Spring 2016 Forecast Production Tax Credits Detail, FY 2007 to FY 2025

Preparer: Mackenzie Merrill, Economist, 465-5636

Purpose: Provide detailed data on refunded production tax credits and production tax credits against liability historically from FY 07 to FY 15, and forecasted from FY 16 to FY 25; broken out by North Slope and Non-North Slope.

Date: 3/29/2016

Data Source: PRELIMINARY Spring 2016 revenue forecast and supporting data/models.

Key Assumptions: All assumptions are as of the PRELIMINARY Spring 2016 revenue forecast. Also see notes and comments embedded in the spreadsheet. The final Spring 2016 Revenue Sources Book will be released in early April.

History: First version that provides a summary of historical and forecasted refunded credits broken out by credit type and geographic region for FY 2007 through FY 2025.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

3/31/16

Table 8-4: Detail on Historical Production Tax Credits and Forecast per PRELIMINARY Spring 2016 Forecast

(\$millions)	Historical								Preliminary FY 15 ¹	Forecast ²									
	FY 07	FY 08	FY 09	FY 10	FY 11	FY 12	FY 13	FY 14		FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25
Refunded Credits³																			
North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b)	55	*	173	223	399	267	*	*	203	*	340	252	180	145	110	111	142	139	137
Credits under AS 43.55.025 ⁴	0	*	14	23	12	53	*	*	21	*	67	35	0	0	0	0	0	0	0
Total North Slope	55	53	187	246	411	320	261	281	224	214	407	287	180	145	110	111	142	139	137
Non-North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b); Well lease expenditure, AS 43.55.023(l)	0	*	*	*	*	29	*	*	384	*	368	111	79	75	114	122	103	108	113
Credits under AS 43.55.025 ⁴	0	*	*	*	*	4	*	*	21	*	29	24	5	5	5	5	5	3	0
Credits under AS 43.20 ⁵	0	*	*	*	*	0	*	15	0	0	18	28	20	20	20	10	0	0	0
Total Non-North Slope	0	1	7	4	39	33	108	312	404	286	414	162	104	100	139	137	108	111	113
Total Refunded Credits	55	54	193	250	450	353	369	592	628	500	825	450	285	250	250	250	250	250	250
Credits Used Against Tax Liability^{6,7}																			
North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b)	292	219	279	339	313	306	486	332	0	23	95	152	166	175	187	133	77	72	1
Transitional investment expenditure: AS 43.55.023(i) ⁸	171	73	0	0	0	*	*		595	28	16	24	55	97	105	90	76	64	52
Per taxable barrel credit, AS 43.55.024(i)-(j) ⁹	*	*	*	*	*	*	*	516	*	23	27	14	14	19	17	13	5	4	3
Small producer credit, AS 43.55.024(a)(c)	*	*	*	*	*	*	*	*	*	0	0	0	0	0	0	0	0	0	0
Total North Slope	541	368	328	402	345	347	536	907	655	74	138	190	235	291	309	236	158	140	56
Non-North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b); Well lease expenditure, AS 43.55.023(l)	*	*	0	*	11	*	*	*	*	7	11	11	11	11	11	34	34	34	33
Small producer credit, AS 43.55.024(a)(c)	*	*	6	*	6	*	*	*	*	0	0	3	5	5	5	12	12	12	6
Total Non-North Slope	16	10	6	10	17	16	14	12	9	7	11	14	16	16	16	46	46	46	39
Total Credits Used Against Tax Liability	557¹⁰	378	334	412	361	363	550	919	664	80	150	205	250	305	325	280	205	185	95
Total Credits North Slope	596	421	*	647	756	667	797	1188	879	288	545	476	415	437	419	347	300	280	193
Total Credits Non-North Slope	16	11	*	14	56	49	122	323	413	293	426	177	120	116	155	183	154	156	152
Total Statewide Production Tax Credits	\$612	\$432	\$526	\$662	\$811	\$716	\$918	\$1,511	\$1,292	\$580	\$975	\$655	\$535	\$555	\$575	\$530	\$455	\$435	\$345
Carried-Forward Credits Balance for Companies Not Eligible for Refund ¹¹	0	0	0	0	0	0	0	0	0	385	632	766	747	600	284	151	74	1	0

Source: PRELIMINARY Spring 2016 Revenue Sources Book Backup

* An asterisk indicates that the data is restricted to protect confidentiality.

¹ These numbers are preliminary pending Annual Returns.

² Forecasted total refunded credits are rounded to the nearest \$5 million and forecasted credits against liability are also rounded to the nearest \$5 million.

³ Forecasted refunded credits in the near-term are based on known projects and company activities. For FY 2020 and beyond, the forecast of credits available for refund is held constant at \$250 million per year.

⁴ Credits under AS 43.55.025 include the Alternative Credit for Exploration, the Frontier Basin Credit, and for Cook Inlet only the Cook Inlet Jack-up Rig Credit.

⁵ Credits under AS 43.20 include the Gas Exploration and Development Credit, Gas Storage Facility Credit, the In-State Gas Refinery Credit, and the LNG Storage Facility Credit.

⁶ The Education Credit, AS 43.55.019, though not reported in its own credit category in the summary was less than \$1 million in each year reported and is calculated in the total.

⁷ For historical credits against tax liability, geographic location was determined by attributing all .023(l) credits to Non-North Slope, all .025 Credits to North Slope, and the other credits were placed according to where the company primarily operated. Since multiple companies had operations in multiple areas, these numbers should be treated as rough estimates.

⁸ The Transitional Investment Expenditure Credit sunset on Dec 31, 2013.

⁹ For FY 2014, the Per Taxable Barrel Credit was in effect for only the last six months of the fiscal year. Credits applied against liability in the forecast are limited by a company's tax liability including the minimum tax.

¹⁰ Three months of 2006 credits data are included in the FY 2007 credits used against tax liability number.

¹¹ This row includes estimates of carried-forward credits for previous calendar years for companies with over 50,000 BOE of production, plus an estimate of credits that will be earned on activity through June 30 of the fiscal year. Carried-forward credits are primarily for net operating losses under AS 43.55.023(b).



Sectional Analysis, CS HB 247(RES) \ I
Oil and Gas Tax Credit Reform Bill
March 23, 2016

- Sec. 1-5.** Conforming language related to the repeal of AS 41.09, an old DNR exploration incentive credit program, in Sec. 29 of the bill.
- Sec. 6.** Changes from simple interest to compound interest for delinquent taxes. The current rate of 3% above the Federal Reserve rate is retained.
- Sec. 7-9.** Amends the Gas Storage Facility, LNG Facility, and In-State Refinery Tax Credits so that these cannot be paid if the taxpayer has any outstanding liability to the state. Currently this is restricted to only a tax liability. Conforms with new language in Sec. 17.
- Sec. 10-11** Conforming language related to the repeal of AS 38.05.180(i) and AS 41.09, old DNR exploration incentive credit programs, in Sec. 29 of the bill.
- Sec. 12.** Reduces the amount of the carried-forward annual loss credit (also known as the NOL credit) for areas outside the North Slope from 25% to 10%.
Modifies the NOL credit so that, for "new" oil production eligible to receive the Gross Value Reduction (GVR), the GVR cannot be used to increase the size of an annual loss.
- Sec. 13.** Effective in 2022, conforming to the change in placement to the definition of "qualified capital expenditure," related to the repeal of AS 43.55.023(a) in Sec. 30 of the bill.
- Sec. 14.** Effective in 2022, conforming language related to the repeal of AS 43.55.023(a), the Qualified Capital Expenditure Credit, in Sec. 30 of the bill.
- Sec. 15.** Reduces the 40% Well Lease Expenditure (WLE) credit from 40% to 30% in 2017, and to 20% in 2018.
- Sec. 16.** Amends AS 43.55.028(e) to add a limitation of \$200 million per company per year to state repurchase of credit certificates. Provides that a company cannot artificially divide themselves into multiple entities to receive more than the \$200 million cap.
- Sec. 17.** Ensures the state cannot repurchase a credit certificate if the company has an outstanding liability to the state related to their oil and gas activity. The Department may use the withheld amount to satisfy the liability, with the applicant's consent. Adds a definition of "outstanding liability."
- Sec. 18.** Effective in 2022, conforming language related to the repeal of AS 43.55.023(a), the Qualified Capital Expenditure Credit, in Sec. 30 of the bill.

- Sec. 19-20.** Effective in 2022, conforming to the change in placement to the definition of “qualified capital expenditure,” related to the repeal of AS 43.55.023(a) in Sec. 30 of the bill.
- Sec. 21.** Effective in 2022, conforming language related to the repeal of AS 43.55.165(j) and (k) in Sec. 30 of the bill. The repeal is the “standard deduction” limitation on lease expenditure inflation that expired in 2010.
- Sec. 22.** Effective in 2022, conforming to the change in placement to the definition of “qualified capital expenditure,” related to the repeal of AS 43.55.023(a) in Sec. 30 of the bill.
- Sec. 23-24.** Effective in 2022, conforming language related to the repeal of AS 43.55.023(a), the Qualified Capital Expenditure Credit, in Sec. 30 of the bill.
- Sec. 25.** Effective in 2022, conforming to the change in placement to the definition of “qualified capital expenditure,” related to the repeal of AS 43.55.023(a) in Sec. 30 of the bill.
- Sec. 26.** In the case where a municipal entity has an interest in oil and gas production, and sells only a portion of that production to an outside party, their ability to deduct lease expenditures and claim credits is limited in proportion to their taxable production.
- Sec. 27.** Effective in 2022, adds a definition for “qualified capital expenditure” to the general definitions section of AS 43.55. This replicates the definition that was in AS 43.55.023 which is repealed because the .023 “qualified capital expenditure” credit is also being repealed in Sec. 30. Most of the conforming sections that currently reference AS 43.55.023(a) use this definition.
- Sec. 28.** Adds a requirement that persons engaged in exploring for and developing oil or gas file a surety bond of \$250,000. The bond will protect unsecured creditors. The bond requirement is waived once the person produces oil or gas in commercial quantities.
- Sec. 29.** Repeals two unused DNR exploration incentive credit programs, AS 38.05.180(i) and AS 41.09.
- Sec. 30.** Effective in 2022, repeals the QCE and WLE programs in AS 43.55.023(a) and (l), as well as the former Standard Deduction provisions in AS 43.55.165(j) and (k), with related sections.
- Sec. 31.** Creates a legislative working group, with co-chairs appointed by the presiding officers, to review the fiscal regime for Cook Inlet and Middle Earth during the interim, and present recommended changes to the legislature during the 2017 regular session.
- Sec. 32.** Applicability language related to the new requirements for purchasing transferable tax credit certificate through the Oil and Gas Tax Credit Fund.
- Sec. 33.** Transition language for the 2022 repeal of the QCE and WLE credits in Sec. 30; ensures that expenditures incurred before the repeal date are eligible for the credits.

- Sec. 34.** Transition language for the 2022 repeal of the Standard Deduction provisions in Sec. 30.
- Sec. 35-36.** Transition language enabling DOR and DNR to draft regulations to implement the changes in this Act, and establishing that regulations may be retroactive to the effective date if they are finalized after the effective date.
- Sec. 37.** Immediate effective date for the legislative working group and the authority for DOR and DNR to write regulations for this bill.
- Sec. 38.** Delayed effective date of January 1, 2022 for the repeal of the QCE and WLE credits, the Standard Deduction, and various conforming sections related to these repeals.
- Sec. 39.** Effective date of January 1, 2017 for the remaining sections of the bill.

STATE CAPITOL
P.O. Box 110001
Juneau, AK 99811-0001
907-465-3500
fax: 907-465-3532



550 West Seventh Avenue, Suite 1700
Anchorage, AK 99501
907-269-7450
fax 907-269-7461
www.Gov.Alaska.Gov
Governor@Alaska.Gov

Governor Bill Walker
STATE OF ALASKA

January 15, 2016

The Honorable Mike Chenault
Speaker of the House
Alaska State Legislature
State Capitol, Room 208
Juneau, AK 99801-1182

Dear Speaker Chenault:

Under the authority of Article III, Section 18 of the Alaska Constitution, I am transmitting a bill relating to oil and gas tax credits and the minimum tax amount for certain oil and gas production.

This bill proposes through four elements to protect the State's fiscal future while instituting cautious reforms to the oil and gas tax credit system. First, the bill would simplify the oil and gas tax credit system by repealing numerous narrowly targeted credits. The bill would repeal the 20 percent tax credit under AS 43.55.023(a) for qualified capital expenditures incurred for exploration, development, or production of oil and gas south of 68 degrees North latitude and the 40 percent well lease expenditure credit under AS 43.55.023(f) for well lease expenditures incurred south of 68 degrees North latitude. The oil and gas tax credit system with the changes in the bill would move towards a system based on nontransferable production-based credits and transferable credits based on carried-forward annual losses. The bill would repeal unused exploration incentive credits under AS 38.05.180(i) and AS 41.09. Also, the bill would limit the lease expenditures and tax credits available to municipal entities in proportion to the taxable production of the municipal entity.

Second, the bill would strengthen the minimum tax amount for certain oil and gas produced north of 68 degrees North latitude ("North Slope") to protect the State's tax revenue stream. The bill would require the minimum tax amount on certain oil and gas produced on the North Slope to equal at least five percent of the gross value at the point of production regardless of the price of the oil and gas. The oil and gas tax credits would no longer be able to reduce the tax levied in AS 43.55.011(e) below the minimum amount calculated in AS 43.55.011(f). This credit limitation would take effect on January 1, 2016.

Third, the bill would reinvigorate the State's investment strategy in purchases of oil and gas tax credit certificates under AS 43.55.028(e) to focus on small companies that hire state residents. The State would only purchase tax credit certificates from an applicant with revenues of less than \$10,000,000 from its oil and gas business during the previous calendar year. The State would not purchase a certificate from an applicant with an outstanding liability to the State. Outstanding

The Honorable Mike Chenault
Transmittal Tax Credit Reform
January 15, 2016
Page 2

liabilities to the State would include unpaid taxes, penalties, royalties, rental, interest, and fees. The State's purchases from each applicant would be limited to \$25,000,000 a year. The bill would limit the percentage of the State's purchase of a tax credit certificate to the percentage of the applicant's workforce in the state, in the previous calendar year, that were resident workers. This builds on my commitment to promote healthy and safe communities by encouraging employment of state residents in the state's vital natural resources industry.

Finally, the bill would institute a number of changes to promote good governance in tax administration. The bill would delete a number of inapplicable provisions from the tax statutes to provide greater clarity. The bill would increase the interest rate applicable to delinquent taxes. The bill would make public more information about taxpayers that claim oil and gas production tax credits. Most provisions of the bill would take effect on July 1, 2016.

The bill is an integral component of the New Sustainable Alaska Plan to provide a balanced and sustainable budget for Alaska's long-term fiscal stability.

I urge your prompt and favorable action on this measure.

Sincerely,

A handwritten signature in black ink that reads "Bill Walker". The signature is written in a cursive, flowing style.

Bill Walker
Governor

Enclosure



Key Terms Used in HB 247 Sectional Analysis Oil and Gas Tax Credits

Carried-Forward Annual Loss Credit (also called the Net Operating Loss Credit)

Under AS 43.55.023(b), this credit allows companies to carry forward 35% of their North Slope annual loss or 25% of their loss in other areas of the state to apply against a future tax liability. This credit is transferable and refundable and can reduce tax liability below the minimum tax in annual tax calculations. In practice, most companies receive cash refunds from the state for these credits. Companies with greater than 50,000 BTU-equivalent barrels of production are not eligible for refunds and instead must carry the credits forward to a future liability.

Confidential Information Held by Department of Natural Resources

Under AS 43.55.025(f)(2)(C), the Department of Natural Resources keeps well data confidential for two years and seismic or geophysical data confidential for 10 years, at which point the data can be released to the public.

Confidentiality statutes

Currently under AS 40.25.100, any "particulars of the business or affairs of a taxpayer or other person" are confidential, which include the amounts, recipients, and types of credits issued by the department.

Credits used against tax liability/Refundable credits/Transferable credits

Depending on the credit, production tax credits can be applied against a tax liabilities, "refunded" via cash purchase by the state, or transferred to another company. Only companies with fewer than 50,000 BOE per day of production are eligible for refunded credits, and only certain credits are eligible for refund. In particular, the small producer credit and per-taxable-barrel credits can only be used against a tax liability; any unused amount is forfeited.

Exploration Credits under AS 43.55.025

These include:

Alternative Credit for Exploration

- For 30% or 40% for certain seismic or drilling costs based on the location of the unit.
- Expires 7/1/2016 for North Slope and Cook Inlet and 1/1/2022 everywhere else,

Frontier Basin Credit

- The lesser of 80% of qualified exploration or drilling expenses or \$25 million per well, or

- The lesser of 75% of seismic exploration expenditures or \$7.5 million
- For areas other than the North Slope and Cook Inlet
- Expires 7/2/2016

Cook Inlet Jack-Up Rig Credit

- A credit for exploration expenses for the first three wells drilled by the first jack-up rig brought to Cook Inlet
- Ranges from up to 100% of expenses for the first well, 90% for the second, 80% for the third
- If wells are brought into production, operators must repay 50% of the credit
- Expires 7/1/2016.

These credits can reduce tax liability below the minimum tax in annual tax calculations and can be refunded as cash. These credits also can be transferred to another company.

Exploration Incentive Credit under AS 41.09

- This credit is up to 50% of drilling or seismic work, not to exceed 50% of tax liability.
- This credit must be pre-approved by the Commissioner of the Department of Natural Resources
- This credit has not been utilized in recent years

Gas Storage Facility Credit/LNG Facility Credit/In-State Refinery Credit

These credits can be applied against Corporate Income Tax or refunded through the Oil and Gas Tax Credit Fund.

The Gas Storage Facility Credit

- \$1.50 per thousand cubic feet for the costs incurred to establish a natural gas storage facility
- Must be for a facility used by public utilities
- Maximum credit was the lesser of \$15 million or 25% of the costs to establish the facility
- Was taken in 2014 and is no longer available

The LNG facility Credit

- Non-transferable and refundable
- For the costs incurred to establish a storage facility for liquefied natural gas
- Is the lesser of \$15 million or 50% of costs incurred to establish the facility

The In-State Refinery Tax Credit

- Can be applied to tax liability or purchased by the state
- For qualified infrastructure expenditures for in-state refineries
- For costs incurred between December 31, 2014 and January 1, 2020
- May not exceed 40% of total qualifying expenditures or \$10 million per tax year per refinery

Gross Minimum Tax

The gross minimum tax (AS 43.55.011(f)) was first established with the 2006 switch to a net profits-based tax under the Petroleum Profits Tax (PPT) and was based on a percentage of gross value at the point of production (GVPP). A minimum tax of 4% of gross wellhead value was imposed if the ANS oil

price was greater than \$25 per barrel and the minimum tax was greater than the calculated tax liability. When oil prices are lower than \$25, the minimum taxes are as follows:

- 3% when price is between \$20 but less than \$25
- 2% when price is between \$17.50 but less than \$20
- 1% when price is between \$15 but less than \$17.50
- 0% when the price is \$15 or less

Under PPT, the primary tax credit, for qualified capital expenditures, could not be used to reduce a tax liability below the minimum tax. With the switch to the Alaska's Clear and Equitable Share (ACES) tax in 2007, the minimum tax was not changed, but tax credits could reduce the minimum tax to zero. Under SB 21, taking effect in 2014, the minimum tax remained the same. However it was partially "hardened," in that some of the new per-taxable-barrel credits, added by SB 21, could not reduce liability below the minimum tax. Only per-taxable-barrel credits from GVR-eligible oil can reduce the minimum tax to zero in the monthly calculations. In contrast, per-taxable-barrel credits for non-GVR eligible oil, which represent the vast majority of such credits, cannot reduce a liability below the minimum tax.

Gross Value at the Point of Production (GVPP)

The Gross Value at the Point of Production (AS 43.55.150) is calculated by taking the West Coast oil price for Alaska oil and subtracting transportation costs (such as pipeline tariffs, marine costs, and quality adjustments) to arrive at a value at the unit boundary.

Gross Value Reduction (GVR)

For oil that qualifies as "new oil" under AS 43.55.160(f), a 20% reduction of GVPP is allowed in the tax calculation. "New oil" is oil from either a new unit, a new participating area in an existing unit, or oil from certain acreage added to a participating area, as defined in statute.

Interest rate for delinquent taxes

Pre-SB 21 delinquent taxes, assessments, and refunds (from before January 1, 2014) are charged an interest rate of either five percentage points above the Federal Reserve Discount Rate or 11%, whichever is greater. Post SB-21 (after January 1, 2014) interest rates for delinquent taxes are three percentage points above the Federal Reserve Discount Rate. The interest rate specified in AS 43.05.225 applies to most tax types, including production taxes. These rates apply not only to delinquent taxes, but the same rates apply to the state's refunds to these taxpayers. Most interest for oil and gas taxes accrues to the Constitutional Budget Reserve Fund; the General Fund also receives some oil and gas interest as well as interest for non-minerals taxes.

Lease Expenditures

Lease expenditures are defined under statute in AS 43.55.165. They are costs incurred by a producer to explore for, develop, or produce oil or gas deposits located within the producer's leases or properties in the state or costs for costs to explore for oil or gas in other areas of the state. They must be upstream costs, they must be considered "ordinary and necessary" costs of exploring, developing, or producing oil and gas, and they must be a "direct" cost.

Monthly Installment Payments

Monthly installed payments are established under AS 43.55.020 and require producers to pay monthly estimated taxes by the last day of the month following the tax period month. The estimated tax is net of allowable tax credits. Monthly payments cannot be below zero. Per-taxable-barrel credits are calculated on a monthly basis and only per-taxable-barrel GVR-eligible credits may reduce payments past the minimum tax. However, any unused per-taxable-barrel credits in a given month can potentially be applied against other month's liability when filling the annual tax return (sometimes referred to as the "annual true up.")

Oil & Gas Tax Credit Fund

The Oil and Gas Tax Credit Fund was established under AS 43.55.028 by the ACES bill, and it allows the state to buy certain tax credits subject to availability of funds. The legislature has customarily appropriated money into this fund every year.

Per-Taxable-Barrel Credit

The per-taxable-barrel credits, though referred to as "credits," differ from other tax credits as they are actually a component of the tax structure. They are a step in the calculation that determine tax payments. AS 43.55.024(i) is a \$5 per-taxable-barrel credit for oil that qualifies as "new" oil or oil eligible for the GVR, which can reduce tax liability below the minimum tax, and AS 43.55.024(j) is a sliding \$0 to \$8 per barrel credit for oil that is not classified as "new." During FY 2016, approximately 7% of oil production is expected to qualify as "new" oil.

Production Tax Value

Production tax value is the gross value at the point of production minus deductible lease expenditures, which include operating expenditures and capital expenditures with certain adjustments. All capital expenditures can be deducted in the year they were earned.

Qualified Capital Expenditure Credit/Well Lease Expenditure Credit

These credits are for 20% of qualified capital expenditures or 40% of well lease expenditures in areas other than the North Slope. These credits are transferable and refundable and can essentially be "stacked" with other credits. These credits can currently reduce tax liability below the minimum tax in annual tax calculations. Beginning with 2014, the 20% capital expenditure credit was eliminated for the North Slope and replaced with the per-taxable-barrel credit as part of the SB 21 tax change.

Small Producer Credit

This credit is up to \$12 million per year for producers with less than 50,000 BTU-equivalent barrels per day of production, and phases out from \$12 million to zero between 50,000 and 100,000 BTU-equivalent barrels of production. Qualified companies who have oil production before May 1, 2016 can receive the credit for up to nine years after their first production of oil or gas. This credit is not transferable or refundable, but can be used to reduce tax liability below the minimum tax in annual tax calculations.



THE STATE
of **ALASKA**

GOVERNOR BILL WALKER

PREVIOUS VERSION

Department of Revenue

TAX DIVISION

Juneau Office
333 Willoughby Ave, 11th Floor
Juneau, AK 00801
Main: 907.465.2320
www.tax.alaska.gov

Sectional Analysis, HB 247

Governor's Oil and Gas Tax Credit Reform Bill

January 22, 2016

Sec. 1-5. Conforming language related to the repeal of AS 41.09 in Sec. 40 of the bill. The repeal is a currently unused exploration incentive credit program.

Sec. 6. Conforming language related to changes to reporting requirements and confidentiality rules in Sec. 8 of the bill.

Sec. 7. Changes the interest rate for delinquent taxes from 3 percent above the Federal Reserve Discount Rate to 7 percent above. This would currently result in an interest rate of about 8%; about halfway between the current 4% and the 11% that was in place before the passage of SB21 in 2013.

If the state were to begin using earnings from our major savings account, the Permanent Fund, to fund government operations, there would be an "opportunity cost" that comes from unpaid taxes. Our interest rate on these unpaid taxes should reflect the expected rate of earnings on our savings.

Sec. 8. Provides an exception to the general taxpayer confidentiality statutes, so that the name of each company claiming credits, the amount they claim, and a general description of their activities can be made public.

Sec. 9-11. Amends the Gas Storage Facility, LNG Facility, and In-State Refinery Tax Credits so that these cannot be paid if the taxpayer has any outstanding liability to the state. Currently this is restricted to only a tax liability.

Sec. 12. Increases the minimum tax rate in AS 43.55.011(f) to 5% at all oil prices. Currently it is 4% at any oil price above \$25 per barrel, stepping down at lower prices. The minimum tax applies only to production from the North Slope.

Sec. 13. Changes the description of monthly installment payments in AS 43.55.020(a), to conform with the higher minimum tax rate in Sec. 12. (*long technical section*)

Sec. 14-16. Conforming language related to the repeal of AS 43.55.020(a)(1) and (2) in Sec. 40 of the bill. The repeal is obsolete installment payment language related to production prior to 2014.

Sec. 17. Strengthens the minimum tax in two distinct ways:

(b) Prevents several credits that currently can be used to reduce payments below the 4% level from being used for this purpose. Those credits would be carried-forward until the taxpayer had sufficient tax liability against which to use them.

(c) Prevents the circumstance in which per-taxable-barrel credits that could not be used in the month in which they were earned, because of the limitations of the minimum tax, could be claimed at annual tax true-up. This effectively turns the per-taxable-barrel credit into a monthly rather than an annual calculation. Currently if there is substantial price volatility within a year it could result in large tax refunds.

Sec. 18. Modifies the carried-forward annual loss credit in AS 43.55.023(b) so that, for “new” oil production eligible to receive the Gross Value Reduction (GVR), the GVR cannot be used to increase the size of an annual loss. Thus, if a company has oil production but is operating at a loss, their loss credit is limited to the actual size of the loss. Currently there are circumstances in which a company could receive credit refunds for amounts in excess of 100% of their loss.

Sec. 19. Amends AS 43.55.023 so that credits in that section cannot reduce tax liability below the minimum tax, rather than zero as in current statute. Also establishes a sunset when certain credits must be carried forward instead of being cashed out; in these circumstances the credits can only be carried forward for 10 years.

Sec. 20. Establishes a sunset in which credit certificates can only be held for 10 years before they expire.

Sec. 21. Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the “qualified capital expenditure” credit outside of the North Slope.

Sec. 22. New language adding the notice and data sharing requirements that are currently part of the alternative credit for exploration, and applying them to other credits. This will enable DNR to continue to receive seismic and downhole information after the sunset of the exploration credits.

Sec. 23. Amends AS 43.55.024 so that the small producer credit cannot be used to reduce tax liability below the minimum tax. Although this credit will be closed to new recipients in May of 2016, some companies will continue to receive this benefit until approximately 2024.

Sec. 24. Amends AS 43.55.024 so that the \$5 per-taxable-barrel credit received by GVR-eligible North Slope oil production cannot reduce tax liability below the minimum tax. Currently this can be reduced to zero; only the sliding-scale credit for non-GVR oil is limited by the minimum tax.

Sec. 25. Amends AS 43.55.025 so that exploration credits cannot reduce tax liability below the minimum tax.

- Sec. 26.** Amends AS 43.55.028(e) to add limitations on which companies can receive refunded tax credits versus which must hold their certificates and use them against tax liability:
- (2) Companies with any liability to the state are ineligible to receive payment for their tax credit certificates. Currently this is restricted to only a tax liability.
 - (5) Limits cash repurchase to only companies whose gross revenues in the previous year were less than \$10 billion.
 - (6) Limits annual per-company repurchase to \$25 million.
- Sec. 27.** Adds a new limitation to a company's ability to receive a cash repurchase of their tax credits. The state can only repurchase that percentage of a certificate that equals that company's percentage of Alaska resident hire in the previous calendar year.
- Sec. 28-30.** Conforming language related to the repeal of AS 43.55.023(a) and / or (l) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" and "well lease expenditure" credits outside of the North Slope.
- Sec. 31.** New section specifying that the Gross Value at the Point of Production, defined as sales price less eligible transportation costs, may not be less than zero
- Sec. 32.** Conforming language related to the repeal of AS 43.55.165(j) and (k) in Sec. 40 of the bill. The repeal is the "standard deduction" limitation on lease expenditure inflation that expired in 2010.
- Sec. 33-36.** Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" credit outside of the North Slope.
- Sec. 37.** In the case where a municipal entity has an interest in oil and gas production, and sells only a portion of that production to an outside party, their ability to deduct lease expenditures and claim credits is limited in proportion to their taxable production.
- Sec. 38.** Adds a definition for "qualified capital expenditure" to the general definitions section of AS 43.55. This replicates the definition that was in AS 43.55.023 which is repealed because the .023 "qualified capital expenditure" credit is also being repealed in Sec. 40. Most of the conforming sections that currently reference AS 43.55.023(a) use this definition.
- Sec. 39.** Adds a definition for "outstanding liability to the state." This conforms with the changes made in Sections 9, 10, 11, and part (2) of 26.
- Sec. 40.** Repeals multiple sections. All of these have been specifically referenced elsewhere in this analysis or are technical repeals that conform with other repealed statutes.

Sec. 41. Applicability section with multiple sub-parts. In general, ensures that the changes only apply to production after the effective date. Also provides that applications that come in later for credits related to expenditures before the effective date are protected under the former program. Clarifies the timing related to the new 10-year sunset for carried-forward annual loss credits.

Sec. 42-43. Transition language enabling DOR and DNR to draft regulations to implement the changes in this Act, and establishing that regulations may be retroactive to the effective date if they are finalized after the effective date.

Sec. 44. Section 17 is retroactive to January 1, 2016. This is the key floor-hardening provision preventing certain credits from being used against the minimum tax, and is related to the specific concern that one or more major producers could have an operating loss in 2015 and use the carried-forward credit to reduce 2016 tax payments below the minimum tax to zero.

This is the only provision of the bill for which we are seeking this retroactivity.

Sec. 45. Immediate effective date for the transition and regulatory language.

Sec. 46. Effective date of July 1, 2016 for the rest of the Act.

Table of Tax Credits under AS 43.55 - The Alaska Oil and Gas Production Tax and Comparison to Proposed Changes in HB 247

Below is a table relating to credits under AS 43.55, the Oil and Gas Production Tax, for the State of Alaska. This is intended as an informational guide only. The State of Alaska makes no warranty, expressed or implied, of the accuracy of this. To be certain of the current statutes and regulations, refer to the official printed version of the statutes and regulations. This information only relates to credits in effect on January 1, 2016.

Credits under AS 43.55

Statute for Credit	Credits that may be issued as Certificates and Submitted to the State for Cash Purchase								Credits that may only be used to offset a tax liability					
	AS 43.55.023(b)	AS 43.55.023(a)(1)	AS 43.55.023(a)(2)	AS 43.55.023(f)(1)	AS 43.55.023(f)(2)	AS 43.55.025(a)(1-4)	AS 43.55.025(a)(5)	AS 43.55.025(a)(6) & (7)	AS 43.55.019	AS 43.55.024(a)	AS 43.55.024(c)	AS 43.55.024(j)	AS 43.55.024(j)	AS 38.05.100(f) / AS 41.09.010
Informal Title	Carried-Forward Annual Loss Credit; NOL Credit	Qualified Capital Expenditures (QCE) Credit	Qualified Capital Expenditures (QCE) Credit for Exploration	Well Lease Expenditure (WLE) Credit	Well Lease Expenditure (WLE) Credit for Exploration	Alternative Credit for Exploration	Exploration - Jack-up Rig	Exploration - Frontier Basins	Education Credit	New Area Development ("Middle Earth") Credit	Small Producer Credit	Credit on GVR Oil	Sliding Scale Credit	(DNR) Exploration Incentive Credits
Initial and Most Recent Effective Date(s)	4/1/2006, amended 7/1/2007 & 1/1/2014	4/1/2006, amended 7/1/2007, 1/1/2013 & 1/1/2014		7/1/2010		9/9/2003, amended 7/1/2008 & 1/1/2013	5/10/2010	1/1/2013	1987, amended 1/1/2011	4/1/2006	4/1/2006	1/1/2014	1/1/2014	
Expiration Date	No expiration	North Slope QCEs expire on 12/31/2013		No expiration		7/1/2016 for projects in North Slope and Cook Inlet; 1/1/2022 for "Middle Earth"	7/1/2016	7/1/2016	Changes 1/1/2021, no expiration	If started before 5/1/16, after 9th calendar year of production	If started before 5/1/16, after 9th calendar year of production	No expiration	No expiration	
Credit Percentage / Amount	North Slope 35%; rest of state 25%	20%		40%		30% or 40% (pre-7/1/08 20% or 40%)	80%, 90%, or 100% (up to \$20, \$22.5 or \$25 million)	80% (up to \$25 million) for wells; 75% (up to \$7.5 million) for seismic	Max of \$5,000,000	\$6,000,000	\$12,000,000	\$5 per bbl	\$0-\$8 per bbl	N/A
Description	Calculated for each segment by taking 25% or 35% of excess lease expenditures.	A QCE must be a lease expenditure and treated as a capitalized cost under 26 IRC.	A QCE must be a lease expenditure and related to exploration.	A WLE must be a lease expenditure, QCE, and an Intangible Drilling and Development Cost (IDC)	A WLE must be a lease expenditure, QCE, and an Intangible Drilling and Development Cost (IDC) related to exploration	Costs directly related to drilling an exploration well or performing a seismic shoot; amount depends on location	For the first 3 unaffiliated wells drilled by the same jack-up rig in Cook Inlet pre-Tertiary zone	The first two qualified exploration wells and the first seismic project in each basin	A part of cash donations to qualified educational institutes or foundations	For production south of 68 degrees North latitude and outside of Cook Inlet	Full credit if the taxpayer produces less than 50,000 BTU equiv. barrels. Prorated between 50,000-100,000 BTU equiv. barrels	\$5 per barrel, based on oil produced that meets one of the criteria for "new oil"	Sliding scale of \$0-\$8, based on average monthly gross value, for oil that does not meet the criteria for "new oil"	DNR administers this credit, two statutes depend on state land vs. non-state land
DNR Data Requirements	No	No	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No	
Location Requirements	No	Effective 1/1/2014, no QCEs on North Slope	Must be south of 68 degrees North latitude			Some have distance requirements from other wells and units	Yes - must be a jack-up rig in Cook Inlet	Yes - six basins defined in AS 43.55.025(o)	No	Outside North Slope and Cook Inlet	No	Must be north of 68 degrees North latitude (North Slope)		N/A
Regulations**	15 AAC 55.310-320 and 15 AAC 55.250-260	15 AAC 55.310-320 and 15 AAC 55.250-260	15 AAC 55.310-320 and 15 AAC 55.250-260				15 AAC 55.350-360		None		15 AAC 55.335			15 AAC 55.520(f)
Combinations	May be "stacked" with credits under AS 43.55.023(a), (f), or 025(a)	Same expenditures may also qualify for credit under AS 43.55.023(b)				None of the expenditures included in this credit may receive a credit under any other section of this chapter			Credit may be in addition to all other credits	Not for specific expenditures - credit may be in addition to all other credits				N/A
Uses of Credit	Applied directly to tax or issued as a certificate. The certificate may be transferred to another company, applied against tax liability, or "cashed" out with the State under AS 43.55.028								Applied directly to tax at 1/12 each month and may not be carried forward or transferred				Applied to tax at actual amount earned each month. Can't be carried forward or transferred	Applied against royalty, rental payments, or tax liability

Proposed Changes to Credits in HB 247

See below	These credit are repealed	Cannot reduce tax liability below the minimum tax under AS 43.55.011(f), retroactive to 1/1/16. (Sec. 17, 19, and 44)	No change	Credits cannot reduce tax liability below the minimum tax under AS 43.55.011(f), retroactive to 1/1/16. (Sec. 17(b) and 19)	The Per-Taxable-Credits are monthly calculations instead of annual. (Sec. 17(c))	This credit is repealed
<p>Changes to Carried-Forward Annual Loss (NOL) Credit</p> <p>1) If a company producing at a loss is producing oil that qualifies as "new oil" that is eligible for the Gross Value Reduction (GVR), the GVR is added back into the production tax value calculation for determining the NOL credit. (Sec. 18)</p> <p>2) Any unused portion of this credit can only be used up to the 10th calendar year after the carried-forward annual lost was incurred. (Sec 19)</p> <p>3) Applies the current DNR seismic and well data sharing requirements currently mandated for exploration credits (Sec. 22)</p> <p>General Changes</p> <p>1) The name of each company claiming credits, the aggregate amount of credits in a calendar year, and the general description of the activities which generated the credit will be public information. (Sec. 8)</p> <p>2) Companies with a non-tardy liability to the state cannot receive a cash refund for a credit from the state; it must be applied towards that liability</p> <p>Changes Impacting Repurchase of Certificates</p> <p>1) Companies can only receive \$25 million in cashed out credits annually.</p> <p>2) Only companies whose gross revenues in the previous year were less than \$10 billion can get a cash refund for a credit</p> <p>3) The state will only repurchase a percentage of a credit certificate equal to the percentage of a company's Alaska resident hire in the previous calendar year. (Sec. 9, 10, 11, 26, 27, & 39)</p>						

Statute for Credit	Informal Title	Initial and Most Recent Effective Date(s)	Expiration Date	Credit Percentage / Amount	Description	DNR Data Requirements	Location Requirements	Regulations**	Combinations	Uses to Credit	Filing Requirements	Can be Taken Against Other Tax Types or Royalty
AS 43.55.023(a)(1)	Qualified Capital Expenditures Credit	4/1/2006, amended 7/1/2007, 1/1/2013 & 1/1/2014	North Slope QCEs expire on 12/31/2013	20%	A Qualified Capital Expenditure (QCE) must be a lease expenditure and treated as a capitalized cost under 26 IRC. Effective 1/1/2013, these credits are issued as one certificate. Effective 1/1/2014, there is no longer a QCE credit for North Slope expenditures.	No	Effective 1/1/2014, no QCEs on North Slope Pre-1/1/2014, QCEs allowed Statewide	15 AAC 55.310-320	Some expenditures may also qualify for credit under AS 43.55.023(b)	Applied directly to tax or issued as a certificate. The certificate may be transferred to another company, applied against tax liability, or "cashed" out with the State under AS 43.55.025 - or a combination of the above. Effective 6/23/2013, the certificate may also be assigned. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State. If applied against tax - must be 1/12 against each month (except credits under 025 and 023(a)).	Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(a)(2)	Qualified Capital Expenditures Credit in Relation to Exploration	4/1/2006, amended 7/1/2007, 1/1/2013 & 1/1/2014	North Slope QCEs expire on 12/31/2013	20%	A Qualified Capital Expenditure (QCE) must be a lease expenditure and related to exploration. Effective 1/1/2013, these credits are issued as one certificate. Effective 1/1/2014, there is no longer a QCE credit for North Slope expenditures.	Yes	Effective 1/1/2014, no QCEs on North Slope Pre-1/1/2014, QCEs allowed Statewide	15 AAC 55.310-320	Some expenditures may also qualify for credit under AS 43.55.023(b)		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(b)	Carried-Forward Annual Loss Credit	4/1/2006, amended 7/1/2007 & 1/1/2014	No expiration	Cook Inlet 25% North Slope 1/1/14-12/31/15 45% North Slope 1/1/16 forward 35% Statewide pre-7/1/07 25% Statewide pre-7/1/07 20%	The carried forward annual loss is calculated for each segment by taking 25% or 45% of excess lease expenditures (these expenditures not deductible in calculating production tax values). Effective 1/1/2013, these credits are issued as one certificate. Calendar years 2014-2014, North Slope losses have a 45% credit. After 2015, the credit is 35% for North Slope.	No	No	15 AAC 55.310-320	Some expenditures may also qualify for credit under AS 43.55.023(a), (f), or 025(a)(1-4)		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(f)(1)	Well Lease Expenditure Credit	7/1/2010	No expiration	40%	A Well Lease Expenditure (WLE) must be a lease expenditure, QCE, AND an Intangible Drilling and Development Cost (IDC) south of 68 degrees North latitude.	No	Yes - must be south of 68 degrees North latitude	None	Some expenditures may also qualify for credit under AS 43.55.023(b)		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(f)(2)	Well Lease Expenditure Credit in Relation to Exploration	7/1/2010	No expiration	40%	A Well Lease Expenditure (WLE) must be a lease expenditure, QCE, AND an Intangible Drilling and Development Cost (IDC) related to exploration south of 68 degrees North latitude.	Yes	Yes - must be south of 68 degrees North latitude	None	Some expenditures may also qualify for credit under AS 43.55.023(b)		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(f)(4)	Alternative Credit for Exploration	9/9/2003, amended 7/1/2008 & 1/1/2013	7/1/2016 for projects in North Slope and Cook Inlet; 1/1/2022 for "Middle Earth"	30% or 40% (pre-7/1/08 20% or 40%)	These credits are narrowly defined by both the statute and regulations as costs directly related to drilling an exploration well or performing a seismic shoot. An exploration well may receive either the 30% or 40% depending on location and seismic exploration may receive 40% credit.	Yes	For some of these credits there are distance requirements from other wells and units	15 AAC 55.350-380	Some expenditures may also qualify for credit under AS 43.55.023(b)		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(a)(5)	Alternative Credit for Exploration - Jack-up Rig	5/10/2010	7/1/2016	80%, 90%, or 100% (up to \$20, \$22.5 or \$25 million)	The qualified expenditures related to the first 3 unaffiliated wells drilled by the same jack-up rig in Cook Inlet pre-Tertiary zone qualify for this credit. The first well receives a 100% credit up to \$25 million, the second well receives a 90% credit up to \$22.5 million, and the third well receives a 80% credit up to \$20 million.	Yes	Yes - must be a jack-up rig in Cook Inlet	15 AAC 55.350-380	None of the expenditures included in this credit may receive a credit under any other section of this chapter.		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.023(a)(6) & (7)	Alternative Credit for Exploration - Frontier Basins	1/1/2013	7/2/2016	80% (up to \$25 million) for wells; 75% (up to \$7.5 million) for seismic	The first two exploration wells drilled inside each of six frontier basins receives 80% credit up to \$25 million of qualified expenditures. The first seismic project performed inside each of six frontier basins receives 75% credit up to \$7.5 million of qualified expenditures.	Yes	Yes - projects must be located in one of the six prescribed basins under AS 43.55.025(p)	15 AAC 55.350-380	None of the expenditures included in this credit may receive a credit under any other section of this chapter.		Application through ROL must be submitted to receive certificate as well as all backup required under regulation to support the credit claim. Credit against tax is reported on the return.	
AS 43.55.019	Education Credit	1987, amended 1/1/2011	Changes 1/1/2021, no expiration	Max of \$5,000,000	For cash donations to qualified educational institutes or foundations a portion of the donation may be taken as a credit against tax liability.	No	No	None	Credit may be in addition to all other credits	Applied directly to tax at 1/12 each month and may not be carried forward or transferred	Reported on the return - no form needed	
AS 43.55.023(i)	Transitional Investment ("TIE") Credit	4/1/2006, amended 1/1/2008	12/31/2013	20%	For taxpayers that did not have commercial production before January 1, 2008, a 20% credit for QCEs for the period April 1, 2001 to March 31, 2008 is allowed. This credit is limited to 1/10 of the QCEs incurred April 1, 2007 through December 31, 2007.	No	No	15 AAC 55.330	May not have received an AS 43.55.025 credit for the same expenditure	Applied directly to tax at 1/12 each month and may not be transferred or used after 2013.	Reported on the return - no form needed	
AS 43.55.024(a)	New Area Development ("Middle Earth") Credit	4/1/2008	Later of 12/31/2016 or the 9th calendar year after production started in Middle Earth (if started before 5/1/2016)	\$8,000,000	For production south of 68 degrees North latitude and outside of Cook Inlet (aka "Middle Earth"), a producer may take a credit of \$8,000,000 to offset tax liability. Expires 2016.	No	Yes - must be outside of Cook Inlet and south of the North Slope aka "middle earth"	15 AAC 55.335	Not for specific expenditures - credit may be in addition to all other credits	Applied directly to tax at 1/12 each month and may not be carried forward or transferred	Reported on the return - no form needed	
AS 43.55.024(c)	Small Producer Credit	4/1/2006	Later of 12/31/2016 or the 9th calendar year after production started (if started before 5/1/2016)	\$12,000,000	If the taxpayer produces less than 50,000 BTU equivalent barrels average daily production, then they may take the full \$12,000,000 credit. For production between 50,000-100,000 BTU equivalent barrels the credit is prorated. Expires 2016.	No	No	15 AAC 55.335	Not for specific expenditures - credit may be in addition to all other credits	Applied directly to tax at 1/12 each month and may not be carried forward or transferred	Reported on the return - no form needed	
AS 43.55.024(f)	Credit on GVR Oil	1/1/2014	No expiration	\$5 per bbl	A credit of \$5 per barrel is allowed based on oil produced that meets one of the criteria under AS 43.55.160(f) or (g).	No	Yes - must be north of 68 degrees North latitude (North Slope)	15 AAC 55.335	Not for specific expenditures - credit may be in addition to all other credits	Applied directly to tax at 1/12 each month and may not be carried forward or transferred	Reported on the return - no form needed	
AS 43.55.024(j)	Sliding Scale Credit	1/1/2014	No expiration	\$1-\$8 per bbl	A sliding scale credit of \$1-\$8 per barrel is allowed based on oil that does not meet the criteria under AS 43.55.160(f) or (g) when the monthly average Gross Value at the Point of Production is less than \$150.	No	Yes - must be north of 68 degrees North latitude (North Slope)	15 AAC 55.335	Not for specific expenditures - credit may be in addition to all other credits	Applied directly to tax at 1/12 each month DR actual amount earned each month and may not be carried forward or transferred	Reported on the return - no form needed	
AS 43.55.023(d)	Credit Certificate from AS 43.55.023(a), (f), or (b) credits		No expiration							Applied directly against tax liability may be taking all in one month & may be carried forward, transferred, split	Reported on the return - no form needed	
AS 43.55.025	Credit Certificate from AS 43.55.025 credits		No expiration							Applied directly against tax liability may be taking all in one month & may be carried forward, transferred, split	Reported on the return - no form needed	
AS 43.98	Film Tax Credits	7/1/2013 Effective for AS 43.55 Tax Liability	7/1/2023	N/A	A tax credit certificate is issued and may be applied against tax - Film Division issues the certificates	N/A	N/A	43.98.030	N/A	Applied directly against tax liability	Reported on the return - no form needed	offset taxes imposed under AS 21.09.210, AS 21.09.110, AS 43.29, AS 43.55, AS 43.59, AS 43.65, AS 43.75, and AS 43.77
AS 41.09.010	(DNR) Exploration Incentive Credits			N/A	DNR administers this credit (does not need to be on State leased land).	N/A	N/A	41.09.010 15 AAC 55.520(f)	N/A	Applied directly against tax liability	Reported on the return - no form needed	a payment or obligation against which a credit authorized by AS 38.05.180(i) may be claimed; taxes payable under AS 43.20; and oil and gas bonus payments due the state under AS 38.05.180(f).
AS 38.05.180(j)	(DNR) Exploration Incentive Credits			N/A	DNR administers this credit in leasing portion (must be on State leased land). A credit may not exceed 50 percent of the payment toward which it is being applied.	N/A	N/A	38.05.180 15 AAC 55.520(f)	N/A	Applied directly against tax liability	Reported on the return - no form needed	Credits may be applied against (1) royalty and rental payments for oil and gas or for gas only payable to the state or (2) taxes payable under AS 43.55.

Small Producer Credit	A credit of up to \$12 million for producers with less than 100,000 btu equivalent barrels per day. A credit for qualified contributions to vocational education programs or accredited Alaska universities or colleges.
Oil and Gas Producer Education Credit	Exploration Incentive Credits granted under AS 41.09.010
Exploration Incentive Credits under AS 41.09.010	Exploration Incentive Credits granted under AS 41.09.010
Film Tax Credits under AS 43.98	Film Tax Credits granted under AS 43.98
Exploration Incentive Credits under AS 38.05.180	Exploration Incentive Credits granted under AS 38.05.180
	Non Transferable Tax Credit that is not from the North Slope nor Cook Inlet, A.K.A. "Middle Earth."
New Area Development Credit	Alternative Tax Credit for Oil and Gas Exploration used (applied against tax) in the tax year.
Alternative Tax Credit for Exploration	Alternative Tax Credit for Oil and Gas Exploration that were not earned, rather transferred.
Transferred alternative tax credit certificates	
Transitional Investment Expenditure Credits	Credit for transition of investment expenditure. Carry-forward of a Qualified Capital Expenditure Credit from a prior period earned for expenditures
Carry-forward Qualified Capital Expenditure Credits from a prior year	
Qualified Capital Expenditure Credits earned during this period - Election to Apply a Tax Credit Against Oil and Gas Production Tax	Qualified capital expenditure credits earned during the reported month for expenditures.
Qualified Capital Expenditure Credits earned during this period - Geological or Geophysical Exploration	Qualified capital expenditure credits earned during the reported month for expenditures
Carry-forward Well Lease Expenditure Credit from a prior year	Carry-forward of a Well Lease Expenditure Credit from a prior year.
Well Lease Expenditure Credit- Election to Apply a Tax Credit Against Oil and Gas Production Tax	Well Lease Expenditure Credits earned this period.
Well Lease Expenditure Credit- Geological or Geophysical Exploration	Well Lease Expenditure Credits earned this period.
Carry-forward Annual Loss Credit from a previous year	Carry-forward Annual Loss Credit from a previous year
	Credits from Transferable Tax Credit Certificates under AS 43.55.023(d) as limited by AS 43.55.23(e)
Credits from Transferable Tax Credit Certificates	
Per Barrel Credit for Oil subject to the Gross Value Reduction	For North Slope Oil subject to the Gross Value Reduction
	For North Slope Oil not subject to the Gross Value Reduction.
Sliding Scale Production Credit	

43.55.024(c)
15 AAC 55.520(f)

43.55.019
15 AAC 55.520(f)
41.09.010
15 AAC 55.520(f)
43.98.030
38.05.180
15 AAC 55.520(f)

43.55.024(a)
15 AAC 55.520(f)

AS 43.55.025
15 AAC 55.520(f)

43.55.025
15 AAC 55.520(f)
43.55.023(i)
15 AAC 55.520(f)

43.55.023(a)
15 AAC 55.520(f)

43.55.023(a)(1)
15 AAC 55.520(f)

43.55.023(a)(2)
15 AAC 55.520(f)
43.55.023(l)
15 AAC 55.520(f)

43.55.023(l)(1)
15 AAC 55.520(f)
43.55.023(l)(2)
15 AAC 55.520(f)
43.55.023(b)
15 AAC 55.520(f)

43.55.023(d)
15 AAC 55.520(f)

43.55.024(i)

43.55.024(j)

Title: **Production Tax Credits Detail FY 2007 to FY 2025**

Preparer: Mackenzie Merrill, Economist, 465-5636

Purpose: Provide detailed data on refunded production tax credits and production tax credits against liability historically from FY 07 to FY 15, and forecasted from FY 16 to FY 25; broken out by North Slope and Non-North Slope.

Date: 1/19/2016

Data Source: Fall 2015 Revenue Sources Book and supporting data/models.

Key Assumptions: All assumptions are as of the Fall 2015 Revenue Sources Book. Also see notes and comments embedded in the spreadsheet.

History: This version incorporates the Fall 2015 forecast numbers and, based on updated analysis, includes slight revisions to the geographic location of refunded credits in FY 2009 through FY 2012.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Table B-4: Detail on Historical Production Tax Credits and Forecast

(\$Millions)	Historical								Preliminary FY 15 ¹	Forecast ²								
	FY 07	FY 08	FY 09	FY 10	FY 11	FY 12	FY 13	FY 14		FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24
Refunded Credits³																		
North Slope																		
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b)	55	*	173	223	399	267	*	*	203	224	360	199	89	50	50	50	50	50
Credits under AS 43.55.025 ⁴	0	*	14	23	12	53	*	*	21	0	0	0	0	0	0	0	0	0
Total North Slope	55	53	187	246	411	320	261	281	224	224	360	199	89	50	50	50	50	50
Non-North Slope																		
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b); Well lease expenditure, AS 43.55.023(l)	0	*	*	*	*	29	*	*	384	268	210	136	125	166	167	197	198	198
Credits under AS 43.55.025 ⁴	0	*	*	*	*	4	*	*	21	8	8	7	5	4	3	3	2	2
Credits under AS 43.20 ⁵	0	*	*	*	*	0	*	15	0	0	45	30	30	30	30	0	0	0
Total Non-North Slope	0	1	7	4	39	33	108	312	404	276	263	173	161	200	200	200	200	200
Total Refunded Credits	55	54	193	250	450	353	369	592	628	500	625	375	250	250	250	250	250	250
Credits Used Against Tax Liability^{6,7}																		
North Slope																		
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b)	292	219	279	339	313	306	486	332	0	40	52	1	0	0	0	0	0	0
Transitional investment expenditure: AS 43.55.023(i) ⁸	171	73	0	0	0	*	*	595	28	189	367	614	625	703	671	613	584	543
Per taxable barrel credit, AS 43.55.024(i)-(j) ⁹	*	*	*	*	*	*	*	*	*	37	43	37	48	42	36	27	19	5
Small producer credit, AS 43.55.024(a)(c)	*	*	*	*	*	*	*	*	*	0	0	0	0	0	0	0	0	0
Credits under AS 43.55.025 ⁴	*	*	*	*	*	*	*	*	*	0	0	0	0	0	0	0	0	0
Total North Slope	541	368	328	402	345	347	536	907	655	105	284	405	662	666	739	698	632	589
Non-North Slope																		
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b); Well lease expenditure, AS 43.55.023(l)	*	*	0	*	11	*	*	*	*	17	23	23	23	22	22	21	20	30
Small producer credit, AS 43.55.024(a)(c)	*	*	6	*	6	*	*	*	*	0	0	0	0	0	0	0	3	6
Total Non-North Slope	16	10	6	10	17	16	14	12	9	17	23	23	23	22	22	21	23	36
Total Credits Used Against Tax Liability	557¹⁰	378	334	412	361	363	550	919	664	120	310	430	690	690	760	720	660	630
Total Credits North Slope	596	421	*	647	756	667	797	1188	879	329	644	604	752	716	789	748	682	639
Total Credits Non-North Slope	16	11	*	14	56	49	122	323	413	292	286	196	184	222	222	221	223	236
Total Statewide Production Tax Credits	\$612	\$432	\$526	\$662	\$811	\$716	\$918	\$1,511	\$1,292	\$620	\$936	\$805	\$940	\$940	\$1,010	\$970	\$910	\$880

Source: Fall 2015 Revenue Sources Book Backup

* An asterisk indicates that the data is confidential.

¹ These numbers are preliminary pending Annual Returns.

² Forecasted refunded credits are rounded to the nearest \$5 million. Forecasted credits against liability are rounded to the nearest \$10 million.

³ Forecasted refunded credits in the near-term are based on known projects and company activities. For FY 2020 and beyond, the forecast of credits available for refund is held constant at \$250 million per year.

⁴ Credits under AS 43.55.025 include the Alternative Credit for Exploration, the Frontier Basin Credit, and for Cook Inlet only the the Cook Inlet Jack-up Rig Credit.

⁵ Credits under AS 43.20 include the Gas Exploration and Development Credit, Gas Storage Facility Credit, the In-State Gas Refinery Credit, and the LNG Storage Facility Credit.

⁶ The Education Credit, AS 43.55.019, though not reported in its own credit category in the summary was less than \$1 million in each year reported and is calculated in the total.

⁷ For historical credits against tax liability, geographic location was determined by attributing all .023(l) credits to Non-North Slope, all .025 Credits to North Slope, and the other credits were placed according to where the company primarily operated. Since multiple companies had operations in multiple areas, these numbers should be treated as rough estimates.

⁸ The Transitional Investment Expenditure Credit sunset on Dec 31, 2013.

⁹ For FY 2014, the Per Taxable Barrel Credit is for only the last six months of the fiscal year. Credits applied against liability in the forecast are reduced because of the 4% minimum gross tax.

¹⁰ Three months of 2006 credits data are included in the FY 2007 credits used against tax liability number.

Title: **Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land**

Preparer: Dan Stickel, Assistant Chief Economist, 465-3279

Date: 3/4/2016

Purpose: To provide a summary of applicability of royalty and taxes for land with various geographic location and ownership.

Data Source: All information is per state and federal law.

Key Assumptions: All laws in place as of March 2016.

History: This is the first version of this document.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land

Prepared 3/4/16 by Dan Stickel

Land status	Revenue component			
	Production tax / credits	Royalty	Corporate Income Tax	Property Tax
Offshore beyond 6 miles - Federal OCS	Do not apply	Federal royalties applies; zero shared back to state (in Alaska; other states do receive shared royalties)	Not included in apportionment factor	Does not apply
Offshore 3-6 miles - Federal OCS 8(g) area	Do not apply	Federal royalties applies; 27% shared back to state with no restrictions	Not included in apportionment factor	Does not apply
State lands	All credits available; tax applies to all taxable production	State royalty applies	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
NPR-A - federal owned	All credits available; tax applies to all taxable production	Federal royalty applies; 50% of royalties are shared back to state but must be used for benefit of local communities	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
ANWR	All credits available; tax applies to all taxable production	Federal royalty applies; 90% shared back to state with no restrictions (under current law)	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
Other federal land	All credits available; tax applies to all taxable production	Federal royalties applies; 90% shared back to state with no restrictions	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
Private land (including Alaska Native Corporation)	All credits available; tax applies to all taxable production	Privately negotiated royalty applies; not shared with state. However state levies 5% gross tax on the value of private landowner royalty interest as part of production tax	All property, production, and sales included in apportionment factor	Applies to all oil and gas property

Notes:

Offshore submerged lands in the 0-3 miles category treated same as similar onshore land.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Revenue

TAX DIVISION

Juneau Office
333 Willoughby Ave, 11th Floor
Juneau, AK 99801
Main: 907.465.2320
www.tax.alaska.gov

February 2, 2016

The Honorable Paul Seaton
Alaska State Representative
State Capitol Room 102
Juneau AK 99801

Representative Seaton,

This letter is in response to a request you made on January 7, 2016 for a second set of revisions to our analysis of a hypothetical North Slope oil project. You requested that we modify one of the net present value tables at the end of the analysis to reflect not only total State/muni revenue, but to also include an approximation of general fund unrestricted revenue. This modification is shown along with a note about the amount of property tax the State gets from North Slope upstream property tax. We have also added graphs showing total production tax to the State over the life cycle of GVR-eligible and non-GVR eligible fields. And lastly, we added net present value totals for the State/muni revenue and for the State production tax to the bottom of each of the life cycle revenue graphs. For the net present value analyses, we used 6.15% as the discount rate, which was the earnings rate for the Permanent Fund Corporation in September 2015.

It is also important to know that the entire analysis was prepared using real 2015 dollars, and assumes no inflation for oil prices or costs.

Analysis requested, assumptions, and description of attached graphs

This letter is in response to your request to the Department of Revenue on January 26, 2015 for modeling of a hypothetical North Slope oil project. Specifically, you requested the following:

An analysis of a new projected lease on a North Slope field producing 15,000 b/d, what would be the potential state investment over 10-year development phase with net operating loss credits if the company had no other production in the state? What is the projected net revenue or loss to the state over the life of the field? Please provide this analysis at oil prices of \$50, \$60, \$80 and \$100.

Thank you for allowing us to make use of the interim to prepare this analysis. Based on the above request, this analysis assumes the development of known resources from a North Slope oil field by a company that has no other business activity in the state. The oil field is a standalone field that is reasonably close to existing pipeline infrastructure. Over the 30-year life of the field, the company produces approximately 50 million barrels of technically and economically recoverable light conventional oil, with oil production peaking at 15,000 barrels per day.

Capital costs to develop the field total approximately \$900 million, or about \$18 per barrel, with most of the costs incurred early in the project life. Operating costs total \$750 million over the 30-year period, and average \$15 per barrel, although during peak production, operating costs are reduced to \$11-\$13 per barrel. These costs are in the range of a "normal field," although many of the fields on the North Slope left to develop likely have specific challenges that may make them more costly to develop. With respect to State revenue, more costly projects generally lower the overall take for the State, since any net operating losses would be greater and there would be fewer net profits on which to levy production tax.

We also assume that the company that develops the field receives cash refunds from the State for production tax credits received in excess of any production tax liability.

On the following pages are some of the results of the 30-year life cycle modeling given the assumptions above. Please note that the charts assume two classes of fields for production tax purposes: (1) Non-Gross Value Reduction fields, sometimes called "legacy" fields, which are presented in graphs 1-9; and (2) Gross Value Reduction (GVR) fields at the 20% GVR level, sometimes called "new" fields, presented in graphs 10-18. The end of the report includes a table showing net present values of total State/Municipal Revenues over the 30-year period, as well as an approximation of State General Fund Unrestricted Revenue (GFUR) over the 30-year period. The discount rate for the net present value calculations is the same as the Permanent Fund Corporation's September 2015 earnings rate of 6.15%.

I hope you find the enclosed analysis to be useful. Please do not hesitate to contact me if you would like further analysis or if you have any questions.

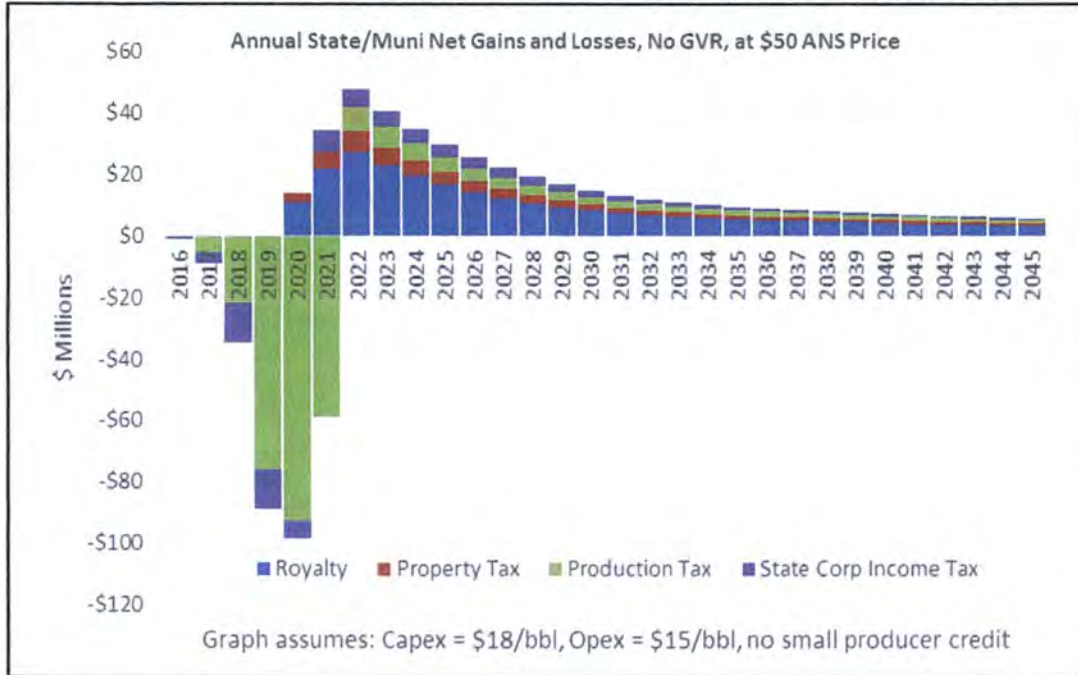
Sincerely,

A handwritten signature in blue ink, appearing to read "Ken Alper". The signature is fluid and cursive, with a long horizontal stroke at the end.

Ken Alper
Tax Division Director

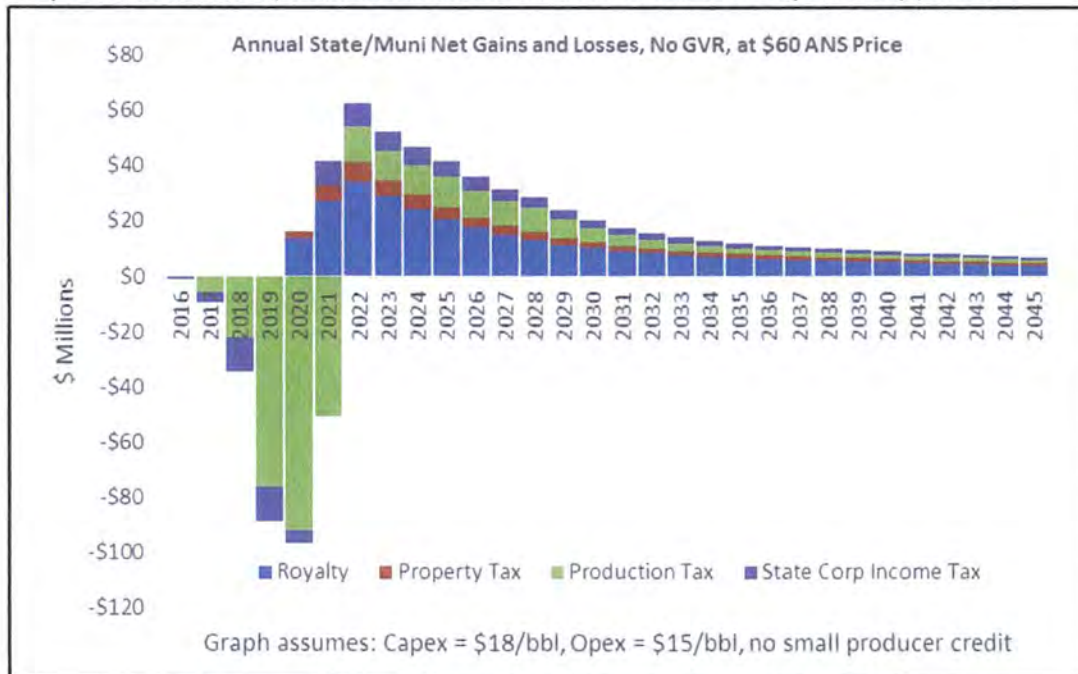
NO GVR, Legacy Fields Analysis

Graph 1: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$50 ANS



Total Annual State/Muni Losses = \$243 million
Total Annual State/Muni Gains = \$379 million
Net State/Muni Gain (Loss) = \$136 million
State/Muni NPV 0.0615 = \$-13 million

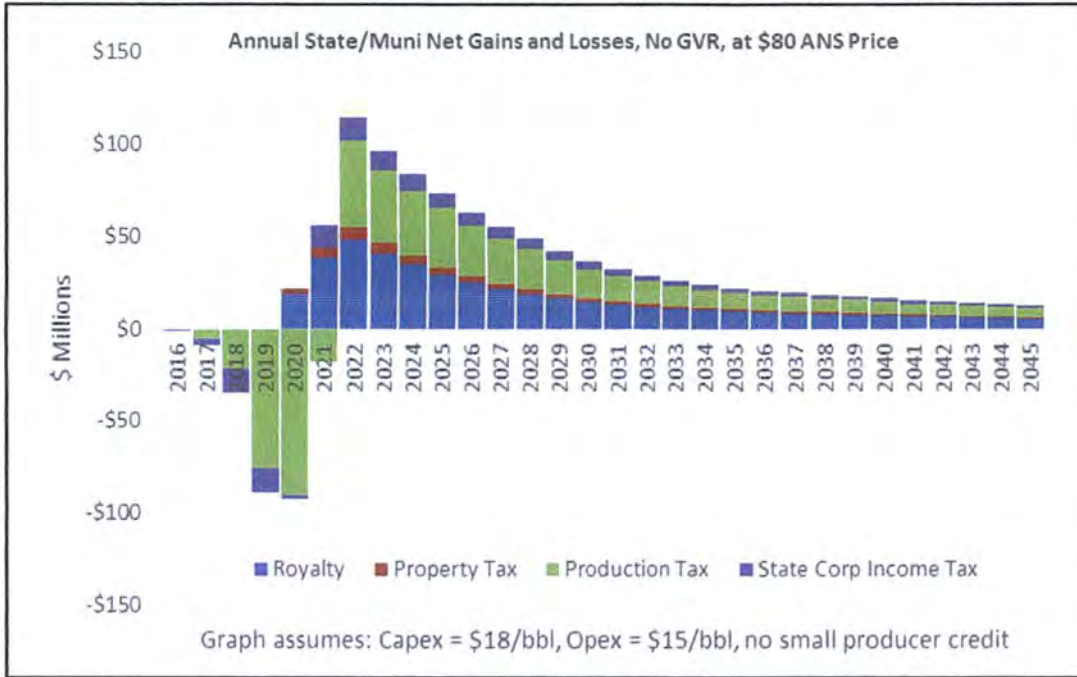
Graph 2: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$60 ANS



Total Annual State/Muni Losses = \$222 million
Total Annual State/Muni Gains = \$507 million
Net State/Muni Gain (Loss) = \$285 million
State/Muni NPV 0.0615 = \$63 million

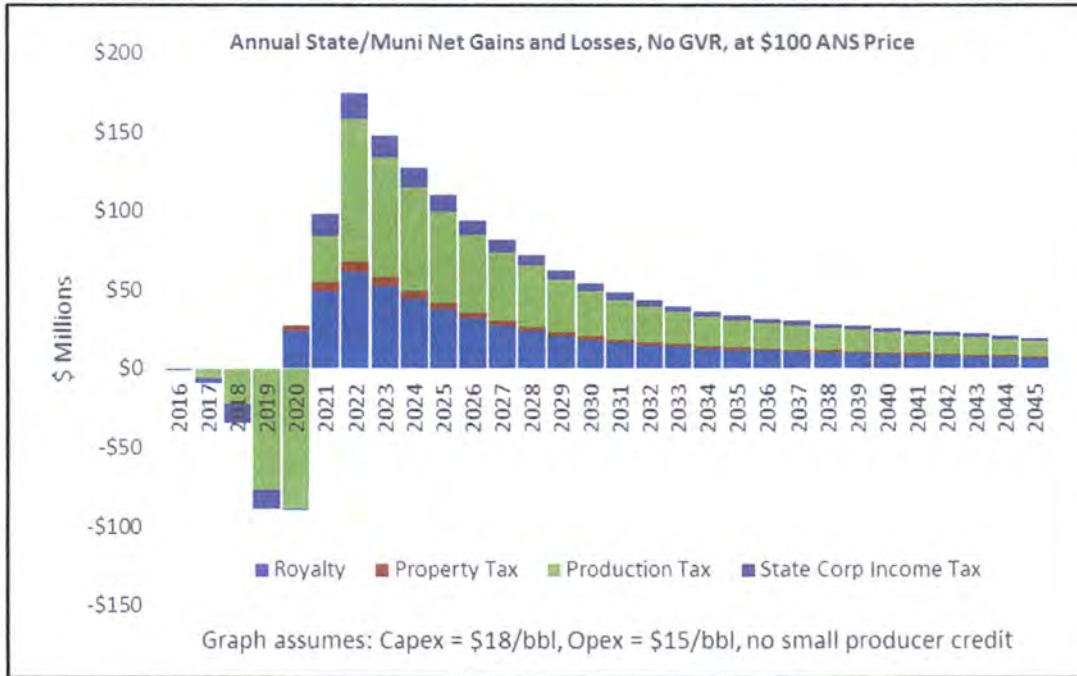
NO GVR, Legacy Fields Analysis

Graph 3: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$80 ANS



Total Annual State/Muni Losses = \$204 million
Total Annual State/Muni Gains = \$944 million
Net State/Muni Gain (Loss) = \$740 million
State/Muni NPV 0.0615 = \$288 million

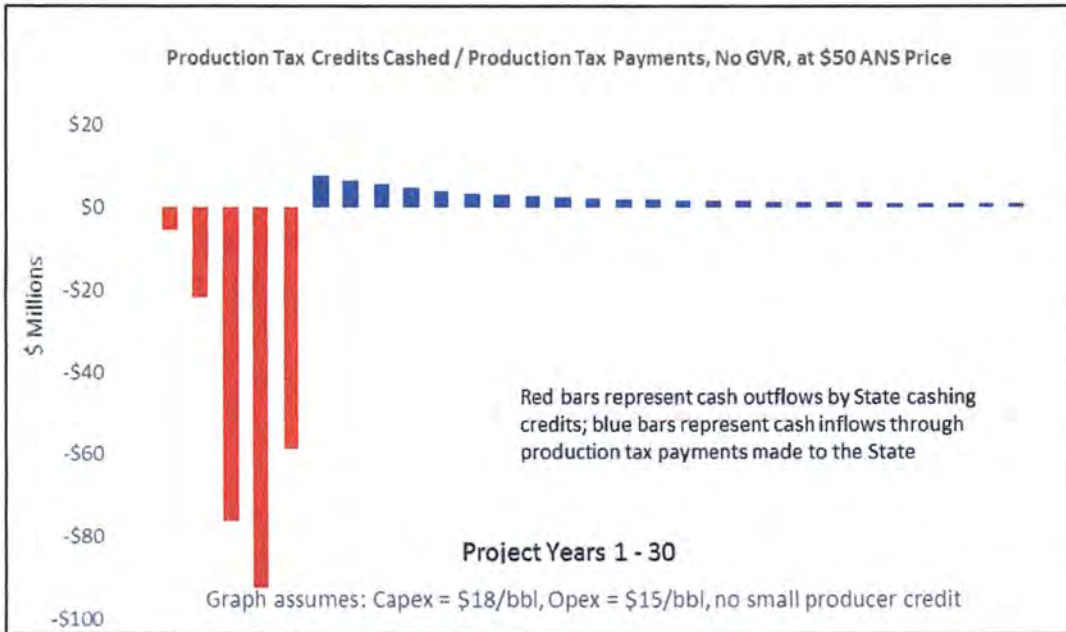
Graph 4: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$100 ANS



Total Annual State/Muni Losses = \$195 million
Total Annual State/Muni Gains = \$1481 million
Net State/Muni Gain (Loss) = \$1286 million
State/Muni NPV 0.0615 = \$556 million

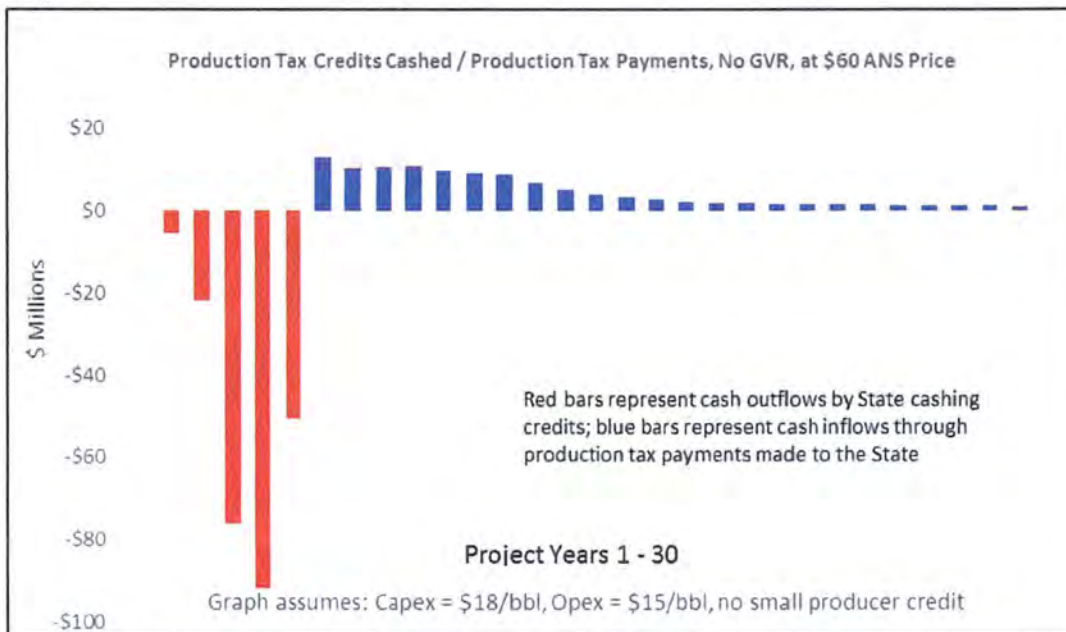
No GVR, Legacy Fields Analysis – Production Tax Specific

Graph 5: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$50 ANS



Production Tax Credits Used = \$254 million
Production Tax Paid = \$61 million
Net Production Tax = \$-194 million
Production Tax NPV 0.0615 = \$-165 million

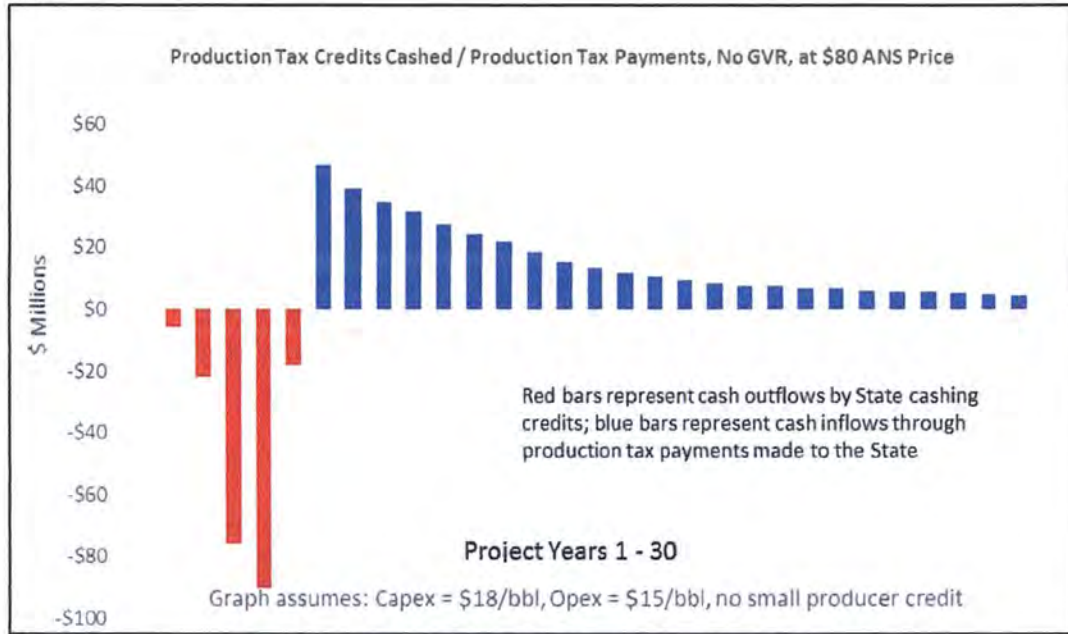
Graph 6: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$60 ANS



Production Tax Credits Used = \$245 million
Production Tax Paid = \$114 million
Net Production Tax = \$-132 million
Production Tax NPV 0.0615 = \$-132 million

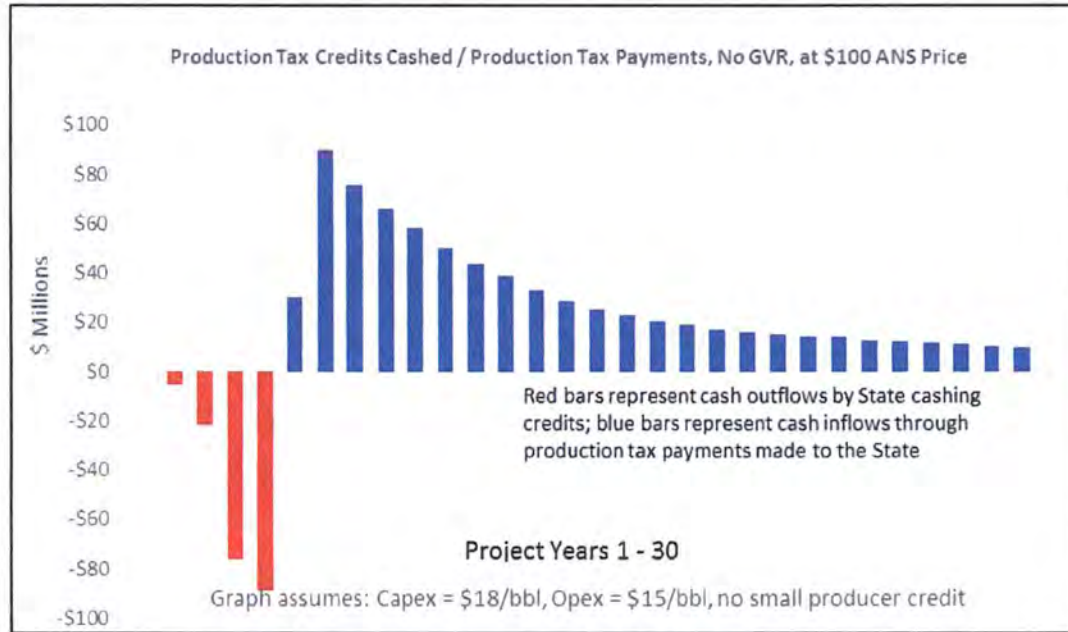
No GVR, Legacy Fields Analysis – Production Tax Specific

Graph 7: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$80 ANS



Production Tax Credits Used = \$211 million
Production Tax Paid = \$372 million
Net Production Tax = \$161 million
Production Tax NPV 0.0615 = \$13 million

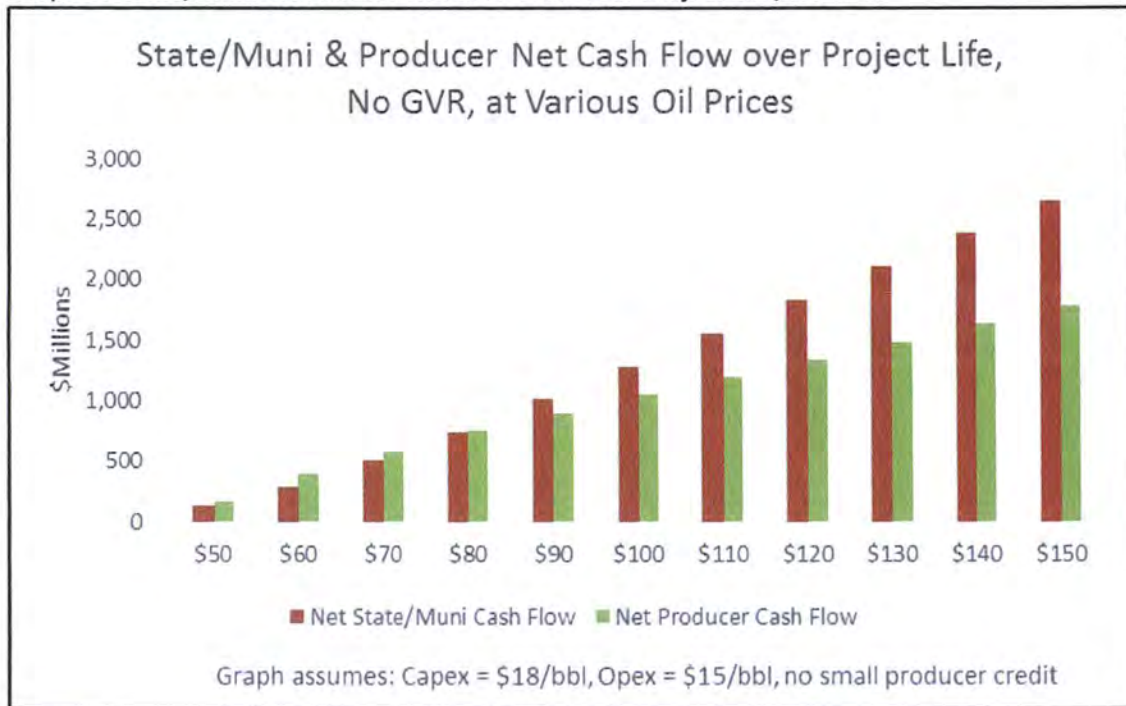
Graph 8: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$100 ANS



Production Tax Credits Used = \$192 million
Production Tax Paid = \$743 million
Net Production Tax = \$551 million
Production Tax NPV 0.0615 = \$204 million

NO GVR, Legacy Fields Analysis

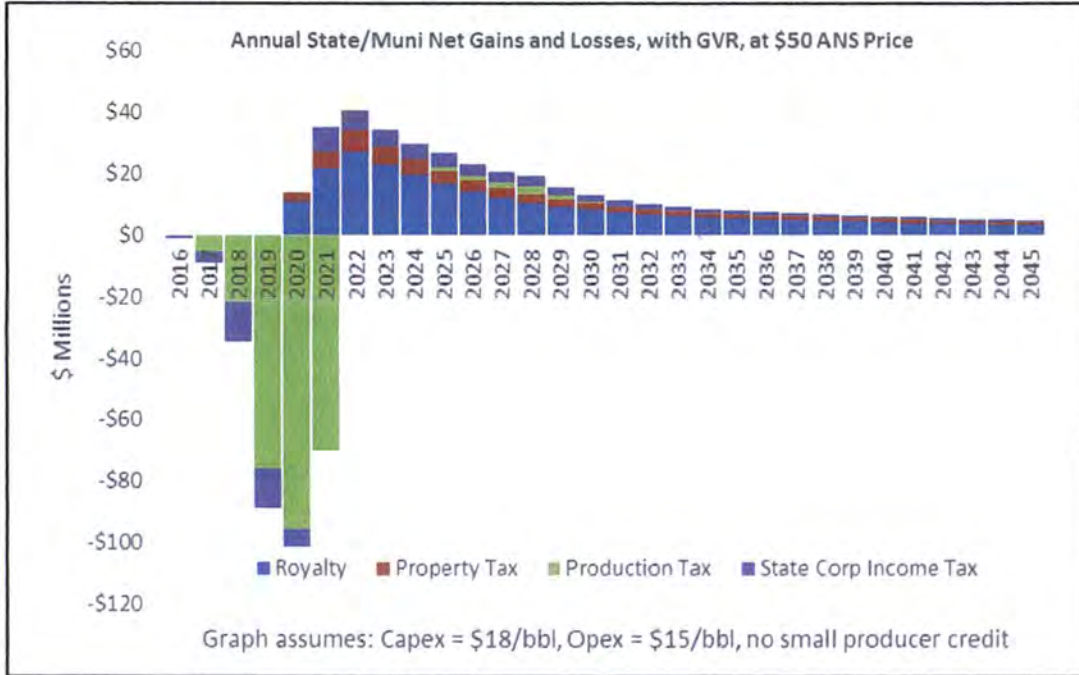
Graph 9: State/Muni & Producer Net Cash Flow over Project Life, No GVR



Please see the following pages for analyses of new fields receiving the Gross Value Reduction of 20%.

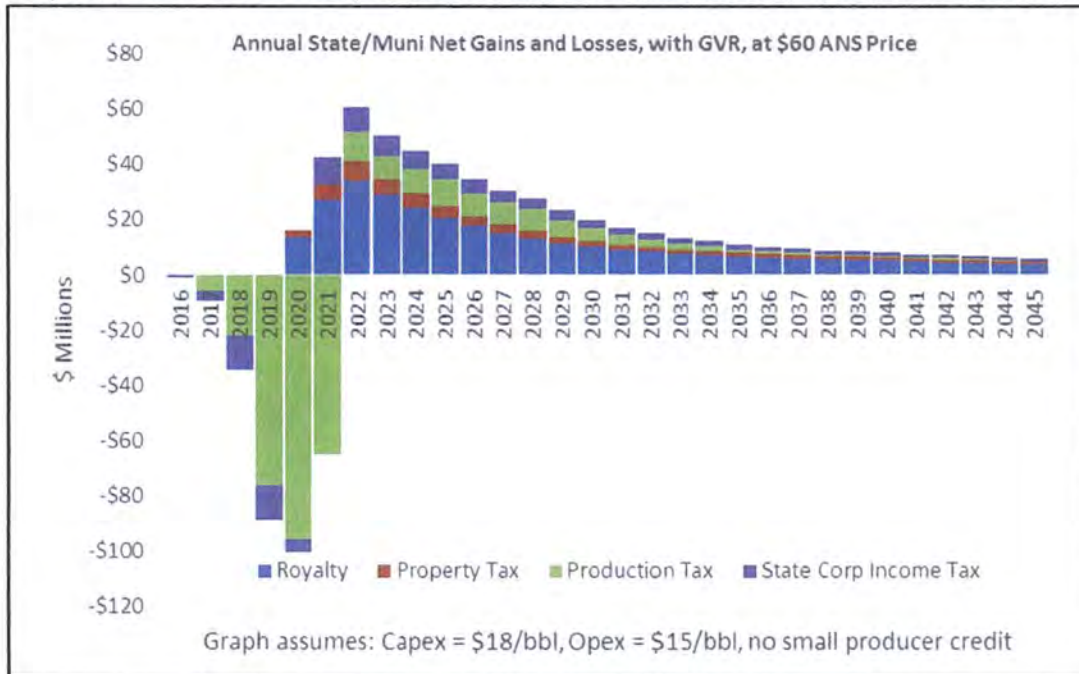
WITH 20% GVR, New Fields Analysis

Graph 10: Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$50 ANS



Total Annual State/Muni Losses = \$256 million
Total Annual State/Muni Gains = \$331 million
Net State/Muni Gain (Loss) = \$75 million
State/Muni NPV 0.0615 = \$-44 million

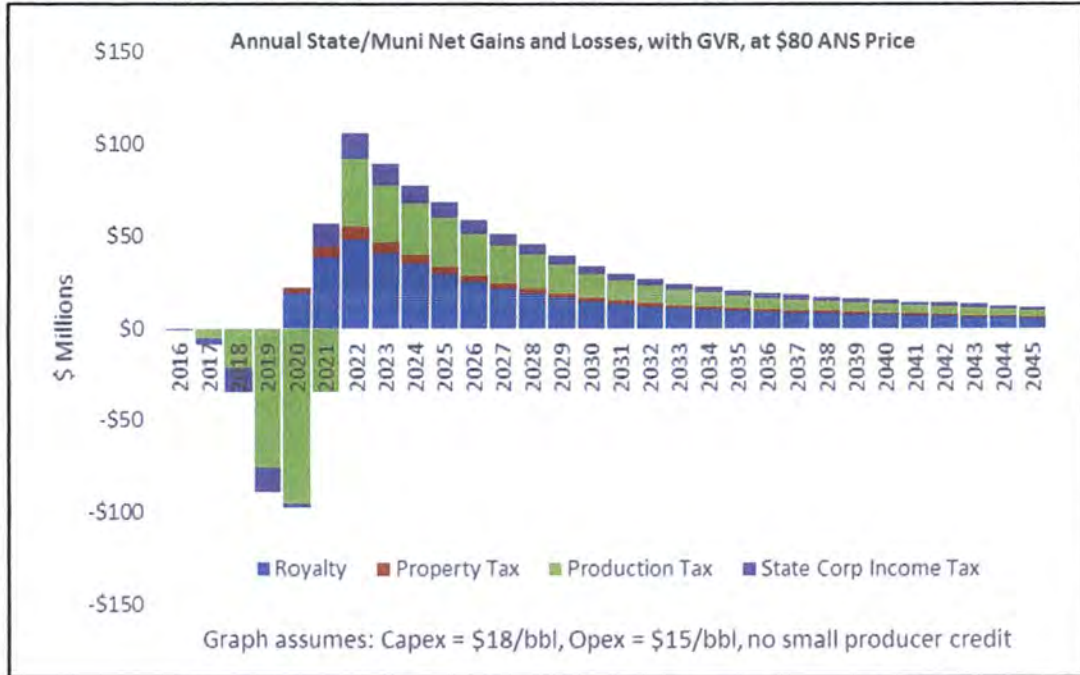
Graph 11: Total Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$60 ANS



Total Annual State/Muni Losses = \$239 million
Total Annual State/Muni Gains = \$483 million
Net State/Muni Gain (Loss) = \$244 million
State/Muni NPV 0.0615 = \$41 million

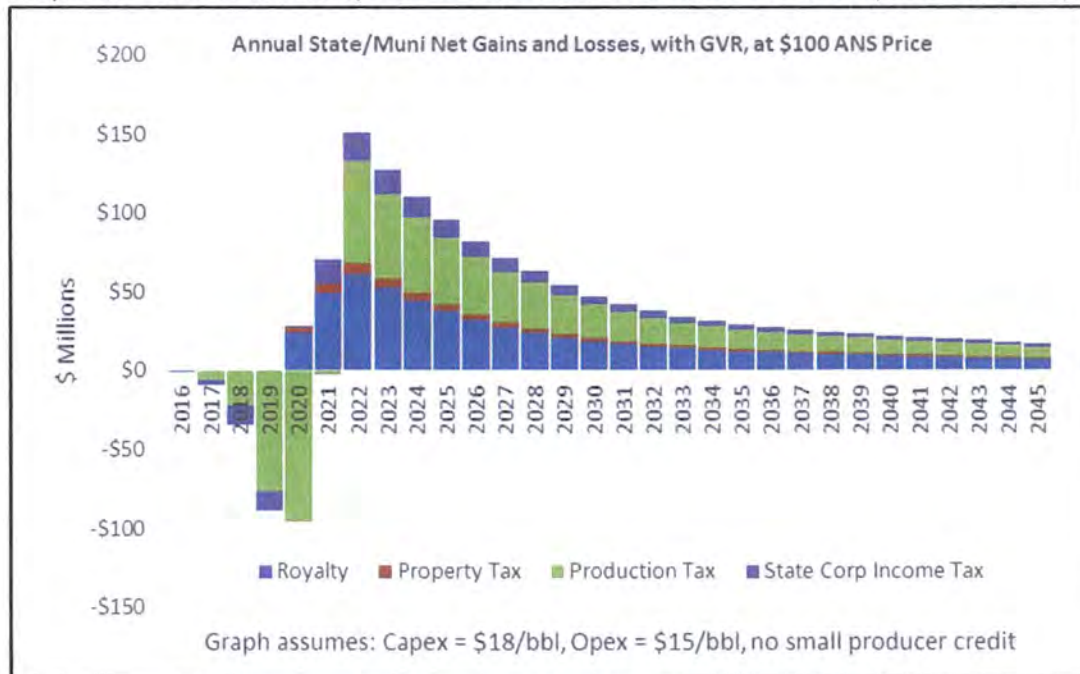
WITH 20% GVR, New Fields Analysis

Graph 12: Total Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$80 ANS



Total Annual State/Muni Losses = \$209 million
Total Annual State/Muni Gains = \$861 million
Net State/Muni Gain (Loss) = \$652 million
State/Muni NPV 0.0615 = \$242 million

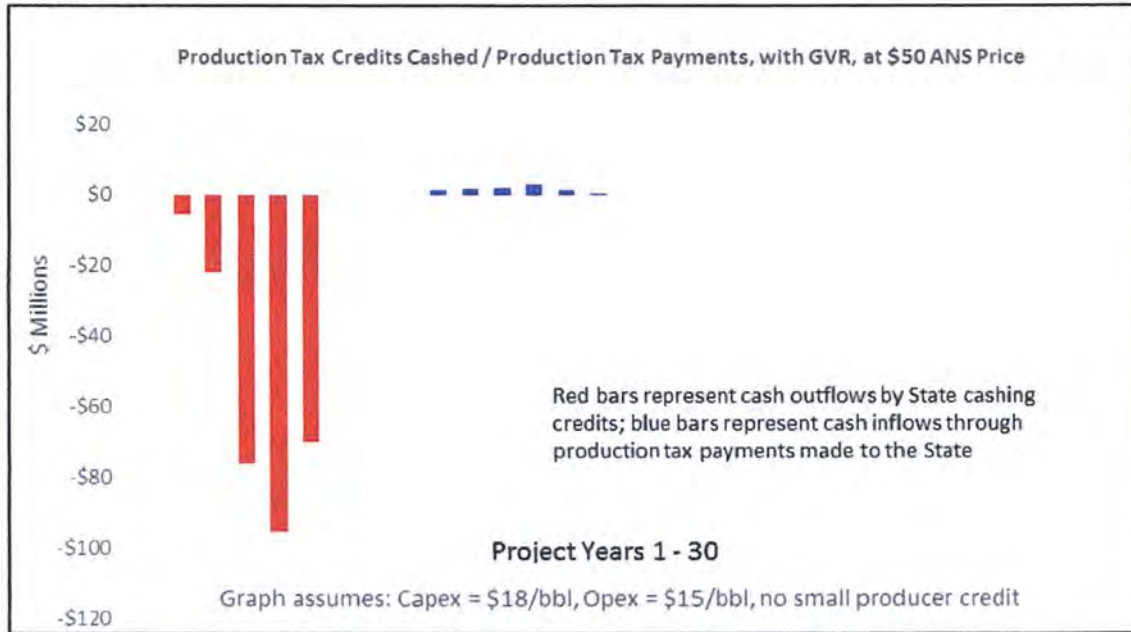
Graph 13: Total Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$100 ANS



Total Annual State/Muni Losses = \$201 million
Total Annual State/Muni Gains = \$1263 million
Net State/Muni Gain (Loss) = \$1062 million
State/Muni NPV 0.0615 = \$444 million

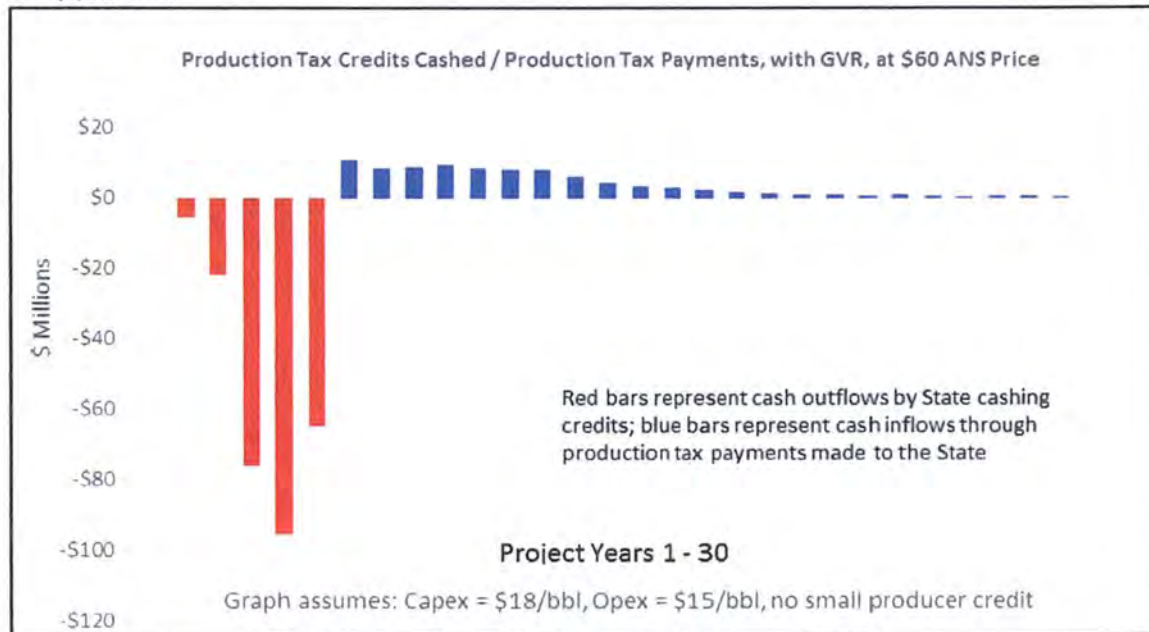
WITH 20% GVR, New Fields Analysis – Production Tax Specific

Graph 14: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$50 ANS



Production Tax Credits Used = \$269 million
Production Tax Paid = \$9 million
Net Production Tax = \$-260 million
Production Tax NPV 0.0615 = \$-198 million

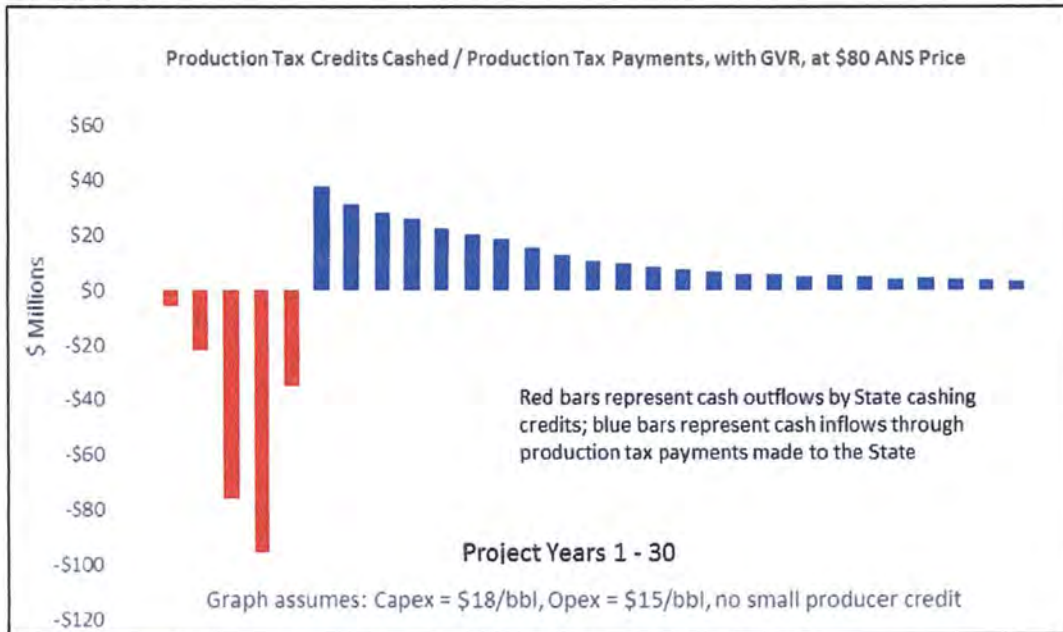
Graph 15: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$60 ANS



Production Tax Credits Used = \$264 million
Production Tax Paid = \$88 million
Net Production Tax = \$-175 million
Production Tax NPV 0.0615 = \$-155 million

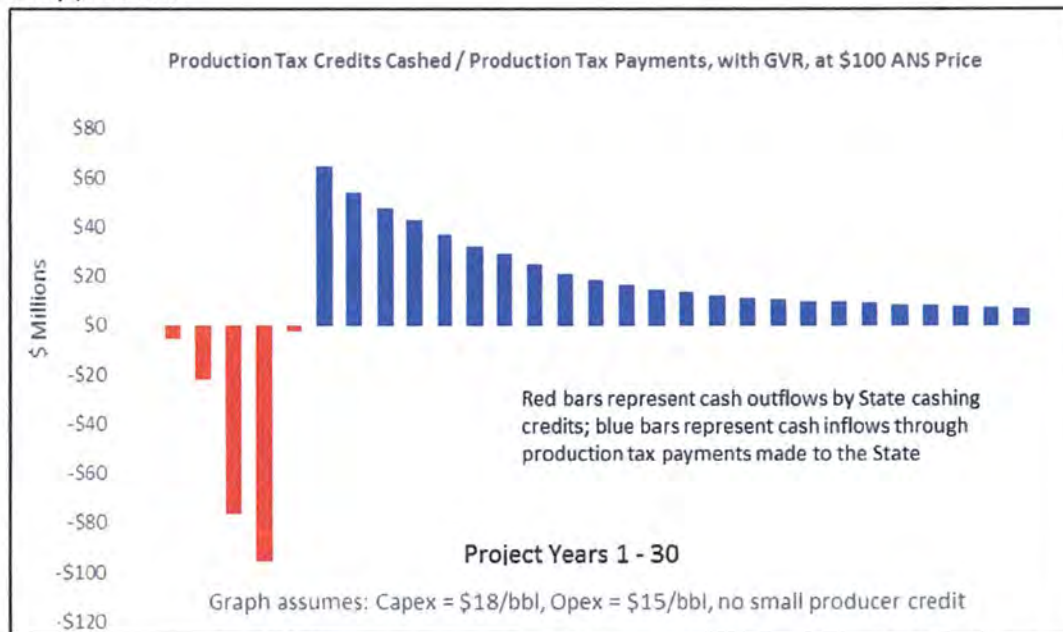
WITH 20% GVR, New Fields Analysis – Production Tax Specific

Graph 16: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$80 ANS



Production Tax Credits Used = \$234 million
Production Tax Paid = \$300 million
Net Production Tax = \$67 million
Production Tax NPV 0.0615 = \$-36 million

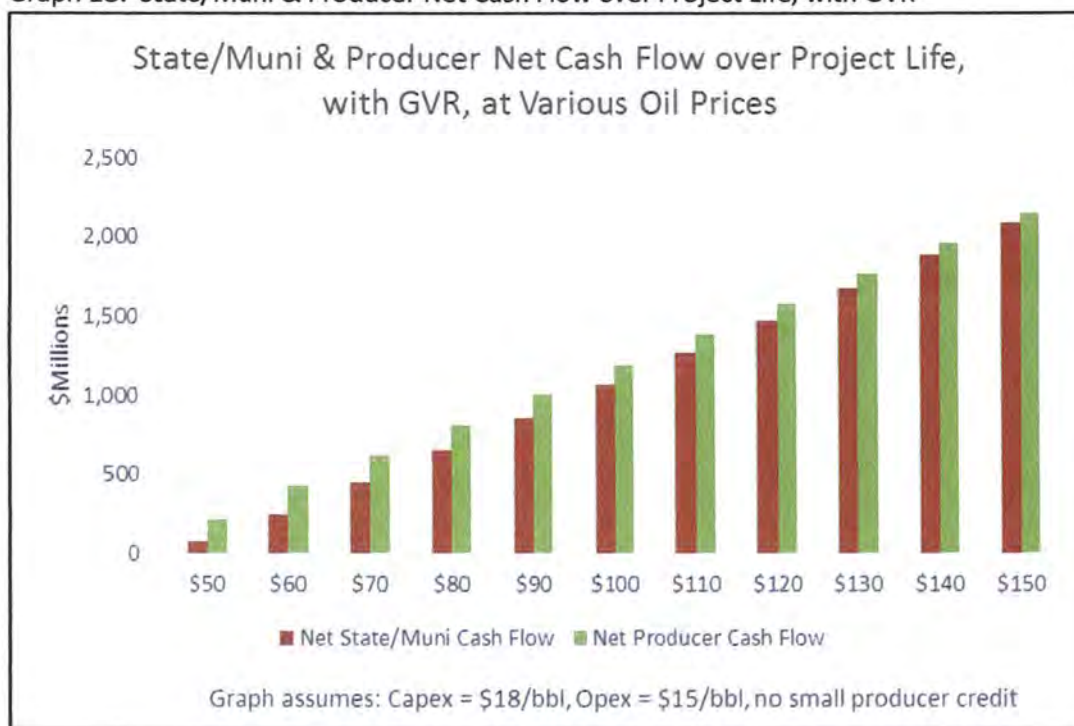
Graph 17: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$100 ANS



Production Tax Credits Used = \$201 million
Production Tax Paid = \$512 million
Net Production Tax = \$311 million
Production Tax NPV 0.0615 = \$84 million

WITH 20% GVR, New Fields Analysis

Graph 18: State/Muni & Producer Net Cash Flow over Project Life, with GVR



Net present values for State/Muni total revenues and an approximation of General Fund Unrestricted Revenue to the State at the prices you indicated for fields with no GVR and fields with a 20% GVR are shown below. Following that is a table with net present values for production tax only. The discount rate used in the analysis is 6.15% -- the earnings rate used Permanent Fund for investments as of September 2015.

Net Present Value of 30-Year Project Total Revenues to State/Muni at NPV6.15%

Oil Price	NO GVR	With 20% GVR	NO GVR	With 20% GVR
	State/Muni Total Revenues NPV 6.15% in \$Millions	State/Muni Total Revenues NPV 6.15% in \$Millions	GFUR* Approximation NPV 6.15% in \$Millions	GFUR* Approximation NPV 6.15% in \$Millions
\$50	-13	-44	-72	-103
\$60	63	41	-4	-26
\$80	288	242	205	160
\$100	556	444	459	346

Note: The values shown in columns two and three of this table include all State and muni revenues from this project, including all taxes (production, corp income and property), and and all royalties. The fourth and fifth columns are the same as the previous two columns, minus 25% of royalties and minus the municipal share of property tax (about 92.5%), approximating General Fund Unrestricted Revenue from the project. The State currently receives about 7.5% of property tax collected from North Slope properties.

**Net Present Value of 30-Year Project
Production Tax Only to State at NPV6.15%**

Oil Price	<u>NO GVR</u> <u>Production Tax</u> <u>Only</u> NPV 6.15% in \$Millions	<u>With 20% GVR</u> <u>Production Tax</u> <u>Only</u> NPV 6.15% in \$Millions
	\$50	-165
\$60	-132	-155
\$80	13	-36
\$100	204	84

Note: The values shown in this table include only production tax revenue.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Revenue

TAX DIVISION

Juneau Office
333 Willoughby Ave, 11th Floor
Juneau, AK 99801
Main: 907.465.2320
www.tax.alaska.gov

February 19, 2016

The Honorable Paul Seaton
Alaska State Representative
State Capitol Room 102
Juneau AK 99801

Representative Seaton,

This letter is in response to your request to the Department of Revenue on December 2, 2015 for life cycle modeling of a hypothetical Cook Inlet oil project. You indicated that you would like modeling of the development of an oil field similar in size to the 50 million barrel field that we modeled for the North Slope life cycle analysis provided to you in a letter dated November 5, 2015 (with subsequent updates containing additional requested information).

Like the development of oil fields on the North Slope, the method and cost to develop one oil field in Cook Inlet could be completely different than the method and cost to develop another. Among the largest influencing factors is whether the oil is located on land or offshore. Whereas some Cook Inlet fields can be developed with conventional drilling or with extended reach drilling methods, there are potential developments that require the installation of offshore drilling platforms. The method in which the field is developed will influence the cost of the project, and therefore it's economic viability. Our Cook Inlet modeling has been prepared with such cost variability in mind. Presented in this analysis is one set of assumptions about production and costs, but we can provide additional analyses as appropriate.

The analysis presented in this letter contemplates the development of known resources from a Cook Inlet oil field by a company that has no other business activity in the state. Over the 30-year life of the field, the company produces approximately 50 million barrels of technically and economically recoverable light conventional oil, with oil production peaking at 16,900 barrels per day. The field pays a 12.5% royalty rate.

Capital costs to develop the field total approximately \$600 million, or about \$12 per barrel, with most of the costs incurred early in the project life. Operating costs average \$20 per barrel and total \$1 billion over the 30-year period. The field is developed under the current Alaska production tax statutes for Cook Inlet oil, which includes credits for exploration, capital expenditures, well lease expenditures, net operating losses, and small producers. We assume that the company that develops the field receives cash refunds from the State for all production tax credits received in excess of any production tax liability. Current statutes also include Cook Inlet production tax limitations, which on oil are currently zero. These limitations are set to expire in

CY 2022, and our modeling incorporates that expiration date. All oil prices and oil development costs are in real 2016 dollars—that is, they are not adjusted in future years for inflation.

On the following pages are some of the results of the 30-year life cycle modeling given these assumptions. The end of the report includes a table showing Net Present Values (NPV) using the Permanent Fund's September 2015 earnings rate of 6.15% as a discount rate. NPV is shown for Total State and Municipal Revenues, General Fund Unrestricted Revenue to the state, and Total Production Tax Revenues (including credits) over the 30-year period.

I hope you find the enclosed analysis to be useful. Please do not hesitate to contact me if you would like further analysis or if you have any questions.

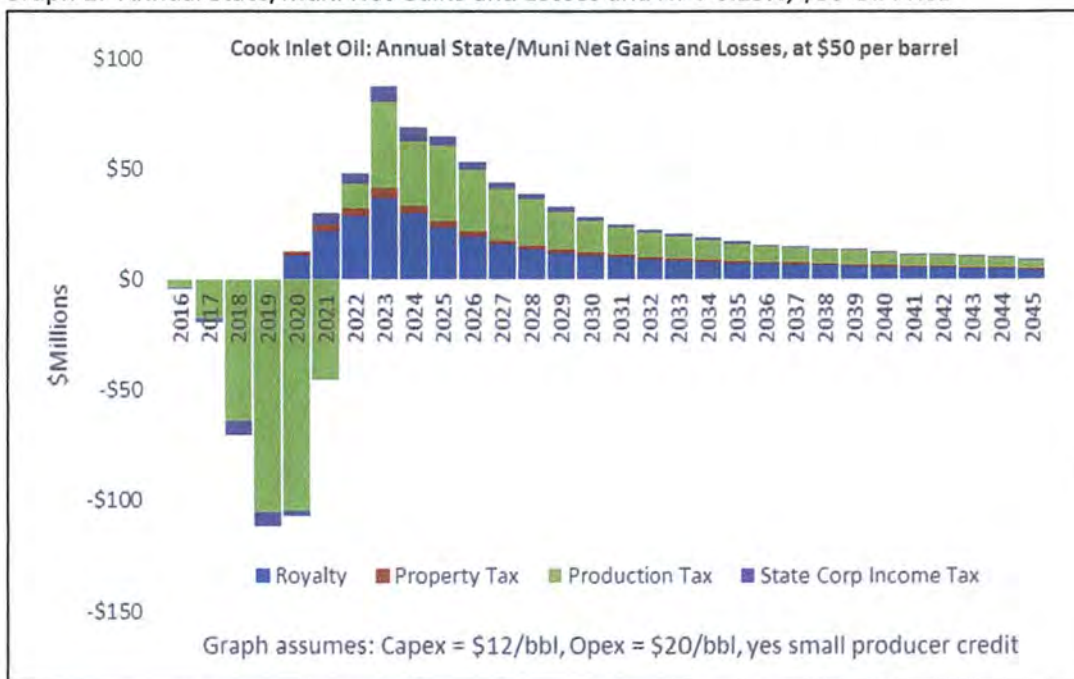
Sincerely,



Ken Alper
Tax Division Director

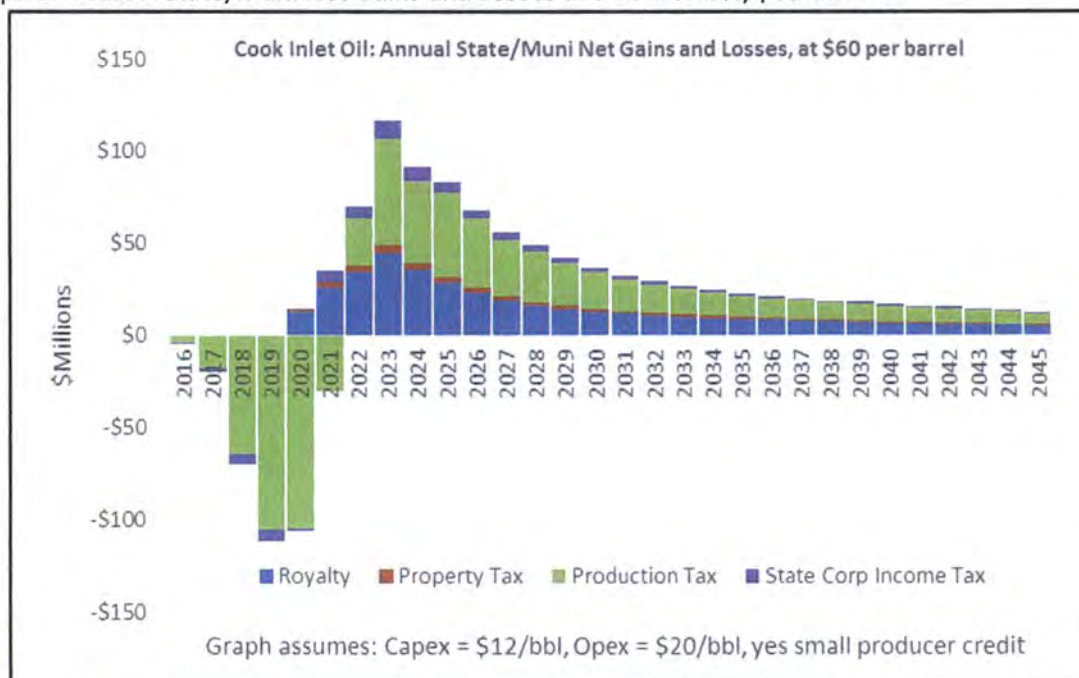
Cook Inlet Oil: Annual State/Muni Net Gains and Losses

Graph 1: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$50 Oil Price



Total Annual State/Muni Losses = \$316 million
Total Annual State/Muni Gains = \$691 million
Net State/Muni Gain (Loss) = \$375 million
Production Tax NPV 0.0615 = \$68 million

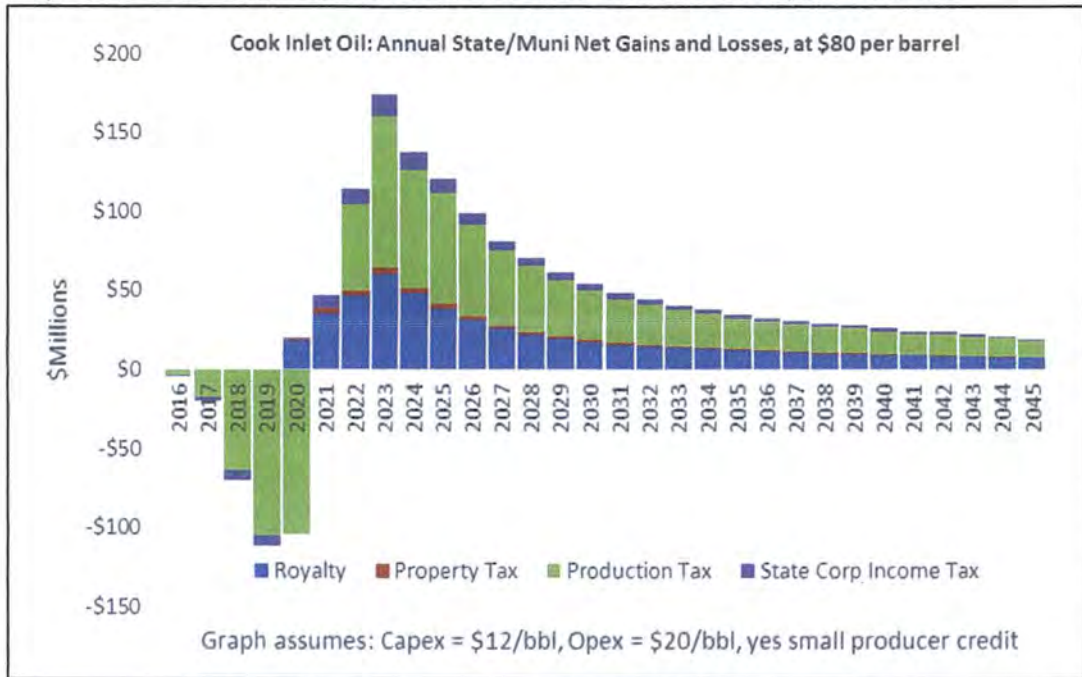
Graph 2: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$60 Oil Price



Total Annual State/Muni Losses = \$297 million
Total Annual State/Muni Gains = \$922 million
Net State/Muni Gain (Loss) = \$625 million
Production Tax NPV 0.0615 = \$190 million

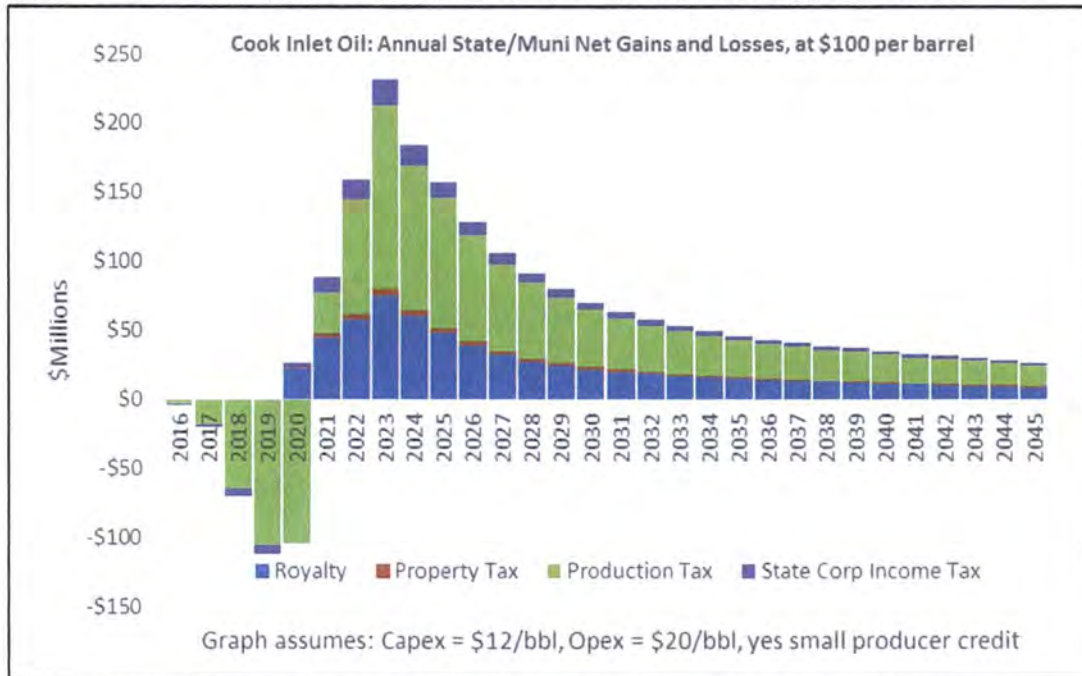
Cook Inlet Oil: Annual State/Muni Net Gains and Losses

Graph 3: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$80 Oil Price



Total Annual State/Muni Losses = \$290 million
Total Annual State/Muni Gains = \$1417 million
Net State/Muni Gain (Loss) = \$1127 million
Production Tax NPV 0.0615 = \$432 million

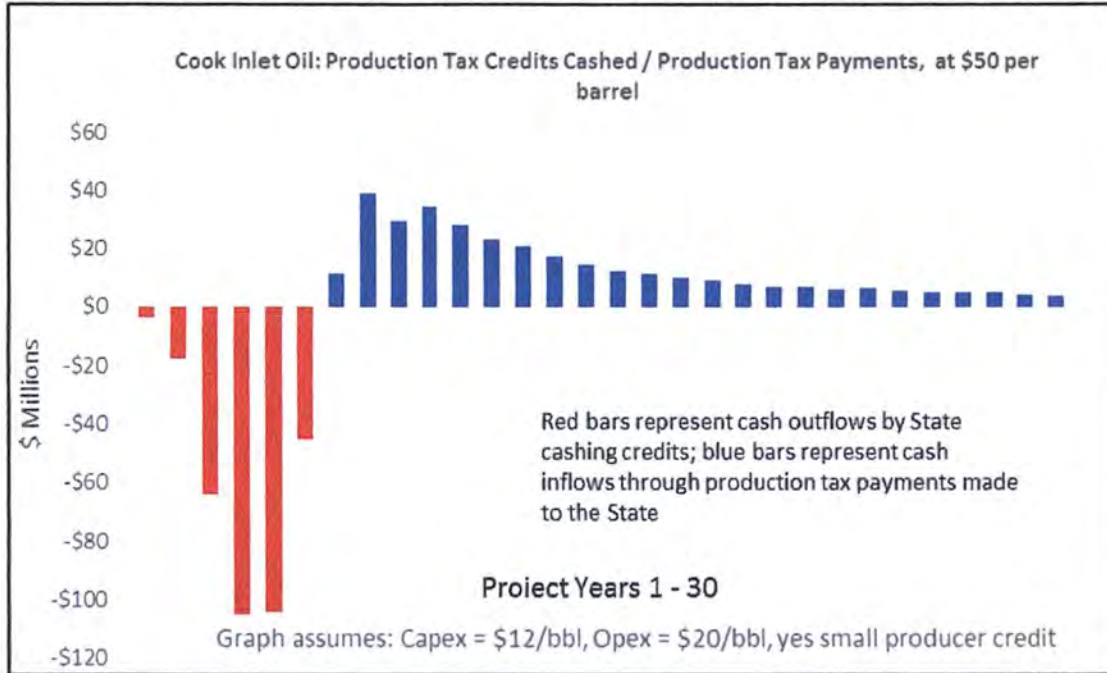
Graph 4: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$100 Oil Price



Total Annual State/Muni Losses = \$284 million
Total Annual State/Muni Gains = \$1911 million
Net State/Muni Gain (Loss) = \$1628 million
Production Tax NPV 0.0615 = \$674 million

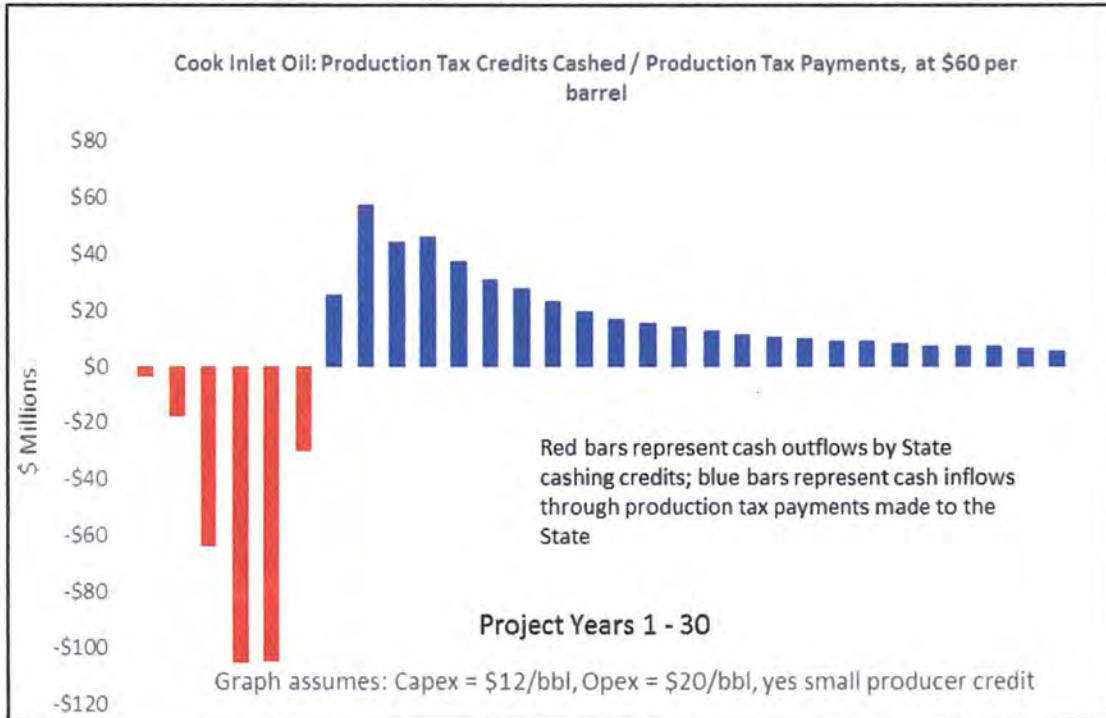
Cook Inlet Oil: Production Tax Credits Cashed and Payments

Graph 5: Production Tax Credits Cashed/Production Tax Payments and NPV 6.15%, \$50 Oil Price



Production Tax Credits Used = \$341 million
Production Tax Paid = \$317 million
Net Production Tax = \$-24 million
Production Tax NPV 0.0615 = \$-121 million

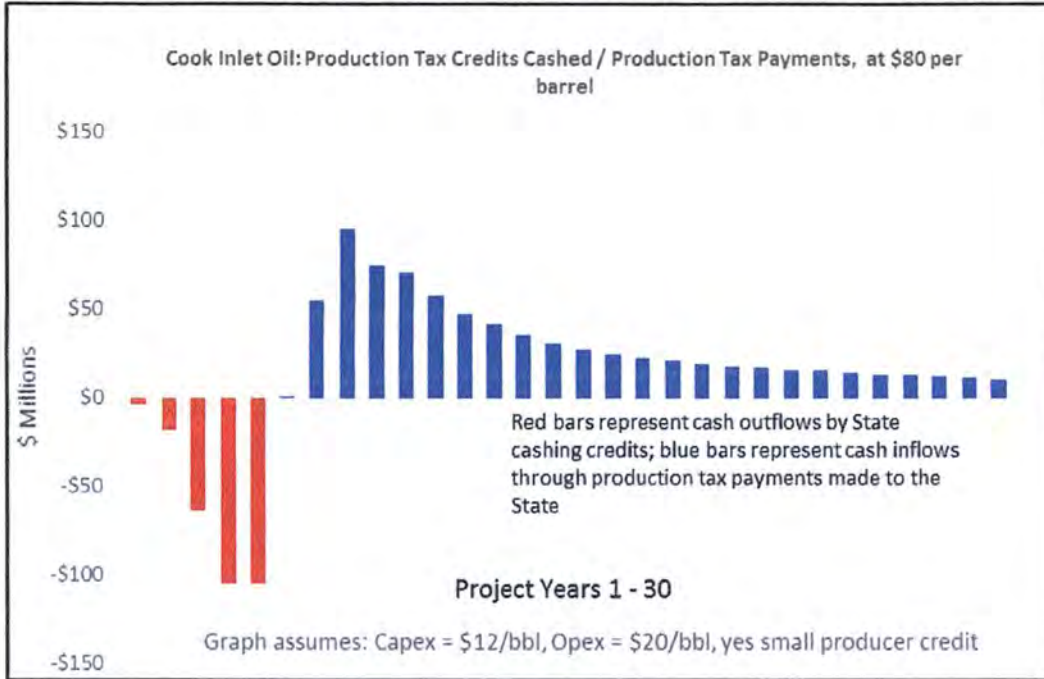
Graph 6: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, \$60 Oil Price



Production Tax Credits Used = \$326 million
Production Tax Paid = \$465 million
Net Production Tax = \$139 million
Production Tax NPV 0.0615 = \$-42 million

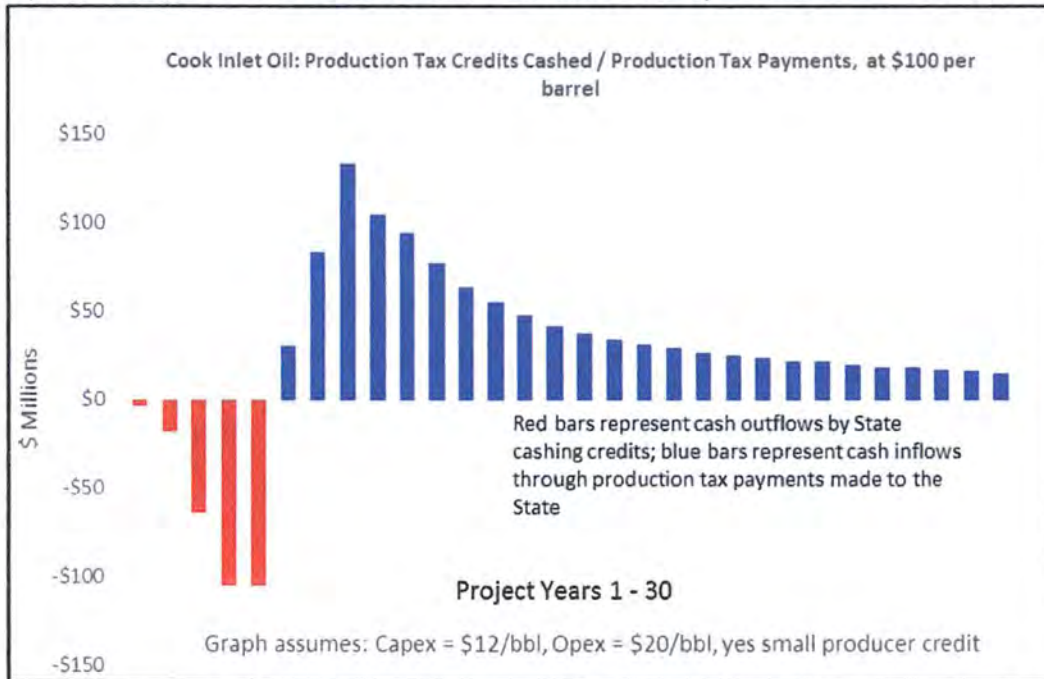
Cook Inlet Oil: Production Tax Credits Cashed and Payments

Graph 7: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, \$80 Oil Price



Production Tax Credits Used = \$296 million
Production Tax Paid = \$761 million
Net Production Tax = \$466 million
Production Tax NPV 0.0615 = \$115 million

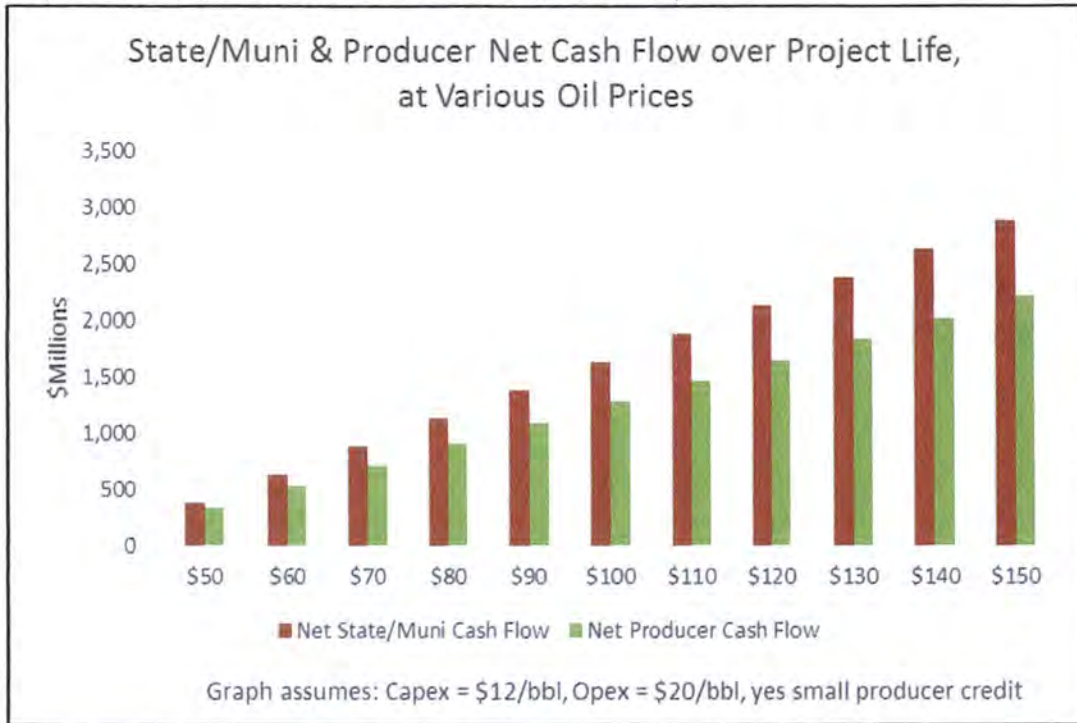
Graph 8: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, \$100 Oil Price



Production Tax Credits Used = \$296 million
Production Tax Paid = \$1088 million
Net Production Tax = \$792 million
Production Tax NPV 0.0615 = \$273 million

Cook Inlet Oil: Net Cash Flow over Project Life

Graph 9: State/Muni & Producer Net Cash Flow over Project Life



Net Present Value of 30-Year Project

Total Revenues to State/Muni at NPV6.15%

Oil Price	Producer Total	State/Muni	GFUR*	Production Tax
	Revenues NPV 6.15% in \$Millions	Total Revenues NPV 6.15% in \$Millions	Approximation NPV 6.15% in \$Millions	<u>Only</u> NPV 6.15% in \$Millions
\$50	120	68	20	-121
\$60	211	190	133	-42
\$80	393	432	359	115
\$100	576	674	585	273

Note: *The values shown in columns two and three of this table include all revenue from the project as divided between the Producer and the State/Muni. Total State/Muni revenue includes all taxes (production, corp income and property), and all royalties. The fourth column is the same as the third column minus 25% of royalties and minus the municipal share of property tax (about 49%), approximating General Fund Unrestricted Revenue revenue from the project. The State currently receives about 51% of property tax collected from Kenai Peninsula Borough properties.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Revenue

COMMISSIONER'S OFFICE
State Office Building
333 Willoughby Avenue, 11th Floor
PO Box 110400
Juneau, Alaska 99811-0400
Main: 907.465.2300
Fax: 907.465.2389

March 20, 2016

The Honorable Benjamin Nageak and the Honorable David Talerico
Alaska State Representatives
Co-Chairs, House Resources Committee
State Capitol Rooms 126 and 104
Juneau AK 99801

Dear Co-Chairs Nageak and Talerico,

The purpose of this letter is to provide you with responses to the questions asked of the Department of Revenue regarding House Bill 247 during our presentations to the House Resources Committee on March 7-8, 2016. Please see questions in italics and our responses immediately below the questions.

- 1. Clarify whether annual State revenues shown in conjunction with the life cycle modeling reflected all State revenues or only general fund unrestricted revenues and whether they reflected State and municipal property tax or only State property tax.*

The State revenues shown with the life cycle modeling include all State revenues, including restricted royalties, and only the State share of the property tax.

- 2. Provide individual and summary slides for life cycle modeling of the following:*
 - a. A field with a 1/6 royalty share and 30% GVR*
 - b. A field where a portion of the leases are privately owned*
 - c. A Cook Inlet gas development*
 - d. A field in "middle earth" including consideration of the LNG storage facility and refinery infrastructure credit*

Supplemental slides with the requested analysis are attached.

Note that for the Cook Inlet gas analysis, we created a representative cost and production profile that is similar in magnitude to a representative gas field presented by Analytica. For the "middle earth" analysis, we used this same Cook Inlet gas field profile, and simply applied the middle earth fiscal regime to that field. For middle earth, we did not directly account for LNG storage facility and refinery infrastructure credits. The reason for this is that the life cycle model is intended to model an upstream development from the standpoint of a producer, and these credits would likely fall outside the scope of any particular upstream development. They are, however, important components of the state's overall regime regarding oil and gas development.

3. *Provide the committee with land ownership and credits analysis as referenced by Director Alper in committee hearings.*

The requested analyses are attached. Note that the land ownership analysis is slightly revised from an earlier version provided to the committee. This analysis includes a simple model that enables the user to estimate the state's royalty revenue (and, if applicable, production tax on private royalties) for a given project.

We also include below a summary of the revenue from oil and gas operations on federal lands in Alaska. The table summarizes the revenue disbursed to the State of Alaska for its share of the revenues received by the federal government.

Federal Disbursements to Alaska for Oil and Gas Royalties			
Federal Land Designation	FFY 2013	FFY 2014	FFY 2015
Federal Offshore (8g)	\$2,940,962	\$2,519,780	\$1,957,767
Federal Onshore	\$15,695,140	\$17,624,835	\$16,200,909
Total Federal Disbursements	\$18,636,102	\$20,144,615	\$18,158,676

Source: Office of Natural Resources Revenue

4. *Provide an example of Section 18 of the bill applied to a 750 million barrel field. Also provide an example of Section 18 of the bill applied to a field with 1/6 royalty.*

The question was asked to determine the potential "upside" cost of the circumstance in which the Gross Value Reduction (GVR) is used to increase the size of a net operating loss (NOL) and associated credit. The examples below show how a \$10 per barrel loss couples with the 20% GVR and the 30% GVR scenarios to create even larger net operating losses for credit purposes. When multiplied by production of 100,000 taxable barrels per day, the size of the credit is increased substantially. Such scenarios could occur in an environment similar to our current one, in which oil prices sharply decline in a relatively short period of time. Specifically, the 20% GVR scenario could result in a NOL credit that equaled 56% of the actual loss, or \$77 million more than a NOL credit based on 35% of the actual loss. The 30% GVR scenario could result in a NOL credit that equaled 67% of the actual loss, or \$115 million more than a NOL credit based on 35% of the actual loss.

**750 mmbo Field - 20% GVR-Eligible Production increasing
 Size of a Net Operating Loss and Proposed Change***

	Current Law	Proposed Change
West Coast Price (\$/tax bbl)	\$40	\$40
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$30	\$30
Lease Expenditures (\$/tax bbl)	-\$40	-\$40
Net Value before GVR (\$/tax bbl)	-\$10	-\$10
Wellhead Value from above (\$/tax bbl)	\$30	\$30
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction (\$/tax bbl)	\$6	\$6
GVR-Adjusted Net Value (\$/tax bbl)	-\$16	-\$16
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$0.00	\$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	\$30	\$30
Minimum Tax (\$/tax bbl)	\$1.20	\$1.20
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$5	\$5
Production Tax after credits (\$/tax bbl)	\$0.00	\$0.00
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit (\$/tax bbl)	-\$5.60	-\$3.50
NOL per barrel times 100,000 taxable b/d (\$M)	-\$204	-\$128
Difference (\$M)		-\$77

*Assumes oil price decrease when field is producing at near peak rate. Proposed change here includes only changes to the law on the GVR creating or increasing a net operating loss.

**750 mmbo Field - 30% GVR-Eligible Production increasing
 Size of Net Operating Loss and Proposed Change***

	Current Law	Proposed Change
West Coast Price (\$/tax bbl)	\$40	\$40
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$30	\$30
Lease Expenditures (\$/tax bbl)	-\$40	-\$40
Net Value before GVR (\$/tax bbl)	-\$10	-\$10
Wellhead Value from above (\$/tax bbl)	\$30	\$30
Gross Value Reduction Rate (%)	x 30%	x 30%
Gross Value Reduction (\$/tax bbl)	\$9	\$9
GVR-Adjusted Net Value (\$/tax bbl)	-\$19	-\$19
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$0.00	\$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	\$30	\$30
Minimum Tax (\$/tax bbl)	\$1.20	\$1.20
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$5	\$5
Production Tax after credits (\$/tax bbl)	\$0.00	\$0.00
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit (\$/tax bbl)	-\$6.65	-\$3.50
NOL per barrel times 100,000 taxable b/d (\$M)	-\$243	-\$128
Difference (\$M)		-\$115

*Assumes oil price decrease when field is producing at near peak rate. Proposed change here includes only changes to the law on the GVR creating or increasing a net operating loss.

5. *Provide possible language for a revised Section 22 that would limit data collected to only what is currently collected.*

We have been working with the Department of Law and the Department of Natural Resources, Division of Oil and Gas, and have developed language that we believe will resolve the committee's concerns that the publicly released data is the same as what currently occurs.

The requested language was provided to the co-chair's staff on 3/14; a copy is attached with this memo. Please note that this revision substantially adds to the length of the current Section 22, because instead of referencing data sharing language in AS 43.55.025 it creates new language in AS 43.55.023.

Additional clarification from the hearings:

During our presentations, a question was asked regarding how costs are allocated between oil and gas production for tax calculation purposes, and was answered incorrectly. Per Department of Revenue regulation, in instances where allocation of lease expenditures is necessary, those lease expenditures are allocated based on BTU-equivalent barrels of oil produced.

I hope you find this information to be useful. Please do not hesitate to contact me if you have further questions.

Sincerely,



Randall J. Hoffbeck
Commissioner

Attachments:

- Supplemental Life-cycle modeling analysis slides
- Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land. with Royalty Revenue model
- Proposed rewrite of Sec. 22 of HB247, DNR data sharing and public release

Title: **Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land**

Preparer: Dan Stickel, Assistant Chief Economist, 465-3279

Date: 3/12/2016

Purpose: To provide a summary of applicability of royalty and taxes for land with various geographic location and ownership.

Data Source: All information is per state and federal law.

Key Assumptions: All laws in place as of March 2016.

History: This is the second version of this document; updated to clarify tax rate that applies to private landowner royalties for gas production.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Assumptions for Revenue Estimates	Price of Oil	\$50
	Transport Cost	\$10
	Volume in BBL / Day	10,000
	Royalty Rate	12.50%

Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land

Revised 3/12/16 by Dan Stickel

Land status	Revenue component				Royalty or Tax on Pvt. Royalty (revenue in \$millions)
	Production tax / credits	Royalty	Corporate Income Tax	Property Tax	
Offshore beyond 6 miles - Federal OCS	Do not apply	Federal royalties applies; zero shared back to state (in Alaska; other states do receive shared royalties)	Not included in apportionment factor	Does not apply	\$ -
Offshore 3-6 miles - Federal OCS 8(g) area	Do not apply	Federal royalties applies; 27% shared back to state with no restrictions	Not included in apportionment factor	Does not apply	\$ 4.9
State lands	All credits available; tax applies to all taxable production	State royalty applies	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 18.3
NPR-A - federal owned	All credits available; tax applies to all taxable production	Federal royalty applies; 50% of royalties are shared back to state but must be used for benefit of local communities	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 9.1
ANWR	All credits available; tax applies to all taxable production	Federal royalty applies; 90% shared back to state with no restrictions (under current law)	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 16.4
Other federal land	All credits available; tax applies to all taxable production	Federal royalties applies; 90% shared back to state with no restrictions	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 16.4
Private land (including Alaska Native Corporation)	All credits available; tax applies to all taxable production	Privately negotiated royalty applies; not shared with state. However state levies 5% (oil) or 1.667% (gas) gross tax on the value of private landowner royalty interest as part of production tax	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 0.9

Notes:

Offshore submerged lands in the 0-3 miles category treated same as similar onshore land.

AMENDMENT

OFFERED IN THE HOUSE

BY _____

TO: HB 247

1 Page 18, line 2:

2 Delete "section"

3 Insert "subsection"

4

5 Page 18, lines 3 - 10:

6 Delete all material and insert:

7 "(q) For a credit under this section,

8 (1) a producer or explorer shall comply with the notice and information
9 requirements in this subsection for lease expenditures incurred for

10 (A) a seismic survey, except that seismic data collected within the
11 boundaries of a unit by a producer in that unit is not subject to the notice and
12 information requirements of this subsection;

13 (B) an exploration or stratigraphic test well;

14 (2) a producer or explorer shall

15 (A) notify the Department of Natural Resources, within 30 days
16 after completion of seismic or geophysical data processing or completion of well
17 drilling, whichever is the latest, for which the lease expenditures are claimed, of
18 the date of completion and submit a report to the department describing the
19 processing sequence and providing a list of data sets available;

20 (B) provide to the Department of Natural Resources, within 30
21 days after the date of a request, unless a longer period is provided by the

1 Department of Natural Resources, specific data sets, ancillary data, and reports
2 identified in (A) of this paragraph; in this subparagraph,

3 (i) a seismic or geophysical data set includes the data for
4 an entire seismic survey irrespective of whether the survey area covers
5 nonstate land in addition to state land or land in a unit in addition to land
6 outside a unit;

7 (ii) well data includes all analyses conducted on physical
8 material, and well logs collected from the well, results, and copies of data
9 collected and data analyses for the well, including well logs; sample
10 analyses; testing geophysical and velocity data including seismic profiles
11 and check shot surveys; testing data and analyses; age data; geochemical
12 analyses; and tangible material;

13 (3) that, notwithstanding any provision of AS 38, information provided
14 under this subsection will be held confidential by the Department of Natural Resources,

15 (A) in the case of well data, until the expiration of the 24-month
16 period of confidentiality described in AS 31.05.035(c), at which time the
17 Department of Natural Resources will release the information after 30 days'
18 public notice unless, in the discretion of the commissioner of natural resources, it
19 is necessary to protect information relating to the valuation of unleased acreage in
20 the same vicinity, or unless the well is on private land and the owner, including
21 the lessor but not the lessee, of the oil and gas resources has not given permission
22 to release the well data;

23 (B) in the case of seismic or other geophysical data, for 10 years
24 following the completion date, at which time the Department of Natural
25 Resources will release the information after 30 days' public notice, except as to
26 seismic or other geophysical data acquired from private land, unless the owner,
27 including a lessor but not a lessee, of the oil and gas resources in the private land
28 gives permission to release the seismic or other geophysical data associated with
29 the private land;

30 (4) notwithstanding any contrary provision of AS 38, AS 40.25.100, or
31 AS 43.05.230, the following information is not confidential after the credit, based on the

1 lease expenditures, has been applied or, in the case of a transferable certificate, after the
2 certificate has been issued:

- 3 (A) the producer or explorer's name;
- 4 (B) the location of the well or seismic exploration;
- 5 (C) the date on which the information required to be submitted
- 6 under this subsection will be released."

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version:	CSHB 247(RES)
Fiscal Note Number:	3
(H) Publish Date:	3/23/2016

Identifier: CS HB247 (RES) 3-22-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: House Resources Committee

Department: Department of Revenue
 Appropriation: Taxation and Treasury
 Allocation: Tax Division
 OMB Component Number: 2476

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES	***	***	***	***	***	***	***	***
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits								
Miscellaneous								
Total Operating	***	***	***	***	***	***	***	***

Fund Source (Operating Only)

None								
Total	***	***	***	***	***	***	***	***

Positions

Full-time								
Part-time								
Temporary								

Change in Revenues	***	***	***	***	***	***	***	***
---------------------------	-----	-----	-----	-----	-----	-----	-----	-----

Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes
 If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

The House Resources Committee deleted the \$1.5 million in capital costs and adopted an indeterminate fiscal note. The updated fiscal note is one page.

Prepared By: Representative Nageak Phone: (907)465-3473
House Resources Committee Date: 03/22/2016
Representative Talerico
House Resources Committee

so much depends

upon

a red wheel

barrow

glazed with rain

water

beside the white

chickens.

That poem is by Dr. William Carlos Williams and is called The Red Wheelbarrow. When it was first published in 1923 it was determined to be revolutionary in its simplicity. I like it, even though I don't fully understand it.

Like the red wheelbarrow, the issue of oil tax credit reform is simple and so much depends on the Alaska State Legislature bravely passing oil tax credit reform as part of a sustainable fiscal plan. I support HB 247. I do not support CS HB 247 Resources. I hope what comes out of this committee is closer to HB 247 than CSHB 247.

So much depends on fixing this 800 million dollar problem. If we leave this tax credit system in place and wind up paying more for oil tax credits than we receive in oil tax income, Alaskan residents will be paying corporations their dividends, they will likely be paying corporations an income tax and they won't be happy not one bit.

So much for industry depends on a reasonable give and take here. Our economy cannot withstand \$800 million dollars a year in tax credit payments at this time. When our roads are full of potholes, our classroom sizes are increasing, our teachers are getting laid off, our public safety is underfunded, our fish and game harvest is restricted due to management cuts, and we are paying an income tax, how many years will it be before a legislative majority comes forward that will claw back lost revenue some how some way? Not many years I would think.

So much depends on a vibrant economy in Alaska and a healthy oil industry. Lets meet in the middle and come up with a plan. This spring.

Another famous poem, this one by William Butler Yeats, talks of "Turning and turning in the widening gyre", where "The falcon cannot hear the falconer"; and "Things fall apart; the centre cannot hold;"

The center here cannot hold. We cannot afford the current fiscal regime. We need to act this spring and part of this action needs to include reasonable modification of the oil tax credit system.

Thanks for your bravery and your hard work. So much is depending on it. It's national poetry month by the way.

Louie Flora

64535 Sheep Drive

Homer, AK 99603

HB-247 Public Testimony to House Finance on April 2nd, 2016

My Name is Bryan Clemenz, SVP at **Bristol Bay Industrial (BBI)**, testifying in opposition to HB 247.

BBI is a **Bristol Bay Native Corporation Company (BBNC)** which represents the Bristol Bay region, nearly equal in size to the state of Oklahoma. BBNC employs 4400 on the average and touches all markets in Alaska and beyond with business activities which include Construction, Government Service, Petroleum Distribution, Tourism, and, their largest market, Oilfield and Industrial Services. Our industrial service companies comprise the majority of BBNC's shareholder hire and wages. BBNC has dedicated more than 20% of their operating assets to this business line and intends to invest more provided a stable business investment climate prevails.

I represent **Bristol Bay Industrial (BBI)**, a wholly owned subsidiary of BBNC that is headquartered in Alaska. BBI's member companies, Kakivik Asset Management, CCI Industrial, and Peak Oil Field Service, are all based in Alaska and form one of the largest industrial presences in the state. BBI and its member companies together are the third largest oil and gas service provider in Alaska. Peak Oil Field Service Company alone is the third largest employer on the Kenai Peninsula. We excel in promoting Alaska content within our companies maximizing the economic benefits to Alaska and her people. We employ close to 1100 employees (168 Alaska Native hire), and we have invested nearly \$150 million in assets comprised of equipment, facilities and real estate primarily in Anchorage, Palmer, Nikiski, and the North Slope.

We have seen the tax policy work in Cook Inlet. It has provided a baseline business for companies like ours. Our current near term prospects are with developers and operators who have invested based on the current policy. These include new operators in the Cook Inlet area and "middle earth". The change jeopardizes the success of future development and the viability of our baseline business. BBNC and BBI are deeply committed to Alaska and investment in our industry, but the proposed bill creates fiscal uncertainty.

Alaska should maintain a policy that encourages investment and promotes a stable and durable tax structure. Regardless of differing views on industry tax structures today, stability is vital to endure. Business decisions require confidence in delivering predictable results. Changes would unquestionably bring yet another dimension of uncertainty diminishing our confidence in Alaska's commitment and policies.

BBNC is a significant investor in Alaska; and, like the oil companies or any business for that matter, we need certainty to remain committed for the long term. We ask that the State of Alaska also remain committed for the long term by promoting a stable pro-business policy. Don't change the rules, reject HB-247.

April 2, 2016

Representative Mark Neuman
Representative Steve Thompson
Representative Dan Ortiz

Gentlemen,

The Alaska Forest Association supports the current oil tax policy in Alaska

The Alaska Forest Association (AFA) is a non-profit business association that was formed in 1957 to represent the interests of the timber industry in Alaska. The AFA currently manages a pension program, a group health insurance program, a scholarship program for the timber industry and also sponsors the Sustainable Forestry Initiative program for Alaska.

According to the information provided by AOGA, many of the oil and gas businesses in Alaska are currently operating at or below a break even and raising their taxes at this time could result in significant job losses. The Alaska Forest Association does not support raising taxes on the oil industry while the industry is already struggling to remain profitable.

The timber industry in Alaska pays competitive rates for timber sales and, similar to the oil and gas companies, the stumpage rates are usually a small percentage of the overall cost of business. However, when market prices are low, the stumpage rates can mean the difference between operating and shutting down. Similarly, increasing oil taxes may result in oil and gas job losses in the short term and who knows how that will impact the industry in the long term.

We urge you to encourage more private business activity through efforts to create a more friendly business environment rather than increasing taxes. For instance, the State timber sales in Southeast Alaska are much less costly to operate than timber sales on adjacent federal land. These lower costs make State timber sales more profitable for both the industry and the State. That is one reason why we are seeking to establish a larger State Forest in Southeast Alaska. Perhaps the State can work with the oil industry to find similar savings.

Sincerely,



Owen Graham
Executive Director
Alaska Forest Association.

From: Rep. Steve Thompson
Sent: Thursday, March 31, 2016 5:59 PM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: Constituent Opposition to HB 247

From: Dan Schok [mailto:dan@twsalaska.com]
Sent: Thursday, March 31, 2016 4:25 PM
To: Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>
Cc: Sen. Click Bishop <Sen.Click.Bishop@akleg.gov>; Sen. Pete Kelly <Sen.Pete.Kelly@akleg.gov>; Sen. John Coghill <Sen.John.Coghill@akleg.gov>
Subject: Constituent Opposition to HB 247

Representative Thompson & Representative Wilson,

As you know, I am currently running The Welding Shop out here in Fox, Alaska. It is a family owned business purchased in 2011 from Tommy King, who ran it as a family business for over 30 years. We have been providing goods and services to the producers up North since the inception of the pipeline. As a fellow "Fairbanksian" you recognize the difficulty of doing business in this climate; and so far I have not witnessed government doing much to help the cause. We are now looking at raising taxes on my clients for the 6th time in 11 years through HB247 to fund government spending. Taking away tax credits and increasing the gross tax IS a tax increase and undermines the industry's ability to plan due to an instable tax climate. In fact, when Governor Walker vetoed the new producer tax credits last year, I had clients cancel projects that would have created work for my 26 full time employees. Instead, I have piles of pipe and beam in my yard meant for VSM and HSM production, now on the backburner until the companies have a stable work environment.

I can appreciate as a business owner that a STABLE tax environment is critical to business investment. If you are in favor of the Bill to increase government revenues to the detriment of small businesses like mine, please reconsider. If you are currently opposed to the bill, I appreciate your support of small business. Because investment from the large producers invariably means my shop gets busy again.

Please contact me with any questions or concerns. Additionally, please distribute among committee members, House members.

Dan Schok, PE

President

The Welding Shop, Inc.

Fox, AK

907/457-3426

From: Lynette Bergh
Sent: Monday, April 04, 2016 9:23 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: Constituent Opposition to HB 247

From: Genevieve Schok [mailto:genevieve@flowline-alaska.com]
Sent: Friday, April 01, 2016 3:08 PM
To: Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>
Cc: Rep. David Guttenberg <Rep.David.Guttenberg@akleg.gov>; Rep. Scott Kawasaki <Rep.Scott.Kawasaki@akleg.gov>
Subject: Constituent Opposition to HB 247

Happy Friday to my Local Fairbanks Legislators! Genevieve Schok with Flowline Alaska here. Please read my thoughts on 247 and please pass on to your committee members.

As you listen to debate on HB 247, please keep in mind the trickle effect that dis-incentivizing our biggest industry has on small businesses. Flowline Alaska is right in the Heart of Fairbanks and we service the needs of the producers by providing corrosion coatings, pipeline insulation and welding, among other things. Our employee parking lot is a barometer for the economy in Fairbanks, and we have a lot of open parking spots. After SB 21 we saw an uptick in work and planning; now with oil prices hitting record lows, we see our clients fighting to keep projects online. If we change their tax structures AGAIN for the 6th time in less than a dozen years, I am not optimistic about further investments. SB 21 IS working & frankly we should be doing more to spur investment from the resource industry instead of taxing them more.

Please remember that when you take away money from the private sector to fund the public, it hurts those of us that employ your constituents and all of our local vendors. Like clockwork, every other year we have to keep lobbying the legislature for the right to work; please keep Alaska competitive by tossing HB 247 in its entirety and fund our bloated government another way.

Genevieve Schok Jr.

Flowline Alaska

1881 Livengood Ave.

Fairbanks, AK 99701

W (907) 456-4911

C (480) 209-0029

HB 247 Comments April 2016

Reasons to change Alaska's oil and gas production tax as proposed in the administration's version of HB 247:

1. There is no evidence that the state's investment in oil and gas projects will pay off.

Tax credits are an investment by the state in oil and gas exploration and development. The assumption is that the state's investment will pay off in new production that leads to additional revenue. Yet it is unknown whether the state's investment will in fact result in more production and revenue that makes the investment worthwhile, or whether the state incentives substantively contribute to potential future production that would not have occurred without tax credits.

What is known is that previous tax incentive programs failed to result in more production sufficient to be worth the loss of billions to the state.

Starting in the 1970s, the tax rate decreased as a field's oil production declined as an incentive to prevent the premature shutdown of marginal fields. Decades later, the state found that companies were not making the investments necessary to secure future production in the state, even with low or no production tax.

In 2006, a net profits tax with tax credits was introduced as a way to provide incentives for investment in oil and gas exploration and development. In 2013, when the Parnell administration analyzed what the state was getting as a result of approximately \$6 billion in tax credits, they could find no direct connection to future oil production that would not have occurred without the credits.¹

Whether the state's current investment will result in new production and revenue is unknown because of taxpayer confidentiality that keeps most company records secret and the multitude of factors that go into a company's investment decisions. Consequently, the state is paying billions without knowing whether it is worth the cost.

2. The state is paying out billions with no control over how or where the money is spent.

Either through reduced tax revenue or direct cash payments from the state, Alaska is a major indirect investor in new oil and gas projects, sharing in the risks of company investment decisions but not the decision-making. Companies control the state's investment regardless of their financial soundness, expertise, or the viability of a project. The state has no control over how the companies spend money the state subsequently reimburses.

While the intent is for state tax credit refund dollars to be reinvested in Alaska projects, the requirement for in-state investment in order to qualify for a refund was

¹ Senate Special Committee on TAPS Throughput, January 22, 2013, page 11; Senate Resources Committee, February 11, 2013, page 11.

repealed in 2010. With no investment requirements, companies can use tax credits as collateral to obtain financing from private investors. Some sell their refundable tax credits to a bank or investment company for less than the credits are worth. The buyer gets the full refund from the state, meaning the state is paying the buyer's profit on the credits. The company can spend the proceeds from selling their credits any way they want and anywhere they choose, including outside Alaska.

3. There are too many tax credits and other incentives.

Over the years, as oil production on the North Slope declined and Cook Inlet oil and gas exploration stagnated, more incentives were added and existing tax credits increased. High oil prices allowed the addition of new tax credits without adequate consideration of their cumulative impact to the state's production tax revenue, particularly when oil prices are low.

In addition, a taxpayer can take advantage of more than one incentive. For some oil and gas activities, the state is reimbursing up to 70 percent of a project's expenses with no control over project expenditures and no evidence showing that the state's investment will pay off with future production.

4. Adjustment of the tax credit refund program during low oil prices was anticipated.

In 2006, legislators were reluctant to introduce a tax credit cash refund program. They were concerned about the impact to state finances if oil prices dropped and the state was on the hook for millions in credit refunds. During legislative hearings, oil and gas companies suggested that there could be limitations to protect the state's cash flow in the event of low oil prices.²

The refund program passed in 2006 with provisions to help reduce the risks to the state, including a \$25 million cap per company, limiting refunds to companies with no or minimal oil and gas production, and the requirement that to qualify for a cash refund, an applicant had to incur instate expenditures within 24 months of applying for a credit.

In 2007, the \$25 million cap was lifted and a tax credit fund established to pay for credits. The amount of money available to the fund was based on a set percentage of production tax revenue. Legislative committee discussions made it clear that low oil prices could lead to insufficient money in the fund after credits were paid out, and the legislature might choose to not spend money on credits.³ Accordingly, the law allows for funds to be allocated among refund applicants if there is insufficient money to pay all the credits.

This history shows that legislators and the oil and gas companies were aware and accepted that low oil prices could create too much of a burden for the state and necessitate adjustments to the tax credit program to protect the state's finances.

² House Resources Committee, March 1, 2006, page 45-48; Senate Resources Committee, March 1, 2006.

³ Senate Judiciary Committee, October 30, 2007, page 24.

April 2, 2016

Representative Mark Neuman
Representative Steve Thompson
Representative Dan Ortiz

Gentlemen,

The Alaska Forest Association supports the current oil tax policy in Alaska

The Alaska Forest Association (AFA) is a non-profit business association that was formed in 1957 to represent the interests of the timber industry in Alaska. The AFA currently manages a pension program, a group health insurance program, a scholarship program for the timber industry and also sponsors the Sustainable Forestry Initiative program for Alaska.

According to the information provided by AOGA, many of the oil and gas businesses in Alaska are currently operating at or below a break even and raising their taxes at this time could result in significant job losses. The Alaska Forest Association does not support raising taxes on the oil industry while the industry is already struggling to remain profitable.

The timber industry in Alaska pays competitive rates for timber sales and, similar to the oil and gas companies, the stumpage rates are usually a small percentage of the overall cost of business. However, when market prices are low, the stumpage rates can mean the difference between operating and shutting down. Similarly, increasing oil taxes may result in oil and gas job losses in the short term and who knows how that will impact the industry in the long term.

We urge you to encourage more private business activity through efforts to create a more friendly business environment rather than increasing taxes. For instance, the State timber sales in Southeast Alaska are much less costly to operate than timber sales on adjacent federal land. These lower costs make State timber sales more profitable for both the industry and the State. That is one reason why we are seeking to establish a larger State Forest in Southeast Alaska. Perhaps the State can work with the oil industry to find similar savings.

Sincerely,



Owen Graham
Executive Director
Alaska Forest Association.

Founded 1975

Executive Director
Marleanna Hall

**2015-2016
Executive Committee**
Ralph Samuels, President
Eric Fjelstad, Sr. Vice President
Lorna Shaw, Vice President
L.F. "Len" Horst, Treasurer
Ethan Schutt, Secretary
Phil Cochrane, Past President

Bob Berto
Patty Bielawski
Pat Carter
Ella Ede
Stan Foo
Tim Gallagher
Bill Jeffress
Scott Jepsen
Wendy Lindskoog
Tom Maloney
Lance Miller
Kara Moriarty
Hans Neidig
Glenn Reed
Mike Satre
John Shively
Jeanine St. John
Cam Toohy

Directors

Jaeleen Araujo
Anna Atchison
Greg Baker
Tom Barrett
Greg Beischer
Jason Bergerson
Rick Boyles
Jason Brune
Dave Chaput
Steve Connelly
Dave Cruz
Steve Denton
Mike Ferris
Carol Fraser
Gideon Garcia
Ricky Gease
Paul Glavinovich
Stephen Grabacki
Dan Graham
Scott Habberstad
Karl Hanneman
Steve Hites
Teresa Imm
Monica James
Michael Jespersen
Mike Jungreis
Thomas Krzewinski
John Lau
Tom Lovas
Thomas Mack
John MacKinnon
Stephanie Madsen
Karen Matthias
Sam Mazzeo
Joey Merrick
James Mery
Lori Nelson
Tom Panamaroff
Lisa Parker
Judy Patrick
Shannon Price
Christy Resler
Rick Rogers
Joe Schierhorn
Keith Silver
Lorali Simon
Doug Smith
Phil Steyer
John Sturgeon
Casey Sullivan
Jan Trigg
Doug Vincent-Lang
Doug Ward
Sinclair Wilt

Ex-Officio Members

Senator Lisa Murkowski
Senator Dan Sullivan
Congressman Don Young
Governor Bill Walker



RESOURCE DEVELOPMENT COUNCIL

Growing Alaska Through Responsible Resource Development

April 5, 2016

The Honorable Steve Thompson
State Capitol Room 515
Juneau, AK 99801

Re: CS HB 247, TAX; CREDITS; INTEREST; REFUNDS; O & G

Dear Representative Thompson:

I am writing to follow up with additional comments to build on the testimony I provided on behalf of the Resource Development Council for Alaska, Inc. (RDC) on Saturday, April 1st during public testimony on Committee Substitute House Bill 247.

RDC is a statewide non-profit business association comprised of individuals and companies from Alaska's oil and gas, mining, forest products, fisheries and tourism industries. RDC's membership of hundreds of corporate members and individual members, includes the 12 land owning Alaska Native corporations, local communities, organized labor and industry-support firms across the entire economy, all of which depend on a healthy oil and gas industry. RDC's purpose is to encourage a strong, diversified private sector in Alaska and expand the state's economic base through the responsible development of our natural resources.

As you can see, RDC members are truly the life-blood of Alaska's economy. We believe the best approach to expand the economy and generate new revenues for the state is to produce more oil, attract more tourists, harvest more fish, and mine more minerals. Increasing taxes on our natural resource industries will not increase production for the Trans Alaska Pipeline System (TAPS), it will not encourage the development of new mines in Alaska, it will not attract more tourists, and it will not increase investment in the fishing industry. Higher taxes in this low-priced commodity environment will likely deter investment and lead to lower state revenues and a weaker private sector over the long run.

With regard to Committee Substitute HB 247, raising taxes on companies that are reporting record losses and are in negative cash flow is not sound fiscal policy.

This is clearly not the time to raise taxes on the primary engine of Alaska's economy. The oil industry is struggling with low oil prices and tight capital markets. Companies are cutting budgets and making tough investment decisions. Increasing taxes on the industry at this time will compound a bad situation and jeopardize new investment, further damaging our private sector economy and shrinking the economic pie for everyone.

According to the Energy Information Administration, oil prices today are not only the lowest we've seen in a decade, when adjusted for inflation, they are the lowest since the mid-1980s. In less than two years, oil prices have fallen 70 percent. This obviously has impacted state revenues, but also the industry, which receives 100 percent of its revenue based on the commodity price.

121 West Fireweed Lane, Suite 250, Anchorage, Alaska 99503

Phone: 907-276-0700 • Fax: 907-276-3887 • Email: resources@akrdc.org • Website: akrdc.org

Changing the tax regime now will make a bad situation worse. But a little good news: A release issued by the Alaska Oil and Gas Association recently announced more proof of the current tax regime working. It said, "public data provided by the State of Alaska shows an almost one percent increase of year-over-year oil production during the past 12 months."

When you incentivize something, you get more of it. We need to incentivize the industry to drill more, create more wealth, create more activity, and aim for next year's production to be even higher than this year's.

Look at the current tax policy. It has brought new exploration, jobs, and continued investment to the state. It has stabilized North Slope production and has somewhat shielded Alaska from the massive cut backs that have occurred elsewhere. Following the enactment of the new tax law in 2013, Alaska saw \$5 billion in new investment across the state from legacy companies to new companies that have made big investments in good faith under the current regime. The sudden and dramatic drop in oil prices have slowed progress as companies struggle with low cash flows, but Alaska is in a much better position because of those investments. The tax policy has done what it was supposed to do: increase investment.

The oil industry is truly the foundation of Alaska's economy and keeping it strong is the key to sustaining the private sector, Alaskan jobs, state government, and the overall economy. A healthy and strong oil and gas industry is also vital to progressing the Alaska LNG mega project. To sustain our economy, Alaska needs to encourage new investment, jobs and production by maintaining a stable, competitive tax structure.

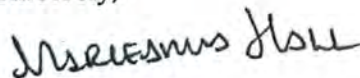
Conversely, this bill moves us in the wrong direction. It represents the sixth major tax change in Alaska in the last 11 years. Raising taxes when prices go up, and then raising them again when prices are down, creates instability and fails to provide investors with any fiscal certainty. This bill will make Alaska less competitive for global investment and risks future projects that would put more oil in TAPS, which should be our number one goal. Alaska needs a plan that grows the pie bigger for everyone.

Our members are not asking for a tax decrease during this time of low commodity prices like other states and countries are considering, but we do request that as the state considers changes to tax policy, it do no harm to the state's largest industry, an industry facing significant economic hardship. Otherwise, we may soon learn that the more Alaska taxes companies, the less likely a company will invest here – and the more likely its limited capital will go to jurisdictions that do encourage investment.

In closing, it is important for Alaskans to remember that the oil industry is a major revenue producer for the State of Alaska, and is the largest producer of revenue for the North Slope Borough, the City of Valdez, and the Kenai Peninsula Borough.

In closing, I urge you to reject this legislation, and thank you for the opportunity to provide additional information.

Sincerely,



Marleanna Hall
Executive Director

Written Testimony for CSHB 247(RES)

Submitted by Sarah Obed
Vice President of External Affairs for Doyon, Limited
April 7, 2016

The Honorable Mark Neuman
The Honorable Steve Thompson
Co-Chairs of House Finance Committee
Alaska State Capitol
Juneau, Alaska 99811-1182

My name is Sarah Obed, and I am the vice president of external affairs for Doyon, Limited (“Doyon”). Doyon is the state-chartered Alaska Native Claims Settlement Act regional corporation for Interior Alaska. Doyon has over 19,300 shareholders, most of whom reside within the State. Doyon is the largest private land owner in the State, and one of our highest priorities is the continued exploration for oil and gas resources on State owned lands in the Minto Flats/Nenana Basin, as well as on Doyon-owned lands near Steven’s Village.

Tax Credits support Exploration and Development in Middle Earth

The structure of the Alaska oil and gas production tax is vital to the exploration and development of areas of the state sometimes referred to as “Middle Earth,” which encompasses all areas of the state south of the North Slope and outside of Cook Inlet. Middle Earth includes the Nenana Basin and Yukon Flats in central Alaska where Doyon holds oil and gas interests, including over 400,000 acres of state leases. Middle Earth also includes Kotzebue, Copper River, Bristol Bay, and the Aleutians. These areas are uniquely situated and the opportunities and challenges for economic development and oil and gas exploration and development are dramatically different than the opportunities and challenges on the North Slope and in Cook Inlet.

Currently there is no oil and gas production in Middle Earth and the prospective basins are unexplored or underexplored, with no commercial discoveries. Federal and state studies indicate that many of the basins in Middle Earth are highly prospective areas for oil and gas. Some areas are near infrastructure and could be quickly developed to bring oil and gas into production in the near future. There are great opportunities for major oil and gas discoveries that could accelerate economic development and provide jobs, local sources of gas to communities, revenues from royalties, lease rentals, and taxes, and also valuable well and seismic data.

There are several Middle Earth projects that are moving forward and production tax rates and credits impact these projects and the appetite for investment in them. Doyon has been drilling wells and shooting seismic in the Nenana Basin and Yukon Flats for the last several years, is currently building a road and pad for one additional well, is currently shooting seismic, and has moved forward with permitting and contracts for services and equipment. Doyon has advanced its projects from unknown to the demonstration of an active hydrocarbon system and has methodically de-risked the Nenana Basin prospect to a 1-in-2 chance of success for gas and a 1-in-5 chance for oil. These prospects are roughly 40-60 miles from the Trans-Alaska Pipeline and

the likely route of a major gas line, and can provide gas to Fairbanks. These projects are already spurring economic development and providing revenue to the state and localities — Doyon pays the state over \$1.2 million in lease rentals annually.

The oil and gas production tax credits are vital to Middle Earth exploration and development, but the amount of credits associated with Middle Earth activity is miniscule compared to the total amount of credits in the state. Total rebates to Doyon for 2005-2016 are estimated to be only \$62-65 million. However, if there is an oil discovery in 2016, a simple royalty calculation for Doyon's mean production estimate would be: 70 million barrels x \$60/bbl = \$525,000,000 in oil royalties alone. Further, that estimate is for just one of several similar traps identified in Doyon's most recent 3-D seismic survey, which covered less than 10% of the area Doyon is actively exploring. Success with one of these traps strongly suggests that there will be success with many others. There are also significant opportunities for gas production, estimated to yield enough gas to supply Fairbanks for over 20 years. In addition, over 30 local groups will provide services for Doyon's 2016 programs and over 150 people will be directly employed. Such opportunities are repeatable throughout the basin.

Overwhelmingly, Doyon's oil and gas exploration investment dollars in the Nenana basin have gone into State of Alaska and Alaska Mental Health Trust ("MHT") lands. In addition to 400,000 acres in 78 state leases, Doyon holds about 9,500 acres in a Mental Health Trust lease. By comparison, Doyon owns only about 43,000 acres in the basin. The vast majority of seismic Doyon has gathered has been on State lands and of the two wells drilled, one was on a State lease and the other on a MHT lease. The road access constructed by Doyon has been on public land — State, MHT and City of Nenana. The pad for the well to be drilled by Doyon this summer is on a State lease, other traps imaged in the central part of the basin are on shared lands, and traps in the northern and southern parts of the basin will all be on state lands. The State and MHT will continue to benefit from lease rentals and will benefit from royalties if production commences. Further, production from all lands in Alaska, public and private, is subject to production taxes.

HB 247 ("the Bill") leaves intact certain elements of the oil and gas production tax that are very important for Middle Earth exploration and development, in recognition of the lack of commercial discoveries and infrastructure. For instance, Middle Earth production will benefit from a ceiling tax rate of 4% of the gross value at the point of production for 7 years after the start of commercial production. This ceiling was clearly intended to help "jump-start" Middle Earth production. The Bill also does not change the alternative credit for exploration under AS 43.55.025, which benefits seismic exploration and exploration drilling, and sunsets January 1, 2022 for Middle Earth projects (July 1, 2016 everywhere else).

However, the Bill *as introduced* would repeal the tax credits that have been the most vital to exploration and development in Middle Earth and Cook Inlet, specifically: the 20% qualified capital expenditure credit under AS 43.55.023(a) (QCE) and the 40% well lease expenditure credit under AS 43.55.023(l) (WLE). Further, this repeal would be effective July 1, 2016 — in the middle of Doyon's drilling season. Doyon decided to drill a well this summer based on the reasonable expectation of receiving these credits, and a repeal at that time would catch the project in mid-stride. The repeal of these credits, which are based upon capital expenditures, will also hamper Middle Earth development and production. In addition, if production commences and continues

after the 7-year sunset date of the Middle Earth tax ceiling, oil production will bear the 35% tax rate, yet Middle Earth only has a 25% loss credit under AS 43.55.023(b) (Loss Credit), compared to the North Slope where the tax rate and Loss Credit are both 35%.

The House Resources Committee substitute would repeal the QCE and WLE credits, which have been critical for Middle Earth projects. However, the date of the repeal would be farther into the future rather than during the upcoming summer drilling season. This change is important for Doyon's 2016 exploration drilling project. The House Resources Committee substitute would also reduce the Loss Credit to 10% in 2017, which exacerbates the difference between the 35% tax rate and Loss Credit rate discussed above. In sum, the repeal of the QCE and WLE and reduction of the Loss Credit would hamper Middle Earth exploration and development.

From: Rep. Steve Thompson
Sent: Friday, April 08, 2016 11:17 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: Non Support for SB 247

From: Matt Melton [mailto:MMelton@chadux.com]
Sent: Friday, April 08, 2016 10:39 AM
To: Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>
Subject: Non Support for SB 247

Representative Thompson,

Please consider the following when voting on HB 247.

- Higher taxes will discourage investment and shrink the pie for everyone. When you tax something, you get less of it; in this case, oil.
- The number one goal of the Senate Resources Committee should be to protect the jobs and investment necessary to maximize TAPS throughput. However, SB 130 will increase taxes on an industry already operating at a loss, resulting in lower investment, fewer jobs, lower production and less state revenues over the long term.
- After many years of debate and a failed referendum in 2014, Alaska should not be looking to change its taxes yet again. This sends the wrong message to investors in all industries.
- Tax reform of recent years improved Alaska's competitive position for investment and partially insulated the state from massive industry cuts that are occurring elsewhere. The governor's tax proposal moves us in the opposite direction, jeopardizing future investment, jobs and production.
- Recent data from the State of Alaska offers proof the current tax regime is working, showing an almost one percent increase of year-over-year oil production during the past 12 months.
- Higher industry taxes in this low-priced commodity environment could be a game changer for Alaska, leading to lower state revenues and a weaker private sector over the long term. The private sector is the foundation of Alaska's economy and its underlying health is the key to sustaining jobs, state government and the overall economy.
- It is not good policy to raise taxes on businesses that are already losing money. Raising taxes will make a bad situation worse.
- The current oil tax system is balanced, setting a higher minimum floor than the previous tax system, while setting a stable and predictable rate when oil prices rise again. At current prices, Alaska's oil tax policy has brought hundreds of millions of dollars more in tax revenue to the state than it would have under the previous system.
- Tax credits have attracted significant investments from companies new to Alaska. Without credits, Southcentral Alaska might still face the prospect of importing its energy at high costs to heat homes and generate electricity. Thanks to tax credits, local utilities have security of supply for several years. In the long term, additional investment will be needed to meet demand.

Thank you,

Matt

Matt Melton | General Manager

(907) 348.2348 | Cell (907) 330.4550 | **24 Hour (907) 348.2365**

2347 Azurite Court, Anchorage, AK 99507 | www.chadux.com



This E-Mail transmission and any accompanying attachments may contain confidential information intended only for the use of the individual or entity named above. Any dissemination, distribution, copying or action taken in reliance on the contents of this E-Mail by anyone other than the intended recipient is strictly prohibited and is not intended to, in anyway, waive privilege or confidentiality. If you have received this E-Mail in error please immediately delete it and notify sender at the above E-Mail address.

From: Rep. Steve Thompson
Sent: Friday, April 08, 2016 11:18 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: HB247 NO!

From: Dave Atchison [mailto:dave@alaskatent.com]

Sent: Friday, April 08, 2016 9:55 AM

To: Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>; Rep. Bryce Edgmon <Rep.Bryce.Edgmon@akleg.gov>; Rep. Neal Foster <Rep.Neal.Foster@akleg.gov>; Rep. Lynn Gattis <Rep.Lynn.Gattis@akleg.gov>; Rep. Bob Herron <Rep.Bob.Herron@akleg.gov>; Rep. Shelley Hughes <Rep.Shelley.Hughes@akleg.gov>; Rep. Craig Johnson <Rep.Craig.Johnson@akleg.gov>; Rep. Wes Keller <Rep.Wes.Keller@akleg.gov>; Rep. Bob Lynn <Rep.Bob.Lynn@akleg.gov>; Rep. Charisse Millett <Rep.Charisse.Millett@akleg.gov>; Rep. Cathy Munoz <Rep.Cathy.Munoz@akleg.gov>; Rep. Benjamin Nageak <Rep.Benjamin.Nageak@akleg.gov>; Rep. Mark Neuman <Rep.Mark.Neuman@akleg.gov>; Rep. Kurt Olson <Rep.Kurt.Olson@akleg.gov>; Rep. Lance Pruitt <Rep.Lance.Pruitt@akleg.gov>; Rep. Lora Reinbold <Rep.Lora.Reinbold@akleg.gov>; Rep. Dan Saddler <Rep.Dan.Saddler@akleg.gov>; Rep. David Talerico <Rep.David.Talerico@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Liz Vazquez <Rep.Liz.Vazquez@akleg.gov>; Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>

Subject: HB247 NO!

- No to job loss
- No to tax increases
- No on HB 247

We are a small business here in Alaska I am very concerned with the direction HB247 would take us. Sure it sounds good to hold onto more money for the state....But at what cost?!

As oil companies are closing up shop on slope faster than I can count, this is a bad plan. We should be discussing how the state can help keep them working.

Our company has seen a 30+ percent decrease in oil and gas related project revenue in the last 12 months. We have had to lay-off 25% of our laborers that made products for the slope. Our long time production supervisor has now left our company after 10 years. His reason was he was afraid that legislation like HB247 would lead to additional reduction in force.

I shutter to think were we would be if the Vote no on One campaign had failed. That is exactly were HB247 would take us.

Please consider voting No on HB247, my employee's would be grateful.

Dave Atchison

General Manager

Alaska Tent and Tarp

907-456-6328

907-699-3203 Cell

From: Rep. Steve Thompson
Sent: Friday, April 08, 2016 11:18 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: HB 247

From: Don Maupin [mailto:don.maupin@cb-pacific.com]

Sent: Friday, April 08, 2016 9:39 AM

To: Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>; Rep. Bryce Edgmon <Rep.Bryce.Edgmon@akleg.gov>; Rep. Neal Foster <Rep.Neal.Foster@akleg.gov>; Rep. Lynn Gattis <Rep.Lynn.Gattis@akleg.gov>; Rep. Bob Herron <Rep.Bob.Herron@akleg.gov>; Rep. Shelley Hughes <Rep.Shelley.Hughes@akleg.gov>; Rep. Craig Johnson <Rep.Craig.Johnson@akleg.gov>; Rep. Wes Keller <Rep.Wes.Keller@akleg.gov>; Rep. Bob Lynn <Rep.Bob.Lynn@akleg.gov>; Rep. Charisse Millett <Rep.Charisse.Millett@akleg.gov>; Rep. Cathy Munoz <Rep.Cathy.Munoz@akleg.gov>; Rep. Benjamin Nageak <Rep.Benjamin.Nageak@akleg.gov>; Rep. Mark Neuman <Rep.Mark.Neuman@akleg.gov>; Rep. Kurt Olson <Rep.Kurt.Olson@akleg.gov>; Rep. Lance Pruitt <Rep.Lance.Pruitt@akleg.gov>; Rep. Lora Reinbold <Rep.Lora.Reinbold@akleg.gov>; Rep. Dan Saddler <Rep.Dan.Saddler@akleg.gov>; Rep. David Talerico <Rep.David.Talerico@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Liz Vazquez <Rep.Liz.Vazquez@akleg.gov>; Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>

Subject: HB 247

I am against any change in the current Oil & Gas tax structure. It is a great political talking point to try and manipulate the message that we give more tax credits than we receive in revenue but the sentence needs to be completed. Since the previous administration put into place the current tax structure the Oil & Gas companies have immediately and significantly increased their investment in Alaska. Since then we have seen an increase in production, something we have not seen in decades. This current tax structure has not only increased investment from the majors like Conoco Philips but more so from the smaller Oil Companies like Hilcorp, Brooks Range and Armstrong. Without these incentives the smaller companies cannot afford these investments.

Oil & Gas investment is the only way to stimulate our economy. This proposal will generate more revenue for the state in the short term but as investments decrease so will production and state revenue as well as further job reduction. Already all of the Oil companies have scaled back due to the low oil prices. Rather than risk further decline in these investments the state needs to further attract and stimulate investment as well as scale back just as we are all doing. Thousands of people related to the Oil & Gas market have lost their jobs and more are on the way but I have not seen one state employee laid off. And now you want to purchase the Literature Building in Anchorage! The message you are all sending is arrogance and incompetence in representing the people of Alaska and a disconnect in the reality of our economy.

With that said I encourage you to kill HB 247 and come up with something more comprehensive to increase revenue and reduce state spending.

One suggestion on state spending I would look at the last budget that was in line with the current revenue and start with that as a bases for the budget. And then take a close look at “wants and needs” like the rest of us are doing.

Regards;
Don Maupin
Alaska General Manager

O: 907-696-2799 | M: 907-982-4806

5610 Silverado Way. Suite A01. Anchorage, AK. 99518

Don.Maupin@cb-pacific.com | www.cb-pacific.com



NOTE: This message, including any attachments, may include privileged, confidential and/or inside information. Any distribution or use of this communication by anyone other than the intended recipient is strictly prohibited and may be unlawful. If you are not the intended recipient, please notify the sender by replying to this message and then delete it from your system.

From: Rep. Steve Thompson
Sent: Friday, April 08, 2016 11:19 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: HB 247, revenue

From: Randy Brand [mailto:RBrand@grtnw.com]

Sent: Friday, April 08, 2016 9:16 AM

To: Sen. John Coghill <Sen.John.Coghill@akleg.gov>; Rep. David Guttenberg <Rep.David.Guttenberg@akleg.gov>

Cc: Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>; Rep. Bryce Edgmon <Rep.Bryce.Edgmon@akleg.gov>; Rep. Neal Foster <Rep.Neal.Foster@akleg.gov>; Rep. Lynn Gattis <Rep.Lynn.Gattis@akleg.gov>; Rep. Bob Herron <Rep.Bob.Herron@akleg.gov>; Rep. Shelley Hughes <Rep.Shelley.Hughes@akleg.gov>; Rep. Craig Johnson <Rep.Craig.Johnson@akleg.gov>; Rep. Wes Keller <Rep.Wes.Keller@akleg.gov>; Rep. Bob Lynn <Rep.Bob.Lynn@akleg.gov>; Rep. Charisse Millett <Rep.Charisse.Millett@akleg.gov>; Rep. Cathy Munoz <Rep.Cathy.Munoz@akleg.gov>; Rep. Benjamin Nageak <Rep.Benjamin.Nageak@akleg.gov>; Rep. Mark Neuman <Rep.Mark.Neuman@akleg.gov>; Rep. Kurt Olson <Rep.Kurt.Olson@akleg.gov>; Rep. Lance Pruitt <Rep.Lance.Pruitt@akleg.gov>; Rep. Lora Reinbold <Rep.Lora.Reinbold@akleg.gov>; Rep. Dan Saddler <Rep.Dan.Saddler@akleg.gov>; Rep. David Talerico <Rep.David.Talerico@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Liz Vazquez <Rep.Liz.Vazquez@akleg.gov>; Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>

Subject: HB 247, revenue

1. I would first like to voice my objection to HB 247. We cannot tax ourselves into prosperity. This will only stifle growth, and create additional job losses. Oil is like beach property; there is only so much of it. While the value may be low now, it cannot sustain at those levels. Oil will eventually be made obsolete by other energy sources. The time to sell is now while there are buyers.

2. I would second like to address our revenue shortfalls. We cannot depend upon oil to carry us on. An income tax alone cannot close the gap. It is my opinion that we also need a State sales tax to enable us to stand solidly on our own two feet. Any surplus oil revenues generated in the future should be socked away for the benefit of future generations.



Randy Brand | Great Northwest, Inc. | www.grtnw.com

2975 Van Horn Road, Fairbanks, AK 99709

T: (907) 452-5617 **F:** (907) 456-7779 **C:** (907) 322-8898 **E:** RBrand@grtnw.com

From: Rep. Steve Thompson
Sent: Friday, April 08, 2016 11:23 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: HB 247

From: BENSON, Brian [mailto:brian.benson@airliquide.com]
Sent: Friday, April 08, 2016 11:18 AM
To: Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>; Rep. Bryce Edgmon <Rep.Bryce.Edgmon@akleg.gov>; Rep. Neal Foster <Rep.Neal.Foster@akleg.gov>; Rep. Lynn Gattis <Rep.Lynn.Gattis@akleg.gov>; Rep. Bob Herron <Rep.Bob.Herron@akleg.gov>; Rep. Craig Johnson <Rep.Craig.Johnson@akleg.gov>; Rep. Shelley Hughes <Rep.Shelley.Hughes@akleg.gov>; Rep. Wes Keller <Rep.Wes.Keller@akleg.gov>; Rep. Bob Lynn <Rep.Bob.Lynn@akleg.gov>; Rep. Charisse Millett <Rep.Charisse.Millet@akleg.gov>; Rep. Cathy Munoz <Rep.Cathy.Munoz@akleg.gov>; Rep. Benjamin Nageak <Rep.Benjamin.Nageak@akleg.gov>; Rep. Kurt Olson <Rep.Kurt.Olson@akleg.gov>; Rep. Lance Pruitt <Rep.Lance.Pruitt@akleg.gov>; Rep. Lora Reinbold <Rep.Lora.Reinbold@akleg.gov>; Rep. Dan Saddler <Rep.Dan.Saddler@akleg.gov>; Rep. David Talerico <Rep.David.Talerico@akleg.gov>; Rep. Liz Vazquez <Rep.Liz.Vazquez@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>; Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>
Subject: HB 247

A quick comment on HB 247: Just Say NO.

Passing this bill would be a step backward to the days where Alaska turned to bite the hand that feeds it-the Palin Era and burdensome taxes that send resource extraction to overseas, less expensive regions. Especially at times of low oil prices, Alaska has to remain an investment partner; not a greedy landlord. Tenants maintain the option to move. We've lost hundreds of jobs in the oil patch, and trickle down jobs in service industries. It will continue to get worse with predatory taxation.

Incentives have helped increase production in the Alyeska pipeline, and the south-central gas crisis to become a non-issue.

Going wild with a new tax scheme this close to the passage (with positive outcomes) of SB 21 is going to reinforce a less than positive image of Alaska as a place to invest, as unstable as the worst of 3rd world countries.

Alaskans need investment to keep the state in business, both in the private as well as state sectors. Passage of HB 247 will put us on a slide to fiscal ruin.

--
Best regards,

Brian Benson
Alaska Sales Manager, Air Liquide America L. P.
6510 Arctic Spur Rd., Anchorage, AK 99518 U.S.A.
mailto:brian.benson@airliquide.com> office (907)273-9763 /cellular (907)529-8787

From: Lynette Bergh
Sent: Friday, April 08, 2016 10:00 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: No on HB247

From: Clint Winzenburg [mailto:cwinzenburg@aih.com]

Sent: Friday, April 08, 2016 9:43 AM

To: Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>; Rep. Bryce Edgmon <Rep.Bryce.Edgmon@akleg.gov>; Rep. Neal Foster <Rep.Neal.Foster@akleg.gov>; Rep. Lynn Gattis <Rep.Lynn.Gattis@akleg.gov>; Rep. Bob Herron <Rep.Bob.Herron@akleg.gov>; Rep. Shelley Hughes <Rep.Shelley.Hughes@akleg.gov>; Rep. Craig Johnson <Rep.Craig.Johnson@akleg.gov>; Rep. Wes Keller <Rep.Wes.Keller@akleg.gov>; Rep. Bob Lynn <Rep.Bob.Lynn@akleg.gov>; Rep. Charisse Millett <Rep.Charisse.Millett@akleg.gov>; Rep. Cathy Munoz <Rep.Cathy.Munoz@akleg.gov>; Rep. Benjamin Nageak <Rep.Benjamin.Nageak@akleg.gov>; Rep. Mark Neuman <Rep.Mark.Neuman@akleg.gov>; Rep. Kurt Olson <Rep.Kurt.Olson@akleg.gov>; Rep. Lance Pruitt <Rep.Lance.Pruitt@akleg.gov>; Rep. Lora Reinbold <Rep.Lora.Reinbold@akleg.gov>; Rep. Dan Saddler <Rep.Dan.Saddler@akleg.gov>; Rep. David Talerico <Rep.David.Talerico@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Liz Vazquez <Rep.Liz.Vazquez@akleg.gov>; Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>

Subject: No on HB247

I am writing with my concern for the proposed HB247 and how it affects all us Alaskans. I have seen many friends now get laid off and jobs lost. Some even moving out of state to find new work. I have seen sales drop off and affect the company that I work for. I have seen and witnessed oil companies pull completely out of the State of Alaska. Some due to the current low oil prices, but also because of the State budget and proposal of new taxes or the elimination of the tax incentives.

Please reconsider and look at other ways to save money, and do not put another burden or hit on the Oil and Gas industry. Let everyone get in the black and back on stable ground, before hitting someone when they are already down. I hate to say it, but if I have to give up my PFD, so be it. Use the funds for what they were designed for and get our state back on track. I wish the state would just do a one-time payout and be done with the PFD and finally use it 100% for the state.

The point being, HB247 affects all of us Alaskans, and in the worst way.

Clint Winzenburg

Oil & Gas Sales Account Manager

AK INDUSTRIAL Hardware
2192 Viking Dr Anchorage AK 99501
907-243-2421

From: Rep. Steve Thompson
Sent: Friday, April 08, 2016 11:14 AM
To: Helen Phillips
Cc: Jane Pierson
Subject: FW: NO on HB 247

From: Heather March [mailto:march.hc@gmail.com]

Sent: Friday, April 08, 2016 11:12 AM

To: Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>; Rep. Bryce Edgmon <Rep.Bryce.Edgmon@akleg.gov>; Rep. Neal Foster <Rep.Neal.Foster@akleg.gov>; Rep. Lynn Gattis <Rep.Lynn.Gattis@akleg.gov>; Rep. Bob Herron <Rep.Bob.Herron@akleg.gov>; Rep. Shelley Hughes <Rep.Shelley.Hughes@akleg.gov>; Rep. Craig Johnson <Rep.Craig.Johnson@akleg.gov>; Rep. Wes Keller <Rep.Wes.Keller@akleg.gov>; Rep. Bob Lynn <Rep.Bob.Lynn@akleg.gov>; Rep. Charisse Millett <Rep.Charisse.Millett@akleg.gov>; Rep. Cathy Munoz <Rep.Cathy.Munoz@akleg.gov>; Rep. Benjamin Nageak <Rep.Benjamin.Nageak@akleg.gov>; Rep. Mark Neuman <Rep.Mark.Neuman@akleg.gov>; Rep. Kurt Olson <Rep.Kurt.Olson@akleg.gov>; Rep. Lance Pruitt <Rep.Lance.Pruitt@akleg.gov>; Rep. Lora Reinbold <Rep.Lora.Reinbold@akleg.gov>; Rep. Dan Saddler <Rep.Dan.Saddler@akleg.gov>; Rep. David Talerico <Rep.David.Talerico@akleg.gov>; Rep. Steve Thompson <Rep.Steve.Thompson@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Liz Vazquez <Rep.Liz.Vazquez@akleg.gov>; Rep. Tammie Wilson <Rep.Tammie.Wilson@akleg.gov>

Subject: NO on HB 247

Legislators-

As life-long Alaskan, hard-working mother, and employee in the oil & gas industry, I appeal to you not to support HB 247. The bill will lead to even further job loss in ALL industries in our state, and we will see a mass exodus of the hard working Alaskans to the Lower 48. I want to continue to work and live in Alaska, and the current economic climate in the State is already making it difficult to do that. Families like mine need you to make it economical for the oil business to thrive as much as possible here.

Sincerely,
Heather Joseph