

SB

130

<TARGET><BILL>SB 130</BILL><SUBJECT>SB
130</SUBJECT><COMM>SRES29</COMM></TARGET>

**SENATE COMMITTEE REPORT
First Committee of Referral**

DATE: 1/19/16

FURTHER: Finance

Date of 5-Day Notice: 3/31/16
(in accordance with Uniform Rule 23)

DATE TURNED IN TO OFFICE: APR 13 2016

Resources Committee considered SENATE BILL NO. 130

SB 130-TAX;CREDITS;INTEREST;REFUNDS;O & G

"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."

and recommends:

- be replaced with CS SB 130 (RE) [] Same Title New Title
- [] adopt previous CS _____ (_____) [] Same Title [] New Title
- [] attached amendment(s)
- [] adopt _____ Letter of Intent
- [] further referral to _____ Committee

Dept Abbr.	
ADM	LWF
CED	LAW
COR	LEG
EED	MVA
DEC	DNR
DFG	DPS
GOV	REV
DHS	DOT
AJS	UA

NEW FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #
Fiscal Info Forthcoming				

PREVIOUS FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #

[] APPROPRIATION - no fiscal note

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
	Costello			<input checked="" type="checkbox"/>	
	Witekowski				<input checked="" type="checkbox"/>
	Cahill			<input checked="" type="checkbox"/>	
	Micciche			<input checked="" type="checkbox"/>	
	Sherman			<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>
	Stoltz			<input checked="" type="checkbox"/>	
CHAIR:	Gicelli	<input checked="" type="checkbox"/>			

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Governor Bill Walker
STATE OF ALASKA

January 15, 2016

The Honorable Kevin Meyer
President of the Senate
Alaska State Legislature
State Capitol, Room 111
Juneau, AK 99801-1182

Dear President Meyer:

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(l) 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 \$10,000,000,000 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 Kevin Meyer
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 cursive script that reads "Bill Walker".

Bill Walker
Governor

Enclosure



ALASKA STATE LEGISLATURE

SENATE RESOURCES COMMITTEE

SEN. CATHY GIESSEL

Chair
State Capitol, Room 427
Juneau, AK 99801-1182
(907) 465-4843 Fax 465-3871

Sen. Mia Costello, Vice-Chair
Sen. Peter Micciche
Sen. Bert Stedman

Sen. John Coghill
Sen. Bill Stoltze
Sen. Bill Wielechowski

Senate Bill 130: Explanation of Changes: Version W

1. Title is changed to reflect subsequent changes in the committee substitute, and to conform with legislative drafting protocol.
2. Section. 6 of the previous version A of the bill, dealing with confidentiality requirements, is removed.
3. Page 2, Line 31- Page 3, Line 25: Amends the previous Section. 7 of version A of the bill, by changing the interest rate to 7% above the Federal Reserve rate, compounded quarterly, for only 3 years. For the following 3 years of the statute of limitations, no interest would be accrued.
4. Section. 8 of the previous version A of the bill, dealing with confidentiality requirements, is removed.
5. Page 3, Line 26- Page 4, Line 28: Amends the previous Sections. 9, 10, and 11 of version A of the bill, by incorporating a new definition of outstanding liability to the state that is created in a later section.
6. Section. 12 of the previous version A of the bill, hardening the floor at 5%, is removed.
7. Page 4, Line 29- Page 5, Line 19: Adds a new Section. 10, repealing the calculation for the Cook Inlet tax cap, as well as the subsection for the tax calculation for gas produced elsewhere in the state for use in state.
8. Page 5, Line 20- Page 7, Line 4: Adds a new Section. 11, conforming to Section. 10.

9. Page 7, Lines 5-10: Adds a new Section. 12, making oil and gas produced in the Cook Inlet sedimentary basin after January 1, 2018 exempt from any production tax, and prevents an explorer or producer in the basin from acquiring credits.
10. Page 7, Line 11-Page 15, Line 1: Amends the previous Section. 13 in the A version of the bill by removing references to hardening the gross minimum floor, and conform to the new Section. 10.
11. Page 15, Line 2-23: Repeals the previous Section. 14 in the A version of the bill, dealing with interest calculations, and conforming to the new Section. 6 on interest calculations.
12. Page 15, Line 24-Page 17, Line 10: Conforms Sections. 15, 16 of the bill to the new Section. 6 on interest calculations.
13. Section. 17 of the previous version A of the bill, dealing with recalculating the per-barrel credit on a monthly rather than a yearly basis, is removed.
14. Page 17, Line 11-30: Adds a new Section. 17, reduces the Qualified Capital Expenditure Credit to 10% as of January 1, 2017.
15. Page 17, Line 31- Page 18, Line 21: Adds a new Section. 18, eliminating the Qualified Capital Expenditure Credit for the Cook Inlet sedimentary basin as of January 1, 2018.
16. Page 18, Line 22-Page 19, Line 17: Amends the prior Section. 18 of the A version of the bill, by eliminating the provision that expired net operating loss credits after 10 years, and adds new language that lowers the Net Operating Loss Credit for non-North Slope activity to 15% as of January 1, 2017. The provision that prevented the Gross Value Reduction from enhancing a Net Operating Loss remains in the Committee Substitute.
17. Page 19, Line 18-Page 20, Line 15: Adds a new Section. 20 by conforming to Section. 19 of the Committee Substitute, eliminating the Net Operating Loss Credit for the Cook Inlet sedimentary basin as of January 1, 2018.
18. Page 20, Line 16-Page 21, Line 2: Removes the language in the previous Section. 20 of the A version of the bill, related to the expiration of Net Operating Loss Credits after 10 years.
19. Page 21, Line 3-14: Conforms to renumber subsections earlier in the bill.

20. Section. 22 of the previous version A of the bill, dealing with confidentiality requirements, was removed.
21. Sections. 23, 24, and 25 of the previous version A of the bill, provisions that hardened the minimum tax floor, were removed.
22. Page 21, Line 15- Page 22, Line 7: Adds a new Section. 23, lowering the Well Lease Expenditure Credit to 20% by January 1, 2017.
23. Page 22, Line 8-Page 23, Line 3: Adds a new Section. 24, conforming to Section. 23 and eliminating the Well Lease Expenditure Credit for the Cook Inlet sedimentary basin by January 1, 2018.
24. Page 23, Line 4- Page 24, Line 11: Adds a new Section. 25 that grandfathers exploration activity that has spudded but not completed in the Frontier Basins.
25. Page 24, Line 12-Page 25-Line 5: Amends the previous Section. 26 of the A version of the bill by removing the limitation on companies to receive credits if their global revenues are in excess of \$10 billion; raises the per-company annual refund credit to \$85 million; and adds language to prevent a company from splitting into subsidiaries in order to claim more than the per-company annual refund limit.
26. Page 25, Lines 6-20: Amends the previous Section. 27 of the A version of the bill, related to Alaskan resident hire. Rather than tying the percentage of cashable credits to a company based upon the rate of Alaskan resident hire, the Department of Revenue would be required to promulgate regulations, giving priority for payment from the tax credit fund for companies whose employees, and contractors, have a resident hire rate in excess of 75%.
27. Page 25, Line 21- Page 26, Line 5: Amends the previous Section. 27 of the A version of the bill, related to a definition of an outstanding liability to the state. The current definition now defines that only the same amount of a liability to the state for oil and gas related activity can be used to reserve a credit refund.
28. Page 26, Line 8: Conforms to the elimination of the Net Operating Loss Credit in the Cook Inlet sedimentary basin; is essentially the same language, renumbered, as the previous Section. 28 of the A version of the bill.
29. The previous Section. 31 of the A version of the bill, preventing the Gross Value at the Point of Production, from going below 0, is removed.

30. Page 27, Line 31-Page 30, Line 14: Adds a new Section. 32 to conform to the elimination of the Cook Inlet tax cap calculation, and the calculation for the tax on gas produced elsewhere in state for use in-state.
31. Page 30, Line 15- Page 31, Line 34: Adds a new Section. 33, conforming to Section. 10 and 33 of the bill.
32. Page 31, Lines 5-Page 32, Line 18: Adds new Sections. 34 and 35, putting a lifespan on oil or gas qualifying for the Gross Value Reduction, to five years after the production of commercial quantities. For oil or gas that qualifies for the Gross Value Reduction that is in production as of January 1, 2017, the Gross Value Reduction expires on January 1, 2021.
33. Page 36, Lines 16-24: Adds a new Section. 39 to conform to the changes in Section. 10 of the bill.
34. Page 37, Lines 19-25: Amends the previous Section. 37 of the A version of the bill, related to the limiting of a tax credit to the municipal entity. The only changes were conforming changes to the legislative drafting manual.
35. The previous Section. 39 of the A version of the bill, the prior definition of outstanding liability to the state, is removed.
36. Page 38, Line 19-Page 39, Line 27: Adds a new Section. 44, requiring a taxpayer seeking a refundable tax credit, to post a surety bond in the amount of \$250,000. The bond would serve as financial relief to political subdivisions and local contractors in Alaska in the event the taxpayer entered into bankruptcy.
37. Page 39, Lines 28-Page 40, Line 2: Conforms the Sections. 45, 46, and 47, related to repealing statutes earlier in the bill.
38. Page 40, Line 3-6: Adds a new Section. 48, makes Sections. 7-9, 26 and 28 effective January 1, 2017.
39. Page 40, Lines 7-Page 42, Line 9: Adds new Sections. 49, 50, 51, and 52 placing transition language for the Qualified Capital Expenditure Credit and the Well Lease Expenditure Credit; the Net Operating Loss Credit; Filing of a tax credit.
40. Page 43, Line 3: Adds a new Section. 55, making Sections. 25 and 53 effective immediately.

41. Page 43, Lines 4-5: Adds a new Section. 56, making Sections. 10-16, 18, 20, 24, 32, 33, 39, 46, 51 and 52 effective January 1, 2018.
42. Page 43, Lines 6-7: Adds s new Section. 57, making Sections. 21, 22, 29-31, 36-38, 40, 41, 43, 47, 49, and 50 effective January 1, 2022.
43. Page 43, Lines 8-9: Adds a news Section. 58, providing that, except for Sections. 55-57, the Act takes effect January 1, 2017.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version:	CSSB 130(RES)
Fiscal Note Number:	3
(S) Publish Date:	4/13/2016

Identifier: SB130CS(RES)-DOR-TAX-04-13-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: Senate 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

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues	10,000.0	55,000.0	75,000.0	70,000.0	120,000.0	125,000.0
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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 amendments made in the Senate Resources Committee to the governor's original version. Baseline scenario assumes the Final Spring 2016 Revenue Forecast. The cover sheet of this document only includes the revenue raising numbers, with any program expenditure savings noted in the detail table on p. 4.

Prepared By:	Ken Alper, Director	Phone:	(907)465-8221
Division:	Tax Division	Date:	04/13/2016 04:00 PM
Approved By:	Jerry Burnett, Deputy Commissioner	Date:	04/13/16
Agency:	Department of revenue		

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

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 Senate Resources Committee substitute, we anticipate additional revenue of -\$15 to \$40 million per year over the time period contained in the fiscal note, with the changes concentrated in the last two years of the period. Revenue reductions in 2022 result in the zero tax rate in Cook Inlet as the statutory tax caps are scheduled to sunset. Positive revenues will come from certain production moving from the lower "new oil" regime to the higher "legacy oil" regime after five years of production. A small indeterminate amount would come from the restoration of compound interest and an interest in the interest rate for assessed delinquent taxes.

Budget reduction impact of \$0 to \$140 million per year over the period of the fiscal note is due to the credit reductions, primarily in Cook Inlet, described in the detail of specific provisions on the next page.

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 Resources committee substitute reduce Cook Inlet credits for Net Operating Losses (AS 43.55.023(b)) from 25% to 15% in 2017, and to zero in 2018. The Qualified Capital Expenditure credit (AS 43.55.023(a)) is reduced from 20% to 10% in 2017, and to zero in 2018. The Well Lease Expenditure credit (AS 43.55.023(l)) is reduced from 40% to 20% in 2017 and to zero in 2018. "Middle Earth" credits will remain at the 2017 Cook Inlet levels.

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%-35% in 2017 and zero in 2018. A tax rate of zero for oil and gas production in Cook Inlet is also imposed in 2018, along with elimination of the current ELF-based "tax caps."

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 \$85 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 very large 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.

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 7% above for the first three years a tax is delinquent, going to zero interest thereafter.

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 priority for companies with greater than 75% Alaska Hire in event that the available funds in the Oil and Gas Tax Credit Fund is inadequate to meet the demand.

Analysis Continued

Revised 4-12-16 by Department of Revenue

Provisions in CSSB 130(RES) 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 15% effective 1/1/17, then to 0% on 1/1/18 (modeled separately from items 2 and 3).	\$0	\$0	\$0	\$0	\$0	\$0
2. The rates for QCE credits and WLE credits for Cook Inlet are changed to 10% and 20%, respectively, on 1/1/17; then to 0% for both on 1/1/18 (modeled separately from items 1 and 3).	\$0-\$5	\$0-\$5	\$10-\$15	\$10-\$15	\$10-\$15	\$30-\$40
3. Cook Inlet tax caps are repealed and a tax rate of 0% for Cook Inlet oil and gas is implemented effective 1/1/18 (modeled separately from items 1 and 2).	(\$5)-\$0	(\$5)-\$0	(\$5)-\$0	(\$5)-\$0	(\$5)-\$0	(\$50)-(\$25)
4. The interest rate on delinquent taxes is changed to 7% above the Fed Res Discount rate, compounded quarterly for the first three years, then to zero interest thereafter.	Indeterminate					
5. The GVR cannot be used to create or increase a net operating loss.	\$0	\$0	\$0	\$0	\$0	\$5-\$15
6. 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
7. A tax exempt entity may earn credits applicable to only those lease expenditures subject to tax	Indeterminate					
8. Special tax treatment for qualifying "gas used in state" outside of Cook Inlet eliminated on 1/1/18 (currently tied to Cook Inlet gas ceiling)	Indeterminate					
Total Revenue Impact (does not include provisions 1-2)	(\$5)-\$0	(\$5)-\$0	(\$5)-\$0	(\$5)-\$0	(\$5)-\$10	(\$15)-\$40
A. Budget impact of change in net operating loss credits for Cook Inlet (provision 1 above)	\$0	\$5-\$10	\$10-\$20	\$10-\$20	\$10-\$20	\$10-\$20
B. Budget impact of change in QCE/WLE credits for Cook Inlet (provision 2 above)	\$5-\$10	\$30-\$40	\$30-\$40	\$30-\$40	\$75-\$100	\$75-\$100
C. Budget impact of change in net operating loss, QCE, and WLE credits for Middle Earth effective 1/1/17.	\$0-\$5	\$0-\$5	\$0-\$5	\$0-\$5	\$0-\$5	\$0-\$5
D. Budget impact of limiting refunds to \$85 million per company per year (only shifts timing of refunds - impact is after all other provisions of bill)	Limited impact under forecast - net neutral between FY18-19-20					
E. The GVR cannot be used to create or increase a net operating loss (provision 5 above)	\$0	\$10-\$20	\$20-\$30	\$15-\$25	\$5-\$15	\$0-\$10
F. Budget impact of exploration credit extension for well spudded by 7/1/16	(\$5)-\$0	(\$5)-\$0	\$0	\$0	\$0	\$0
G. Budget impact of GVR applying to fields for a period of 5 years (provision 6 above)	\$0	\$0	\$0	\$0	\$0	\$0
Total Budget Impact	\$0-\$15	\$40-\$75	\$60-\$95	\$55-\$90	\$90-\$140	\$85-\$135
Total Fiscal Impact - does not include revenue impacts from potential changes in investment²	(\$5) - \$15	\$35 - \$75	\$55-\$95	\$50-\$90	\$85-\$150	\$70-\$175
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	\$605	\$718	\$677	\$508	\$242	\$128
Change in year-end balance due to bill	-\$13	-\$33	-\$55	-\$77	-\$23	-\$8

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.

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 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:	SB 130
Fiscal Note Number:	2
(S) Publish Date:	1/19/2016

Identifier: DOR-TAX-01-13-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: Governor

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							
Miscellaneous		(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)
Total Operating	0.0	(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)

Fund Source (Operating Only)

1004 Gen Fund		(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)
Total	0.0	(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues		100,000.0	100,000.0	50,000.0	50,000.0	50,000.0	50,000.0
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Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 1,500.0 *(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:

Not applicable, initial version.

Prepared By: Ken Alper, Director
 Division: Tax Division
 Approved By: Jerry Burnett
 Agency: Deputy Commissioner, DOR

Phone: (907)465-8221
 Date: 01/13/2016 12:00 PM
 Date: 01/13/16

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

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 2015, about \$7.4 billion in tax credits were 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 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. 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, separate legislation will be proposing an appropriation to cover any tax credits earned through the effective date. This includes 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.

In addition, separate legislation is being developed to establish a direct loan program administered by the Alaska Industrial Development and Export Authority (AIDEA). The loans will support the development of proven oil and gas reserves, providing an attractive alternative to conventional financing. The transition appropriation, as described in the prior paragraph, will endow this new loan fund with an initial deposit of \$200 million.

Summary of Fiscal Impact

DOR's estimate is that this legislation will have an initial fiscal impact of \$500 million per year. Of this, \$400 million would be saved through reduced operating budget expenditures and \$100 million would come from increased revenues. In subsequent years, the estimated impact particularly on the total amount of refunded credits is limited by DOR's current revenue and credit forecasts. DOR uses a conservative methodology to estimate future credits, and typically these figures are revised upwards as we get closer to a given forecast year.

The savings and new revenues come via three different mechanisms:

- 1) About \$200 million in reduced expenditures, as some tax credit certificates would no longer be earned due to the repeal of certain specific credits as well as the closing of certain loopholes.

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. 0

Analysis Continued

2) About \$200 million in reduced expenditures, as some tax credit certificates would continue to be earned by companies but would not be immediately eligible to be turned into cash. In most cases, credit certificates would have to be held by the companies until such time as they had tax liability. At that time the certificates could be used to reduce their liability.

3) About \$100 million would be earned in additional revenue. About half of this would come through "hardening" the minimum tax floor, thus reducing the ability of companies to offset the 4% payment. The other half would come from increasing the minimum tax rate from 4% to 5%. Also, the proposed change to interest rates would raise a small amount of additional revenue.

Based on DOR's oil price forecast, prices should be sufficiently recovered by FY 2019 that it would be unlikely that one or more of the major oil producers would have a net operating loss. That will eliminate the impact of one specific floor hardening provision, reducing the additional revenue estimate.

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 requested an estimate from the software developer, and currently assume a one-time cost of about \$1,500,000 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.

Detail of Specific Provisions

1) Repeal of certain credits and closing of loopholes

The bill repeals the Qualified Capital Expenditure Credit (AS 43.55.023(a)) and the Well Lease Expenditure Credit (AS 43.55.023(l)). These credits of 20% and 40% respectively apply only outside of the North Slope. For companies without a tax liability, they are generally "stacked" with the carried-forward annual loss credit (AS 43.55.023(b)) resulting in total state contribution to projects in the 45%-65% range. Companies who do not have an operating loss are also eligible to receive these credits. This provides large cash subsidies 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 several other restrictions to repurchase. Companies that do not meet these restrictions will be required to hold their certificates until they have a tax liability. Alternatively, they can transfer their certificates to another company to use against that company's liability. The additional restrictions are:

Analysis Continued

- * Any company with global annual revenue of greater than \$10 billion in the past calendar year;
- * Annual per-company limit of \$25 million;
- * Companies with any current outstanding liability to the state;
- * The percentage of a given certificate that can be repurchased is limited by that company's percentage of Alaska resident hire;
- * Credit certificates expire after ten years.

3) Floor hardening and other revenue increasing measures

Currently, the production tax on North Slope oil from fields not eligible for the Gross Value Reduction is limited by the 4% gross minimum tax, or "floor." Specifically, the sliding scale per-barrel credit cannot be used to reduce taxes below that level. However, there are several other credits that can reduce tax payments below the level of the floor, as far as zero. The bill makes several changes to prevent this and thus guarantee a minimum tax payment to the state.

- * Prevents several credits including carried-forward annual loss credit (NOL) from being used to reduce a minimum tax payment. If one or more of the three major producers has an operating loss at the end of a tax (calendar) year, under current law, they could use their NOL credit to offset their minimum tax payments beginning in January of the next calendar year. Our current projections show this happening in 2016 and 2017. With this change, the loss credit would be held until a future year when the producer had adequate tax liability against which to offset it. This specific change is being made retroactive to January 1, 2016.
- * Prevent per-taxable-barrel credits that cannot be used in a month, due to the limitation of the minimum tax, from being claimed at annual true-up of the monthly tax payments. Without this change, in years where there is substantial price volatility the state could be paying large refunds at the end of the year.
- * Extends the 4% minimum tax to all North Slope production, including fields eligible for the Gross Value Reduction.

The bill also increases the tax rate of the floor itself from a variable tax rate that is 4% if the price of oil is greater than \$25 per barrel, to 5% at all oil prices.

One final change that will generate additional revenue is to increase the interest rate for delinquent taxes, underpayments, and tax assessments. The new rate is designed to roughly equal the state's rate of return on its investment assets, thus reimbursing the state for its opportunity cost due to unpaid taxes.

4) Technical and non-revenue changes

The bill makes several other changes without a specific fiscal impact:

- * Repeals several older and currently unused exploration incentive credit programs
- * Repeals several obsolete or superseded statutory sections that refer to oil and gas production from prior years
- * Ensures that the Department of Natural Resources continues to receive appropriate seismic and downhole data as a condition of receiving state credits, despite the sunset of the exploration incentive credit program
- * Provides a confidentiality waiver so the state can release specific information about tax credits repurchased from individual companies.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version:	SB 130
Fiscal Note Number:	1
(S) Publish Date:	1/19/2016

Identifier: DNR-DOG-1-11-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: Governor

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							
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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?

Why this fiscal note differs from previous version:

Not applicable, initial version.

Prepared By: Corri Feige, Director
 Division: Division of Oil & Gas
 Approved By: Mark Myers, Commissioner
 Agency: Department of Natural Resources

Phone: (907)269-8775
 Date: 01/11/2016 12:00 AM
 Date: 01/11/16

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

Analysis

No fiscal impact.

NEW SUSTAINABLE

ALASKA

PLAN



Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform

SB130

Department of Revenue

Presentation to Senate Resources Committee

April 2, 2016

Bill Title

“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 calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments on 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 of “qualified capital expenditures”; 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 payment 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.” (273 words)

Suggested Informal Short Title

An Act reforming oil and gas tax credits and strengthening the minimum oil and gas production tax.

What We'll Be Discussing

1. Lay of the Land- Why Credit Reform is Needed
2. Credit Cost in Perspective
3. Work over Last Interim
4. Provisions of SB130
5. Impact of SB130 on Specific Industry Sectors
6. Fiscal Impact
7. Implementation
8. Future Presentations

**Lay of the Land:
Why Tax Credit Reform
is Needed**

Why Credit Reform is Needed

FY 2007 thru 2016, \$8.0 Billion in Credits

North Slope

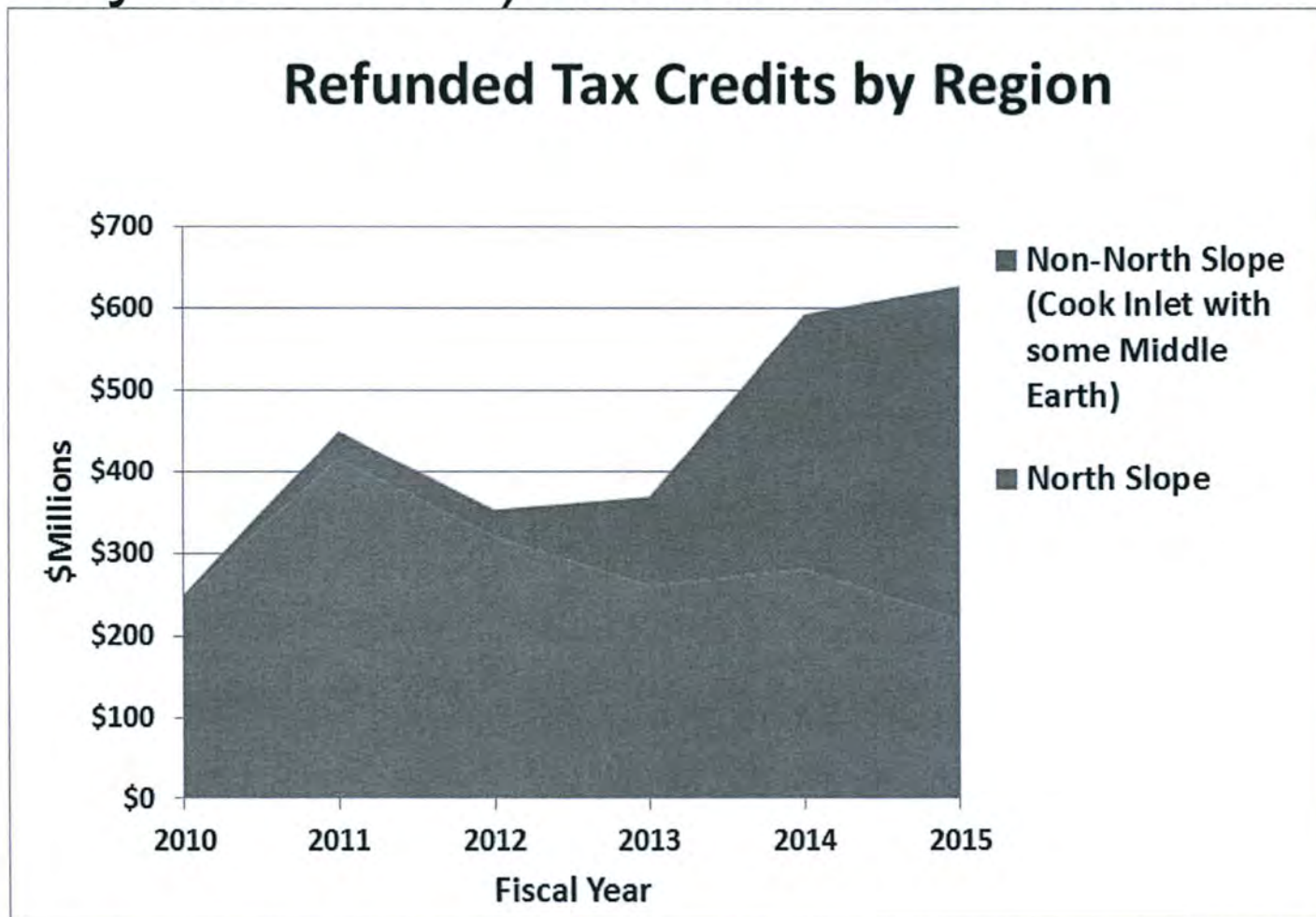
- \$4.4 billion credits against tax liability
 - Major producers; mostly 20% capital credit in ACES and per-taxable-barrel credit in SB21
- \$2.3 billion refunded credits
 - New producers and explorers developing new fields

Non-North Slope (Cook Inlet & Middle Earth)

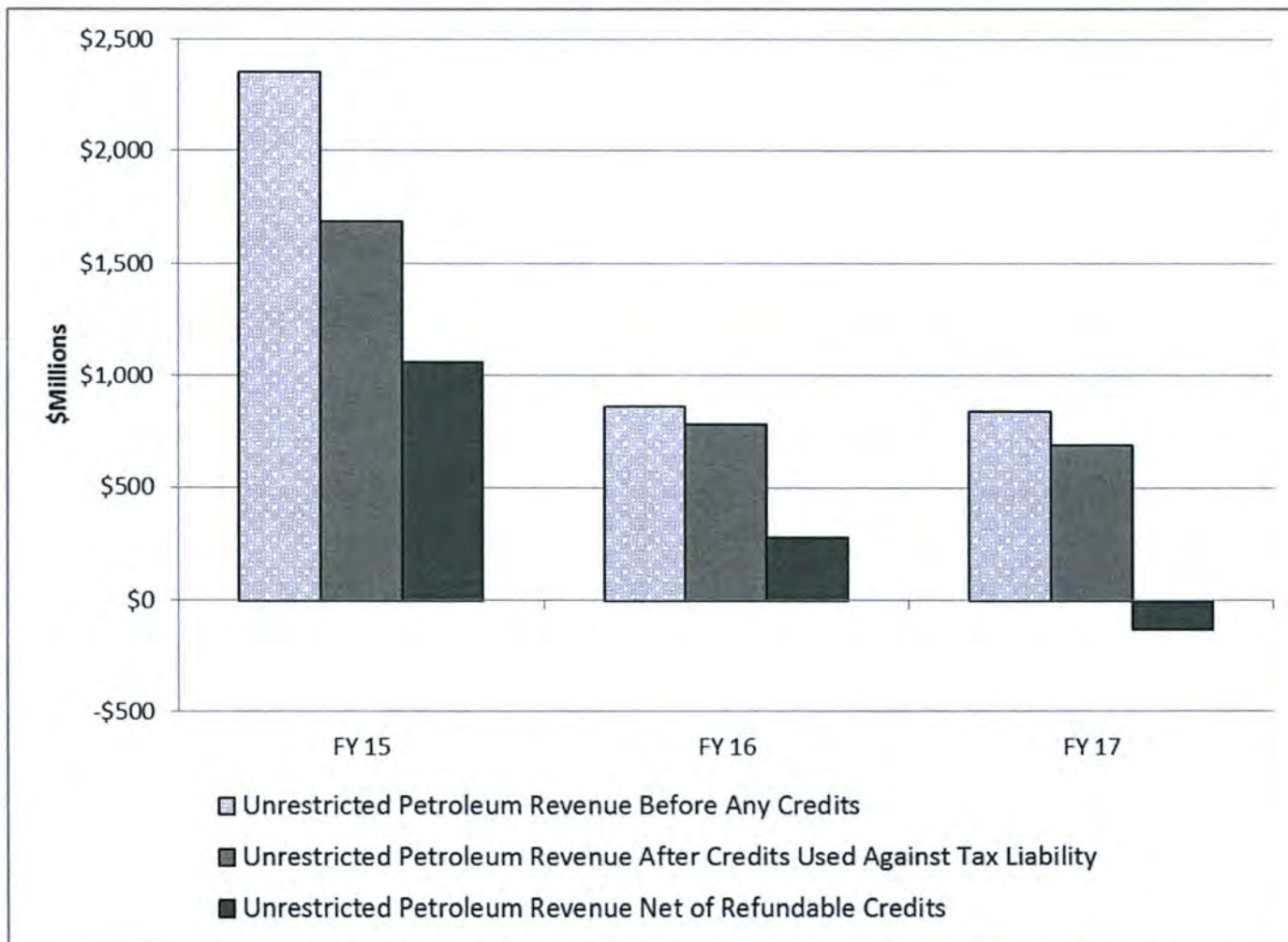
- \$0.1 billion credits against tax liability
 - Another \$500 to \$800 million Cook Inlet tax reductions (through 2013) due to the tax cap still tied to ELF
- \$1.2 billion refunded credits (most since 2013)

Why Credit Reform is Needed

- Tremendous growth in non-North Slope (almost entirely Cook Inlet) refunded credits since FY10



Why Credit Reform is Needed



*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

Credit Cost in Perspective

Credit Cost in Perspective

Of the \$3 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 million BOE
- Using midpoint \$700 million estimate, value of caps = **\$5.30 / barrel** or **\$0.88 / mcf**
- **Sum of Credits + Tax Caps: \$2.18 / mcf**

Credit Cost in Perspective

Status of Credit Fund / Demand for FY16-17

- **FY16 Appropriation Capped at \$500 million**
 - \$473 million paid out to date
 - About \$200 million North Slope, \$273 million non-North Slope
 - \$27 million left in fund with \$4 million in-process claims
- **Current DOR Work Pool \$675 million**
 - \$10 million in older NOL credits
 - \$22 million in older exploration credits
 - \$552 million in 2015 NOL, QCE, WLE credits
 - \$60 million in 2015 exploration credits
 - \$31 million additional 2015 NOL, QCE, WLE expected via amended returns

Credit Cost in Perspective

Status of Credit Fund / Demand for FY16-17

- All the “in hand” applications, if eligible, result in a known demand for FY2017 of **\$652 million**
- This is very current information, based on the CY15 tax “true-up” which was due on Thursday 3/31
- Expected credit applications during CY2016, which could also be paid in FY17:
 - Another \$40 million in quarterly requests for QCE and WLE outside the North Slope
 - Another \$60 million in “last minute” exploration claims
 - About \$20 million in LNG storage and refinery claims
- Total, foreshadowing “final” Spring 2016 forecast, \$775 million- slight reduction from \$825 million

Credit Cost in Perspective

- What impacts the change from \$825 to \$775?
 - Higher than expected NOL claims for CY 2015 (increases about \$100 million)
 - Decision to treat all CY 2016 claims for NOL credits as FY 2018 obligations, whereas in the past we had treated them as partly FY17 and party FY18 (decreases about \$150 million)
- So FY17 decreases by about \$50 million, but FY18 and FY19 will increase by at least that amount

Credit Cost in Perspective

Growing Carried Forward NOL's: A New Problem

- Since the beginning (2007) all companies except the three major producers have been able to receive cash for their tax credits. Majors must “carry them forward”
 - Companies producing less than 50,000 bbl /day
 - Hilcorp crossed over this threshold in 2015
- One or more of the majors had an operating loss in 2015. That becomes an NOL credit that can be used against taxes starting this January (to reduce payments below the minimum tax, as far as zero)
 - This only partly offsets minimum tax payments this calendar year. We still have some positive production tax income.
- With the Spring Revenue Forecast, we now see all three majors with much larger losses in 2016, and possibly for years beyond

Credit Cost in Perspective

- By January 2017, production tax monthly payments will be effectively zero (mainly the private royalty tax)
- Loss credits from the majors, in excess of what it takes to reduce taxes to zero, are carried into a future year

Production Tax and Carried Forward Production Tax Credits, per the spring forecast

Fiscal Year	ANS Oil Price	Production Tax Revenue (\$millions)	Carried Forward Credits at Year End (\$millions)
2016	\$39.52	\$133.4	\$385
2017	\$38.89	\$45.6	\$632
2018	\$43.79	\$15.7	\$766
2019	\$48.89	\$10.7	\$747
2020	\$54.48	\$12.5	\$600
2021	\$60.29	\$32.2	\$284
2022	\$61.64	\$105.2	\$151
2023	\$63.03	\$216.9	\$74
2024	\$65.45	\$198.0	\$1
2025	\$65.90	\$272.1	\$0

Work Over Last Interim

Work 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

Recommendations of Senate Working Group

1. Gradual implementation
2. Consider Timeline / Sector Impacts
3. Protect local vendors at bankruptcy
4. Protect Minimum Tax “Floor”
5. Protect Frontier Basin Tax Breaks
6. Enhance Reporting Requirements

Provisions of SB 130

Provisions of SB 130

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.

Provisions of SB 130

Main Bill Components

- 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*

Summary of Major Bill Provisions

Exploration Credits

- On 7/1/16, the “Jack up Rig” and “Frontier Basin” credits expire
- Also, regular .025(a) credits expire for North Slope and Cook Inlet
 - .025(a) credits remain for “Middle Earth” until 2022
- **Administration policy is to let them expire.**
- Preemptively repeal other exploration credit programs that are not currently being used, in AS 38.05.180(i) and AS 41.90.
- Add .025 DNR data requirements to .023(b)

Summary of Major Bill Provisions

Cook Inlet Drilling Credits

- **Repeal AS 43.55.023(a) and .023(I)**
 - SB21 repealed the “spending based” credits for the North Slope
 - Prevent profitable companies who pay zero taxes from receiving state credit payments
 - Need for a broader Cook Inlet tax reform before 2022
- **Reduce general Cook Inlet cash support for development to the 25% .023(b) credit**

Summary of Major Bill Provisions

Repurchase Limits

- Expand current .028(e)(4) restriction saying companies who produce greater than 50,000 BOE / day can't have credit certificates repurchased, and must hold them to use against future production
 - **Any company with global annual revenue greater than \$10 billion / year**
 - Restore PPT-era cap of \$25 million / company / year
 - Percentage of repurchase tied to percentage of Alaska resident hire
 - **Carried-forward loss credits expire after 10 years**

Summary of Major Bill Provisions

Remove Exceptions / Loopholes

- Provisions that artificially inflate 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

Summary of Major Bill Provisions

Strengthen Minimum Tax

- **Can't use an operating loss credit, small producer credit, or exploration credits to reduce payments below the 4% floor**
 - This is an actual fiscal impact in FY16; in calendar year 2015 one or more major producers had a net operating loss. In that case, NOL credits can reduce minimum tax to zero beginning this year.
 - This one provision is retroactive to 1/1/16
- **Extend 4% floor to GVR-eligible "new" oil**
- **Prevent per-taxable-barrel credits earned in one month from being used against another month's taxes at true-up**
- **Increase from 4% (at prices above \$25) to 5%**

Summary of Major Bill Provisions

Other Provisions

- Interest Rate Reform
 - Eliminate error in SB21 that prevents compound interest on underpayments and assessments
 - **Increase interest rate to state's "opportunity cost," seven percent above Fed Discount Rate**
- Confidentiality Waiver
 - Name of company and how much they received in state repurchased credits
- Transportation Costs can't reduce Gross Value below zero
- Credit certificates must first be used to satisfy any obligation to the state

Impact of SB 130 on Specific Industry Sectors

Bill Impact: Example Scenarios

North Slope Major Producer

- Higher oil prices: no change
- Prices below ~\$85: currently paying 4% minimum tax; must pay increase to 5%
- Extended period of very low prices: cannot use Net Operating Loss credit to reduce payments below the “floor”

Bill Impact: Example Scenarios

North Slope New or Smaller Producer

- Higher oil prices: no change
- Prices below ~\$85: must pay minimum tax. Currently per-barrel credit can reduce taxes to zero
- If company has an operating loss, the Gross Value Reduction cannot be used to increase the size of the loss to earn a larger NOL credit

Bill Impact: Example Scenarios

North Slope New Project Developer

- Net Operating Loss Credits continue to be earned at the 35% level – no change
- Large Multinational Companies: must hold their credit certificates to be used against future tax liability
- Smaller Companies: limited by \$25 million / company / year cap. Must carry forward all credits in excess of this

Bill Impact: Example Scenarios

Cook Inlet Existing Producer

- Currently pays low to zero taxes due to Cook Inlet tax caps, yet is eligible for 20%-40% credit repurchase for Capital and Well Lease Expenditure credits
- Repeal of these credits means producers without an operating loss do not earn refundable credits. Tax caps remain through the end of 2021

Bill Impact: Example Scenarios

Cook Inlet New Field Developer

- Currently receives a 25% Net Operating Loss credit stacked with either the 20% Capital or 40% Well credit. State typically refunds 50-60% of costs
- With repeal of Capital and Well credits, will continue to receive 25% Net Operating Loss credit
- Large Multinational Companies: must hold their credit certificates to be used against future tax liability
- Smaller Companies: limited by \$25 million / company / year cap. Must carry forward all credits in excess of this

Bill Impact: Example Scenarios

Interior / Frontier Area Explorer

- Currently receiving 65% state credits for exploration; 50-60% for development
- With repeal of Capital and Well credits, development projects will only receive the 25% Net Operating Loss credit
- However, exploration credits have been extended through 2022, meaning qualified expenditures continue to receive 65%

Fiscal Impact of SB 130 on State of Alaska Budget

Fiscal Impact

**At the time the bill was introduced,
FY17 Impact Est. \$500 Million / year**

- Elimination of about \$200 million / year in certificates
 - Mostly from repeal of .023(a) and (l) as well as elimination of so-called loopholes
- Deferral of payment on another \$200 million / year in certificates that would have to be held for use against future tax liability
 - Based on various new repurchase limits
- Additional revenue of about \$100 million
 - Strengthening minimum tax plus increase to 5%
 - Interest rate reform

Fiscal Impact

**Based on the Spring 2016 Revenue Forecast,
plus more granular modeling,
FY17 Impact Est. \$785 Million / year**

- Elimination of about \$50 million / year in certificates
- Deferral of payment on another \$550 million / year in certificates that would have to be held for use against future tax liability
 - Larger NOL's due to lower prices
 - Larger exploration spending before program sunset
- Additional revenue of about \$185 million
 - Added hardening; most producers will have 2016 NOL's, further reducing revenue below floor

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

Implementation

Implementation

Transition

- Bill is being written with an effective date of 7/1/16 for nearly all changes
- “Honoring Existing Credits” means:
 - Roughly \$200 million FY2016 “overhang”
 - Estimated \$625 million credits expected to be earned and payable in FY2017 (likely revised to \$575)
 - Plus all credits earned in first half of CY2016 prior to the effective date
 - Total equals about \$1 billion which will be paid via an appropriation to the .028 Tax Credit Fund
 - \$926.6 million fund cap in fiscal note, in addition to \$73.4 million in the operating budget

Implementation

Connection to Fiscal Plan

- SB130 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
 - HB129 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

Future Presentations

Content of Future Presentations

We've provided seven different presentations to other committees; all are on BASIS

- History and development of tax credits, and history of the minimum production 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
- Life cycle modeling of typical new projects, with impact of legislation
- Explanation and modeling of changes made in other committees

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Pulling Together to Build Our Future

Thank You!

Contact Information

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ALASKA OIL & GAS CREDITS

Presentation to Senate Resources Committee
Juneau, Alaska > Saturday, April 2, 2016

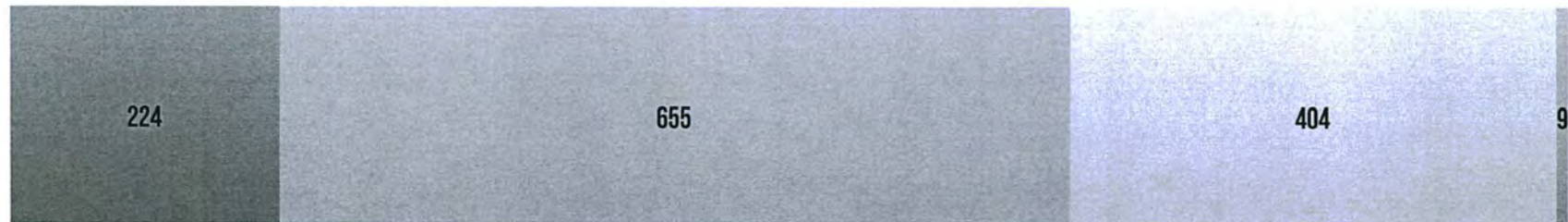
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<http://enalytica.com>

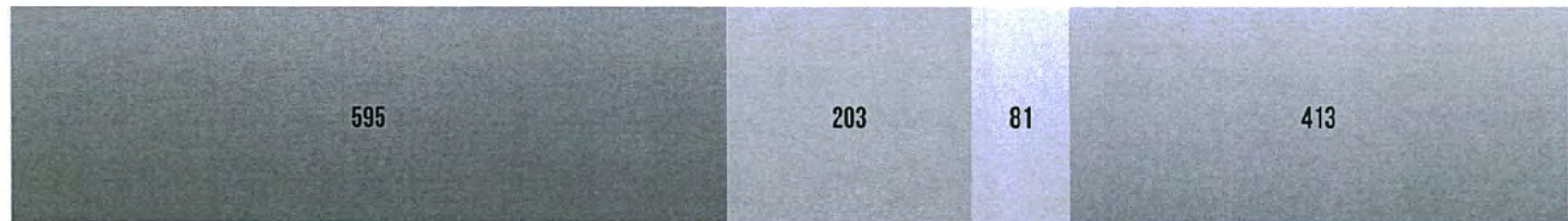
VISUALIZING ALASKA'S CREDIT SYSTEM (FY 2015)



■ NORTH SLOPE ■ NON-NS



■ NS REFUNDED ■ NS NON-REFUNDED ■ NON-NS REFUNDED ■ NON-NS NON-REFUNDED



■ NS \$ PER BARREL CREDIT ■ NS NET OPERATING LOSS ■ NS OTHER ■ NON-NS STATE SUPPORT

SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION

NS CREDITS ARE INTEGRAL TO OVERALL TAX SYSTEM

Credit	Details	Status	Purpose
Net Operating Loss (NOL) or Carried Forward Annual Loss credit (.023b)	Credit of 35% of a carried forward annual loss Refundable for producers with <50,000 boe/d of production	Current From January 1 2014 to January 1 2016 was at elevated level of 45% (SB21 transition arrangements)	Make impact of tax system the same for new developer as incumbent producer
\$/bbl Credit (.024 i&j)	\$0-\$8/bbl produced ('old' oil) or \$5/bbl produced ('new' oil). Used against liability. Sliding credit may not reduce liability below 4% gross floor, fixed credit may not reduce below 0	Current	Provide a measure of 'progressivity' to tax system, reducing tax rates at lower oil prices; integral to component of tax system
Exploration Credits (.025)	30%-40% of qualifying exploration costs for exploration wells or seismic outside existing units	Expire on July 1 2016	Incentivize new exploration
Small Producer Credit (.024c)	\$12mm/yr for producers with <50,000 boe/d production, tapering to 0 for producers with 100,000 boe/d	Closes to new applicants that do not have commercial production by May 1 2016 9 year 'tail' from first production for companies already eligible	Ease burden of previous fiscal system changes on new small companies that had come to the North Slope prior to changes

NON-NS CREDITS GEARED TO SUPPORT ACTIVITY

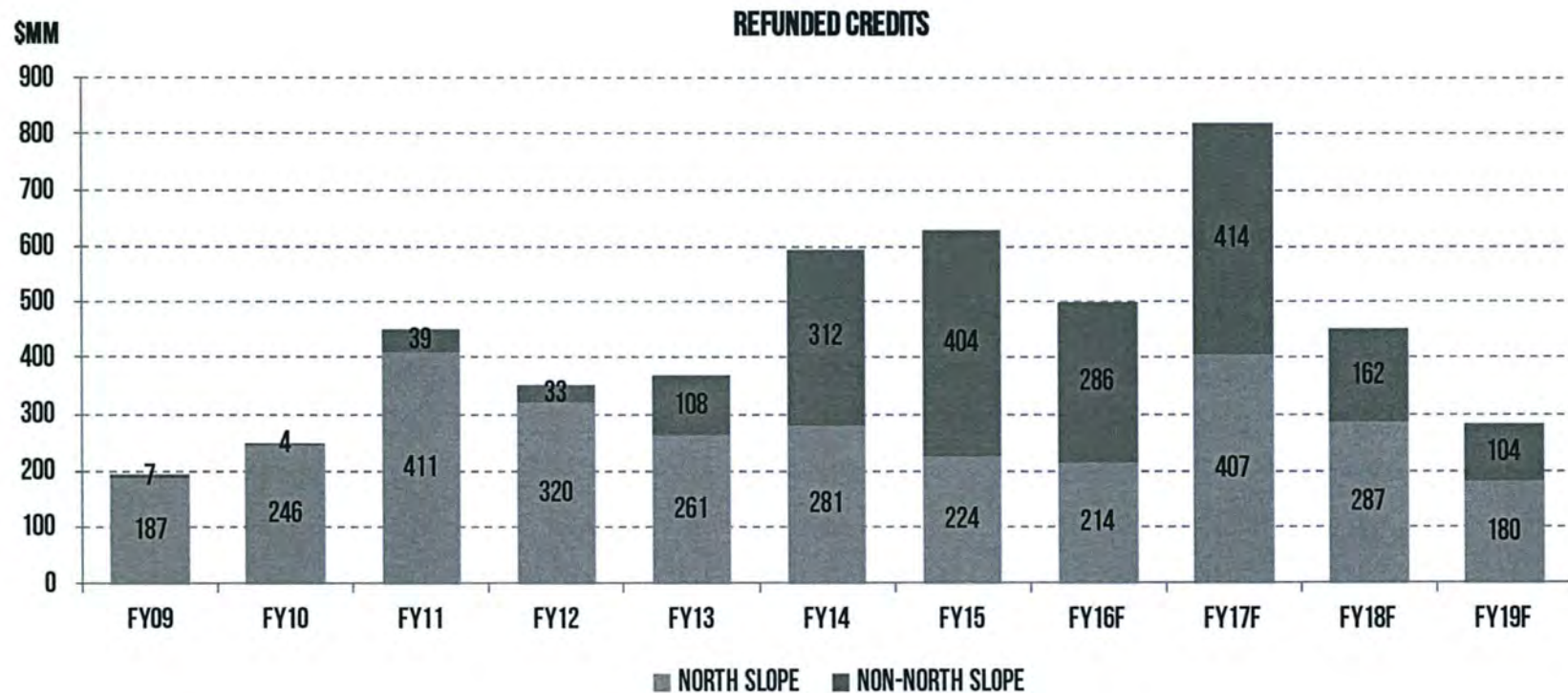
Credit	Details	Status	Purpose
Net Operating Loss (NOL) or Carried Forward Annual Loss credit (.023b)	Credit of 25% of a carried forward annual loss Refundable for producers with <50,000 boe/d of production	Current	Incentivize Cook Inlet Production
Capital & Well Expenditures (.023 a&l)	Credit of 20% for qualified capital expenditures (QCEs) Credit of 40% for QCEs that are intangible drilling costs	Current	Incentivize Cook Inlet Production
Exploration Credits (.025)	30%-40% of qualifying exploration costs for exploration wells or seismic based on distance from existing wells/units	Expire on July 1 2016	Incentivize new exploration
Small Producer Credit (.024c)	Up to \$12mm/yr for producers with <50,000 boe/d production, tapering to 0 for producers with 100,000 boe/d Non-refundable	Closes to new applicants that do not have commercial production by May 1 2016 9 year 'tail' from first production for companies already eligible	Limited applicability given low to zero tax liabilities and other credits
Frontier Basin Credit (.024a)	Up to \$6mm/yr	Closes to new applicants that do not have commercial production by May 1 2016 9 year 'tail' from first production for companies already eligible	Incentivize exploration & development outside North Slope and Cook Inlet

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



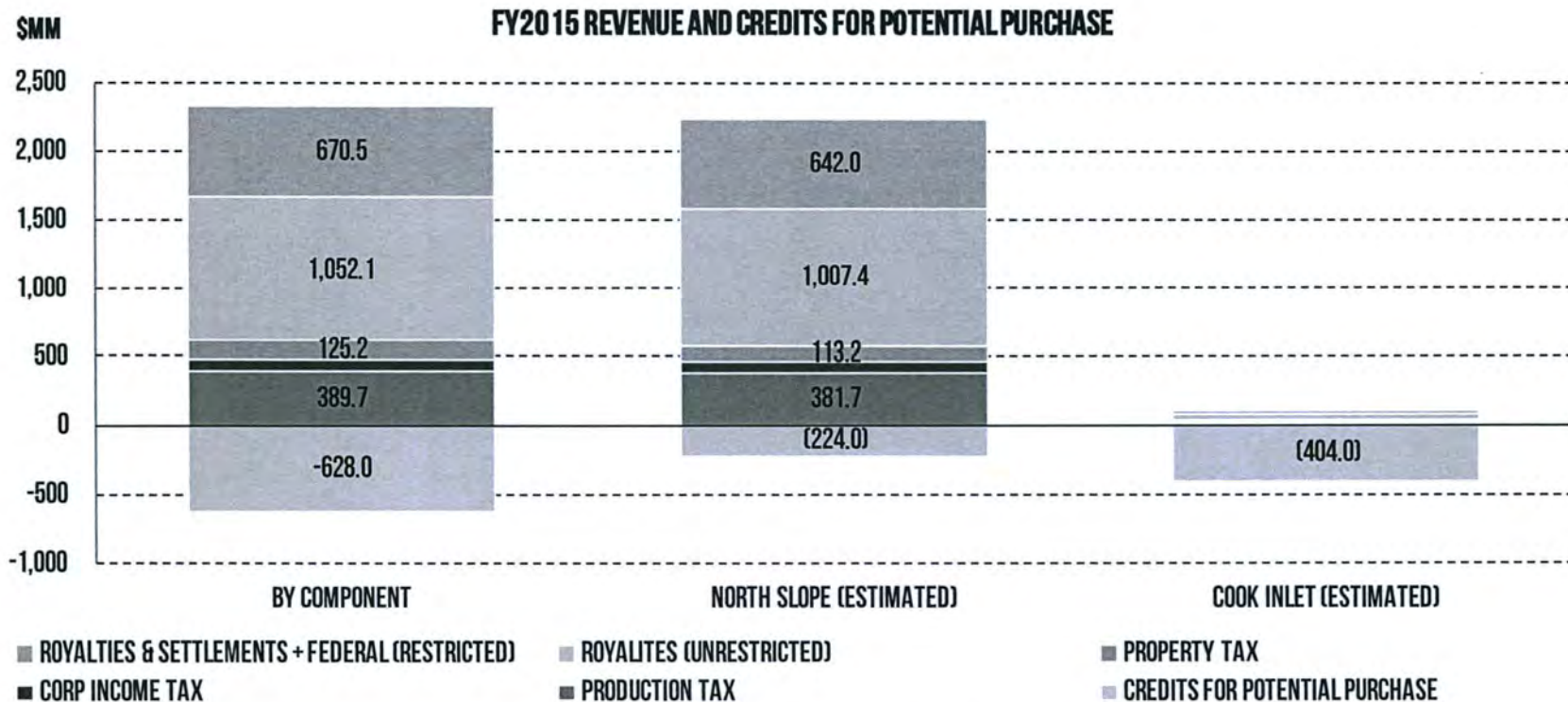
SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION

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; ENALYTICA ESTIMATES

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

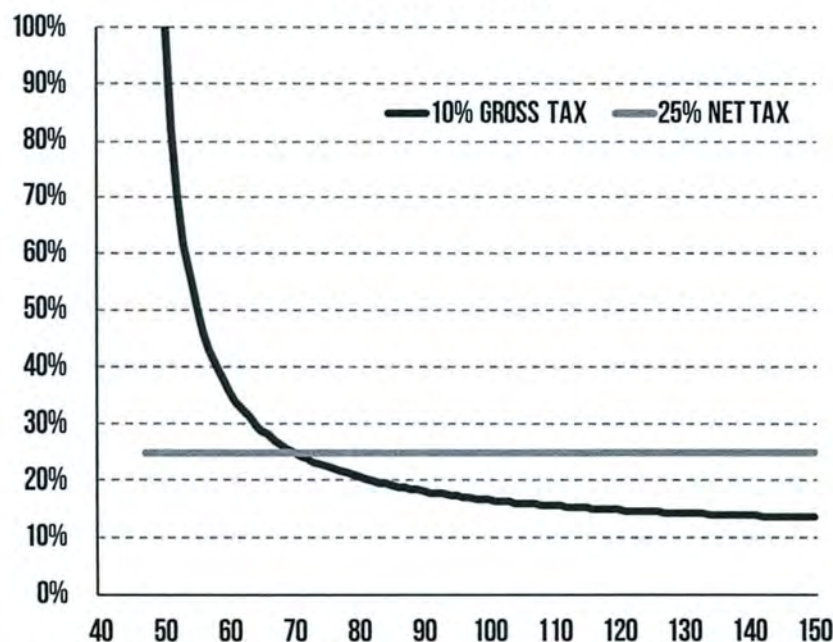
Harder to administer

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

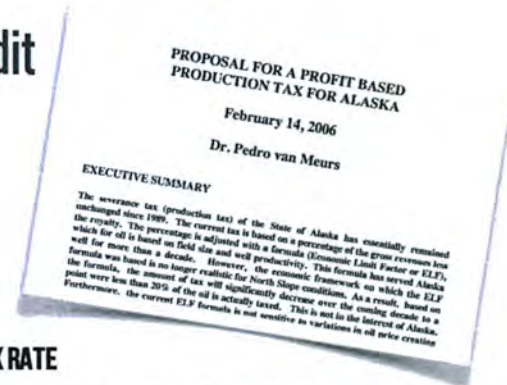
ALASKA'S PRODUCTION TAX: ORIGINS IN 2006 PROPOSAL

PPT as proposed by Dr Pedro van Meurs useful to understand core of system and evolution to date

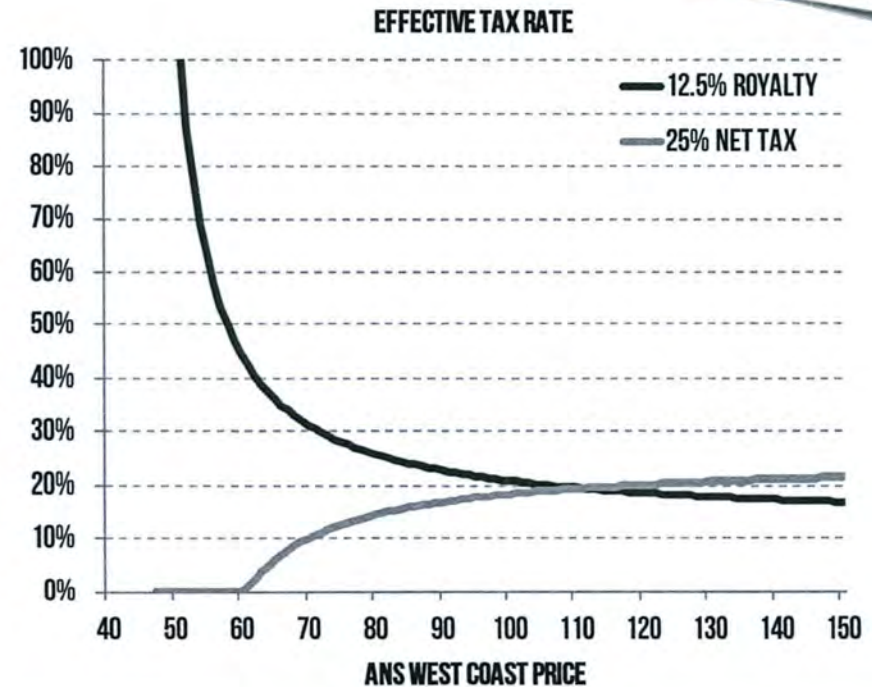
25% flat cashflow tax, 25% credit for net operating losses (NOLs), 20% capital credit

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

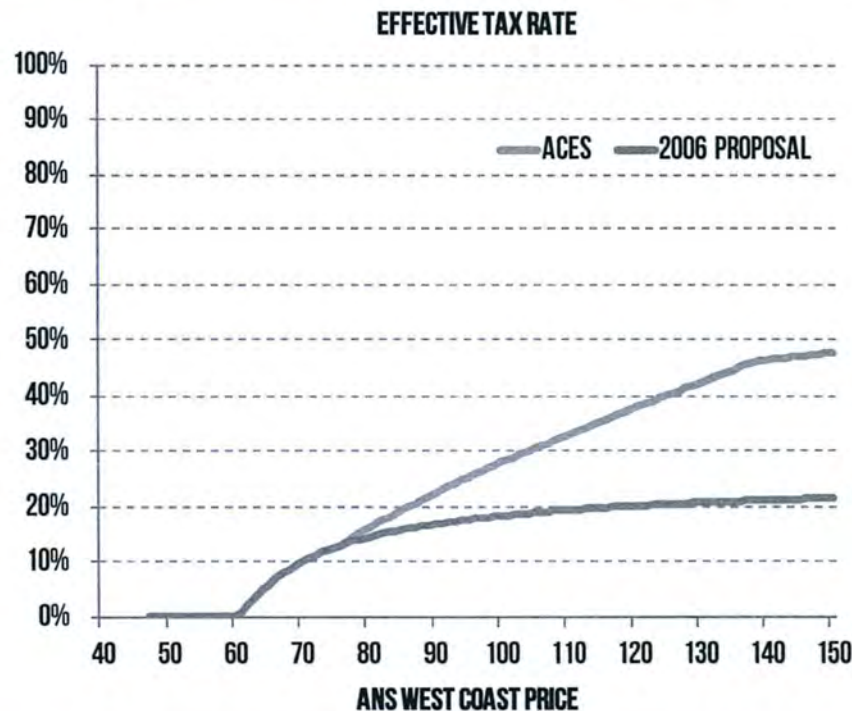
Tax rate 25% to 75% (variable with PTV/bbl), 20% capital credit, 40% exploration credit, 25% NOL credit

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

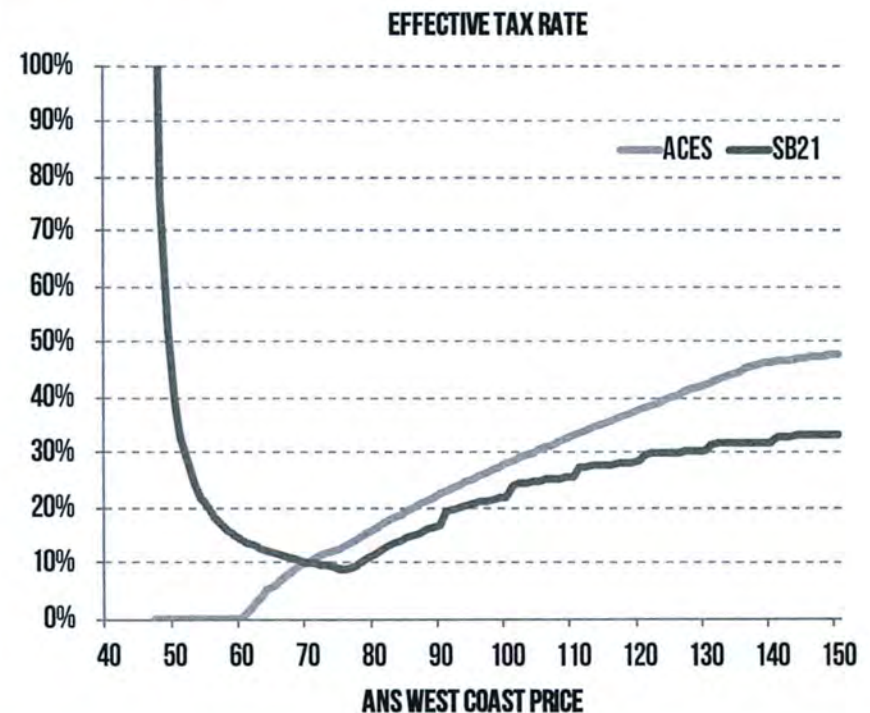
Tax rate 35%, \$0 to \$8 per-bbl credit, hardened gross floor, 35% NOL credit

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%



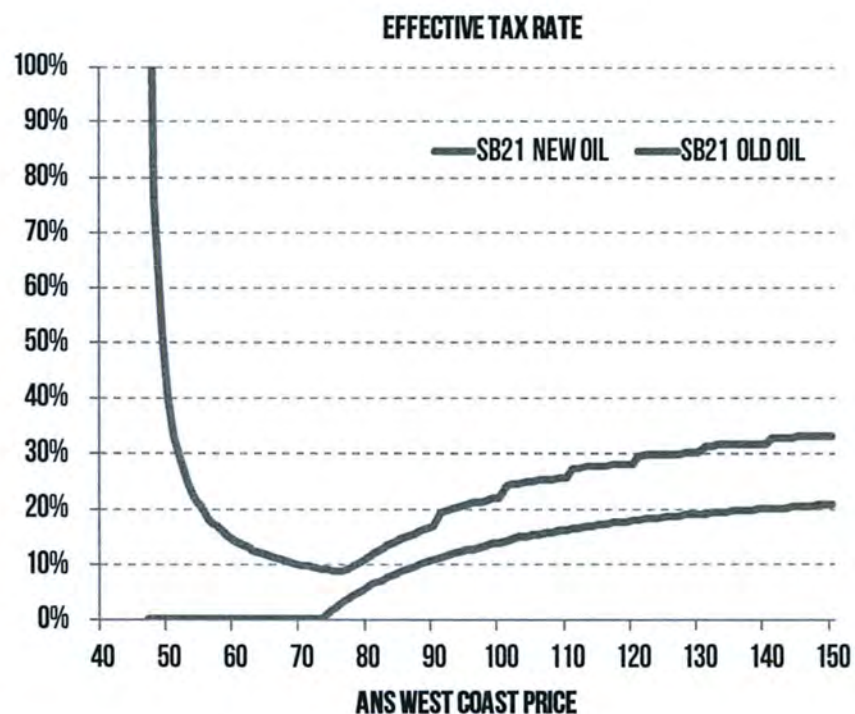
SB21: SPECIAL INCENTIVES FOR “NEW OIL”

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%



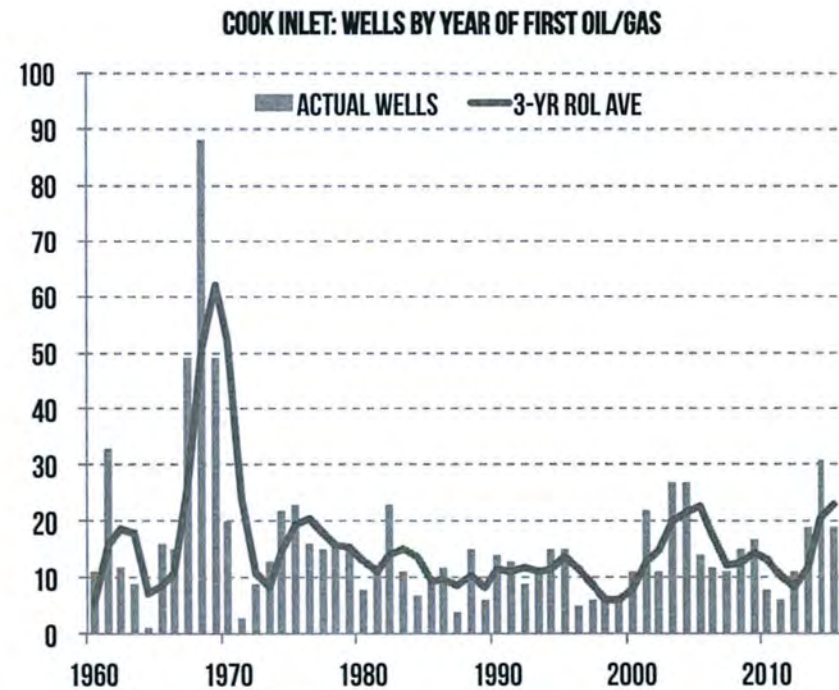
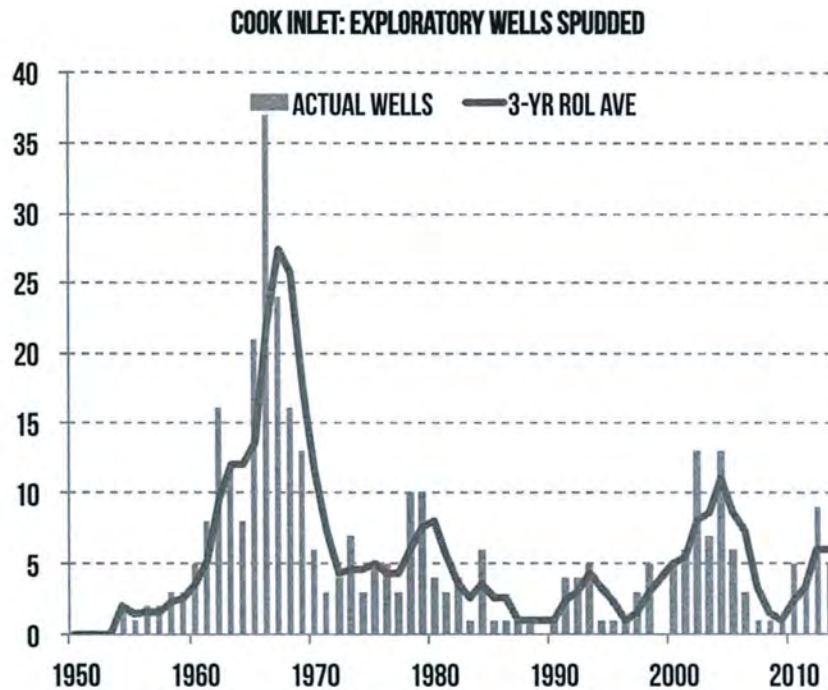
CI ACTIVITY HAS RESPONDED TO INCENTIVES

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



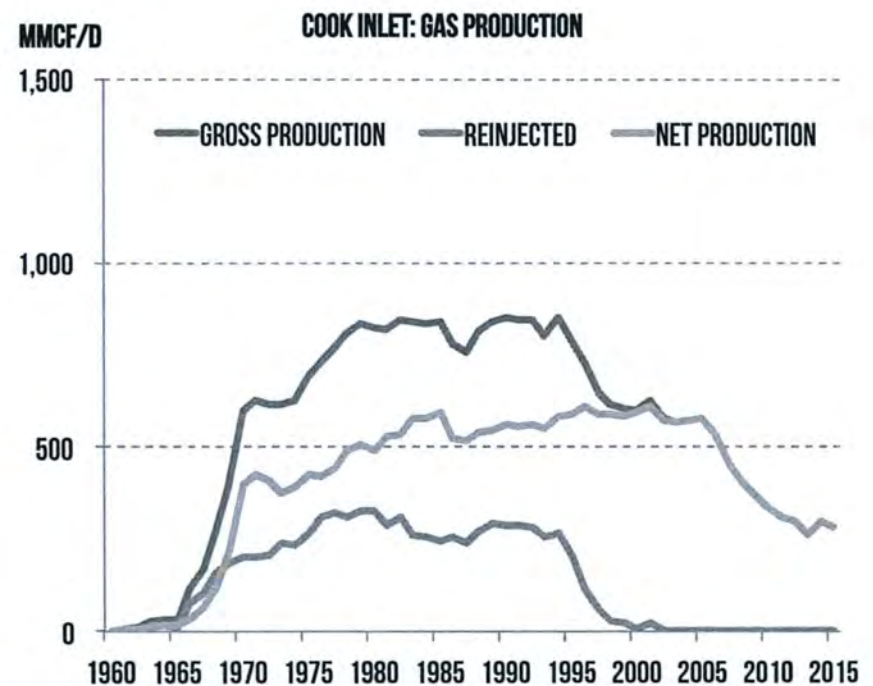
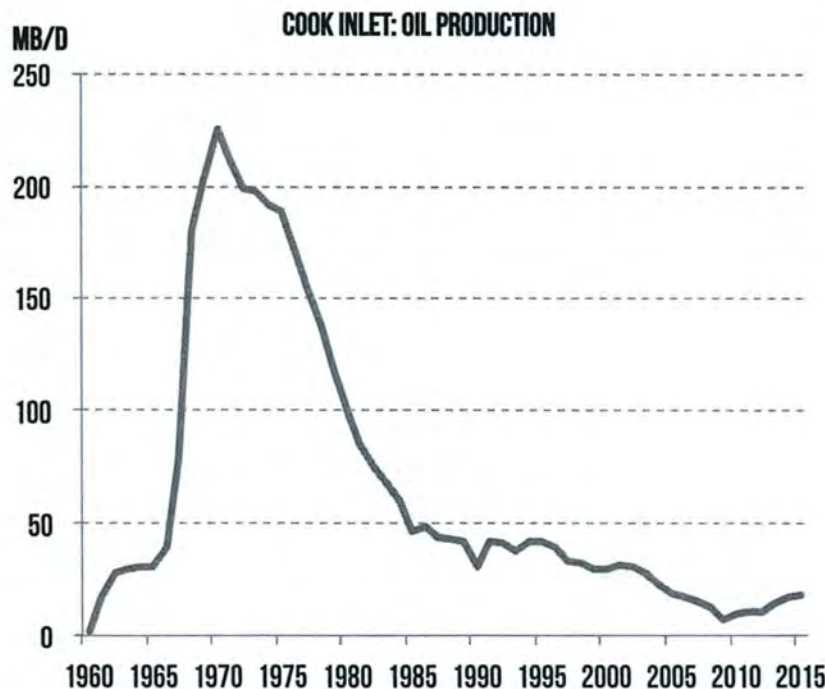
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

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



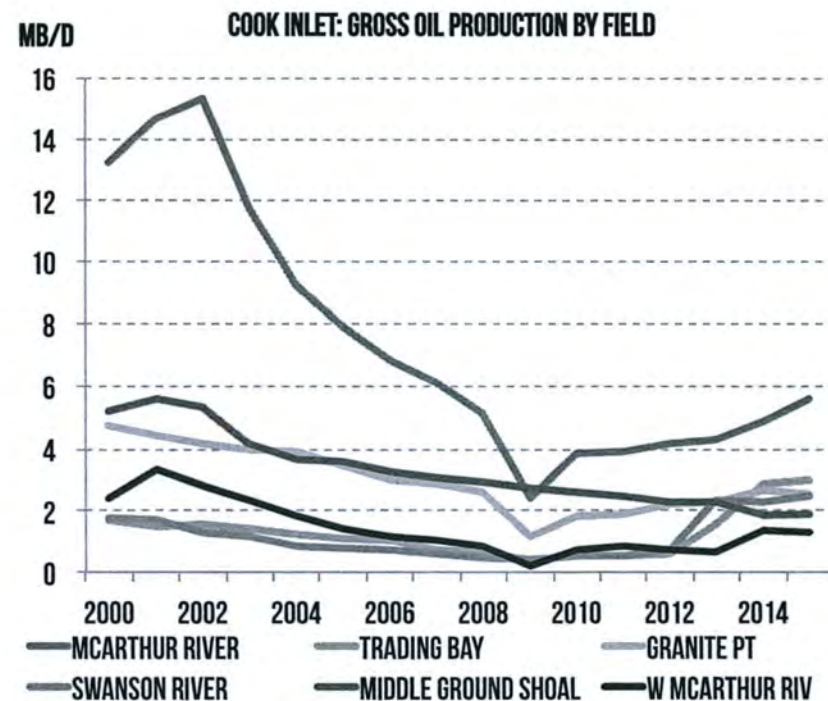
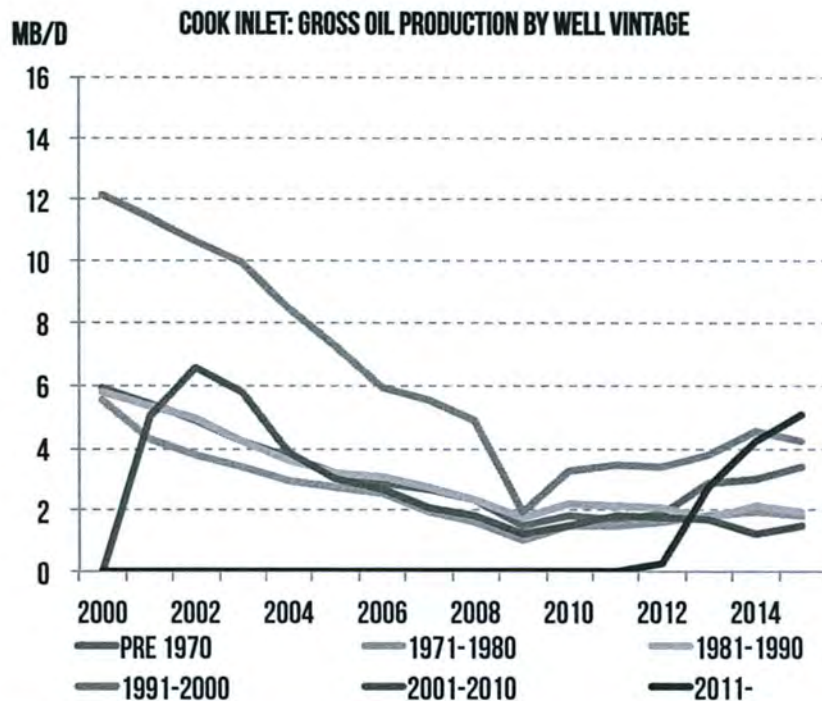
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

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)

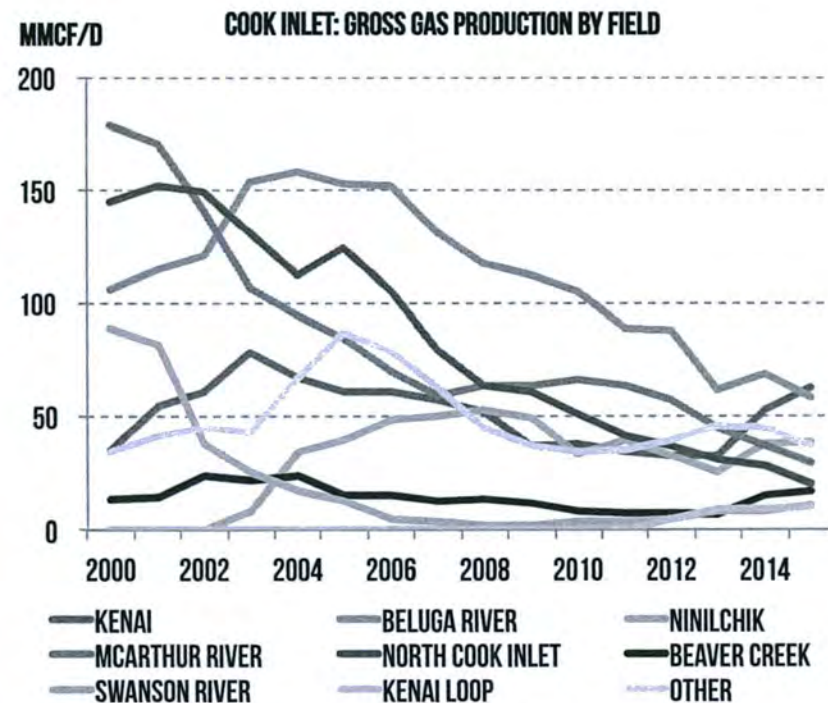
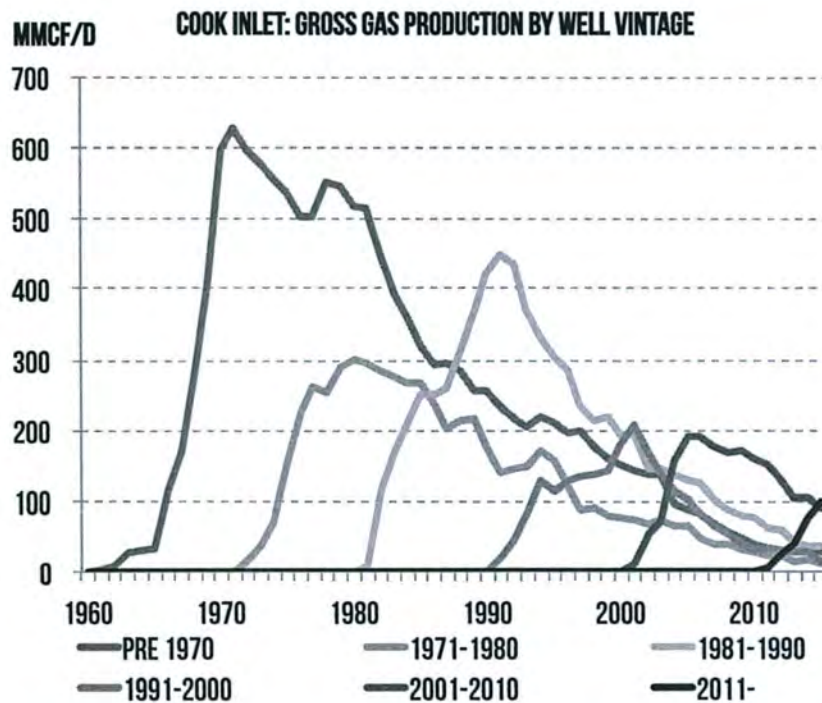
GAS FLATTENING FROM NEW WELLS IN EXISTING FIELDS

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)

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

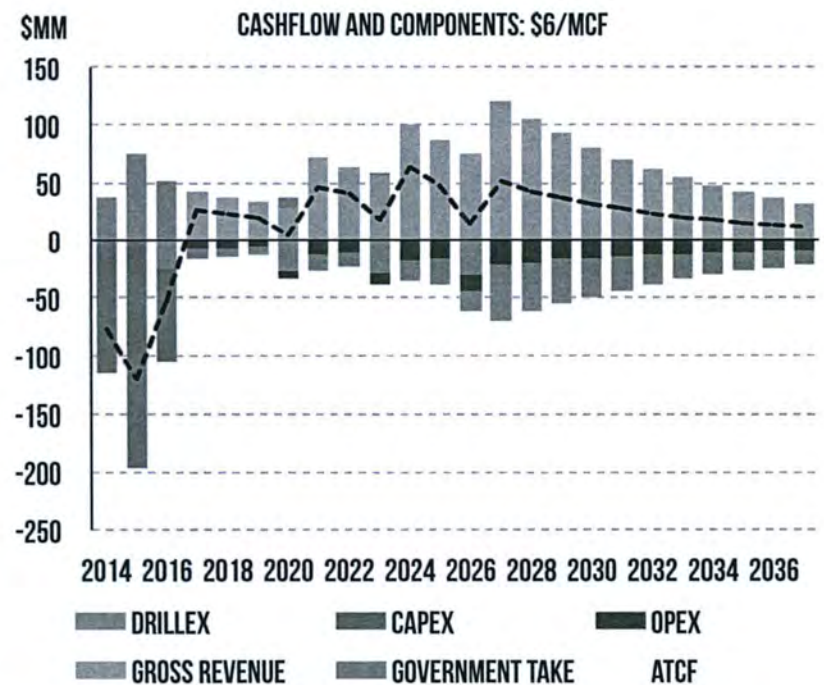
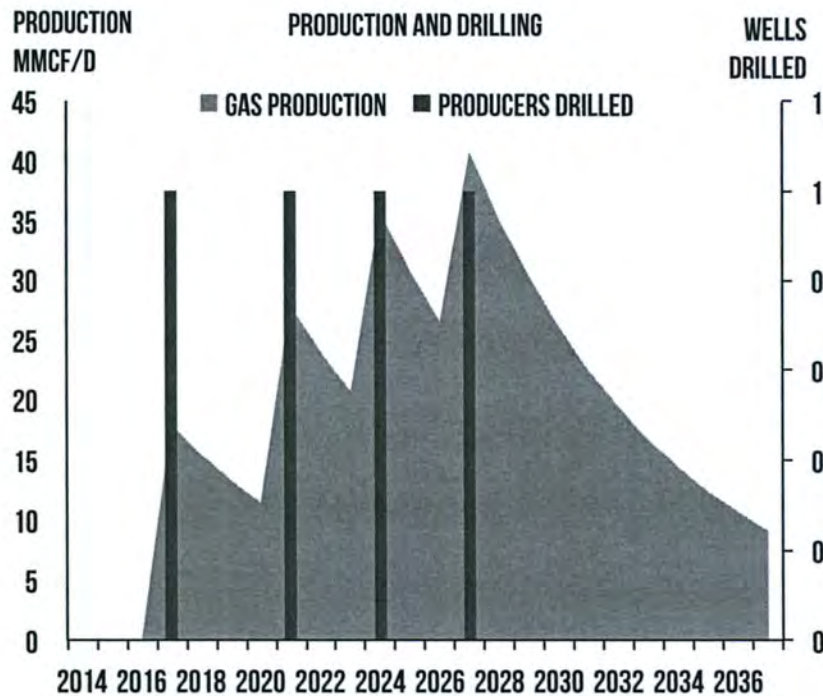
Credits more important for developing new resources, especially with demand constraints

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

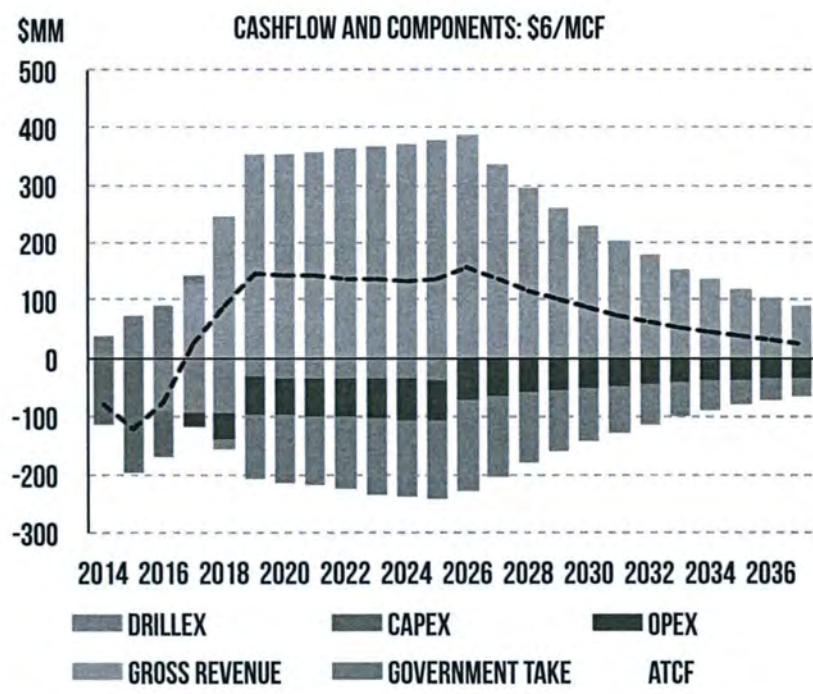
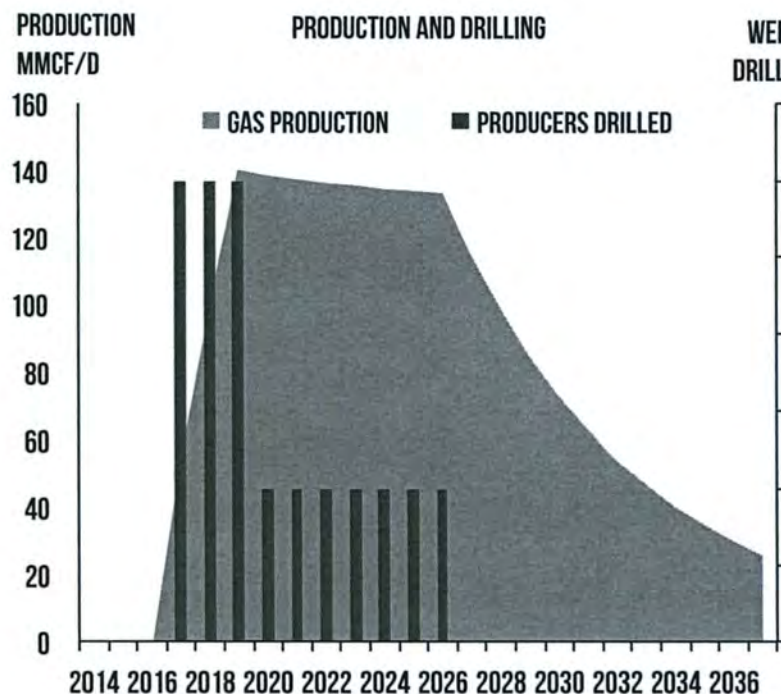


PROJECT #2: MARKET UN-CONSTRAINED (ASSUMPTIONS)

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

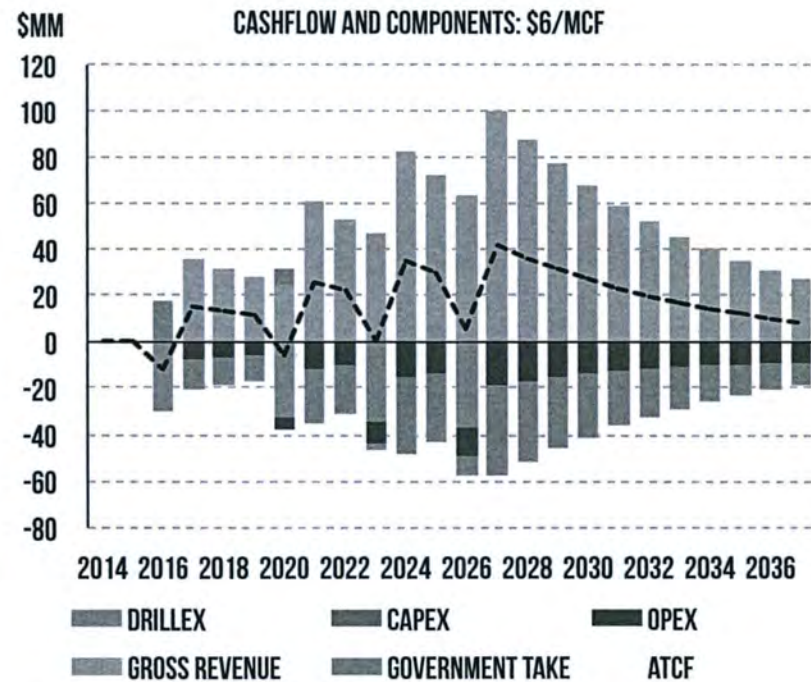
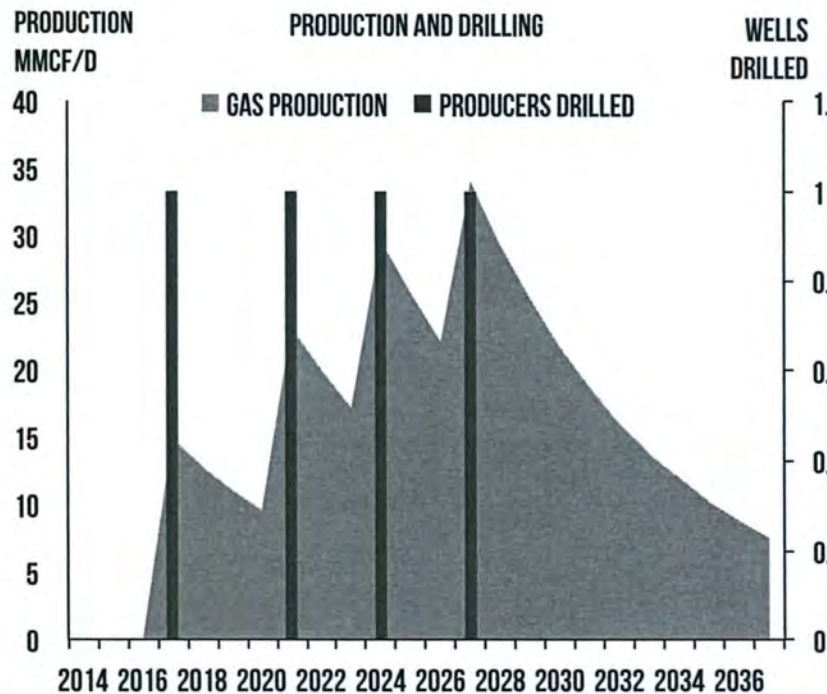


PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)

Drilling expenditures at existing production—smaller upfront investment

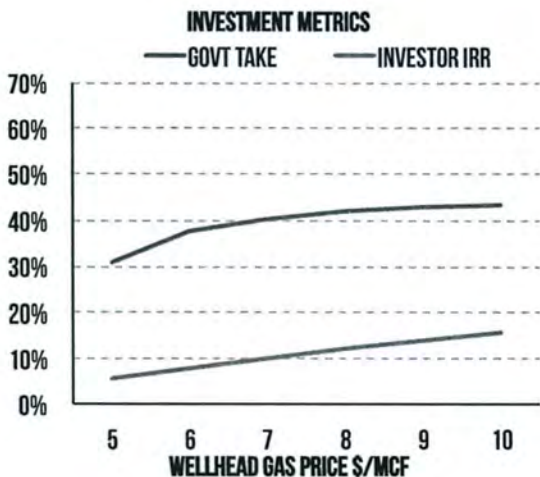
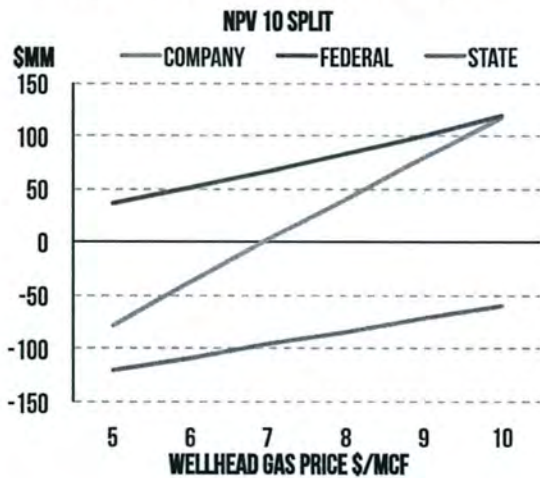
No market constraints assumed

This is a point-forward analysis—it ignores sunk, entry or acquisition costs

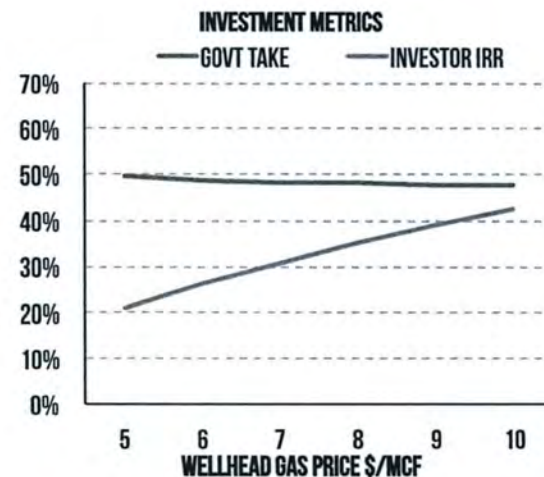
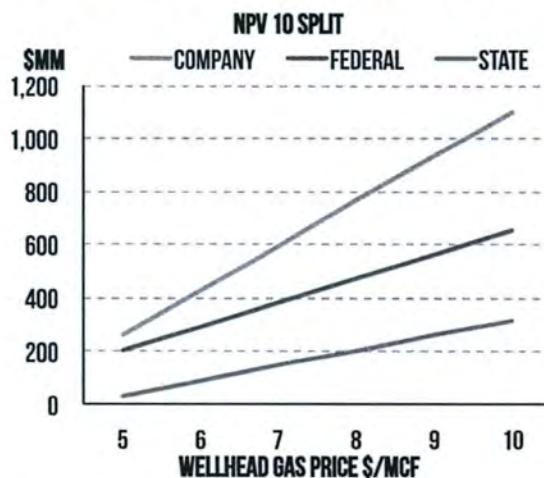


PROJECT ECONOMICS FOR DIFFERENT PROJECT TYPES

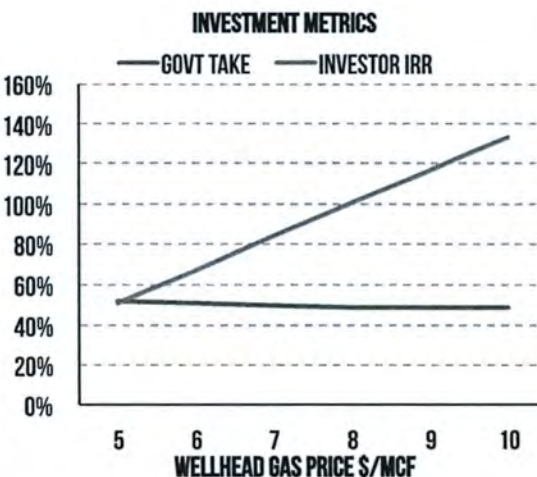
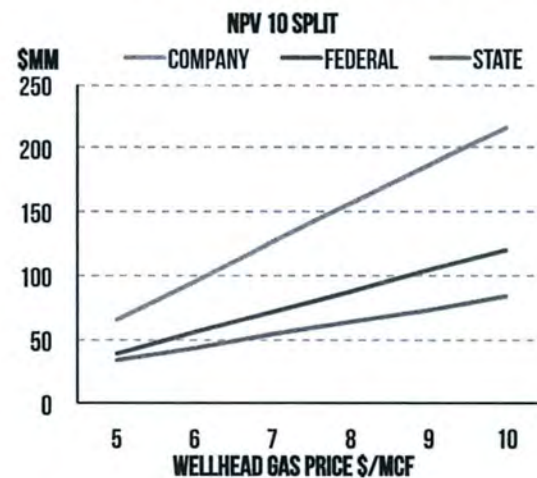
PROJECT 1 (CONSTRAINED)



PROJECT 2 (UN-CONSTRAINED)



PROJECT 3 (EXISTING)



NEW SUSTAINABLE

ALASKA

PLAN



Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform- SB130

Department of Revenue

Second Presentation: “Additional Modeling and Scenario Analysis”

Presentation to the Senate Resources Committee

April 4, 2016

What We'll Be Discussing

- Follow-ups from Prior Presentation
- Bill Details- Analysis and Modeling of Complex Sections
- Summary of Scenario Analysis and Life Cycle Modeling: Economics of Changes

Follow-Ups From Prior Presentation

Tax Credit Fund- Alternative History if Appropriation had Been at Statutory Level

Oil and Gas Tax Credit Fund: Budgeted vs. Actual vs. Statutory Tax Credit Fund Transfer Cap
 (Beginning with the first budget cycle after the passage of ACES in November 2007)

Fiscal Year	Original Appropriation (\$million)	Actual Claimed Credits (\$million)	Actual Production Tax (\$million)	Plus Credits Against Liab (\$million)	AS 43.55.011 Revenue (\$million)	Oil Price Per Spring 16 Forecast	Credit Cap per AS 43.55.028(c)	End Year Fund Balance	Non-Cashable Carried-Forward	Total Credit Oblig
Actual										
FY09	not to exceed \$175	\$193	\$3,101	\$334	\$3,435	\$85.73	\$343	\$150	\$0.0	n/a
FY10	unspec **	\$250	\$2,861	\$412	\$3,273	\$65.70	\$327	\$228	\$0.0	n/a
FY11	est. \$180	\$450	\$4,543	\$361	\$4,904	\$73.32	\$490	\$268	\$0.0	n/a
FY12	est. \$400	\$353	\$6,137	\$363	\$6,500	\$94.70	\$650	\$565	\$0.0	n/a
FY13	est. \$400	\$369	\$4,043	\$550	\$4,593	\$110.44	\$459	\$655	\$0.0	n/a
FY14	est. \$400	\$593	\$2,589	\$919	\$3,508	\$109.61	\$351	\$413	\$0.0	n/a
FY15	est. \$450	\$628	\$363	\$664	\$1,027	\$95.24	\$103	(\$112)	\$0.0	\$112
FY16	est. \$700	\$500	\$133	\$80	\$213	\$39.52	\$32	(\$580)	\$385	\$965
Forecasted										
FY17	\$73.4 (tent)	\$775	\$46	\$80	\$126	\$38.89	\$19	(\$1,336)	\$632	\$1,968
FY18	n/a	\$500	\$16	\$150	\$166	\$43.79	\$25	(\$1,811)	\$766	\$2,577
FY19	n/a	\$375	\$11	\$205	\$216	\$48.89	\$32	(\$2,154)	\$747	\$2,901
FY20	n/a	\$270	\$13	\$250	\$263	\$54.48	\$39	(\$2,384)	\$600	\$2,984
FY21	n/a	\$250	\$32	\$305	\$337	\$60.29	\$34	(\$2,601)	\$284	\$2,885
FY22	n/a	\$250	\$105	\$325	\$430	\$61.64	\$43	(\$2,808)	\$151	\$2,959
FY23	n/a	\$250	\$217	\$280	\$497	\$63.05	\$50	(\$3,008)	\$74	\$3,082
FY24	n/a	\$250	\$198	\$205	\$403	\$64.45	\$40	(\$3,218)	\$1	\$3,219
FY25	n/a	\$250	\$274	\$185	\$459	\$65.90	\$46	(\$3,422)	\$0	\$3,422

*Detail on Current Tax Division Work Pool
of Refundable Credit Applications
(As Presented at 4/2 Hearing)*

(All amounts in \$millions)			
Amount	Description	North Slope	CI / ME
\$10	Older NOL Credits	\$7	\$3
\$22	Older Exploration Credits	\$0	\$22
\$552	2015 NOL, QCE, WLE	\$335	\$217
\$60	2015 Exploration	\$53	\$7
\$31	Additional 2015 Amended	\$27	\$4
\$675		\$422	\$253

Bill Details & Calculations

Analysis of Complex Sections

Section 7: Interest Rate Compounding

Evolution of the interest rate language in SB21:

- Early Senate versions simply changed the rate in existing statute (kept compounding language)
- Final Senate version failed to pass an effective date clause vote (requires 14 senators)
- First House CS (Resources) added “applicability” language in many portions of the bill, to ensure that the old rates and conditions applied before 1/1/14 and the new rates and conditions after that date. Interest rate section kept compounding language

Section 7: Interest Rate Compounding

- Work Draft House CS (Finance) fixed technical error in Resources version, but inadvertently restored “higher of 11%” language for after 1/1/14. Kept compounding language.
- Technical committee amendment #15 (by co-chair Austerman) intended to delete the 11% language, but also deleted compounding. This was explained to the committee as simply restoring the floating rate language. The amendment passed unanimously.

Page 2, lines 23 - 25:

Delete ", or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter"

Section 7: Interest Rate Increase

Middle ground tied to opportunity cost

- Seeking a point between the historic 11% and the current (effective) 4%
- **Currently, each dollar of tax not paid is another dollar out of savings**
- When this tax is eventually paid, it should compensate for what would have earned had it stayed in savings
- Current Permanent Fund estimate (Callan & Assoc.) is about 7%

Section 7: Interest Rate Increase

Illustration: \$1 million assessment to a tax due 12/31/15, and assessed 6/30/17

Current Law						
	<u>Q1 2016</u>	<u>Q2 2016</u>	<u>Q3 2016</u>	<u>Q4 2016</u>	<u>Q1 2017</u>	<u>Q2 2017</u>
Principal	\$ 1,000,000	\$ 1,010,000	\$ 1,020,000	\$ 1,030,000	\$ 1,040,000	\$ 1,050,000
Subject to interest	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000
Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Interest	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000
					Total Due 6/30/17	\$ 1,060,000
HB 247						
	<u>Q1 2016</u>	<u>Q2 2016</u>	<u>Q3 2016</u>	<u>Q4 2016</u>	<u>Q1 2017</u>	<u>Q2 2017</u>
Principal	\$ 1,000,000	\$ 1,010,000	\$ 1,020,000	\$ 1,040,000	\$ 1,060,400	\$ 1,081,208
Subject to interest	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 1,020,000	\$ 1,040,400	\$ 1,061,208
Rate	4.00%	4.00%	8.00%	8.00%	8.00%	8.00%
Interest	\$ 10,000	\$ 10,000	\$ 20,000	\$ 20,400	\$ 20,808	\$ 21,224
					Total Due 6/30/17	\$ 1,102,432

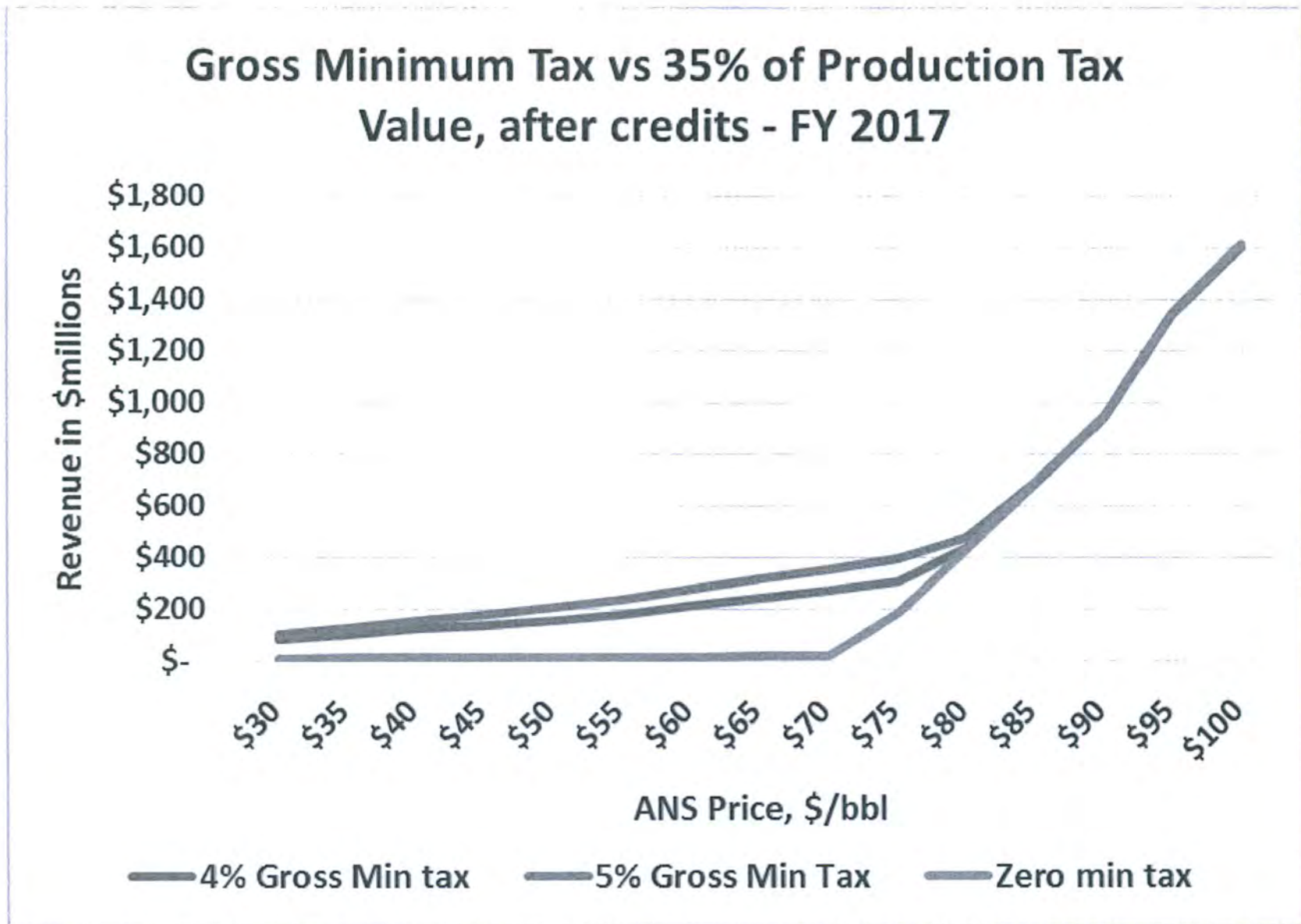
*Does not account for potential changes in Federal Reserve rate

*This example would apply to either taxes due to state, or refunds payable

Section 7: Interest Rate Increase

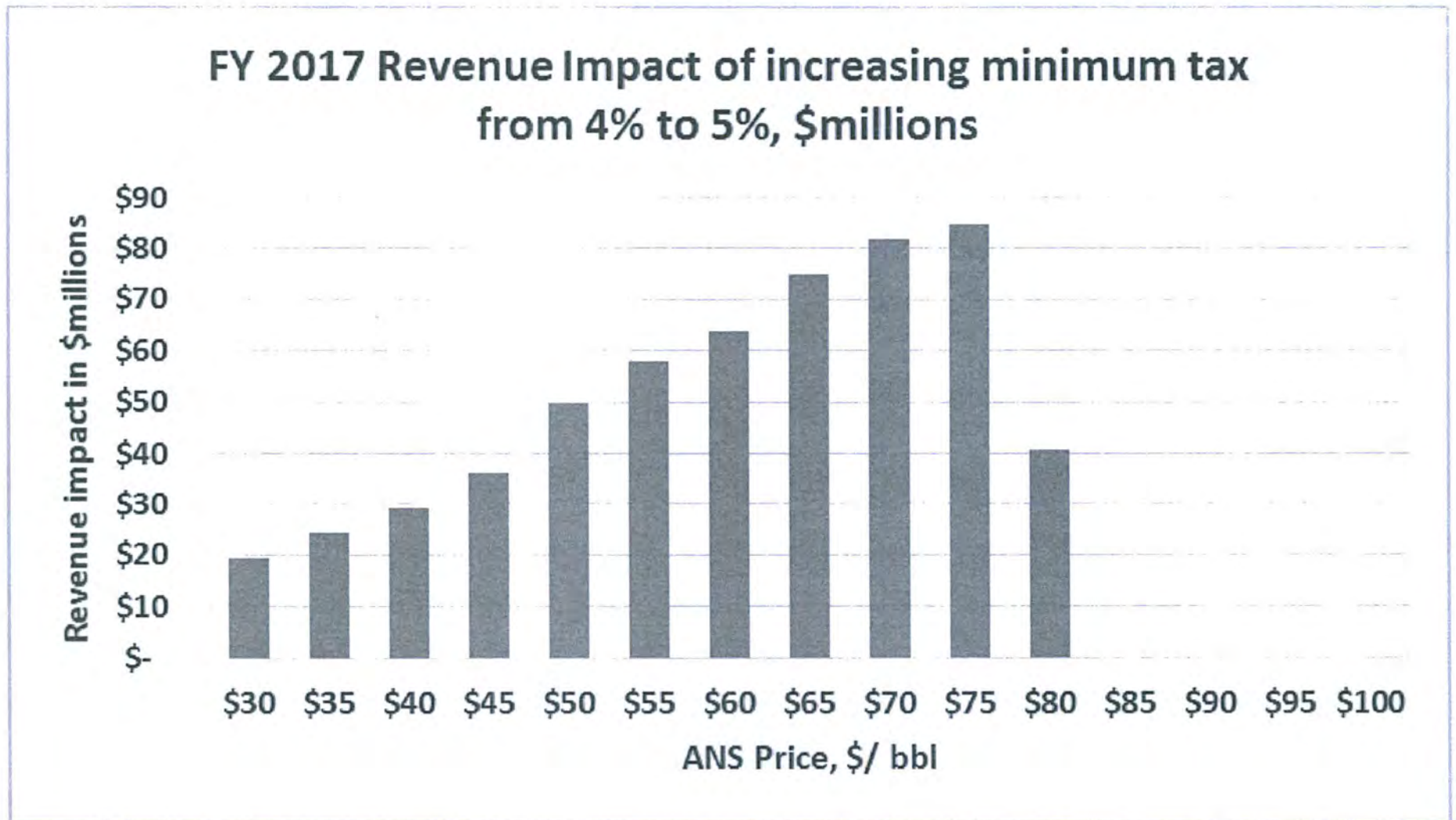
- **Future revenue impact difficult to quantify, since future tax assessments or refunds can't be predicted**
- **Little near-term impact, since change applies only to interest for quarters after 7/1/16**
- **For production tax, most impact will be on the Constitutional Budget Reserve Fund, since audit assessment revenues go to the CBR**

Section 12: Increase Minimum Tax



Source: DOR Fall 2015 forecast modeling

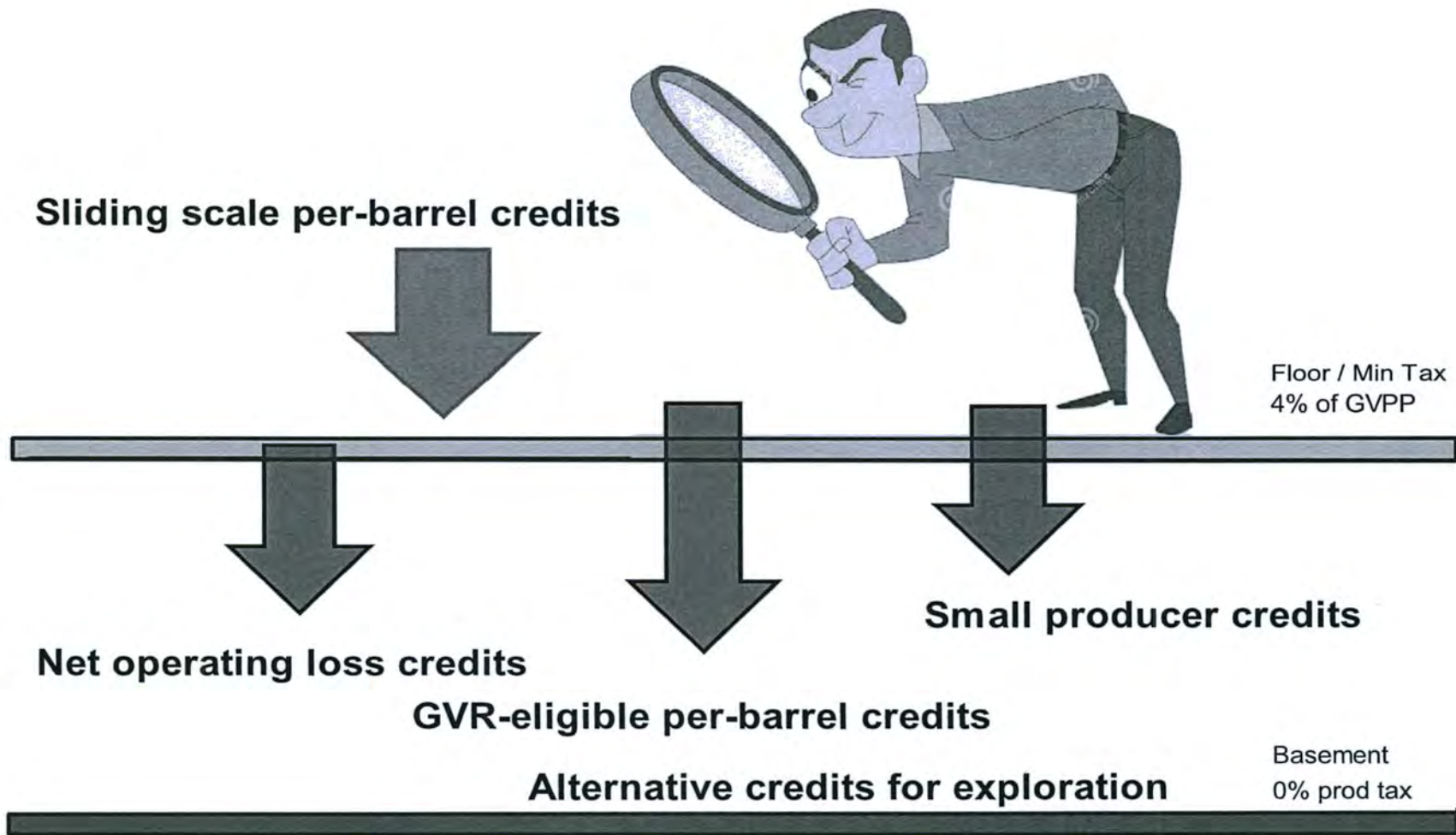
Section 12: Increase Minimum Tax



Source: DOR Fall 2015 forecast modeling

Section 17(b): Strengthen the Minimum Tax

Which credits can break through the floor under current law?



Section 17(b): Strengthen the Minimum Tax

- Current law allows all credits with the exception of the sliding scale per-barrel credits for legacy oil to reduce taxes below the minimum tax (also called the “floor”)
- SB130 seeks to change law so that the following additional credits cannot reduce taxes below the minimum tax
 - Net operating loss credits
 - GVR-eligible per-barrel credits
 - Small producer credits
 - Alternative credits for exploration

Section 17(b): Strengthen the Minimum Tax

Preventing certain credits from being used against the minimum tax, or “floor”

This is really three different issues / policy questions
All of these only pertain to the North Slope:

- 1) Net Operating Loss for producers not eligible for refundable credits**
(should the major producers ever be able to go below the floor? And should this be retroactive to Jan. 1?)
- 2) Per-Barrel Credits for GVR “New” Oil**
(should the tax on production from new fields be allowed to go to zero?)
- 3) Small Producer / Exploration Credits**
(should everyone, not just major producers, pay a minimum tax?)

Section 17(b): Strengthen the Minimum Tax

#1- Preventing companies from applying a net operating loss (NOL) credit against the minimum tax

- Net operating losses occur when a producer's total amount of lease expenditures for the year exceed the gross value at the point of production
- In plain English, this is when a producer has negative net income (based on Alaska production tax laws)
- NOL for Alaska production tax purposes is calculated on a calendar (tax) year basis, not a fiscal year basis

If this section is implemented, NOL's not used to reduce the minimum tax are still carried forward

Section 17(b): Strengthen the Minimum Tax

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

Section 17(b): Strengthen the Minimum Tax

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

Section 17(b): Strengthen the Minimum Tax

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>

Section 17(b): Strengthen the Minimum Tax

\$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)
<i>Approx. Operating Loss</i>	<i>\$800 million</i>	<i>\$800 million</i>
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
<i>Carried-Forward Loss Credit 35%</i>	<i>\$280 million</i>	<i>\$370 million</i>

Section 17(b): Strengthen the Minimum Tax

Using the scenario on the previous slide

- The net operating loss for Year 1 is estimated to be about \$800 million. At a NOL credit rate of 35%, this loss will generate a credit of about \$280 million
- Producers can apply their net operating loss credits against taxes due starting in January of Year 2
- \$190 out of the \$280 million in credits is used to reduce production tax payments to zero. The remaining \$90 million is carried forward
- In Year 2, using same oil production and lease expenditure assumptions, the net operating loss would be another \$800 million, resulting in another \$280 million in NOL credits at 35%
- These are added to the \$90 million carried forward from Year 1, resulting in \$370 million to be carried to Year 3²²

Section 17(b): Strengthen the Minimum Tax

#2- How GVR-eligible per-barrel credits can reduce taxes below the minimum tax (\$80 oil):

Minimum Tax and 20% and Legacy Production and GVR-Eligible Production*

	Legacy	GVR-Eligible
West Coast Price (\$/tax bbl)	\$80	\$80
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$70	\$70
Lease Expenditures (\$/tax bbl)	-\$36	-\$36
Net Value (\$/tax bbl)	\$34	\$34
Gross Value Reduction Rate (%)	x 0%	x 20%
Gross Value Reduction (\$/tax bbl)	\$0	\$14
Net Value after GVR (\$/tax bbl)	\$34	\$20
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$11.90	\$7.00
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$8	\$5
Base Production Tax after credits (\$/tax bbl)	\$3.90	\$2.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	x \$70	x \$70
Minimum Tax (\$/tax bbl)	\$2.80	\$2.80

This credit can reduce tax below minimum tax; company pays \$2 per barrel

*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.

Section 17(b): Strengthen the Minimum Tax

#2- How GVR-eligible per-barrel credits can reduce taxes below the minimum tax (\$60 oil):

Minimum Tax and 20% and Legacy Production and GVR-Eligible Production*		
	Legacy	GVR-Eligible
West Coast Price (\$/tax bbl)	\$60	\$60
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$50	\$50
Lease Expenditures (\$/tax bbl)	-\$36	-\$36
Net Value (\$/tax bbl)	\$14	\$14
Gross Value Reduction Rate (%)	x 0%	x 20%
Gross Value Reduction (\$/tax bbl)	\$0	\$10
Net Value after GVR (\$/tax bbl)	\$14	\$4
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$4.90	\$1.40
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$8	\$5
Base Production Tax after credits (\$/tax bbl)	\$0.00	\$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	x \$50	x \$50
Minimum Tax (\$/tax bbl)	\$2.00	\$2.00

This is the amount paid. Legacy fields pay minimum tax of \$2 while GVR-eligible fields pay zero.

*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.

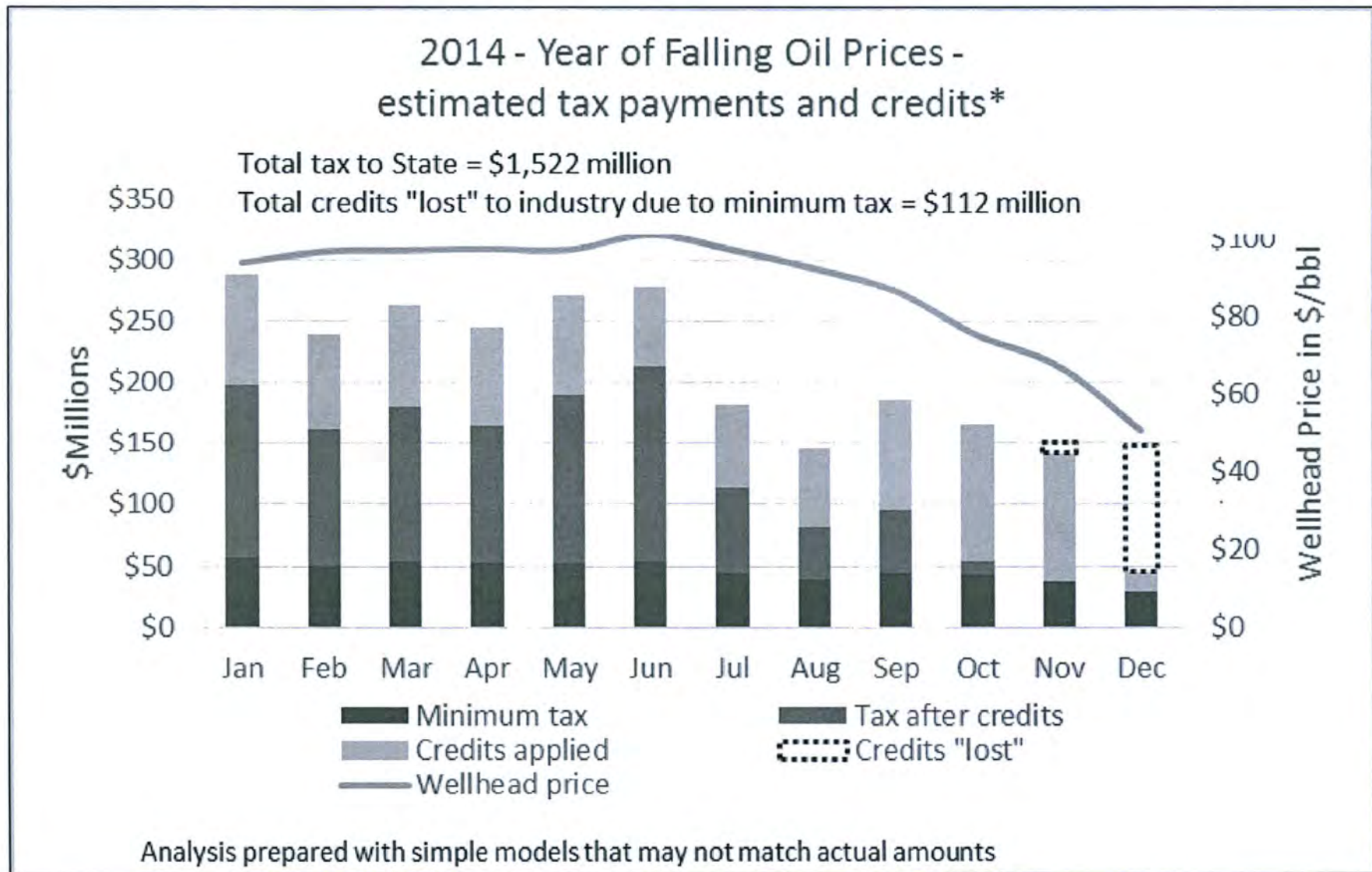
Section 17(c): Strengthen the Minimum Tax

Preventing per-taxable barrel credits from being used in another month other than the month earned

- Current law allows sliding scale credits “lost” to the minimum tax to be recovered at annual true-up under certain conditions
- This reduces the “upside” potential for the State in a year with moderate oil price volatility
- ACES progressivity was a monthly calculation with no annual true-up
- If sliding scale credits were intended to be a form of “reverse progressivity,” then the calculation should be monthly with no annual true-up

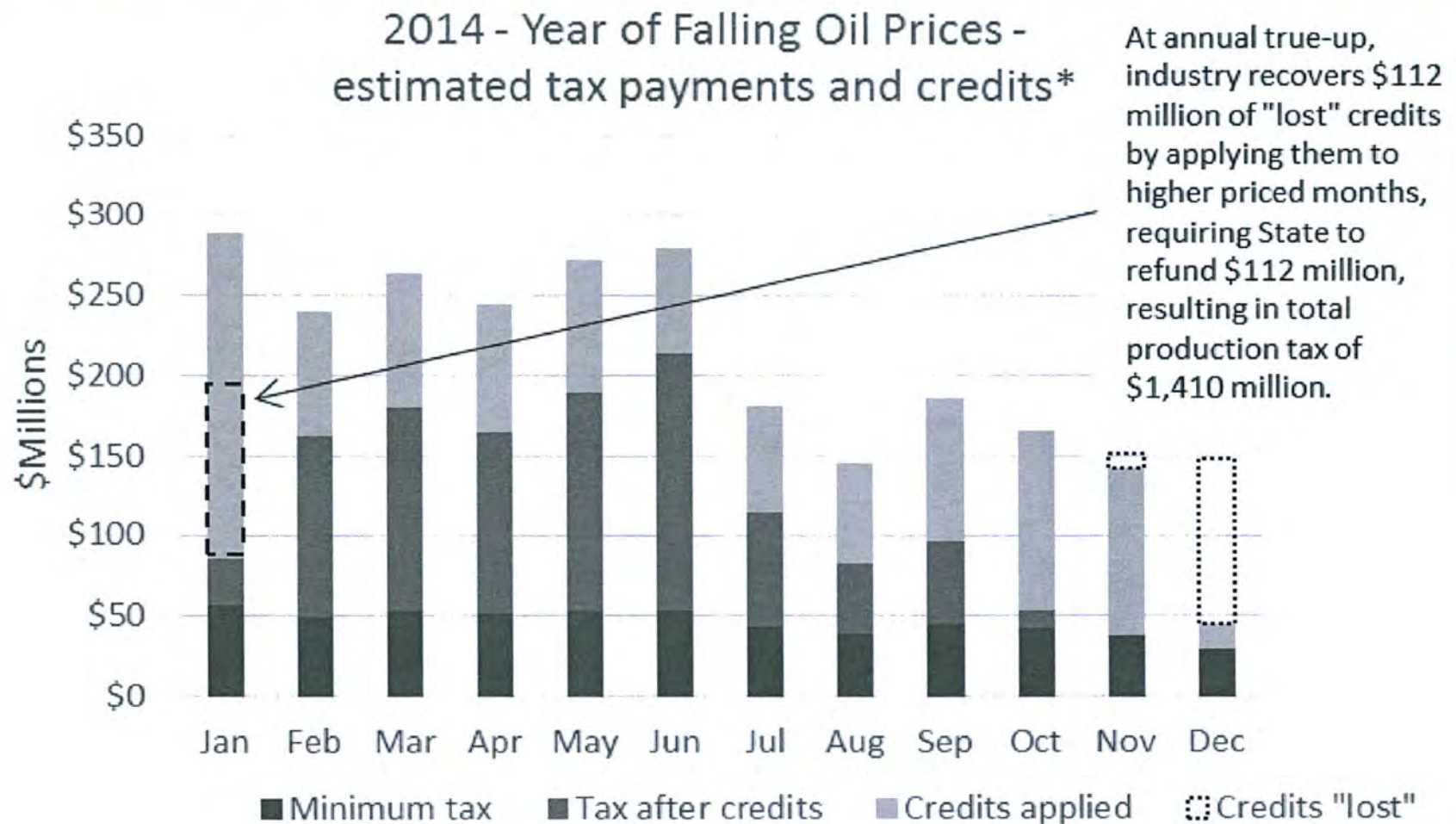
Section 17(c): Strengthen the Minimum Tax

Credits "lost" to the minimum tax before annual true-up



Section 17(c): Strengthen the Minimum Tax

“Lost” credits recovered at annual true-up



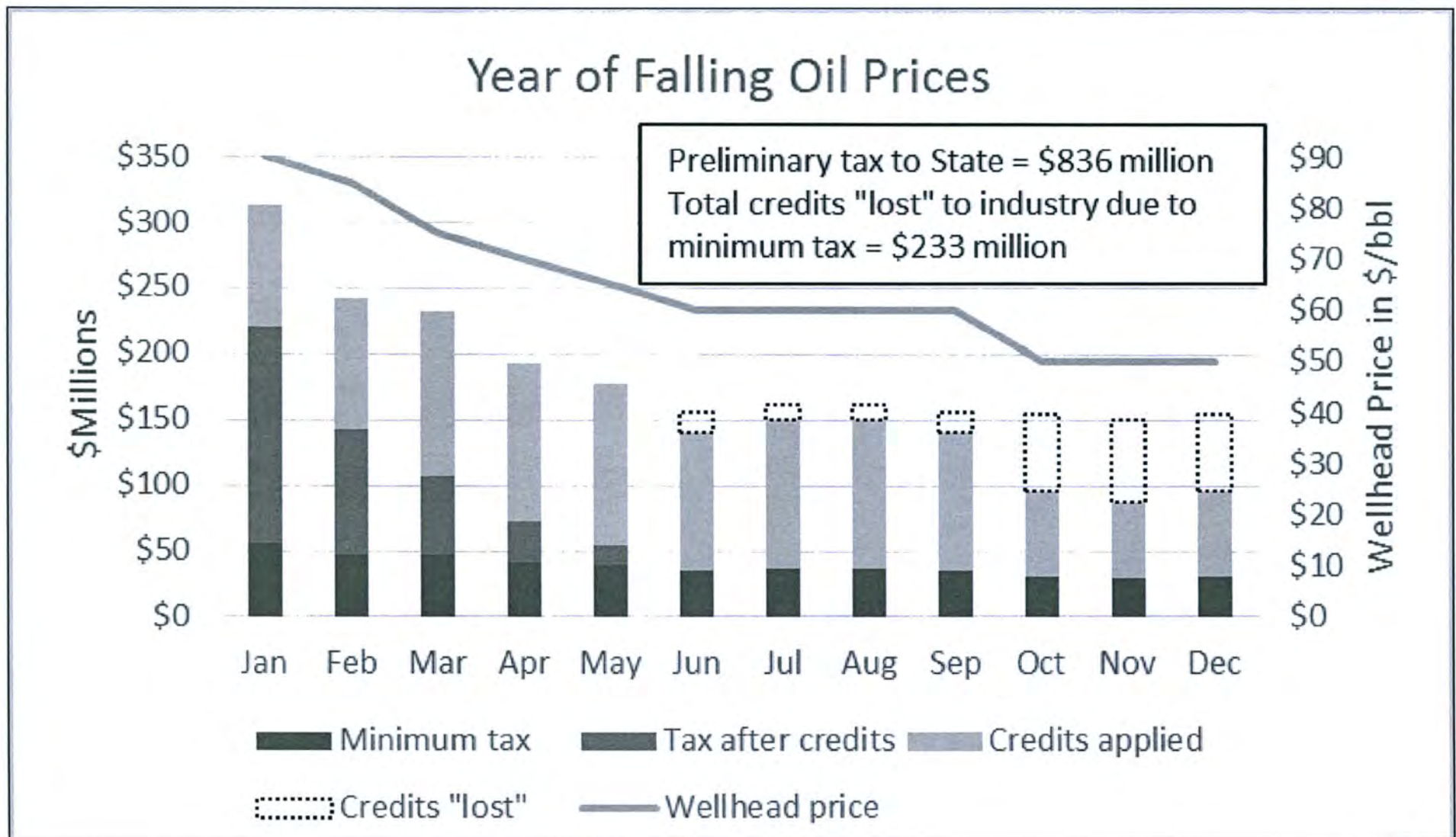
Analysis prepared with simple models that may not match actual amounts

Section 17(c): Strengthen the Minimum Tax

- In years of greater oil price volatility, credit recovery can take a greater share and could reduce State production tax collection to the minimum tax.
- This occurs because the minimum tax is an annual tax, and credits that cannot be used within the year can be recovered at year's end.
- Next two slides show a hypothetical year with greater oil price volatility

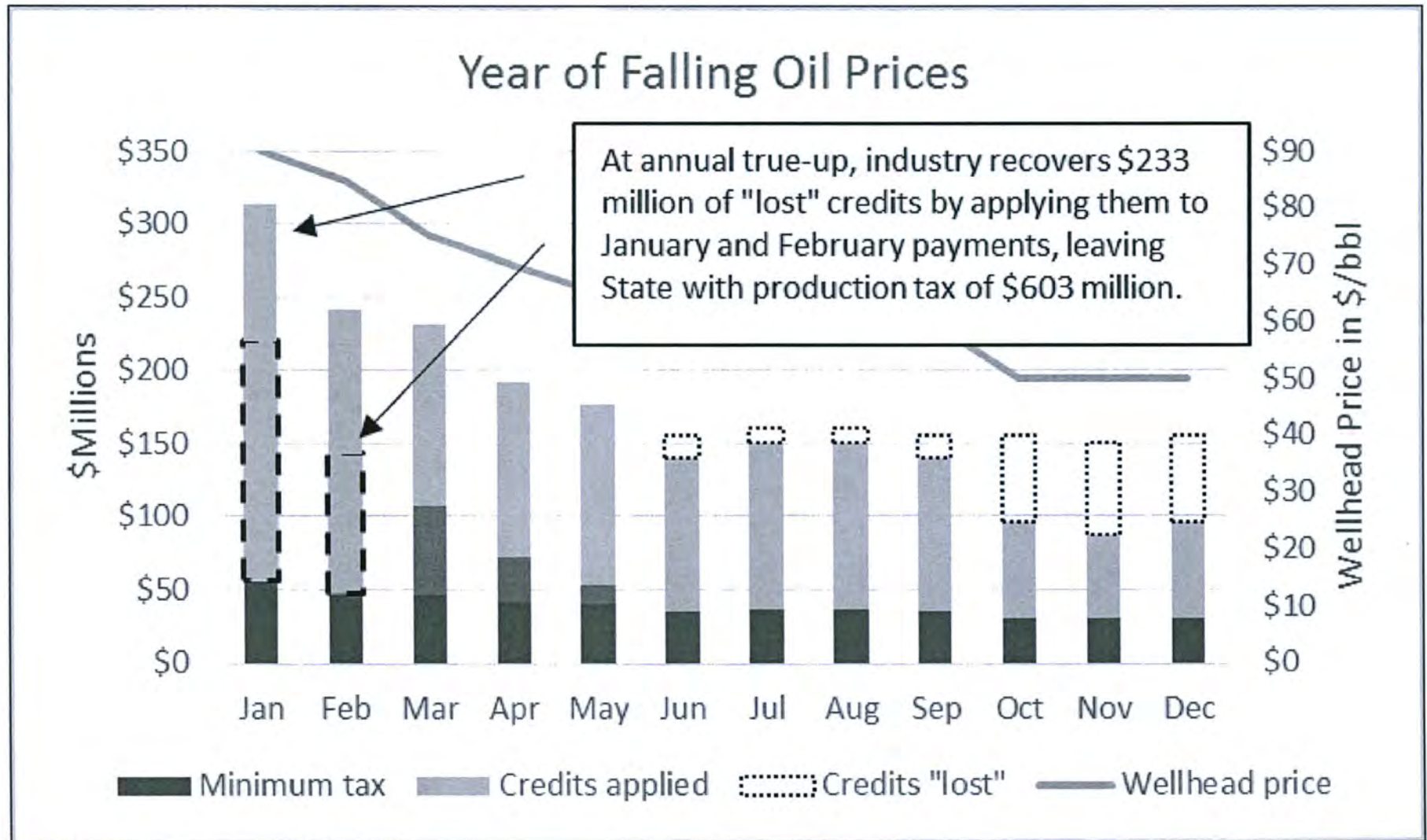
Section 17(c): Strengthen the Minimum Tax

Credits "lost" to the minimum tax before annual true-up



Section 17(c): Strengthen the Minimum Tax

“Lost” credits recovered at annual true-up



Section 17(c): Strengthen the Minimum Tax

- Only an issue in years of oil price volatility, where some but not all months trigger the minimum tax
- Example on previous two slides showing moderate oil price volatility
 - Reduces State tax payments by close to 30%
 - Reduces effective tax rate on net from 14.5% to 10.5%
 - Results in State forfeiting some of the “upside” in years where monthly oil prices could reach \$100 per barrel or more

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

- SB 130 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

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

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.

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

- In the high oil price / high cost example shown on the next page, the net operating loss would be limited to the net value before GVR, which is \$10 per barrel instead of \$24 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 close to \$18 million

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

Current law allows GVR to increase an NOL credit

Example showing NOL due to higher prices with high continued investment

20% GVR-Eligible Production increasing Size of Net Operating Loss and Proposed Change*		
	Current Law	Proposed Change
West Coast Price (\$/tax bbl)	\$80	\$80
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$70	\$70
Lease Expenditures (\$/tax bbl)	\$80	\$80
Net Value before GVR (\$/tax bbl)	-\$10	-\$10
Wellhead Value from above (\$/tax bbl)	\$70	\$70
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction (\$/tax bbl)	\$14	\$14
GVR-Adjusted Net Value (\$/tax bbl)	-\$24	-\$24
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)	\$70	\$70
Minimum Tax (\$/tax bbl)	\$2.80	\$2.80
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)	-\$24	-\$10
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit (\$/tax bbl)	\$8.40	\$3.50
NOL per barrel times 10,000 taxable b/d	\$30,660,000	\$12,775,000
Difference		\$17,885,000

*Assumes early development of new field, producing small amounts of oil while still drilling and building out infrastructure.

Sections 26-27: Credit Refund Limitations

Four New Limitations on Cash Refunds:

- Refunds limited to companies with gross revenues less than \$10 billion in previous year
- Limit State credit refunds to \$25 million / company / year (same limitation as in PPT, from 2006)
- Percentage of refund limited to percentage of Alaska resident hire in previous year
- Any unused net operating loss credits expire 10 years from the date they were issued

This section has one of the largest fiscal impacts of any in the bill. Several hundred million in the first year; future years will depend on actual projects

These credits are deferred rather than saved; companies will use them to offset future years' taxes

Section 31: Gross Value can't go below Zero

- SB130 would prohibit the Gross Value at the Point of Production from being less than zero
- At current market oil prices of around \$30 per barrel, this means that transport costs must be \$30 or less
- At current prices, there are few properties that have transport costs approaching \$30 per barrel
- If prices were to go lower than \$20 per barrel, more properties could be affected

Section 31: Gross Value can't go below Zero

Jan. 2016 TAPS and feeder pipeline tariffs (these are before adding the \$3.37 marine transport cost)

TAPS Tariff **\$6.13** Weighted Average

Badami Unit Tariffs	\$1.41	Badami Connection
	\$1.78	Badami Pipeline
	\$6.13	TAPS
Badami Unit Tariffs	\$9.32	Total

Colville River Unit Tariffs	\$0.32	Kuparuk Pipeline
	\$0.94	Alpine Tariff
	\$6.13	TAPS
Colville River Unit Tariffs	\$7.39	Total

Duck Island Unit Tariffs	\$2.22	Endicott Pipeline
	\$6.13	TAPS
Duck Island Unit Tariffs	\$8.35	Total

Kuparuk River Unit Tariffs	\$0.32	Kuparuk Pipeline
	\$6.13	TAPS
Kuparuk River Unit Tariffs	\$6.45	Total

Milne Point Unit Tariffs	\$0.24	Kup - Milne Connection
	\$1.44	Milne Pt Pipeline
	\$6.13	TAPS
Milne Point Unit Tariffs	\$7.81	Total

Pt Thomson Unit Tariffs	\$1.41	Badami Connection
	\$1.78	Badami Pipeline
	\$19.17	Pt Thomson Pipeline
	\$6.13	TAPS
Pt Thomson Unit Tariffs	\$28.49	Total

Northstar Unit Tariffs	\$1.09	Northstar Pipeline
	\$6.13	TAPS
Northstar Unit Tariffs	\$7.22	Total

Section 31: Gross Value can't go below Zero

Example of gross value potentially going below zero

West Coast Price (\$/bbl)	\$30.00
Point Thomson Unit Tariffs (\$/bbl)	\$28.49
Marine Transportation (\$/bbl)	\$3.37
Wellhead Price (\$/bbl)	-\$1.86

Annual Oil Production (bbls)	3,650,000
Royalty Oil Production (bbls)*	456,250
Taxable Oil Production (bbls)	3,193,750

Wellhead Price from above (\$/bbl)	-\$1.86
Taxable Oil Production from above (bbls)	3,193,750
Gross Value at Point of Production	-\$5,940,375

*Royalty rate of 12.5% assumed; actual royalty rates may differ from those shown in this analysis.

This negative GVPP could be used to offset positive values from elsewhere on the North Slope, resulting in a tax reduction of 35% of the difference (about \$2 million)

Section 37: Municipal Utility Limitation

- 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. SB130 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

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
 - Been asked by House Finance for \$20, \$100, and \$120
 - Will provide these runs to this committee when done
- Status quo modeled vs. Governor's original bill
- Full modeling runs will be provided as a separate document

Introduction to Scenario Analysis

Fields Analyzed:

North Slope Oil Scenarios

- 50 million barrel
- 750 million barrel (12.5% Royalty / 20% GVR)
- 750 million barrel (16.67% Royalty / 30% GVR)
- 750 million barrel (50% Private Royalty)

Cook Inlet Oil Scenarios

- 50 million barrel (tax caps sunset)
- 50 million barrel (tax caps extended)

Gas Scenarios

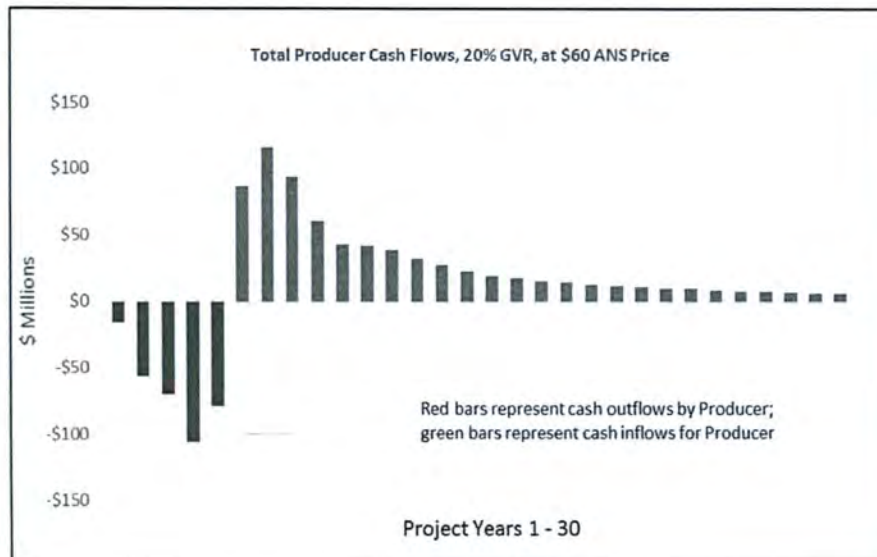
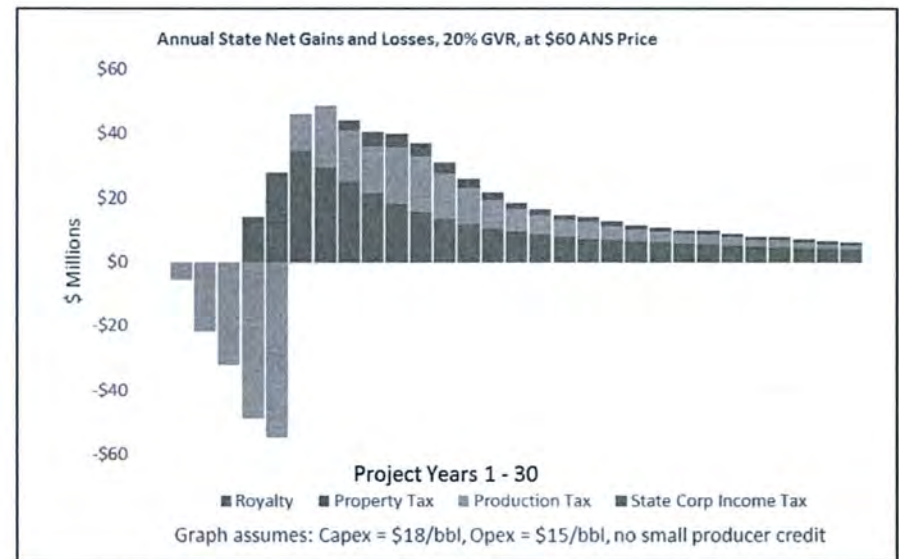
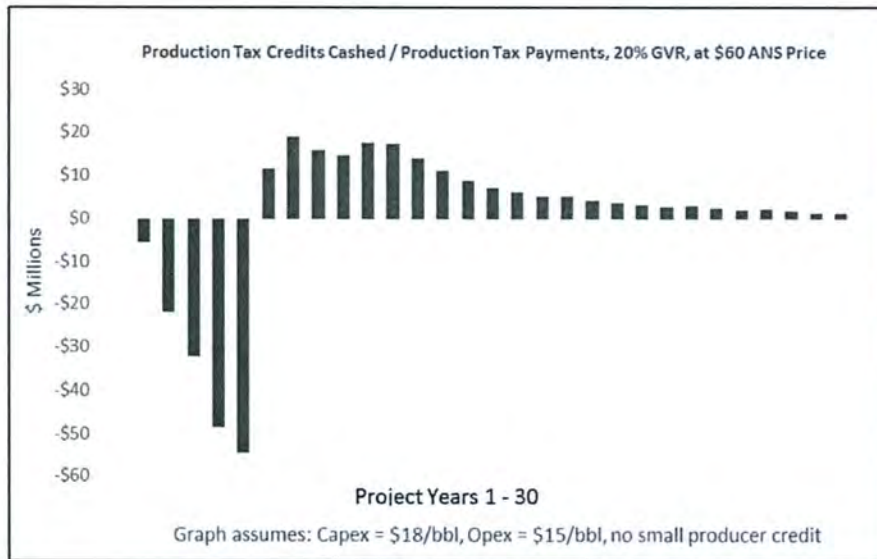
- 670 bcf Cook Inlet Gas (tax cap sunset and extended)
- 670 bcf Middle Earth Gas

Each analyzed at \$40 oil, \$60, \$80, and Fall Forecast

Been asked by House Finance to do \$20, \$100, and \$120

Sample of Scenario Analysis

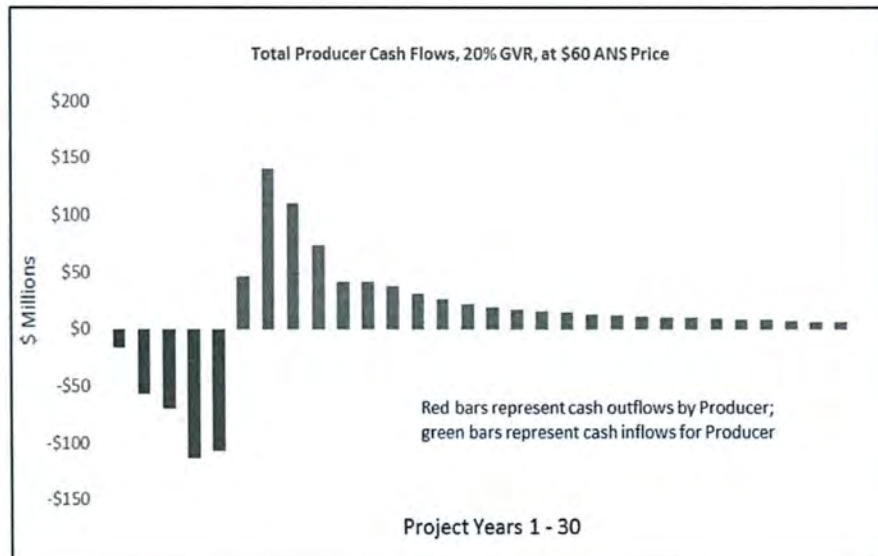
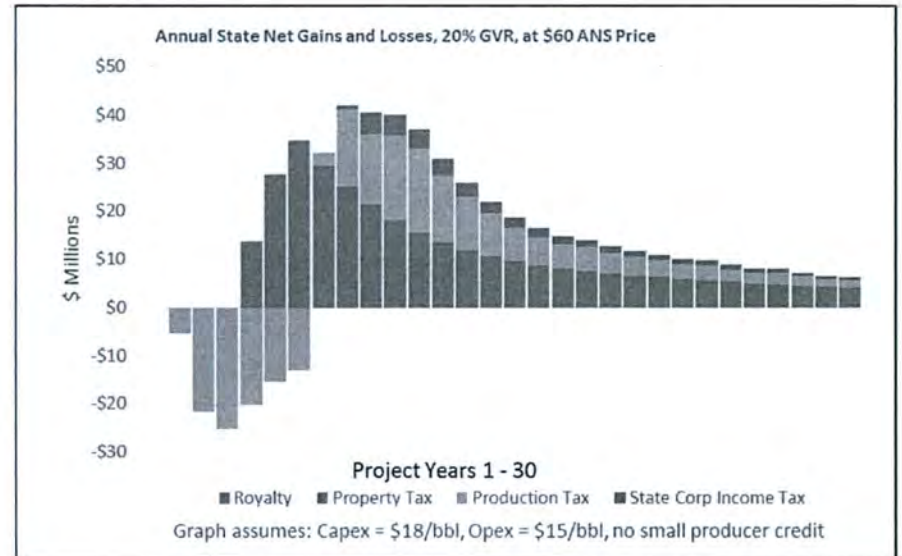
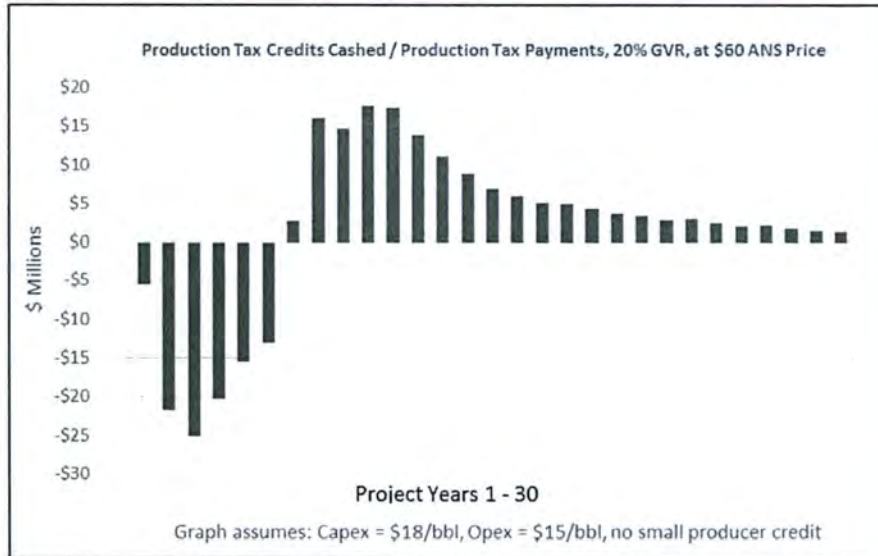
North Slope- 50 mmbo Status Quo, \$60/bbl



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

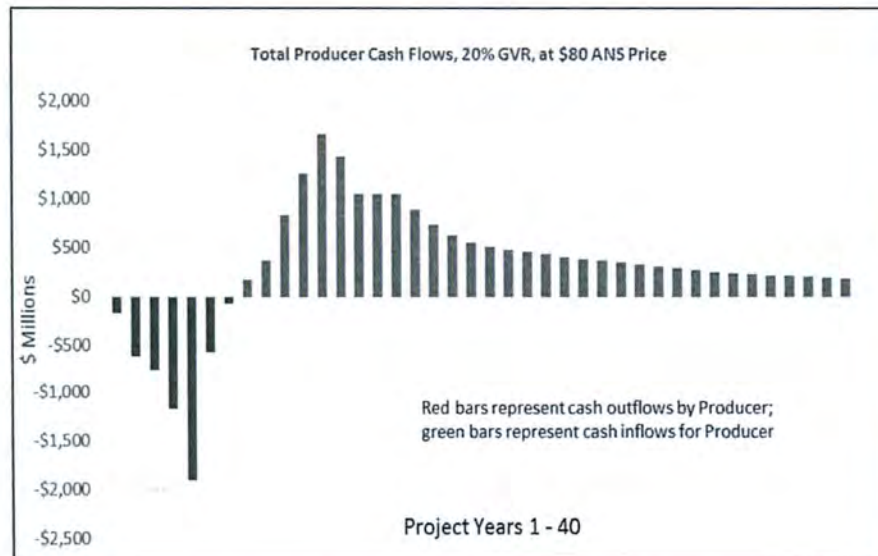
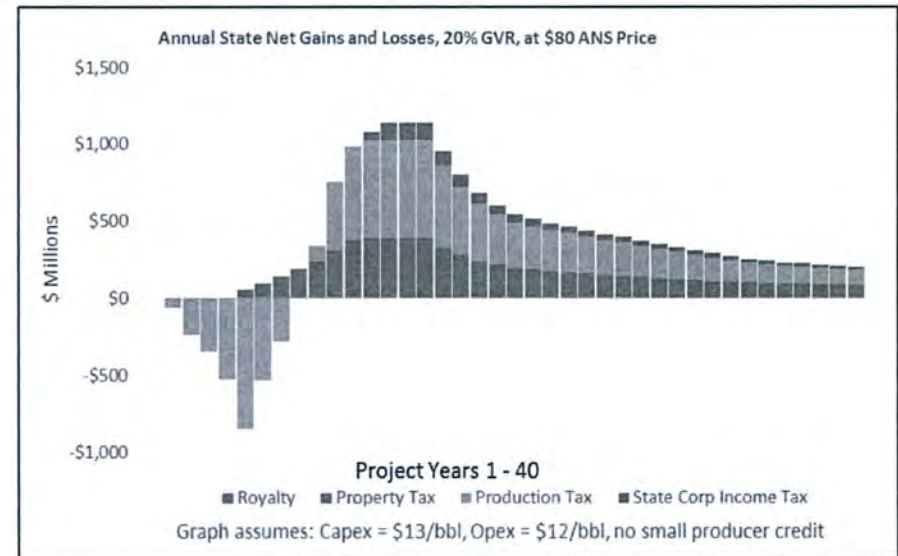
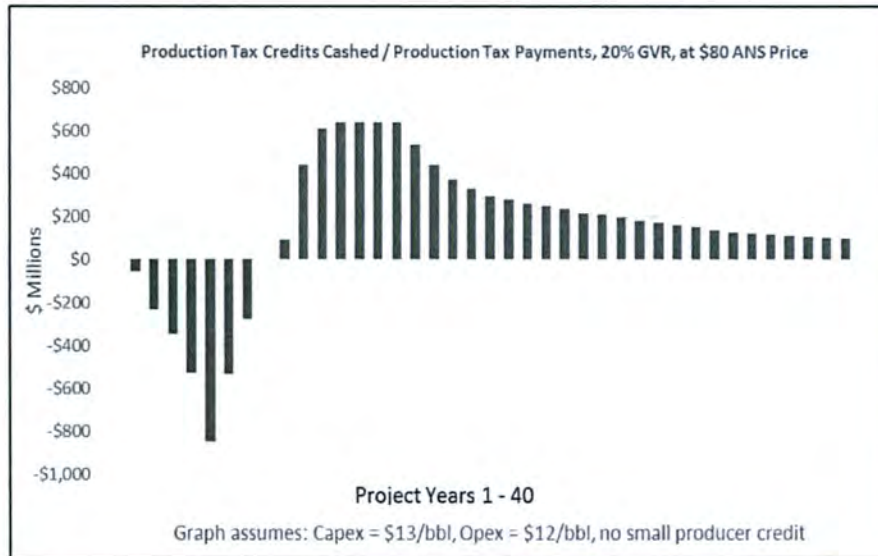
North Slope- 50 mmbo HB 247, \$60 / bbl



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

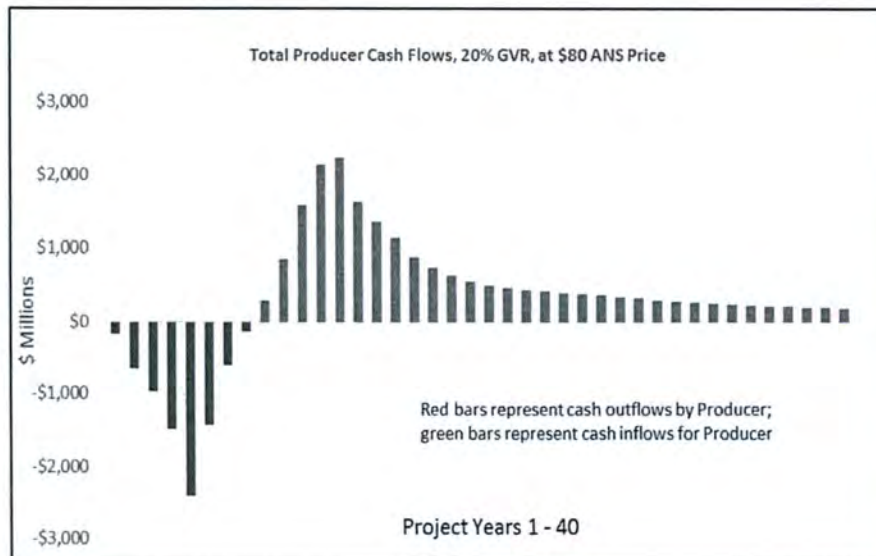
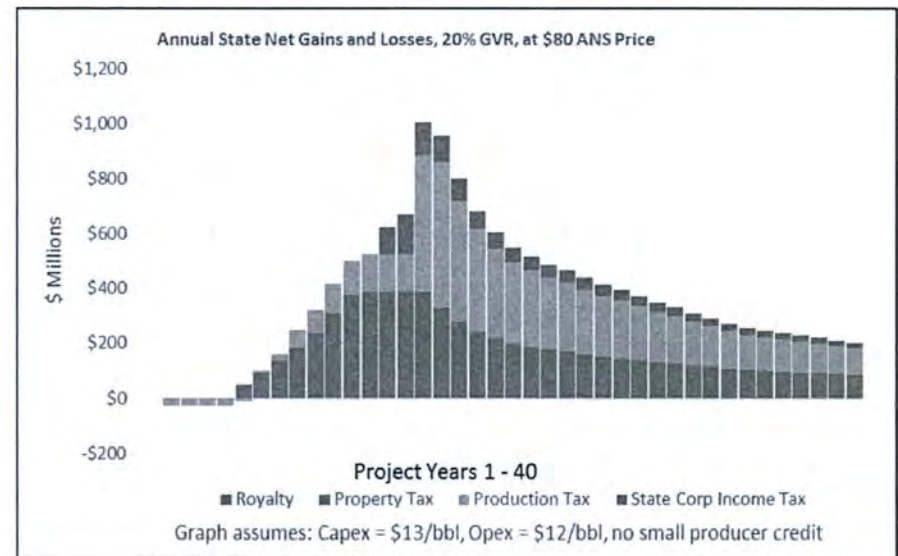
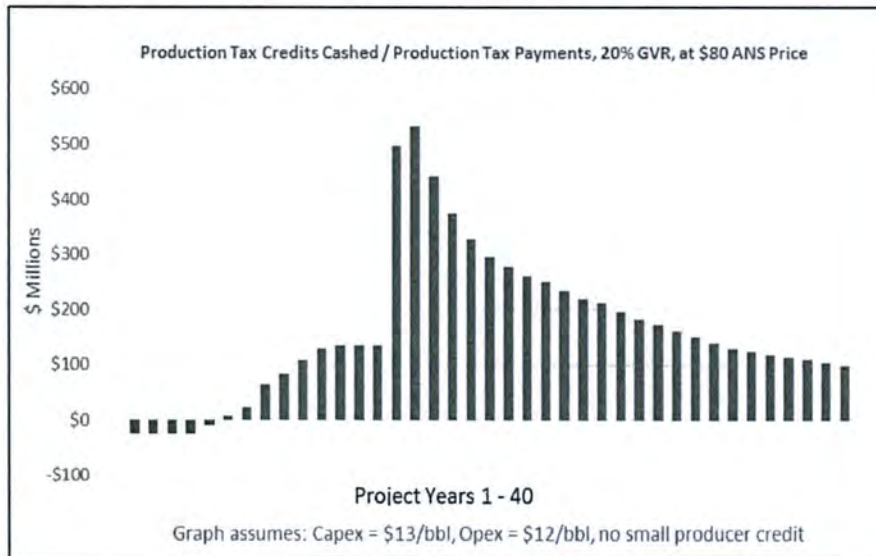
North Slope- 750 mmbo Status Quo, \$80/bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cash	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

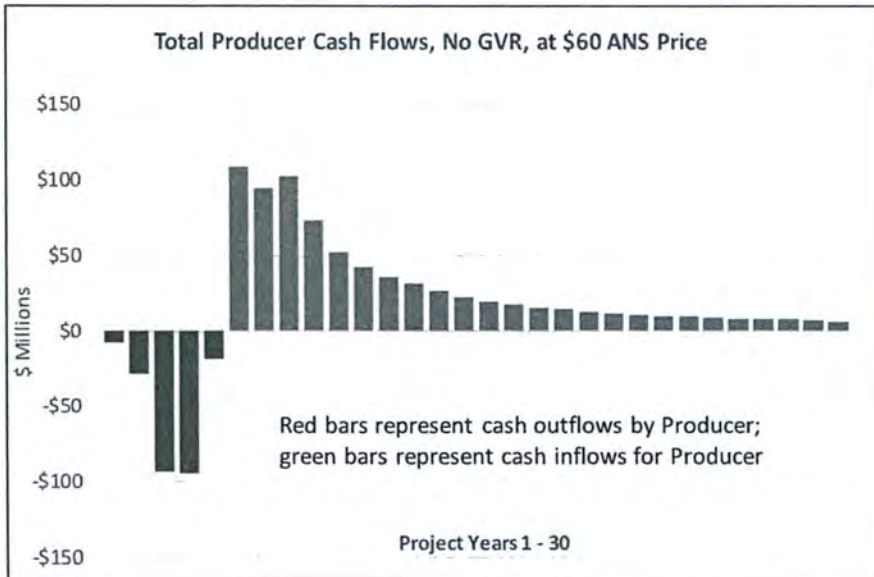
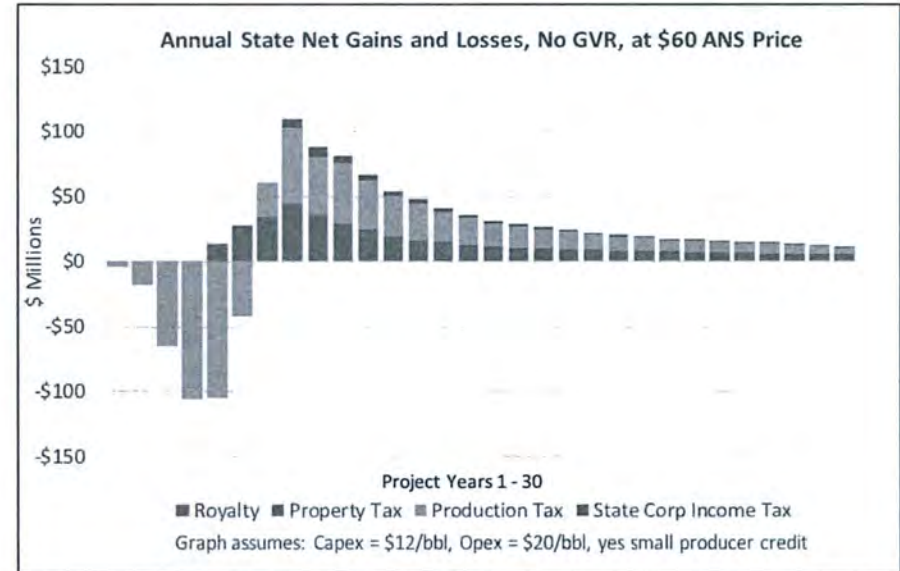
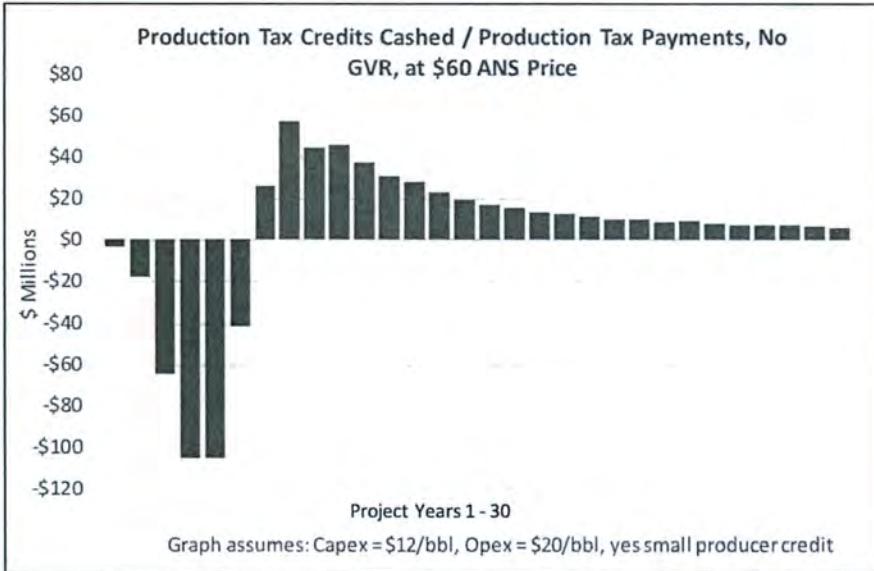
North Slope- 750 mmbo HB 247, \$80 / bbl



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

Sample of Scenario Analysis

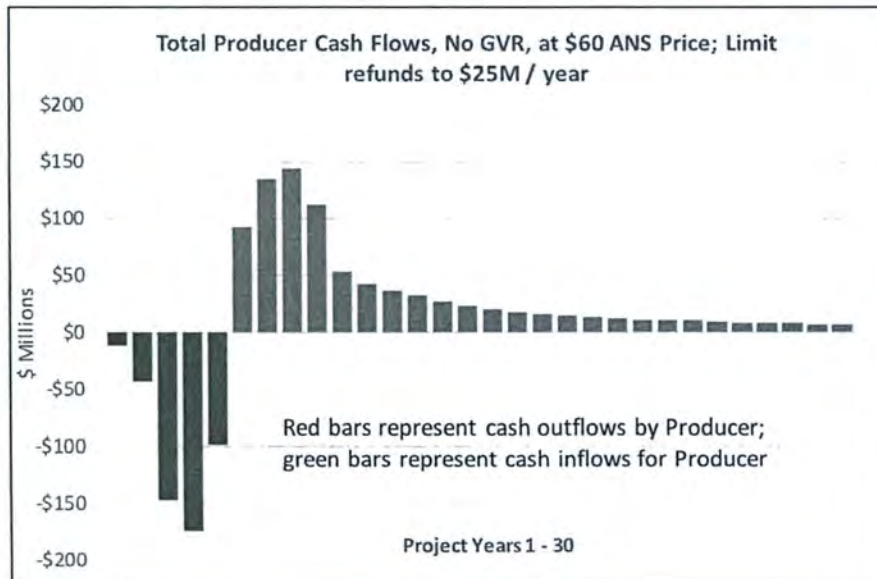
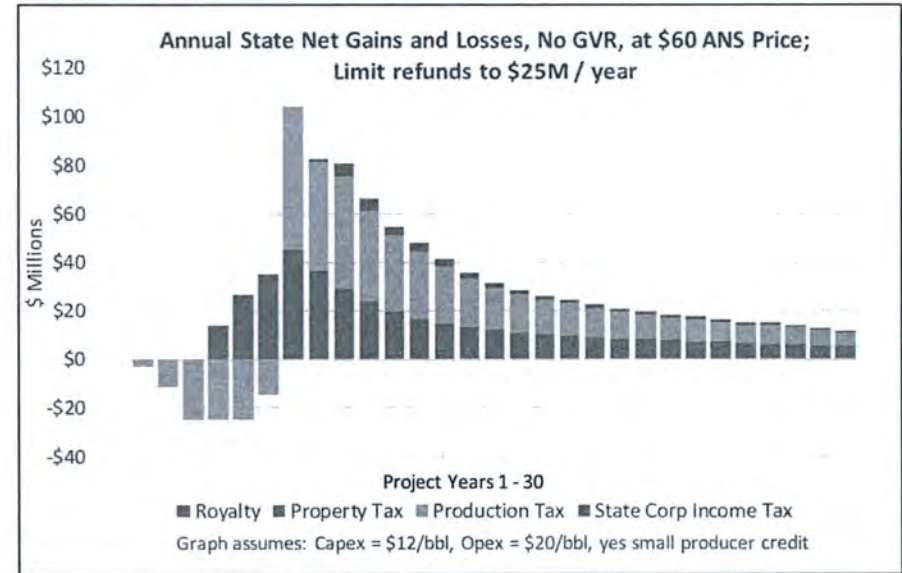
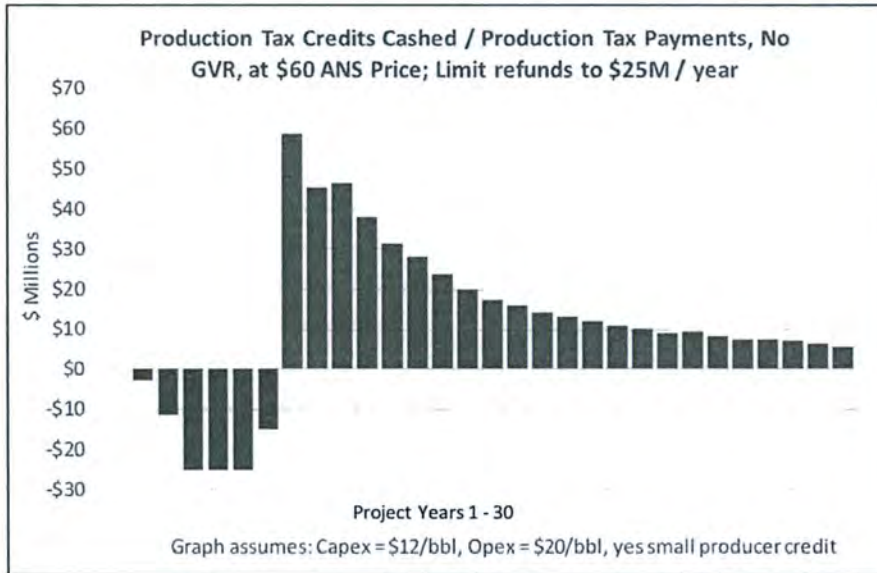
Cook Inlet 50 mmbo Status Quo, 2022 Tax Caps expire, \$60/bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cashed	337
Production Tax Paid	465
Net Production Tax	128
Production Tax NPV 6.15%	-50
Total Annual State Losses	297
Total Annual State Gains	877
Net State Gain (Loss)	579
State NPV 6.15%	167
Total Producer Cash Out	241
Total Producer Cash In	768
Net Producer Cash Flow	527
Producer Cash NPV 6.15%	202

Sample of Scenario Analysis

Cook Inlet 50 mmbo HB247, 2022 Tax Caps expire, \$60/bbl



Life Cycle Totals	\$Millions
Production Tax Credits Cashed	104
Production Tax Paid	447
Net Production Tax	343
Production Tax NPV 6.15%	121
Total Annual State Losses	51
Total Annual State Gains	831
Net State Gain (Loss)	780
State NPV 6.15%	331
Total Producer Cash Out	473
Total Producer Cash In	869
Net Producer Cash Flow	397
Producer Cash NPV 6.15%	80

Summary of Scenario Analysis

North Slope Oil 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

North Slope Oil (nonstandard royalty) 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

Cook Inlet Oil 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

Cook Inlet and Middle Earth Gas 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

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Oil and Gas Tax Credit Reform- SB130

REVISED SLIDE #4

Department of Revenue

Second Presentation: “Additional Modeling and Scenario Analysis”

Presentation to the Senate Resources Committee

April 4, 2016

REVISED slide 4 from 4/4

Alternative History & Forecast for Tax Credit Fund

Oil and Gas Tax Credit Fund: Budgeted vs. Actual vs. Statutory Tax Credit Fund Transfer Cap
 (Beginning with the first budget cycle after the passage of ACES in November 2007)

Fiscal Year	NS Production (000)	Original Appropriation (\$million)	Actual Claimed Credits (\$million)	Actual Production Tax (\$million)	Plus Credits Against Liab (\$million)	AS 43.55.011 Revenue (\$million)	Oil Price Per Spring 16 Forecast	Credit Cap per AS 43.55.028(c)	End Year Fund Balance	Non-Cashable Carried-Forward	Total Credit Oblig
Actual											
FY09	692.8	not to exceed \$175	\$193	\$3,101	\$334	\$3,435	\$85.73	\$343	\$150	\$0.0	n/a
FY10	642.6	unspec **	\$250	\$2,861	\$412	\$3,273	\$65.70	\$327	\$228	\$0.0	n/a
FY11	599.9	est. \$180	\$450	\$4,543	\$361	\$4,904	\$73.32	\$490	\$268	\$0.0	n/a
FY12	579.3	est. \$400	\$353	\$6,137	\$363	\$6,500	\$94.70	\$650	\$565	\$0.0	n/a
FY13	531.6	est. \$400	\$369	\$4,043	\$550	\$4,593	\$110.44	\$459	\$655	\$0.0	n/a
FY14	531.1	est. \$400	\$593	\$2,589	\$919	\$3,508	\$109.61	\$351	\$413	\$0.0	n/a
FY15	501.5	est. \$450	\$628	\$363	\$664	\$1,027	\$95.24	\$103	(\$112)	\$0.0	\$112
FY16	500.2	est. \$700	\$500	\$133	\$70	\$203	\$39.52	\$30	(\$582)	\$385	\$967
Forecasted											
FY16	500.2	est. \$700	\$500	\$134	\$70	\$204	\$39.99	\$500	\$0	\$0	n/a
FY17	507.9	\$73.4 (tent)	\$775	\$59	\$135	\$194	\$38.89	\$29	(\$746)	\$618	\$1,364
FY18	497.7	n/a	\$500	\$16	\$205	\$221	\$43.79	\$33	(\$1,213)	\$751	\$1,964
FY19	487.6	n/a	\$375	\$11	\$250	\$261	\$48.89	\$39	(\$1,549)	\$732	\$2,281
FY20	460.5	n/a	\$270	\$13	\$305	\$318	\$54.48	\$48	(\$1,771)	\$585	\$2,356
FY21	423.9	n/a	\$250	\$33	\$325	\$358	\$60.29	\$36	(\$1,985)	\$265	\$2,250
FY22	391.1	n/a	\$250	\$110	\$275	\$385	\$61.64	\$39	(\$2,197)	\$136	\$2,333
FY23	359.8	n/a	\$250	\$217	\$205	\$422	\$63.05	\$42	(\$2,404)	\$59	\$2,463
FY24	329.2	n/a	\$250	\$212	\$170	\$382	\$64.45	\$38	(\$2,616)	\$0	\$2,616
FY25	302.1	n/a	\$250	\$275	\$95	\$370	\$65.90	\$37	(\$2,829)	\$0	\$2,829

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ALASKA'S OIL & GAS INDUSTRY

Overview & Activity Update

Senate Resources Committee

Presented by:

Paul Decker, Petroleum Geologist

Alex Nouvakhov, Commercial Analyst

Division of Oil and Gas

Alaska Department of Natural Resources

April 6, 2016



OVERVIEW

- **North Slope:**
 - Resources and Reserves
 - Current Activity & New Developments
 - Who's Working the North Slope?
 - Leasing Activity

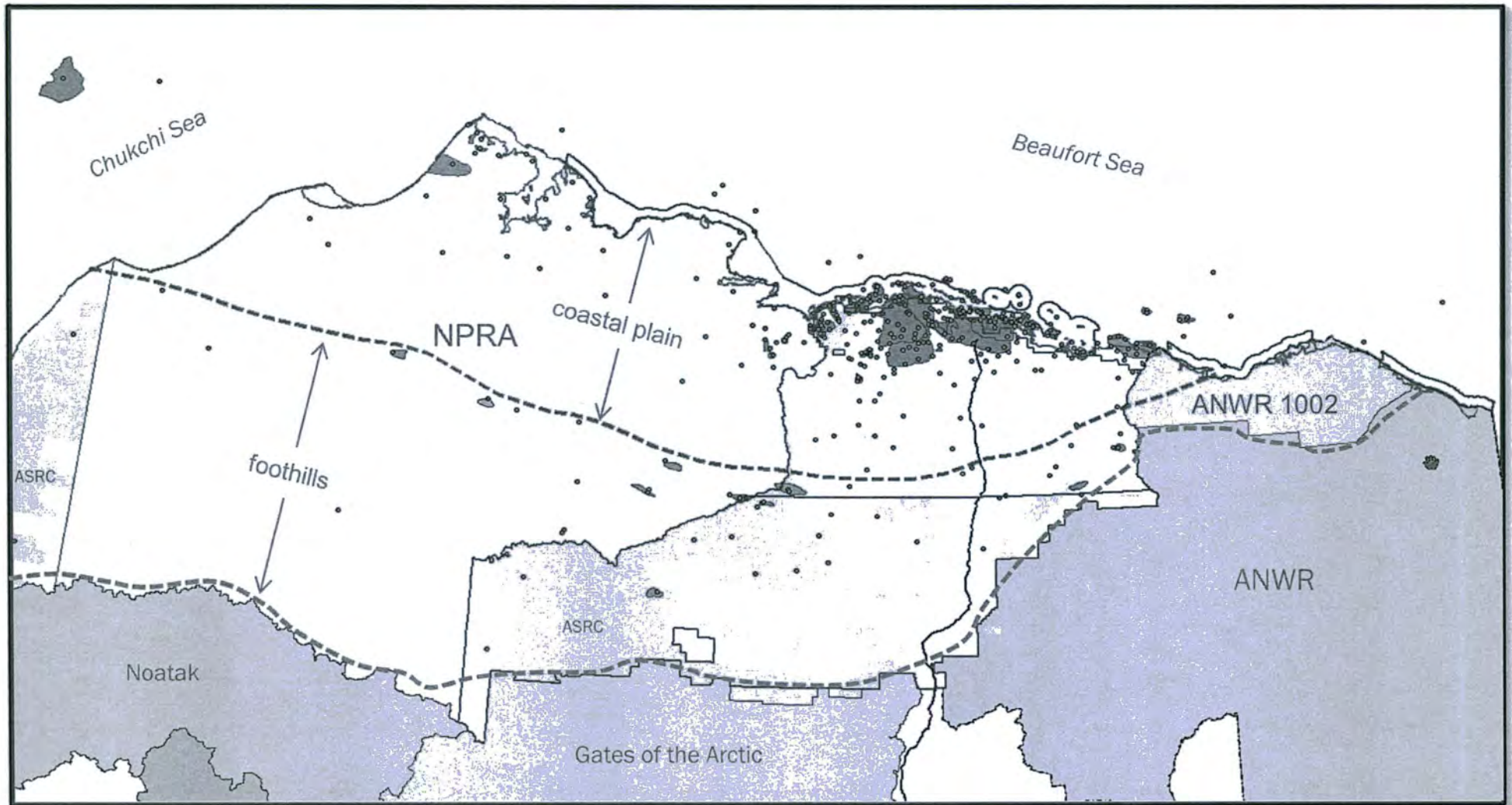
- **Cook Inlet:**
 - Resources and Reserves
 - Current Activity & New Developments
 - Who's Working the Cook Inlet?
 - Leasing Activity

- **Frontier Basins:**
 - Resources and Reserves
 - Current Activity & New Development
 - Who's Working the Frontier Basins?
 - Exploration Licensing & Lease Conversion

- **DNR Involvement in DOR Tax Credit Process**

- **DNR Royalty Modification & Relief**

NORTH SLOPE RESOURCES OVERVIEW



Red Area – Gas Accumulations
Dark Green Area - Oil Accumulations

Black Dots - Exploration Wells
Red Outlines - State Areawide Lease Sale Boundaries.
Light Green Areas - Permanently Protected Federal Lands.

ARCTIC ALASKA OIL & GAS RESOURCES

MEAN ESTIMATES* OF UNDISCOVERED,
TECHNICALLY RECOVERABLE CONVENTIONAL RESOURCES IN ARCTIC ALASKA:

- ~ 40 billion barrels of oil
- ~ 207 trillion cubic feet of gas

Arctic Alaska	Mean Oil Estimate (Millions of Barrels)	Mean Gas Estimate (Billion Cubic Feet)
Onshore	15,908	98,960
Offshore	23,750	108,180
TOTAL	~ 40 BBO	~ 207 TCF

* Multiple USGS and BOEM sources

ARCTIC ALASKA OIL & GAS RESOURCES

■ Gas Reserves:

- ~ 30 trillion cubic feet of associated gas is estimated to be recoverable from producing or developing North Slope fields, mostly at Prudhoe Bay & Point Thomson. Without a pipeline, most of that gas is best described as contingent resource, not reserves.
- ~ 5.9 trillion cubic feet of proved associated gas reserves estimated in Alaska, virtually all on North Slope (Energy Information Administration (EIA), 2014)

■ Oil Reserves:

- ~ 2.8 BBO of proved oil reserves estimated on the North Slope (EIA, 2014)

NORTH SLOPE CURRENT ACTIVITY & NEW DEVELOPMENTS

▪ **Accumulate Energy**

- Franklin Bluffs area shale play evaluation
 - Drilled Icewine #1 well in October-December 2015
 - Seismic survey of lease area this winter

▪ **AEX (ASRC)**

- Placer Unit
 - Currently drilling Placer #3 well – spud in late January 2016

▪ **BP**

- Prudhoe Bay Unit
 - Completed 8 new wells, 46 new sidetracks, ~420 well workovers in Initial Participating Area (IPA), 2015
 - Completed first wells in Lisburne PA in 9 years, 2015
 - Completed 3D seismic program in North Prudhoe, 2015

NORTH SLOPE CURRENT ACTIVITY & NEW DEVELOPMENTS

■ **Caelus Natural Resources**

- Oooguruk Unit
 - On-going development (4-5 wells/year; all long-reach & frac'd)
- Nuna
 - First production from Nuna Torok Phase 1 in late 2018(?)
 - No construction activity this winter
- Smith Bay Exploration (shallow water ice pad)
 - Second of two exploration wells nearly complete

■ **Conoco Phillips**

- Colville River Unit
 - Initiated first production at CD5 in 2015
 - Plan for a total of 8 new wells in 2016
- Greater Mooses Tooth Unit (Federal/NPRA)
 - Approved funding for \$900MM GMT1 project
 - Plan to drill two Tinmiaq exploration wells in western part of unit

NORTH SLOPE CURRENT ACTIVITY & NEW DEVELOPMENTS

■ **Conoco Phillips**

- Kuparuk River Unit
 - First wells came online at Kuparuk DS-2S in 2015
 - Significant drilling planned in 2016 for Kuparuk PA, Tarn PA and West Sak PA during 2015-16

■ **ExxonMobil**

- Point Thomson Unit
 - Completion of Initial Production System in 2016
 - Completed 22 mile liquid hydrocarbon pipeline from Point Thomson to Badami Field, which connects to TAPS
 - Start-up expected by mid-May 2016 (10,000 bpd condensate)

■ **Great Bear Petroleum**

- Currently acquiring large 3D seismic dataset (~450 sq miles)
- Planning for additional work at Alkaid #1 in 2017

NORTH SLOPE CURRENT ACTIVITY & NEW DEVELOPMENTS

■ Hilcorp

- Northstar Unit
 - Returned 2 wells to production
- Milne Point Unit
 - Drilled 3 new wells, started new G&I plant construction in 2015
 - Plan to drill 10 new wells and complete 16 workovers in 2016

■ Repsol/Armstrong

- Pikka Unit (Nanushuk Project Development)
 - Drilled 3 exploration wells & sidetracked 1 in 2015 (total of 12 wells & sidetracks since 2012)
 - Commenced the project EIS under NEPA in June 2015
 - Plan to drill 1 additional exploration well in 2017

NORTH SLOPE WELLS DRILLED & SEISMIC ACQUIRED

- **New Exploration & Development Wells Drilled 2004-2014**
 - 110 Exploratory Wells and Well Branches
 - 1,646 Development & Service Wells and Well Branches

- **2D & 3D Seismic Data Acquired (Tax Credit Data) 2004-2014**
 - Line Miles 2D (onshore/shorezone ice) ~ 870
 - Square Miles 3D (onshore/shorezone ice) ~ 9,945

WHO'S WORKING NORTH SLOPE?

- **Large Majors (>\$40B Market Cap):**

- BP Exploration, Inc.
- Chevron USA, Inc.
- ConocoPhillips Alaska
- Eni
- Exxon Mobil Corporation
- Shell Offshore, Inc.

- **Large Independents & Mid-Sized Companies:**

- Armstrong Oil and Gas/70 & 148 LLC
- Anadarko E&P Onshore LLC
- BG Alaska E&P Inc.
- Caelus Natural Resources Alaska LLC
- Halliburton Energy Services
- Hilcorp Alaska, LLC
- Repsol

WHO'S WORKING NORTH SLOPE?

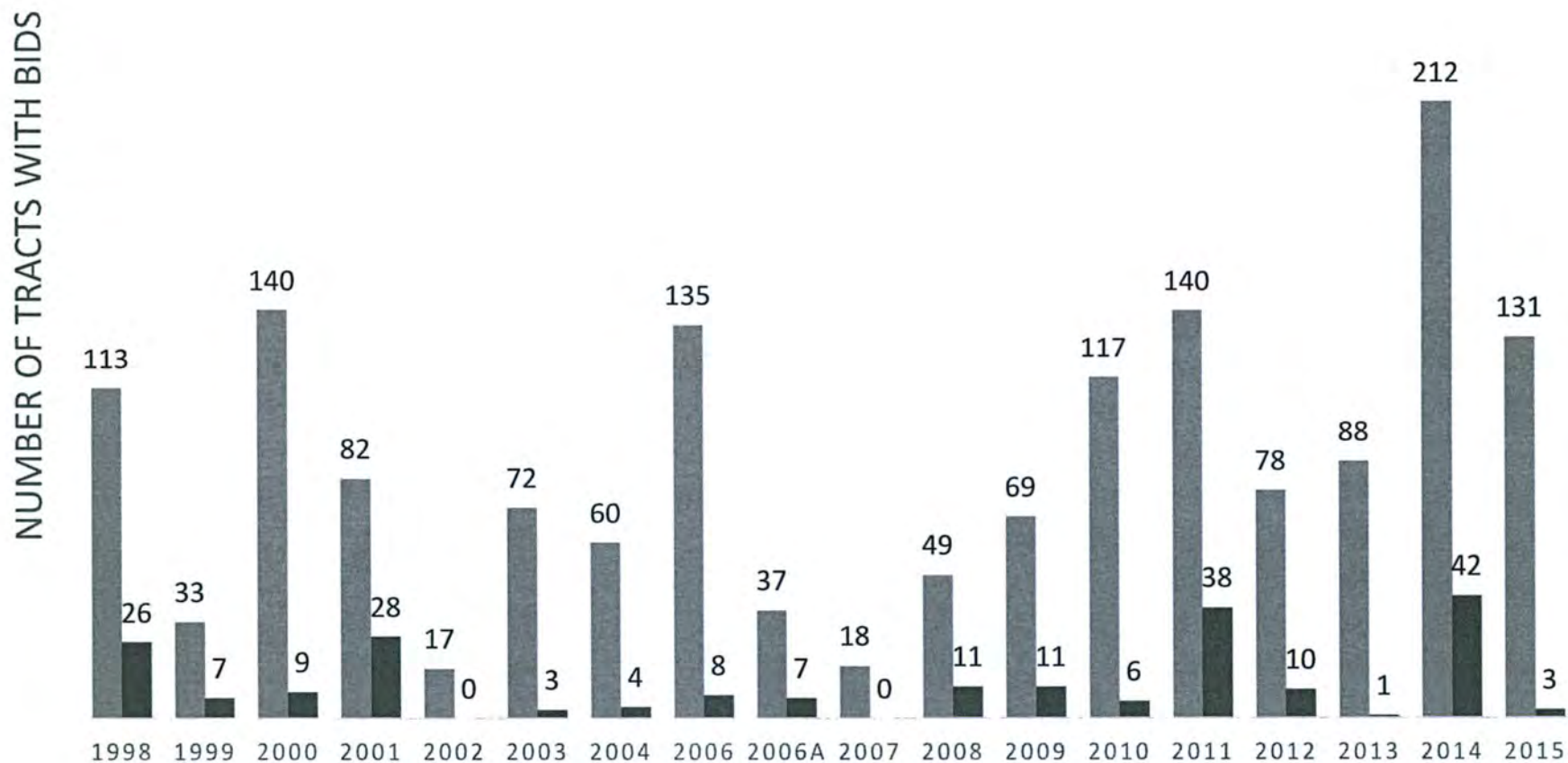
■ Small Independents:

- Accumulate Energy Alaska, Inc.
- Alaska, LLC
- Alaskan Crude Corp.
- ASRC Exploration LLC
- Aubris Resources, LP
- AVCG, LLC
- Brooks Range Development Corporation
- Burgundy Xploration LLC
- Caracol Petroleum LLC
- Chap-KDL, Ltd.
- Colt Alaska LLC
- Dewline Petroleum LLC
- Donkel Oil & Gas, LLC
- Eastland Property and Minerals
- GMT Exploration Company LLC
- Great Bear Petroleum Ventures
- MEP Alaska, LLC
- Mustang Operations Center 1, LLC
- NordAq Energy Inc.
- Pacific Lighting Gas Development
- Petro-Hunt, LLC
- Pinta Real Development, LLC
- Petro-Hunt, LLC
- Pinta Real Development, LLC
- Ramshorn Investments, Inc.
- Red Technology Alliance, LLC
- Renaissance Umiat, LLC
- Royale Energy, Inc.
- Samson Offshore, LLC
- Savant Alaska, LLC
- Sunlite International Inc.
- The Eastland Oil Company
- TP North Slope Development, LLC
- Transworld Oil & Gas Ltd.
- Ultrastar Exploration LLC
- URSA Major Holdings LLC
- Woodbine Petroleum, Inc.
- Woodstone Resources, LLC

NORTH SLOPE LEASING ACTIVITY TRENDS

NORTH SLOPE AREAWIDE LEASE SALE RESULTS: NUMBER OF TRACTS THAT RECEIVED BIDS

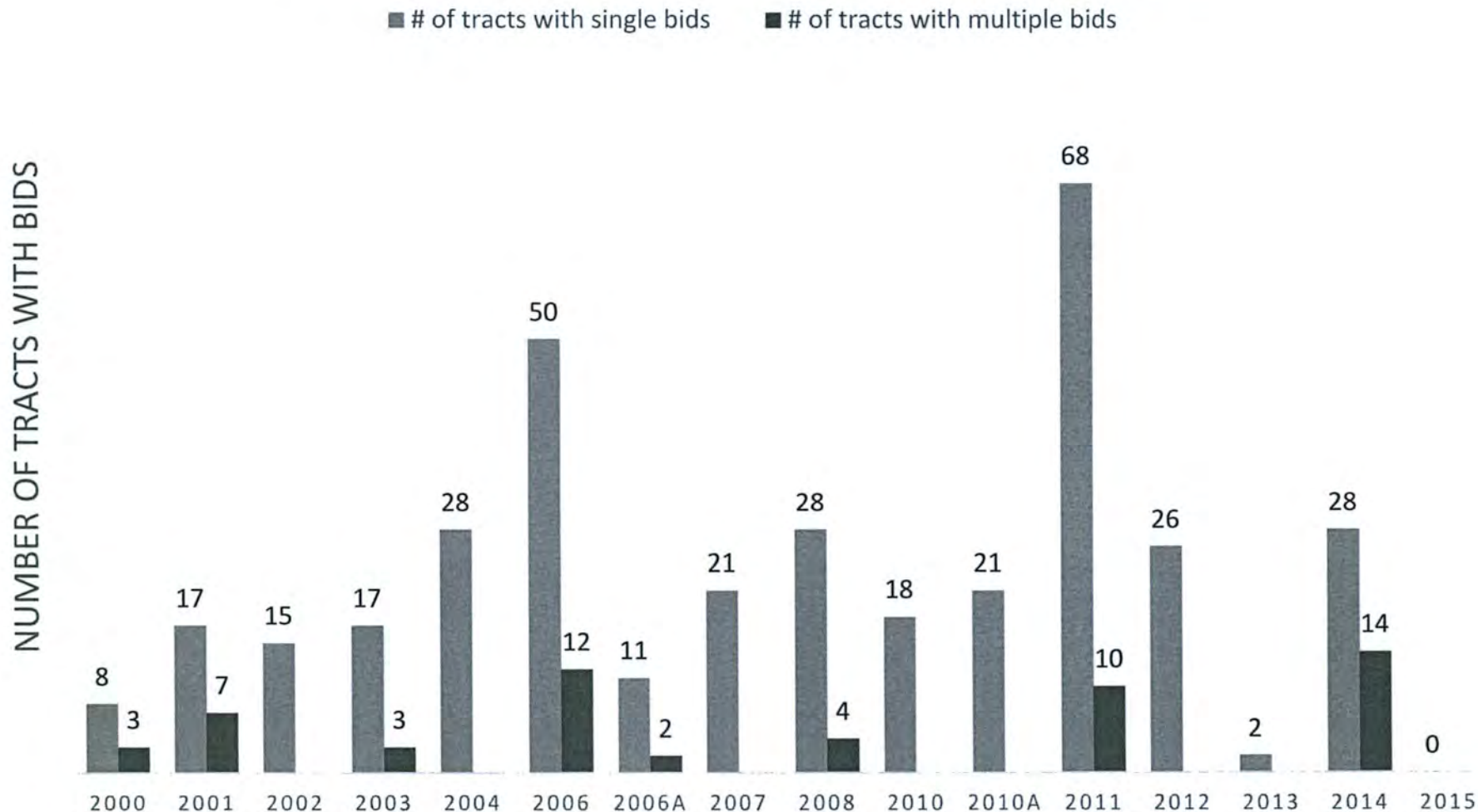
■ # of tracts with single bids ■ # of tracts with multiple bids



NORTH SLOPE AREAWIDE LEASE SALE

NORTH SLOPE LEASING ACTIVITY TRENDS

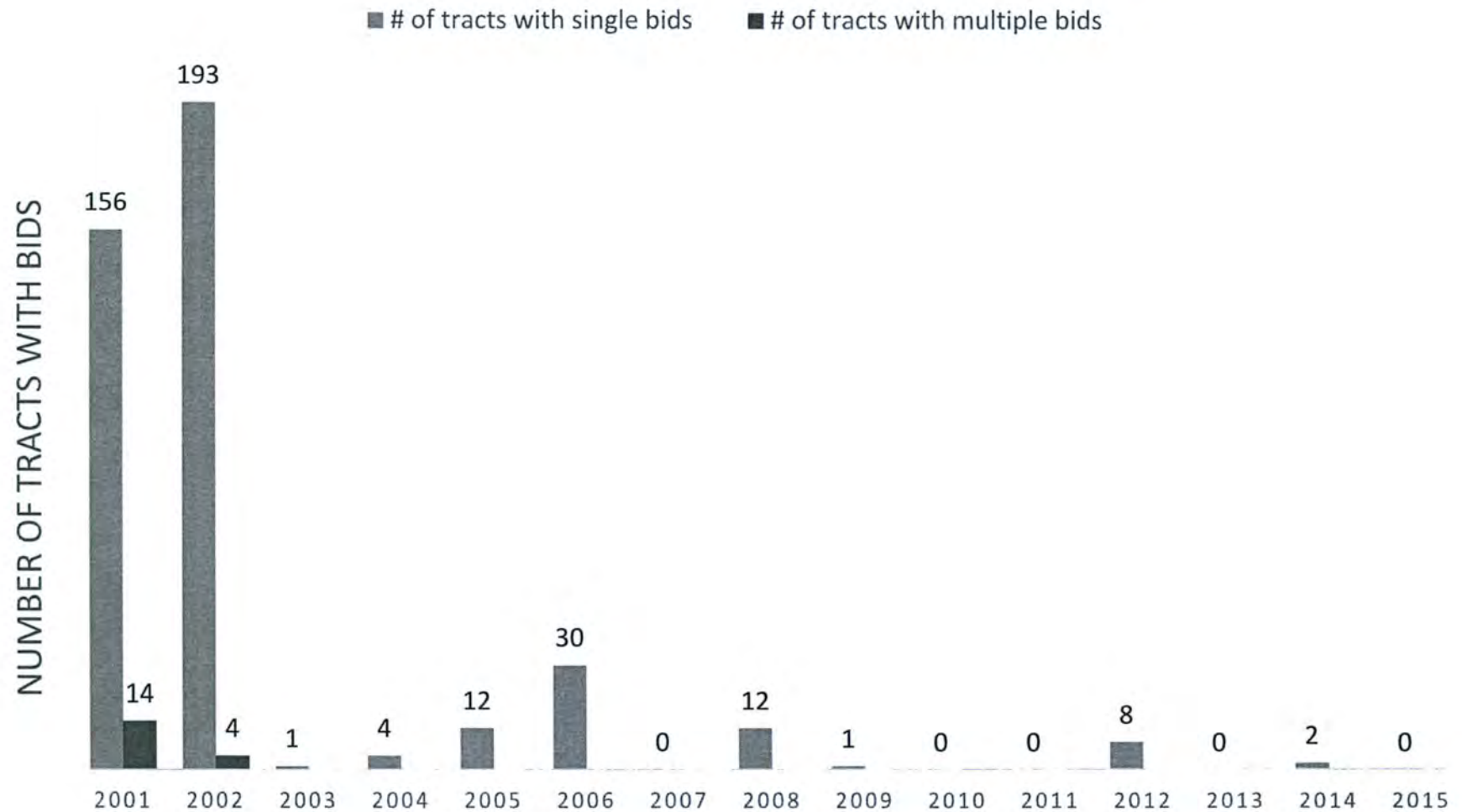
BEAUFORT SEA AREAWIDE LEASE SALE RESULTS: NUMBER OF TRACTS THAT RECEIVED BIDS



BEAUFORT SEA AREAWIDE LEASE SALE

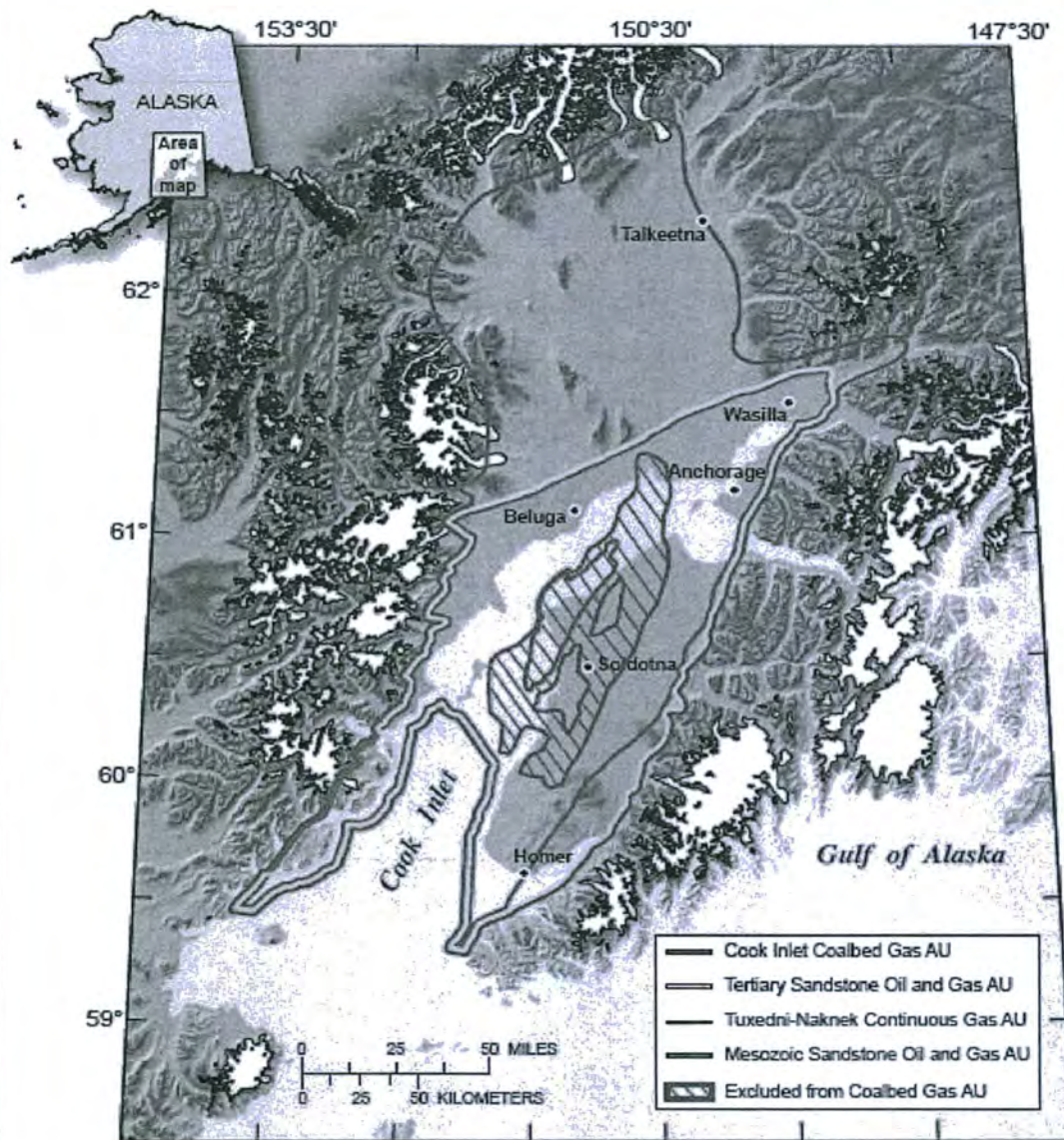
NORTH SLOPE LEASING ACTIVITY TRENDS

NORTH SLOPE FOOTHILLS AREAWIDE LEASE SALE: NUMBER OF TRACTS THAT RECEIVED BIDS



NORTH SLOPE FOOTHILLS AREAWIDE LEASE SALE

COOK INLET RESOURCE & RESERVES OVERVIEW



- **Undiscovered, Technically Recoverable Oil & Gas (USGS, 2011):**
 - mean conventional oil 599 MMBO
 - mean conventional gas 13.7 TCF
 - mean unconventional gas 5.3 TCF

- **Natural Gas Reserves (ADNR, 2015)**
1.18 TCF (Proved + Probable)

- 1.2 TCF additional mean resource assessed in OCS waters (BOEM, 2011)

COOK INLET CURRENT ACTIVITY & NEW DEVELOPMENTS

- **Apache Alaska Corporation:**
 - Ceasing all seismic acquisition and other exploration activity in Alaska
 - Intend to hold leases until expiration
- **Conoco Phillips:**
 - Recent sale of interest in Beluga River Unit
- **Furie Operating Alaska**
 - Kitchen Lights Unit:
 - Set monopod platform in 2015;
 - Completed onshore gas facilities & pipeline in 2015
 - Commenced production in December 2015
 - Randolph Yost, 2nd jack-up rig, arrived in Homer early March, plan to drill two development wells in 2016
- **BlueCrest Energy, Inc.**
 - Cosmo Unit:
 - Planned arrival of new land-based drill rig for oil development in 2016
 - Plan 1st oil in mid-2016 (oil production will be from onshore)
 - Possible offshore drilling for gas (Spartan 151 jack-up rig) in 2016

COOK INLET CURRENT ACTIVITY & NEW DEVELOPMENTS

▪ Hilcorp Alaska, LLC:

- Cannery Loop Unit:
 - Completed 2 new wells in 2015
 - Planned 2 workovers in 2016
- Deep Creek Unit:
 - Drilled 1 new well in 2015 and 2nd is planned for 2016
- Ninilchik Unit:
 - Completed 3 new gas wells in 2015 and 7 new gas wells in 2014
- Trading Bay Unit:
 - 19 workover jobs in 2015 and 3 new wells in 2016
- Purchased XTO Energy, Inc. assets in southern Cook Inlet
- Projected ~\$120 MM investment in Cook Inlet in 2016

COOK INLET WELLS DRILLED & SEISMIC ACQUIRED

- **New Exploration & Development Wells Drilled 2010-2014**
 - 24 Exploratory Wells and Well Branches
 - 65 Development & Service Wells and Well Branches

- **2D & 3D Seismic Data Acquired (Tax Credit Data) 2004-2014**
 - Line Miles 2D (onshore/offshore) ~ 725
 - Square Miles 3D (onshore/offshore) ~ 660

WHO'S WORKING COOK INLET?

- **Large Majors (>\$40B Market Cap):**

- ConocoPhillips Alaska

- **Mid-Sized Independents:**

- Hilcorp Alaska, LLC
- Apache Alaska Corp.

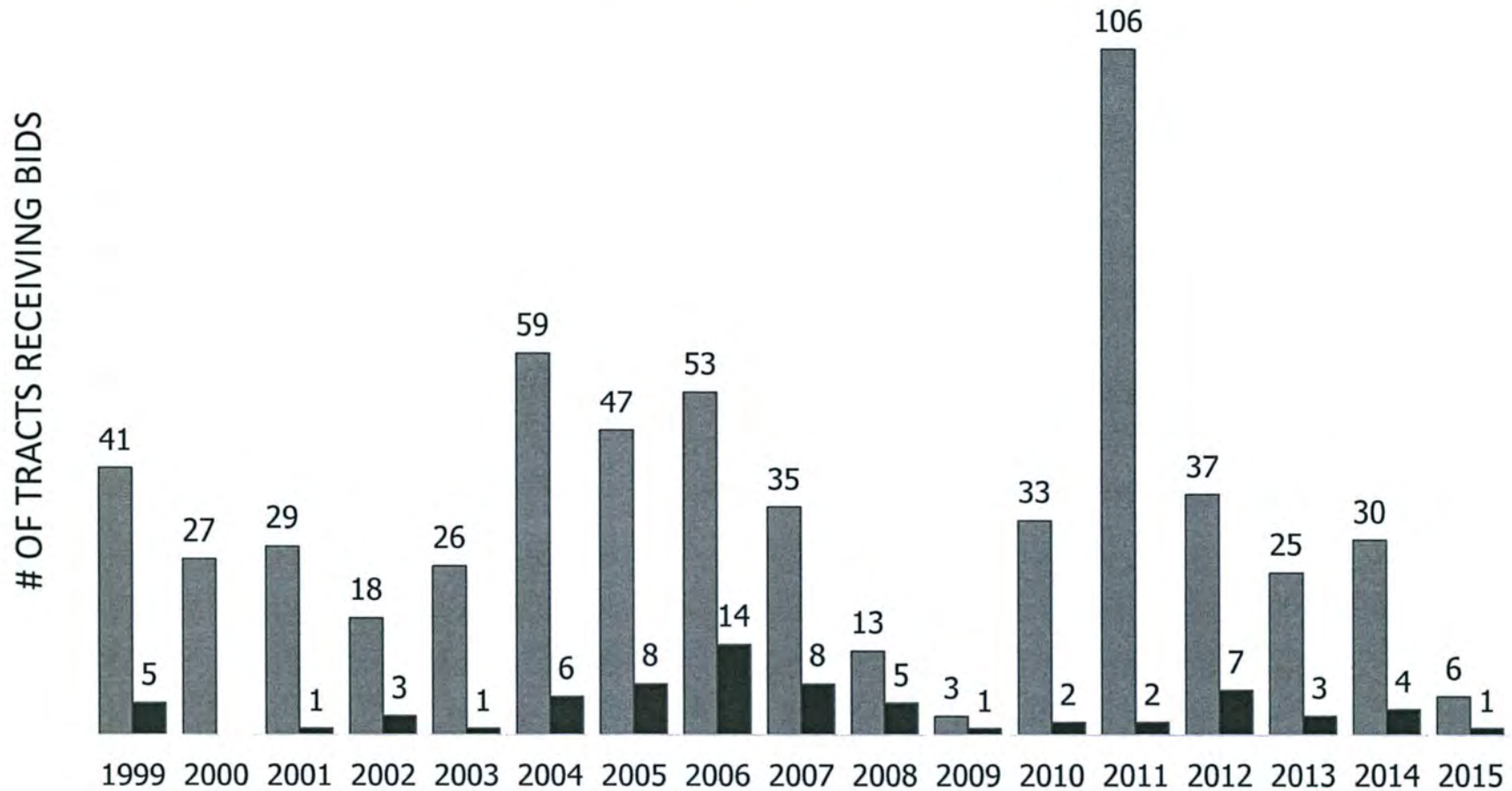
- **Small Independents & LLCs:**

- Alaska Energy Alliance Inc.
- AIX Energy LLC
- Alaska LLC
- Aurora Gas LLC
- Aurora Exploration LLC
- BlueCrest Energy Inc.
- CIRI Production Company
- Cook Inlet Energy LLC
- Cornucopia Oil & Gas Company LLC
- Corsair Oil & Gas Company LLC
- Furie Operating Alaska LLC
- New Alaska Energy LLC
- NordAq Energy LLC
- Taylor Minerals LLC
- Woodstone Resources LLC

COOK INLET LEASING ACTIVITY TRENDS

COOK INLET AREAWIDE LEASE SALE RESULTS: 1999 - 2015

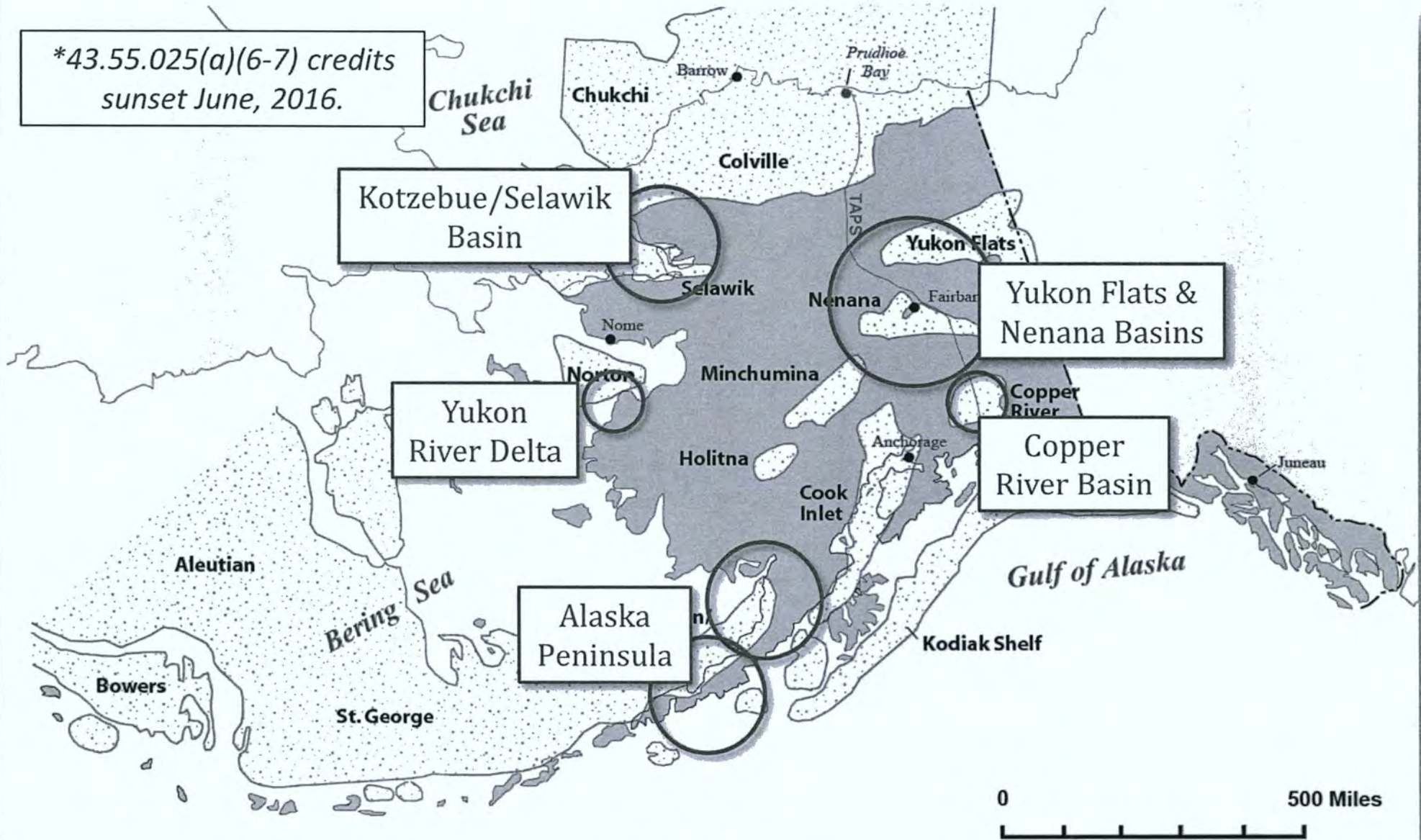
■ # of tracts with single bids ■ # of tracts with multiple bids



COOK INLET AREAWIDE LEASE SALE

FRONTIER BASINS TAX CREDIT* AREAS

*43.55.025(a)(6-7) credits
sunset June, 2016.



STATEWIDE RESOURCE ASSESSMENTS

- UNDISCOVERED, TECHNICALLY RECOVERABLE RESOURCE -

Region	Mean Oil Estimate (Million Barrels)	Mean Gas Estimate (Billion Cubic Feet)
Onshore Arctic	15,908	98,960
Offshore Arctic	23,750	108,180
Interior Basins (only partially assessed)	234	5,641
Upper Cook Inlet	599	19,037
Other Southern Alaska	2,859	23,458
TOTAL	43 BBO	255 TCF

Includes Yukon Flats and Kandik basins
(Nenana, Kotzebue, Copper River,
Holitna, & Susitna basins not assessed)

Mainly federal OCS waters,
minor AK Peninsula
onshore

EXPLORATION LICENSE PROGRAM

- The program supplements the state's oil and gas leasing efforts & encourages exploration outside of known oil & gas provinces
- Every April, DNR accepts proposals to conduct exploratory activity outside existing leasing areas
- The DNR Commissioner may issue a notice requesting proposals to explore a designated area (encourages competition)
- The applicant has up to 90 days to submit their proposal
- Three exploration licenses have been converted to lease: Susitna II, Copper River, & Nenana

WHO'S WORKING THE FRONTIER BASINS?

■ **Ahtna**

- Copper River Basin, Tolsona Exploration License:
 - Reprocessed 2D seismic data & acquired new Tolsona 2D seismic in spring 2014
 - Plan to drill Tolsona #1 gas exploration well in early 2016; follow up to the Ahtna #1-19 well drilled in 2007-2009 (Rutter & Wilbanks)

■ **Doyon**

- Nenana Basin:
 - Drilled Nunivak #1 and #2 exploratory wells, 2009-2013
 - Acquired 2D and 3D seismic, gravity, magnetics, and lakebed geochemical surveys, 2005 - 2014
 - Converted exploration license to leases between 2013 & 2014
 - Additional 2D seismic in progress
 - Plan to spud Toghotthele #1 this June

WHO'S WORKING THE FRONTIER BASINS?

- **Doyon**

- Yukon Flats Basin:

- Acquired 2D seismic, gravity, magnetics, and lakebed geochemical surveys

- **NANA**

- Kotzebue Basin:

- Evaluating and marketing prospects based on legacy industry seismic

- **Usibelli Coal Mine Inc.**

- Healy Basin Gas-Only Exploration License:

- Drilled one shallow exploration well in 2014

FRONTIER BASINS WELLS DRILLED & SEISMIC ACQUIRED

- **New Exploration Wells Drilled 2004-2014**
 - 7 Exploratory Wells and Well Branches

- **2D & 3D Seismic Data Acquired (Tax Credit Data) 2004-2014**
 - Line Miles 2D (onshore) ~ 1,220
 - Square Miles 3D (onshore) ~ 340

FRONTIER BASINS EXPLORATION LICENSES

LOCATION	ADL FILE NUMBER	ACRES	COMMITMENT	EFFECTIVE DATE	TERM	STATUS
Healy – Gas Only	390606	204,883	\$500,000	Jan. 1, 2011	10 years	Issued/Active
Nenana Basin	390079	498,813	--	--	10 years	Converted to Leases
Southwest Cook Inlet	392536	168,582	\$1,501,000	Oct. 1, 2014	4 years	Issued/Active
Tolsona	392209	43,492	\$415,000	Dec. 1, 2013	5 years	Issued/Active
Susitna V	391794	45,764	\$250,000	Apr. 1, 2012	5 years	Relinquishing Issued/Active

DNR INVOLVEMENT IN DOR TAX CREDITS UNDER AS 43.55

- DNR involvement is limited to projects that yield geological, geophysical, and engineering data – mainly exploration wells and seismic surveys
- DNR collects and adjudicates data generated and releases to the public as per specified schedule & private land restrictions
- DNR has no role in credits that do not require data submission
 - .023(a)(1) Capital Expenditure for development work
 - .023(b) Net Operating Loss
- Statutes vary but provide minimal ability to screen proposed projects for geologic or commercial risk. When called for, pre-qualification mostly ensures “wildcat”/new exploration status.

EXPLORATION TAX CREDITS

- DNR ADJUDICATION REQUIREMENTS -

AS 43.55	Credit	Pre- Qualification	Major Criteria (in addition to data submission)
.025(a)(1)	30%	Yes (Well)	<ul style="list-style-type: none"> • Distinctly separate potential O&G trap • Except in Cook Inlet, > 3 miles from pre-existing wells
.025(a)(2)	30%	No (Well)	<ul style="list-style-type: none"> • > 25 miles from 7/1/2003 unit boundaries
.025(a)(3)	40%	Yes (Well)	<ul style="list-style-type: none"> • Distinctly separate potential O&G trap • Except in Cook Inlet, > 3 miles from pre-existing wells • Cook Inlet, 10 miles from 7/1/2003 unit boundaries • Elsewhere, 25 miles from 7/1/2003 unit boundaries
.025(a)(4)	40%	No (Seismic)	<ul style="list-style-type: none"> • Seismic outside of existing unit boundaries
.025(a)(5)	Up to 80-100%	No (Well)	<ul style="list-style-type: none"> • Jack-up rig, drill & evaluate Cook Inlet pre-Tertiary prospect
.025(a)(6)	Up to 80%	Yes (Well)	<ul style="list-style-type: none"> • Within specified Frontier Basin area • Seismically-defined O&G trap, evaluate full depth range • Private landowner data release authorization, plus more
.025(a)(7)	Up to 75%	Yes (Seismic)	<ul style="list-style-type: none"> • Within specified Frontier Basin area • Private landowner data release authorization, plus more
.023(a)(2)	20%	No (Well/Seismic)	<ul style="list-style-type: none"> • Qualified Capital Expenditure for exploration
.023(l)(2)	40%	No (Well/Seismic)	<ul style="list-style-type: none"> • Well Lease Expenditure south of 68 degrees North

PRE-QUALIFICATION PROCESS

- Presentation (pre-exploration)
 - Dates
 - Location relative to preexisting wells, units, etc.
 - Separate trap requirement (GG&E)
 - Additional factors for Frontier Basin wells & seismic
- Brief DNR Commissioner
- Commissioner decision letter

POST-EXPLORATION PROCESS

- Data Adjudication: Submittal, Inventory, QC
- Presentation [post-exploration & processing, only required for .025 (a)(1, 3, 5, 6, & 7)]
 - Dates
 - Operations consistent with exploration objectives
 - Findings (Geological, Geophysical, & Engineering)
- Brief DNR Commissioner
- Commissioner decision letter
- Data Management: Load for internal use, Prepare for public release, Archive, Release

ROYALTY MODIFICATION

AS 38.05.180(j)

- Commissioner may modify royalty to
 - Allow for production from a field or pool that has not previously produced
 - Field or pool must be sufficiently delineated
 - Production would not otherwise be economically feasible
 - Royalty rate shall not be less than 5%
 - Prolong economic life of a field or pool
 - Future production is no longer economically feasible
 - Royalty rate shall not be less than 3%
 - Reestablish production of shut-in oil or gas
 - Production would not otherwise be economically feasible
 - Royalty rate shall not be less than 3%
- Commissioner may not grant royalty modification unless lessee makes clear and convincing showing that modification meets criteria and is in the best interests of the state.
 - Without royalty modification, development would not proceed

Royalty Modification History

Year	Company	Field	Outcome
1995	BP	Milne Point	Application denied
1997	Unocal	10 Cook Inlet platforms	Application withdrawn
1999	Phillips	Cook Inlet platform	Application withdrawn
2005	Pioneer	Ooguruk	5% royalty until NPSL payout
2006	Kerr-McGee	Nikaitchuq and Tuvaq	Application denied
2007	Chevron	West Cook Inlet fields	Application withdrawn
2008	ENI	Nikaitchuq	5% royalty rate with oil price threshold (\$42.64/barrel escalated with inflation)
2014	Caelus	Nuna Torok	5% royalty rate until \$1.25 billion of gross revenue accumulated

Cook Inlet Discovery Royalty

AS 38.05.180(f)(4)

- Lessee of a discovery well shall pay 5% royalty on all oil & gas production from a pool that is attributable to the discovery lease for 10 years following the date of discovery.
- Available only for leases in Cook Inlet sedimentary basin
- More than one pool is eligible for discovery royalty from a single discovery well.
- After 10 years, royalty returns to rate specified in lease
- Discovery well certification (11 AAC 83.1000 – .1049)
 - Discovery of a previously undiscovered oil or gas pool
 - Well has been drilled in a pool that is capable of producing in paying quantities defined under 11 AAC 83.395(4)

Cook Inlet Discovery Royalty History

- Prior to Furie's Kitchen Lights Unit Well No. 3 (KLU #3), no lessee had utilized the program.

- Furie KLU #3, Discovery Lease ADL 389197
 - 4 previously undiscovered gas pools
 - Discovery date was June 30, 2013
 - Lessees pay 5% on production from these 4 pools that is allocated to discovery lease—until June 29, 2023
 - Lessees will pay 12.5% on all other gas produced in the discovery lease

Other Royalty Relief Statutes

- AS 38.05.180(f)(5) automatically grants 5% royalty for 10 years for specific Cook Inlet fields identified in statute:
 - Falls Creek, Nicolai Creek, North Fork, Point Starichkof (not producing), Redoubt Shoal, and West Foreland—all currently pay 12.5% rate
- AS 38.05.180(f)(6) reduces royalty for specific platforms in Cook Inlet if production falls below certain levels.
 - Lower production based on reservoir conditions
 - Cannot be “the result of short-term production declines due to mechanical or other choke-back factors, temporary shutdowns or decreased production due to environmental or facility constraints, or market conditions.”

Platforms	Current Royalty Rate
Bruce, XTO.C	5%
King Salmon, Steelhead	7%
Dolly	10%
Anna, Granite Point, Grayling, Monopod, XTO.A	12.5%

- AS 38.05.180(n)(2) Nonconventional Natural Gas Rent and Royalty
 - Annual rental reduced to \$1 per acre and royalty reduced to 6.25%

THANK YOU!



550 W. 7TH AVE, STE. 1100, ANCHORAGE, AK 99501
www.dog.dnr.alaska.gov



Natural Gas Supply

Senate Resources Committee

April 7, 2016



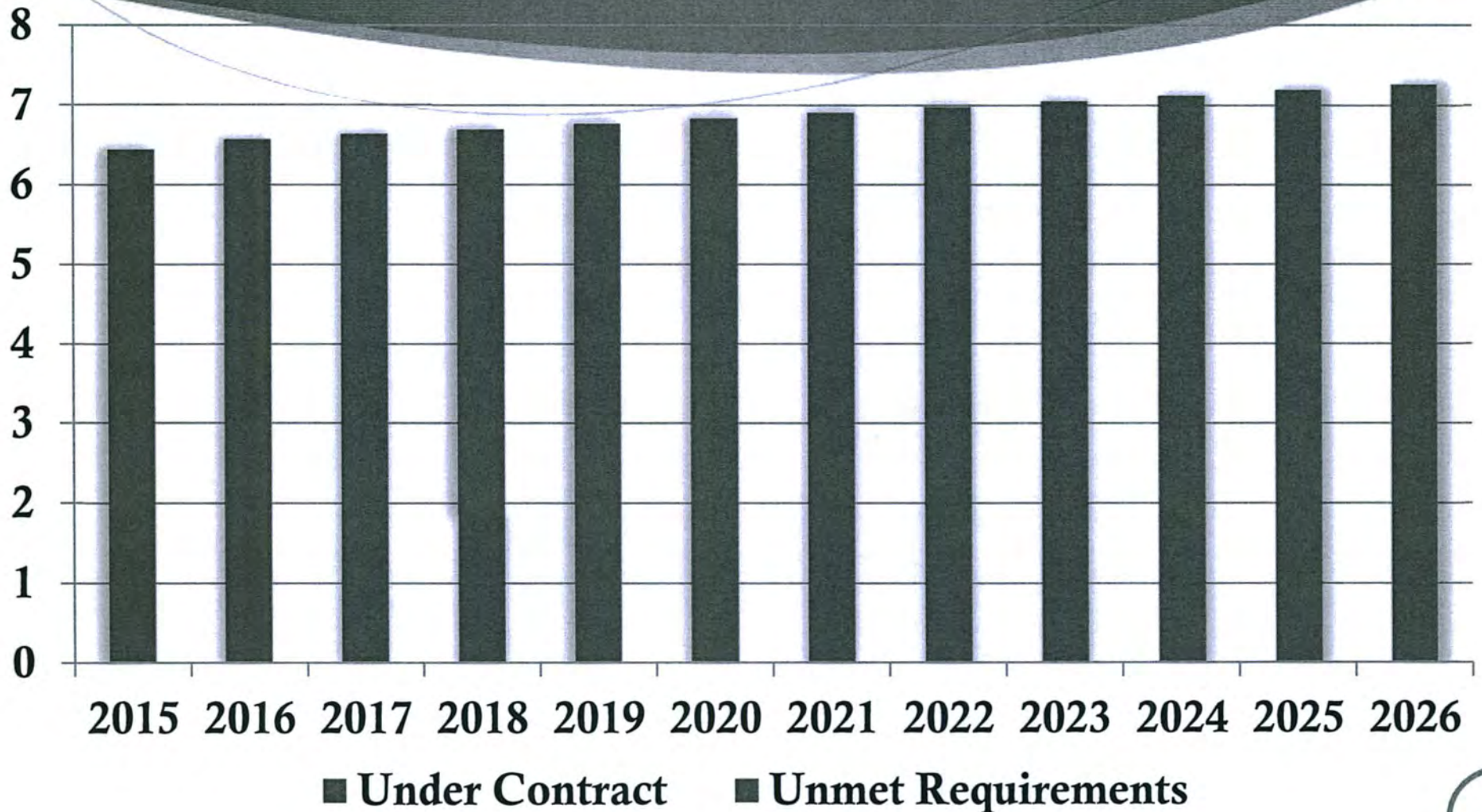
Cooperative Profile

- 61,100 meters, 50,500 members
- Over 4,200 miles of power lines & 22 substations
- Service area the size of West Virginia
- Generation portfolio: 90% natural gas, 10% hydro
- 2015 natural gas demand: 6.5 Bcf
 - 6.5 Bcf = 6,500 MMcf = 6,500,000 Mcf
- 2015 natural gas cost: \$46,345,000
 - Not including peaking services or transportation

Today's Questions

- **What is MEA's gas supply forecast?**
- **What has changed in Cook Inlet gas supply over the past 5 years?**
- **How have tax credit programs in Cook Inlet affected gas supply?**

MEA Gas Supply forecast - (Bcf)



What has changed in the last 5 years?

- 5 Years ago gas supply was available in small quantities and short terms (2 years).
- Most significant positive change is Hilcorp investment in existing Cook Inlet assets.
- Multiple new players investing significant capital.
- What has not changed?
 - USGS assessment of up to 19 Tcf remains to be found in Cook Inlet.
 - Additional reserves are not yet commercially available.

Impact of tax credit programs on gas supply

- **Good News:**
 - Multiple new Cook Inlet investors available for gas supply discussions
 - Life of mature fields have been extended
 - Some additional proven reserves
 - Temporary energy security
- **Bad News:**
 - New reserves are not “behind pipe”, which requires significant current and future investment
 - Temporary energy security

Contingencies

How can I be more efficient?

As consumers, each of us should use energy wisely. Snug, well-insulated structures will retain heat and reduce the amount of gas needed to fuel furnaces and boilers. If you are buying a major new appliance like a refrigerator, look for one that has earned an ENERGY STAR rating. Gas and electric utilities can provide information to help you better understand your energy bill and how to take steps to control it through conservation and energy efficiency. The U.S. Department of Energy, the Alaska Housing Finance Corporation and the website www.akenenergyefficiency.org are other great resources for information.

How can I help in an emergency?

If the gas delivery system is going to come under extra stress, it is likely going to be during a prolonged cold snap. In addition to the steps you're already taking to use energy wisely, you may be asked to further reduce your use of natural gas and electricity to help take pressure off the gas delivery system. Relatively small steps can make a big difference in the amount of gas that's needed during a few critical hours.

How will I know if you need my help?

If it's necessary to call for customer action, an announcement will be made through the media by local government officials. Announcements will outline the situation, spell out specific actions customers are being asked to take, and provide some idea of the length of the problem.

How will outages be handled ... and will I lose gas service?

Electric utilities can do something that gas utilities generally can't: interrupt service to selected customers for short periods of time and then restore it. Therefore, no scheduled service outages are planned for ENSTAR customers. Planned power outages would be a last resort, necessary only if the combination of system operations and customer actions fails to solve the problem. If it

In the event of gas system problems, emergency managers might use a chart like this to advise customers.

CONDITION	MEASING	Customer Action
Green	Stable	<ul style="list-style-type: none"> Use energy wisely Be conservative in use Stay alert for any service energy saving tips
Yellow	Caution	<ul style="list-style-type: none"> Set thermostat to 65 degrees in living areas, and 43 degrees in the garage Lower water heater setting to "warm" or "vacation" Minimize usage of natural gas range Postpone doing laundry and dishes Turn off unnecessary lights and electronics
Red	Emergency	<ul style="list-style-type: none"> See thermostat manufacturer's instructions Turn thermostat gas valve to "off" Turn off all natural gas appliances, including lawnmowers, grills, etc. Collaborate with other customers to help make up shortages Use the nonpaying fire cooling

becomes necessary to interrupt service to electric customers, outages are planned to be 20-30 minutes long and rotated among customers, with consideration for critical facilities.

How can I learn more?

Check the websites of your municipal or borough government, electric utility or ENSTAR for additional information.



good from ENERGI

GAS CONTINGENCY PLANNING

Railbelt electric and gas utilities harmonize efforts with local governments

Organizations throughout the Railbelt are ready to deal with a potential natural gas shortfall this winter. While it's not considered likely, all agree that it is important to be prepared. Nobody wants to be caught unprepared on a cold, dark winter evening. That's why ENSTAR, the electric utilities in the Railbelt, the Municipality of Anchorage, and the Kenai Peninsula and Mat-Su boroughs have been working together on a collective approach to the situation.

WINTER 2011-2012

Summary

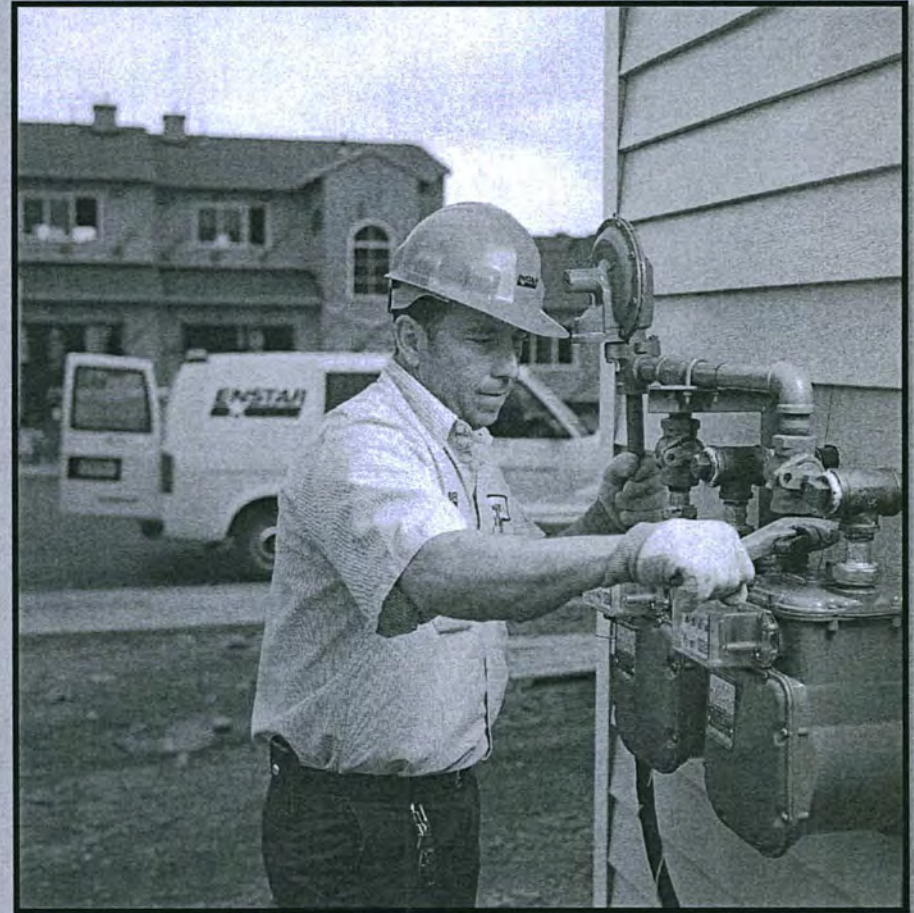
- **Uncertainty is the enemy of energy security**
- **Exploration & production risks are not typical core competencies of regulated utilities**
- **Bringing new gas reserves to the point they can be prudently purchased by a regulated utility requires \$100's of millions and many years**



Presentation to the
Senate Resources Committee
April 7, 2016

Natural Gas Supply Needs

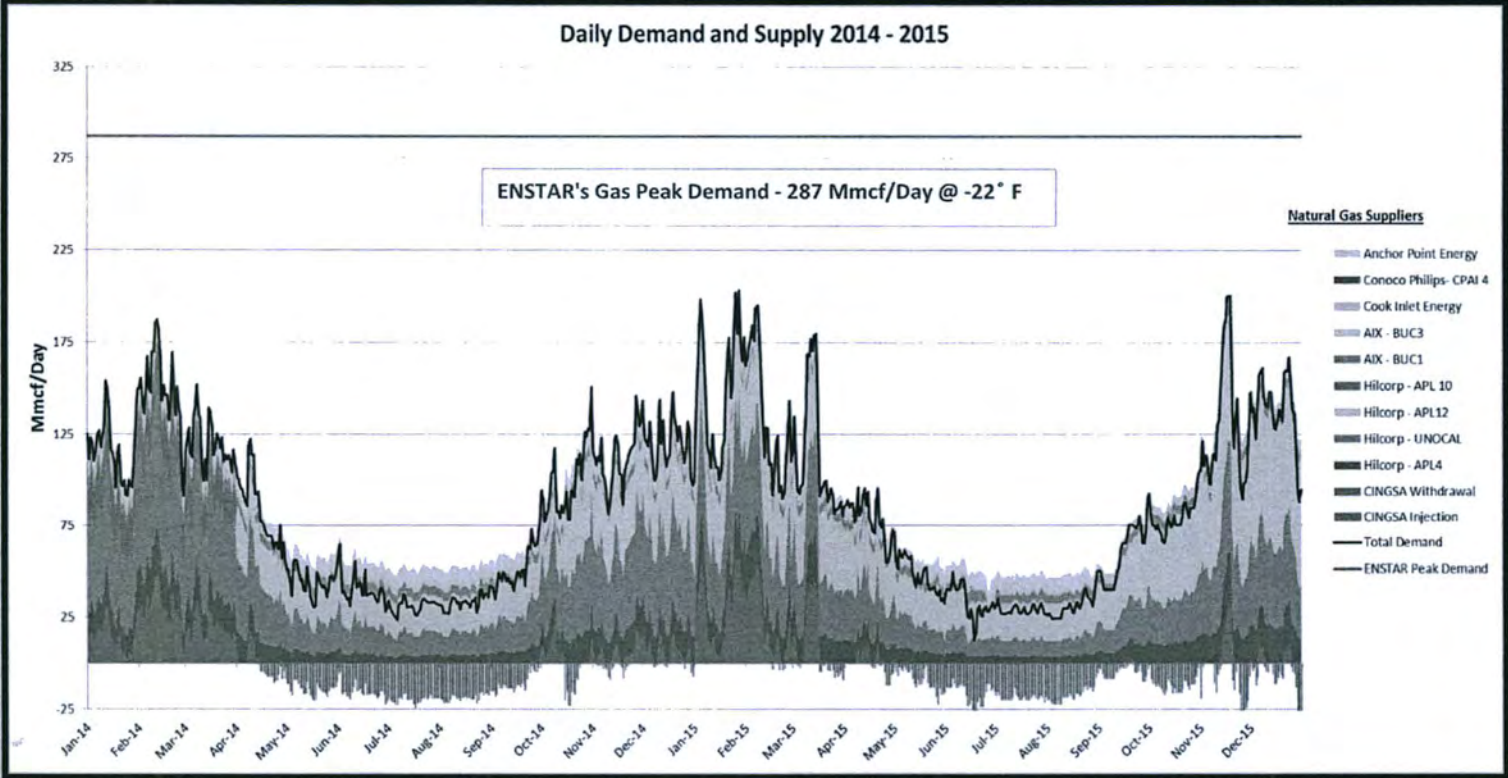
- 140,935 Customers
- Anchorage, Anchor Point, Big Lake, Girdwood, Homer, Houston, Kenai, Palmer, Soldotna, Wasilla, and Whittier
- 33 Bcf/year
- Peak deliverability 287 MMcf/day



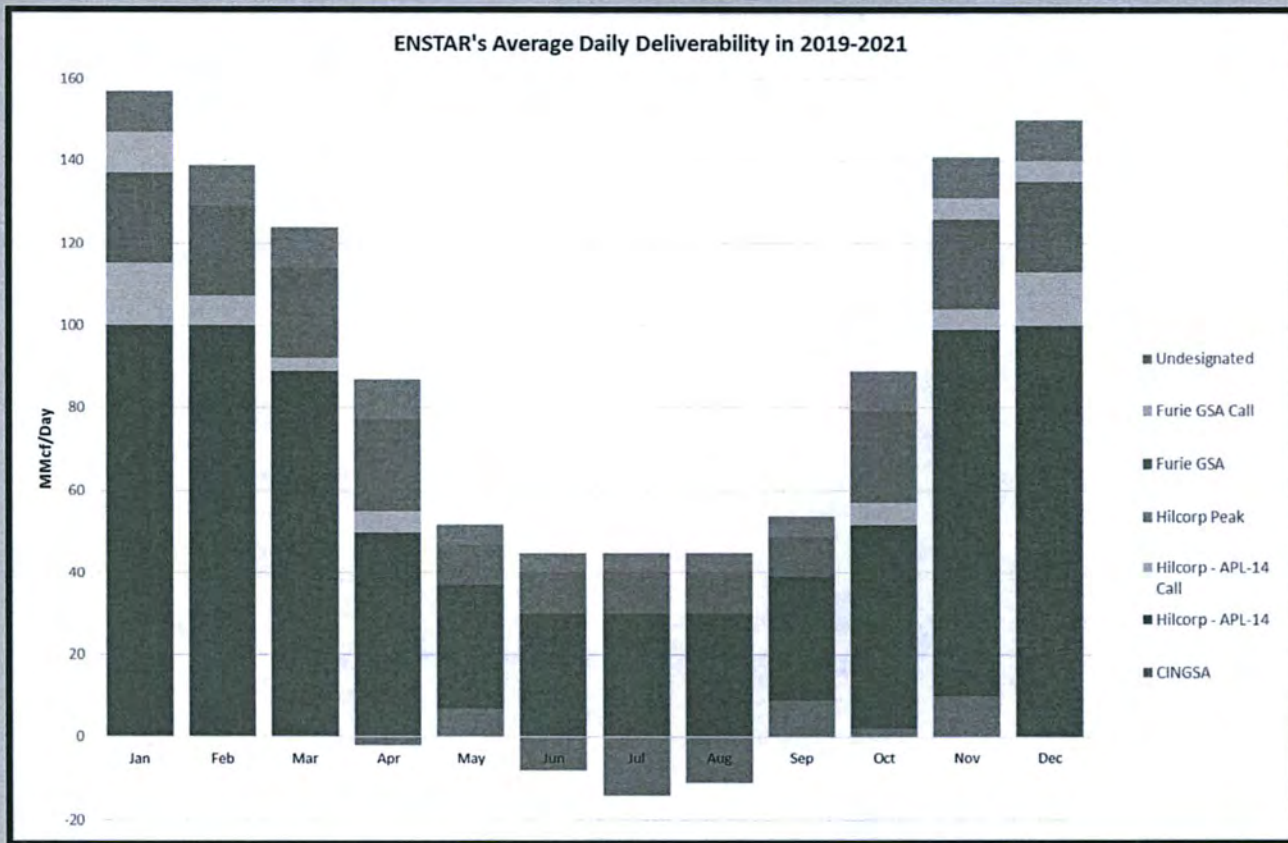
Senate Resources Committee



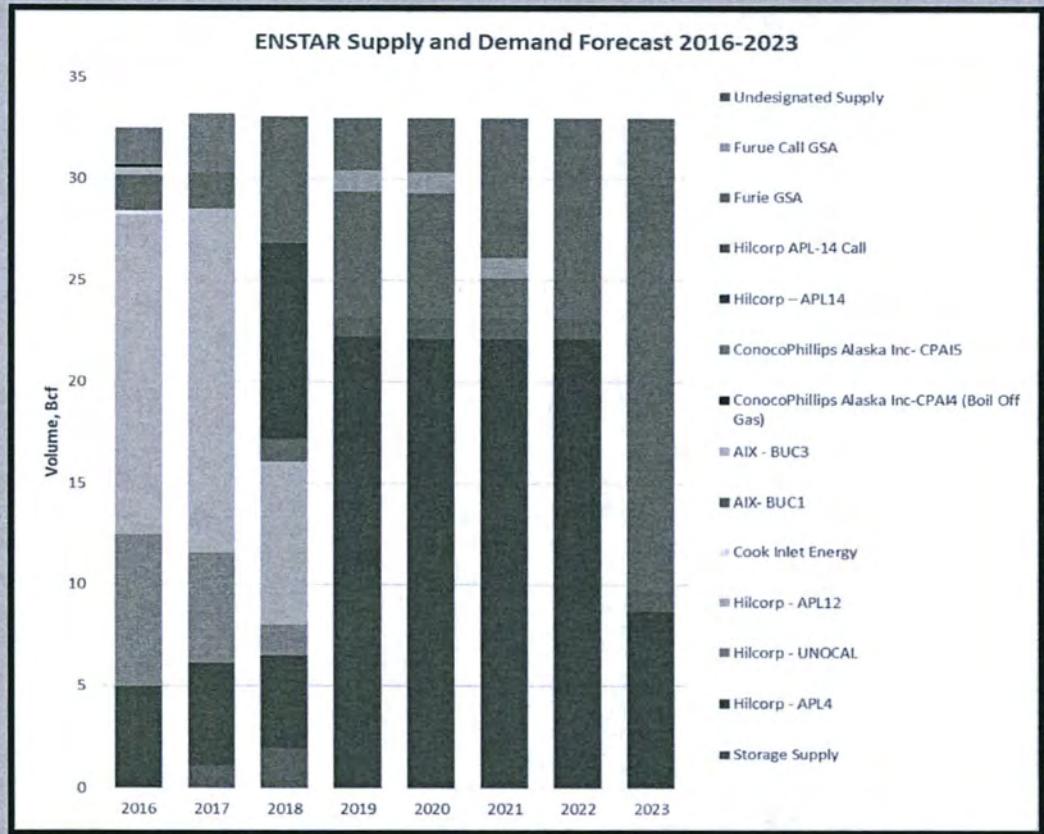
Supply and Demand



Seasonal Average Deliverability



Supply Contracts 2016-23



Senate 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
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Alaska Oil and Gas Association



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AOGA Testimony on Senate Bill 130

Senate Resources Committee

April 8, 2016

Good Afternoon Madam Chair and members of the Committee. For the record, my name is Kara Moriarty and I'm the President/CEO of the Alaska Oil and Gas Association, commonly referred to as "AOGA".

AOGA is a professional trade association for the oil and gas industry and I thank you for the opportunity to testify today on Senate Bill 130, Governor Walker's oil and gas tax policy proposal. Although I am here on behalf of a diverse group of companies, my testimony today represents the thoughts and sentiments of each and every member. On matters related to tax, AOGA requires unanimous consent on testimony.

There is no denying it – as legislators you have a tremendous challenge in these economic times. And whether you want to believe it or not, the reality is, the oil and gas industry is facing similar challenges. Loss of revenue. Cutting budgets. Laying people off.

As the Resources Committee you are tasked with looking at policies that will either benefit the state's resources or they won't. Currently the policy you have in place for the oil industry places an emphasis on production, investment and jobs. And, while the industry is responding as any business would in this low price environment, we also recognize the value of investment and jobs to Alaska and we are doing our part to sustain what we can in this tough environment. We are doing our best to weather this storm in the interest of long term sustainability for all of us, but changing policies that will have further negative impact on industry will be costly for the state in the long-term.

You've been asked, again, for the 6th time in 11 years to examine and change oil tax policy. No other industry has had so many changes to its fiscal structure in Alaska. And, we can find no other jurisdiction in the world that has considered changing oil tax policy more than

Alaska. Nevertheless, here we are, in a low price environment, considering changes to the oil industry.

Slide 1

In fact, the only reason you are being asked to change the policy, again, is because of oil prices. The Administration stated to us before they introduced the bill, and they've said it to you here, that they would not have introduced this bill if they didn't need more money for government.

Commissioner Hoffbeck even said as much, two months ago when he said that the motivation to look at oil tax credits was the budget. He went onto say that the motivation was not to redefine oil and gas taxes. Regardless of the motivation, their final proposal in SB130 does both. It increases taxes on the industry to generate more government revenue, and it redefines oil and gas taxes.

Slide 2

As you consider SB 130, we encourage you to ask us, ask the Administration, ask your consultants, and ask yourselves, four important questions.

Will the Governor's bill increase production? Will it make Alaska more or less competitive, will SB 130 provide stability, and will it provide predictability?

Slide 3

Of course, the last major change in tax policy occurred three years ago with the passage of SB 21, followed by the referendum to repeal the new law in August 2014. Voters decided the state's current fiscal policy was good for Alaska, and we would agree.

Since April 2013, when the bill passed the legislature, industry has announced more than \$5 billion in additional spending across the state. That increased spending could not have happened at a better time, as the investments made in the last 18-24 months are helping the industry, Alaskans, and the state as a whole get through this low price environment.

Objectives like stability and predictability are important in any business setting. But let's not lose sight of the prize here. More oil and gas production is the ultimate objective for Alaskans and Alaska's oil and gas industry. For the first time since 2002, we have seen a production increase. From March 2015 to March 2016, we've seen an increase of just over 4,000 barrels a day, which is just under a 1% increase.

It is also important to look at the forecast for the outlying years. Two and a half years ago, in Dec. 2013, the production forecast for FY16 was 487,600 barrels per day. We are now on track to realize an increase of 33,000 barrels per day over that forecast, even though oil prices have plummeted by 70% during the same time frame. The next few years are forecasted to bring similar results. Even though the price forecast today is about \$50 less per barrel than the price forecast in 2013, the Spring 2016 production forecast is still 50,000 barrels per day more in 2020. And more production is always good for the state, regardless of oil price.

Speaking of prices, they are the lowest we've seen in more than a decade. You are well aware of the impact this has had on the State of Alaska's revenues. While it is significant that the state has historically received 85-90% of its revenue from oil, it's important to recognize that our industry receives 100% of its revenue based on the market prices for what it produces. As my friends in other industries will tell you, we are price takers, we are not price makers.

Slide 4

And these low prices are causing the industry to be cash flow negative. What does that mean? That means we are not collecting enough revenue each day to pay our daily bills.

The oil and gas industry is no different than any other business that does not have enough cash flow to pay their expenses. They cut back. Unfortunately, we have seen a dramatic increase in project delays, deferrals, and rigs going idle. Most painfully, Alaskans have lost jobs. We recognize that state employees are losing their jobs too. Estimates from the operating budget passed by the House will result in 50 fewer state employees. But for the oil and gas industry, the job loss has been even more severe. Individual companies can give you specific job loss numbers, but by June of this year, over 1,000 Alaskans will no longer be working directly for the industry. This does not include the contractor workforce.

To add insult to injury, Alaska has been and continues to be a high cost environment. According to the Department of Revenue's Spring Sources Book, the estimated average cost of producing a barrel of oil on the North Slope and getting it to market on the West Coast – before a company pays even one penny of tax – is right around \$50/barrel.

Yet despite this, here we are, testifying about legislation to add significant additional costs to the industry by raising the production tax and eliminating incentives.

Let me very clear. If you raise taxes or reduce credits, there will be a negative impact.

This is not about politics, it is about economics. Industry is cash negative. Some companies may already be burning through savings to pay for operations, and the reserves are not unlimited. If a company has \$100 million to spend in Alaska, and the government wants to take an additional \$20 million, they will have no choice but to further eliminate operating and/or capital expenditures. That means less investment, less production, less long-term state revenues, and even more Alaskans without a job.

Slide 5

In the interest of time, I will not belabor each and every concern we have with the Governor's bill. However, I do want to comment on a few of the substantial concerns.

The governor's proposal would increase the minimum gross tax from 4% to 5%. Although a one percentage point increase might not sound significant to some, in reality, it represents at least a 25% increase for those companies who already pay the 4% minimum tax.

Additionally, the Governor's proposal would forbid companies from using any earned or available tax credits to reduce the minimum tax below the new 5% floor. It is likely that there will be companies, large and small, that have earned "new oil" tax credits or loss credits from prior year investments for explorations and drilling and prior year losses, while also operating in the red due to low oil prices. For those companies, using those tax credits is the only way they can also continue to invest in the state. The proposal would delay, or possibly deny, vital economic recovery at the very time companies need it the most.

In other words, raising the minimum tax affects everyone, and the proposed increase is a flagrant money grab that is large enough to cause substantial negative impacts on all producers at today's oil prices.

For smaller companies or newcomers to the state who have yet to make a profit in Alaska, they are not required to pay the 4% minimum tax under current tax law. Under the governor's proposal, they would go from paying zero in production tax because they don't make a profit, to immediately being hit with a 5% gross value tax, a punitive tax increase described by the Administration as an "infinite increase."

Additionally, the proposal would change the way the minimum tax is determined and would prevent a producer from taking the actual tax credits available for a month to the extent they are greater than the initially estimated amount. Both of these incremental changes amount to a fundamental change in how the tax is calculated and will result in a tax increase.

Another major concern relates to the change in the net operating loss (NOL) tax credits. The Administration has testified that they are preserving the NOL credit, but we contend that under the current proposal the NOL credits become virtually useless.

NOL tax credits are utilized both on the North Slope and Cook Inlet and were established to help level the playing field for new companies trying to get a foothold in Alaska. The NOL tax credits allow all companies making critical investment to truly understand the economics under which those investments were made.

SB 130 would prevent the use of NOL tax credits to reduce the minimum tax. This change is analogous to the federal government not allowing a company's losses to be applied against its corporate income tax. Additionally, the proposal imposes a ten-year limit for a company to apply unused NOL credits. All of these changes to the NOL essentially eliminate the value of the credit in the first place, and will have a tremendous impact on companies.

There are several other major changes proposed to credits, both for the North Slope and Cook Inlet. Arbitrarily limiting cash credits to \$25 million per company per year, when even the "smallest" of projects range in the \$500 million - \$1billion range, is unreasonable and will be a strong disincentive for future investment. Eliminating or discouraging cash rebates for companies that may not yet have production or profits, strongly disadvantages new companies, especially considering that they invested in good faith based on the tax policy in place when the investments were committed. For the State to basically say, after the fact, that it is not going to allow companies to realize the true economics of their developments as originally promised, is bad business practice because it would put some companies at risk of going out of business.

Eliminating two important credits for Cook Inlet and "middle earth" is also dangerous as the Cook Inlet drilling tax credits were unequivocally the driver for several key investments in the region that have already led to increased production and jobs. These credits are not a "cost".

They are an investment by the state with clear benefits. For example, the Department of Revenue showed the State has paid over \$8 billion in cumulative credits from FY 07-16. That implies a huge capital investment of \$30-40 billion. Additionally, during that same time the state collected over \$32.8 billion in cumulative tax revenues.

And, we fundamentally disagree that Cook Inlet has gas in search of a market as has

been asserted by the Administration. DOR, DNR and enalytica have all testified that additional investments are necessary to meet the increasing demand of Alaska's residents. Without continued investment, gas production will rapidly decline. Any decline will inevitably result in higher utility rates for consumers and increase the likelihood of gas shortages.

The proposed revisions in Section 39 of SB 130 define "outstanding liability to the state" in the broadest of terms. Thus, the State could deny or delay tax credit payments for virtually any outstanding and alleged liability, even if it was with a state agency unrelated to taxes.

Although there are plenty more aspects of this proposal that warrant further discussion, I will conclude by addressing the proposed increase in the interest rate. We are one week away from tax day. Can you imagine filing your taxes, utilizing the best interpretations of the tax code, and 1 – 2 – 3 – 4 – 5 – 6 years later, the IRS comes back and says, I'm sorry, we have finally finished auditing your taxes, and not only do you have additional taxes due, you not have to pay compounded interest on top of it. Sound crazy? Well that is the situation the industry is facing with the Governor's proposal and that is why AOGA supports the current rate and believes it is reasonable, particularly considering the lengthy statute of limitations. Because the Department has a track record of taking all six years to complete audits, there could be scenarios where the interest payment is more than the actual tax bill.

Slide 6

Under Governor Hammond, Alaska first established an equitable policy of one-third for the state, one-third for the federal government, and the last third for industry. During the ACES regime, government take climbed to a higher level, which, in turn, led directly to SB 21 in an effort to normalize total government take over a broad range of prices.

As Janak Mayer from enalytica has explained, government take is about 62% in a price range from \$60-150, including government take on new oil.

This is why it is important to look at the production tax, in conjunction with the rest of the fiscal system. As Division of Oil and Gas Director Corri Feige stated during previous testimony to House Resources, companies lump taxes and royalties as a cost. Any increase in production taxes, will impact overall government take.

As this slide indicates, at today's prices, due to the regressive nature of the royalty system, government take exceeds 100% at these prices. SB 130 will increase government take, for legacy and new oil alike and also for gas.

Slide 7

The Governor's proposal will not add more oil to the pipeline. There is no plausible scenario where increasing taxes by \$782 million dollars will result in increased production. So, let's assume the state begins to see a production decline, and for the ease of math, we just used a 10% decline. Utilizing data from the Department of Revenue, a 10% decline would result in the loss of \$793 million dollars in royalties over the next five years. This demonstrates it won't matter if prices go back up to \$60 or \$80 or \$100 per barrel if production declines. Can the state really afford to increase taxes when the long-term potential loss is so significant?

The Administration has said they believe this bill will provide certainty and predictability, I can assure you, none of my member companies sees any certainty or predictability from SB 130. In fact, the message you would be sending is that Alaska has a bit of an identity crisis.

One year, Alaska hangs out the "Open for Business" sign and says, welcome! We want you to spend money here to increase production and create jobs. Please choose Alaska, we have even created incentives to entice you to do business here. The strategy works, companies come, they invest, and the future looks bright.

Fast forward a few years, and the sign seems to change to "Caution". Why? Tell me how many companies, regardless of industry, will beat down Alaska's doors to invest when they can count on their taxes being increased at times of high commodity prices, and then again when prices are low. The policy of the state of Alaska is becoming, "I'm sorry, I know you are bleeding, but the state treasury is broke so we need more money from you anyway."

Would Alaska be considering an increase in fishing taxes if every boat leaving the harbor couldn't pay their daily bills? Or would Alaska consider increasing fuel taxes if the trucking industry was posting record losses? Or on any other industry that is losing money?

We appreciate the need to close the state's fiscal gap. But raising taxes when industry is spending more here than it is making is not a solution to that gap. Instead, it merely addresses short-term concerns at the expense of doing greater long-term harm to the state's economy in the future.

The industry is not before you today asking for a tax decrease or for relief while we struggle through these extraordinarily difficult times. We ask only that you not kick us while we're down because of low prices. You should be asking how tax policy can remain in place

that encourages explorers and new entrants, and ensures current producers remain committed to Alaska?

Proceed with caution, because the fact is, an increase will lead to more Alaskans out of work, and less production and less state revenues in the future.

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Hilcorp Alaska, LLC

**Hilcorp Alaska, LLC Testimony
Senate Bill 130
Senate Resources Committee
April 8, 2016**

For the record my name is Dave Wilkins, I'm the Senior Vice President for Hilcorp Alaska. Madam Chair and members of the committee thank you for the opportunity to address you today about Senate Bill 130.

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.

Over 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.

BP Testimony to Senate Resources Committee

Joe Reese, BP

April 8, 2016

Madame Chair, Members of the Committee: For the record my name is Joe Reese and I am Senior Managing Tax Counsel for BP Alaska. I am very pleased to be here to provide BP's views on tax policy and, in particular, SB 130. BP is a member of AOGA and supports the testimony provided by AOGA earlier today.

The success of Alaska's oil and gas tax policy is critical to BP, to the AK LNG Project, and to the many Alaskans who benefit, both directly and indirectly, from the successful exploration, development, and production of Alaska's oil & gas. A durable, predictable, and administrable oil and gas tax policy must be in place to unlock those benefits.

BP is committed to maintaining a safe and compliant business in Alaska that is sustainable. Over the past two years, there has been a 70% drop in oil price. In 2015, BP paid ~\$263m in royalties and taxes that resulted in a financial loss of ~\$194 million. Under the current market conditions, BP's business in Alaska is spending more cash than it brings in, and this is not sustainable. As a result, BP has undertaken an ~17% reduction in force and the PBU working interest owners have reduced activity levels. PBU economics are at a point where tax increases in the cost structure would result in even lower activity levels and would be detrimental to our business in Alaska – a 1% increase to the minimum tax is equal to 6 months of rig work at PBU. If, for example, production decline were to return to 10% annually over the next five years, the State would lose ~\$793m in royalty revenue alone not to mention the lost production tax and income tax

revenue. Operating under a predictable, durable and administrable oil and gas tax policy is essential to maintaining the activity level at Prudhoe Bay and the long-term viability of an AK LNG Project.

BP is committed to complying with tax laws in a responsible manner and to having open and constructive relationships with tax policy makers. One of the major costs to BP's business in Alaska is oil production tax. While we are currently cash flow negative, we still pay oil production tax because certain of our cash costs, like our investment in the AK LNG Project and other specifically excluded costs, are not deductible for production tax purposes.

At current prices, PBU production does not attract oil production tax credits. While PBU doesn't currently receive production tax credits, we don't support limiting the production tax credits provided in SB 21 because it would negatively impact the oil & gas industry as a whole, including the many other companies that have made investments, created jobs, and added production in Alaska.

Just as the industry is struggling to make ends meet, the State also faces severe budget shortfalls. While reasonable people may disagree about how to improve the current oil and gas tax policy, now is not the right time to make changes that would increase taxes and further inhibit our ability to maintain the activity level at Prudhoe Bay. Near-term changes to the State's oil and gas tax policies will have long-term consequences for all of us.

Now, I'd like to provide a few comments specifically about why SB 130 is bad tax policy:

1. The Administration has proposed an Increase to minimum tax -The Administration's proposal to increase the minimum tax from 4% to 5%

would have a chilling effect on additional investment. This would represent a 25% tax increase to BP at a time when BP needs that cash to maintain our activity level. This proposal does not does not provide durability and therefore is not good tax policy.

2. The Administration has proposed an artificial limitation on the use of credits within a tax year – The production tax is an annual tax paid in monthly installments reflecting budgeted costs and forecasted prices that evolve during the year, with a final “true-up” to the actual figures on March 31st of the following year. This structure of monthly installments and a final true-up reflects the fact that the producers keep their financial books and records on an annual basis and do not close and balance them on a monthly or quarterly basis. The Administration proposes to limit the amount of a tax credit to the specific amount reflected for it in each monthly installment. This means any increase between that initial credit amount and any greater amount determined for it at true-up would be disallowed, but any reductions at true-up in monthly reported credits would be reflected in the total allowable amount for that credit for the year. This inconsistency is not based on good tax policy, but is simply a significant tax increase. It pretends that annual tax credits can be accurately quantified and reported on a monthly basis, even though it is not possible to have perfect full-year information when the monthly installments are filed. This provision is neither predictable nor administrable and therefore is not good tax policy.
3. The Administration has proposed a material increase to the interest rate for tax overpayments and underpayments: Currently, the interest is

calculated at a rate 3% points above the federal funds discount rate, using simple interest. The proposal would more than double the differential from the fed funds rate, to 7% points above the federal funds discount rate, and have interest compound at the end of each calendar quarter. Such a compound rate would reward the Department of Revenue for being slow in its audits, because 7.4% interest compounded quarterly would represent, by itself, more than 55¢ for each \$1 of additional tax claimed by the audit. This provision does not allow for predictability and therefore is not good tax policy.

4. The Administration has proposed limitations on the use of the net operating loss tax credit: The Administration's proposal would prevent the use of net operating loss tax credits to reduce the minimum tax. In other words, companies that made important investments in the prior year, even when they may have been spending more cash than they were bringing in, would be prevented from recovering part of that investment. NOL tax credits are utilized by a broad range of companies both on the North Slope and in Cook Inlet, and changing their value would be a disincentive for future investment decisions. This provision does not allow for durability or predictability and therefore is not good tax policy.
5. The Administration has proposed an erosion of taxpayer confidentiality: Confidentiality is the cornerstone for any self-reporting tax like the production tax. Unlike a property tax — where the government determines the value of your house on the basis of objective market parameters instead of relying on you to provide information about the value of the house — a self-reported tax relies on taxpayers to provide

details about the factors that determine the amount of the tax. For production tax these details include, for instance, specific terms of contracts for production-related services, the arrangements and costs incurred to get the oil or gas to market, and specific terms and conditions for each sale or disposition of that oil or gas. Such information can often be commercially sensitive for competitive reasons, and in some cases it would be a crime to disclose such information to competitors or the public either directly or through a third party. Confidentiality ensures that the Department of Revenue won't disclose such information. SB 130 attacks the principle of confidentiality and therefore SB 130 would be bad tax policy.

Again:

- BP is committed to maintaining a safe and compliant business in Alaska that is sustainable;
- BP is committed to complying with tax laws in a responsible manner and to having open and constructive relationships with tax policy makers; and
- BP supports durable, predictable and administrable oil and gas tax policy and that is why we do not support SB 130.

Thank you.



Senate Resources Committee

◦ Kara Moriarty –President/CEO

April 8, 2016

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

AOGA
Alaska Oil and Gas Association

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.”

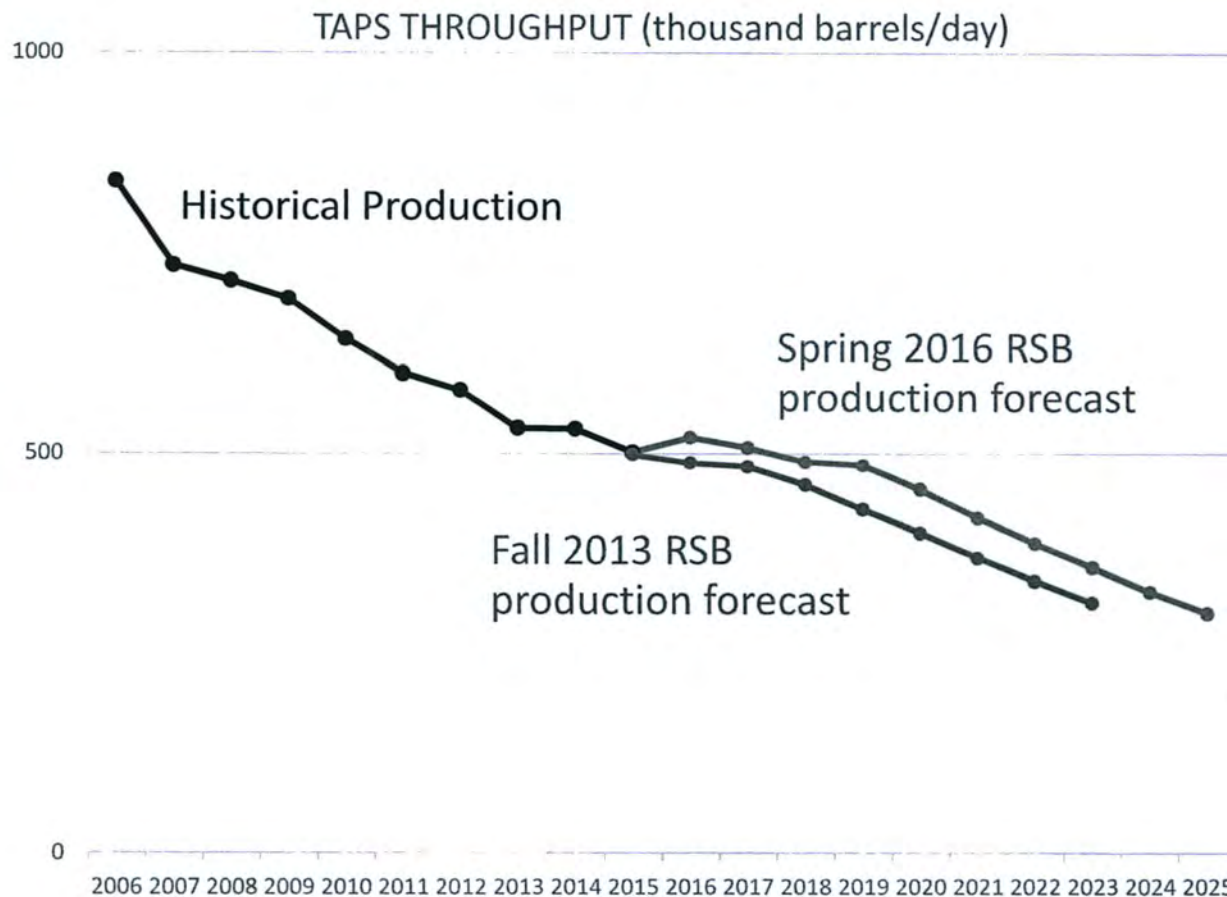
Tax Director Alper – 2/12/16

Policy Questions for SB 130

- *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?*

Alaska has MORE production *FIRST time since 2002*

TAPS Throughput Historical & Forecasted



Year	Fall 2013 Forecast	Spring 2016 Forecast
2016	487.6	520.2
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		300.5

Source: DOR Spring RSB, April 2016

At current prices, industry has *negative cash flow before tax*

Estimate Average March 2016 ANS Price	\$38.11
Transportation Costs	(\$10.50)
Total Operating Expenditures	(\$19.47)
Total Capital Expenditures	(\$19.97)
Total Average Cost Per Barrel Before Tax	(\$49.94)

Source: DOR Spring 2016 Forecast, April 2016

More Production? Competitive? Stable? Predictable?

Specific Concerns with SB 130

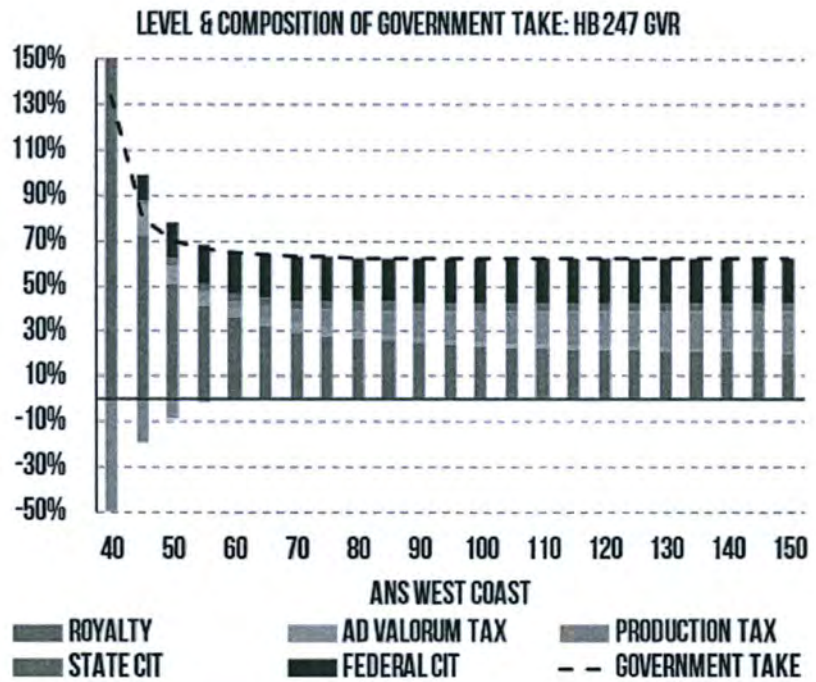
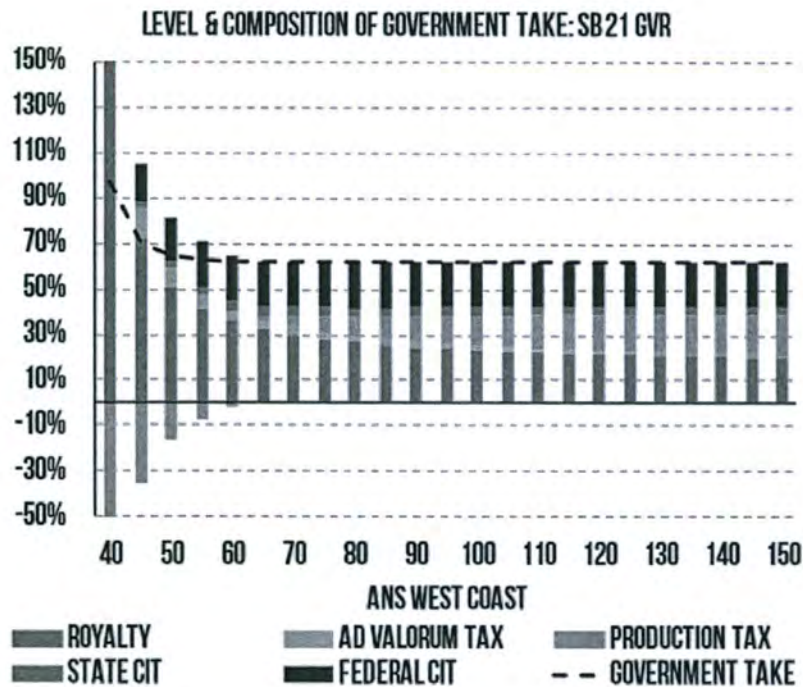
- *Increases minimum tax by at least 25%*
- *Net Operating Loss tax credits lose value*
- *Set limits on credits- discouraging investments by smaller company*
- *Cook Inlet credits eliminated*
- *Interest rates increase significantly*
- *Confidentiality protections jeopardized*
- *Disguised tax increase through the change of the application of Gross Value at the Point of Production*

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%



SB 130 is an Equal Opportunity Offender

AOGA is not asking for assistance from the state of Alaska in this downturn, but do ask for careful consideration of any policy changes.

In this price environment, any change will have a negative impact on industry and will result in Alaskans losing jobs, less production, and less long-term revenues for the state.

Senate Resources Committee

SB130

Scott Jepsen, VP External Affairs
Paul Rusch, VP Finance
ConocoPhillips Alaska

April 8, 2016

Agenda

- Look back since SB21 passed
- Economic Environment
- Key Concerns with SB130
- Observations

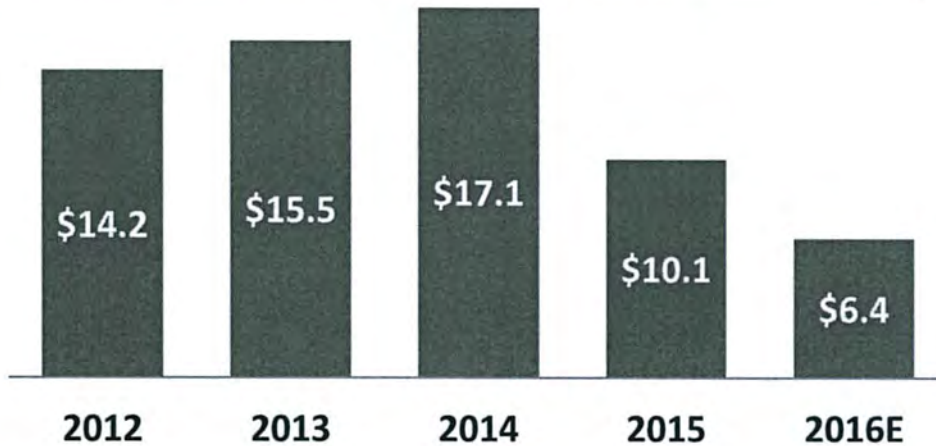
Activities Since Tax reform (MAPA) Passed

- **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**
 - Two wells drilled in 2014
 - Acquired GMT1 Seismic – 2015
 - Three wells in 2016 (NPRA)



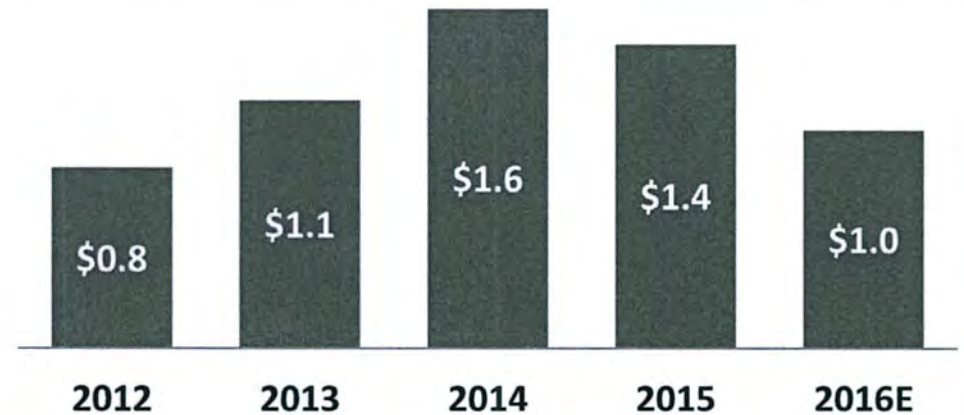
Capital Spending Trends

ConocoPhillips Capital Spend (\$B)



Total Company capital reduced 63% since 2014

ConocoPhillips Alaska Capital Spend (\$B)

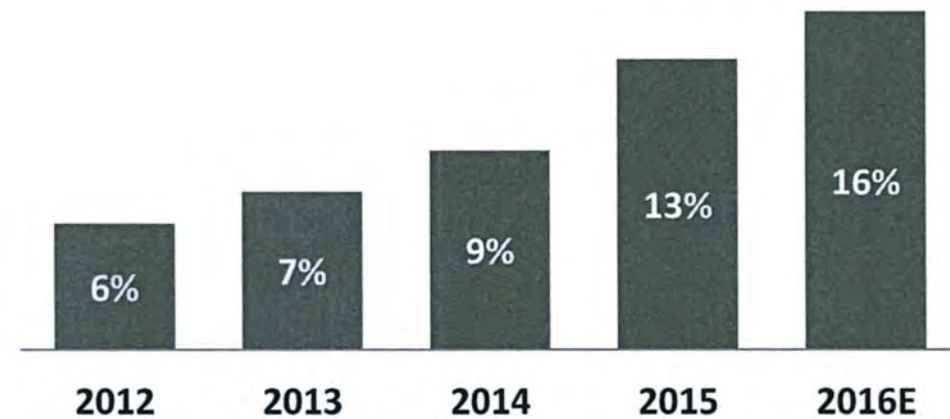


2016E Alaska capex ~ 25% higher than ACES years (~\$0.8 B/yr 2007-2012)

ANS WC Oil Prices (\$/bbl)

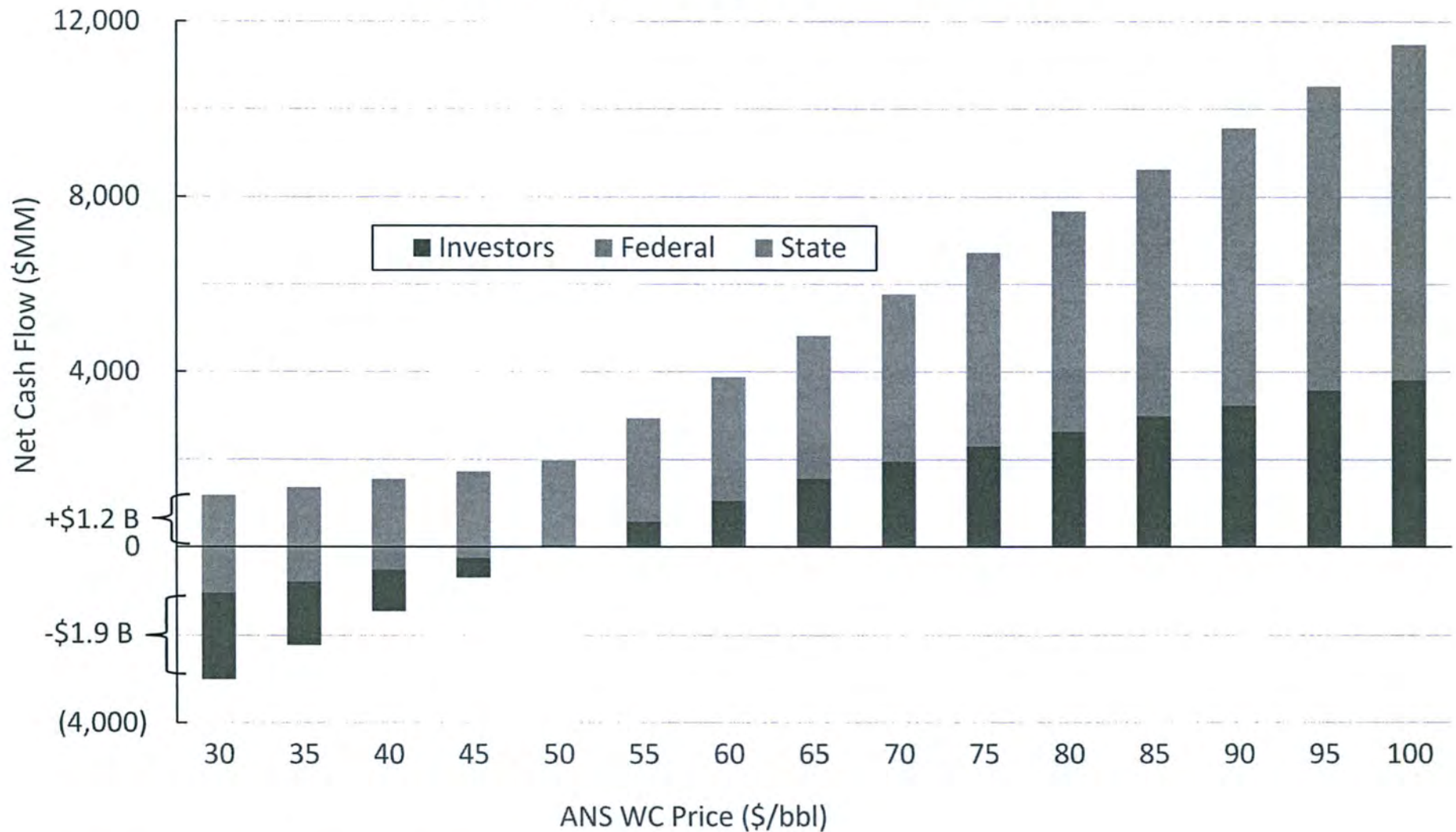


Alaska Capex as % of COP Total



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 SB130

- 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 per barrel credits to the monthly installment violates the principle of an annual tax levy
- Taxpayer 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
- House Resource CS to HB247 an improvement over original bill
- Any changes that increase tax burden/costs could adversely impact ConocoPhillips current and future investments

- 1.Strong Investment Value of Tax Credits**
- 2.Overview of Cosmopolitan Unit**
- 3.Specific Impact of SB 130 on BlueCrest**

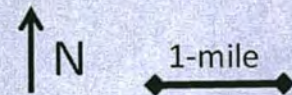




J. Benjamin Johnson
Senate Resources Committee Testimony
April 9, 2016

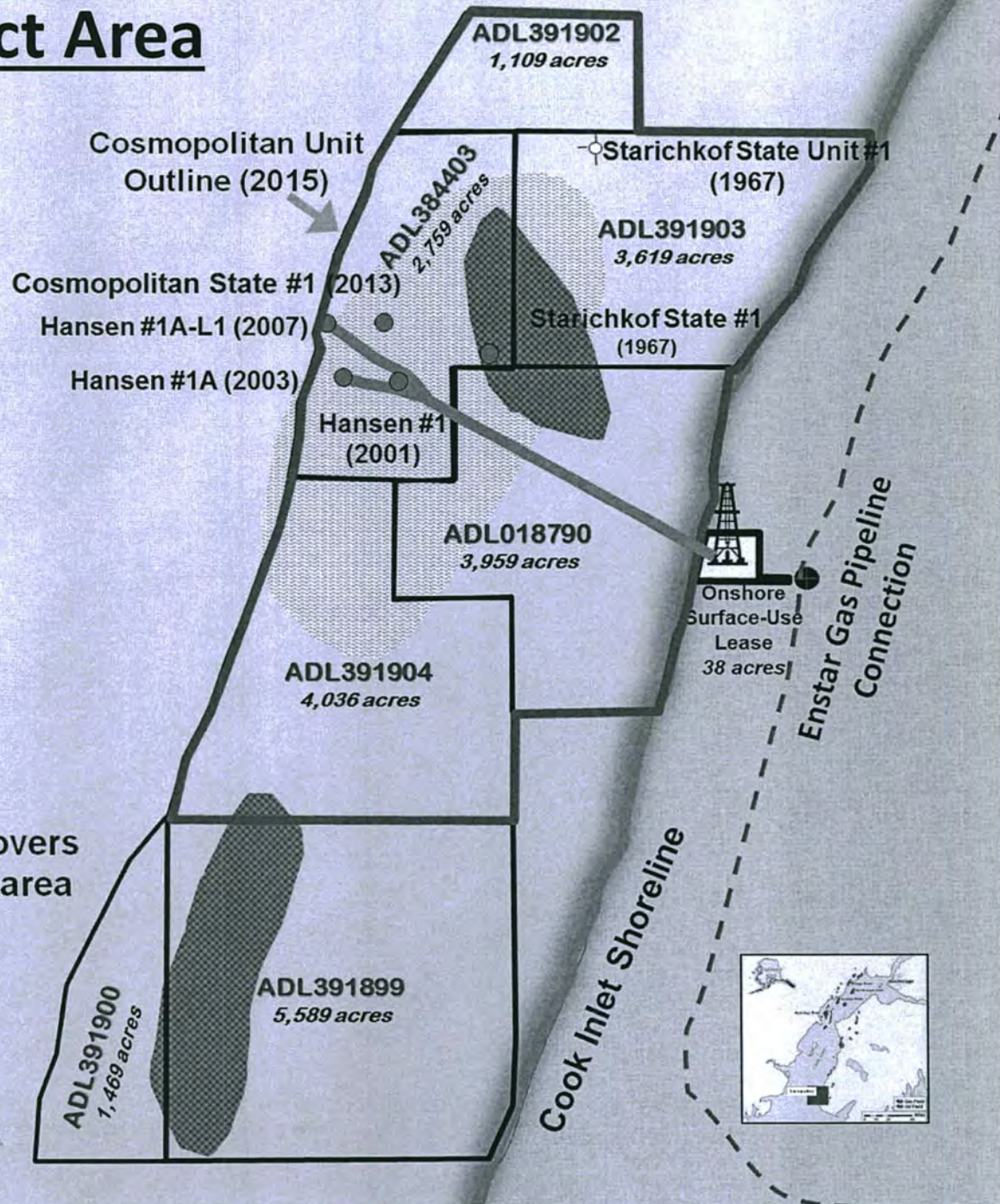
Cosmopolitan Project Area

- 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)

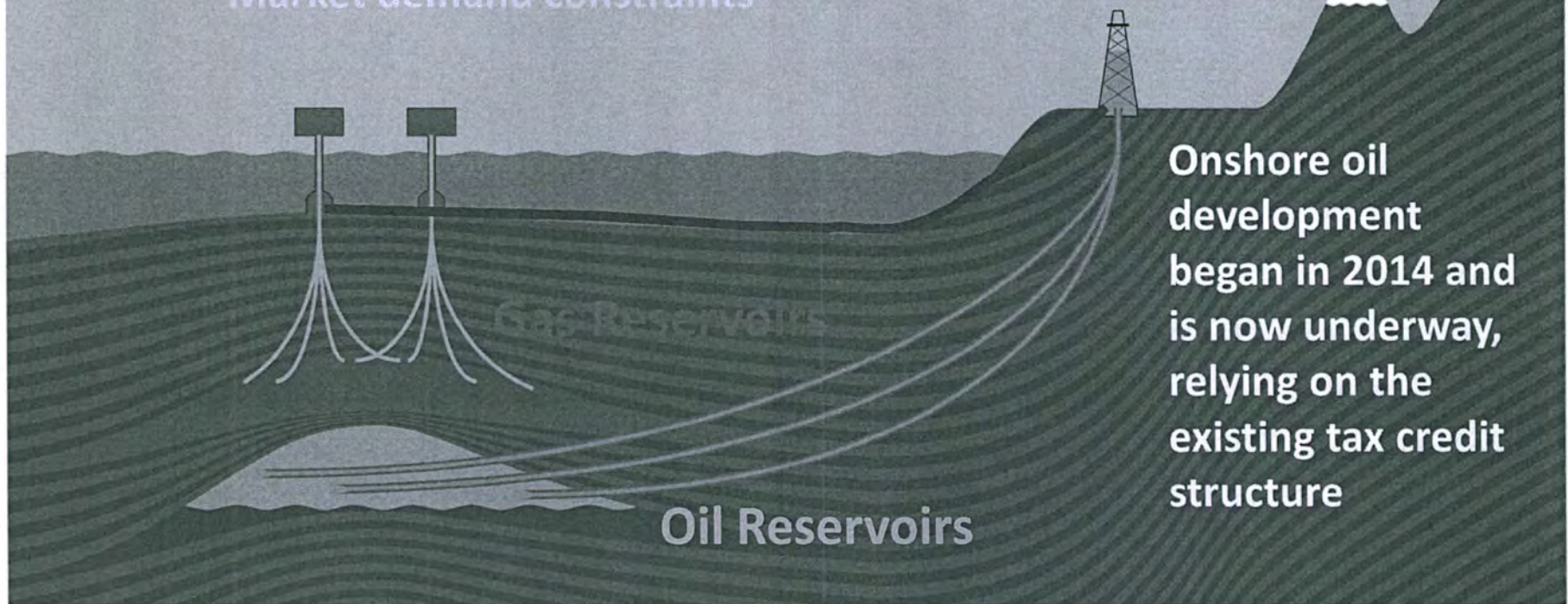


-  Approximate areal extent of known productive reservoirs
-  Approximate areal extent of identified exploratory prospects



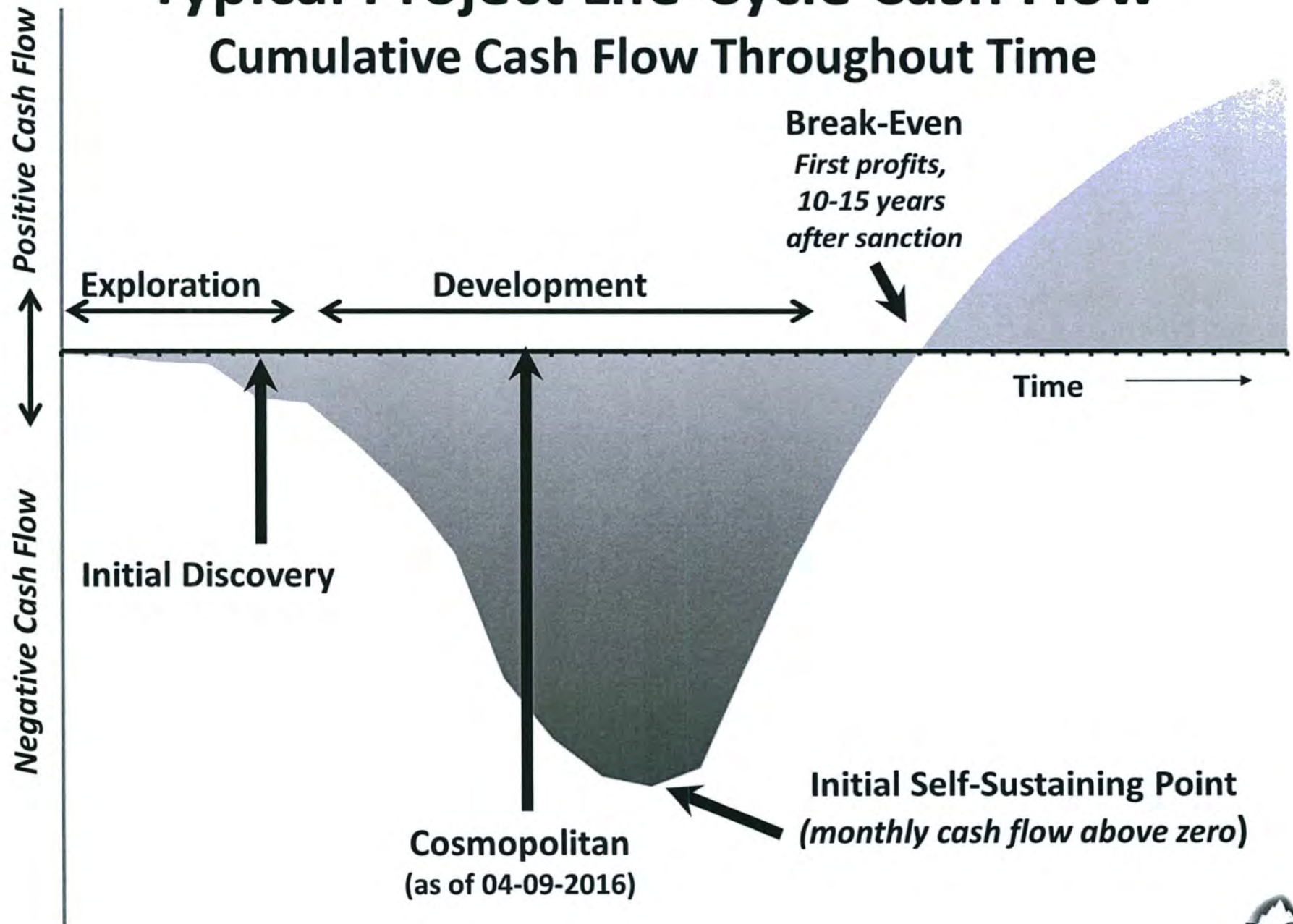
Cosmopolitan Unit Development

- 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



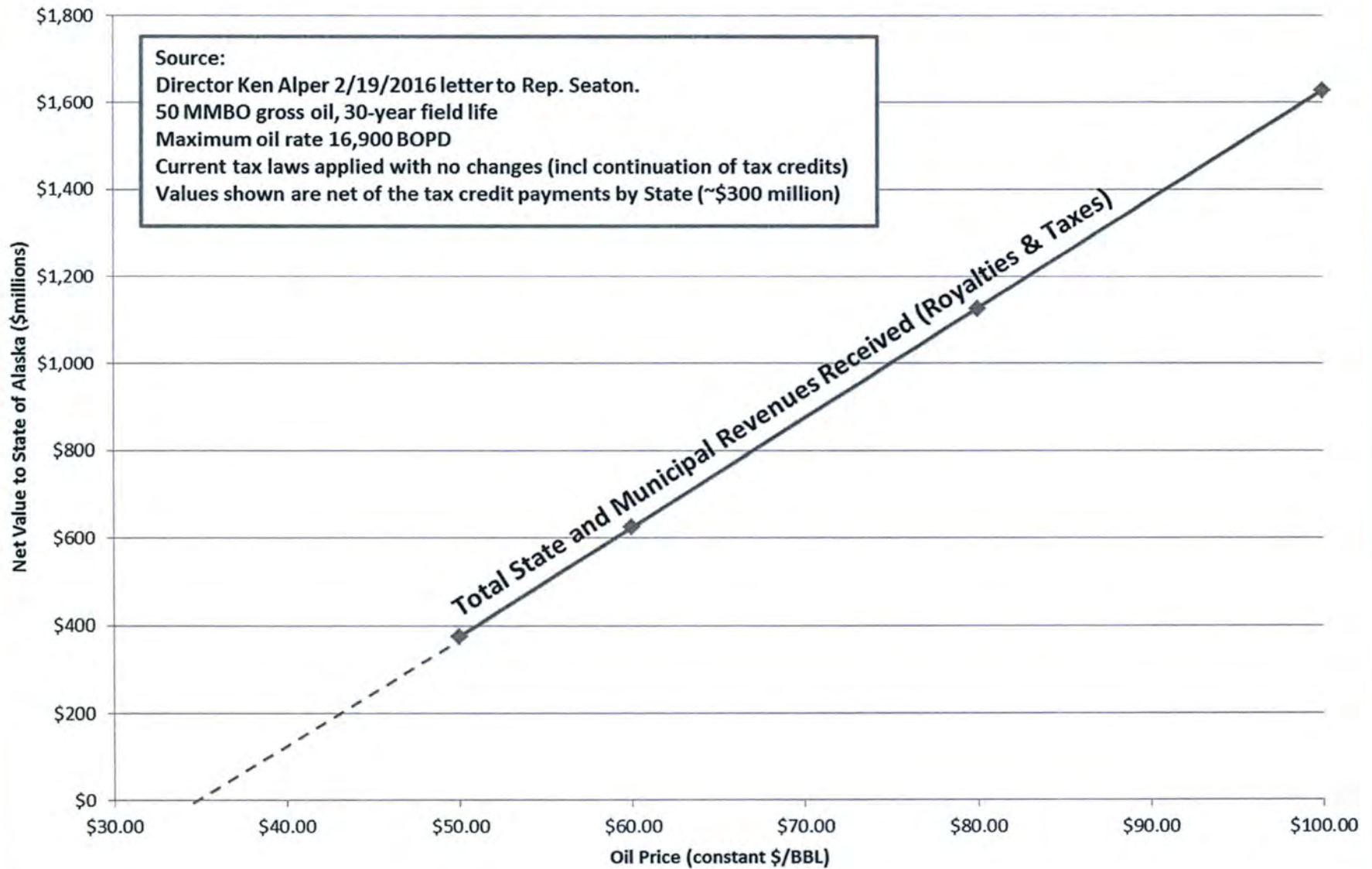
Cosmopolitan Progress as of 04/09/2016



Tax credits for development of previously discovered proven reserves are a solid, low-risk investment for Alaska.

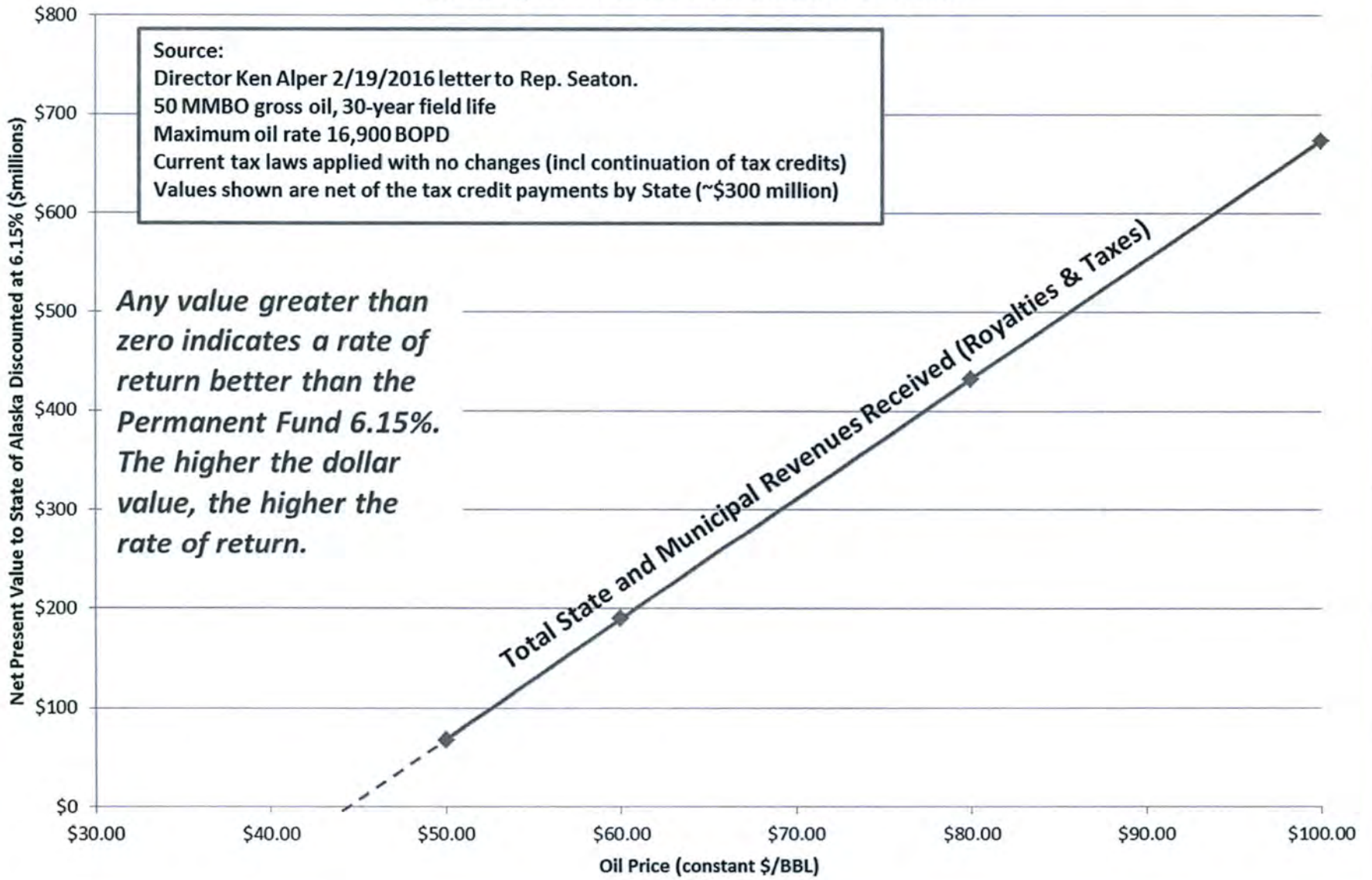
Summary of DOR Analysis Cook Inlet Oil Development 2/19/2016

Net Cash Benefit to State With Continued Tax Credits 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)



Specific Comments on 023(a), 023(b), and 023(l) Changes

Continuation of the 023(a) and 023(l) credits (QCE and WLE) is a solid investment for the State for development of Cosmopolitan oil.

Termination or severe reductions of the 023(a) and 023(l) credits will result in a significant reduction of BlueCrest's ability to continue drilling at Cosmopolitan.

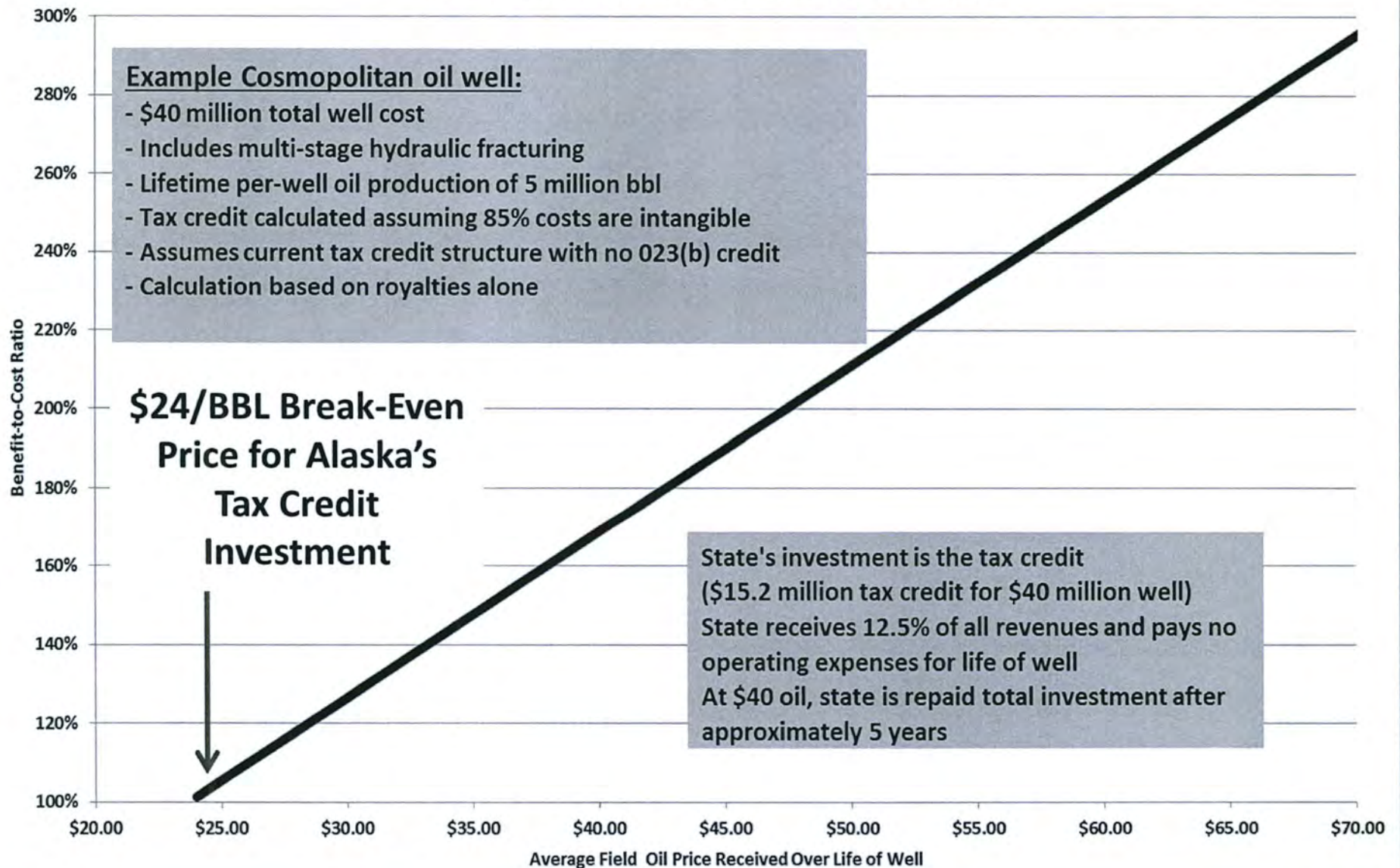
Continuation of the credits facilitates Cosmopolitan continued drilling at ~\$10/BBL lower oil prices.

The NOL credit is most important for exploration and new development work prior to production. Continuing work on new developments after start-up is mostly impacted by the 023(a) and 023(l) credits.

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 limits for cash payments:

- **Arbitrary – different developments have different needs**
- **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**
- **A strong disincentive for future investments**

Effective Date

An effective date of July 1, 2016 is too soon for implementation of substantial reductions in tax credits for ongoing work that has already been contracted for and now underway.

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!**



**Senate Resources
SB 130/HB 247
April 9, 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

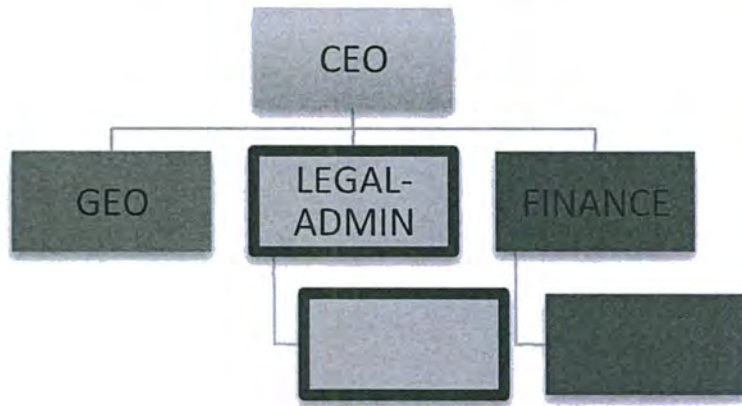
- Original Target -> North Slope Shale Play (aka “source rock play”, aka “unconventional play”)
- Soon Faced an “Alaska Shale Play Catch-22”
 - Not economic without cost reductions
 - Costs reduction requires a critical mass of drilling activity, such as that generated by a shale play
- **Re-directed 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

STRATEGIC EXPANSION OF CAPABILITIES

PARTICULAR FOCUS ON GEOSCIENCE AND OPERATIONS

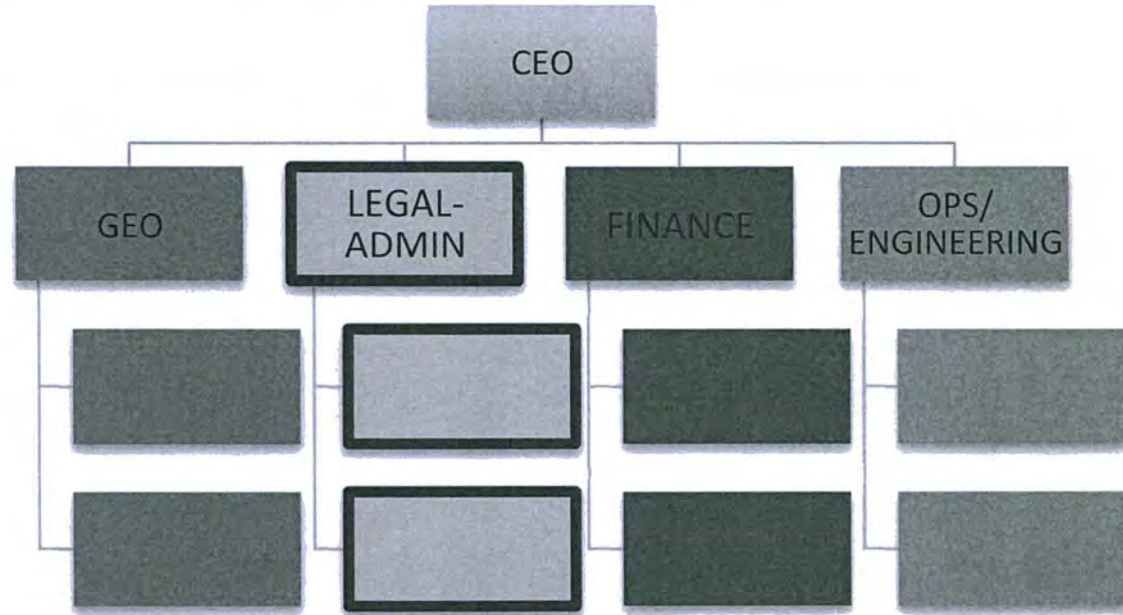
June 2015

5.5 Full Time Employees

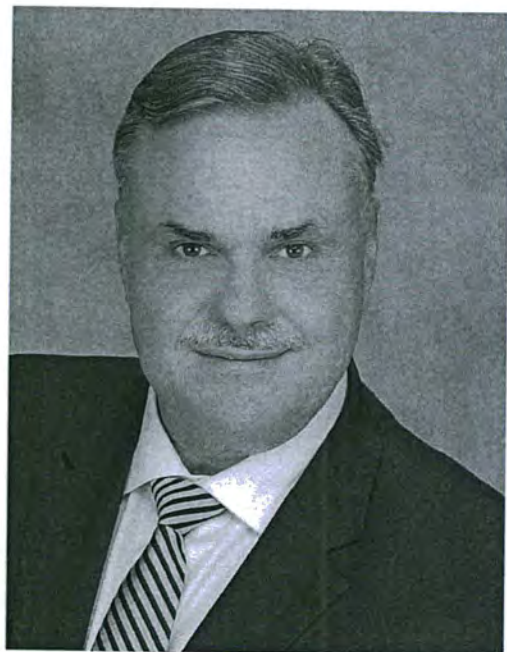


Current

13 Full Time Employees



NEW GREAT BEAR MANAGEMENT TEAM



**Mike
Mason**
President
& CEO



Ryan Moynagh
Chief Financial
Officer



Pat Galvin
Chief Commercial
Officer & General
Counsel



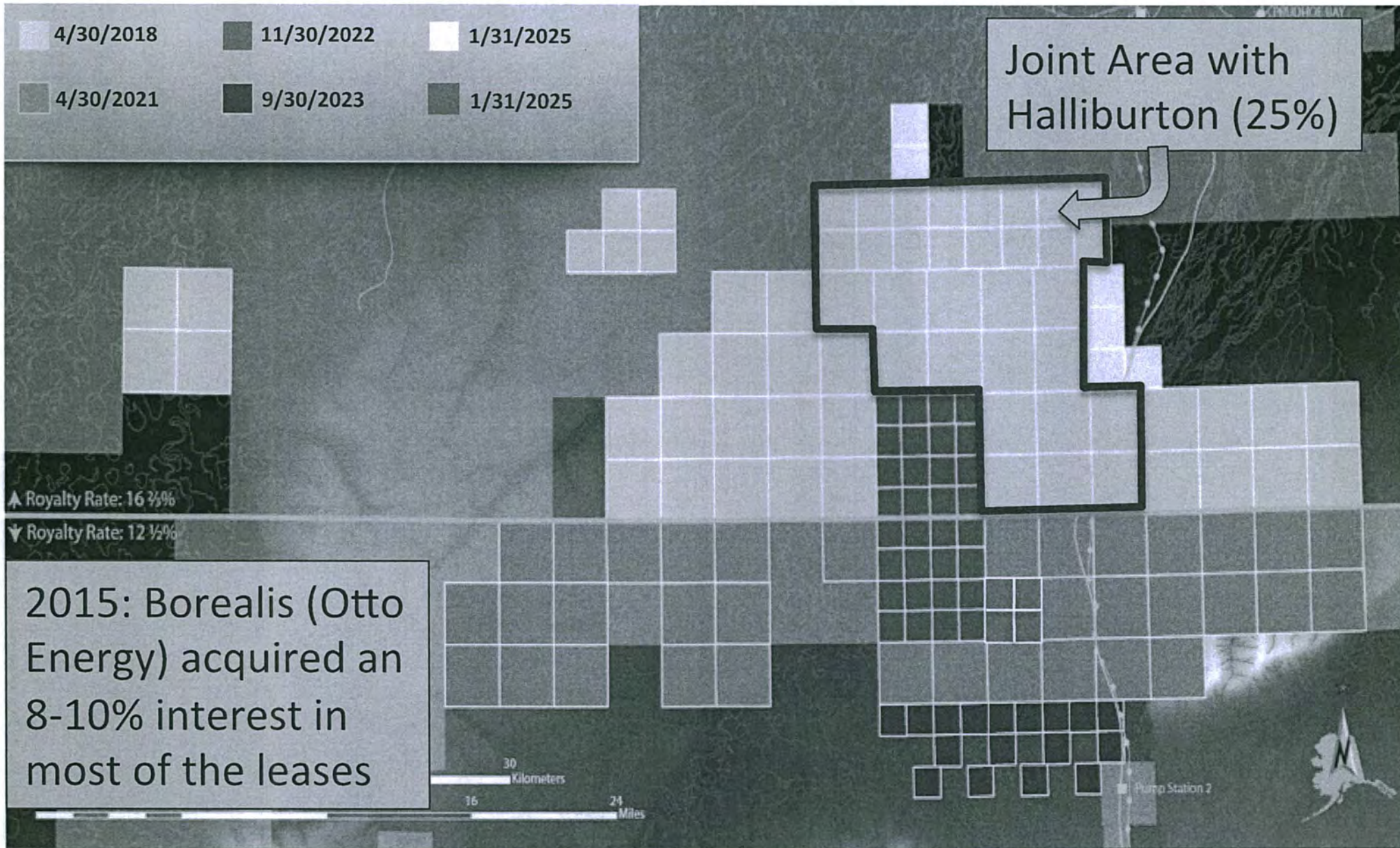
Clark Clement
Chief Operating
Officer



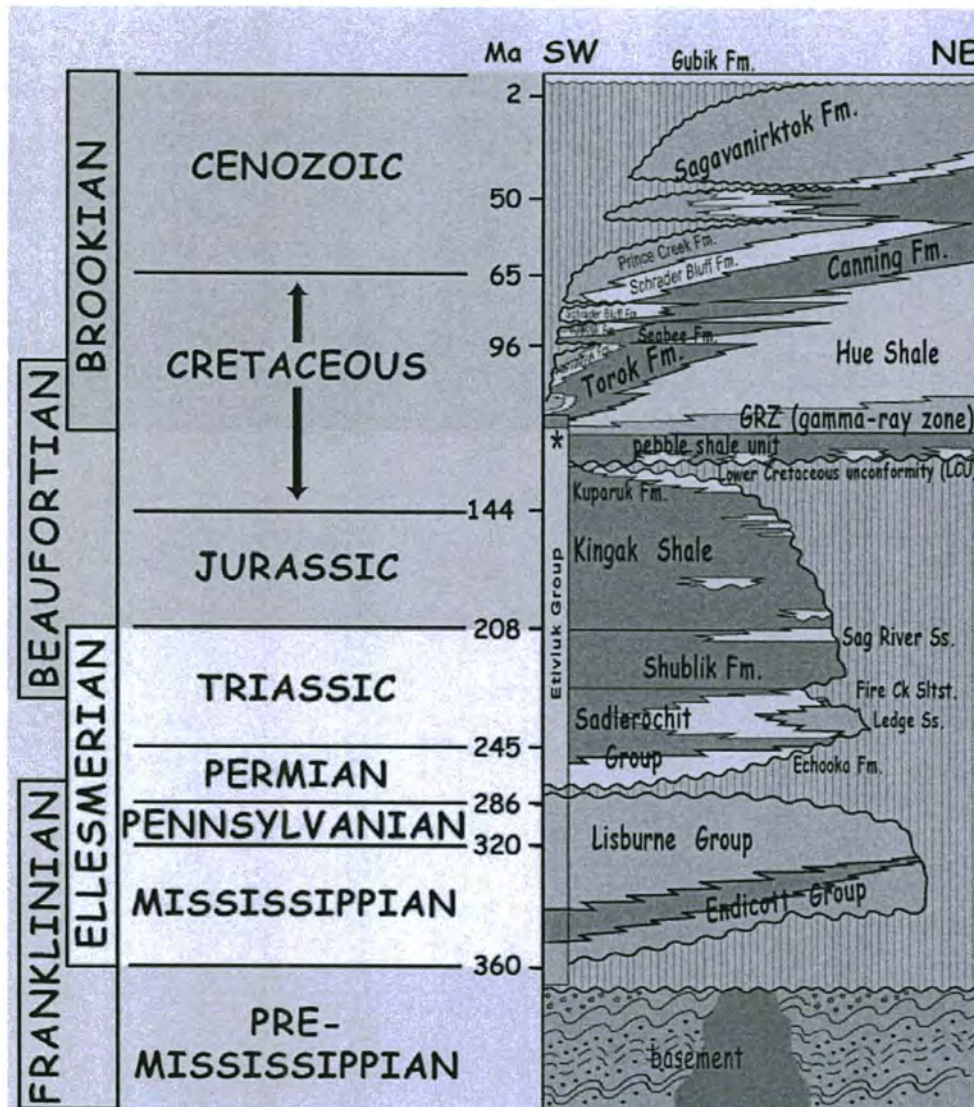
Larry Casarta
VP-Exploration



GREAT BEAR – LEASEHOLD POSITION



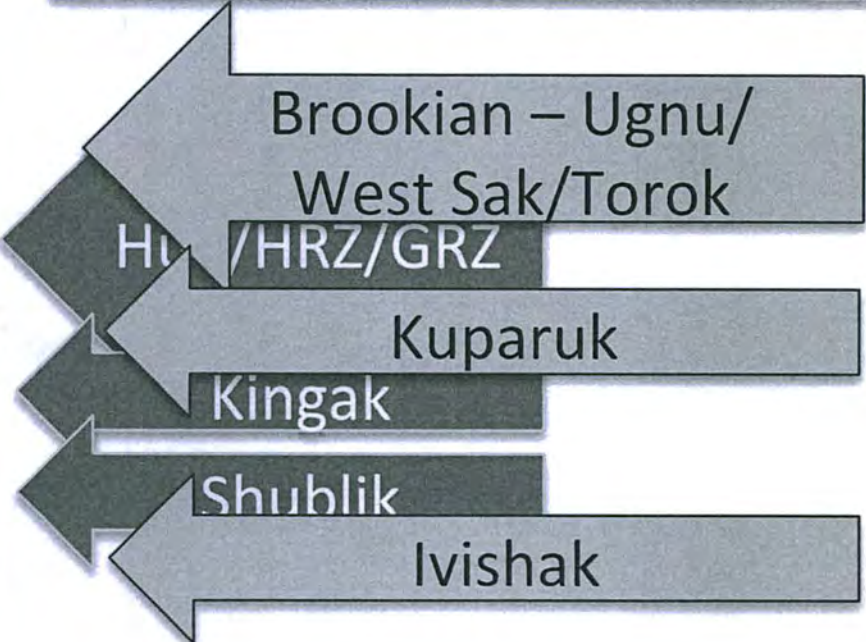
GEOLOGIC TARGETS



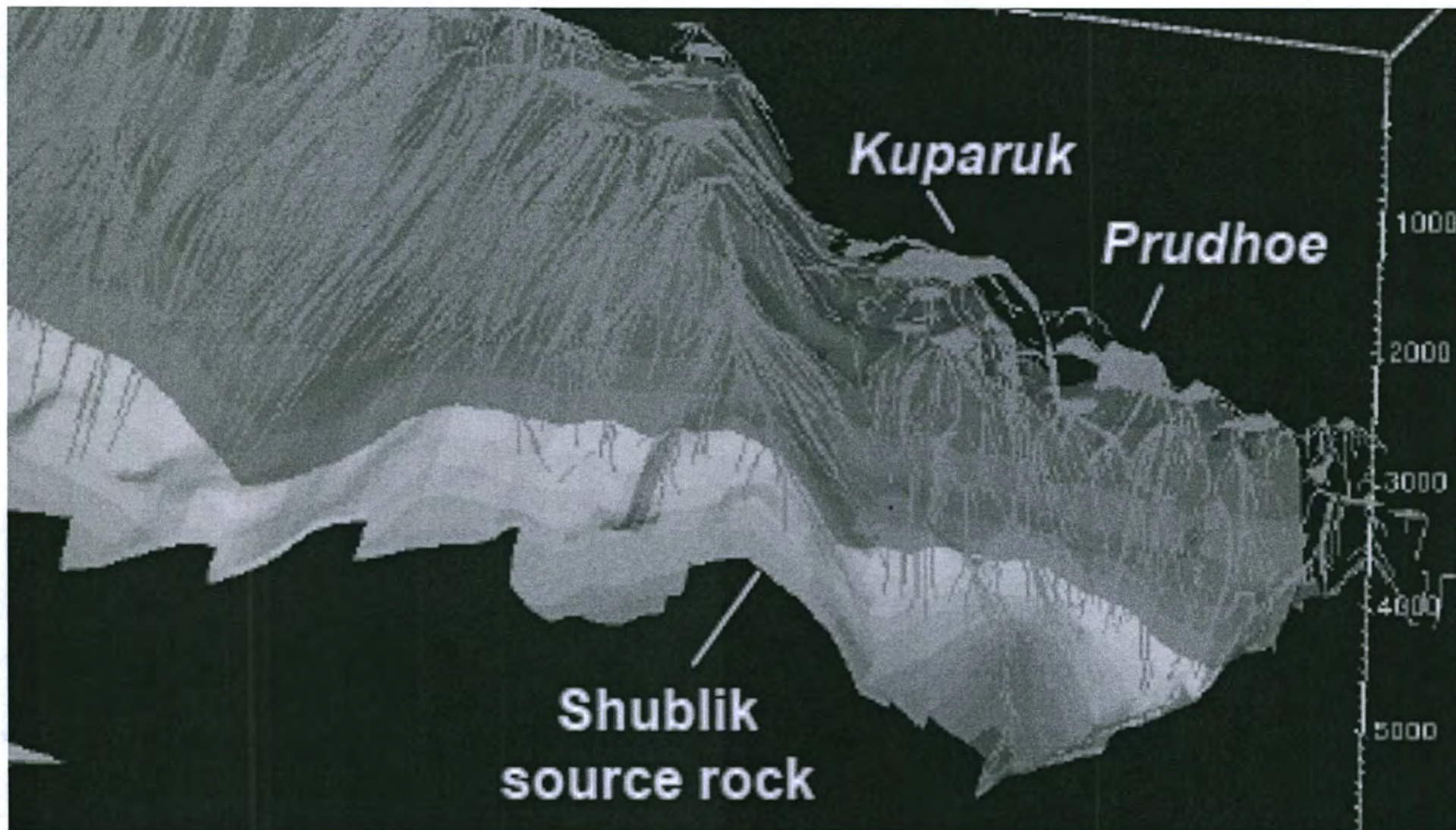
Source
"Shale"

Reservoir

Unconventional ↔ Conventional

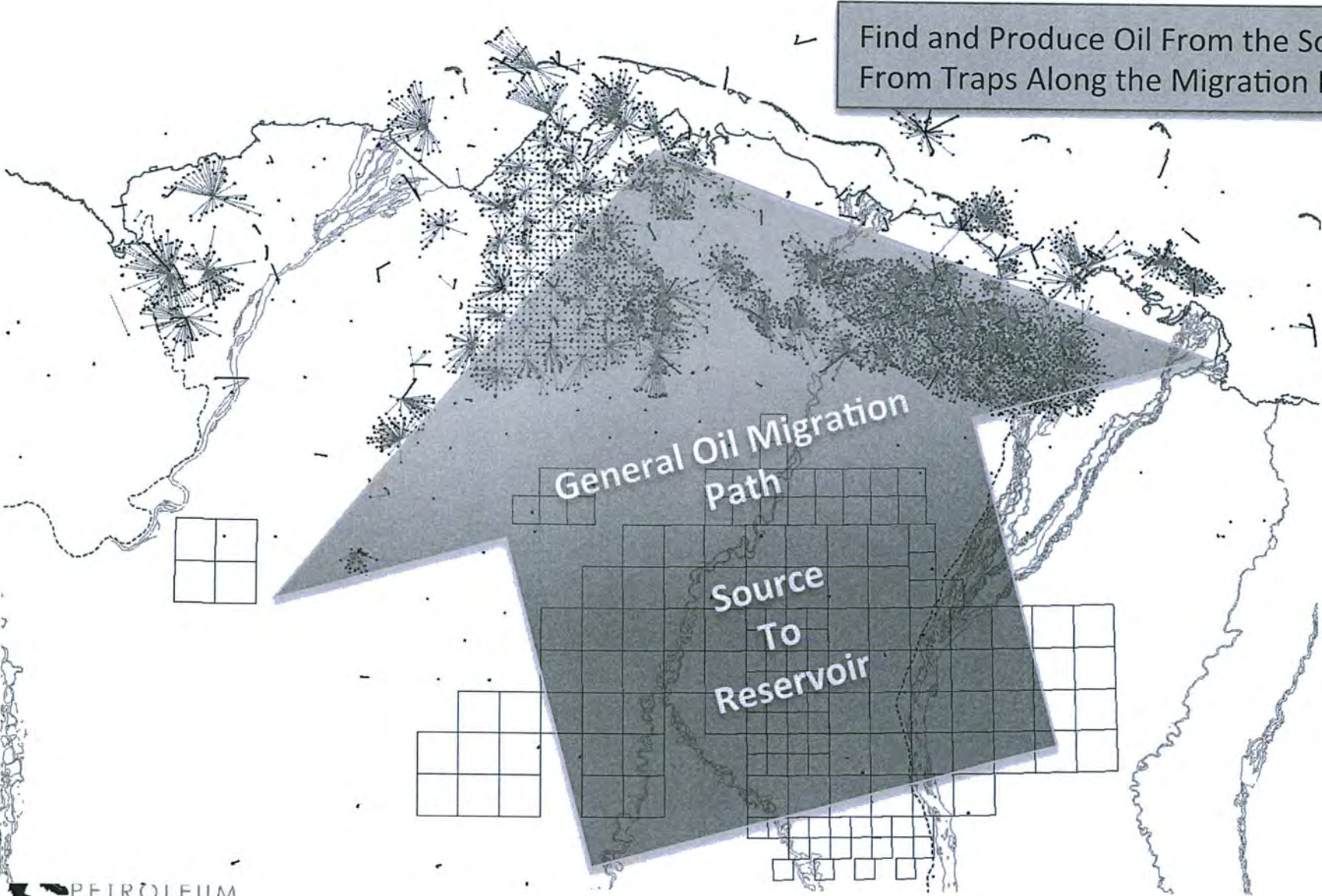


Model – Migration of Shublik Oil

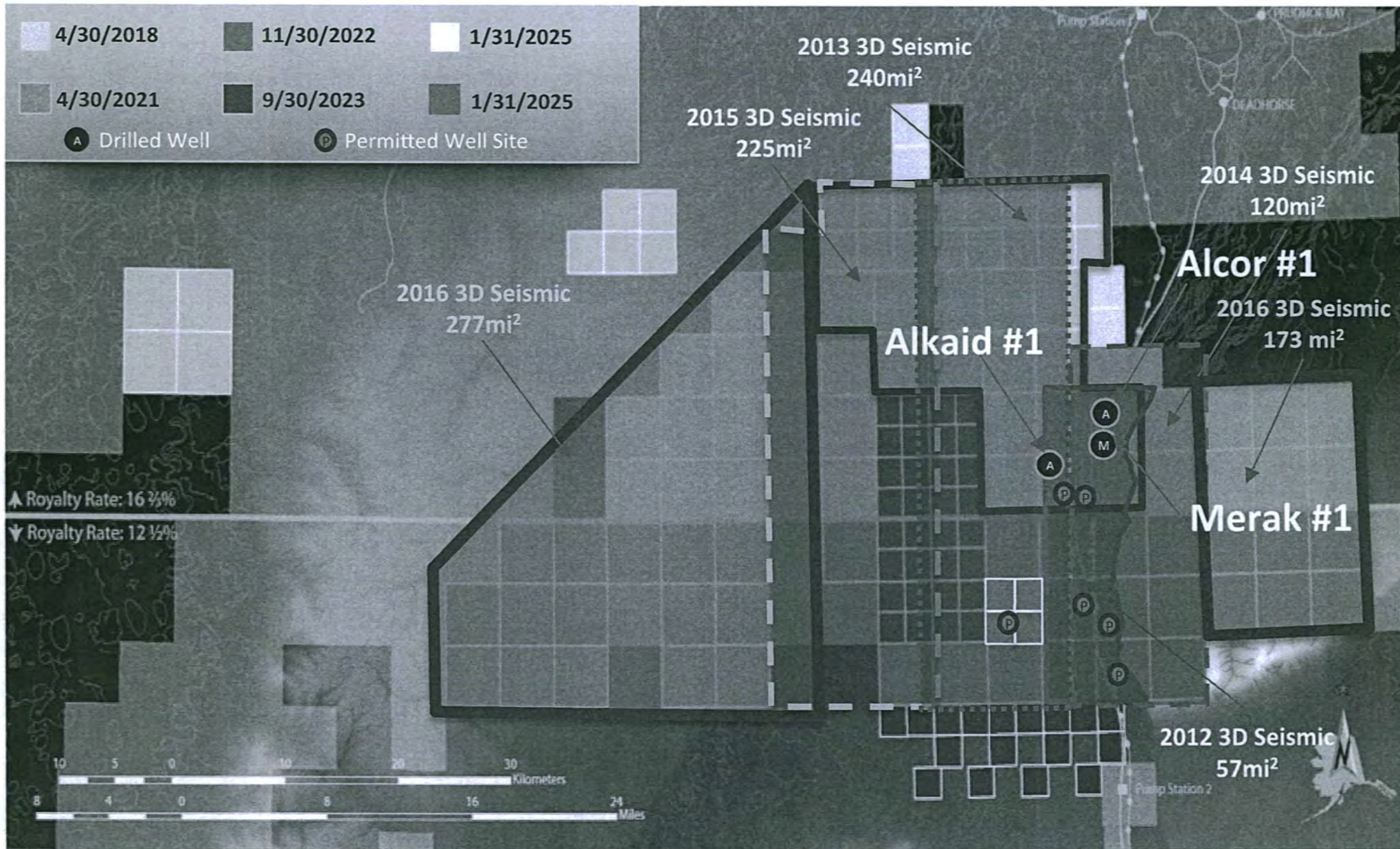


Great Bear's Exploration Concept

Find and Produce Oil From the Source or From Traps Along the Migration Route



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.

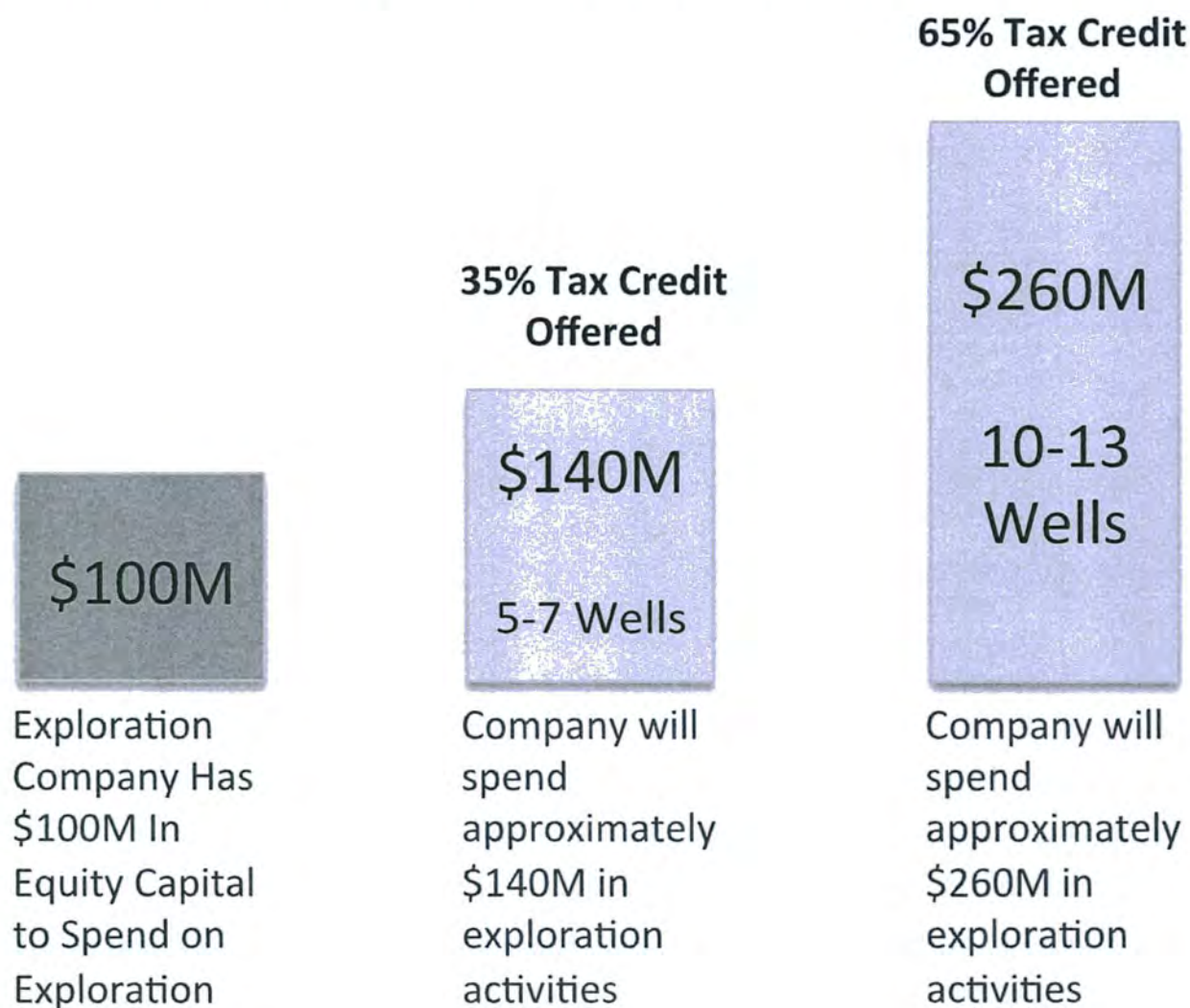
GREAT BEAR PROJECT SPENDING (2010 – PRESENT)

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



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 for Exploration
 - 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 and should be extended.



FRONTIER BASINS TAX CREDITS

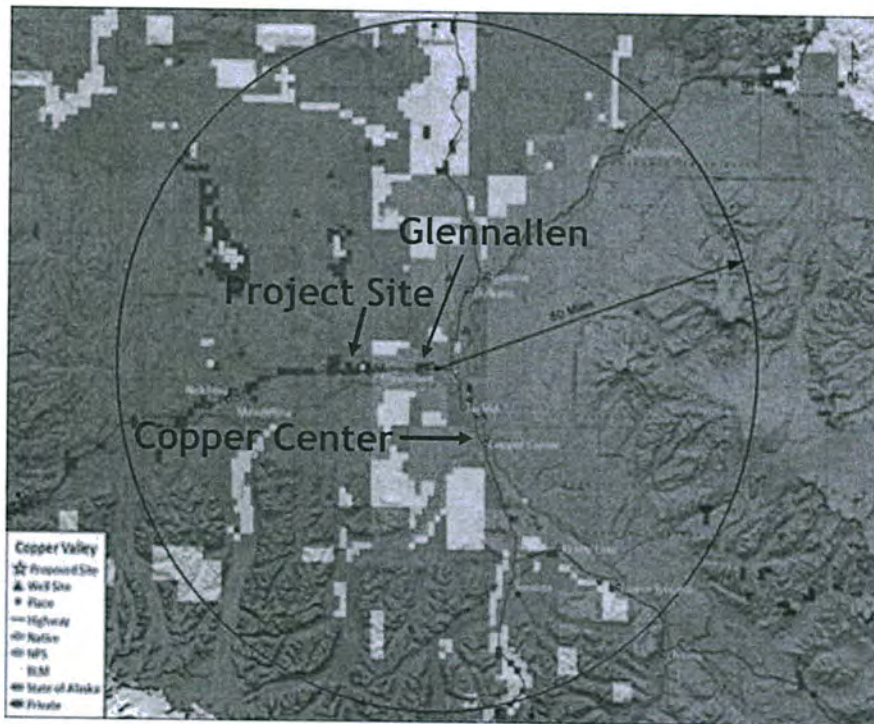
Presented to the Alaska Senate Representatives
Resources Committee

April 9, 2016

1

Ahtna

COPPER RIVER BASIN



- Ahtna is utilizing and would like to continue to utilize AS 43.55.025(a) credits to conduct exploration in the Copper River Basin.
- The .025(a) credits mitigate risk and incentivize Copper River Basin exploration. **Ahtna would not be conducting exploration without these incentives due to the high risk.**
- Upside for the State:
 1. Royalty & Production Tax
 2. Lower Rural Energy Costs
 3. Community and Economic Development

PURPOSE AND NEED FOR GAS IN COPPER RIVER BASIN

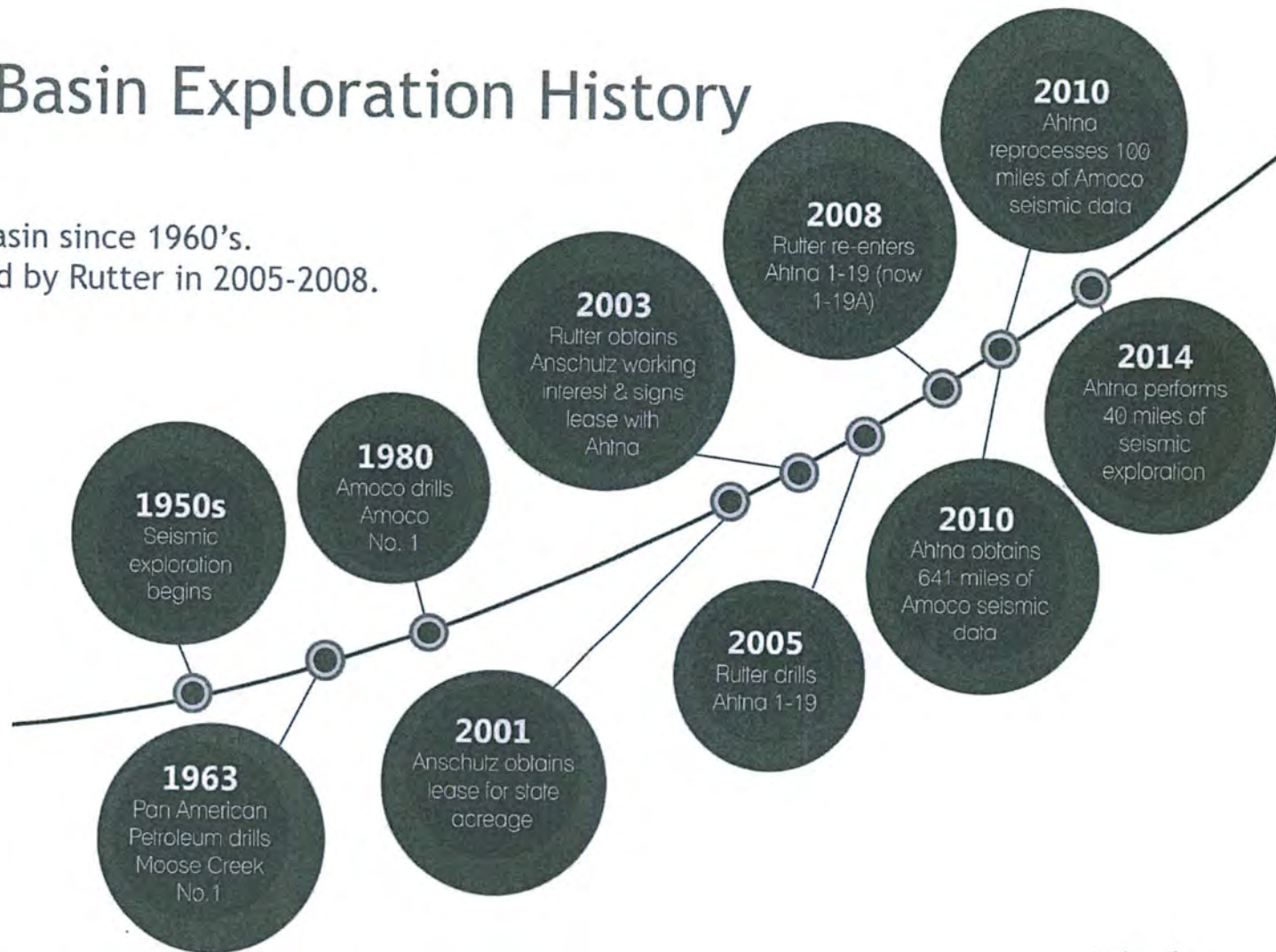
...To continue to conduct exploration in the Copper River Basin by drilling the Tolsona #1 and future targets, with the potential to develop natural gas production for distribution to local residents and electric utilities...

Community and Economic Development Benefits:

- ▶ Lower High Energy Cost in Rural Economy
- ▶ Economical Benefits for Local Business Local Employment
- ▶ Reducing Out-migration
- ▶ Building Infrastructure in the Region

Copper River Basin Exploration History

- 11 wells drilled in the basin since 1960's.
- Most recent well - drilled by Rutter in 2005-2008.

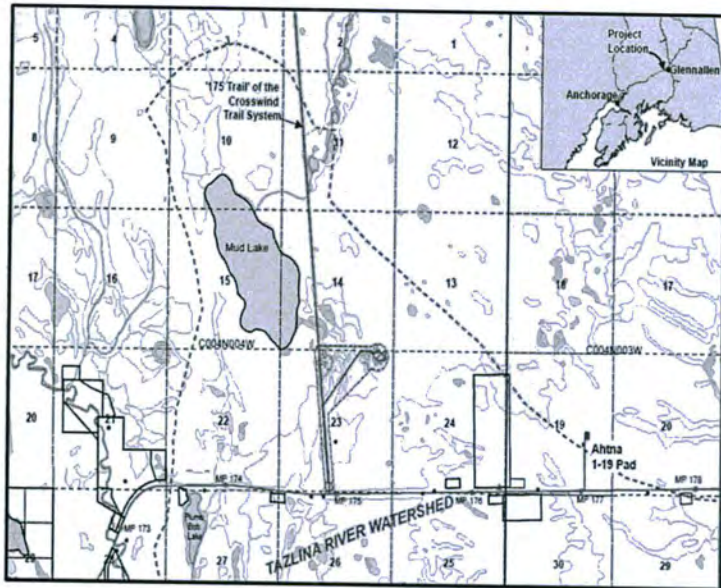


CONFIDENTIAL

AHTNA EXPLORATION PROGRAM HISTORY

- ▶ 2010 Ahtna reprocesses Amoco seismic
- ▶ 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

Current Drillsite Location – Tolsona #1



- ▶ 40 miles of new seismic in winter 2014/15; majority on State land
- ▶ Narrowed down to Tolsona #1 drillsite on State land.
- ▶ Improvement to public access & recreational area.



Ahtna

Tolsona #1

Proposed well depth of 4,500' vertical hole.

- Targeted structure is the Nelchina sandstone.
- Natural gas shows (approximately 94% methane in nearby well).
- Tolsona #1 potential for a great local fuel source.

Ahtna

PROJECT TEAM

Ahtna, Inc. @ 100% - Partners with Copper Basin exploration experience are unable to participate due to low energy prices.

Tolsona Exploration Oil and Gas, LLC

Ahtna Construction

HXR Drilling Services

Restoration Science & Engineering

Michael L Foster Group Companies

Multiple Other 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.

CONCLUSION

- ▶ **Our Request:** It is critical to our project that the Frontier Basin AS 43.55.025(a)(6) & (7) credits be extended from July 2, 2016 to January 1, 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 and also incentivize future Copper River Basin exploration.
- ▶ Ahtna also supports that AS 43.55.023 and 025(a)(1-4) Middle Earth tax credits to be kept in place, as an incentive to the Copper 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.

Ahtna

Questions?

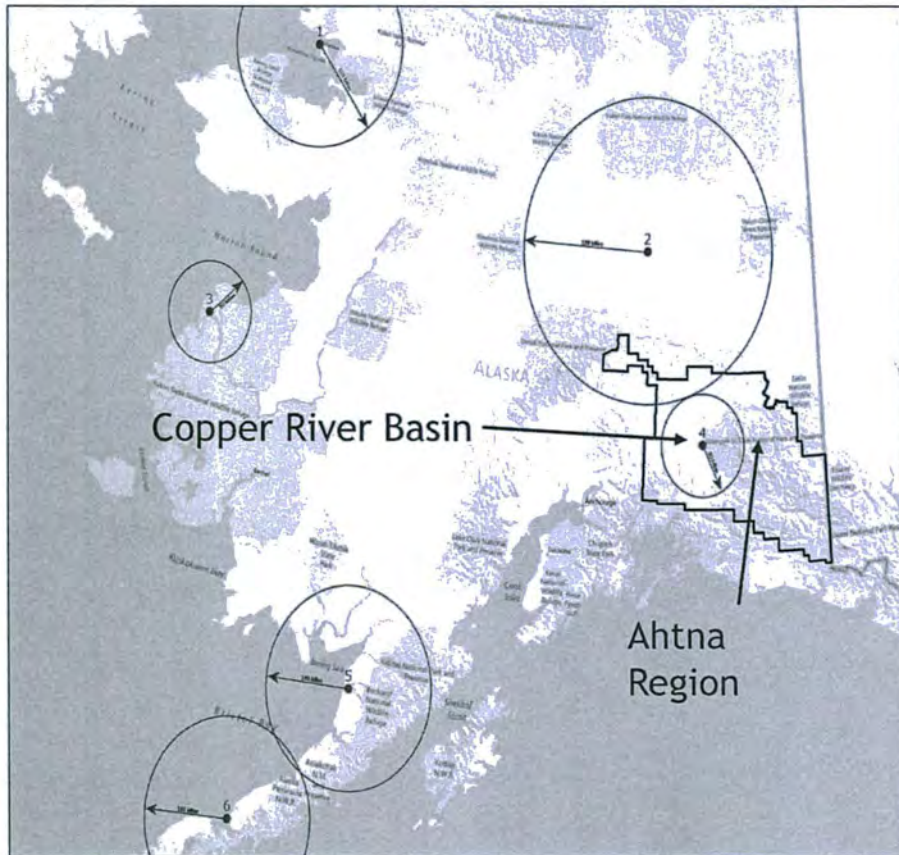
Contact Information

Chris Cook
Ahtna, Incorporated
Director of Finance
110 W. 38th Ave
Anchorage, AK 99503
907-868-8250
ccook@ahtna.net

The Ahtna logo is written in a white, cursive script font. It is positioned in the bottom right corner of the slide, set against a dark, geometric background that features overlapping triangular shapes in shades of grey and black.

BACK UP SLIDES

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

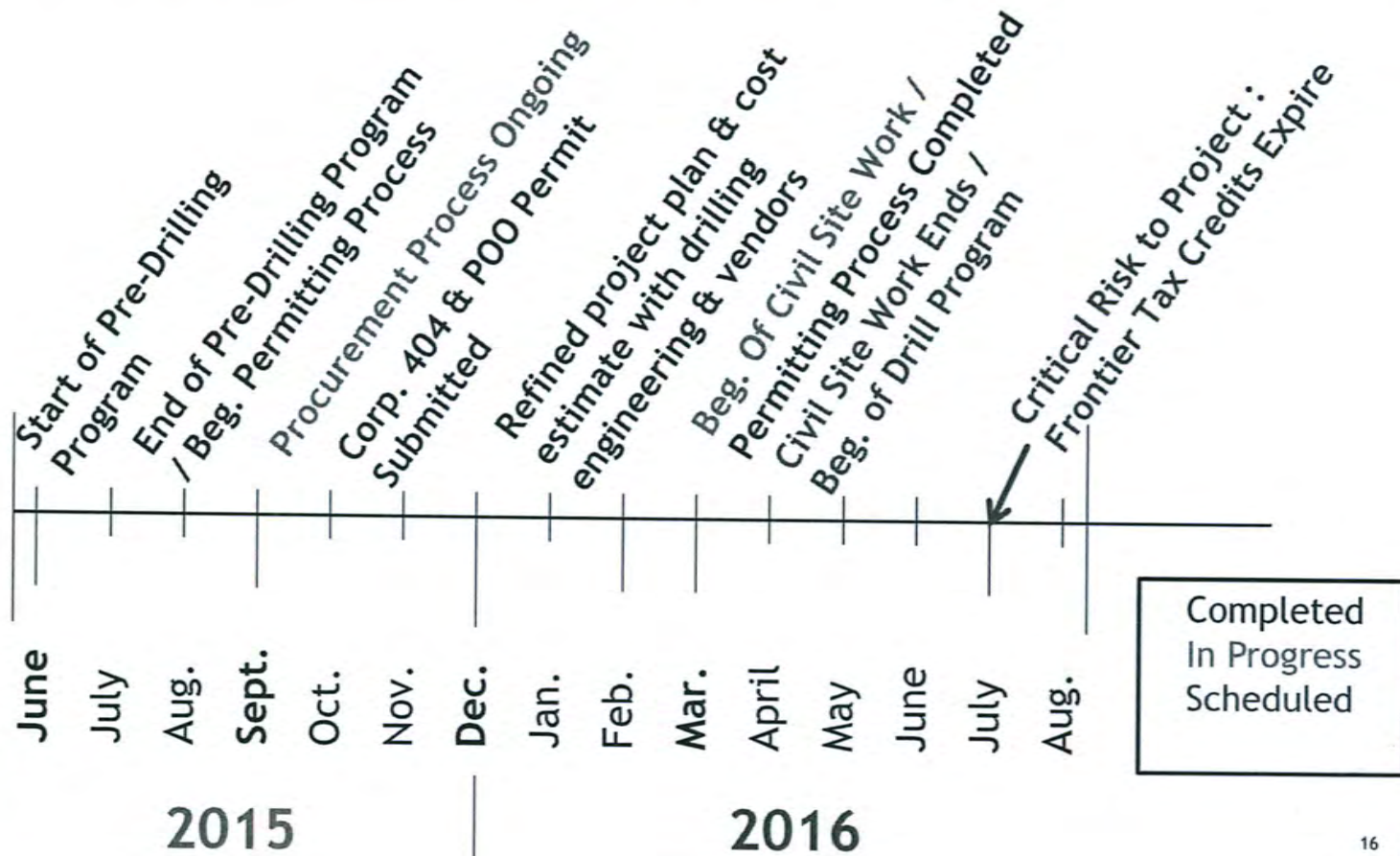
FRONTIER BASIN TAX CREDITS

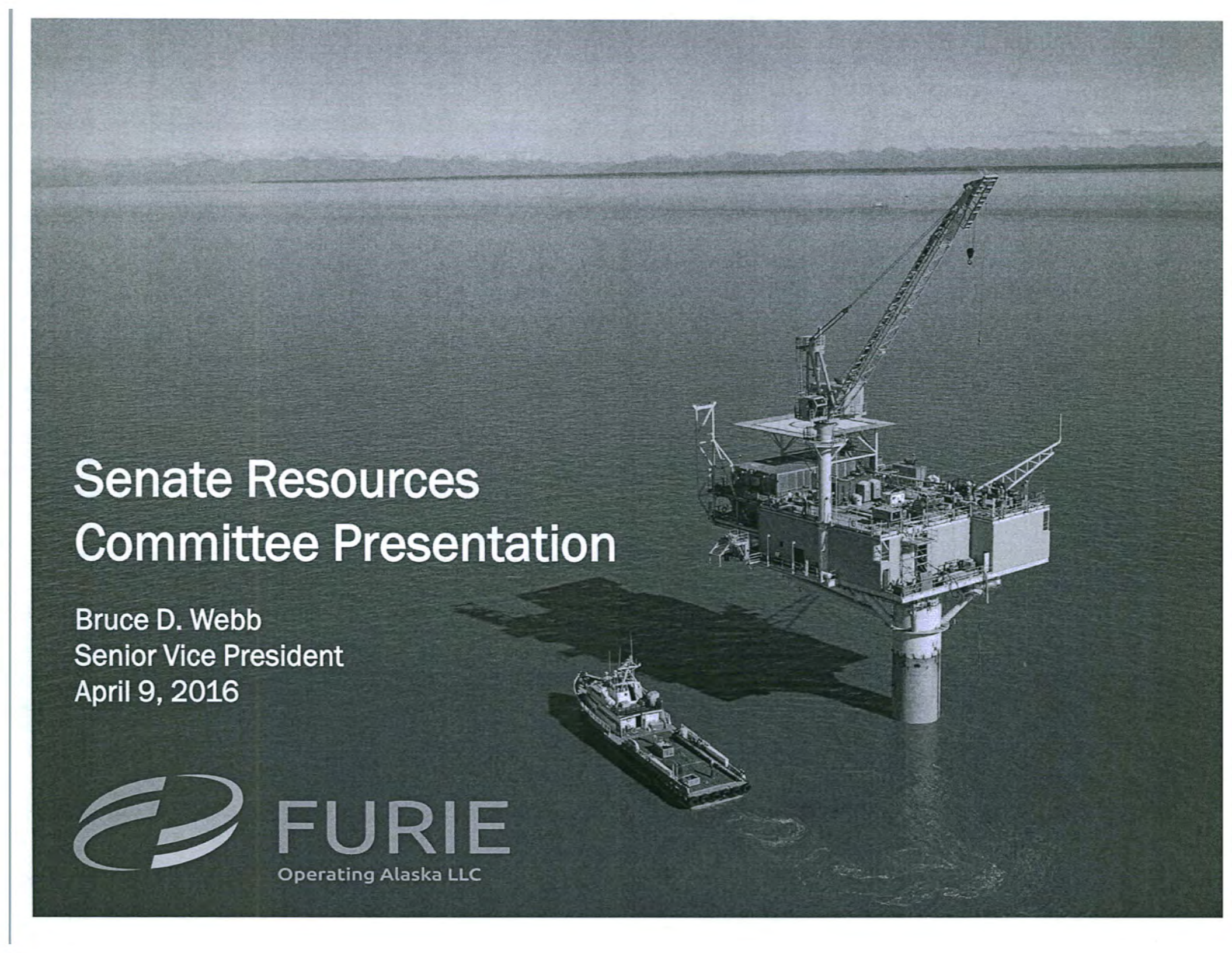
- ▶ AS 43.55.025(a)(6) – The first two exploration wells drilled inside each of the six Frontier Basins receives 80% credit or up to \$25M of qualified expenditures
- ▶ AS 43.55.025(a)(7) – The first seismic project performed inside each of the six Frontier Basins receives 75% credit up to \$7.5M of qualified expenditures
- ▶ Ahtna would not consider any exploration activities without tax credits

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

PROJECT SCHEDULE (Very tight)!



An aerial photograph of an offshore oil rig in the middle of the ocean. The rig is a large, complex structure with a prominent crane arm extending upwards. A smaller supply vessel is positioned nearby, moving towards the rig. The water is dark and calm, with a distant shoreline visible in the background.

Senate Resources Committee Presentation

Bruce D. Webb
Senior Vice President
April 9, 2016



FURIE
Operating Alaska LLC

Overview: Tax Credits = Jobs



- Tax credits support current and future investments in Alaska
- Investments create jobs and bring revenue to the State and local governments
- Furie has invested over \$700 million in Alaska (drilled 5 wells, installed offshore platform, 15+ miles of subsea pipeline, and Nikiski onshore processing facility)
- During 2015, Furie directly employed over 300 people in Alaska
- New gas supply supports local economic activity and reduces cost of energy
- Furie has reinvested all tax credits to fund exploration and development
- Without continued tax credits, we will have to significantly reduce future investment which will result in job losses

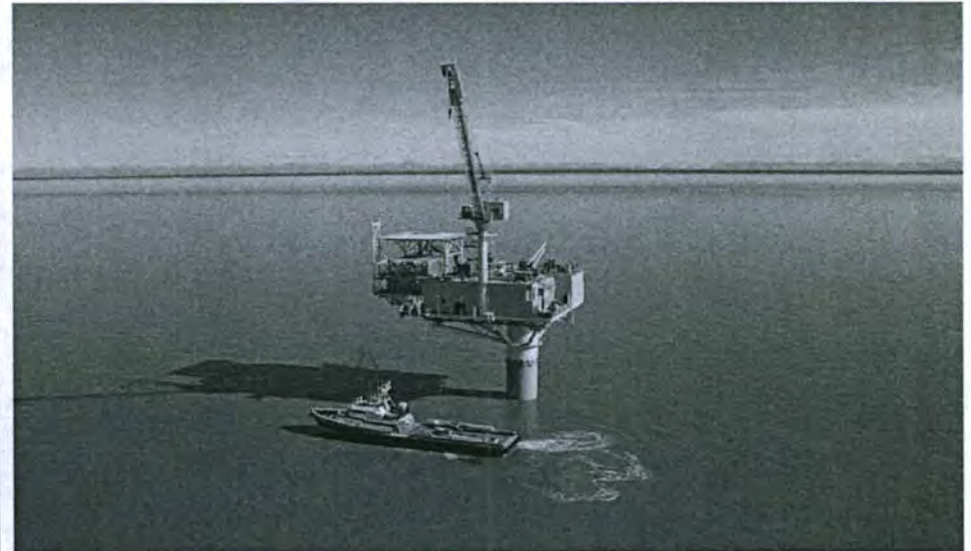
Tax Credits Help Alaskans by Supporting Development

Alaskans have benefitted directly and indirectly from Furie's investments, which would not have been economical without the presence of all the Cook Inlet tax credits.



Tax credits benefit all Alaskans

- Lower energy prices from increased competition and additional supplies of natural gas
- Increased State revenues from royalties, leases rentals, and property taxes
- New jobs (direct and indirect) and influx of income to local businesses
- Lowers risk of future shortfalls in natural gas supply
- Reduced energy costs in Cook Inlet reduces, heating oil, diesel, jet fuel, and transportation costs of goods shipped throughout Alaska



Tax credits enable development

- KLU development economics relied upon all Cook Inlet tax credits for positive returns, including:
 - 20% QCE under AS 43.55.023(a)
 - 25% loss credit under AS 43.55.023(b)
 - 40% WLE under AS 43.55.023(l)
 - Economics of future investments are at risk without tax credits
- Financing of tax credits provides liquidity required to support capital intensive projects, certainty going forward is needed

Benefits for Alaska

Tax credits are an investment in Alaska's economy that will ensure low-cost energy security and provide a return to the State and its citizens for many years to come.

- Over 300 jobs at peak of development, high probability of future developments
- Property taxes paid to the state and various cities and boroughs:
 - 2012-2015: \$2.9 million total
 - 2016 (estimated): \$4.8 million
- Lease rentals paid to the State since 2011: \$1.6 million
- Estimated royalties of up to \$300 million over the life of the current reserves
- Royalties, lease rentals and property taxes support local communities and create jobs

Alaska Partners Supporting Exploration and Development

*Investment in exploration and development creates jobs
and supports local businesses and industry*

Short-list of 100 Alaska businesses that support exploration and development in the Kitchen Lights Unit:

Airport Equipment Rentals	Clippership Motorhome Rentals, Inc.	Five Star Oilfield Services	McJunkin Red Man Corporation
Alaska Crane Consultants	CONAM Construction Company	Five Star Realty	McLane Consulting, Inc.
Alaska Industrial Hardware	Control Concepts & Technology	Fossil Maritime Company	Michael L. Foster & Associates, Inc.
Alaska Marine Surveyors Inc	Cook Inlet Marine LLC	Fugro Chance, Inc	Mobile Concrete and Grout of Alaska
Alaska Maritime Agencies	Cook Inlet Spill Prevention & Response	GCI	Nikiski Fuel, Inc
Alaska Rubber and Supply	Cook Inlet Tug & Barge, Inc.	Global Diving and Salvage Inc	North Air, Inc.
Alaska Safety Inc	CPD Alaska LLC	GRU Engineers, Inc	North Star Terminal
Alaska Satellite Internet	Crowley Logistics	Guess & Rudd LLP	Northwest Crane Service, LLC
Alaska Serigraphics	Crowley Marine Services, Inc	Harbor Consulting Engineers, Inc	NRC Alaska, LLC
Alaska Sewer & Drain	Crowley Solutions, Inc.	Harvest Alaska, LLC	Ocean Marine Services, Inc.
Alaska Steel Company	Cruz Construction, Inc.	Home Depot	Offshore Systems-Kenai
Alaska Tent & Tarp	Davis Block & Concrete	Homer Electric Association, Inc.	Peninsula Pumping, Inc.
Alaska West Express, Inc.	Deepwater Corrosion Services	Homer Septic Services	Petro Star, Inc.
Amak Towing Co., Inc.	Denali Crane Inspection LLC	Hotel Captain Cook	Petro 49
Anchorage Sand and Gravel Co.	Dril-Quip	Industrial Instrument Services, Inc.	Petrotechnical Resources Alaska LLC
Arctic Office Product	Dukowitz Machine, Inc.	Intertek Technical Services	Port Graham Corporation
ARCTOS, LLC	Eagle Enterprise	J.W. Williams, Inc.	Procomm Alaska
ASRC Energy Services	Eagle Safety Solutions	Jacobs Engineering Group, Inc	Professional Adjusters of Alaska
Atigun, Inc.	Emerald Alaska	Jensen Maritime Consultants	RAVN Alaska
Beacon Health and Safety Services	ENSTAR Natural Gas Company	Kenai Catering	Schlumberger Technology Corp
Cameron Surface Systems	Expro Americas	Kenai Peninsula Borough	Stoel Rives LLP
Carey Homes, Inc.	Fire Control Systems, Inc.	MagTech Alaska, LLC	Terrasond
Carlisle Transportation Systems, Inc.	First American Title Ins. Co.	Marine Survey Services	Watson Company, Inc.
Cash Welding and Fabrication	First National Bank Alaska	Maritime Helicopters Inc.	Weaver Brothers, Inc
Certified Inspection Services, Inc.	Fisheries Supply Inc.	Maritimewx	Westpac Logistics, LLC

Tax Credits Helped Furie Bring Lower Gas Prices to Southcentral Alaska



09/20/2015

HEA secures lower price on gas deal with Furie

"The price of Cook Inlet natural gas continues to trend downward..."

Base Load Prices	<u>2016</u>	<u>2017</u>	<u>2018</u>
Hilcorp Consent Decree	7.42	7.72	8.03
Furie Homer GSA ¹	6.50	6.75	7.00
Reduction %	-12%	-13%	-16%



03/18/2016

Price drops in Enstar, Furie gas deal

"...the gas price would be...less than...under a contract...with Hilcorp..."

Base Load Prices	<u>2016</u>	<u>2017</u>	<u>2018</u>
Hilcorp Consent Decree	7.42	7.72	8.03
Furie Enstar GSA ¹	-	-	6.70
Reduction %	-	-	-17%



08/12/2015

Chugach, Hilcorp agree on gas supply contract

"...prospect of more competitive prices from other producers..."

Base Load Prices	<u>2016</u>	<u>2017</u>	<u>2018</u>
Hilcorp Consent Decree	7.42	7.72	8.03
3rd Amendment to GSA	7.42	7.72	7.35
Reduction %	-	-	-8%



¹Price increases occur in the following year's April

General Comments about SB 130 / HB 247

- Repeal of credits under AS 43.55.023(a) (QCE) and (l) (WLE) will stifle or stop investments
- 25% loss credit under AS 43.55.023(b) -- which HB 247 leaves in place -- is helpful, but not adequate if QCE and WLE are repealed given:
 - high costs of oil and gas exploration and development in Alaska's Cook Inlet
 - tax rate on oil will be 35% after 2021
- \$25 million annual limitation on purchases of certificates is unreasonable and represents a virtual repeal of the program -- credits must be monetized timely to be useful for companies during capital intensive exploration and early development
- Transferable credits can be assigned and are vital for financing, which has provided needed liquidity -- repeal of credits and additional limitations on purchase of credits will dramatically impact financing and investment
- Any changes to tax credits in 2016 is unreasonable and hits Cook Inlet in the middle of the offshore drilling season (perhaps even in the middle of the drilling of a well):
 - budgets have been approved in light of current law
 - contracts are already in place
 - Furie is bringing another jack-up rig to Cook Inlet for additional exploration and development drilling this summer, and all credits are essential
 - impacts on financing arrangements

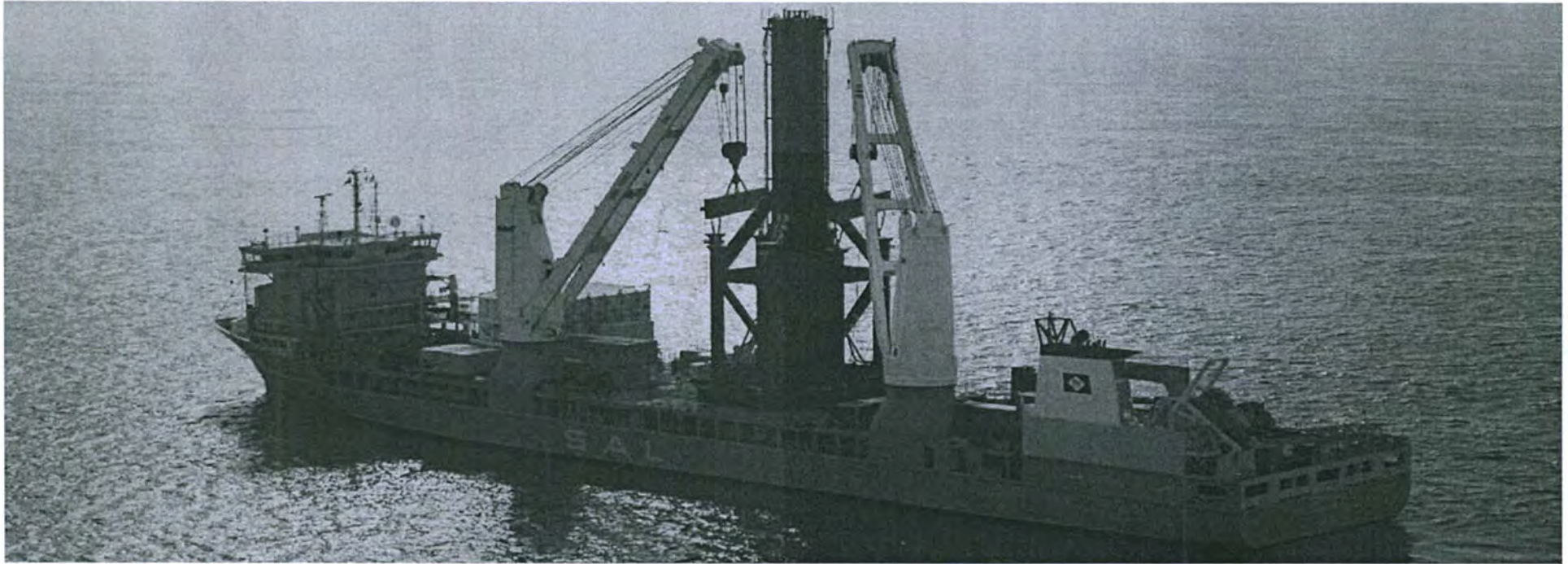
Tax Credits Enable Development Companies to Access Low Cost Capital

- Tax credits have provided Furie with access to economical sources of funding
 - Cost of funding declined from around 20% APR to 8% range
 - Low rates offered by lenders are due to Alaska's historical support of the oil & gas industry and tax credit programs (low perceived "political risk")

- Lower cost of capital helps fund existing and future development of Alaska's resources

- Lenders require certainty and have now stopped lending
 - Veto of 2015 appropriations almost crippled Furie's ability to access funding in the middle of the infrastructure installation
 - Lenders now question if 2015 tax credits will be paid in 2016
 - Proposed legislation with limits on cash repurchase and mid-year effective dates have shut down lending
 - E&P companies need and ask for certainty to avoid curtailing capital investments planned for 2016 and beyond

Summary – Without Certainty Furie Will Have to Curtail Investments



Had the Governor's version of SB 130 / HB 247 been passed prior to 2015, Furie would not have been able to continue exploration nor complete it's first development in the Cook Inlet.
Should HB 247 pass in 2016, investments will drop dramatically.

Credits under AS 43.55.023 and funding for cash purchases of certificates are crucial for liquidity and economical financing

Financing and loan guarantee programs through AIDEA are welcome, but not a reasonable alternative to the tax credit program

Repeal in July 2016 will catch Cook Inlet in the middle of a drilling season

Tax credits have led to increased:
gas supplies for local users, jobs, economic activity, and revenues to the State

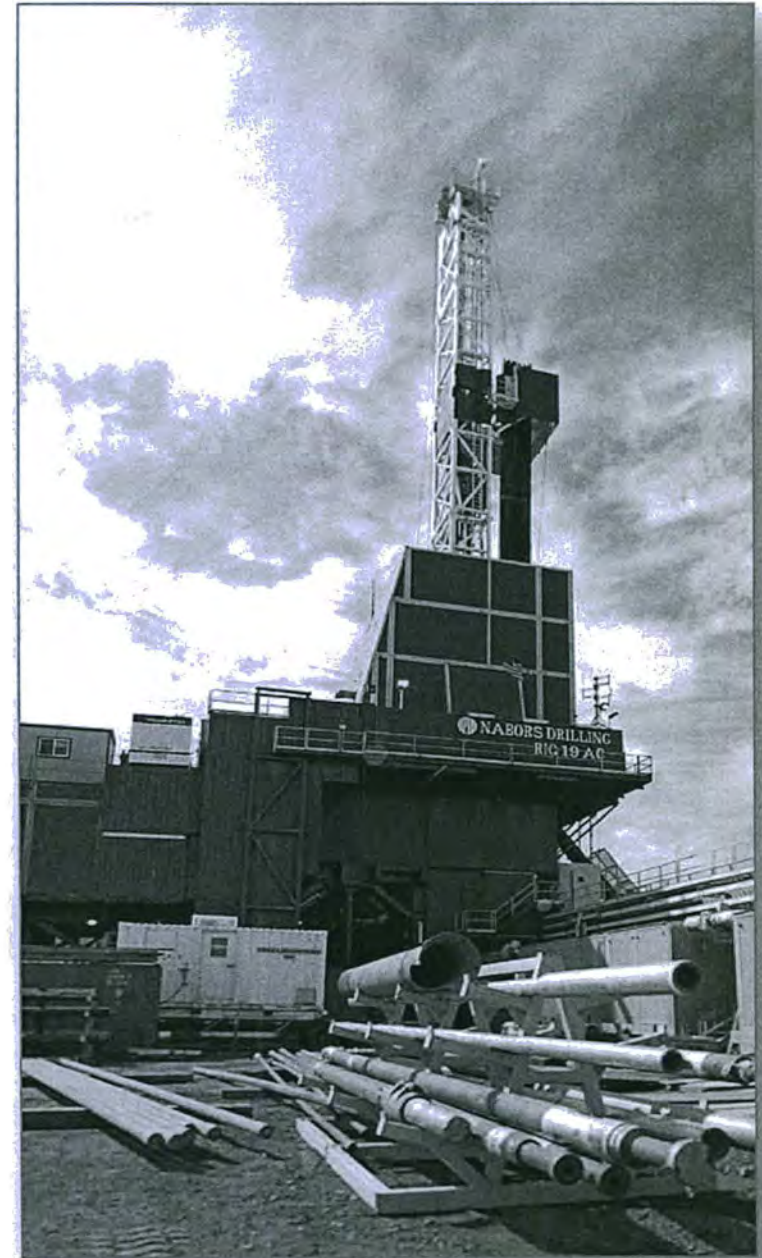
Senate Resources SB 130 Testimony

April 8, 2016

J. Patrick Foley
Senior Vice President, Alaska Operations



- ❖ 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 'Tulimaniq



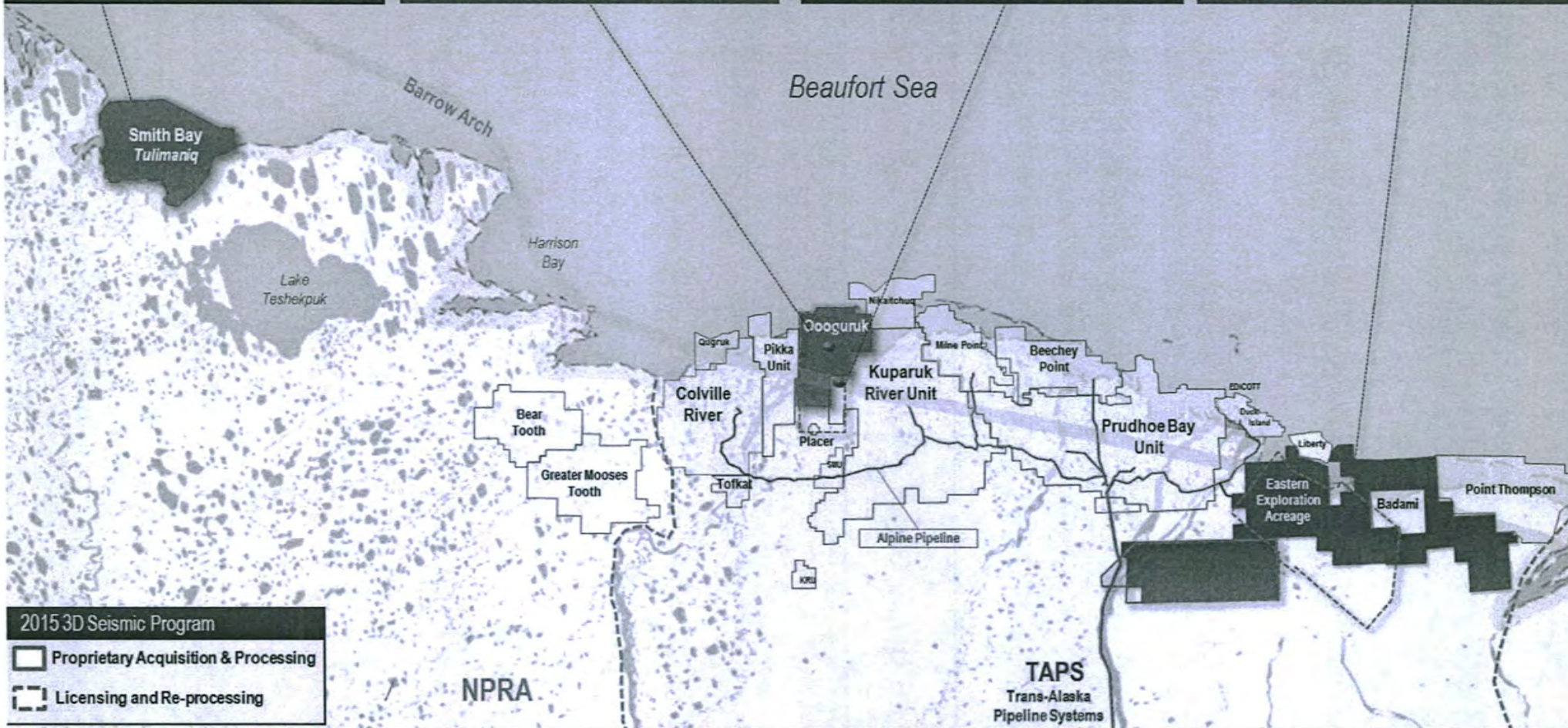
Oooguruk Unit (ODS / OTP)



Nuna Drill Site



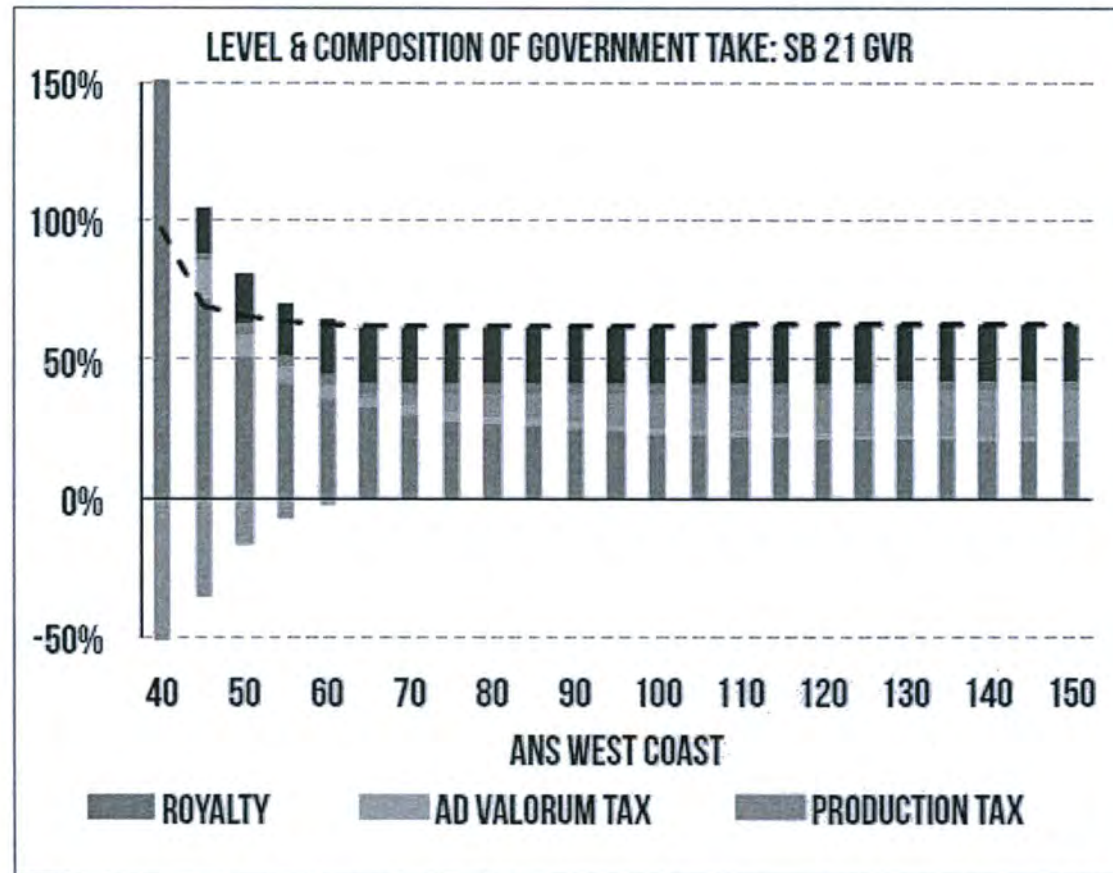
Eastern ANS Exploration Acreage



2015 3D Seismic Program
 [Solid Black Box] Proprietary Acquisition & Processing
 [Dashed Black Box] Licensing and Re-processing

Alaska : An Attractive Investment Opportunity?

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

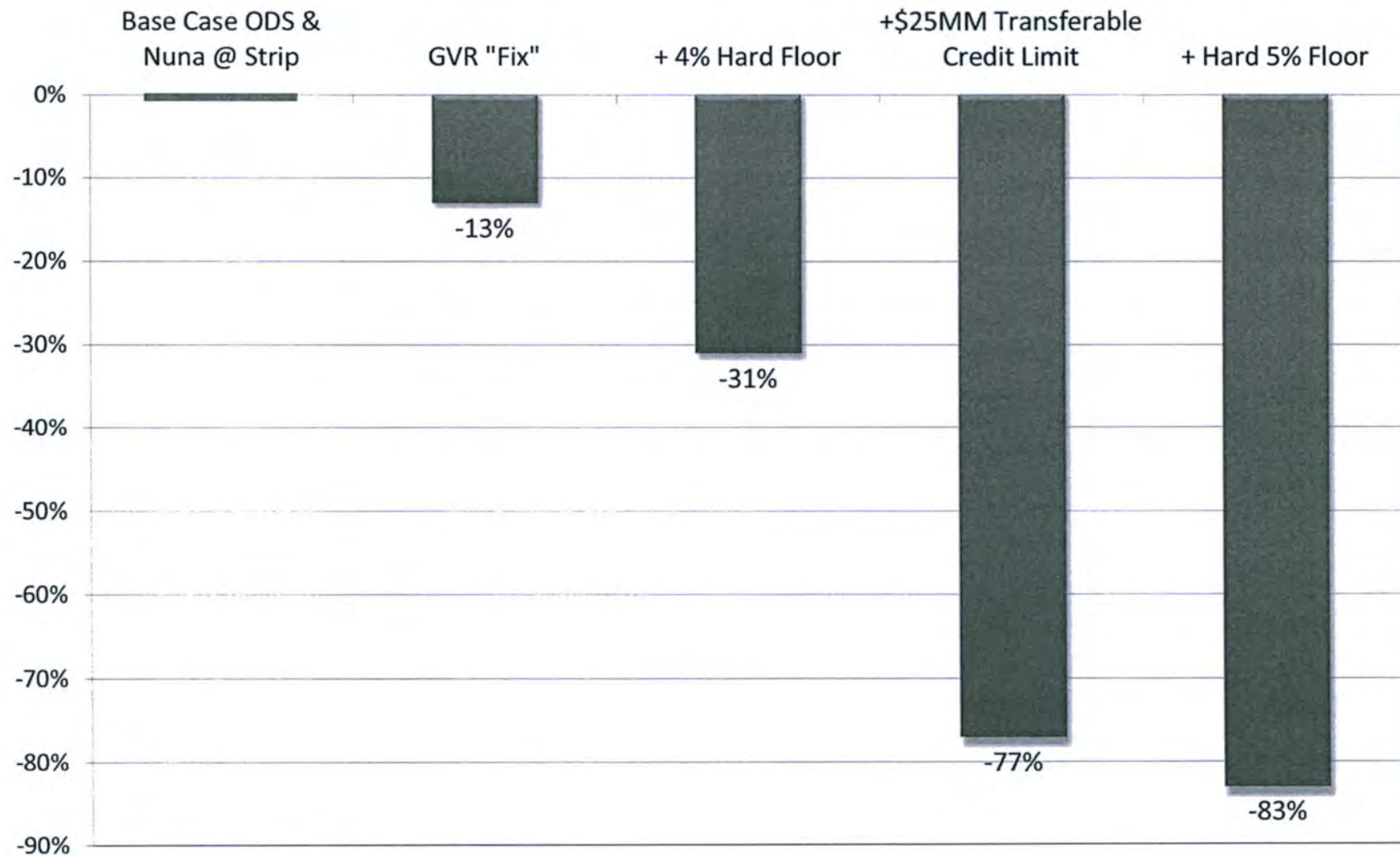


“At \$40 per barrel and below, (the government) is taking so much value, when there is not value to take”

~Janek Mayer, analytica,
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

❖ HB247:

- > 40 hrs of examination: experts, industry, public
- Increase taxes and eliminates incentives
- Represents yet another change in oil tax law
 - > instability > uncertainty

❖ Recommendations

- **NO U-Turn!**
 - Smaller caps limit new capital, projects, oil production
 - Hard floor generates little, impact a lot
 - GVR remains critical
- Thoughtful policy considerations:
 - Is result more production, or less?





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Comparison of Provisions of HB247- Oil and Gas Tax Credits Prepared by Dept. of Revenue Tax Division

Item	Current Law	GOV	CSHB247(RES)	CSHB247(FIN)	CSSB130(RES)
Cook Inlet Taxes	ELF caps until 2022	no change	no change	no change	Caps repealed and zero tax added 1/1/18
Cook Inlet Credits					
Net Operating Loss (NOL)	25%	25%	10%	10%	15% in 2017, 0% in 2018
Qualified Capital Expenditure (QCE)	20%	0%	20%	10%	10% in 2017, 0% in 2018
Well Lease Expenditure (WLE)	40%	0%	30% in 2017, 20% in 2018	30% in 2017, 20% in 2018	20% in 2017, 0% in 2018
Avg. Total Support for Developers	55%	25%	35% in 2017, 30% in 2018	30% in 2017, 25% in 2018	30% in 2017, 0% in 2018
Avg. Total Support for Producers	30%	0%	25% in 2017; 20% in 2018	20% in 2017; 15% in 2018	15% in 2017, 0% in 2018
Middle Earth Credits	same as CI	same as CI	same as CI	NOL stays 25%; WLE stays 30% through 2018	NOL / QCE / WLE stay at 15% / 10% / 20%
North Slope Minimum Tax "Floor"	4%, but many credits incl. NOLs can reduce to zero	Harden so all NS production must pay the min tax; increased 4% to 5%	No changes to current law	Partially harden so that credits can't reduce payments below 2%	No changes to current law
Repurchase Caps	none	\$25 million / company / year; none for large companies > \$10 billion revenue	\$200 million / company / year	\$100 million / company / year	\$85 million / company / year
Gross Value Reduction (North Slope new oil)					
GVR interaction with an Operating Loss	Loophole allows NOL credits to approach 100% of loss	GVR can't artificially increase size of an NOL	Kept GOV language	Kept GOV language	Kept GOV language

Comparison of Provisions of HB247- Oil and Gas Tax Credits Prepared by Dept. of Revenue Tax Division

Item	Current Law	GOV	CSHB247(RES)	CSHB247(FIN)	CSSB130(RES)
GVR oil reverts to "legacy" oil	GVR-eligible oil remains "new" forever	No change	No change	New oil becomes legacy oil after 5 years	New oil becomes legacy oil after 5 years
Interest on Delinquent Taxes	3% over fed, simple interest	7% over fed, compounding	3% over fed, compounding	5% over fed, compounding, for only 1st 4 years	7% over fed, compounding, for only 1st 3 years
Exploration Credits	Most sunset 7/1/16	Allow sunset, repeal older unused credits	Same as GOV	Same as GOV; extend Frontier credit to allow single well completion	Same as GOV; extend Frontier credit to allow single well completion
Effective Dates	n/a	Most 7/1/16	Most 1/1/17	Most 1/1/17	Most 1/1/17
Misc / Non-Dollar Issues					
Confidentiality	Absolute	Can report how much indiv. companies get in cash credits	not in CS	not in CS	not in CS
Alaska Hire	n/a	Limit repurchases to percent of AK hire	not in CS	not in CS	DOR must give repurchase priority to high % AK hire
Other obligation to the state	Can withhold part of credit if company owes tax	Can withhold part of credit if company has other obligation to the state (i.e. royalty)	Modified in CS, but kept GOV intent	Kept HRES language	Kept HRES language
Bonding / Bankruptcy Protection	n/a	none	\$250k surety bond for unsecured creditors	Modified HRES language	Modified HFIN language
Est. Fiscal Impact- FY18	n/a	\$440 million	\$70 million	\$125 million	\$55 million
Est. Fiscal Impact- FY19	n/a	\$390 million	\$50 million	\$145 million	\$70 million
Est. NOL carryforward- FY19	\$732 million	\$1,065 million	\$708 million	\$1,077 million	\$677 million

CS SB 130: IMPACT ANALYSIS

Senate Resources Committee
Tuesday, April 12, 2016

Janak Mayer, Chairman & Chief Technologist › janak.mayer@enalytica.com
Nikos Tsafos, President & Chief Analyst › nikos.tsafos@enalytica.com

<http://enalytica.com>

CS SB 130 SUMMARY

North Slope Provisions: 'Old' Oil

- Continue ability of NOL to reduce taxes below 4% gross floor
- Continue annual basis of tax assessment

North Slope Provisions: 'New' Oil

- Continue ability of NOL, \$5/bbl and Small Producer credits to reduce taxes below 4% gross floor
- Continue annual basis of tax assessment
- Remove impact of GVR in calculating NOL to ensure 35% support for North Slope spending
- \$85mm per-company cap on refunds to protect against potential liability of major new developments
- 5-year time limit on GVR

CS SB 130 SUMMARY

Cook Inlet Provisions

- Reduce all Cook Inlet credits starting January 1 2017 (WLE to 20%, QCE to 10%, NOL to 15%)
- from 1 January 2018, sunset all credits and exempt Cook Inlet from production tax

Middle Earth Provisions

- Grandfather existing .025 frontier basin credit until 2022, phase down WLE, QCE and NOL

General Provisions

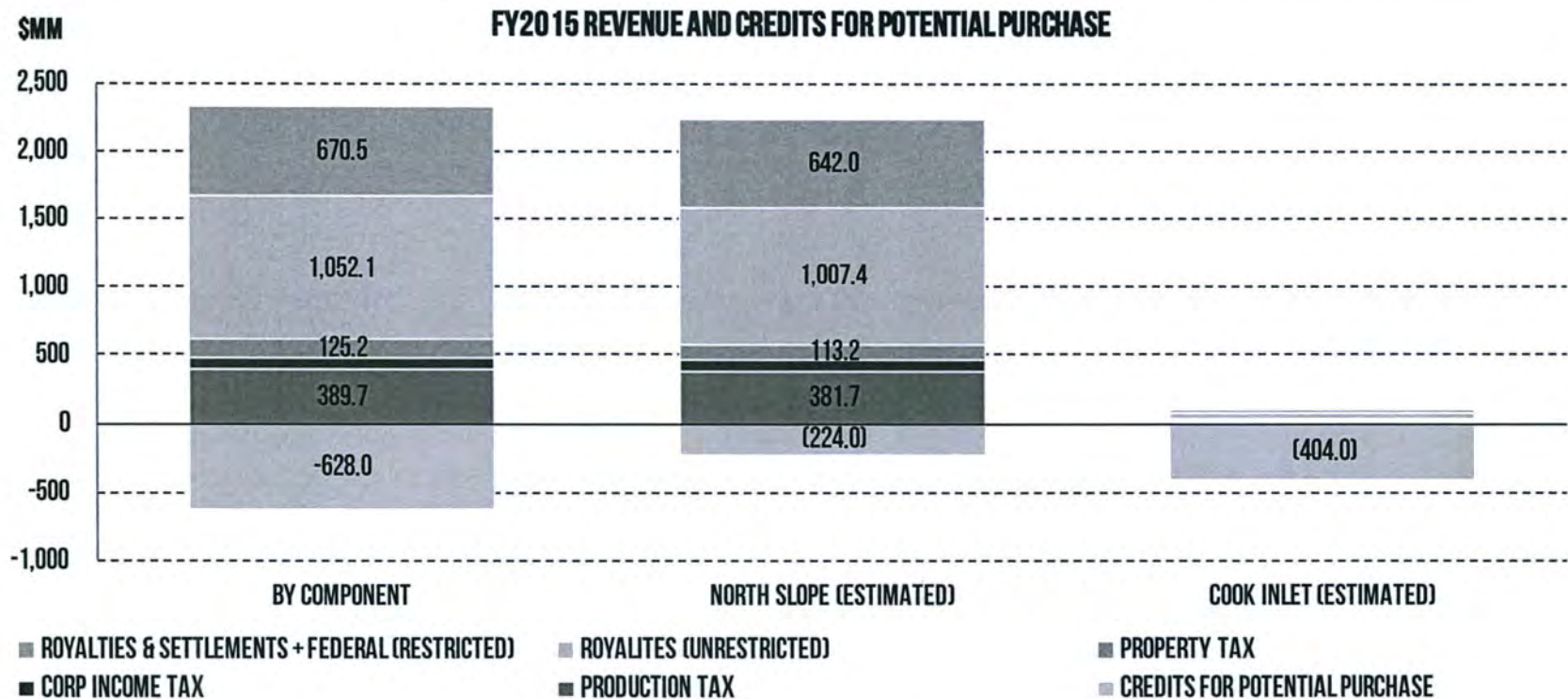
- 7% quarterly compounded Interest on delinquent taxes - but only for 3 years
- Existing liabilities to state from oil & gas production withheld from refundable tax credits
- Alaska hire linked to credit refund priority, not amount
- Surety bond (\$250K) to protect local creditors

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

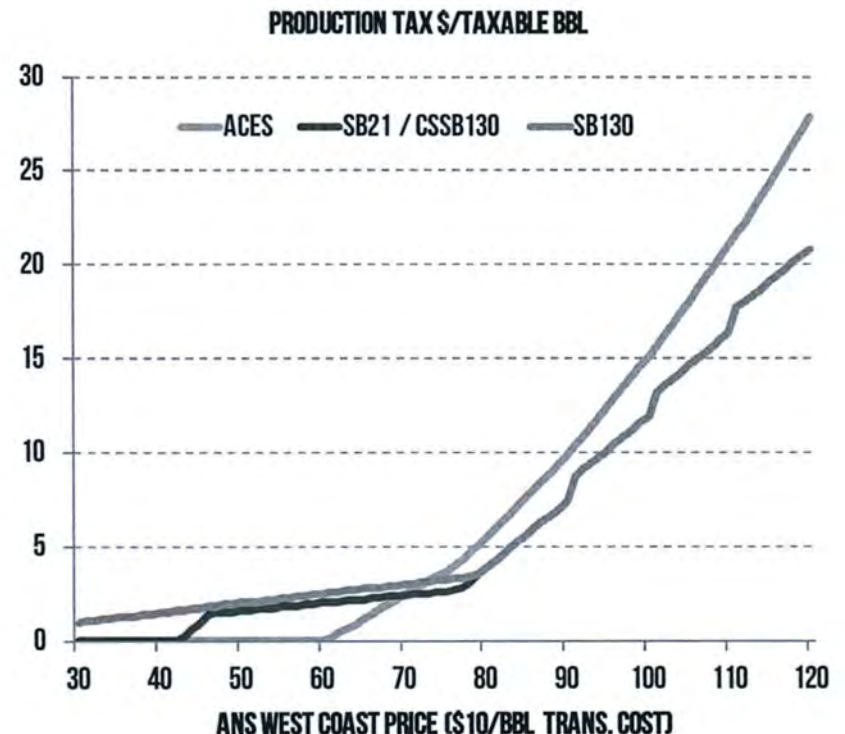
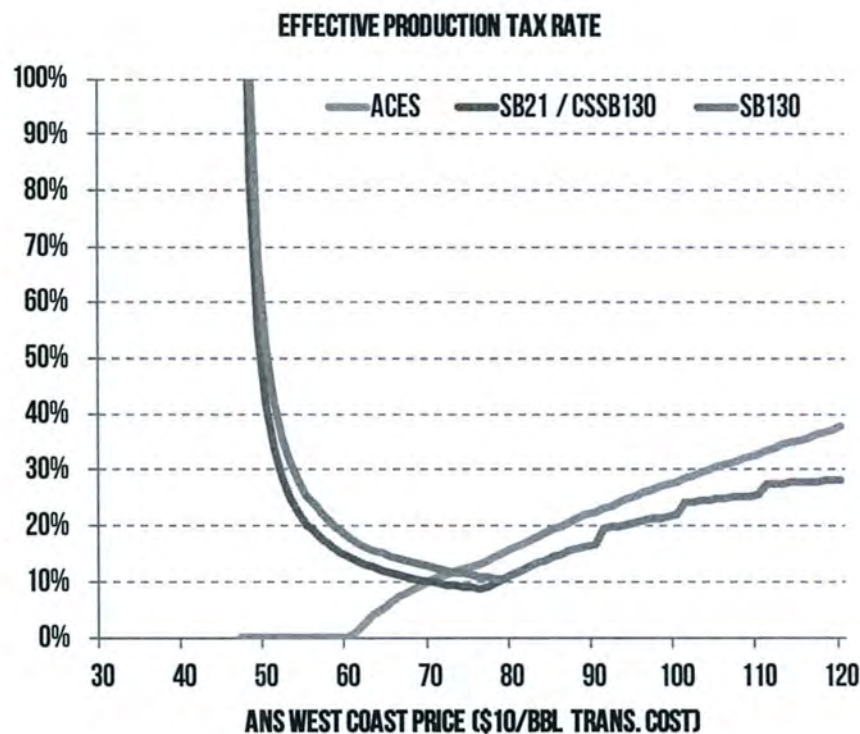
Credits on the North Slope are more limited but also a far smaller fraction of total value generated



SOURCE: ALASKA DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK; TAX DIVISION; ANALYTICA ESTIMATES

CS AVOIDS RAISING 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, but must balance risk and reward at low and high end
 Preventing NOL credit from 'piercing' floor moves state revenue from future to present; total is the same



KEEPING ANNUAL CALCULATION AVOIDS 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-201	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

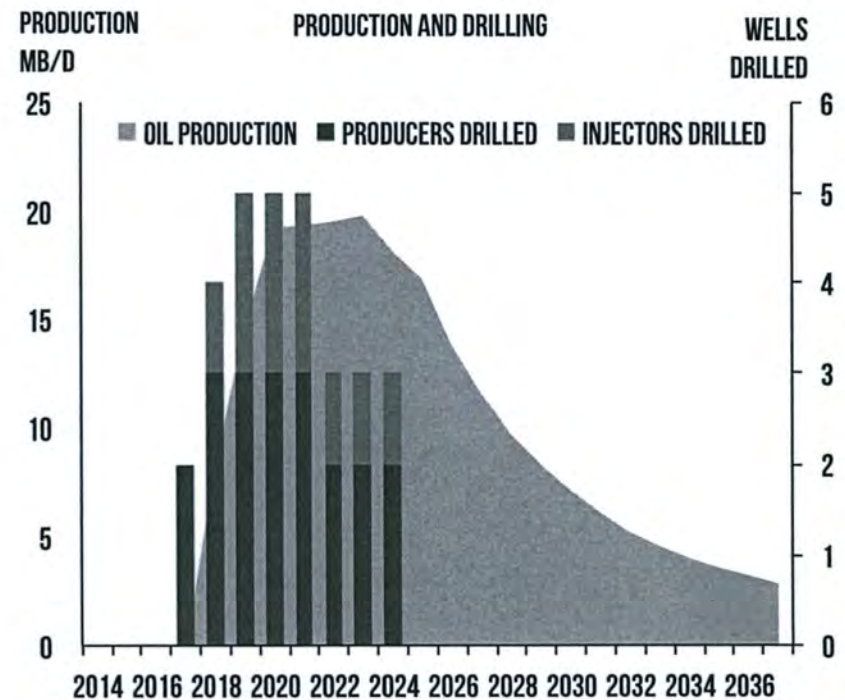
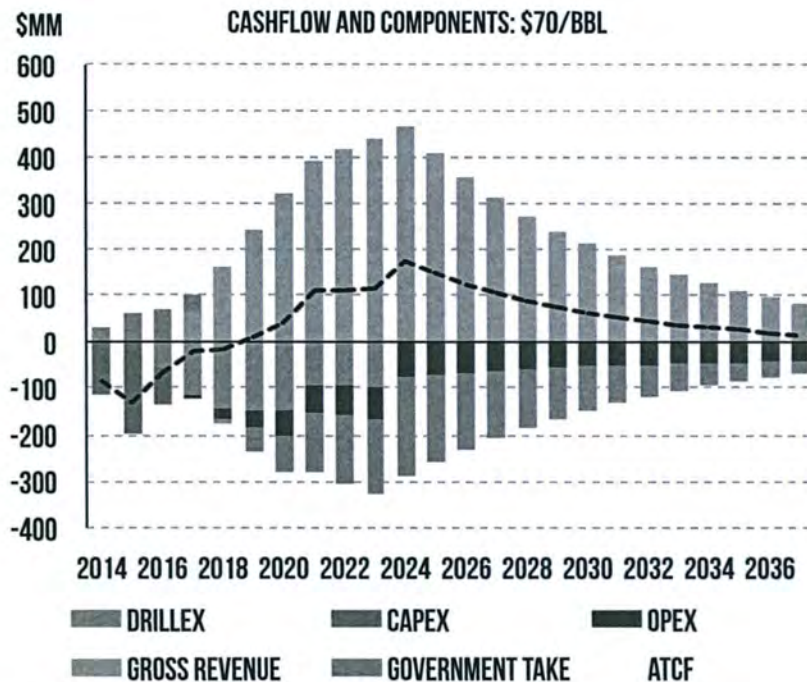
⁺single-taxpayer, taxable-barrel-based approximation, FY2014 DOR RSB costs, assumes no taxable production GVR-eligible

HOW DO CHANGES IMPACT NEW FIELD DEVELOPMENT?

Sample NS investment: Cumulative CAPEX and DRILLEX of \$1.3 bn; average annual OPEX of about \$15/bbl

Peak production of 20 mb/d; 30 wells (production and injection) drilled over 8 years

Ongoing DRILLEX in early years means bulk of tax liability occurs only after several years of production



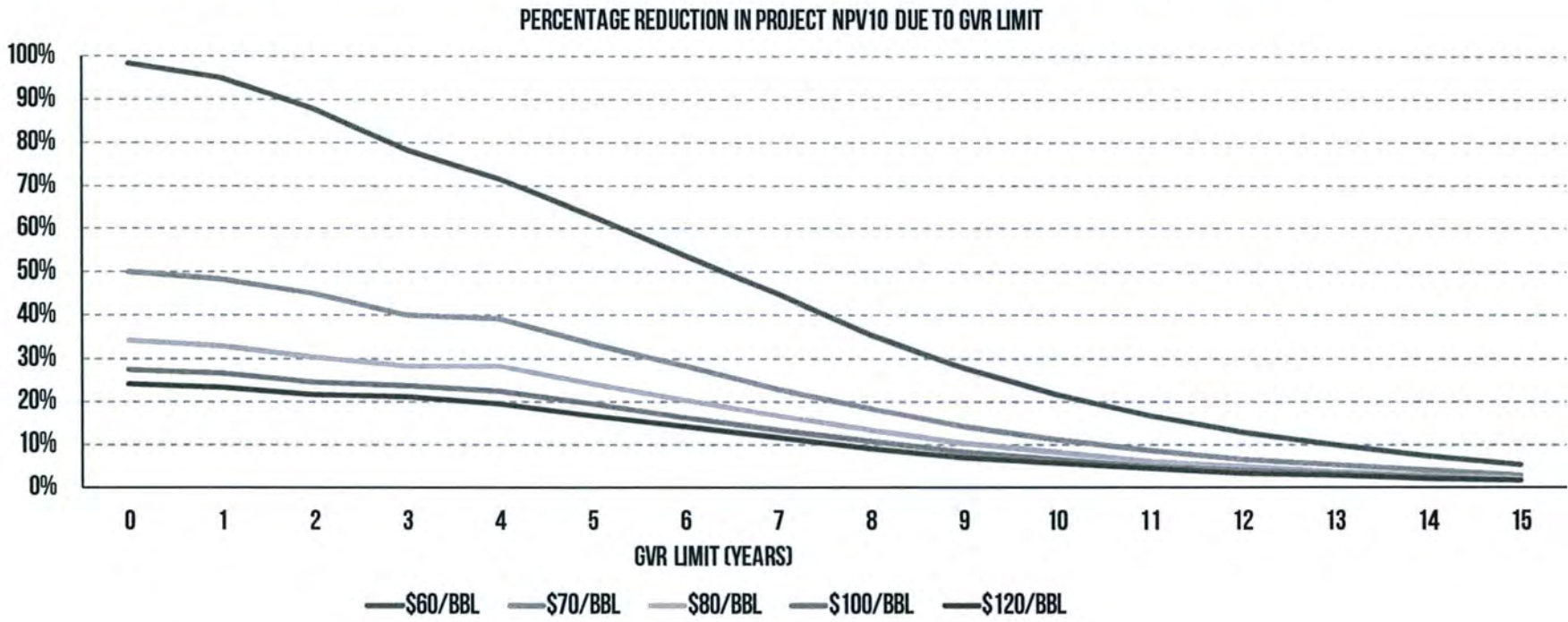
5-YEAR GVR LIMIT HAS MAJOR IMPACT ON PROJECT VALUE

Project is marginal at \$60/bbl; elimination of GVR can wipe out all value at that price

Because most tax liability occurs after end of major spending, short GVR limit provides little benefit

5-year GVR limit destroys over 60% of project value at \$60/bbl, relative to status quo

Impact of 10 year limit much lower; 15 year limit preserves almost all of status quo value



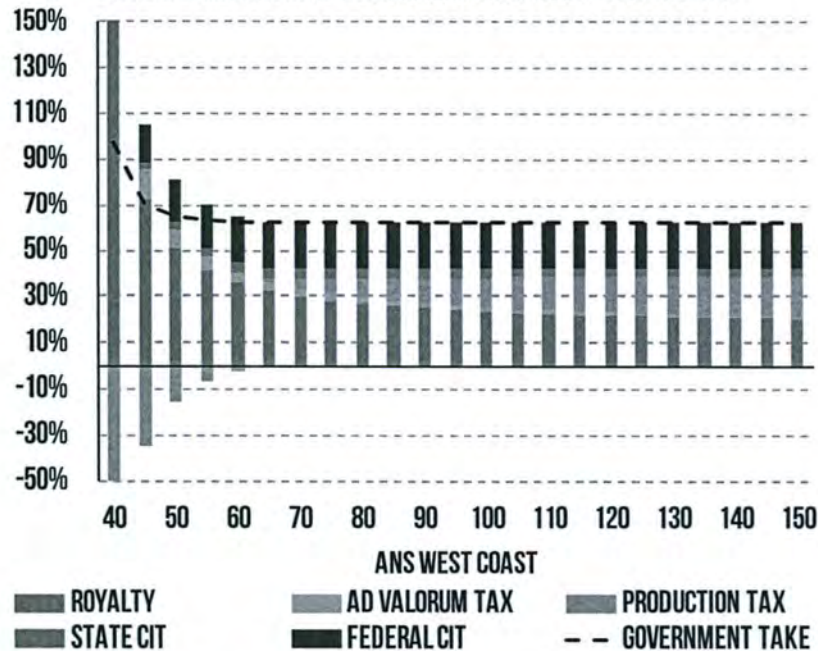
CS AVOIDS MAKING REGRESSIVE SYSTEM EVEN MORE SO

State of Alaska making negative production tax in today's prices; but overall gov't take is still high

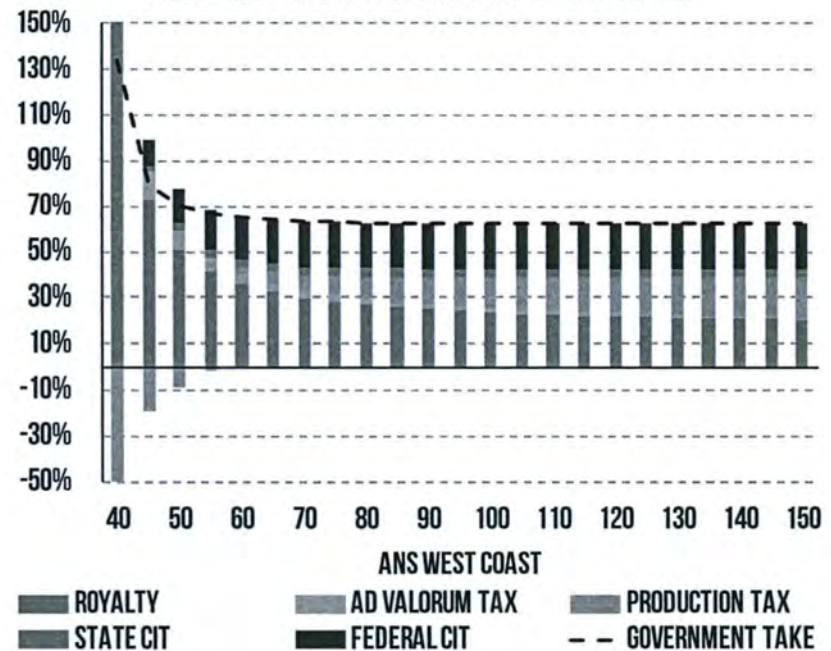
Floor hardening of original bill shifts up government take in lower oil prices

In times of high investment / low prices (as in 2016), effective government take exceeds 100%

LEVEL & COMPOSITION OF GOVERNMENT TAKE: SB21/ CSSB130 GVR*



LEVEL & COMPOSITION OF GOVERNMENT TAKE: SB 130 GVR



* EXCLUDES IMPACT OF 5 YR GVR LIMIT

FIX FOR NOL CREDIT ABOVE 35% OF ACTUAL LOSS

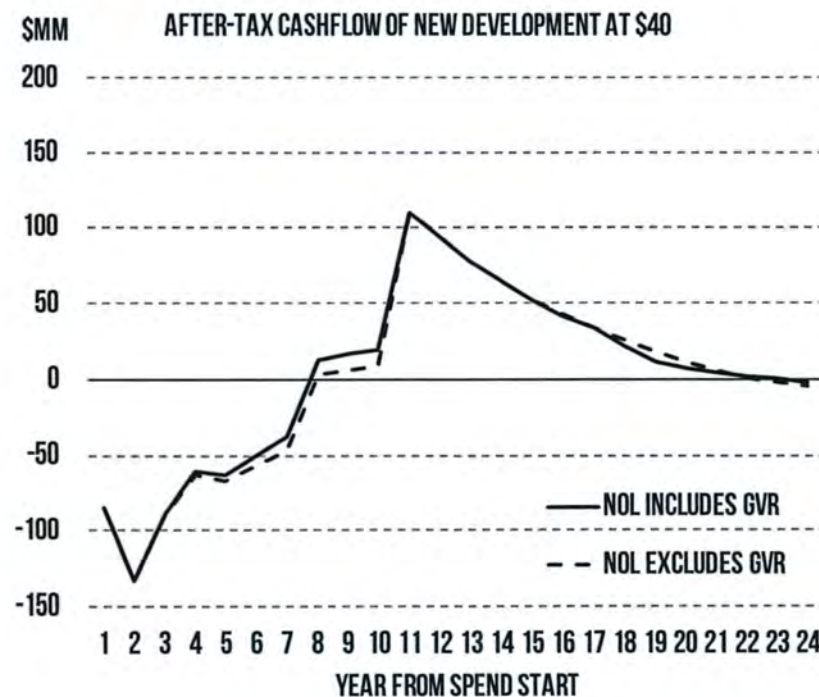
The purpose of the Gross Value Reduction (GVR) is to lower the effective tax rate on new production

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%



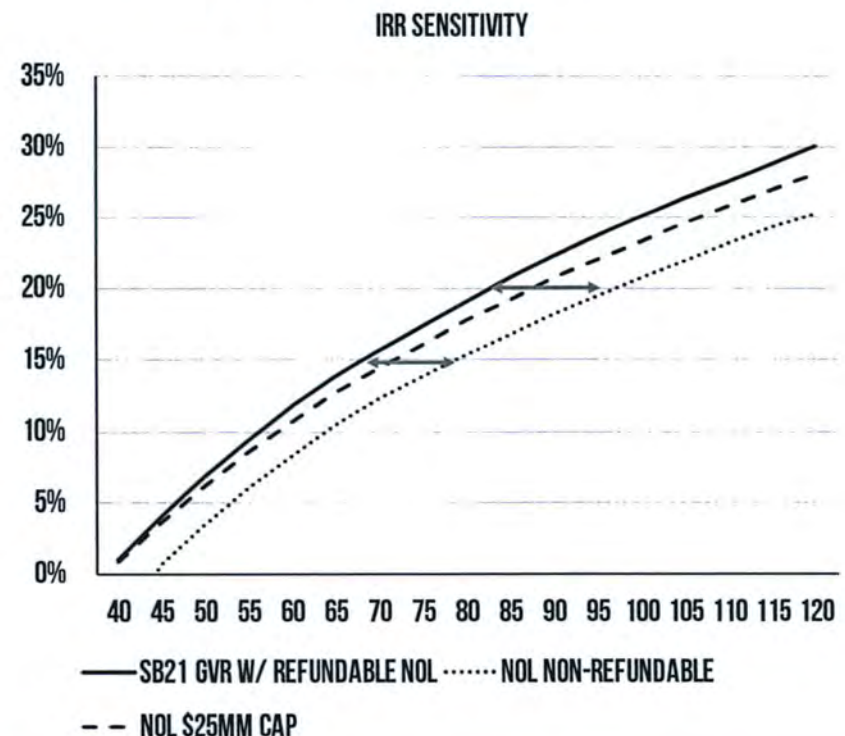
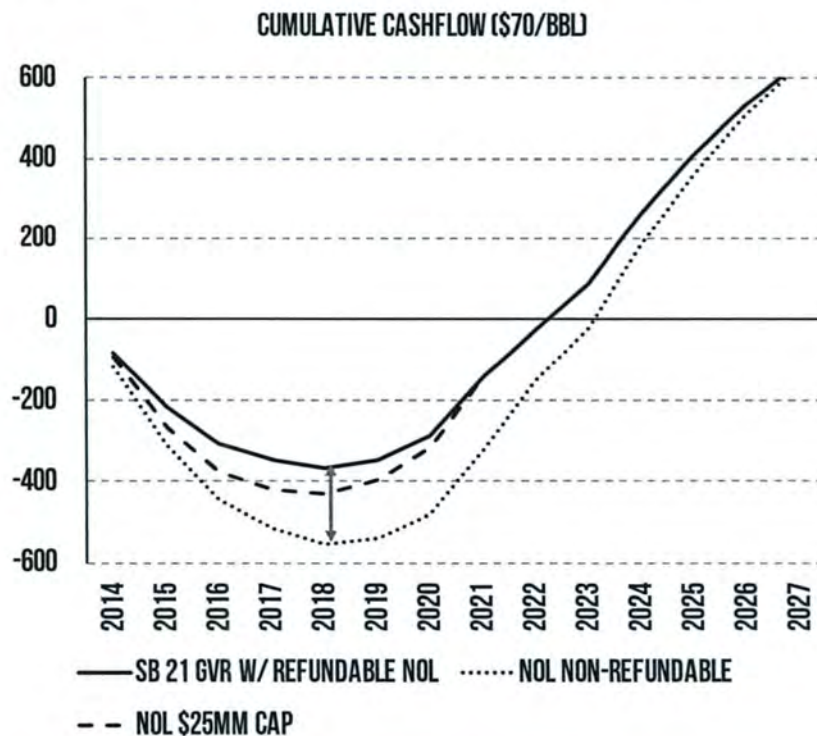
REFUND LIMITS BOOST CAPITAL NEEDS AND LOWER IRR

Strict refundable 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? \$85mm? \$100mm?



REDUCTION IN COOK INLET SPENDING SUPPORT

Currently 3 credits in Cook Inlet

- 25% NOL credit for carried-forward annual loss, 'stackable' with either:
- 20% QCE credit for all qualified capital lease expenditures; or
- 40% WLE credit for well-related capital lease expenditures

On 'average', roughly 55% support for spending under status quo

Under CS, reduced to 15% NOL, 10% QCE, 20% WLE in 2017, then sunset from 2018 onward

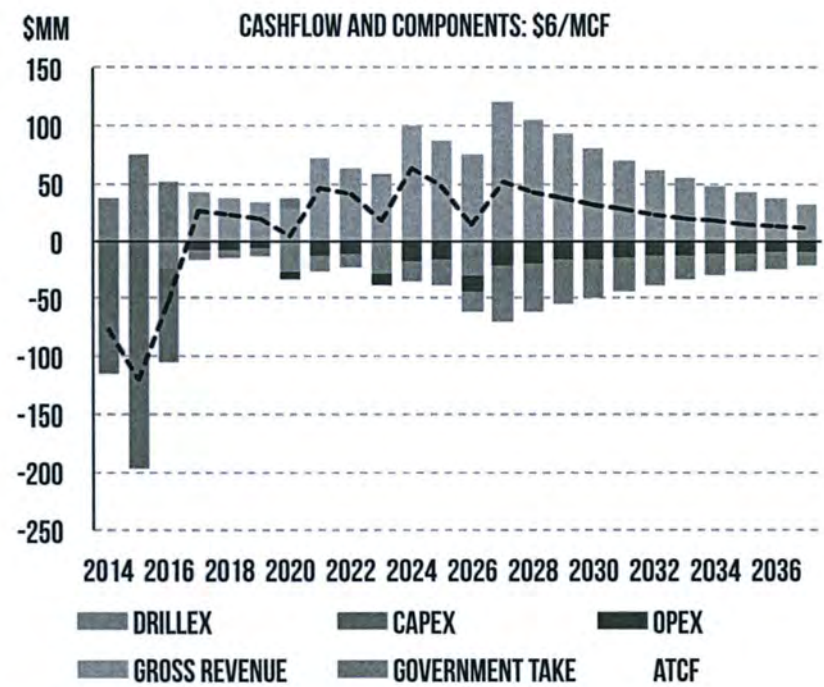
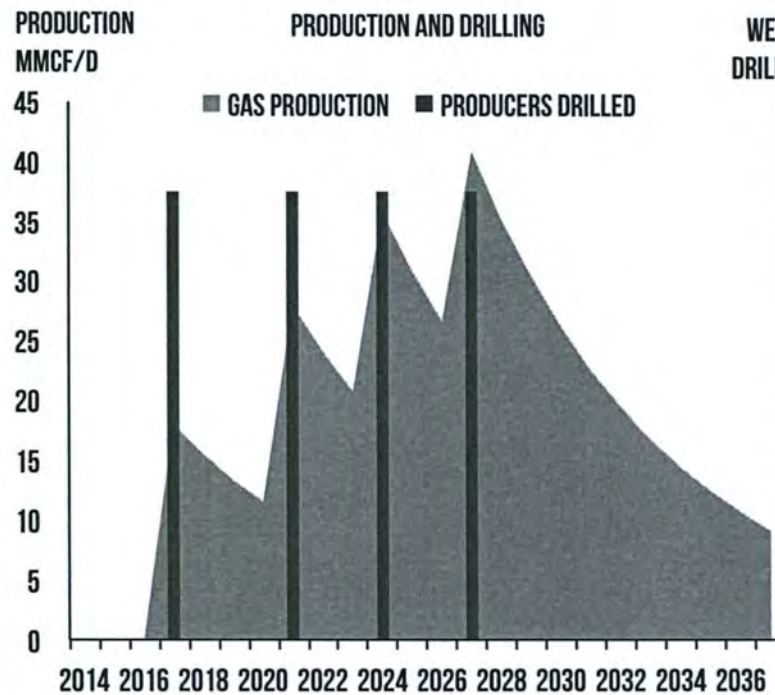
No production tax in Cook Inlet from 2018 onwards - shift to low-government take, free-market approach

Crucial question: Will changes be seen as durable?

COOK INLET #1: MARKET CONSTRAINED (ASSUMPTIONS)

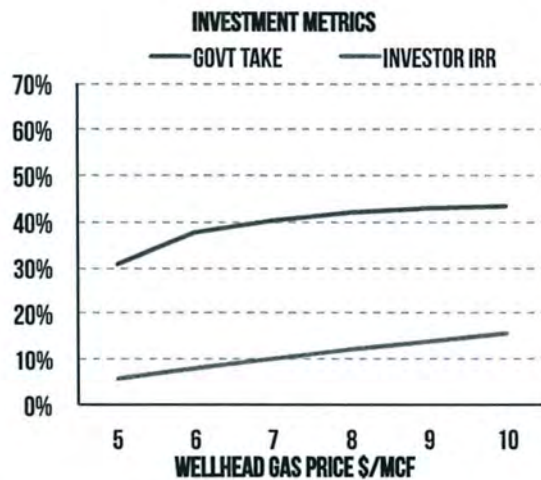
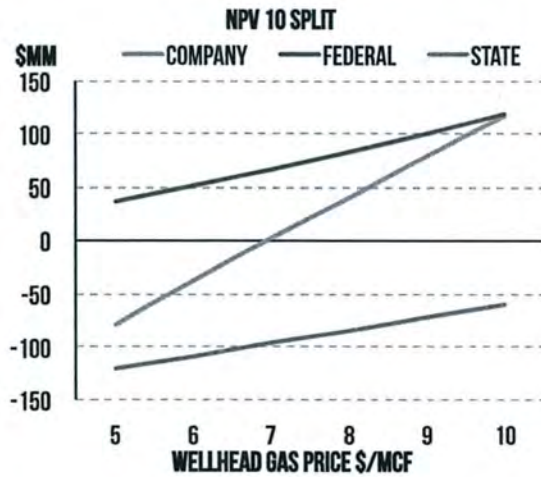
Large upfront investment but constrained gas market

Limited ability to sell gas: can only drill a well every few years

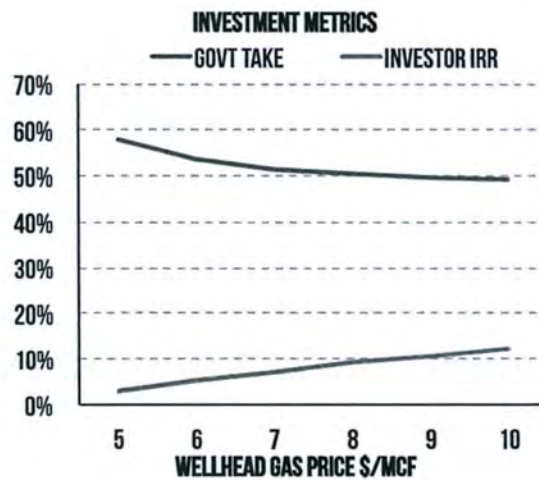
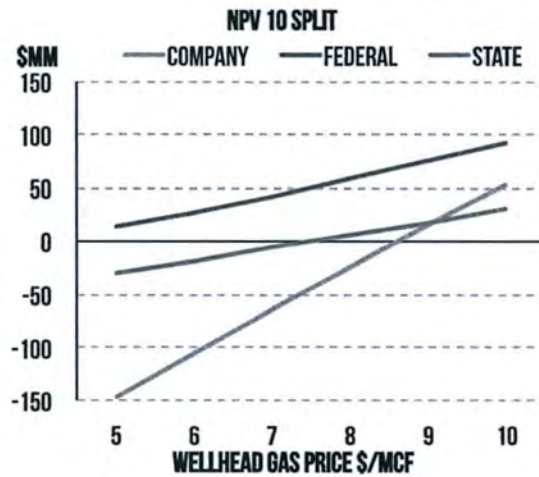


COOK INLET #1: MARKET CONSTRAINED (RESULTS)

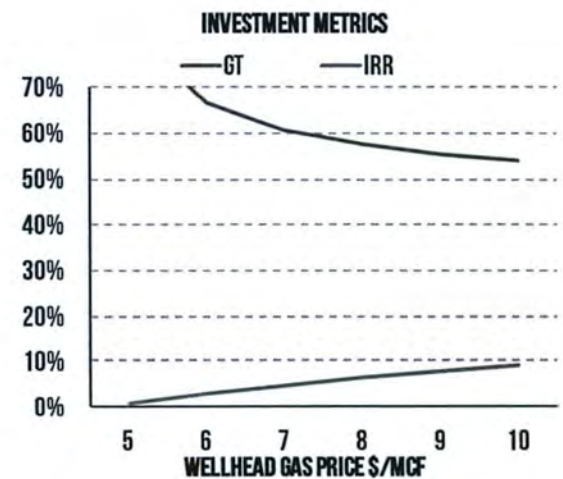
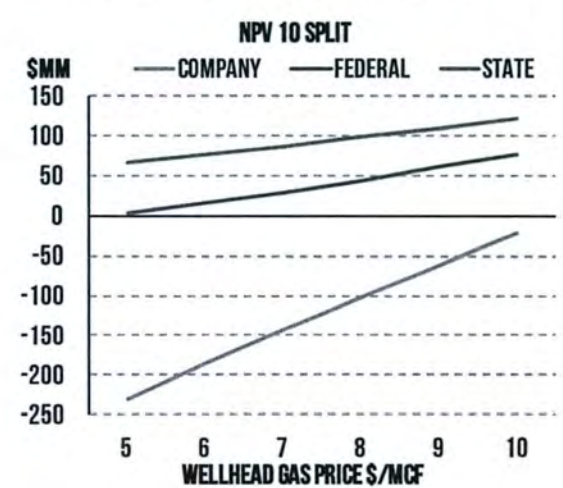
STATUS QUO



SB130: NOL ONLY



CS SB130: NO CREDITS

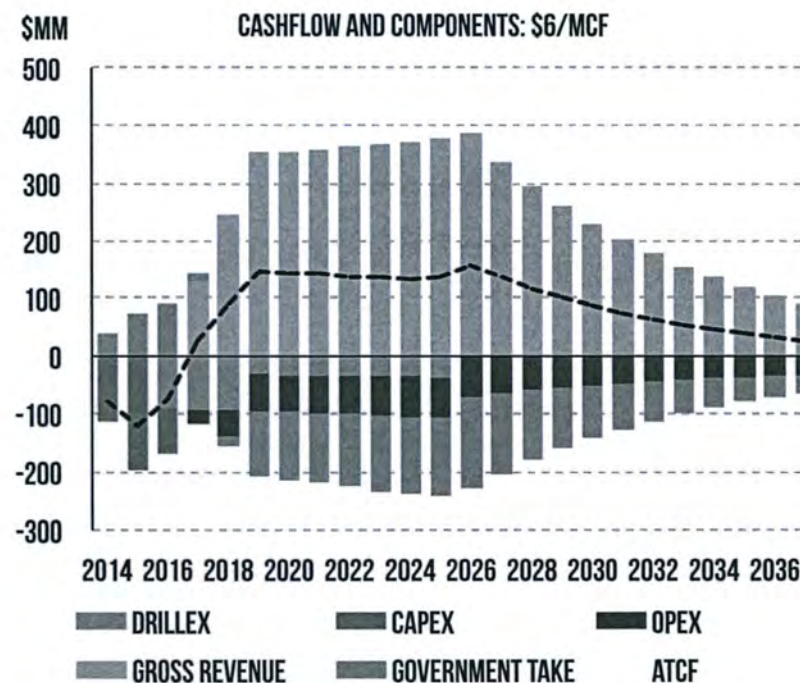
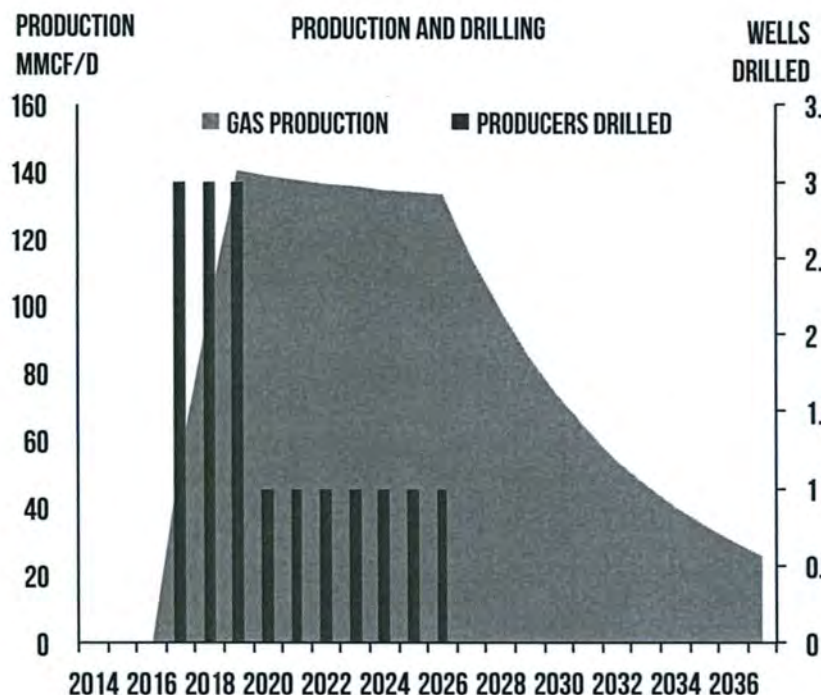


COOK INLET #2: UN-CONSTRAINED (ASSUMPTIONS)

Large upfront investment but un-constrained gas market

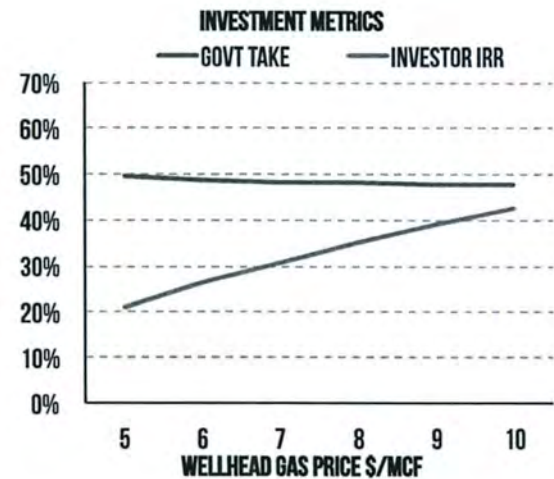
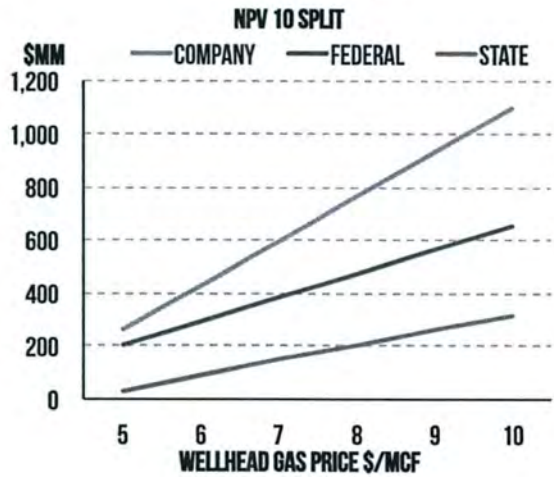
Continued drilling lead to a plateau of 130 mmcf/d

Scenario would require a step change in existing supply-demand dynamics in Cook Inlet

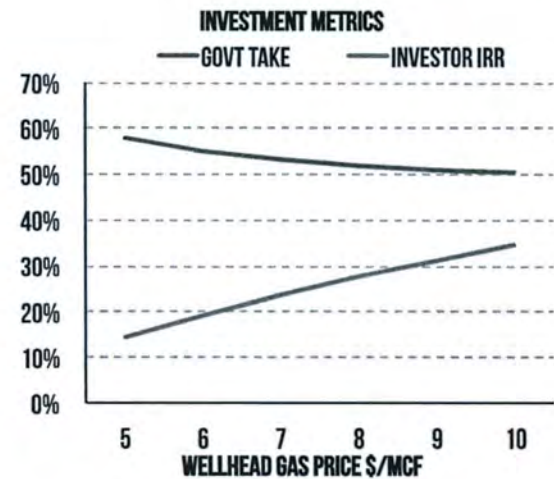
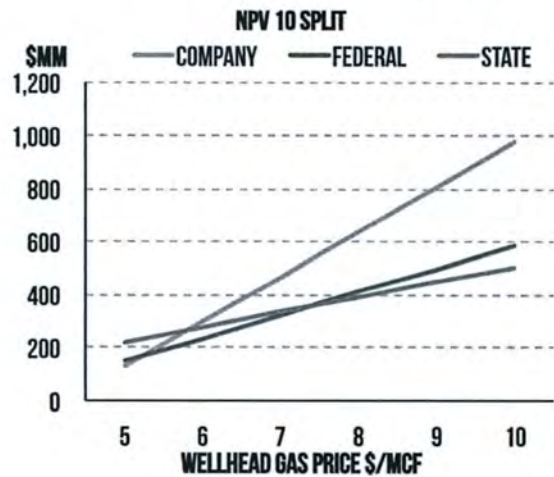


COOK INLET #2: UN-CONSTRAINED (RESULTS)

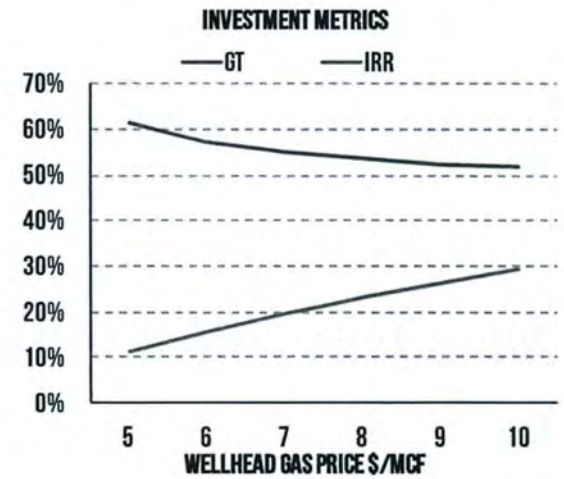
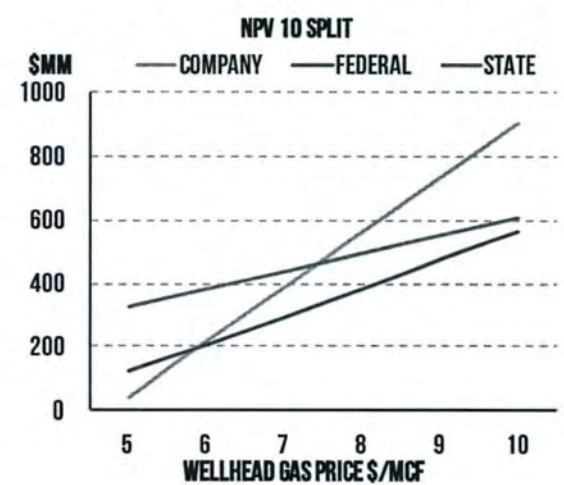
STATUS QUO



SB130: NOL ONLY



CS SB130: NO CREDITS

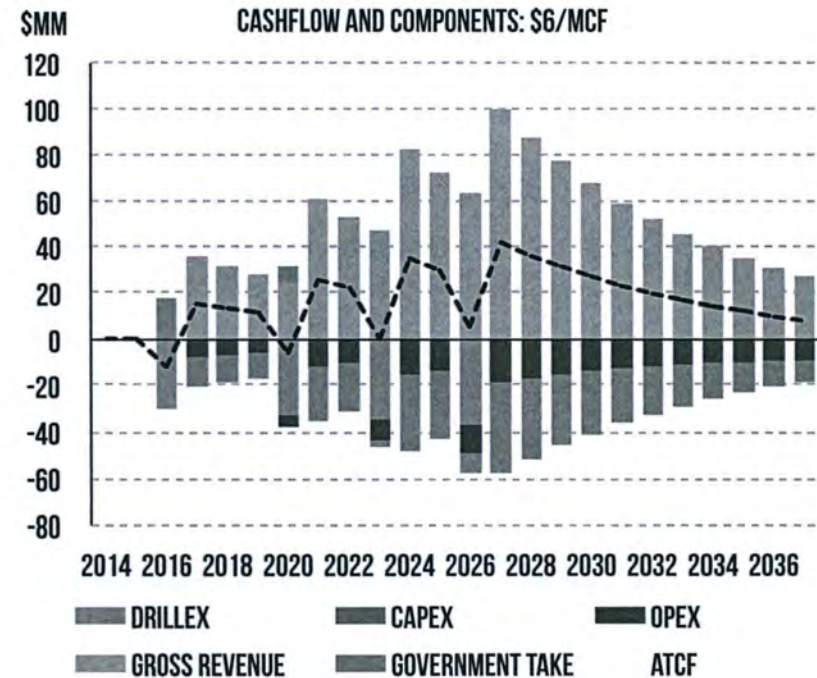
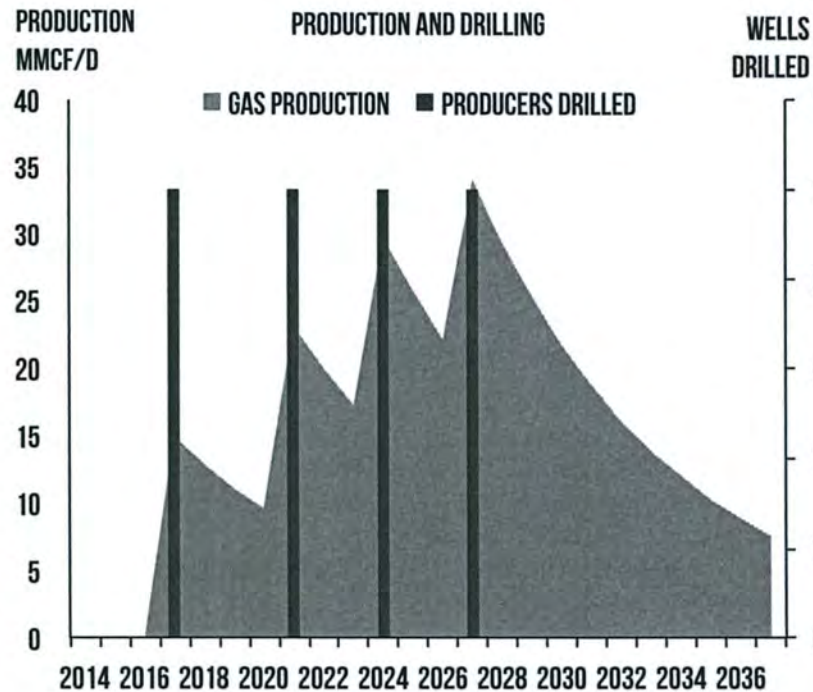


COOK INLET #3: DRILLING EXISTING FIELD (ASSUMPTIONS)

Drilling expenditures at existing production—smaller upfront investment

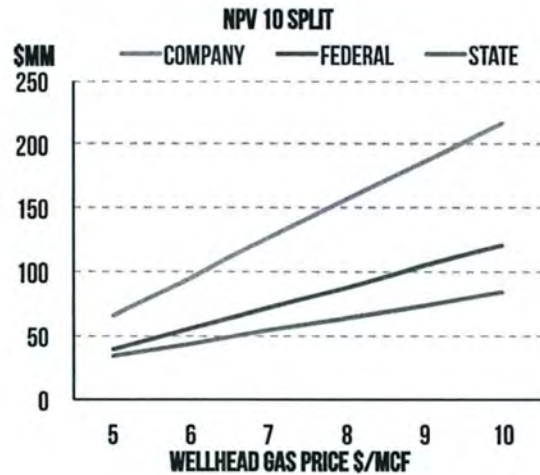
No market constrains assumed

This is a point-forward analysis—it ignores sunk, entry or acquisition costs

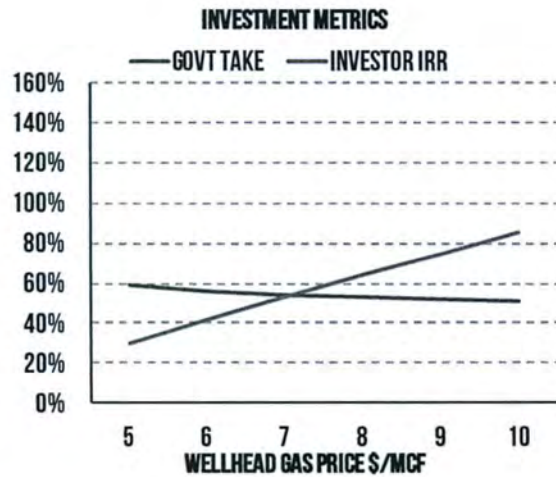
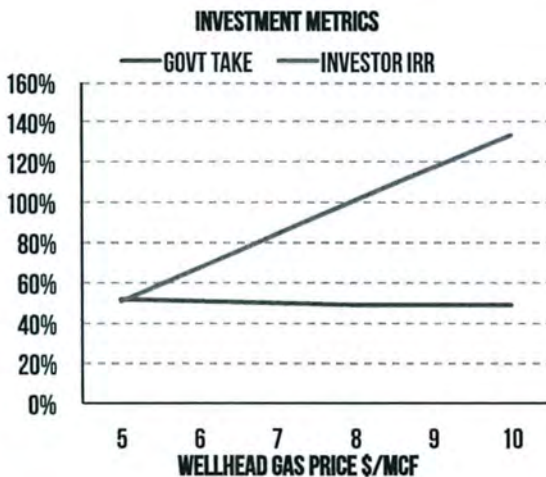
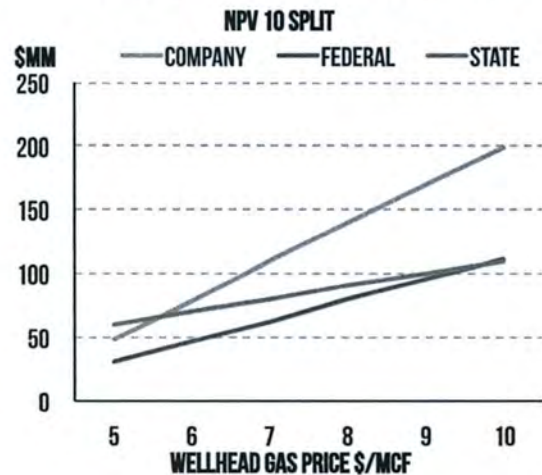


COOK INLET #3: DRILLING EXISTING FIELD (RESULTS)

STATUS QUO



SB130 & CS: NO CREDITS



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Kara Moriarty, President/CEO

AOGA Public Testimony on Committee Substitute for Senate Bill 130
Senate Resources Committee
April 12, 2016

Good Afternoon Morning Madam Chair and members of the Committee. For the record, my name is Kara Moriarty and I'm the President/CEO of the Alaska Oil and Gas Association, commonly referred to as "AOGA".

Thank you for the opportunity to testify as part of public testimony on the Committee Substitute for SB 130. Like others, we got the CS last night and we are still evaluating it and its impacts, but I do have unanimous consent of my diverse group of members to offer these initial thoughts this morning.

On Friday I was before this committee and testified on Governor Walker's original proposal. During that testimony, I shared four policy questions for your consideration as you evaluated the 6th oil and gas tax change in 11 years. Madam Chair, you said there were additional questions that you were also asking yourself. From our view, none of the questions have a positive answer.

- Will this increase production? Frankly the answer is no. This is a significant threat to Cook Inlet production. Dramatically and adversely changing the tax system in the Cook Inlet as proposed in the CS will decrease production of oil and gas in the Inlet. For the North Slope, there will also be a negative impact, especially on smaller fields. Alaska needs every company to be successful because the state needs increased production from every field and region. This CS will not add more production
- Will this make Alaska more competitive? Again, many of the proposals that were included in the Governor's bill remain in the Committee Substitute and make it very difficult to attract new investment and companies to Alaska.
- Will it provide predictability? The only thing that seems to be predictable, even with this CS,

is that the state will constantly change tax policies, regardless of oil price, and regardless of the economic condition of the industry. We hear that everyone has to pay something to solve the state's fiscal crisis. We would ask, what other industry is being asked to pay, or in our case, pay more when the state has clearly demonstrated that industry is losing money?

Your questions Madam Chair were:

- How will this CS affect Alaska families, businesses and jobs? If you passed this CS in its current form there would be less investment by companies, which will result in less production and job loss. You heard the passionate plea from Alaskans who have already suffered from the current economic situation on Saturday. Alaska families, businesses and jobs will continue to be affected in a negative way.
- Lastly, will this CS provide stability? We recognize that many of you are looking for ways to fill the state's budget gap and you see increasing taxes on the oil industry as part of the solution to create a stable environment for Alaska. Our job is to tell you how the industry will react to those changing policies. Again, we still need more time to evaluate the CS you are proposing to adopt, but the CS is bad for Alaska. It is destined to make the economic situation for the industry even worse, and when the industry suffers, the state suffers too. And if policy makers do not find a way to solve the entire solution for the state this year, our fear is we will find ourselves in a similar situation next year.

Again, as I said on Friday, the industry is not asking for a tax decrease or for tax or royalty relief while we struggle through extraordinarily low prices and we asked that you proceed with caution. The tax policy you have proposed will not encourage new entrants to come to Alaska, will not ensure current producers will remain committed to Alaska, will not lead to more jobs or more production, will not lead to more long-term revenues to the state, and will not improve Alaska's long-term fiscal future.