

SB 21

(FILE 1)

<TARGET><BILL>SB 21</BILL><SUBJECT>SB 21 (FILE
1)</SUBJECT><COMM>HRES28</COMM></TARGET>

House Resources Committee

Tuesday, April 2nd

Continuation of April 1 meeting

Reconvene from the morning's recess

House CS CSSB21 (RES)

Presenting today will be:

Mike Pawlowski - DOR Advisor

Dan Stickel - Assistant Chief Economist for DOR

Barry Pulliam – EconOne

Janak Mayer – PFC Energy

In Audience for Questions from DNR:

Joe Balash, Deputy Commissioner

Bill Barron – Director, Division of O&G

On Line for Questions from DOR:

Matt Fonder, Director – Tax Division

Lennie Dees, Audit Master

John Larsen, Audit Master

Dona Keppers, Audit Master

Tim Ryherd, Commercial Analyst

Cherie Nienhuis, Commercial Analyst

John Tichotski, Chief Economist

Ed King, Petroleum Economist II



Preliminary Fiscal Impact

HCS CSSB21(RES)

*For Presentation to the
House Resources Committee*

April 2, 2013



Introduction



1. 12 key provisions analyzed
2. Total fiscal impact under Fall 2012 forecast
3. Hypothetical additional production scenarios

Note: presentation assumes an effective date of January 1, 2014 for major provisions.



1. Repeals progressive surcharge



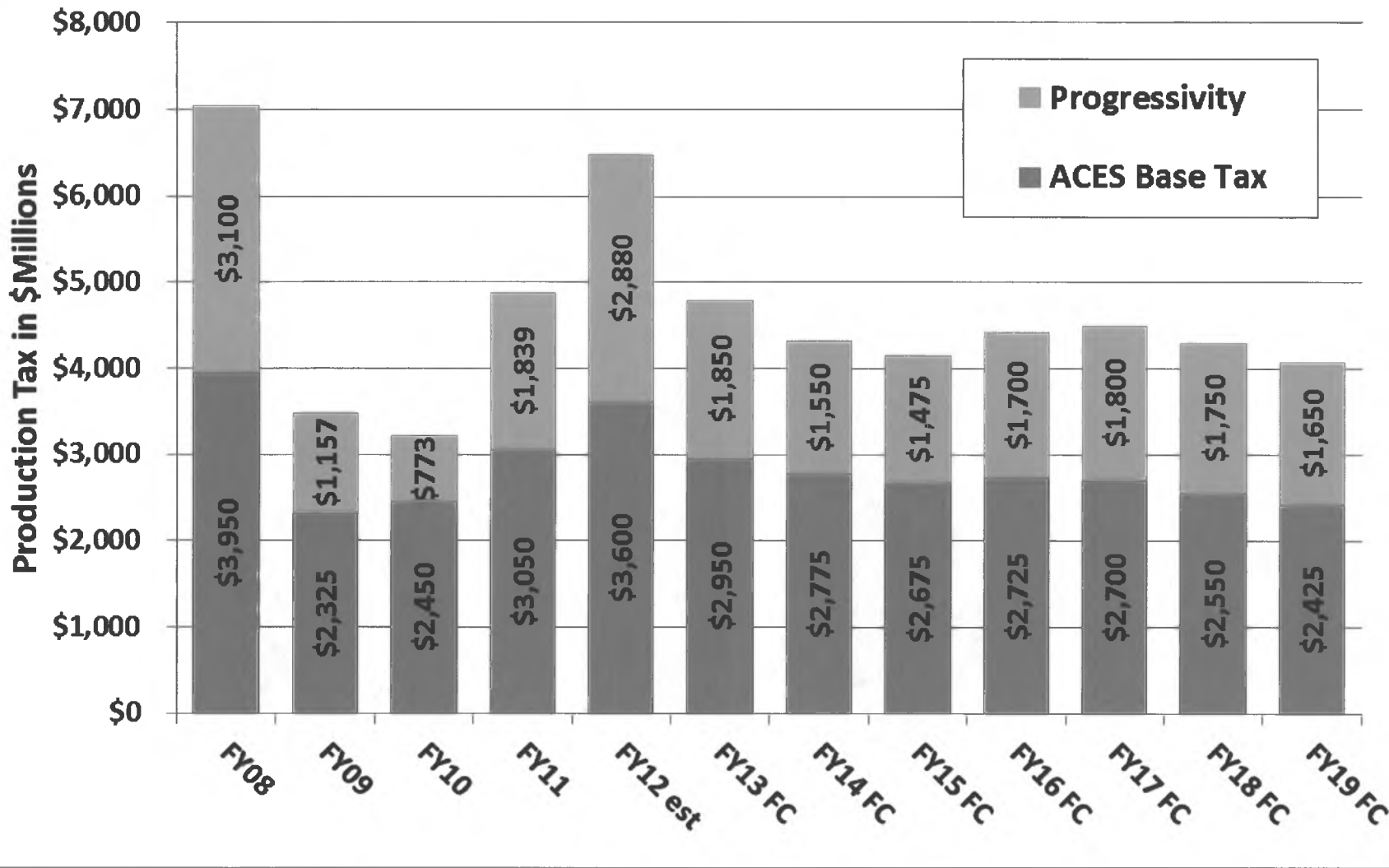
- Progressive surcharge at AS 43.55.011(g) repealed
- Progressive surcharge is an additional tax that is added to base tax
- Progressive surcharge increases tax rate at production tax values of greater than \$30 / barrel
- Progressive surcharge may add up to 50% to the total tax rate at very high prices for a maximum total tax rate of 75%
- Fiscal Impact = varies by fiscal year, up to \$1.8 billion per year under our Fall 2012 forecast



Impact of Progressive Surcharge



Production Tax Revenue before Credits under ACES





2. Increases base production tax rate



- Base tax rate increased to 35% from 25% under ACES
- Base tax rate of 35% applied to production tax value
- The higher base tax rate increases revenue from the base tax
- The higher base tax rate provides greater protection to the state at low oil prices
- Fiscal Impact = varies by fiscal year, up to \$1.1 billion per year under our Fall 2012 forecast



3. Limitations on capital credits



- Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 for the North Slope
- 20% capital credit eliminated for North Slope after 1/1/2014 (replaced with new mechanisms that incentivize production, not spending).
- ACES provisions are unchanged for Cook Inlet and Middle Earth and they retain 20% capital credit
- Since capital credits are taken against liability or refunded, fiscal impact is on both revenue and budget
- Likely fiscal impact is summarized on following slide



Estimated Fiscal Impact for limitations on credits as compared to Fall 2012 Forecast (\$millions)



	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
NS capital credits against tax liability	\$300	\$700	\$650	\$550	\$475	\$400
NS capital credits for refund	\$0	\$150	\$150	\$150	\$150	\$150
Total Fiscal Impact	\$300	\$850	\$800	\$700	\$625	\$550

Note: these are positive fiscal impacts.



4. Changes to Net Operating Loss credit



- Companies that incur net losses from oil and gas operations on the North Slope will earn a credit of 35% of those losses, a 10% increase over the 25% credit provided in ACES.
 - Transferable credit.
 - Eligible for refund by the state.
- The revenue impact of this provision is -\$40 million per year over the amount forecasted under ACES



5. Establishes Gross Value Reduction (GVR)



- Concept formerly known as “Gross Revenue Exclusion” or “GRE”
- For qualifying production, excludes 20% of gross value at the point of production before calculating production tax value
- Qualifying production is any of the following:
 - Land was not in a unit on 1/1/2003
 - Produced within a participating area (PA) established after December 31, 2011, in a unit formed before 1/1/2003, if participating area does not contain a reservoir that had been in a PA established before 12/31/2011
 - Produced from acreage that was added to an existing PA after December 31, 2012.
- Fiscal Impact = Indeterminate, under \$50 million / year under Fall 2012 forecast
- GVR benefit would apply almost entirely to “New Production” which is not currently included in our forecast. The fiscal impact that we are including in the analysis refers only to production in our forecast that is likely to qualify.



6. Eliminates requirement that credits be taken over two years



- Capital credits and Net Operating Loss credits earned had to be split across two years under ACES
- This provision allows credits to be used in the year they were earned
- This provision aligns credit treatment on the North Slope with credit treatment in all other parts of the state
- Fiscal impact is neutral – simply shifts a future obligation to FY14.
- \$400 million total obligation shifted to FY14: \$250 million revenue impact; \$150 million operating budget impact



7. Changes funding source for community revenue sharing



- The community revenue sharing fund is amended to allow the legislature to make appropriations from the tax revenue collected under AS 43.20, as opposed to revenue collected under the provision that is proposed to be repealed - AS 43.55.011(g).
- Corporate income tax revenue under AS 43.20 is adequate to provide the maximum annual appropriation of \$60 million or the amount to bring the fund up to \$180 million.
 - Corporate income tax has exceeded \$500 million every year for the last 8 years.
- Zero fiscal impact.



8. Establishes per oil barrel tax credit



- \$5 credit per taxable barrel for oil production subject to GVR.
 - Must be applied against tax liability and cannot cause tax liability to be less than zero
 - Cannot be saved, does not accrue interest, is not transferable
 - Ties credit to production
- Sliding scale for Non-GVR eligible oil production.
 - Scale is progressive on GVPP (wellhead) value per barrel of oil starting at \$8/barrel at wellhead prices up to \$80/barrel down to \$0/barrel at wellhead prices over \$150/barrel
 - Sliding scale is at rate of \$1 credit per \$10 wellhead price
 - Adds a slightly progressive feature to the system
- Likely fiscal impact is summarized on next slide



Estimated Fiscal Impact for \$5 per oil barrel and sliding scale credit* as compared to Fall 2012 Forecast (\$millions)



FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
-\$425	-\$825	-\$775	-\$750	-\$700	-\$675

* At forecast prices the per barrel credit is \$5 on the sliding scale.



9. Creates service industry expenditures credit



- New Corporate Income Tax Credit for oil and gas service companies
- Credit is 10% of qualifying in-state expenditures:
 - Manufacturing of oil and gas equipment
 - Modification of oil and gas equipment
 - For in-state spending only
- Maximum \$10 million per taxpayer per year
- Non-transferable; any amount of the credit that exceeds the taxpayer's liability under AS 43.20 may be carried forward for 5 years.
- Fiscal Impact = Indeterminate, less than \$25 million / year
- Difficult to estimate due to lack of data



10. Interest rate on delinquent taxes changed



- Currently the higher of 5 percentage points above the annual rate of interest charged by the 12th Federal Reserve District or 11 percent.
- Changed to 3 percentage points above the annual rate of interest charged by the 12th Federal Reserve District.
- Change applied to interest charged on delinquent taxes and refunds and assessments for most taxes administered by DOR.
- Fiscal impacts include \$100,000 for DOR accounting system changes.
- Fiscal impact is estimated to be up to -\$25 million per year, increasing over time as more delinquent taxes are calculated under the new interest rates established with this provision.
- Our fiscal impact estimates do not take into account changes in taxpayer behavior as a result of this reduction in interest rate.



11. Removes 3-mile requirement for “Middle Earth” frontier basin credit



- Explanation:
 - Removes requirement that well be 3 miles from existing well to qualify for credit
 - Applies to frontier basin credit in AS 43.55.025(a)(6)
 - Credit is 80% of eligible drilling expenditures, up to \$25 million, for first four eligible wells
 - Drilled before July 1, 2016 in qualifying frontier basin
 - Must be a new target pre-approved by DNR
 - Well data shared with DNR
 - Credit is transferable
 - Cannot take this credit along with NOL credit
- Fiscal Impact already accounted for in Fall 2012 forecast



12. Establishes Competitiveness Review Board



- New state board within DOR
- 9 member board, 1 meeting per year
- Tasked with collecting and evaluating data on oil and gas development, and providing annual report to Legislature on proposed changes to fiscal system
- Fiscal Impact = Estimated at \$180,000 / year
- Not included in Tax fiscal note – separate Commissioner’s office fiscal note
- Represents costs for travel and use of existing staff

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Fall 2012 Forecast (\$millions)¹

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-\$800	-\$1,500	-\$1,700	-\$1,800	-\$1,750	-\$1,650
2. Base tax rate changed to 35% of production tax value	\$550	\$1,075	\$1,100	\$1,075	\$1,025	\$975
3. Limitation of credits for qualified capital expenditures for North Slope	\$300	\$700	\$650	\$550	\$475	\$400
4. Net operating loss credit rate increased to 35%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross value reduction for oil production in new units and new or expanded participating areas	\$0	-\$25	-\$25	-\$50	-\$25	-\$50
6. Provision requiring credits be taken over 2 years eliminated ²	-\$250					
7. Amendment to the community revenue sharing fund	\$0	\$0	\$0	\$0	\$0	\$0
8. Credit of \$5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-\$425	-\$825	-\$775	-\$750	-\$700	-\$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -\$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -\$25 million annually, increasing over time)					
11. Requirements regarding 3-mile limitation on .025 exploration credits changed for Frontier Basin Credit	\$0	\$0	\$0	\$0	\$0	\$0
Total Revenue Impact	-\$625 to -\$675	-\$575 to -\$625	-\$750 to -\$800	-\$975 to -\$1025	-\$975 to -\$1025	-\$1000 to -\$1050
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-\$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		\$150	\$150	\$150	\$150	\$150
Impact on Operating Budget of increase in Net Operating Loss credits		-\$40	-\$40	-\$40	-\$40	-\$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production³	-\$775 to -\$825	-\$465 to -\$515	-\$640 to -\$690	-\$865 to -\$915	-\$865 to -\$915	-\$890 to -\$940

¹The impacts listed are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between \$109.61 and \$118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is \$400 million, with \$250 million taken against tax liability as a revenue impact and \$150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

³NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in



Production Scenarios



Scenario A:

- New 50 Million barrel field developed by small producer without tax liability
- Peak production = 10,000 bbls/day
- Development costs = \$500,000,000
- Qualifies for GRE and NOL



Production Scenarios



Scenario B:

- Operators of existing units add 4 drill rigs to current plans
- Each rig adds 4,000 bbls/day in new production each year
 - Which each then decline at 15% per year
- Does not qualify for GRE



Production Scenarios

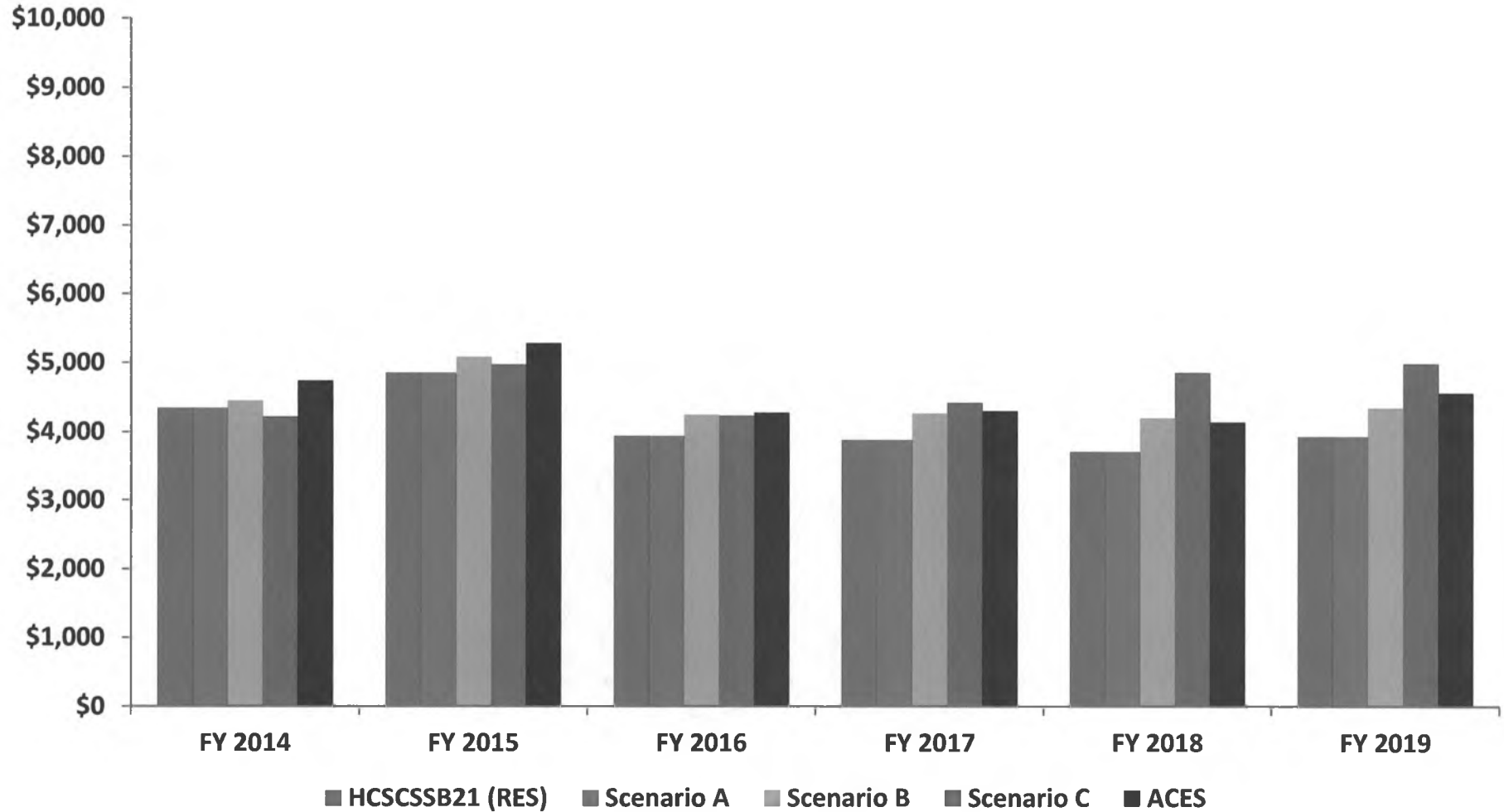


Scenario C:

- Operator of existing legacy unit builds new drill pad
- Development cost = \$5 billion
- Adds 15,000 bbls/day in 2014 increasing to peak rate of 90,000 bbls/day in 2018
- Does not qualify for GRE



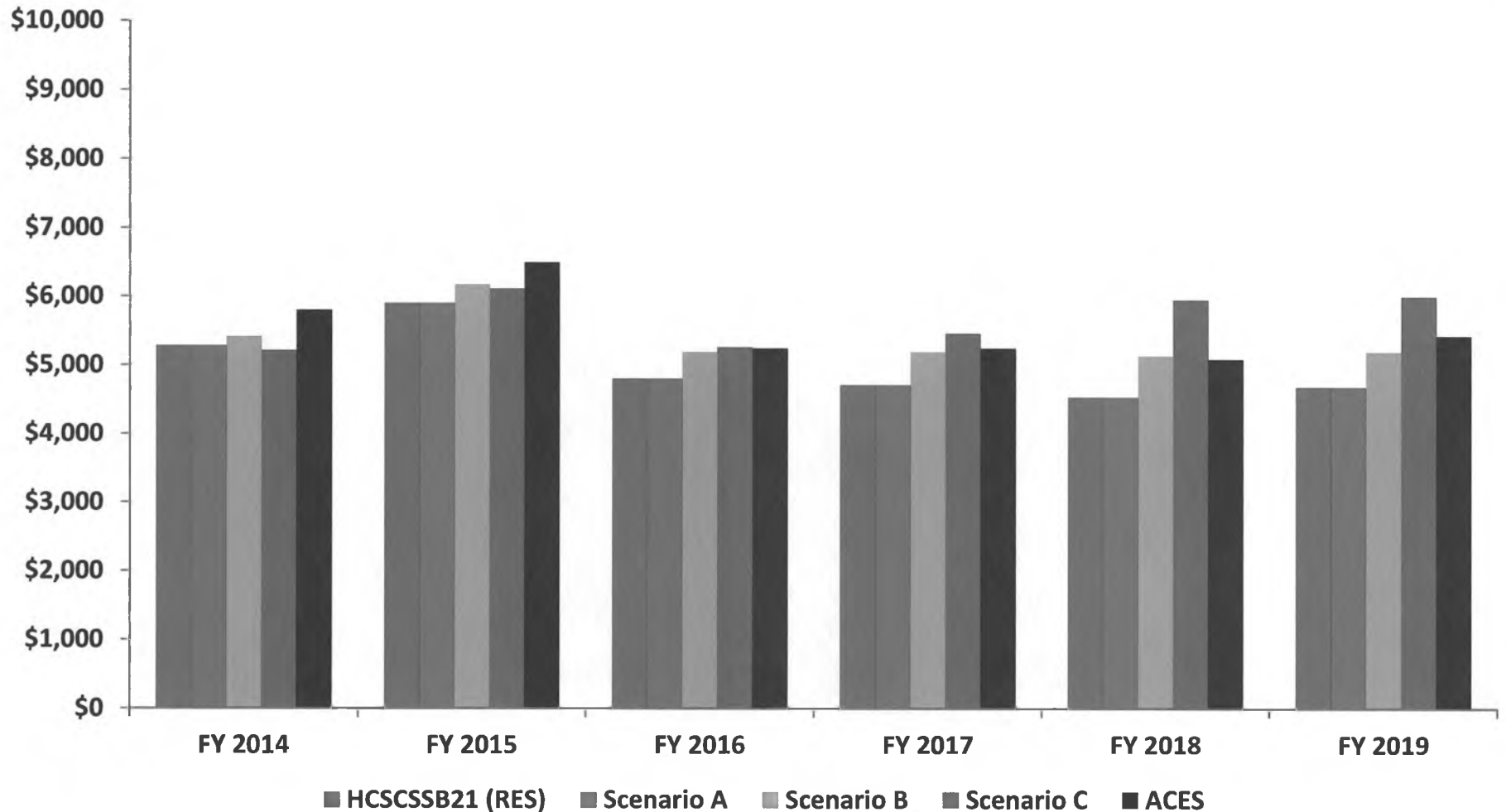
Projected revenues under production scenarios – at \$90 / barrel ANS



Note: Compares HCS CSSB21(RES) under several production scenarios, to ACES under forecast production.



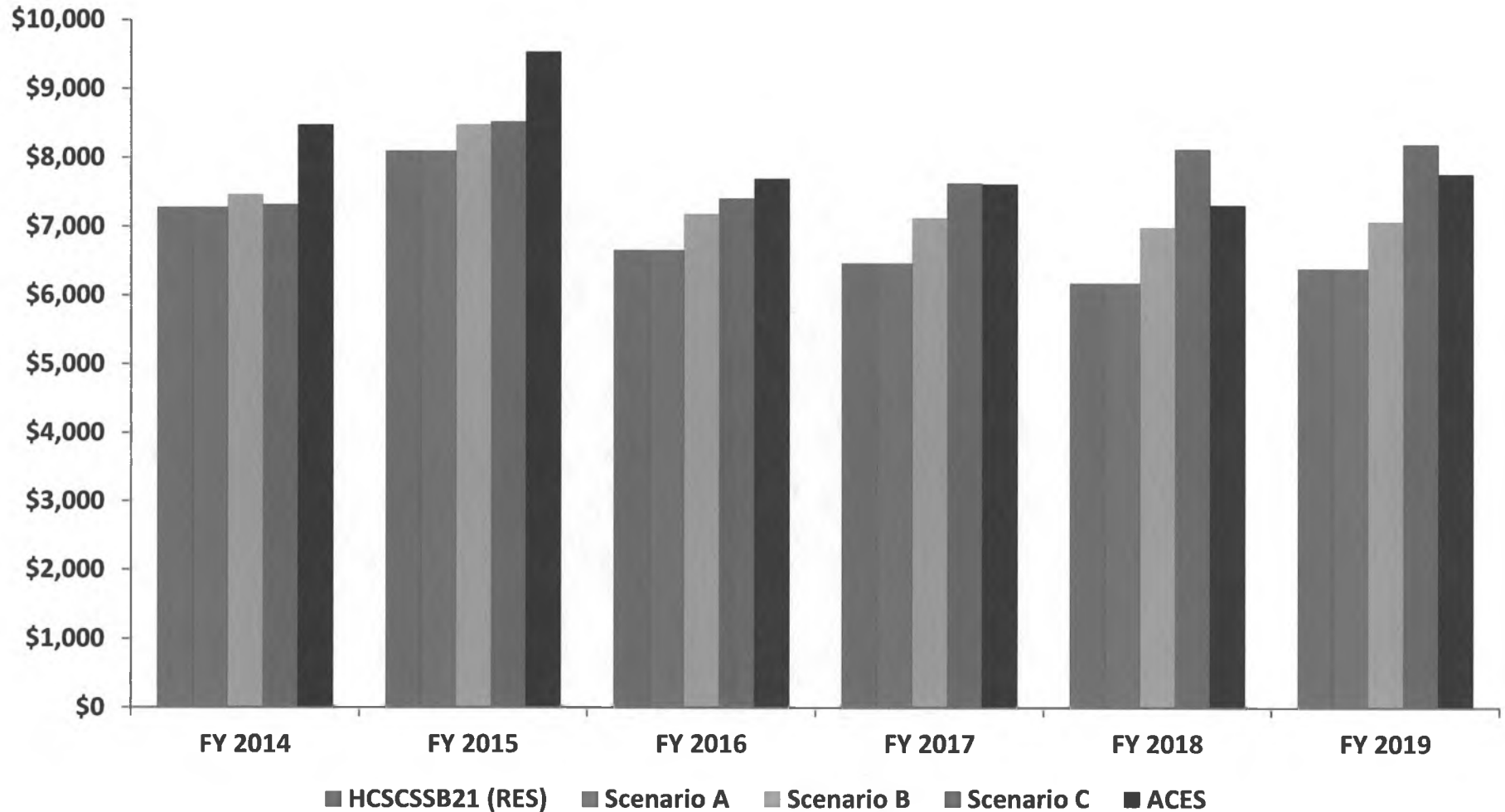
Projected revenues under production scenarios – at \$100 / barrel ANS



Note: Compares HCS CSSB21(RES) under several production scenarios, to ACES under forecast production.



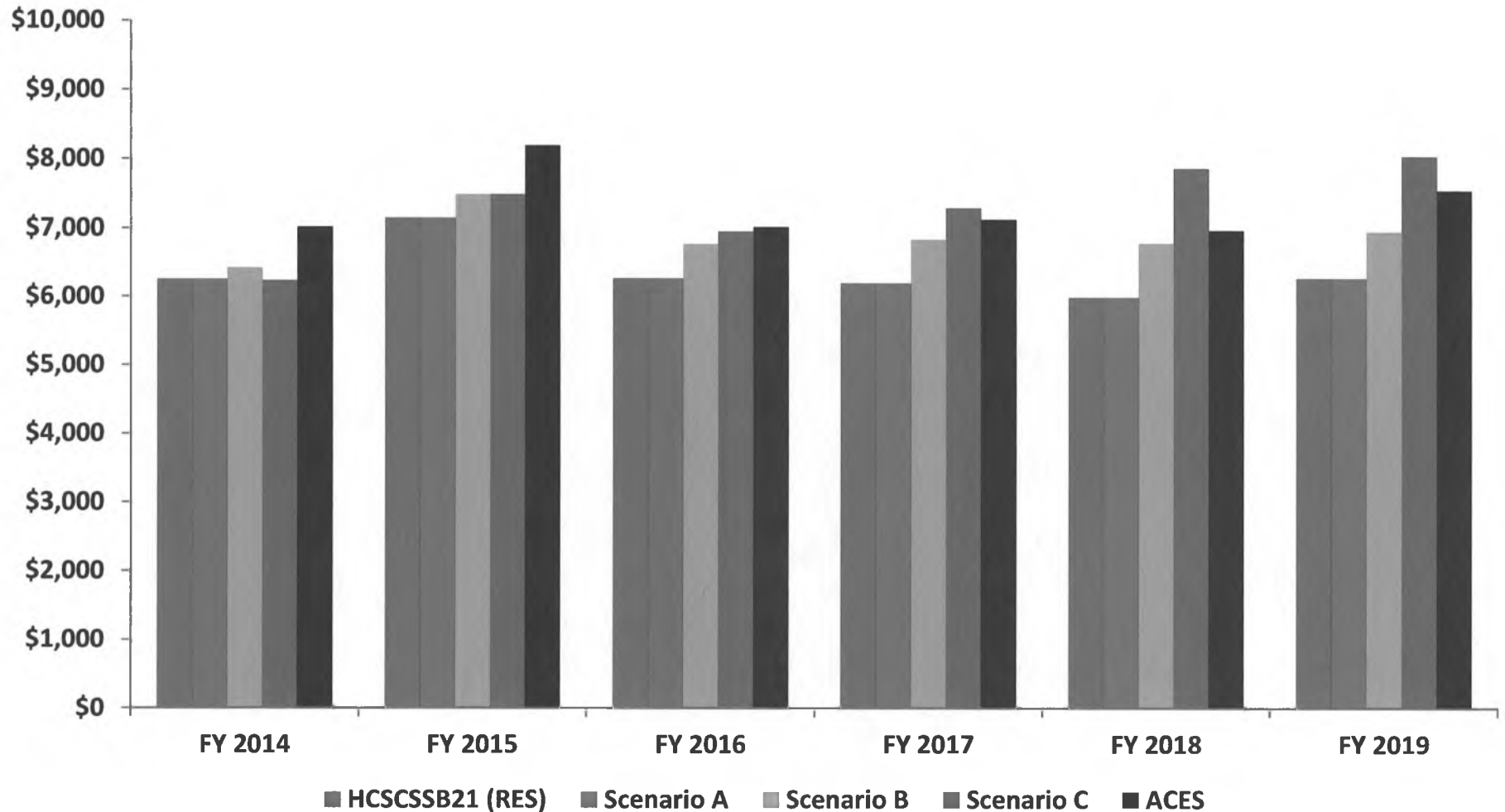
Projected revenues under production scenarios – at \$120 / barrel ANS



Note: Compares HCS CSSB21(RES) under several production scenarios, to ACES under forecast production.



Projected revenues under production scenarios – at forecast ANS price



Note: Compares HCS CSSB21(RES) under several production scenarios, to ACES under forecast production.



Thank You



House Resources Committee

Alaska Fiscal System Discussion Slides

April 2 2013
Janak Mayer
Manager, Upstream
PFC Energy

\$5 production credit like 'reverse progressivity'...

Taxable Production (mmb)	50	50	50	50	50	50	50	50	50	50	50	50
ANS West Coast	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	\$ 130	\$ 140	\$ 150	\$ 160	
Transportation	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10
Gross Value at Point of Production	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	\$ 6,500	\$ 7,000	\$ 7,500	
Lease Expenditures	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500
GVPP/bbl	\$ 50	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	\$ 130	\$ 140	\$ 150	
Lease Expenditures / bbl	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30
PTV before GRE	\$ 1,000	\$ 1,500	\$ 2,000	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	
Prod tax without GRE	\$ 350	\$ 525	\$ 700	\$ 875	\$ 1,050	\$ 1,225	\$ 1,400	\$ 1,575	\$ 1,750	\$ 1,925	\$ 2,100	
GRE	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
PTV	\$ 1,000	\$ 1,500	\$ 2,000	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	
PTV/bbl	\$ 20	\$ 30	\$ 40	\$ 50	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	
Production Tax without Allowance	\$ 350	\$ 525	\$ 700	\$ 875	\$ 1,050	\$ 1,225	\$ 1,400	\$ 1,575	\$ 1,750	\$ 1,925	\$ 2,100	
Production Allowance / bbl	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5
Production Allowance	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250
Production Tax	\$ 100	\$ 275	\$ 450	\$ 625	\$ 800	\$ 975	\$ 1,150	\$ 1,325	\$ 1,500	\$ 1,675	\$ 1,850	
Nominal Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Rate after Allowance	10.0%	18.3%	22.5%	25.0%	26.7%	27.9%	28.8%	29.4%	30.0%	30.5%	30.8%	
Progressive Tax Rate Deduction	25.0%	16.7%	12.5%	10.0%	8.3%	7.1%	6.3%	5.6%	5.0%	4.5%	4.2%	

Just sufficiently 'progressive' to counteract effect of royalty and achieve overall neutrality

...variable production credit increases progressive effect...

Taxable Production (mmb)	50	50	50	50	50	50	50	50	50	50	50	50
ANS West Coast	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	\$ 130	\$ 140	\$ 150	\$ 160	
Transportation	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10	\$ 10
Gross Value at Point of Production	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	\$ 6,500	\$ 7,000	\$ 7,500	
Lease Expenditures	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500
GVPP/bbl	\$ 50	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	\$ 130	\$ 140	\$ 150	
Lease Expenditures / bbl	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30
PTV before GRE	\$ 1,000	\$ 1,500	\$ 2,000	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	
Prod tax without GRE	\$ 350	\$ 525	\$ 700	\$ 875	\$ 1,050	\$ 1,225	\$ 1,400	\$ 1,575	\$ 1,750	\$ 1,925	\$ 2,100	
GRE	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
PTV	\$ 1,000	\$ 1,500	\$ 2,000	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	
PTV/bbl	\$ 20	\$ 30	\$ 40	\$ 50	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	
Production Tax without Allowance	\$ 350	\$ 525	\$ 700	\$ 875	\$ 1,050	\$ 1,225	\$ 1,400	\$ 1,575	\$ 1,750	\$ 1,925	\$ 2,100	
Production Allowance / bbl	\$ 8	\$ 8	\$ 8	\$ 7	\$ 6	\$ 5	\$ 4	\$ 3	\$ 2	\$ 1	\$ -	
Production Allowance	\$ 400	\$ 400	\$ 400	\$ 350	\$ 300	\$ 250	\$ 200	\$ 150	\$ 100	\$ 50	\$ -	
Production Tax	\$ -	\$ 125	\$ 300	\$ 525	\$ 750	\$ 975	\$ 1,200	\$ 1,425	\$ 1,650	\$ 1,875	\$ 2,100	
Nominal Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Rate after Allowance	0.0%	8.3%	15.0%	21.0%	25.0%	27.9%	30.0%	31.7%	33.0%	34.1%	35.0%	
Progressive Tax Rate Deduction	35.0%	26.7%	20.0%	14.0%	10.0%	7.1%	5.0%	3.3%	2.0%	0.9%	0.0%	

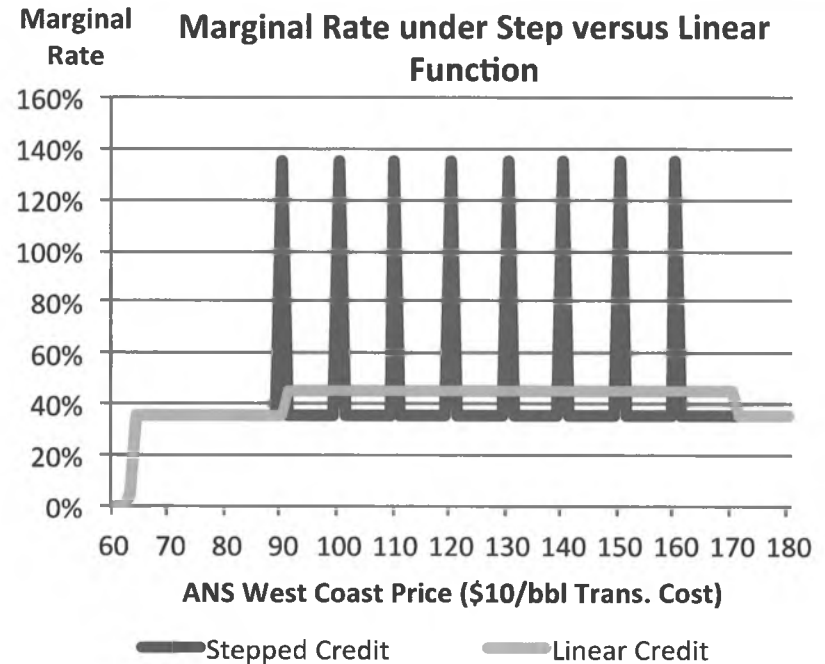
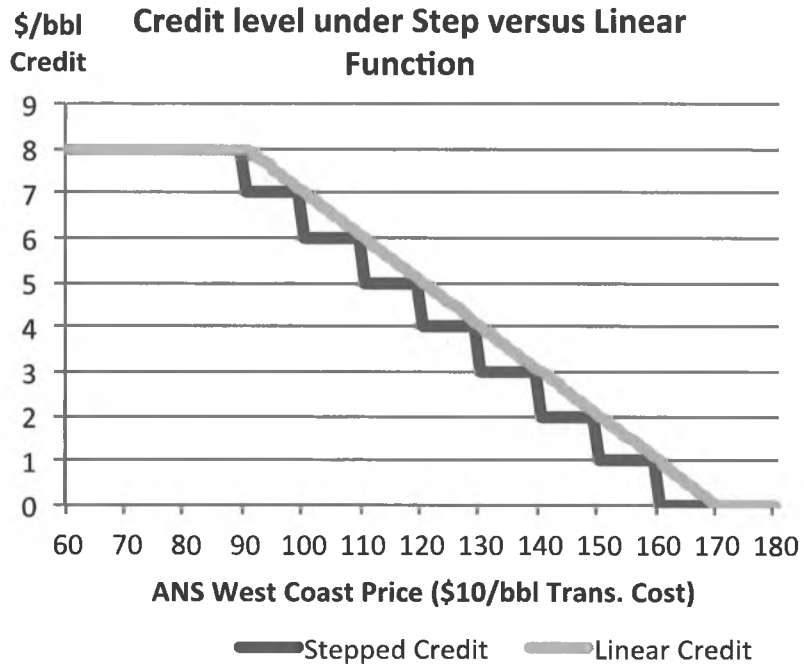
More progressive, reducing rates below \$110, and increasing them above

change to 7 or 6

...but rates with fixed \$5/bbl credit and GVR are lower

Taxable Production (mmb)	50	50	50	50	50	50	50	50	50	50	50	50
ANS West Coast	60	70	80	90	100	110	120	130	140	150	160	
Transportation	10	10	10	10	10	10	10	10	10	10	10	10
Gross Value at Point of Production	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	\$ 6,500	\$ 7,000	\$ 7,500	
Lease Expenditures	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500	\$ 1,500
GVPP/bbl	\$ 50	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	\$ 130	\$ 140	\$ 150	
Lease Expenditures / bbl	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30	\$ 30
PTV before GRE	\$ 1,000	\$ 1,500	\$ 2,000	\$ 2,500	\$ 3,000	\$ 3,500	\$ 4,000	\$ 4,500	\$ 5,000	\$ 5,500	\$ 6,000	
Prod tax without GRE	\$ 350	\$ 525	\$ 700	\$ 875	\$ 1,050	\$ 1,225	\$ 1,400	\$ 1,575	\$ 1,750	\$ 1,925	\$ 2,100	
GRE	\$ 500	\$ 600	\$ 700	\$ 800	\$ 900	\$ 1,000	\$ 1,100	\$ 1,200	\$ 1,300	\$ 1,400	\$ 1,500	
PTV	\$ 500	\$ 900	\$ 1,300	\$ 1,700	\$ 2,100	\$ 2,500	\$ 2,900	\$ 3,300	\$ 3,700	\$ 4,100	\$ 4,500	
PTV/bbl	\$ 20	\$ 30	\$ 40	\$ 50	\$ 60	\$ 70	\$ 80	\$ 90	\$ 100	\$ 110	\$ 120	
Production Tax without Allowance	\$ 175	\$ 315	\$ 455	\$ 595	\$ 735	\$ 875	\$ 1,015	\$ 1,155	\$ 1,295	\$ 1,435	\$ 1,575	
Production Allowance / bbl	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5
Production Allowance	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250
Production Tax	\$ -	\$ 65	\$ 205	\$ 345	\$ 485	\$ 625	\$ 765	\$ 905	\$ 1,045	\$ 1,185	\$ 1,325	
Nominal Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Rate after Allowance and GRE	0.0%	4.3%	10.3%	13.8%	16.2%	17.9%	19.1%	20.1%	20.9%	21.5%	22.1%	
Progressive Tax Rate Deduction	35.0%	30.7%	24.8%	21.2%	18.8%	17.1%	15.9%	14.9%	14.1%	13.5%	12.9%	

Linear Function for Credit may be preferable to Step Function



GVPP Below	Stepped Credit
\$80	\$8
\$90	\$7
\$100	\$6
\$110	\$5
\$120	\$4
\$130	\$3
\$140	\$2
\$150	\$1
\$160	\$0

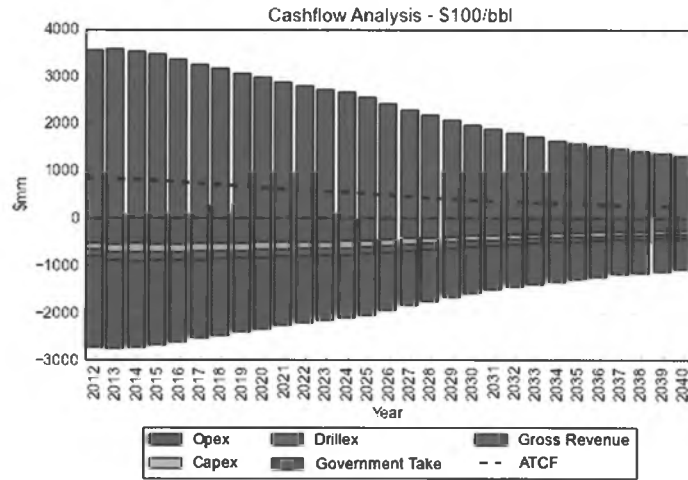
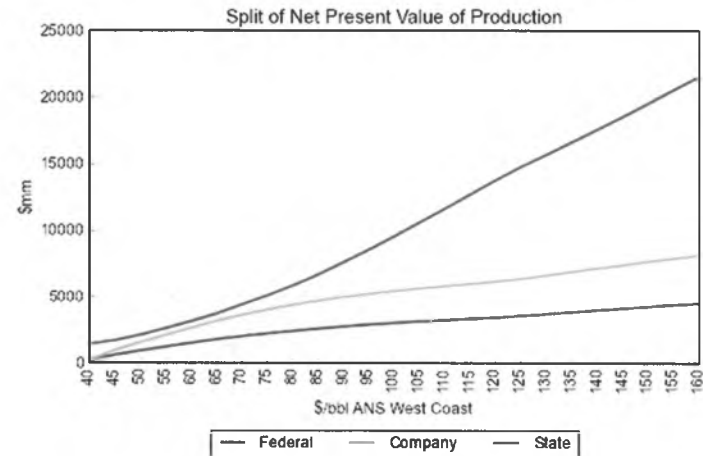
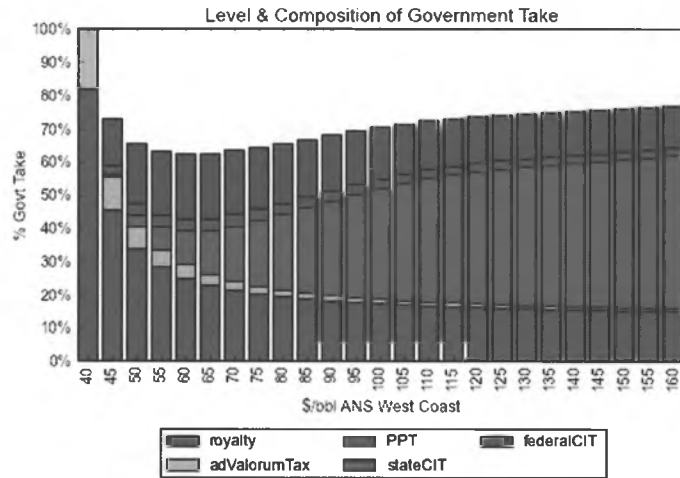
Linear Credit Function

$$\text{Credit} = \text{Max}(0, \text{Min}(8, 16 - (\text{GVPP}/10)))$$

\$16 minus one tenth of the Gross Value of Production; not to exceed \$8 or be below \$0

ACES – Base Production

ACES, 12.5% Royalty, Base Production

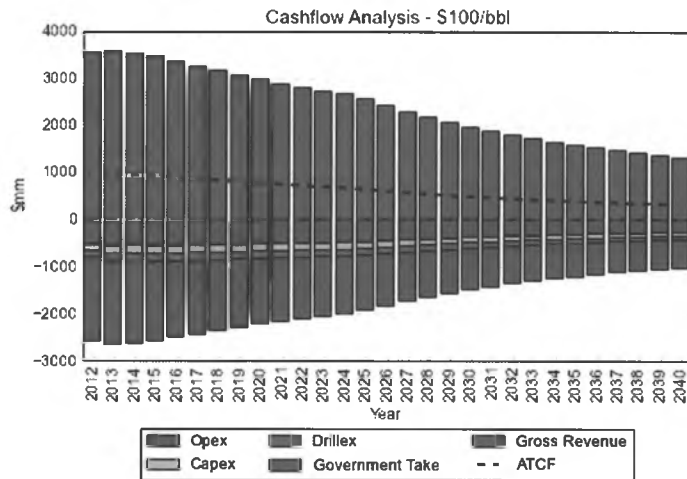
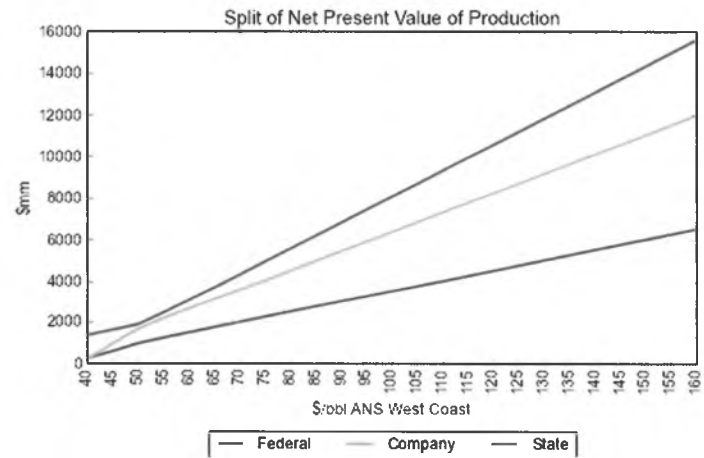
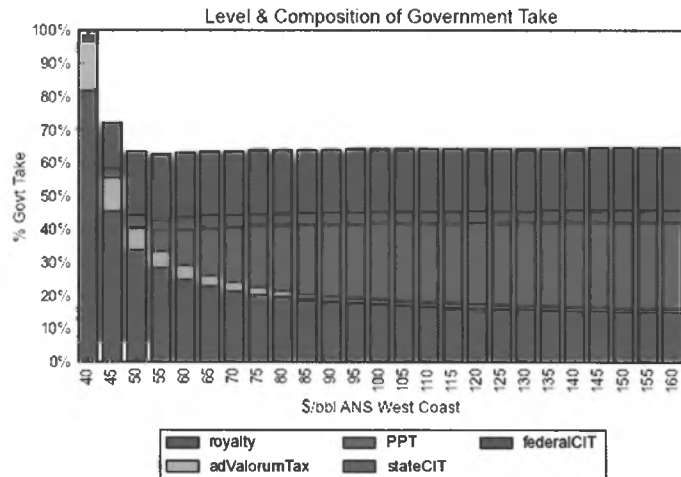


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	65.89%	4.18		19.04
\$100/bbl	70.65%	5.26		23.92
\$120/bbl	73.92%	6.0		27.09
\$140/bbl	75.46%	6.97		31.89

SB21 Base Production

SB21, 12.5% Royalty, Base Production

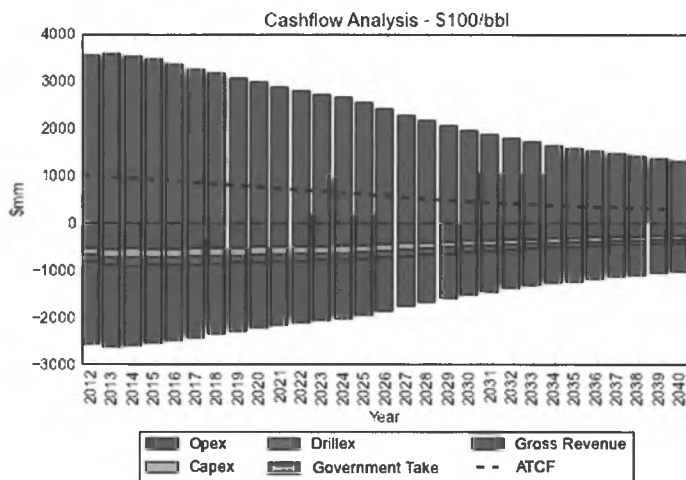
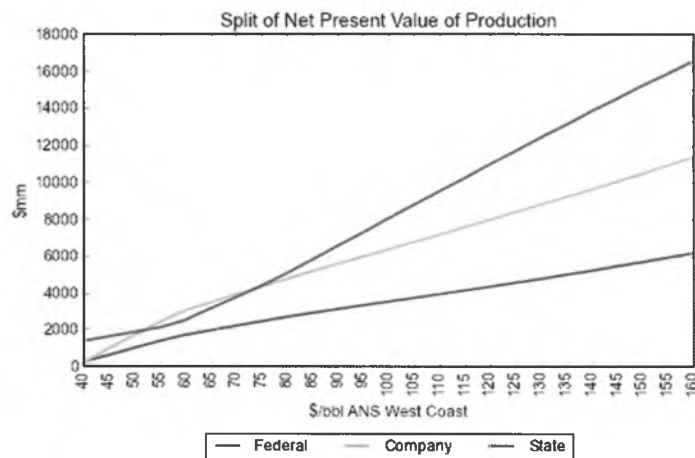
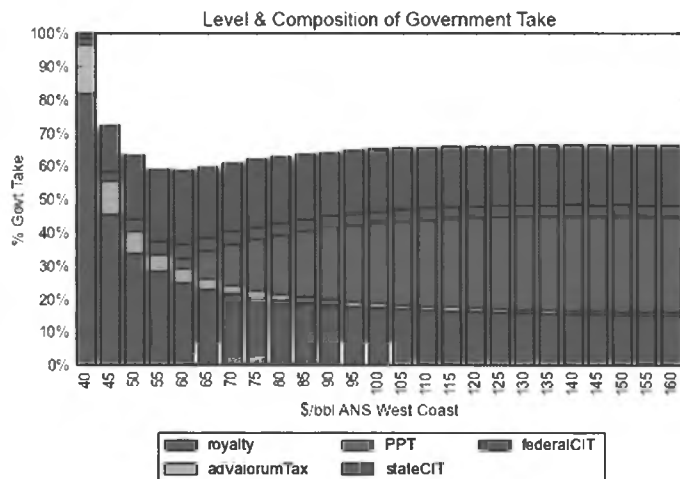


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.22%	4.37		19.77
\$100/bbl	64.54%	6.18		28.11
\$120/bbl	64.71%	8.0		36.45
\$140/bbl	64.81%	9.82		44.78

SB21 with variable production credit Base Production

SB21, 12.5% Royalty, variable production credit, Base Production



Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	62.94%	4.66		20.94
\$100/bbl	65.26%	6.19		27.95
\$120/bbl	66.23%	7.75		34.96
\$140/bbl	66.56%	9.33		42.21

Why is Government Take Higher at \$100/bbl?

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ANS West Coast	100	102.5	105.0625	107.6891	110.3813	113.1408	115.9693	118.8686	121.8403	124.8863	128.0085	131.2087	134.4889	137.8511
Transport Cost	9	9.32	9.64	9.98	10.33	10.69	11.06	11.45	11.85	12.27	12.7	13.14	13.6	14.08
GVPP / bbl	91	93.18	95.4225	97.70906	100.0513	102.4508	104.9093	107.4186	109.9903	112.6163	115.3085	118.0687	120.8889	123.7711
\$/bbl Credit	6	6	6	6	5	5	5	5	5	4	4	4	3	3

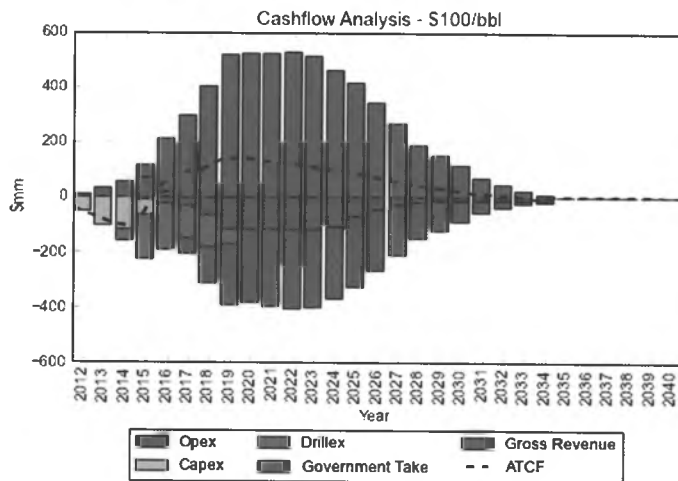
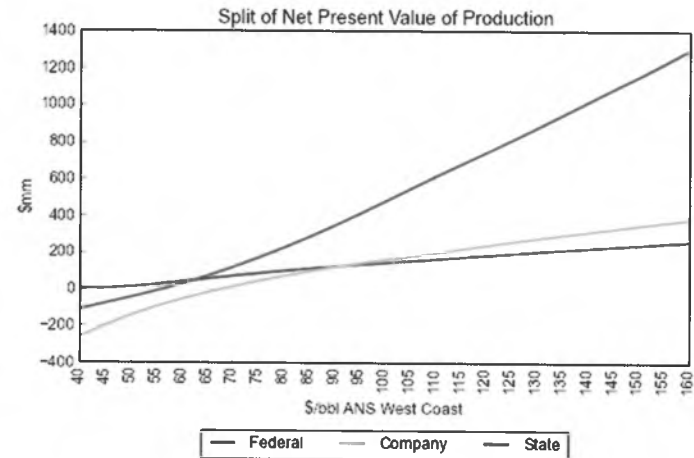
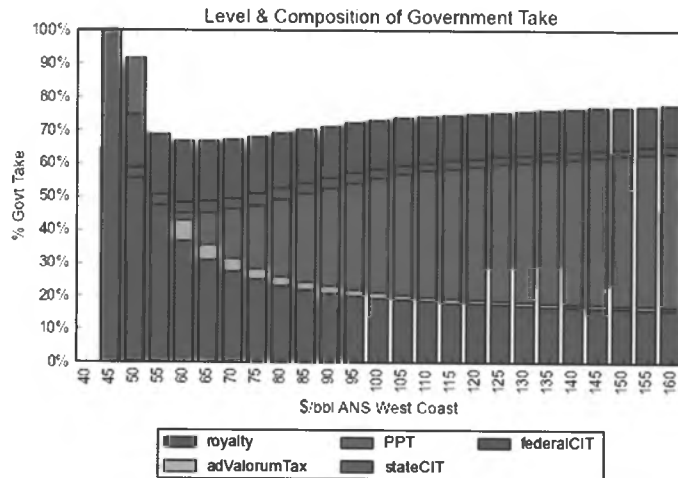
	2026	2027	2028	2029	2030	2031	2032	2033	2034
	141.2974	144.8298	148.4506	152.1618	155.9659	159.865	163.8616	167.9582	172.1571
	14.57	15.08	15.61	16.15	16.72	17.3	17.91	18.53	19.18
	126.7274	129.7498	132.8406	136.0118	139.2459	142.565	145.9516	149.4282	152.9771
	3	3	2	2	2	1	1	1	0

GVPP Below	Stepped Credit
\$80	\$8
\$90	\$7
\$100	\$6
\$110	\$5
\$120	\$4
\$130	\$3
\$140	\$2
\$150	\$1
\$160	\$0

ACES

\$18/bbl New Development

ACES, 12.5% Royalty, \$18/bbl New Development



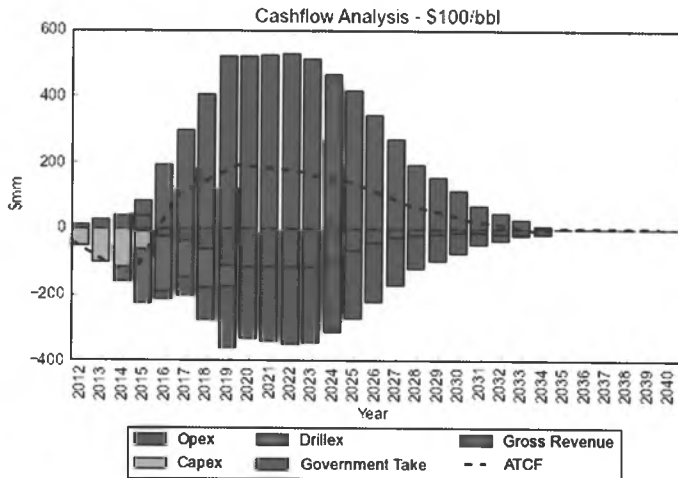
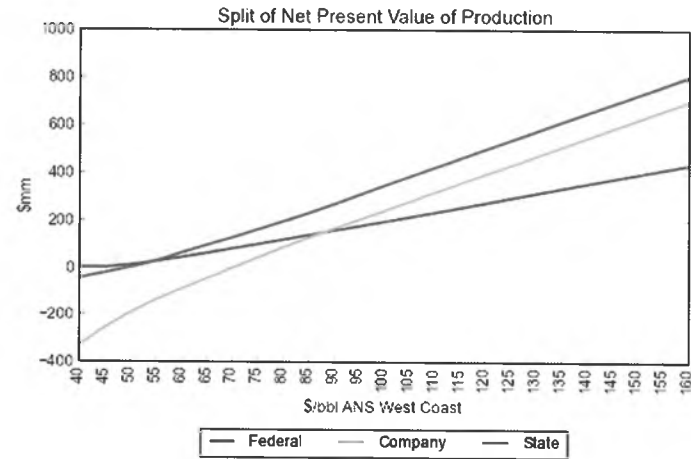
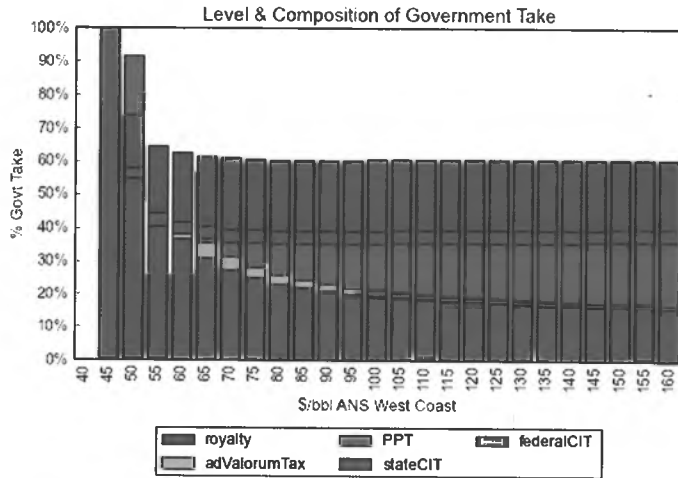
Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	69.25%	1.44	16.15%	22.21
\$100/bbl	73.03%	3.21	20.95%	27.06
\$120/bbl	75.13%	4.78	24.84%	30.63
\$140/bbl	76.52%	6.27	28.18%	34.71

SB21

\$18/bbl New Development, 12.5% Royalty, 20% GRE

SB21, 12.5% Royalty, \$18/bbl New Development With GRE

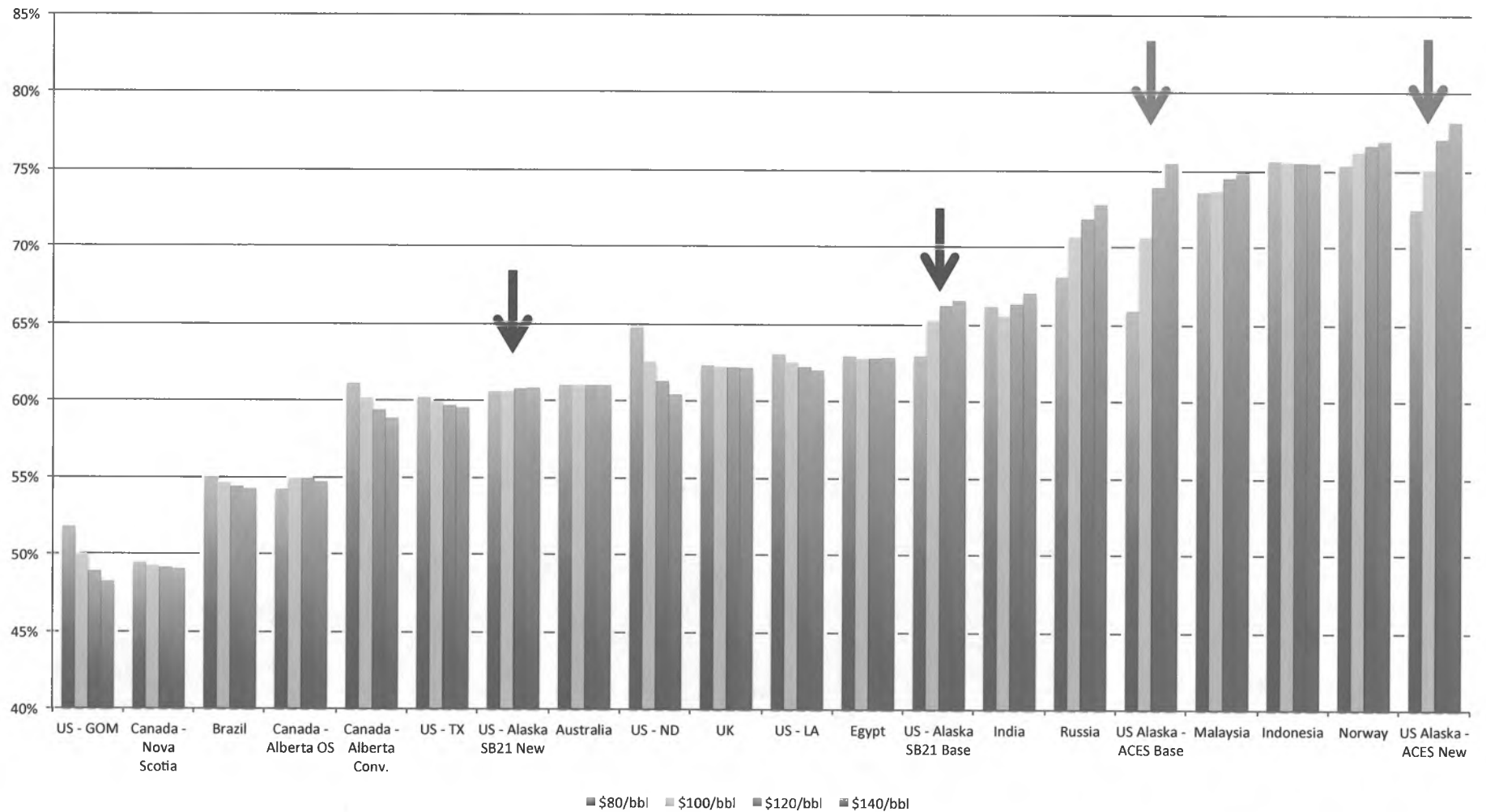


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	60.56%	1.67	15.83%	26.56
\$100/bbl	60.60%	4.83	22.23%	35.76
\$120/bbl	60.76%	7.89	27.63%	44.59
\$140/bbl	60.81%	10.95	32.47%	53.36

Government Take Competitiveness

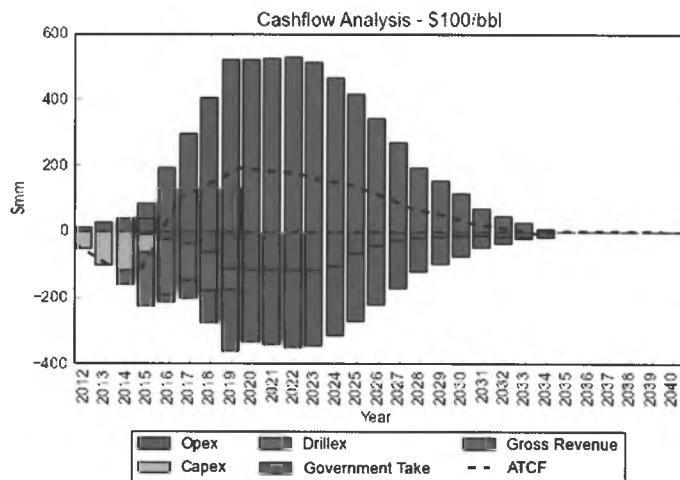
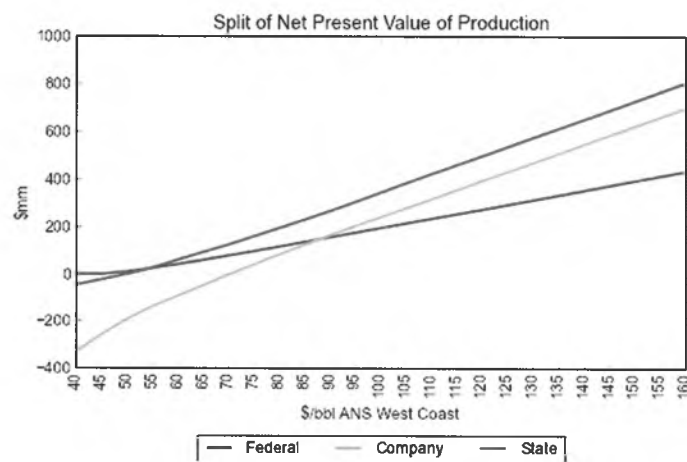
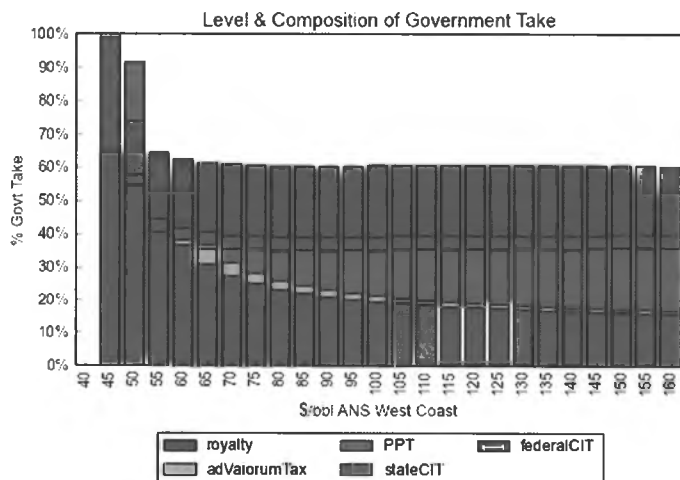
Alaska Government Take Competitiveness - Comparable Regimes



SB21

\$18/bbl New Development, 12.5% Royalty, 20% GRE

SB21, 12.5% Royalty, \$18/bbl New Development With GRE



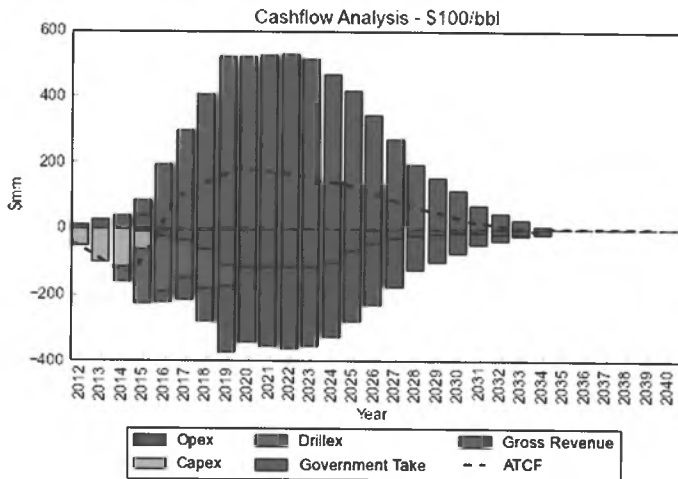
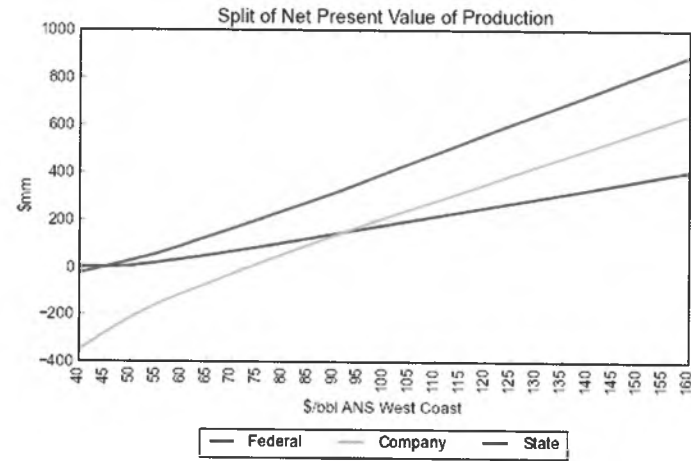
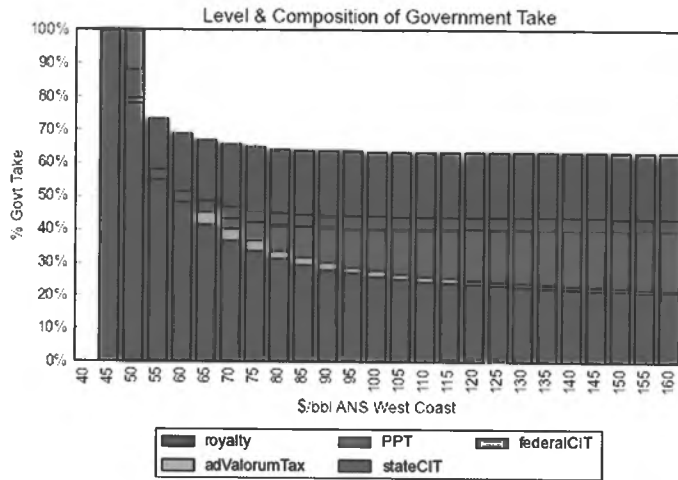
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	60.56%	1.67	15.83%	26.56
\$100/bbl	60.60%	4.83	22.23%	35.76
\$120/bbl	60.76%	7.89	27.63%	44.59
\$140/bbl	60.81%	10.95	32.47%	53.36

SB21

\$18/bbl New Development, 16.7% Royalty, 20% GRE

SB21, 16.7% Royalty, \$18/bbl New Development With GRE



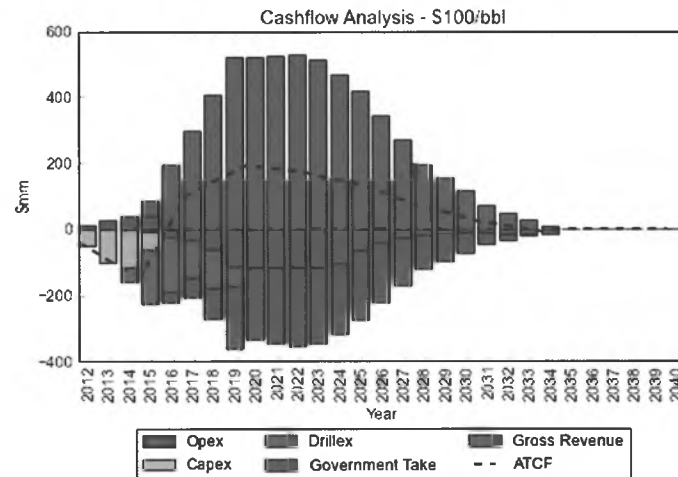
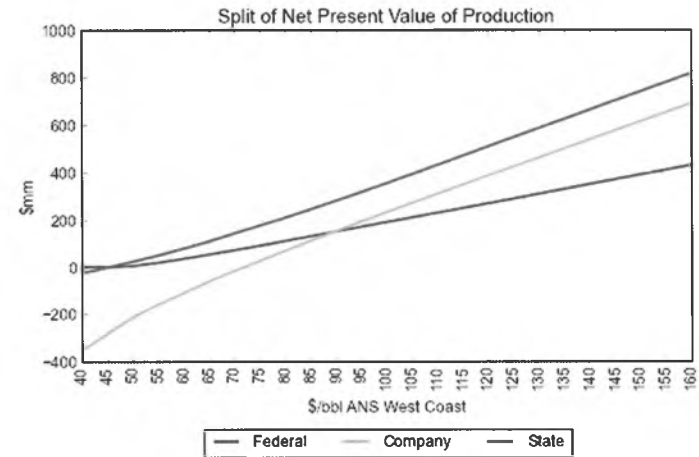
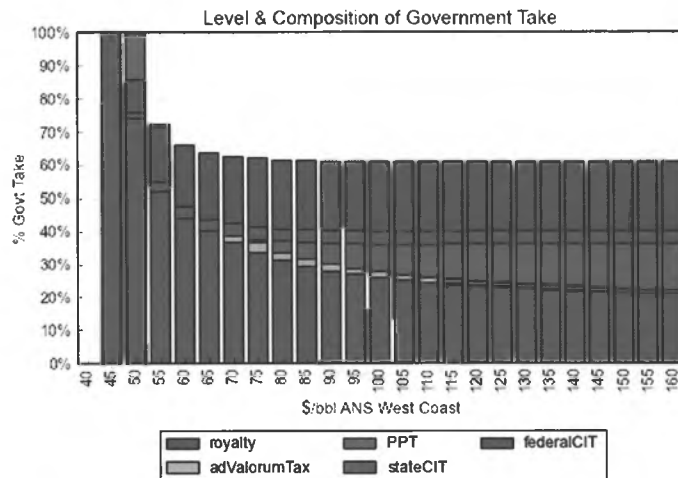
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.40%	1.1	14.55%	24.88
\$100/bbl	63.64%	4.16	20.96%	33.77
\$120/bbl	63.51%	7.05	26.21%	42.21
\$140/bbl	63.38%	9.98	30.98%	50.56

SB21

\$18/bbl New Development, 16.7% Royalty, 30% GRE

SB21, 16.7% Royalty, \$18/bbl New Development With GRE



Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	61.67%	1.43	15.25%	25.95
\$100/bbl	61.07%	4.69	21.89%	35.58
\$120/bbl	61.10%	7.74	27.26%	44.54
\$140/bbl	61.12%	10.78	32.06%	53.32

Notice

This material is protected by United States copyright law and applicable international treaties including, but not limited to, the Berne Convention and the Universal Copyright Convention. Except as indicated, the entire content of this publication, including images, text, data, and look and feel attributes, is copyrighted by PFC Energy. PFC Energy strictly prohibits the copying, display, publication, distribution, or modification of any PFC Energy materials without the prior written consent of PFC Energy.

These materials are provided for the exclusive use of PFC Energy clients (and/or registered users), and may not under any circumstances be transmitted to third parties without PFC Energy approval.

PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED "AS IS" WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

© PFC Energy, Inc. License restrictions apply. Distribution to third parties requires prior written consent from PFC Energy.

PFC Energy Locations and Contact Information

NORTH AMERICA

PFC Energy, Washington
1300 Connecticut Avenue, NW
Suite 800
Washington, DC 20036, USA
Tel +1 202 872 1199
Fax +1 202 872 1219

PFC Energy, Houston
2727 Allen Parkway, Suite 1300
Houston, Texas 77019, USA
Tel +1 713 622 4447
Fax +1 713 622 4448

EUROPE

PFC Energy, France
19 rue du Général Foy
75008 Paris, France
Tel +33 1 4770 2900
Fax +33 1 4770 5905

RUSSIA

PFC Energy, Moscow
10 Vozdvizhenka Street
Voentorg building, Suite 341
Moscow, 125009
Russian Federation
Tel +7 (495) 797 3733

ASIA

PFC Energy, Kuala Lumpur
Level 27, UBN Tower #21
10 Jalan P. Ramlee
50250 Kuala Lumpur, Malaysia
Tel +60 3 2172 3400
Fax +60 3 2072 3599

PFC Energy, China
89 Jianguo Road
China Central Place # 4-1602
Chaoyang District, Beijing 100025, China
Tel +86 10 6530 7010
Fax +86 10 6530 5093

PFC Energy, Singapore
15 Scotts Road
Thong Teck Building, #08-04
Singapore 228218
Tel +65 6736 4317

www.pfcenergy.com | info@pfcenergy.com

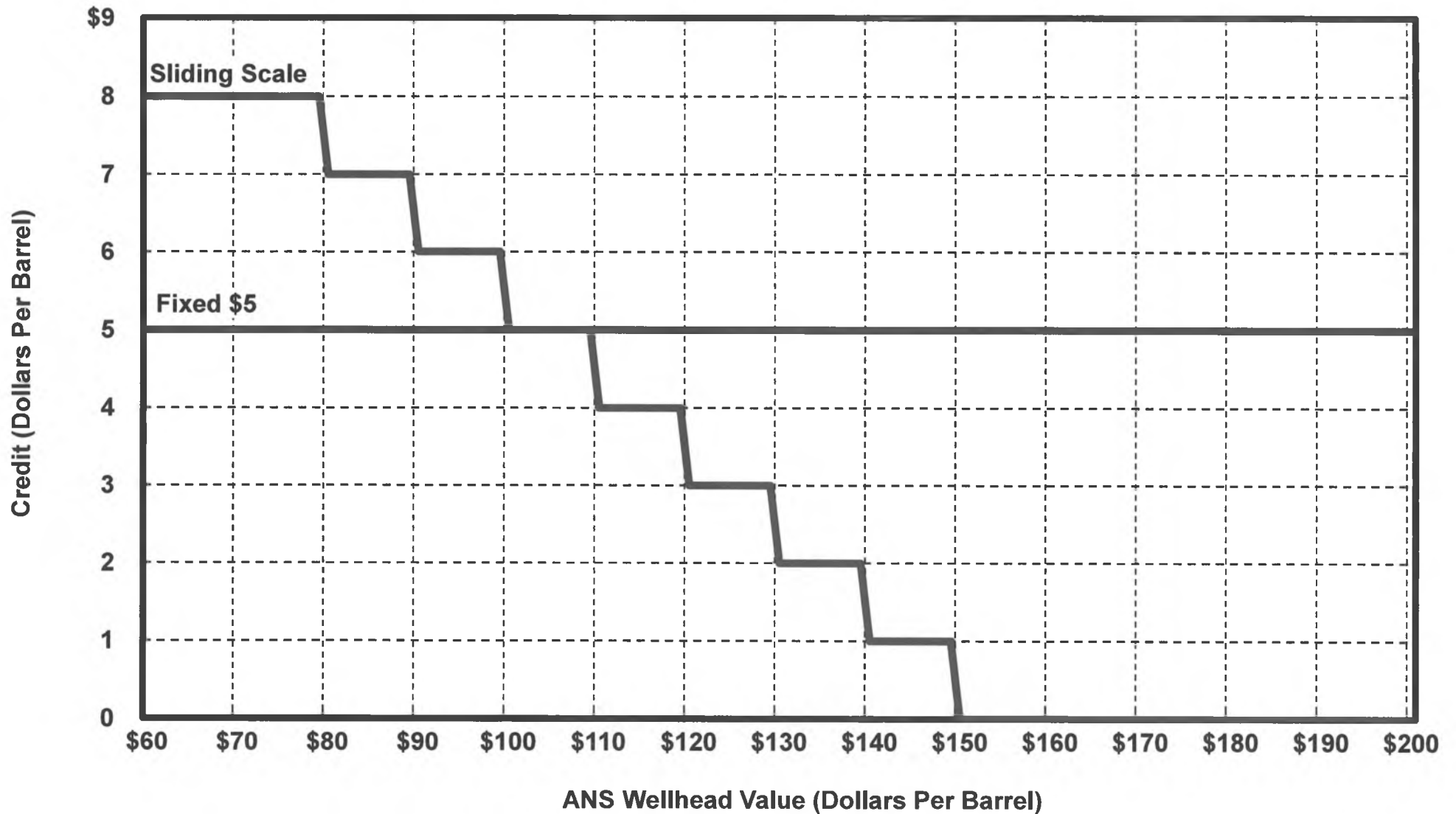
ACES, CS SB21 (FIN) and HCS SB21 (RES) Working Draft

**Barry Pulliam
Managing Director
Econ One Research, Inc.**

April 2, 2013

Per-Barrel Credits

Non-GVR Volumes (Sliding Scale) v. GVR Volumes (Fixed)



Tax Calculation Using Sliding Scale Production Credit (Volumes Not Subject to Gross Value Reduction)

West Coast Price (\$/Bbl)		\$60.00	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00	\$120.00	\$130.00	\$140.00	\$150.00	\$160.00
Transportation (\$/Bbl)	-	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Gross Value (\$/Bbl)	=	\$50.00	\$60.00	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00	\$120.00	\$130.00	\$140.00	\$150.00
Lease Expenditures (\$/Bbl)	-	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Per-Barrel Taxable Value (\$/Bbl)	=	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00	\$120.00
Taxable Barrels (Bbls)	x	100	100	100	100	100	100	100	100	100	100	100
Total Production Tax Value (\$)	=	\$2,000	\$3,000	\$4,000	\$5,000	\$6,000	\$7,000	\$8,000	\$9,000	\$10,000	\$11,000	\$12,000
Tax Rate (Percent)	x	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Production Tax Before Credit (\$)	=	\$700	\$1,050	\$1,400	\$1,750	\$2,100	\$2,450	\$2,800	\$3,150	\$3,500	\$3,850	\$4,200
Per Barrel Production Credit (\$/Bbl)		\$8.00	\$8.00	\$8.00	\$7.00	\$6.00	\$5.00	\$4.00	\$3.00	\$2.00	\$1.00	\$0.00
Total Production Credit (\$)	-	\$800	\$800	\$800	\$700	\$600	\$500	\$400	\$300	\$200	\$100	\$0
Production Tax After Credit (\$)	=	\$0	\$250	\$600	\$1,050	\$1,500	\$1,950	\$2,400	\$2,850	\$3,300	\$3,750	\$4,200
Effective Tax Rate After Credit (%)		0.0%	8.3%	15.0%	21.0%	25.0%	27.9%	30.0%	31.7%	33.0%	34.1%	35.0%
Effective Tax Rate on Gross Value (%)		0.0%	4.2%	8.6%	13.1%	16.7%	19.5%	21.8%	23.8%	25.4%	26.8%	28.0%

Tax Calculation Using Fixed \$5 Production Credit (Volumes Subject to Gross Value Reduction)

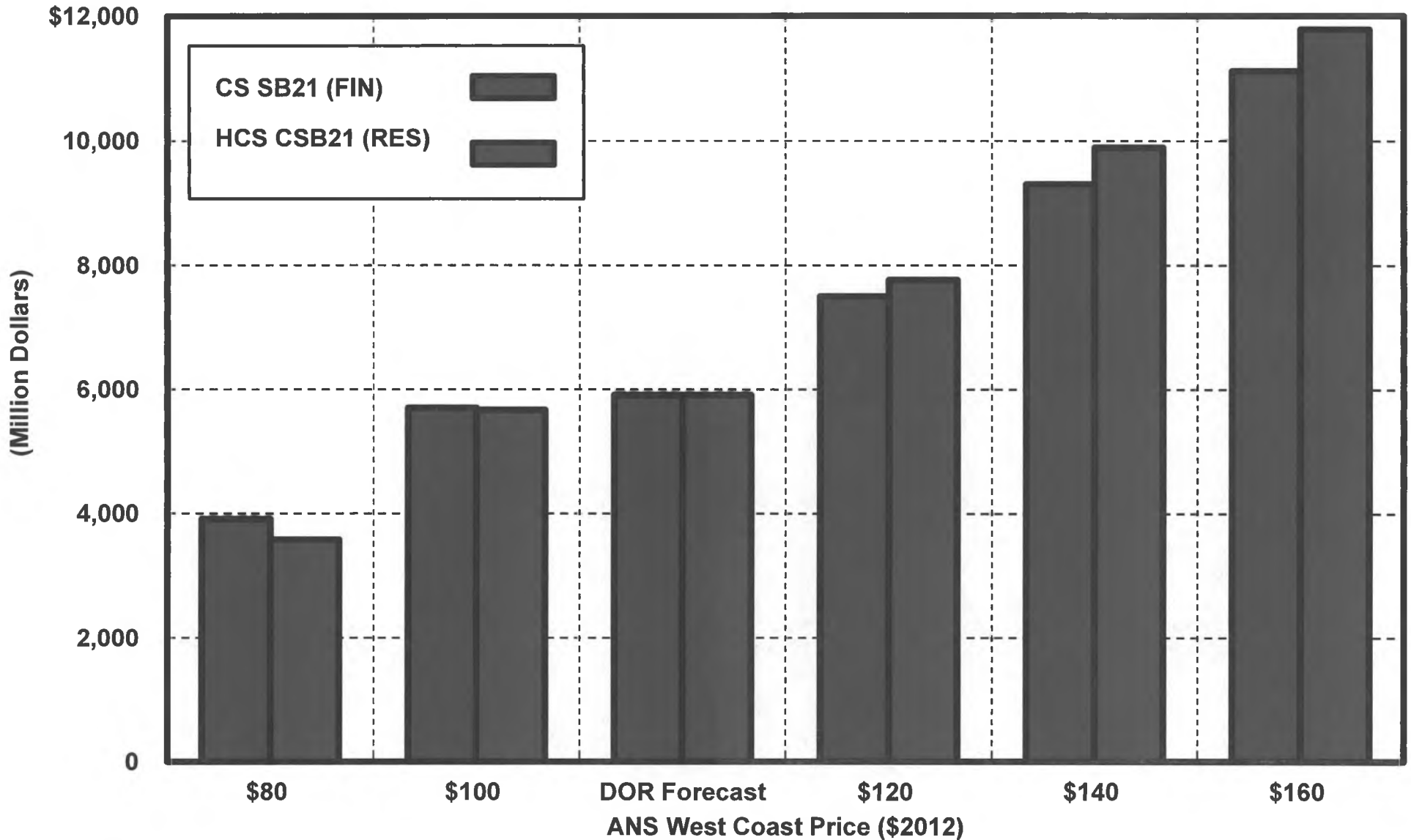
West Coast Price (\$/Bbl)		\$60.00	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00	\$120.00	\$130.00	\$140.00	\$150.00	\$160.00
Transportation (\$/Bbl)	-	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Gross Value (\$/Bbl)	=	\$50.00	\$60.00	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00	\$120.00	\$130.00	\$140.00	\$150.00
Lease Expenditures (\$/Bbl)	-	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Per-Barrel Taxable Value (\$/Bbl)	=	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00	\$120.00
Taxable Barrels (Bbls)	x	100	100	100	100	100	100	100	100	100	100	100
Total Production Tax Value (\$)	=	\$2,000	\$3,000	\$4,000	\$5,000	\$6,000	\$7,000	\$8,000	\$9,000	\$10,000	\$11,000	\$12,000
Gross Value Reduction (%)		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Gross Value Net of GVR (\$/Bbl)		\$40.00	\$48.00	\$56.00	\$64.00	\$72.00	\$80.00	\$88.00	\$96.00	\$104.00	\$112.00	\$120.00
Lease Expenditures (\$/Bbl)	-	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Per-Barrel Taxable Value Net of GVR (\$/Bbl)	=	\$10.00	\$18.00	\$26.00	\$34.00	\$42.00	\$50.00	\$58.00	\$66.00	\$74.00	\$82.00	\$90.00
Taxable Barrels (Bbls)	x	100	100	100	100	100	100	100	100	100	100	100
Total Production Tax Value (\$)	=	\$1,000	\$1,800	\$2,600	\$3,400	\$4,200	\$5,000	\$5,800	\$6,600	\$7,400	\$8,200	\$9,000
Tax Rate (Percent)	x	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Production Tax Before Credit (\$)	=	\$350	\$630	\$910	\$1,190	\$1,470	\$1,750	\$2,030	\$2,310	\$2,590	\$2,870	\$3,150
Per Barrel Production Credit (\$/Bbl)		\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00
Total Production Credit (\$)	-	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500
Production Tax After Credit (\$)	=	\$0	\$130	\$410	\$690	\$970	\$1,250	\$1,530	\$1,810	\$2,090	\$2,370	\$2,650
Effective Tax Rate After Credit (%)		0.0%	4.3%	10.3%	13.8%	16.2%	17.9%	19.1%	20.1%	20.9%	21.5%	22.1%
Effective Tax Rate on Gross Value (%)		0.0%	2.2%	5.9%	8.6%	10.8%	12.5%	13.9%	15.1%	16.1%	16.9%	17.7%

Average Government Take for All Existing Producers (FY2015-FY2019)

\$2012 ANS WC Price (\$2012 /Bbl)	Government Take		
	35%/	35% / \$5	ACES
	Sliding Scale	(Percent)	
(1)	(2)	(3)	(4)
\$60	57.8%	63.0%	61.6%
\$70	59.8%	63.7%	62.2%
\$80	61.6%	64.1%	64.1%
\$90	63.1%	64.3%	66.2%
\$100	64.4%	64.5%	68.5%
\$110	65.3%	64.7%	70.7%
\$120	65.8%	64.8%	72.8%
\$130	66.4%	64.9%	73.8%
\$140	66.8%	65.0%	74.5%
\$150	67.0%	65.0%	75.1%
\$160	66.9%	65.1%	75.7%
\$170	66.8%	65.1%	76.3%
\$180	66.7%	65.2%	77.0%
\$190	66.7%	65.2%	77.6%
\$200	66.6%	65.2%	78.2%

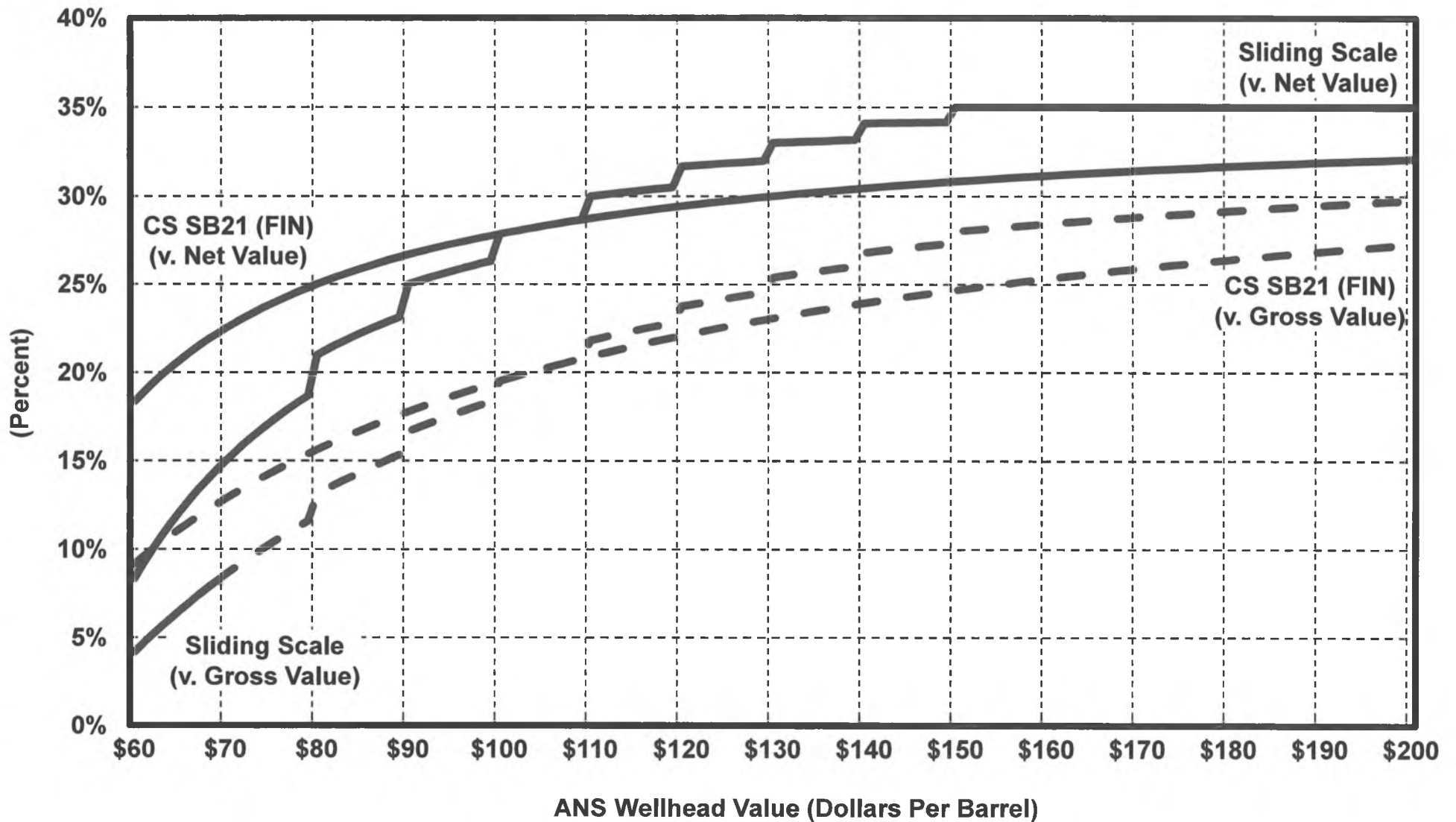
State Revenues

CS SB21 (FIN) v. HCS CSB21 (RES) w/ Proposed Sliding Scale for All Existing Producers (Annual Average FY2015 - FY2019)

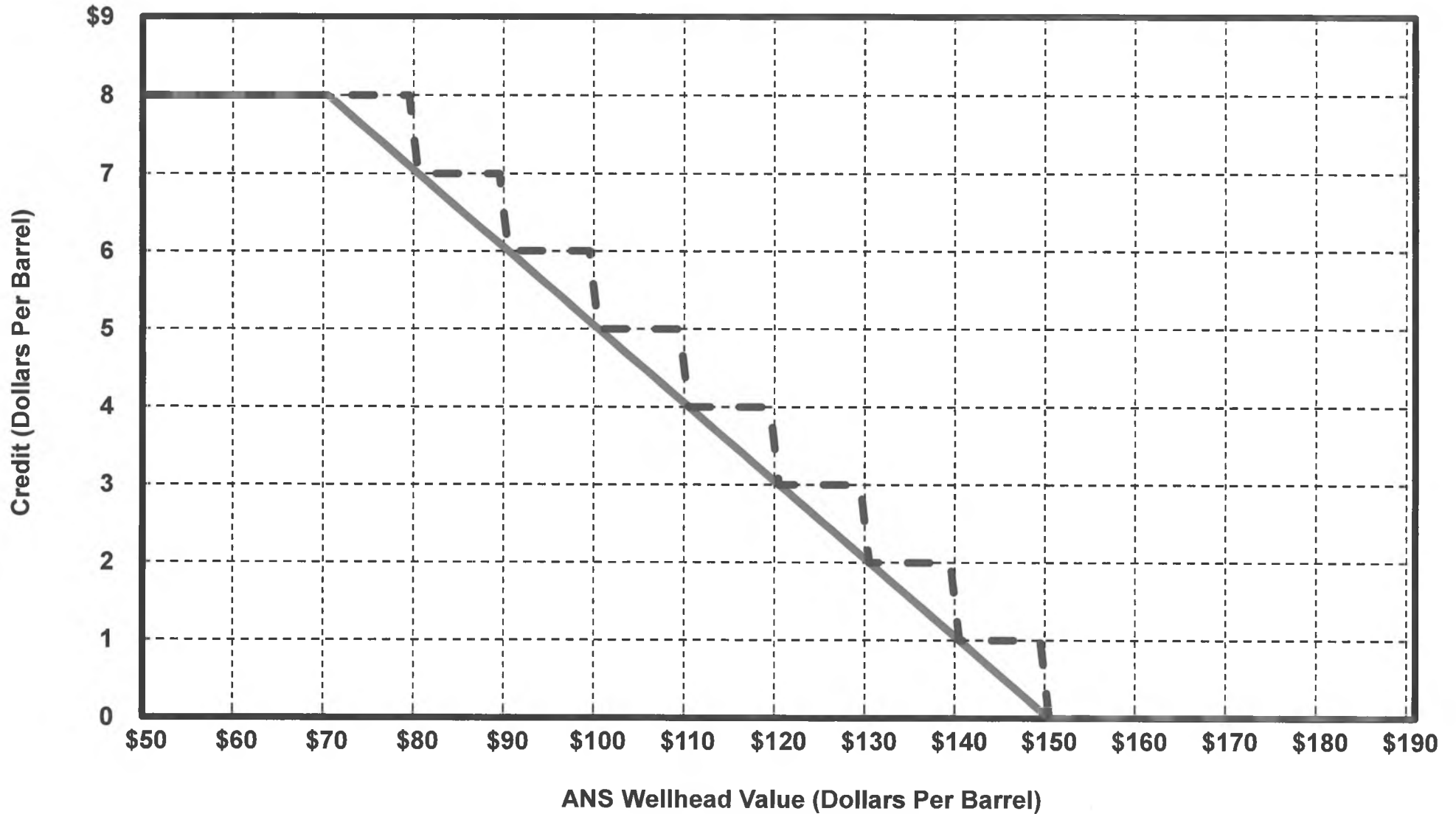


Effective Tax Rate Comparison

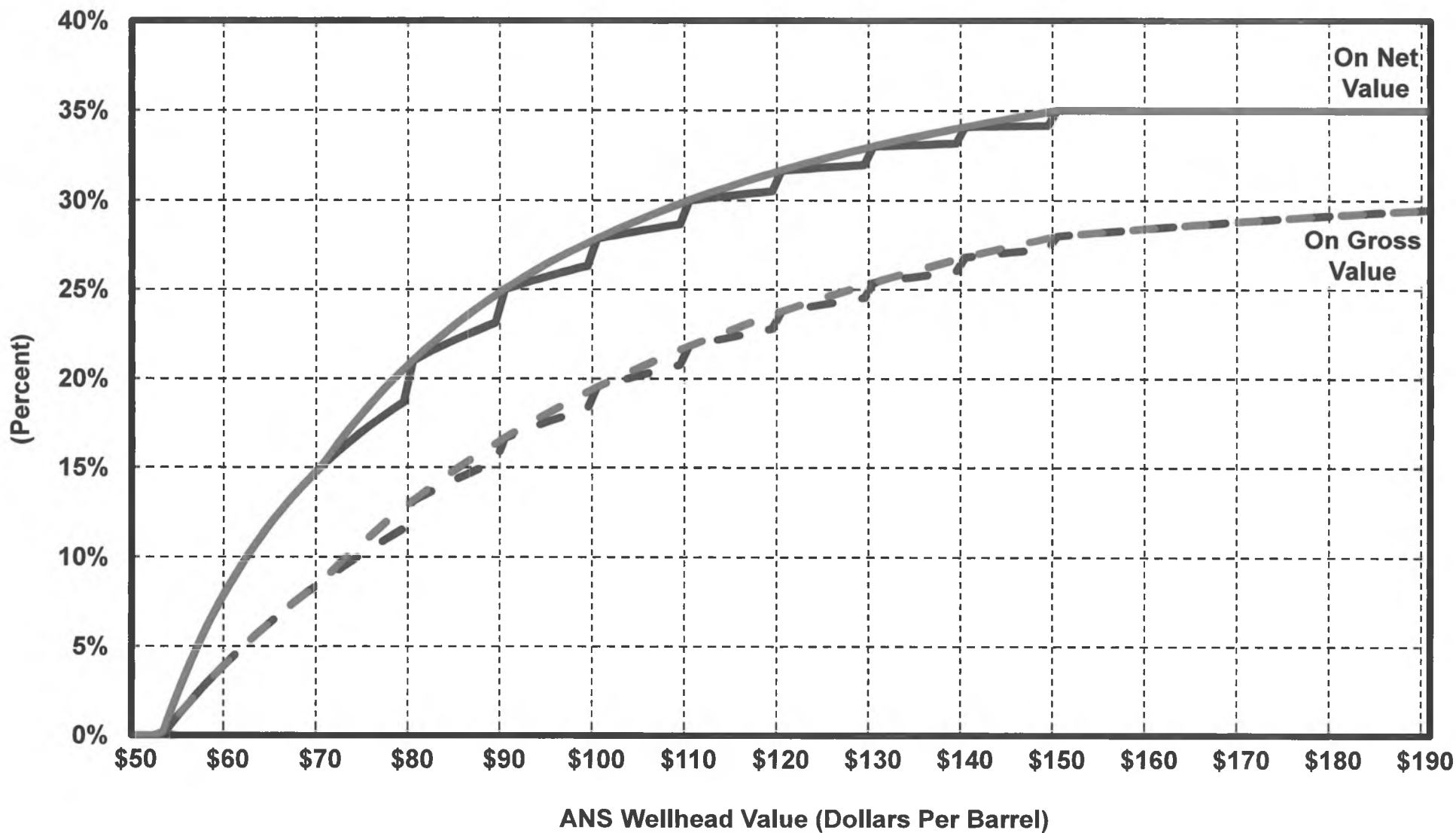
CS SB21 (FIN) v. CS SB21 (FIN) with Sliding Credit Scale (Volumes Not Subject to Gross Value Reduction)



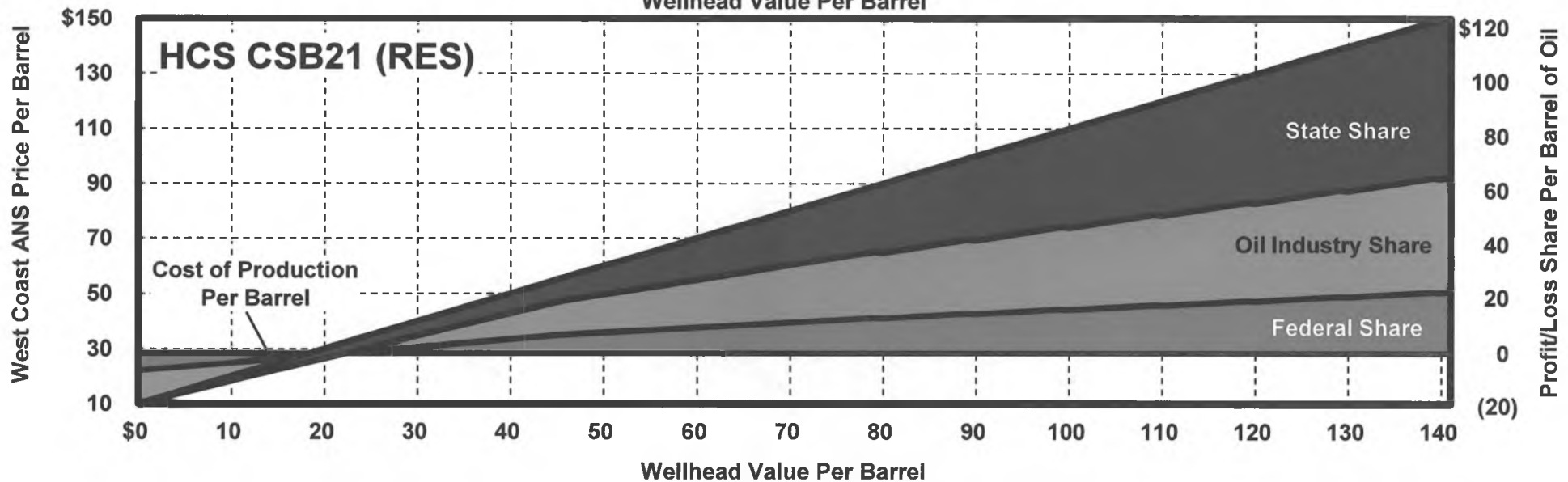
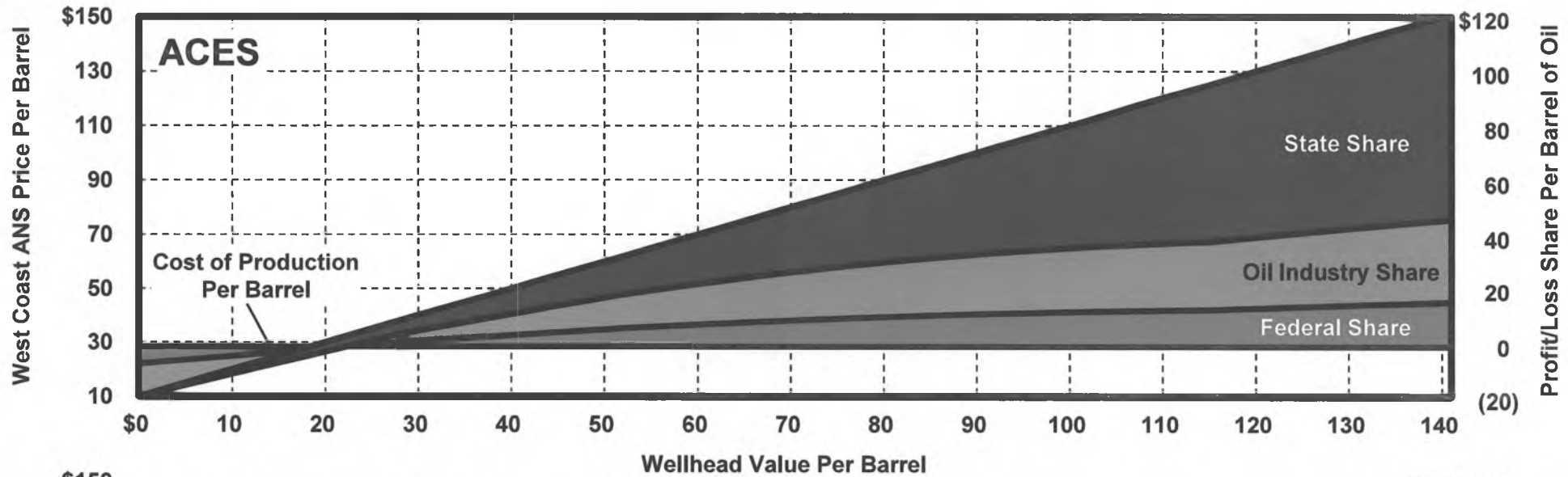
Sliding Scale Credit Stair-Stepped v. Smoothed



Tax Calculation Using Sliding Scale Production Credit (Volumes Not Subject to Gross Value Reduction) Effective Tax Rates



Shares of Per-Barrel Values Under ACES and HCS CSB21 (RES) Using FY2012 Combined PBU/KPU Costs and Volumes



Jim Sykes Testimony to the House Resources Committee on SB21
April 2, 2013

Introduction

I made some brief comments to the House Resources Committee earlier today and they are included below, reconstructed from my notes and included with more detailed remarks with charts and other appendicies. I tried to speak about what I thought the current CS might or might not do.

Maybe it's worth a moment of reflection about what is being attempted—to reach a long term solution on oil taxes. For now, Alaska's short term needs have some cash reserve cushion, which is liable to get thinner mainly by the rising cost of government.

What is the target to work from?

What is the date at which we expect Alaskans to pay taxes and/or start spending down the Permanent Fund to pay for state government?

We can start with the current amount of money being spent and input the sources of revenue, including oil. The natural decline curve of currently producing fields is fairly predictable. How much money can we extract from the economic rent for our oil and gas, including royalties, lease payments and all taxes? If we are able to stimulate more production now, will the finite pool of oil suffer a steeper decline later? What will be the long term effect of a steeper decline?

While I've followed the various proposals and debates, I'm troubled that these kinds of questions aren't being asked. When asked recently about whether the industry would reinvest a tax credit in Alaska, a company representative described the process.

Basically all tax credits are welcome. The company will gladly take any credits and add them to corporate cash. However projects will be developed that are prioritized from among a pool of the most promising. That means there is no assurance that even a large tax credit, aimed at raising production in an older oil field, will raise Alaska above other newer projects elsewhere.

While there will undoubtedly be more oil extracted from Alaska than has already been taken out, it will occur over the next 50-60 years, or longer. [Please see Appendix A].

Alaska is a “big basin” oil patch, developed differently than the small rigs that drill shallow plays in Texas and North Dakota. Why wouldn't an oil producer be interested in a place where you can drive in a truck, set up a small rig extract some oil and move on? This latest boom, based on new technology, was not based on a tax policy change. The government take in North Dakota is smaller, in part because companies pay royalties on the order of 20% to 40% to the private land owners. Alaska's royalty rate is 12.5% on most state lands. If our royalty rate were 35% a lower tax rate would be reasonable.

It is unlikely Alaska can lower its taxes enough to take away another oil region's production boom. No one was able to take away Alaska's boom in the late 1970's and early 1980's. So whatever tax break is considered needs to have a purpose and a predictable outcome. Declines reversed by the use of tax cuts have mainly, perhaps only, happened with a change in oil field operators.

Prudhoe and Kupark are so immensely profitable, the current incumbents are not likely to leave. The state needs to understand that profitability. In my testimony I used the term “like an ATM” to even out highs and lows for corporate activities elsewhere in the world. [Please see Appendix D].

How much is the state prepared to lose from its own cash reserves to get a rise in production? How much production will be required to cover the loss, and when will the state see a profit from the incentives that are given? If ever? If production is actually increased soon will it steepen decline in out years? Are we trying to get extra income now, when cash flows are good, to the detriment of future cash flows?

Alaska's Permanent Fund is a magnet for economic activity. If the flow to the fund is reduced is reduced or cut off there could be a large negative impact on economic activity in Alaska. Because of the Permanent Fund, Alaska to has the narrowest gap between low and high income earners, and that too could decrease and eventually end.

So both the long term and short term questions remain. How does government continue when revenue receipts decrease to the point that government funding is not sustainable? Is the current tax break attempting to push production up for a short time at the expense of future receipts?

We deserve solid answers to these types of questions while the state is in a relative good cash position.

Increased production does not guarantee more revenue to the state.

The hope that more money results from increased production may only be true in a high oil price scenario. If world oil prices go down, as many are predicting, the state can lose in two ways, 1) Starting to credit low oil price losses at the high oil price of \$90, and 2) continuing to give tax credits which may or may not cover losses of credits given or provide adequate profits to the state.

The way the current CS for SB21 starts support for low oil prices below \$90 per barrel, and then severely restricting progressivity on the upside, effectively means the state can count on stable revenue between \$90 and \$120 oil. While we've been in that range for a while there are no assurances such prices will continue.

For those of us who have been observing the ups and downs of oil markets, they've always gone up and they've always come down, and there's no reason to believe it won't happen again. It's up to the legislature to figure out how the state will minimize the risks and maximize its opportunities for the benefit of Alaskans that our constitution requires.

A word about throughput.

In 1988, TAPS oil flowed 2 million bpd at its peak, and that year the state brought in \$2.68 billion, roughly \$5.21 billion in 2012 dollars. In 2012, the state took in \$8.86 billion on 515,000 bpd. In today's dollars, Alaska is making more than six times more per barrel than in 1988. Price is more important than the amount of oil being produced.

There are a couple large variables, somewhat beyond our control, of how much TAPS will handle. Offshore oil, predicted to increase greatly in about 10 years may reach a peak of 1.7 mmbd, which is close to the 2 mmbd of 1988. [Please see Appendix A].

On the low end, suggestions that the pipeline will shut down at 300,000 or 250,000 bpd are not true. The large amount of booked reserves and test projects envision TAPS being able to handle as low of volume as 70,000 bpd, with some modifications. [Please read TAPS Settlement Excerpts in Appendix B]. TAPS was sized to accommodate the anticipated peak of Prudhoe and it will be able to accommodate heavy oil and offshore oil as well.

The practical matter for the legislature to consider is that making a lowball tax deal now, during this 10 year lull between huge developments, could deprive Alaskans and the state government the maximum benefits that our constitution says we must obtain.

We also need to know what the payback period is on new wells from existing pads in Prudhoe and Kuparuk under the current tax law and the CS for SB21 proposal. As I mentioned, companies might be willing to share confidential information, but someone has to have the guts to ask, and also be prepared to sign a confidentiality agreement.

The legislature may have been working on the oil tax issue for the past three years, and it may be frustrating. There's a great deal of knowledge and evidence that needs to be considered. Getting it right is essential.

Source material for Jim Sykes' verbal testimony, April 2, 2013

Co-Chairs and Members of the House Resources Committee,

My name is Jim Sykes, I've followed the oil industry and state oil policy for quite a long time. As one who would also like to see an increase in oil production, I speak against the new CS for SB21.

For companies there are many upsides without downsides. For the state, few potential upsides and huge potential downsides. It looks to me that the current SB21 CS essentially guarantees more corporate profits on top of already record profits without assurances that new investment will happen, or that production will increase or that the state will recoup the loss of the credits given in advance.

Other upsides for companies include:

- Starting to eliminating the downside price risk at about \$90, which does not pass the red face test,
- Eliminates the upside price risk by severely restricting progressivity,
- Allows us use of the state's money without requiring actual performance of new production
- The tax credit for new production looks like it applies to the legacy fields, which are already among the most profitable oil fields on the entire planet. In fact our legacy fields are the ATM that levels out the ups and downs of other investments made by Alaska producers elsewhere in the world. [Please see Appendix D].

The State of Alaska:

- Gives up its cash in advance, risking fairly quick negative cash flows regardless of oil price,
- Hopes, but has no assurance, that oil production will actually increase,
- May not be able to recoup the value of the credits even if production is increased,
- Risks paying for credits if oil prices decline and keeps itself from substantially higher profits if prices substantially rise.

It is certain that larger net profits will accrue to oil companies corporations and the state will essentially be accepting a effective lower net take per barrel.

We face another critical juncture in Alaska's history whether the people of Alaska will control our resources or outside corporations that hold our oil leases. We find ourselves in a similar predicament that Bob Bartlett warned the Alaska Constitutional Convention about in 1955:

“...This moment will be a critical one in Alaska's future history. Development must not be confused with exploitation at this time. The financial welfare of the future state and the well being of its present and unborn citizens depend upon the wise administration and oversight of these developmental activities.

Two very real dangers are present. The first, and most obvious, danger is that of exploitation under the thin disguise of development. The taking of Alaska's mineral resources without leaving some reasonable return for the support of Alaska governmental services and the use of all the people of Alaska will mean a betrayal in the administration of the people's wealth.

The second danger is that outside interests, determined to stifle any development in Alaska which might compete with their activities elsewhere, will attempt to acquire great areas of Alaska's public lands in order NOT to develop them until such time as, in their omnipotence and the pursuance of their own interests, they see fit. If large areas of Alaska's patrimony are turned over to such corporations the people of Alaska may be even more the losers than if the lands had been exploited....”

Both upsides and downsides of SB21 need to be carefully considered and many questions need answers.

Should the state end up with less than it's fair share, or things don't work out has hoped, a large portion of corporate tax burden will be shifted onto the shoulders of Alaska's people. Undoubtedly, people will still want schools, roads, bridges, maybe a hydroelectric dam and public safety, but they will either have to tax themselves, start depleting their Permanent Fund or both.

Before tax credits have the potential to raise production in the short term, funding shortfalls for state government are shortly before us. If new production is realized, how much lost revenue will be replaced? If credits revenue is not replaced, the funding of government services risk decline along with the revenue decline. The state could lose both existing and future cash potential.

Meantime, oil corporation boards will be happy. Shareholders will be glad to see record corporate profits increase. A corresponding decrease will come from state coffers.

If a major change in accounting is to take place, separate accounting could be initiated. All credits and taxes could apply only to Alaska production. The separate accounting mechanism has already been tested and approved in court. Even before that an audit on the current tax system needs to be performed as the only fiscally prudent way to evaluate how any new tax scheme compares with the present one.

SB21 is clearly in the companies interest, but for the State the outcome is uncertain. Please proceed carefully with full consideration for Alaska's future. It is greatly appreciated.

Thank you for the opportunity to testify. I'm glad to answer any of your questions.



Jim Sykes
PO Box 696
Palmer, AK 99645
Phone: 745-6962

Attachments: Appendix A-Charts, Offshore oil, Undiscovered oil, Reserves
Appendix B-Excerpts from Gleason, TAPS Settlement
Appendix C-News Story on TAPS life settlement proposal
Appendix D-PrudhoeATM Chart

Oil Cos. Reach Deal On Trans-Alaska Pipeline's Life Span
<http://www.law360.com/articles/386371>

By Kaitlin Ugolik

Law360, New York (October 12, 2012, 6:21 PM ET) -- The oil giants that own the Trans-Alaska Pipeline System, two of its users and the state of Alaska reached a deal Thursday establishing the depreciation factors to use in setting TAPS rates and settling a long-running dispute over the pipeline's estimated life span.

In an agreement submitted to the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska for approval, the parties said they had agreed to accept the depreciation rate used in the TAPS carriers' FERC and RCA filings that are subject to refund for periods prior to Jan 1, 2013.

The resulting rate depreciation schedule shows the life span of the pipeline ending in 2045, a compromise on both ends. The carriers — BP PLC, ConocoPhillips, Exxon Mobil Corp., Chevron Corp. and Koch Industries Inc. — sought to adopt FERC's original 2034 end date, while two users — Anadarko Petroleum Corp. and Tesoro Corp. — wanted to push the span to 2068.

“If ... FERC approves and the RCA accepts the agreement, without modification or conditions, then the issue of which depreciation factors to use in setting TAPS rates, and hence the appropriate life of line, will be settled with prejudice in the [pending] FERC and RCA dockets,” the parties said.

The dispute stems from the pipeline owners' attempts to recoup certain costs associated with a \$786 million reconfiguration project from Anadarko and Tesoro, including the replacement of certain natural-gas- and liquid-fueled turbines with electric versions. Anadarko and Tesoro have objected to the rate increases, including a 10 percent hike in 2010, arguing that the oil giants mismanaged the planning, design and development of the reconfiguration project.

In 2008, FERC adopted an end-of-life date of 2034 for the pipeline. But in a 2010 property tax dispute, an Alaska state court found the pipeline could continue operating economically until 2067 — a ruling that, if adopted by FERC, could dash the carriers' dreams of higher rates. The parties disagreed over how much weight the tax ruling should have, and in a Feb. 6 order a chief judge ruled that it was “not dispositive of the end-of-life issue in these proceedings,” leaving it to the presiding judge to determine.

A shorter life expectancy would boost prospects for approval of rate increases, because the carriers would have less time to recoup their investment. A longer life span could eliminate the rate hikes and require the companies to reimburse shippers for the difference.

In connection with Thursday's agreement, should it be approved, all rates subject to refund in proceedings at FERC and RCA will receive revised tariffs that will change the ongoing subject-to-refund rate by incorporating the agreed-upon settlement depreciation factor of 3.125 percent for year 2013. For 2014, the depreciation factor rises to 3.226 percent; in 2015, to 3.333 percent, and so on.

The deal will initially last for five years, giving the settling parties an option to revisit the depreciation factors for TAPS rate-making after it expires.

Though an agreement on depreciation factors and the pipeline's end-of-life date knocks down two major hurdles in the case, the settlement does not resolve any of the other issues pending in the parties'

FERC and RCA proceedings.

Counsel for the parties did not immediately respond to requests for comment Friday.

Anadarko and Tesoro are represented by Robin Brena, David Wensel and Laura S. Gould of Brena Bell & Clarkson PC and Joseph Koury, Jeffrey DiSciullo and Andrew Swers of Wright & Talisman PC, as well as in-house counsel Sherri B. Manuel and Barron W. Dowling.

ConocoPhillips is represented by Steptoe & Johnson LLP and Kempel Huffman & Ellis PC. ExxonMobil is represented by Sidley Austin LLP and Patton Boggs LLP. BP is represented by Vinson & Elkins LLP and Guess & Rudd PC. Koch Industries is represented by GKG Law PC and Birch Horton Bittner & Cherot. Chevron subsidiary Unocal is represented by Hogan Lovells.

The cases are docket number IS09-348, before the Federal Energy Regulatory Commission, and docket number P-08-009, in the Regulatory Commission of Alaska.

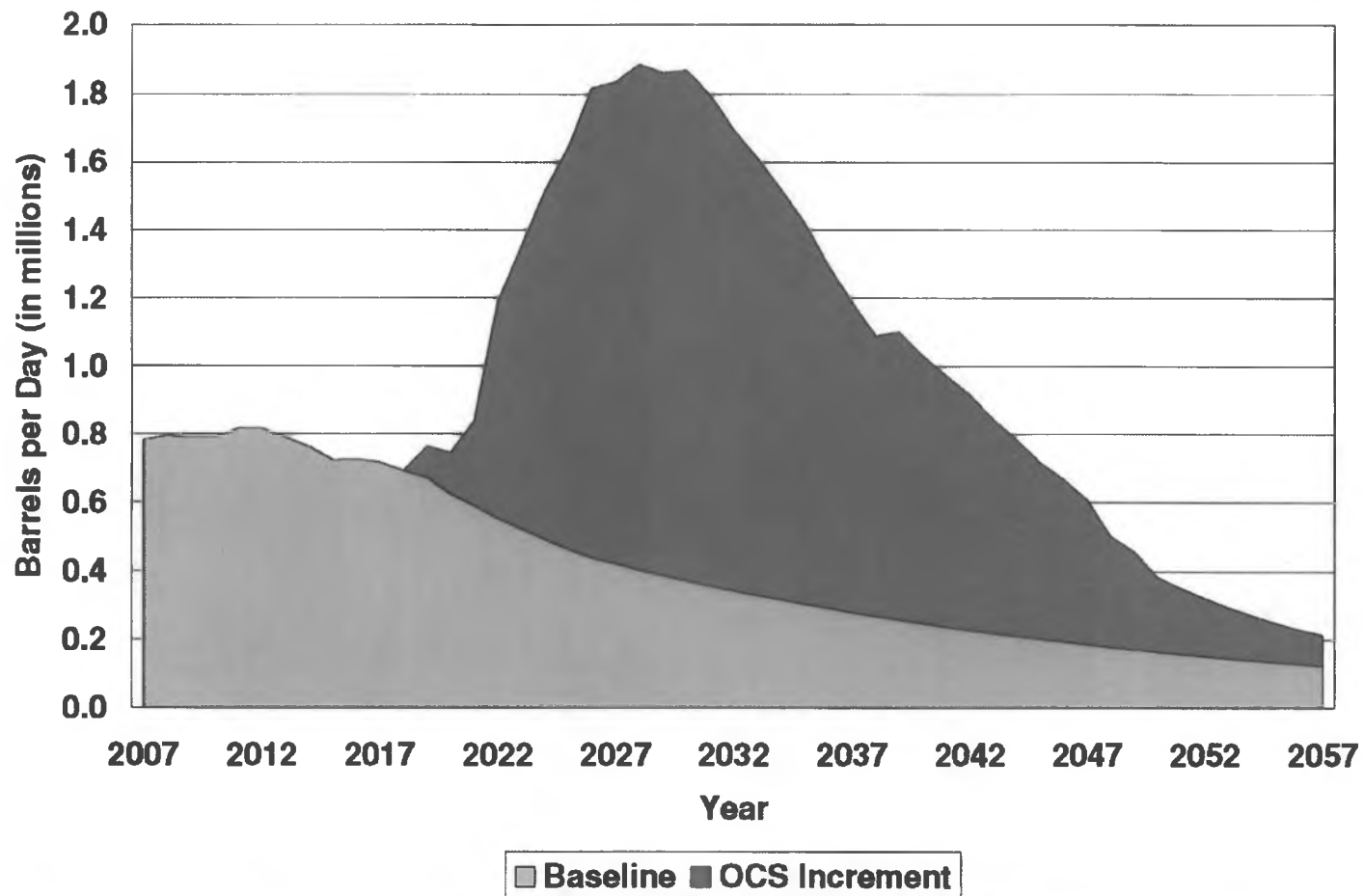
--Additional reporting by Liz Hoffman. Editing by Elizabeth Bowen.

The Life of TAPS

Reserves and Throughput

Oil Production with OCS

MUN7-0653, Page 8 of 10



THE LIFE OF TAPS - Reserves and Throughput

Alaska North Slope Oil Production Forecasts
(Producing, Known Undeveloped, and Undiscovered)

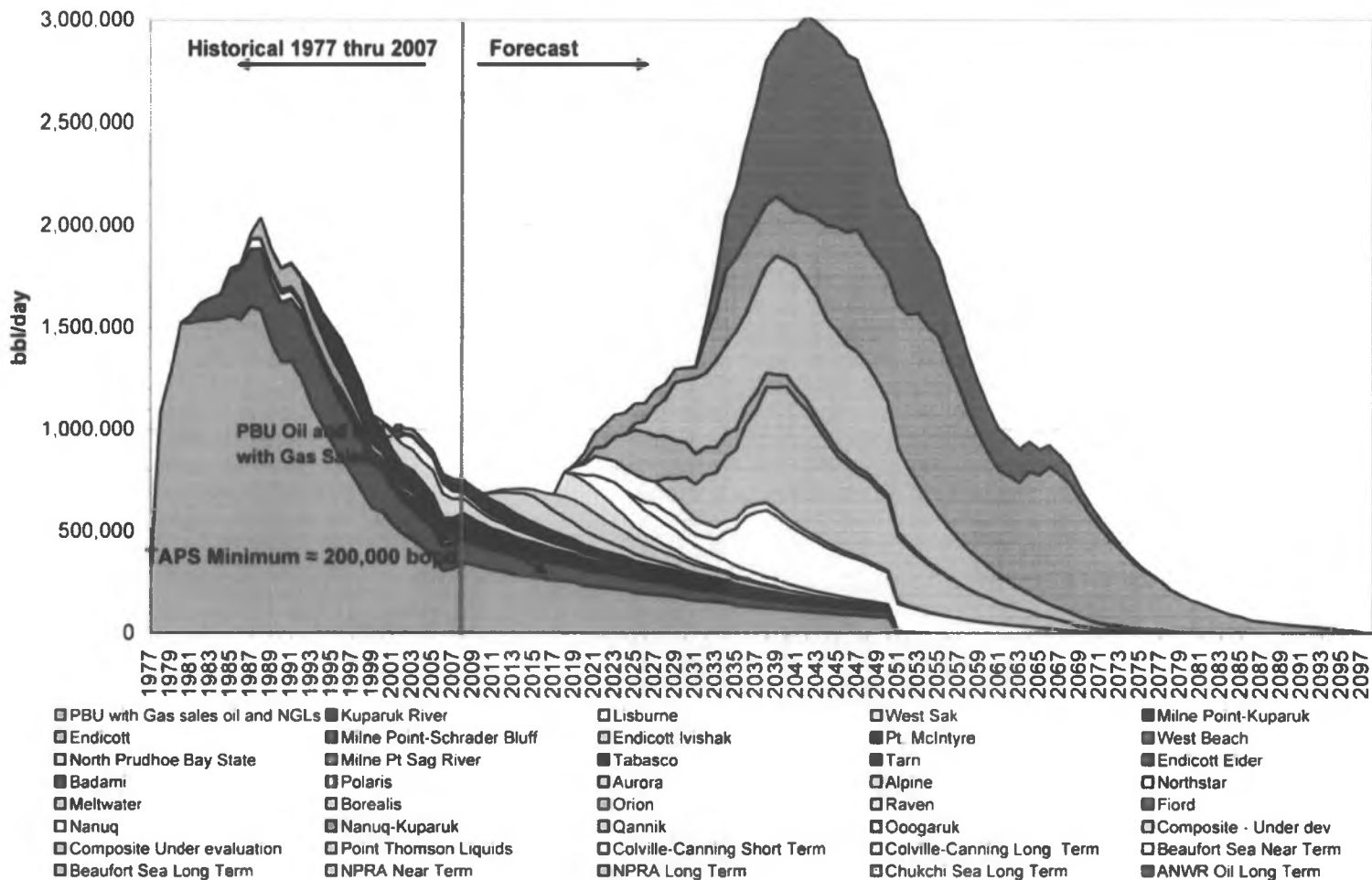


Figure 3-55. Alaska North Slope historical and forecast oil production from producing fields, known undeveloped fields, and undiscovered fields.

MUN7-0014 at 10 (Hite)

Excerpts from From case No. 3AN-06-08446 (Consolidated) Decision 30 Dec 2011

Assertion: Oil is declining and the pipeline might shut down.

Fact-Check:

Court documents reveal that oil companies think the pipeline will continue in service beyond 2050 to perhaps 2064, a far cry from the threat of imminent pipeline shutdown. p. 138 of 213.

409. In its initial year-end 2004 reserves submission to the BP London office, which was scheduled a couple of months before the JTG Study was concluded, BP Exploration and BP Pipelines personnel determined "an effective TAPS minimum throughput level of 150,000 bbl/d at 2053," using "conservative assumptions."⁶⁸¹ The report added:

In the case of GPB [Greater Prudhoe Bay] and KRU [Kuparuk River Unit] (the biggest contributors to the reserves adds) each of these fields were still cash flow positive at 2064 (end of our tariff profile). The reserves coordinators arbitrarily chose to cut-off life at the earlier dates (2053 for GPB and 2047 for GKA) just to give themselves some future cushion.⁶⁸²

Minimum pipeline throughput projections were based on levels as low as 70,000 to 100,000 barrels per day (bpd) even though recent years of propaganda have stated that TAPS would cease to operate at about 300,000 bpd which would be reached around 2025 if the current decline estimates continue. From case No. 3AN-06-08446 (Consolidated) Decision 30 Dec 2011 p. 143 of 213.

422. In the fall of 2010, BPPA used the lower minimum throughput determinations from the Carpenter Study in its transportation tariff calculations. Those calculations, in turn, were provided to BP Production forecasting personnel who then used that information to book BP's proven reserves in 2010.⁷⁰³ That BP relied upon the Carpenter Study's 100,000 to 70,000 bbl/d low flow estimate to book its reserves is compelling evidence that these figures may be reasonably relied upon by this Court to determine the assessed value of TAPS.

401. The Municipalities' expert Dr. Jerry Modisette testified that there is no hydraulic or mechanical minimum throughput limit because the pipeline will be within pressure constraints at flows down to zero and the pump rate can also go down to zero through reducing pumps, throttling, and recirculation.⁶⁷¹ Former Alyeska Chief Operating Officer Dan Hisey concurred that there is no hydraulic or mechanical minimum throughput limit on TAPS.⁶⁷² The Owners' expert, Ulli Pietsch, also testified that there is no hydraulic or mechanical reason that TAPS cannot operate down to 50,000 bbl/d.⁶⁷³ The inquiry therefore turns to whether there is an operational constraint that would prevent TAPS from transporting oil at some minimum capacity limit.

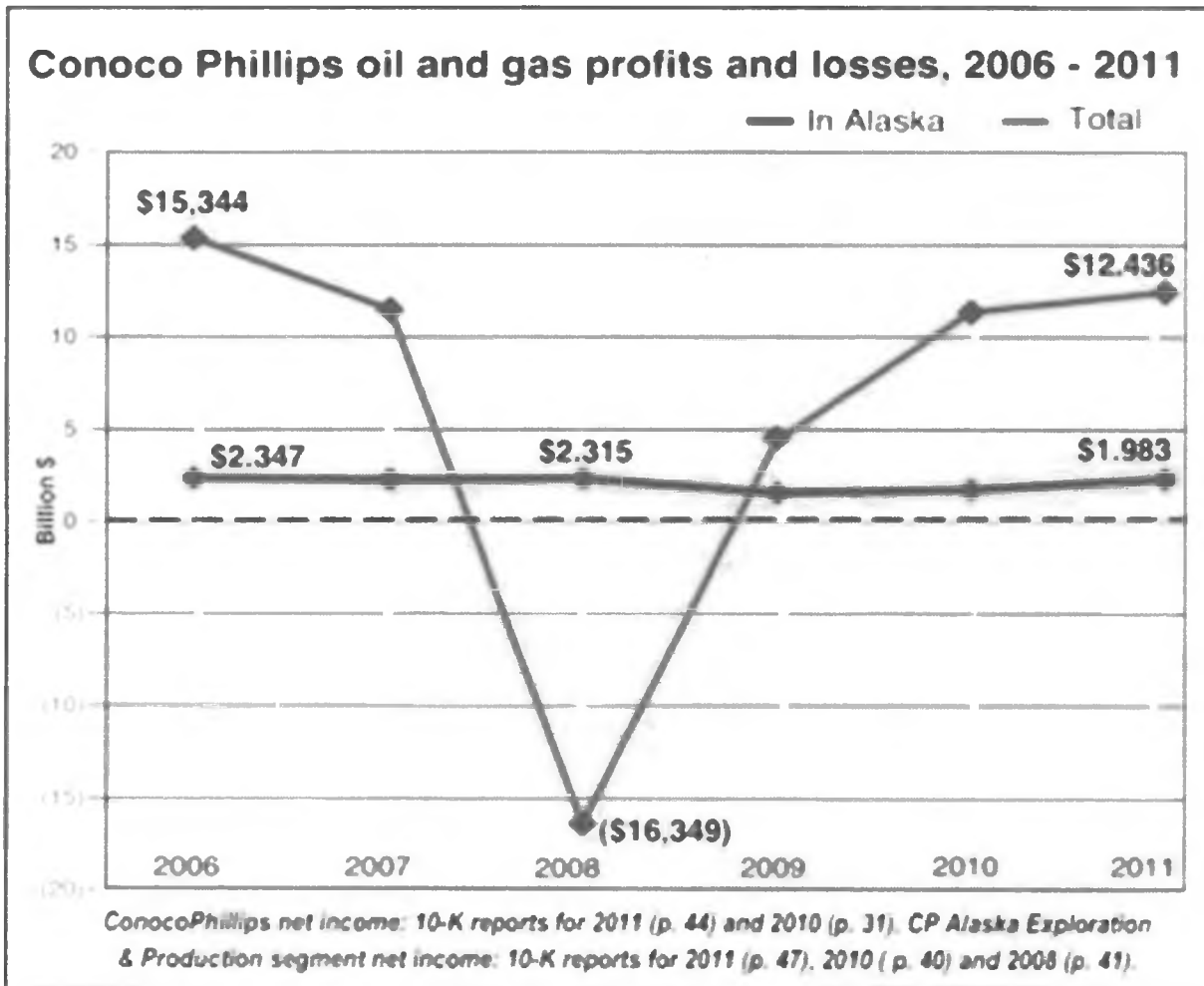
p. 136 of 213

404. BPPA analyst John Haines testified at the trial in this case. In an email dated November 5, 2004, Mr. Haines stated:

Momentum is starting to grow around booking more reserves based on an updated view of TAPS' minimum achievable rates . . . Lastly, when TAPS rates reach 100 MBD [100,000 bbl/d] we stop. Our consultant thinks we can probably operate TAPS below this minimum rate, but we didn't want to push it any further at this time.⁶⁷⁵

There is so much oil, booked as reserves on the North Slope that the current pipeline will continue past 2050, or be rebuilt if necessary. From case No. 3AN-06-08446 (Consolidated) Decision 30 Dec 2011 p. 42 of 213.

economic value of TAPS.¹⁰⁰ To the extent that there is a market for TAPS, it is the ANS producers (or an integrated refinery operation such as Koch). For the evidence persuasively demonstrates that ANS producers would rebuild TAPS at a cost of billions of dollars to transport ANS petroleum products to market if TAPS was not in existence as of the lien dates. And the producers would replace TAPS not for the tariff income they might realize, but to monetize the approximately 7 to 8 billion barrels of proven reserves that were at the ANS as of the lien dates.



Richard A. Fireberg (Research Associates) October 2012



CITY OF BARROW

"Farthest North Incorporated City"

RESOLUTION 19-2013

A RESOLUTION OF THE BARROW CITY COUNCIL FORMALLY REQUESTING GOVERNOR SEAN PARNELL AND THE ALASKA STATE HOUSE OF REPRESENTATIVES RESOURCES AND FINANCE COMMITTEES TO IDENTIFY A SPECIFIC SOURCE OF "REVENUE SHARING" FUNDS

WHEREAS, the Alaska Statehood act and the Alaska Constitution contemplate strong and vibrant local governmental units exercising maximum local control; and

WHEREAS, local governments, including the City of Barrow, are experiencing significant financial pressures resulting from inflation, high energy costs and a faltering economy; and

WHEREAS, the City of Barrow and numerous other communities throughout our great state depend on Revenue Sharing as a major source of funding to insure the operation and in some instances, the survival, of our municipalities; and

WHEREAS, it is critically important for the municipalities to have an identified source of Revenue Sharing since Senate Bill 21 (SB21) removes the Progressivity Tax, the vehicle which currently funds Revenue Sharing; and

WHEREAS, it is impossible for any municipality to create a viable budget if a major portion of the municipality's revenue is in question and may not be forthcoming; and

WHEREAS, since the early 1990s, the Revenue Sharing program has had an identified funding source (the Corporate Income Tax provisions under AS 43.20.); and

WHEREAS, a dependable source of Revenue Sharing helps communities plan for local government services and tax levels, as Revenue Sharing in larger communities helps keep tax levels lower than would otherwise be possible and in smaller communities, it funds basic services; and

WHEREAS, a regular funding source signifies the importance of local government to the State as local government is the entity that provides most of the basic services to Alaskans at the level closest to the people; and

WHEREAS, most local governments have only three (3) ways of raising revenues with the absence of Revenue Sharing and they are:

- a) Local taxes (sales and property)
- b) Fees (boat moorage, garbage collection, etc.) and
- c) Grants

WHEREAS, a significant number of communities such as Barrow does not have the opportunity or political power/will to avail themselves of the aforementioned means of raising revenue because of the additional financial burden this would place on our residents who are already experiencing one of the highest costs of living in the state; and

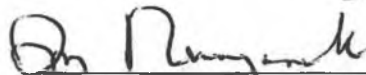
WHEREAS, SB 21 as passed out of the Senate removed any reference to a definite funding source for Revenue Sharing, but simply stated that Revenue Sharing would come out of the General Fund; and

WHEREAS, the General Fund is basically what funds everything else in state government and it would be very easy for the Legislature in years to come to tell the municipalities that there is just not enough money in the General Fund to allow for the funding of Revenue Sharing; and

NOW THEREFORE BE IT RESOLVED, that the Barrow City Council formally requests Governor Sean Parnell and the Alaska State House of Representatives Resources and Finance Committees to identify a specific source of "Revenue Sharing" funds and not jeopardize its future funding by designating the General Fund as the source of those revenues.

**PASSED AND APPROVED UNANIMOUSLY BY THE BARROW CITY COUNCIL
THIS 28th DAY OF MARCH 2013.**

ATTEST:

3-28-13


Don Nungasak, Mayor Pro Tempore



Bertha Akpik, City Clerk



Thoughts on Alaska Oil & Gas

Brad Keithley's Blog

Alaska Oil Policy| SB 21's "Oil & Gas Competitiveness Review Board" needs a fix ...

Posted on [March 22, 2013](#) | [Leave a comment](#) |

As SB 21 moves from the Senate to the House for consideration some will suggest various changes that should be made while in the House. One set of changes that should be made is to the membership of the "Oil & Gas Competitiveness Review Board," a proposal offered and championed by Senator McGuire during the bill's time in the Senate.

I have long been a supporter of such a Review Board and believe I was in the room when it was first discussed. Indeed, one of the earliest pieces I wrote on Alaska oil & gas policy was in support of adopting such a proposal. ("[*Alaska's Future: Sen. McGuire's Proposed Competitiveness Review Is Important*](#)," Feb. 10, 2011).

But the proposed membership in this version is not the same as when the Board was first discussed and the change is for the worse. As the bill travels through the House, the membership of the Board should be modified to reflect a broader constituency.

As originally introduced (as SCR 4 in the 27th Legislature), the Competitiveness Review Board had a far different, largely legislative membership. At that time, the proposed membership was as follows:

(1) one senator appointed by the president of the senate; (2) one representative appointed by the speaker of the house of representatives; (3) five members of the public, including one member who is a petroleum engineer, one member who is a petroleum geologist, and one member who is an economist, appointed jointly by the president of the senate and the speaker of the house of representatives ...

As that Legislature proceeded, the original proposal evolved into something broader, and also narrower, when added to the proposed Committee Substitute for then-SB 85 (at Section 4). There, the proposed membership included the following:

(1) one senator appointed by the president of the senate; (2) one representative appointed by the speaker of the house of representatives; (3) five members of the public appointed by the governor, including one member who is a petroleum engineer, one member who is a geologist, one member who is an economist, and one member who is a member of an environmental or conservation group; (4) the commissioner of natural resources or the

commissioner's designee; and (5) the commissioner of revenue or the commissioner's designee.

As currently proposed (in the version of SB 21 passed by the Senate, at Section 33), the "Oil & Gas Competitiveness Review Board" is to be composed of the following members:

"(1) two members nominated by the two leading nonprofit trade associations representing the oil and gas industry in the state and appointed by the governor, with one member nominated by each association; (2) the chair of the Alaska Oil and Gas Conservation Commission or the chair's designee; (3) three members of the public appointed by the governor, including one member who is a petroleum engineer, one member who is a geologist, and one member who is an economist; (4) the commissioner of environmental conservation or the commissioner's designee; (5) the commissioner of natural resources or the commissioner's designee; and (6) the commissioner of revenue or the commissioner's designee.

Essentially, the grouping is a subsection of the Governor's cabinet (Commissioners of Revenue, DNR and ADEC), one independent agency (the AOGCC), three members of the "public," but who are required to have designated, industry-related backgrounds (economist, geologist and engineer), and "two members nominated by the two leading nonprofit trade associations representing the oil and gas industry in the state."

Or, as Matt Buxton from the Fairbanks News-Miner, not entirely accurately but with some insight, has summed it up, "The competitive review board. The board with two of its five members nominated by the industry. Two more who work for the industry."

Unlike both versions proposed during the prior legislature, the current version has no legislative membership and the "public" seats are all locked down either by membership or expertise. I believe that is a significant mistake.

One of the problems that Alaska has faced in developing needed revisions to its oil & gas policy over the last several years has been the lack of a forum for developing a broad public understanding and consensus on the nature and depth of the problems that Alaska faces in competing for investments. While the various sides have developed their own versions of the "facts," there has been no ongoing, broad forum within which to discuss and debate the facts and, if not arrive at a consensus on a way forward, at least work toward a common and well thought out understanding of the challenges Alaska faces.

That would seem to be a useful step for a state that relies on a single industry for 90% of its governmental revenue and a third of its jobs. It would seem critical for a state that faces significant competition in attracting the investment dollars needed to keep that industry strong.

As a state, we are rightfully insistent that industry continually evaluate and adopt global "best practices" in their operations. Yet, we settle for holding only a few hearings during the 90-day

legislative session every year to evaluate whether, as a state, Alaska is doing the same thing at a governmental level.

In a nutshell, that is the problem the Board is designed to address.

With all due respect, however, in its currently proposed form the Competitiveness Review Board will largely be perceived, if not actually operate, largely as the insider "industry" board that Matt Buxton's recent tweet suggests. Its recommendations will not be given the weight that they would if made by a broader, consensus building body. The Board will not benefit from questions and insights brought to and taken away from meetings by those outside the industry, but who nevertheless could play an important role in educating Alaskans more broadly about the competitive environment in which the state's most important industry operates.

Two models were in the room when the Board was first discussed — the National Commission on Fiscal Responsibility and Reform (the so-called "Simpson/Bowles Commission") and various task forces that the state has used over time to address educational issues the state has faced (e.g., Alaska Advisory Task Force on Higher Education and Career Readiness; Joint Legislative Education Funding Task Force

To various degrees, both models mix Executive Branch, Legislative Branch and public members together. The Simpson-Bowles Commission, for example, included 7 members from the public (some of whom were retired Executive Branch officials or legislators) and 12 then-current legislators. The Alaska Higher Ed task force included 13 from the education sector, 5 legislators and 2 from the Executive Branch. The Education Funding Task force included 10 legislators and 1 from the education sector.

In my view, Alaska would benefit from adopting a similar model for the membership of the Competitiveness Review Board. If the Board is going to serve the function of creating a broader understanding within the state of Alaska's competitive position, then the Board itself also needs to be broader based. More perspectives mean a broader public buy in of the Board's recommendations, and ultimately, broader and more credible communication of its results.

If it were me, I would keep the Executive Branch members proposed in the current legislation (Comm'rs of Revenue, DNR and ADEC). I also would retain the Chair of the AOGCC.

But I would replace the two seats designated for "members nominated by the two leading nonprofit trade associations representing the oil and gas industry in the state" with legislators, one appointed by the President of the Senate and the other appointed by the Speaker of the House of Representatives. The legislature's participation, input and buy in is critical to developing a strong state policy. The members of industry trade groups can participate by testifying before the body.

I also would retain the three members of the public, but eliminate the requirements that they come from certain backgrounds. The Board is not — or at least it should not be — a technical board. It should draw on technical expertise from the various governmental departments, or from consultants, to meet

its technical needs.

Instead, the Board should be composed of members of the public who are capable of asking the hard questions about government policies, understanding the nexus between the Alaska economy and the industry and are capable of making — and then explaining to the public — judgments about changes in policy that are necessary or appropriate to further Alaska's public interest.

By imposing expertise criteria on members, the legislation potentially might exclude as members Alaskans such as [Mark Langland](#) or [Joe Beedle](#) of Northrim Bank, [Betsy Lawer](#) of First National Bank, [Mike Burns](#) of the Permanent Fund Board, Byron Mallott, formerly of the Permanent Fund Board, or former Governor Tony Knowles, all of whom are capable of bringing significant expertise and insight into understanding Alaska's competitive position and, as importantly, then explaining their findings to their fellow Alaskans.

That approach is wrong. The legislation should not from the outset deprive the Governor of the ability to appoint the best Alaskans to meet the objective.

As I have argued since 2010, a "Competitiveness Review Board" is an important step in more fully developing and broadly disseminating Alaska's oil policy. But if it is to succeed, it is important to match the membership to the objective. It isn't now.

Share this:

Facebook 2

Press This

Twitter 2

LinkedIn 1

Email

Print

Like this:

★ Like

Be the first to like this.

This entry was posted in [Immediate Reactions](#). Bookmark the [permalink](#).

Theme: Customized Coraline by Automattic. Blog at WordPress.com.

Oral Testimony before the House Resources Committee – SB 21

April 1, 2013

Delivered by Joe Mathis

Good afternoon, Co-Chairs Feige and Saddler, and committee members. For the record, my name is Joe Mathis and I am the Vice President of External Affairs at NANA Development Corporation. I am also the founding president of the Alaska Support Industry. I appreciate the opportunity to provide public testimony today regarding SB 21. On behalf of NDC and also in my role as Alliance Board member emeriti, I am here to say that we support the passage of SB 21 currently before this body.

Our NANA companies have been meeting the needs of the oil and gas sector for close to four decades. In 2012, we employed close to 5,000 Alaskans (I repeat 5000 employees)and more than 1,600 NANA shareholders. Through our business operations we generate income and are able to deliver valuable benefits back to our shareholder owners.

NANA shareholders have made significant investments in the oil industry over the past 40 years. We hold a small ownership interest in the Endicott Oilfield for over two decades, have invested in new facilities and equipment at Deadhorse for NANA Oilfield Services, and have invested heavily to construct new fabrication facilities in the Mat-Su Valley, specifically designed for oil field modules. Through these business activities, our shareholders and other Alaskans have been afforded the opportunity to hold hundreds of good-paying jobs, as well as the opportunity to receive extensive job training.

Oil industry investment fuels the contracts for the NANA companies, and the jobs those contracts create. We are seeing these opportunities go to places in the Lower 48- like North Dakota and Texas – where the oil industry is booming. In fact, our subsidiary (NMS) has opened a Houston office to pursue work in Texas; and we've had to look to places outside of Alaska for investment opportunities in oil and gas.

Simply put, Alaska's current investment climate is driving away business. We do not have a lack of oil in Alaska; we have a lack of investment. We have heard that the industry has billions of dollars in

projects that could be done in Alaska if the tax structure was more competitive- projects that would increase oil production, but more importantly, projects that our NANA companies have the skills, experience and expertise to carry out. This isn't an industry where we have to look for out-of-state personnel to meet the industry needs. We have a homegrown workforce, a workforce from all parts of the state- rural and urban.

We need to pull together to make sure we have a stable economic climate to serve our citizens both today, and well into the future. SB 21 will set the stage for that continued development for our economy. We believe that work done by the Senate, and this body, will produce a viable and fair tax policy both for the State, Alaskans and the producers

However, it would be remiss of me, as founding president of the Alaska Support Industry Alliance, if I did not address the need for an emphasis and language in this bill to insure that the producers are hiring competitive Alaska contractors... for the needed infrastructure and services to bring more oil to production.

If we have Alaska homegrown contractors not out of state and out of country contracts performing the work, they will insure Alaska content.

Like Machu Picchu, Peru, the Inca Empire's hidden gem that went undiscovered for 5 centuries, we have hidden gems in our vast "Greatland"...- gems that are waiting to "reveal " their fruitful benefits to our State. Significant oil and gas tax reform will make revelation.

Thank you



909 West 9th Avenue
Anchorage, Alaska 99501
nana-dev.com

Joe B Qatugrualluk Mathis
Vice President External Affairs

907 265 4112 DIRECT
907 343 5693 FAX
907 223 2121 MOBILE
joe.mathis@nana.com

Mary Ann Pease Testimony

April 1, 2013

Thank you, Chairman for allowing public comment on tax reform. My name is Mary Ann Pease, owner of MAP Consulting and Board member for Commonwealth North, the State Chamber and Consumers Energy Alliance. I am extremely concerned about the staggering decline in Oil production – We are down from a peak of over 2 million barrels a day to a little over 500 thousand barrels today and this rate continues the downward spiral decline of 5 - 7% per year during times of increasing oil prices.

Last Thursday, I attended the Alliance breakfast meeting and heard from Lydon Ibele as he described “My Bakken Adventure.” What a wakeup Call to the public and policy makers here in Alaska. Here are a few takeaways from that speech:

- The rapid growth and production of the Bakken is incredible
- ND has the 4th lowest tax rate at 9.8% and they are on a path of unprecedented prosperity and economic growth and development.
- We in Alaska need to once again become number 1 in terms of oil production! Texas, ND., California and Alaska is now in 4th place in terms of oil production. You, the Legislature, have that opportunity to reform taxes and enable our

*economy
to have a future
prosperous & sustainable*

*Page 4
Saddler
and members
of House Resource*

*Chair of the
CWN Energy
Action Coalition*

past president of Anchorage Chamber

Mary Ann Pease

High oil prices coupled with new technology have created a boom in the oil and gas industry across the country and world. Alaska, however, is missing out on this boom, and it is no secret why: Alaska's oil taxes are too high, and companies are taking their investment dollars elsewhere.

We need more oil in the pipeline to maintain jobs and strengthen the economy. The Alaska State Legislature must take action now to correct the problem.

The rates and progressivity structure of Alaska's current tax regime provide a disincentive to attracting risk capital to the state as evidenced by declining production during times of high oil prices.

Increased investment through increased global competitiveness will enhance Alaska's ability to fulfill its constitutional mandate to develop natural resources for the maximum benefit of the people.

We certainly need to show the oil and gas industry that we are open for Business and serious about keeping, growing and expanding that business by making meaningful Tax Reform happen Now!

Linda Hay

From: Kelly Walters <uskwait@coloplast.com>
Sent: Wednesday, April 03, 2013 4:03 PM
To: Linda Hay
Subject: Public Testimony for SB21 in the House Resource Committee

Chairman Feige,

Please add my comments to the House Resource Public Testimony:

I strongly object to Governor Parnell's SB21. Voting for SB21 trashes the memory of Jay Hammond and Walter J. Hickel. Both were great Republican leaders who NEVER would have agreed to giving \$ billions of our oil resource wealth away with no strings attached. Both leaders believed strongly in the Owner-State which makes Alaska unique and different from every other state. We must figure out how to fill the pipeline, but doing NOTHING is better than drastically and PERMANENTLY lowering our current tax structure with no ties to increased production.

If this gargantuan giveaway passes, it will NOT be able to be remedied in the future. For that to happen, we would need a pro-Alaska House and Senate and Governor. Never forget, the stars had to align before Alaska could finally grab a fair share of their oil wealth. We needed the FBI to sweep through and indict 10% of the legislature. We needed a governor like Sarah Palin who campaigned on an anti-corruption platform in order to redo the corrupted PPT that was responsible for several legislators' prison sentences. We needed Senate President Lyda Green, who opposed ACES, to allow it to come to the floor for a vote. There are so many incredible little things that had to happen for ACES to pass.

At the very least, put a SUNSET CLAUSE in the bill to return to ACES in 4-5 years if production doesn't increase by a minimum of 10%. That is reasonable and if you're not willing to sunset this massive "CRAPSHOOT" (according to Senator Kevin Meyer) than maybe you ought not pass this bill at all. It will absolutely bankrupt this great state.

The Organization for Economic Cooperation and Development, OEDC are forecasting Brent Crude to be \$270 per barrel within seven short years. At that price and the state forecasted throughput of TAPS, Alaska, under ACES, would earn \$23.5 BILLION DOLLARS in a single year. That's HALF the value of the Alaska Permanent Fund.

Governor Parnell and pro-billion-dollar-giveaway legislators have created the very uncertainty that the oil companies have complained about in the past. This is certainly part of the reason for development hesitation from the Big Three. If a fancy new suit from Nordstrom sells for \$1000, and the salesman told you it would be half price in a few months, you'd wait. And so are our Big 3 Producer-Partners when it comes to filling the pipeline.

We should be more like Norway. Their leaders told our leaders, "...of course the oil companies ask for tax breaks. We just don't give them any!" Norwegian legislators swore an oath to their constitution, just like Alaskan legislators did. Oil company lobbyists and CEOs swore an oath also-- to their shareholders. The Alaskan People are your shareholders. Your oath was sworn for our best interests which are articulated in our great state constitution.

Keep ACES intact with modifications to creat new production. This isn't rocket science. Any oil tax reduction must be tied to New Production. Any new tax reform should not break the bank. In Iraq, ConocoPhillips bid less than \$2 per barrel to develop the Rumallah oil field.

Keep progressivity. Alaska is an Owner-State and we deserve to reap the benefits along with our Producer-Partners when oil prices are high.

Listening to some people testify I have concluded that advertising WORKS even when it's a lie.

Make Alaska Competitive and AOGA have said repeatedly that Alaska has the highest taxes in North America. That isn't true.

At \$100 per barrel:

Mexico has a 94% tax.

Louisiana has an 86% total government take.

Gulf of Mexico Off-Shore has a 79% total government take.

Texas has a 76% Gross total take from barrel one.

Alaska has a 76% NET PROFITS TAX. That's FIFTH not highest tax.

Texas is BOOMING and their tax is higher than ours at \$100 per barrel.

ConocoPhillips made between 5 and 10 times more profit per barrel in Alaska in 2012 than The Lower 48. ConocoPhillips told their investors that Alaska was a CASH COW!

Prior to ACES, 15 of 19 North Slope fields had a zero percent tax. Production still declined. This is why the Governor's plan is a grave mistake. Clearly, based upon well-known state data and decades of history and experience, taxes have little to do with investment. There are other more important and urgent factors that experts have discussed. Experts we have NOT HEARD FROM THIS SESSION!

Under ACES, we have three years of consecutive record north slope employment.

Prior to ACES, 19 companies filed North Slope Tax Returns. Last year, in 2012, 69 companies filed North Slope Tax Returns.

During the senate resource public testimony, I heard someone mention they were testifying from the Chamber of Commerce. Apparently they didn't pay any attention to the debate that Sen. Wielechowski had with Chamber President Andrew Halcro. Mr. Halcro didn't dispute a single FACT Senator Wielechowski cited. And Senator Wielechowski used the state's own data to prove that ACES is working for the mutual benefit of both our oil partners and our great state of Alaska. Perhaps we need to shore up our security when oil prices are low and perhaps we could cap progressivity at \$150 per barrel-but new legislation that trashes ACES is just wrong and anti-Alaskan.

In summation, Alaskans are overwhelmingly opposed to a billion dollar giveaway. If you change ACES and we have no new long term production and the state is in the red, please understand there is NO GOING BACK. You most certainly will NOT (as Representative Millet believes) be able to adjust it upwards in a few years.

Remember, ACES passed due to the 10% of our legislators being indicted by the FBI for their involvement with the CBC. At the time, Governor Palin campaigned on an anti-corruption platform. Senate President Lyda Green, who opposed ACES, allowed it to come to a floor vote and it passed.

The stars will NEVER align like that again. If SB21 passes, it will bankrupt Alaska and production will still decline.

Please support Alaska and the overwhelming will of the Alaskan people. Honor the memory of Jay Hammond and Walter J. Hickel.

Sincerely,

Kelly Walters
Sand Lake
(907) 230-5997

Testimony of Resource Development Council for Alaska to
House Resource Committee,
Regarding CSSB21
April 1, 2013

Good afternoon, Co-Chairs Feige, Saddler and members of the committee. My name is Rick Rogers, Executive Director of the Resource Development Council.

RDC encourages the committee to remain focused on the ultimate goal of this legislation, increased production from both legacy and new oil fields. We understand the tension between balancing short-term impacts to the treasury with the long-term benefits to the treasury and the economy as a whole. We remain concerned that a short-term focus will undermine the overall purpose of this legislation, to increase production activity and stem the TAPS throughput decline.

Competitiveness is not a single point, but rather a continuum. SB21 is far more competitive than ACES. The degree to which we modify our tax policy should keep in mind the challenges of operating in Alaska: a short operating season; high costs; lack of infrastructure; and the very real delay risks associated with the need for federal permits. To attract sufficient investment capital to overcome our Alaska specific challenges, we need to be sufficiently aggressive in tax reduction to stand ahead of the competition.

Smaller producers have less resiliency to overcome these challenges, and we encourage the committee to consider extending the small producer tax credit to 2022 or beyond, again with the goal of helping existing and future small

producers compete in obtaining the capital needed to increase production.

This important public policy decision is not about helping industry. Its about helping Alaska so we have a more prosperous outlook for the future. There has been much discussion about guarantees. The real guarantee is that if we maintain the status quo with ACES, we guarantee continued production declines in the 7% per year range with significant revenue reductions.

In summary, RDC has not conducted a detailed analysis of the new committee substitute introduced by the committee on Friday. Like you, we look forward to hearing from explorers, producers, consultants and the administration, and will be supportive of changes to this evolving tax policy that emphasize increased production from legacy and new fields.

We commend the committee members for their continued diligence on this important policy and remain encouraged that this legislature will establish an oil and gas tax policy this session that leads to a bright future.

Thank you for the opportunity to comment.

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

March 29, 2013

SUBJECT: Oil and Gas Production Tax (HCSCSSB 21(RES) am(efd fld))
(Work Order No. 28-GS1647\B)

TO: Representative Eric Feige
Attn: Linda Hay

FROM: Emily Nauman
Legislative Counsel

Enclosed please find HCSCSSB 21(RES) am(efd fld), related to oil and gas production taxes. Please consider the following two issues.

1. Title

The "R.A" version of CSSB 21(FIN) am(efd fld) contained a defective title. The title is defective because it does not include the adjustments to the gross value at the point of production made by proposed AS 43.55.160(f) in the bill. The other subjects in the current title do not provide sufficient notice of this adjustment.

Although the bill was passed by the Senate containing this defect, it is my opinion that a title change to correct this defect does not require a concurrent resolution waiving the Uniform Rules. While Uniform Rule 24(c) prohibits a committee from reporting out a committee substitute or amendment that requires a title change, other than a technical one, the title change here is not required by an amendment or change in the second house, but rather by the defective title in the first house. Accordingly, our office has in the past considered such changes to be technical. Unfortunately, because the title change does constitute a change to the bill, the Senate will have to concur in the title change, even if the House passed a version that was otherwise identical to the bill passed by the Senate.

2. Effective Dates

Per your request, this bill draft does not include effective dates. As we discussed, this raises logistical issues with the timing and application of many of the bill sections, including statute sections that were to take place sequentially that will, without effective dates, take place simultaneously. It is not clear what the legal effect will be if sections amending, repealing, and reenacting the same statutory section are enacted simultaneously - for example, secs. 28 and 29. The bill simply does not work as drafted. We would be happy to assist you further, but require additional guidance as to how to reconcile conflicting sections without dates.

If I may be of further assistance, please advise.

ELN:Ind
13-195.Ind

Enclosure

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

March 29, 2013

SUBJECT: Problems in HCS CSSB 21(RES)
(Work Order No. 28-GS1647\B)

TO: Representative Eric Feige
Attn: Linda Hay

FROM: Kathryn L. Kurtz
Revisor of Statutes

In an effort to meet your timeline, we are sending the enclosed draft for your consideration, however, I must caution you that the draft contains irreconcilable conflicts and will not work as drafted.

If enacted in this form, I do not know how I would reconcile the conflicting bill sections which would have taken effect sequentially had the effective date sections been retained and would take effect simultaneously under this version. It is not clear what the committee's intent is by both amending and repealing and reenacting the same statutory sections that take effect at the same time. It is not clear how the committee intends the law to read on the date the Act would take effect under Art. II, sec. 18, Constitution of the State of Alaska.

KLK:med
13-100.med

Enclosure

HOUSE CS FOR CS FOR SENATE BILL NO. 21(RES)
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-EIGHTH LEGISLATURE - FIRST SESSION

BY THE HOUSE RESOURCES COMMITTEE

Offered:
Referred:

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

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the interest rate applicable to certain amounts due for fees, taxes,**
2 **and payments made and property delivered to the Department of Revenue; providing a**
3 **tax credit against the corporation income tax for qualified oil and gas service industry**
4 **expenditures; relating to the oil and gas production tax rate; relating to gas used in the**
5 **state; relating to monthly installment payments of the oil and gas production tax;**
6 **relating to oil and gas production tax credits for certain losses and expenditures;**
7 **relating to oil and gas production tax credit certificates; relating to nontransferable tax**
8 **credits based on production; relating to the oil and gas tax credit fund; relating to**
9 **annual statements by producers and explorers; relating to the determination of annual**
10 **oil and gas production tax value including adjustments based on a percentage of gross**
11 **value at the point of production from certain leases or properties; establishing the Oil**
12 **and Gas Competitiveness Review Board; and making conforming amendments."**

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

2 * **Section 1.** AS 05.15.095(c) is amended to read:

3 (c) A delinquent fee bears interest at the rate set by AS 43.05.225(2)
4 [AS 43.05.225].

5 * **Sec. 2.** AS 29.60.850(b) is amended to read:

6 (b) Each fiscal year, the legislature may appropriate to the community revenue
7 sharing fund [AN AMOUNT EQUAL TO 20 PERCENT OF THE] money received by
8 the state during the previous calendar year under AS 43.20.030(c) [AS 43.55.011(g)].

9 The amount may not exceed

10 (1) \$60,000,000; or

11 (2) the amount that, when added to the fund balance on June 30 of the
12 previous fiscal year, equals \$180,000,000.

13 * **Sec. 3.** AS 34.45.470(a) is amended to read:

14 (a) A person who fails to pay or deliver property within the time prescribed by
15 this chapter may be required to pay to the department interest at the annual rate
16 calculated under AS 43.05.225(2) [AS 43.05.225] on the property or the value of it
17 from the date the property should have been paid or delivered.

18 * **Sec. 4.** AS 43.05.225 is amended to read:

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

20 (1) when a tax levied in this title becomes delinquent, it bears interest
21 in a calendar quarter at the rate of three [FIVE] percentage points above the annual
22 rate charged member banks for advances by the 12th Federal Reserve District as of the
23 first day of that calendar quarter [, OR AT THE ANNUAL RATE OF 11 PERCENT,
24 WHICHEVER IS GREATER,] compounded quarterly as of the last day of that
25 quarter;

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

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

28 (B) unclaimed property that is not timely paid or delivered, as
29 allowed by AS 34.45.470(a).

30 * **Sec. 5.** AS 43.20.046(i) is amended to read:

31 (i) The issuance of a refund under this section does not limit the department's

1 ability to later audit or adjust the claim if the department determines, as a result of the
2 audit, that the person that claimed the credit was not entitled to the amount of the
3 credit. The tax liability of the person receiving the credit under this chapter is
4 increased by the amount of the credit that exceeds that to which the person was
5 entitled. If the tax liability is increased under this subsection, the increase bears
6 interest under AS 43.05.225(1) [AS 43.05.225] from the date the refund was issued.

7 * **Sec. 6.** AS 43.20.047(i) is amended to read:

8 (i) The issuance of a refund under this section does not limit the department's
9 ability to later audit or adjust the claim if the department determines, as a result of the
10 audit, that the person that claimed the credit was not entitled to the amount of the
11 credit. The tax liability of the person receiving the credit under this section is
12 increased by the amount of the credit that exceeds that to which the person was
13 entitled. If the tax liability is increased under this subsection, the increase bears
14 interest at the rate set by AS 43.05.225(1) [AS 43.05.225] from the date the refund
15 was issued.

16 * **Sec. 7.** AS 43.20 is amended by adding a new section to read:

17 **Sec. 43.20.049. Qualified oil and gas service industry expenditure credit.**

18 (a) For a tax year beginning after the effective date of this section, a taxpayer may
19 apply a credit against the tax due under this chapter for a qualified oil and gas service
20 industry expenditure incurred in the state. The total amount of credit a taxpayer may
21 receive in a tax year may not exceed the lesser of 10 percent of qualified oil and gas
22 service industry expenditures incurred in the state during the tax year or \$10,000,000.

23 (b) A taxpayer may not apply more than \$10,000,000 in tax credits under this
24 section in a tax year. A tax credit or portion of a tax credit under this section may not
25 be used to reduce the taxpayer's tax liability under this chapter below zero. Any
26 unused tax credit or portion of a tax credit under this section may be applied in later
27 tax years, except that any unused tax credit or portion of a tax credit may not be
28 carried forward for more than five tax years immediately following the tax year in
29 which the qualified oil and gas service industry expenditures were incurred.

30 (c) An expenditure that is the basis of the credit under this section may not be
31 the basis for

- 1 (1) a deduction against the tax levied under this chapter;
2 (2) a credit or deduction under another provision of this title; or
3 (3) any federal credit claimed under this title.

4 (d) Notwithstanding any contrary provision of AS 40.25.100(a) or
5 AS 43.05.230(e), for a year that three or more taxpayers claim a tax credit under this
6 section, the department may publish the aggregated amount of tax credits claimed
7 under this section and a description of the qualified oil and gas service industry
8 expenditures that were the basis for a tax credit under this section.

9 (e) In this section,

10 (1) "manufacture" means to perform substantial industrial operations in
11 the state to transform raw material into tangible personal property with a useful life of
12 three years or more for use in the exploration for, development of, or production of oil
13 or gas deposits;

14 (2) "modification" means an adjustment, equipping, or other alteration
15 to existing tangible personal property that has a useful life of three years or more and
16 is for use in the exploration for, development of, or production of oil or gas deposits;
17 "modification" does not include minor product alterations or inventory activities;

18 (3) "qualified oil and gas service industry expenditure" means an
19 expenditure directly attributable to an in-state manufacture or in-state modification of
20 tangible personal property used in the exploration for, development of, or production
21 of oil or gas deposits, but does not include components or equipment used for or in the
22 process of that manufacturing or modification.

23 * **Sec. 8.** AS 43.50.570 is amended to read:

24 **Sec. 43.50.570. Interest.** A licensee who fails to pay an amount due for the
25 purchase of stamps within the time required

26 (1) is considered to have failed to pay the cigarette taxes due under this
27 chapter; and

28 (2) shall pay interest at the rate established under AS 43.05.225(1)
29 [AS 43.05.225] from the date on which the amount became due until the date of
30 payment.

31 * **Sec. 9.** AS 43.55.011(e) is amended to read:

1 (e) There is levied on the producer of oil or gas a tax for all oil and gas
2 produced each calendar year from each lease or property in the state, less any oil and
3 gas the ownership or right to which is exempt from taxation or constitutes a
4 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), (o), and
5 (p) of this section, the tax is equal to [THE SUM OF

6 (1)] the annual production tax value of the taxable oil and gas as
7 calculated under AS 43.55.160(a) [AS 43.55.160(a)(1)] multiplied by 35 [25] percent
8 [; AND

9 (2) THE SUM, OVER ALL MONTHS OF THE CALENDAR YEAR,
10 OF THE TAX AMOUNTS DETERMINED UNDER (g) OF THIS SECTION].

11 * **Sec. 10.** AS 43.55.011(o) is amended to read:

12 (o) Notwithstanding other provisions of this section, for a calendar year before
13 2022, the tax levied under (e) of this section for each 1,000 cubic feet of gas for gas
14 produced from a lease or property outside the Cook Inlet sedimentary basin and used
15 in the state, other than gas subject to (p) of this section, may not exceed the amount
16 of tax for each 1,000 cubic feet of gas that is determined under (j)(2) of this section.

17 * **Sec. 11.** AS 43.55.020(a) is amended to read:

18 (a) For a calendar year, a producer subject to tax under AS 43.55.011
19 [AS 43.55.011(e) - (i) OR (p)] shall pay the tax as follows:

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

27 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
28 produced from leases or properties in the state outside the Cook Inlet
29 sedimentary basin [BUT NOT SUBJECT TO AS 43.55.011(o) OR (p)], other
30 than leases or properties subject to AS 43.55.011(f), the greater of

31 (i) zero; or

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

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

11 (i) zero;

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

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

25 (C) for oil or [AND] gas [PRODUCED FROM EACH LEASE
26 OR PROPERTY] subject to AS 43.55.011(j), (k), or (o) [, OR (p)], for each
27 lease or property, the greater of

28 (i) zero; or

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

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

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

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

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

20 (2) an amount calculated under (1)(C) of this subsection for oil or gas
21 [PRODUCED FROM A LEASE OR PROPERTY

22 (A)] subject to AS 43.55.011(j), (k), or (o) may not exceed the
23 product obtained by carrying out the calculation set out in AS 43.55.011(j)(1)
24 or (2) or 43.55.011(o), as applicable, for gas or set out in AS 43.55.011(k)(1)
25 or (2), as applicable, for oil, but substituting in AS 43.55.011(j)(1)(A) or (2)(A)
26 or 43.55.011(o), as applicable, the amount of taxable gas produced during the
27 month for the amount of taxable gas produced during the calendar year and
28 substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of
29 taxable oil produced during the month for the amount of taxable oil produced
30 during the calendar year;

31 [(B) SUBJECT TO AS 43.55.011(p) MAY NOT EXCEED

1 FOUR PERCENT OF THE GROSS VALUE AT THE POINT OF
2 PRODUCTION OF THE OIL OR GAS;]

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

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

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

15 (4) any amount of tax levied by AS 43.55.011 [AS 43.55.011(e) OR
16 (i)], net of any credits applied as allowed by law, that exceeds the total of the amounts
17 due as installment payments of estimated tax is due on March 31 of the year following
18 the calendar year of production.

19 * **Sec. 12.** AS 43.55.020(a), as amended by sec. 11 of this Act, is amended to read:

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

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

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

1 the greater of

2 (i) zero; or

3 (ii) **35 percent** [THE SUM OF 25 PERCENT AND
4 THE TAX RATE CALCULATED FOR THE MONTH UNDER
5 AS 43.55.011(g)] multiplied by the remainder obtained by subtracting
6 1/12 of the producer's adjusted lease expenditures for the calendar year
7 of production under AS 43.55.165 and 43.55.170 that are deductible for
8 the oil and gas under AS 43.55.160 from the gross value at the point of
9 production of the oil and gas produced from the leases or properties
10 during the month for which the installment payment is calculated;

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

13 (i) zero;

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

18 (iii) **35 percent** [THE SUM OF 25 PERCENT AND
19 THE TAX RATE CALCULATED FOR THE MONTH UNDER
20 AS 43.55.011(g)] multiplied by the remainder obtained by subtracting
21 1/12 of the producer's adjusted lease expenditures for the calendar year
22 of production under AS 43.55.165 and 43.55.170 that are deductible for
23 the oil and gas under AS 43.55.160 from the gross value at the point of
24 production of the oil and gas produced from those leases or properties
25 during the month for which the installment payment is calculated,
26 **except that, for the purposes of this calculation, a 20 percent**
27 **exclusion from the gross value at the point of production may**
28 **apply for oil and gas subject to AS 43.55.160(f):**

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

31 (i) zero; or

1 (ii) 35 percent [THE SUM OF 25 PERCENT AND
2 THE TAX RATE CALCULATED FOR THE MONTH UNDER
3 AS 43.55.011(g)] multiplied by the remainder obtained by subtracting
4 1/12 of the producer's adjusted lease expenditures for the calendar year
5 of production under AS 43.55.165 and 43.55.170 that are deductible
6 under AS 43.55.160 for the oil or gas, respectively, produced from the
7 lease or property from the gross value at the point of production of the
8 oil or gas, respectively, produced from the lease or property during the
9 month for which the installment payment is calculated;

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

11 (i) 35 percent [THE SUM OF 25 PERCENT AND
12 THE TAX RATE CALCULATED FOR THE MONTH UNDER
13 AS 43.55.011(g)] multiplied by the remainder obtained by subtracting
14 1/12 of the producer's adjusted lease expenditures for the calendar year
15 of production under AS 43.55.165 and 43.55.170 that are deductible for
16 the oil and gas under AS 43.55.160 from the gross value at the point of
17 production of the oil and gas produced from the leases or properties
18 during the month for which the installment payment is calculated, but
19 not less than zero; or

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

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

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

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

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

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

17 * **Sec. 13.** AS 43.55.020(d) is amended to read:

18 (d) In making settlement with the royalty owner for oil and gas that is taxable
19 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
20 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
21 time the tax becomes due to the amount of the tax paid. If the total deductions of
22 installment payments of estimated tax for a calendar year exceed the actual tax for that
23 calendar year, the producer shall, before April 1 of the following year, refund the
24 excess to the royalty owner. Unless otherwise agreed between the producer and the
25 royalty owner, the amount of the tax paid under AS 43.55.011(e) [AS 43.55.011(e) -
26 (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the
27 ownership or right to which constitutes a landowner's royalty interest, is considered to
28 be the gross value at the point of production of the taxable royalty oil and gas
29 produced during the calendar year multiplied by a figure that is a quotient, in which

30 (1) the numerator is the producer's total tax liability under
31 AS 43.55.011(e) [AS 43.55.011(e) - (g)] for the calendar year of production; and

1 (2) the denominator is the total gross value at the point of production
2 of the oil and gas taxable under AS 43.55.011(e) [AS 43.55.011(e) - (g)] produced by
3 the producer from all leases and properties in the state during the calendar year.

4 * **Sec. 14.** AS 43.55.020(g) is amended to read:

5 (g) Notwithstanding any contrary provision of AS 43.05.225, an unpaid
6 amount of an installment payment required under (a)(1) - (3) of this section that is not
7 paid when due bears interest (1) at the rate provided for an underpayment under 26
8 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from the date
9 the installment payment is due until March 31 following the calendar year of
10 production, and (2) as provided for a delinquent tax under AS 43.05.225(1)
11 [AS 43.05.225] after that March 31. Interest accrued under (1) of this subsection that
12 remains unpaid after that March 31 is treated as an addition to tax that bears interest
13 under (2) of this subsection. An unpaid amount of tax due under (a)(4) of this section
14 that is not paid when due bears interest as provided for a delinquent tax under
15 AS 43.05.225(1) [AS 43.05.225].

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

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

19 (1) notwithstanding that a qualified capital expenditure may be a
20 deductible lease expenditure for purposes of calculating the production tax value of oil
21 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
22 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or
23 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
24 against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that
25 expenditure; [HOWEVER, NOT MORE THAN HALF OF THE TAX CREDIT MAY
26 BE APPLIED FOR A SINGLE CALENDAR YEAR;]

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

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

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

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

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

7 (b) **For lease expenditures incurred to explore for, develop, or produce oil**
8 **or gas deposits located south of 68 degrees North latitude, a [A] producer or**
9 **explorer may elect to take a tax credit in the amount of 25 percent of a carried-forward**
10 **annual loss. For lease expenditures incurred after December 31, 2013, to explore**
11 **for, develop, or produce oil or gas deposits located north of 68 degrees North**
12 **latitude, a producer or explorer may elect to take a tax credit in the amount of 35**
13 **percent of a carried-forward annual loss.** A credit under this subsection may be
14 applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a
15 carried-forward annual loss is the amount of a producer's or explorer's adjusted lease
16 expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was
17 not deductible in calculating production tax values for that calendar year under
18 AS 43.55.160.

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

20 (d) Except as limited by (i) of this section, a person that is entitled to take a tax
21 credit under this section that wishes to transfer the unused credit to another person or
22 obtain a cash payment under AS 43.55.028 may apply to the department for a
23 transferable tax credit **certificate** [CERTIFICATES]. An application under this
24 subsection must be in a form prescribed by the department and must include
25 supporting information and documentation that the department reasonably requires.
26 The department shall grant or deny an application, or grant an application as to a lesser
27 amount than that claimed and deny it as to the excess, not later than 120 days after the
28 latest of (1) March 31 of the year following the calendar year in which the qualified
29 capital expenditure or carried-forward annual loss for which the credit is claimed was
30 incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for
31 the calendar year in which the qualified capital expenditure or carried-forward annual

1 loss for which the credit is claimed was incurred; or (3) the date the application was
2 received by the department. If, based on the information then available to it, the
3 department is reasonably satisfied that the applicant is entitled to a credit, the
4 department shall issue the applicant a [TWO] transferable tax credit certificate for
5 [CERTIFICATES, EACH FOR HALF OF] the amount of the credit. [THE CREDIT
6 SHOWN ON ONE OF THE TWO CERTIFICATES IS AVAILABLE FOR
7 IMMEDIATE USE. THE CREDIT SHOWN ON THE SECOND OF THE TWO
8 CERTIFICATES MAY NOT BE APPLIED AGAINST A TAX FOR A CALENDAR
9 YEAR EARLIER THAN THE CALENDAR YEAR FOLLOWING THE
10 CALENDAR YEAR IN WHICH THE CERTIFICATE IS ISSUED, AND THE
11 CERTIFICATE MUST CONTAIN A CONSPICUOUS STATEMENT TO THAT
12 EFFECT.] A certificate issued under this subsection does not expire.

13 * **Sec. 18.** AS 43.55.023(d), as amended by sec. 17 of this Act, is amended to read:

14 (d) A [EXCEPT AS LIMITED BY (i) OF THIS SECTION, A] person that is
15 entitled to take a tax credit under this section that wishes to transfer the unused credit
16 to another person or obtain a cash payment under AS 43.55.028 may apply to the
17 department for a transferable tax credit certificate. An application under this
18 subsection must be in a form prescribed by the department and must include
19 supporting information and documentation that the department reasonably requires.
20 The department shall grant or deny an application, or grant an application as to a lesser
21 amount than that claimed and deny it as to the excess, not later than 120 days after the
22 latest of (1) March 31 of the year following the calendar year in which the qualified
23 capital expenditure or carried-forward annual loss for which the credit is claimed was
24 incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for
25 the calendar year in which the qualified capital expenditure or carried-forward annual
26 loss for which the credit is claimed was incurred; or (3) the date the application was
27 received by the department. If, based on the information then available to it, the
28 department is reasonably satisfied that the applicant is entitled to a credit, the
29 department shall issue the applicant a transferable tax credit certificate for the amount
30 of the credit. A certificate issued under this subsection does not expire.

31 * **Sec. 19.** AS 43.55.023(g) is amended to read:

1 (g) The issuance of a transferable tax credit certificate under (d) of this
2 section or former (m) of this section or the purchase of a certificate under
3 AS 43.55.028 does not limit the department's ability to later audit a tax credit claim to
4 which the certificate relates or to adjust the claim if the department determines, as a
5 result of the audit, that the applicant was not entitled to the amount of the credit for
6 which the certificate was issued. The tax liability of the applicant under
7 AS 43.55.011(e) and 43.55.017 - 43.55.180 is increased by the amount of the credit
8 that exceeds that to which the applicant was entitled, or the applicant's available valid
9 outstanding credits applicable against the tax levied by AS 43.55.011(e) are reduced
10 by that amount. If the applicant's tax liability is increased under this subsection, the
11 increase bears interest under AS 43.05.225(1) [AS 43.05.225] from the date the
12 transferable tax credit certificate was issued. For purposes of this subsection, an
13 applicant that is an explorer is considered a producer subject to the tax levied by
14 AS 43.55.011(e).

15 * **Sec. 20.** AS 43.55.023(n) is amended to read:

16 (n) For the purposes of (l) [AND (m)] of this section, a well lease expenditure
17 incurred in the state south of 68 degrees North latitude is a lease expenditure that is

18 (1) directly related to an exploration well, a stratigraphic test well, a
19 producing well, or an injection well other than a disposal well, located in the state
20 south of 68 degrees North latitude, if the expenditure is a qualified capital expenditure
21 and an intangible drilling and development cost authorized under 26 U.S.C. (Internal
22 Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made
23 under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well
24 includes an expenditure for well sidetracking, well deepening, well completion or
25 recompletion, or well workover, regardless of whether the well is or has been a
26 producing well; or

27 (2) an expense for seismic work conducted within the boundaries of a
28 production or exploration unit.

29 * **Sec. 21.** AS 43.55.024(e) is amended to read:

30 (e) On written application by a producer that includes any information the
31 department may require, the department shall determine whether the producer

1 qualifies for a calendar year under (a) and (c) of this section. To qualify under (a) and
2 (c) of this section, a producer must demonstrate that its operation in the state or its
3 ownership of an interest in a lease or property in the state as a distinct producer would
4 not result in the division among multiple producer entities of any production tax
5 liability under AS 43.55.011(e) that reasonably would be expected to be attributed to a
6 single producer if the tax credit provisions of (a) or (c) of this section did not exist.

7 * **Sec. 22.** AS 43.55.024 is amended by adding new subsections to read:

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

14 (j) A producer may apply against the producer's tax liability for the calendar
15 year under AS 43.55.011(e) a tax credit in the amount specified in this subsection for
16 each barrel of taxable oil under AS 43.55.011(e) that does not meet any of the criteria
17 in AS 43.55.160(f) and that is produced during a calendar year after December 31,
18 2013. A tax credit under this section may not reduce a producer's tax liability for a
19 calendar year under AS 43.55.011(e) to below zero. The amount of the tax credit for a
20 barrel of taxable oil subject to this subsection is

21 (1) \$8 for each barrel of taxable oil if the average gross value at the
22 point of production for the month is less than \$80 a barrel;

23 (2) \$7 for each barrel of taxable oil if the average gross value at the
24 point of production for the month is greater than or equal to \$80 a barrel, but less than
25 \$90 a barrel;

26 (3) \$6 for each barrel of taxable oil if the average gross value at the
27 point of production for the month is greater than or equal to \$90 a barrel, but less than
28 \$100 a barrel;

29 (4) \$5 for each barrel of taxable oil if the average gross value at the
30 point of production for the month is greater than or equal to \$100 a barrel, but less
31 than \$110 a barrel;

1 (5) \$4 for each barrel of taxable oil if the average gross value at the
2 point of production for the month is greater than or equal to \$110 a barrel, but less
3 than \$120 a barrel;

4 (6) \$3 for each barrel of taxable oil if the average gross value at the
5 point of production for the month is greater than or equal to \$120 a barrel, but less
6 than \$130 a barrel;

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

10 (8) \$1 for each barrel of taxable oil if the average gross value at the
11 point of production for the month is greater than or equal to \$140 a barrel, but less
12 than \$150 a barrel;

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

15 * **Sec. 23.** AS 43.55.025(a) is amended to read:

16 (a) Subject to the terms and conditions of this section, a credit against the
17 production tax levied by AS 43.55.011(e) is allowed for exploration expenditures that
18 qualify under (b) of this section in an amount equal to one of the following:

19 (1) 30 percent of the total exploration expenditures that qualify only
20 under (b) and (c) of this section;

21 (2) 30 percent of the total exploration expenditures that qualify only
22 under (b) and (d) of this section;

23 (3) 40 percent of the total exploration expenditures that qualify under
24 (b), (c), and (d) of this section;

25 (4) 40 percent of the total exploration expenditures that qualify only
26 under (b) and (e) of this section;

27 (5) 80, 90, or 100 percent, or a lesser amount described in (I) of this
28 section, of the total exploration expenditures described in (b)(1) and (2) of this section
29 and not excluded by (b)(3) and (4) of this section that qualify only under (I) of this
30 section;

31 (6) the lesser of \$25,000,000 or 80 percent of the total exploration

1 drilling expenditures described in (m) of this section and that qualify under (b) and
2 (c)(1), (c)(2)(A), and (c)(2)(C) [(c)] of this section;

3 (7) the lesser of \$7,500,000 or 75 percent of the total seismic
4 exploration expenditures described in (n) of this section and that qualify under (b) of
5 this section.

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

7 (m) The persons that drill the first four exploration wells in the state and
8 within the areas described in (o) of this section on state lands, private lands, or federal
9 onshore lands for the purpose of discovering oil or gas that penetrate and evaluate a
10 prospect in a basin described in (o) of this section are eligible for a credit under (a)(6)
11 of this section. A credit under this subsection may not be taken for more than two
12 exploration wells in a single area described in (o)(1) - (6) of this section. Exploration
13 expenditures eligible for the credit in this subsection must be incurred for work
14 performed after June 1, 2012, and before July 1, 2016. A person planning to drill an
15 exploration well on private land and to apply for a credit under this subsection shall
16 obtain written consent from the owner of the oil and gas interest for the full public
17 release of all well data after the expiration of the confidentiality period applicable to
18 information collected under (f) of this section. The written consent of the owner of the
19 oil and gas interest must be submitted to the commissioner of natural resources before
20 approval of the proposed exploration well. In addition to the requirements in (c)(1),
21 (c)(2)(A), and (c)(2)(C) [(c)] of this section and submission of the written consent of
22 the owner of the oil and gas interest, a person planning to drill an exploration well
23 shall obtain approval from the commissioner of natural resources before the well is
24 spudded. The commissioner of natural resources shall make a written determination
25 approving or rejecting an exploration well within 60 days after receiving the request
26 for approval or as soon as is practicable thereafter. Before approving the exploration
27 well, the commissioner of natural resources shall consider the following: the location
28 of the well; the proximity to a community in need of a local energy source; the
29 proximity of existing infrastructure; the experience and safety record of the explorer in
30 conducting operations in remote or roadless areas; the projected cost schedule;
31 whether seismic mapping and seismic data sufficiently identify a particular trap for

1 exploration; whether the targeted and planned depth and range are designed to
2 penetrate and fully evaluate the hydrocarbon potential of the proposed prospect and
3 reach the level below which economic hydrocarbon reservoirs are likely to be found,
4 or reach 12,000 feet or more true vertical depth; and whether the exploration plan
5 provides for a full evaluation of the wellbore below surface casing to the depth of the
6 well. Whether the exploration well for which a credit is requested under this
7 subsection is located within an area and a basin described under (o) of this section
8 shall be determined by the commissioner of natural resources and reported to the
9 commissioner. A taxpayer that obtains a credit under this subsection may not claim a
10 tax credit under AS 43.55.023 or another provision in this section for the same
11 exploration expenditure.

12 * **Sec. 25.** AS 43.55.028(e) is amended to read:

13 (e) The department, on the written application of a person to whom a
14 transferable tax credit certificate has been issued under AS 43.55.023(d) or **former**
15 **AS 43.55.023(m)** [(m)] or to whom a production tax credit certificate has been issued
16 under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to
17 purchase, in whole or in part, the certificate if the department finds that

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

21 (2) the applicant does not have an outstanding liability to the state for
22 unpaid delinquent taxes under this title;

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

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

29 (5) the purchase is consistent with this section and regulations adopted
30 under this section.

31 * **Sec. 26.** AS 43.55.028(g) is amended to read:

1 (g) The department may adopt regulations to carry out the purposes of this
2 section, including standards and procedures to allocate available money among
3 applications for purchases under this chapter and claims for refunds and payments
4 under AS 43.20.046 or 43.20.047 when the total amount of the applications for
5 purchase and claims for refund exceed the amount of available money in the fund. The
6 regulations adopted by the department may not, when allocating available money in
7 the fund under this section, distinguish an application for the purchase of a credit
8 certificate issued under former AS 43.55.023(m) or a claim for a refund or payment
9 under AS 43.20.046 or 43.20.047.

10 * **Sec. 27.** AS 43.55.030(e) is amended to read:

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

17 (1) the explorer's or producer's qualified capital expenditures, as
18 defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and
19 adjustments or other payments or credits under AS 43.55.170; and

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

23 * **Sec. 28.** AS 43.55.160(a) is amended to read:

24 (a) Except as provided in (b) of this section, for the purposes of

25 (1) AS 43.55.011(e), the annual production tax value of the taxable oil,
26 gas, or oil and gas subject to this paragraph produced during a calendar year is the
27 gross value at the point of production of the oil, gas, or oil and gas taxable under
28 AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the
29 calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the
30 producer from leases or properties, as adjusted under AS 43.55.170; this paragraph
31 applies to

1 (A) oil and gas produced from leases or properties in the state
2 that include land north of 68 degrees North latitude, other than gas produced
3 before 2022 and used in the state;

4 (B) oil and gas produced from leases or properties in the state
5 outside the Cook Inlet sedimentary basin, no part of which is north of 68
6 degrees North latitude; this subparagraph does not apply to [GAS]

7 (i) gas produced before 2022 and used in the state; or

8 (ii) oil and gas subject to AS 43.55.011(p);

9 (C) oil produced before 2022 from each [A] lease or property
10 in the Cook Inlet sedimentary basin;

11 (D) gas produced before 2022 from each [A] lease or property
12 in the Cook Inlet sedimentary basin;

13 (E) gas produced before 2022 from each [A] lease or property
14 in the state outside the Cook Inlet sedimentary basin and used in the state,
15 other than gas subject to AS 43.55.011(p);

16 (F) oil and gas subject to AS 43.55.011(p) produced from
17 leases or properties in the state;

18 (G) oil and gas produced from leases or properties in the
19 state [A LEASE OR PROPERTY] no part of which is north of 68 degrees
20 North latitude, other than oil or gas described in (B), (C), (D), (E), or (F) of
21 this paragraph;

22 (2) AS 43.55.011(g), the monthly production tax value of the taxable

23 (A) oil and gas produced during a month from leases or
24 properties in the state that include land north of 68 degrees North latitude is the
25 gross value at the point of production of the oil and gas taxable under
26 AS 43.55.011(e) and produced by the producer from those leases or properties,
27 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
28 calendar year applicable to the oil and gas produced by the producer from
29 those leases or properties, as adjusted under AS 43.55.170; this subparagraph
30 does not apply to gas subject to AS 43.55.011(o);

31 (B) oil and gas produced during a month from leases or

1 properties in the state outside the Cook Inlet sedimentary basin, no part of
 2 which is north of 68 degrees North latitude, is the gross value at the point of
 3 production of the oil and gas taxable under AS 43.55.011(e) and produced by
 4 the producer from those leases or properties, less 1/12 of the producer's lease
 5 expenditures under AS 43.55.165 for the calendar year applicable to the oil and
 6 gas produced by the producer from those leases or properties, as adjusted under
 7 AS 43.55.170; this subparagraph does not apply to gas subject to
 8 AS 43.55.011(o);

9 (C) oil produced during a month from a lease or property in the
 10 Cook Inlet sedimentary basin is the gross value at the point of production of
 11 the oil taxable under AS 43.55.011(e) and produced by the producer from that
 12 lease or property, less 1/12 of the producer's lease expenditures under
 13 AS 43.55.165 for the calendar year applicable to the oil produced by the
 14 producer from that lease or property, as adjusted under AS 43.55.170;

15 (D) gas produced during a month from a lease or property in
 16 the Cook Inlet sedimentary basin is the gross value at the point of production
 17 of the gas taxable under AS 43.55.011(e) and produced by the producer from
 18 that lease or property, less 1/12 of the producer's lease expenditures under
 19 AS 43.55.165 for the calendar year applicable to the gas produced by the
 20 producer from that lease or property, as adjusted under AS 43.55.170;

21 (E) gas produced during a month from a lease or property
 22 outside the Cook Inlet sedimentary basin and used in the state is the gross
 23 value at the point of production of that gas taxable under AS 43.55.011(e) and
 24 produced by the producer from that lease or property, less 1/12 of the
 25 producer's lease expenditures under AS 43.55.165 for the calendar year
 26 applicable to that gas produced by the producer from that lease or property, as
 27 adjusted under AS 43.55.170.

28 * **Sec. 29.** AS 43.55.160(a) is repealed and reenacted to read:

29 (a) Except as provided in (b) and (f) of this section, for the purposes of
 30 AS 43.55.011(e), the annual production tax value of taxable oil, gas, or oil and gas
 31 produced by a producer during a calendar year in a specific category for which a

1 separate production tax value is required to be calculated under this subsection is equal
2 to the gross value at the point of production of that oil, gas, or oil and gas,
3 respectively, taxable under AS 43.55.011(e), less the producer's lease expenditures
4 under AS 43.55.165 for the calendar year that are applicable to the oil, gas, or oil and
5 gas, respectively, in that category produced by the producer during the calendar year,
6 as adjusted under AS 43.55.170. A separate annual production tax value must be
7 calculated for

8 (1) oil and gas produced from leases or properties in the state that
9 include land north of 68 degrees North latitude, other than gas produced before 2022
10 and used in the state;

11 (2) oil and gas produced from leases or properties in the state outside
12 the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North
13 latitude, during a calendar year before or during the last calendar year under
14 AS 43.55.024(b) for which the producer could take a tax credit under
15 AS 43.55.024(a); this paragraph does not apply to

16 (A) gas produced before 2022 and used in the state; or

17 (B) oil and gas subject to AS 43.55.011(p);

18 (3) oil produced before 2022 from each lease or property in the Cook
19 Inlet sedimentary basin;

20 (4) gas produced before 2022 from each lease or property in the Cook
21 Inlet sedimentary basin;

22 (5) gas produced before 2022 from each lease or property in the state
23 outside the Cook Inlet sedimentary basin and used in the state, other than gas subject
24 to AS 43.55.011(p);

25 (6) oil and gas subject to AS 43.55.011(p) produced from leases or
26 properties in the state;

27 (7) oil and gas produced from leases or properties in the state no part
28 of which is north of 68 degrees North latitude, other than oil or gas described in (2),
29 (3), (4), (5), or (6) of this subsection.

30 * **Sec. 30.** AS 43.55.160(e) is amended to read:

31 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that

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

19 * **Sec. 31.** AS 43.55.160 is amended by adding a new subsection to read:

20 (f) In the calculation of an annual production tax value of a producer under
21 (a)(1) of this section, the gross value at the point of production of oil or gas meeting
22 one or more of the following criteria is reduced by 20 percent: (1) the oil or gas is
23 produced from a lease or property that does not contain a lease that was within a unit
24 on January 1, 2003; (2) the oil or gas is produced from a participating area established
25 after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before
26 January 1, 2003, if the participating area does not contain a reservoir that had
27 previously been in a participating area established before December 31, 2011; (3) the
28 oil or gas is produced from acreage that was added to an existing participating area by
29 the Department of Natural Resources after December 31, 2012, and the producer
30 demonstrates to the department that the volume of oil or gas produced is from acreage
31 added to an existing participating area. A reduction under this subsection may not

1 reduce the gross value at the point of production below zero. In this subsection,
2 "participating area" means a reservoir or portion of a reservoir producing or
3 contributing to production as approved by the Department of Natural Resources.

4 * **Sec. 32.** AS 43.56.160 is amended to read:

5 **Sec. 43.56.160. Interest and penalty.** When the tax levied by AS 43.56.010(a)
6 becomes delinquent, a penalty of 10 percent shall be added. Interest on the delinquent
7 taxes, exclusive of penalty, shall be assessed at the rate specified in AS 43.05.225(1)
8 [A RATE OF EIGHT PERCENT A YEAR].

9 * **Sec. 33.** AS 43.77.020(d) is amended to read:

10 (d) A person subject to the tax under this chapter shall make quarterly
11 payments of the tax estimated to be due for the year, as required under regulations
12 adopted by the department. A taxpayer will be subject to an estimated tax penalty,
13 determined by applying the interest rate specified in AS 43.05.225(1) [AS 43.05.225]
14 to the underpayment for each quarter, unless the taxpayer makes estimated tax
15 payments in equal installments that total either

16 (1) at least 90 percent of the taxpayer's tax liability under this chapter
17 for the tax year; or

18 (2) at least 100 percent of the taxpayer's tax liability under this chapter
19 for the prior tax year.

20 * **Sec. 34.** AS 43.90.430 is amended to read:

21 **Sec. 43.90.430. Interest.** When a payment due to the state under this chapter
22 becomes delinquent, the payment bears interest at the rate applicable to a delinquent
23 tax under AS 43.05.225(1) [AS 43.05.225].

24 * **Sec. 35.** AS 43.98 is amended by adding new sections to read:

25 **Article 2. Oil and Gas Competitiveness Review Board.**

26 **Sec. 43.98.040. Oil and Gas Competitiveness Review Board.** (a) The Oil and
27 Gas Competitiveness Review Board is established in the department.

28 (b) The board shall consist of nine members as follows:

29 (1) two members nominated by the two leading nonprofit trade
30 associations representing the oil and gas industry in the state and appointed by the
31 governor, with one member nominated by each association;

1 (2) the chair of the Alaska Oil and Gas Conservation Commission or
2 the chair's designee;

3 (3) three members of the public appointed by the governor, including
4 one member who is a petroleum engineer, one member who is a geologist, and one
5 member who is a financial analyst;

6 (4) the commissioner of environmental conservation or the
7 commissioner's designee;

8 (5) the commissioner of natural resources or the commissioner's
9 designee; and

10 (6) the commissioner of revenue or the commissioner's designee.

11 (c) The governor shall, every two years, designate one of the members as
12 chair.

13 (d) Members of the board appointed under (b)(1) and (3) of this section serve
14 for four years. An individual who has served on the board may be reappointed.

15 (e) A vacancy on the board shall be filled in the manner of the original
16 appointment.

17 (f) A member of the board may be removed and replaced at the discretion of
18 the governor.

19 (g) The members of the board appointed under (b)(1) and (3) of this section
20 serve without compensation but shall receive per diem and travel expenses authorized
21 for boards and commissions under AS 39.20.180.

22 (h) The board may enter into contracts for professional services. The
23 department shall provide staff for administrative support for the board.

24 (i) The board may not meet more than once in a calendar year.

25 **Sec. 43.98.050. Duties.** The duties of the board include the following:

26 (1) establish and maintain a salient collection of information related to
27 oil and gas exploration, development, and production in the state and related to tax
28 structures, rates, and credits in other regions with oil and gas resources;

29 (2) review historical, current, and potential levels of investment in the
30 state's oil and gas sector;

31 (3) identify factors that affect investment in oil and gas exploration,

1 development, and production in the state, including tax structure, rates, and credits;
2 royalty requirements; infrastructure; workforce availability; and regulatory
3 requirements;

4 (4) review the competitive position of the state to attract and maintain
5 investment in the oil and gas sector in the state as compared to the competitive
6 position of other regions with oil and gas resources;

7 (5) in order to facilitate the work of the board, establish procedures to
8 accept and keep confidential information that is beneficial to the work of the board,
9 including the creation of a secure data room and confidentiality agreements to be
10 signed by individuals having access to confidential information;

11 (6) make written findings and recommendations to the Alaska State
12 Legislature before January 31, 2015, or as soon thereafter as practicable, and every
13 four years thereafter beginning January 31, 2015, regarding

14 (A) changes to the state's regulatory environment that would be
15 conducive to encouraging increased investment while protecting the interests
16 of the people of the state and the environment;

17 (B) changes to the state's fiscal regime that would be conducive
18 to increased and ongoing long-term investment in and development of the
19 state's oil and gas resources; and

20 (C) alternative means for increasing the state's ability to attract
21 and maintain investment in and development of the state's oil and gas
22 resources.

23 **Sec. 43.98.060. Information to be provided to board.** (a) The commissioner
24 of natural resources, the commissioner of revenue, the commissioner of environmental
25 conservation, and other commissioners and state agencies that have responsibility for
26 and maintain information related to oil and gas investment and activity in the state
27 shall, at the request of the board, provide information required by the board to carry
28 out the duties described in AS 43.98.050.

29 (b) At the request of the board, and except for information that is confidential
30 under AS 40.25.100(a) or AS 43.05.230 and information required to be held
31 confidential by the Alaska Oil and Gas Conservation Commission, a commissioner

1 may disclose to the board information that is otherwise confidential after each member
2 of the board and each staff member for the board with access to the information signs
3 a confidentiality agreement prepared by the commissioner making the disclosure.
4 Information that is confidential under AS 43.05.230 may not be disclosed to the board.

5 **Sec. 43.98.070. Definition.** In AS 43.98.040 - 43.98.070, "board" means the
6 Oil and Gas Competitiveness Review Board.

7 * **Sec. 36.** AS 43.55.023(m) is repealed.

8 * **Sec. 37.** AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are repealed January 1, 2014.

9 * **Sec. 38.** The uncodified law of the State of Alaska is amended by adding a new section to
10 read:

11 APPLICABILITY. (a) Sections 9, 12, 13, 22, and 29 - 31 of this Act apply to oil and
12 gas produced after December 31, 2013.

13 (b) Sections 10 and 28 of this Act apply to oil and gas produced after December 31,
14 2012.

15 (c) Sections 15 and 17 - 20 of this Act and AS 43.55.023(a)(1), as amended by sec. 15
16 of this Act, apply to expenditures incurred after December 31, 2012.

17 (d) Sections 16, 18, and 25 of this Act apply to expenditures incurred after
18 December 31, 2013.

19 * **Sec. 39.** The uncodified law of the State of Alaska is amending by adding a new section to
20 read:

21 TRANSITION: REGULATIONS. The Department of Revenue may adopt regulations
22 to implement this Act. The regulations take effect under AS 44.62 (Administrative Procedure
23 Act), but not before the effective date of the respective provision of this Act.

24 * **Sec. 40.** The uncodified law of the State of Alaska is amended by adding a new section to
25 read:

26 TRANSITION: OIL AND GAS COMPETITIVENESS REVIEW BOARD. The
27 governor shall appoint the initial members of the Oil and Gas Competitiveness Review Board,
28 established in sec. 35 of this Act, before November 1, 2014. The initial terms of the members
29 of the board appointed under AS 43.98.040(b)(1) and (3) shall be four years.

30 * **Sec. 41.** The uncodified law of the State of Alaska is amended by adding a new section to
31 read:

1 RETROACTIVITY. Sections 10, 17, 19, 20, 25, 28, and 36 of this Act and
2 AS 43.55.023(a)(1), as amended by sec. 15 of this Act, are retroactive to January 1, 2013.

Oil Tax Reform—Arresting TAPS Throughput Decline

House Resources Committee

Thursday, March 28, 2013

Commissioner Daniel S. Sullivan, DNR

Commissioner Bryan Butcher, DOR



OUTLINE



PART I: Current Context—Opportunities & Challenges

PART II: Is the Current Tax System Working for Alaskans?

PART III: Production, Production, Production

PART I



Current Context—Opportunities & Challenges

MASSIVE RESOURCE BASE

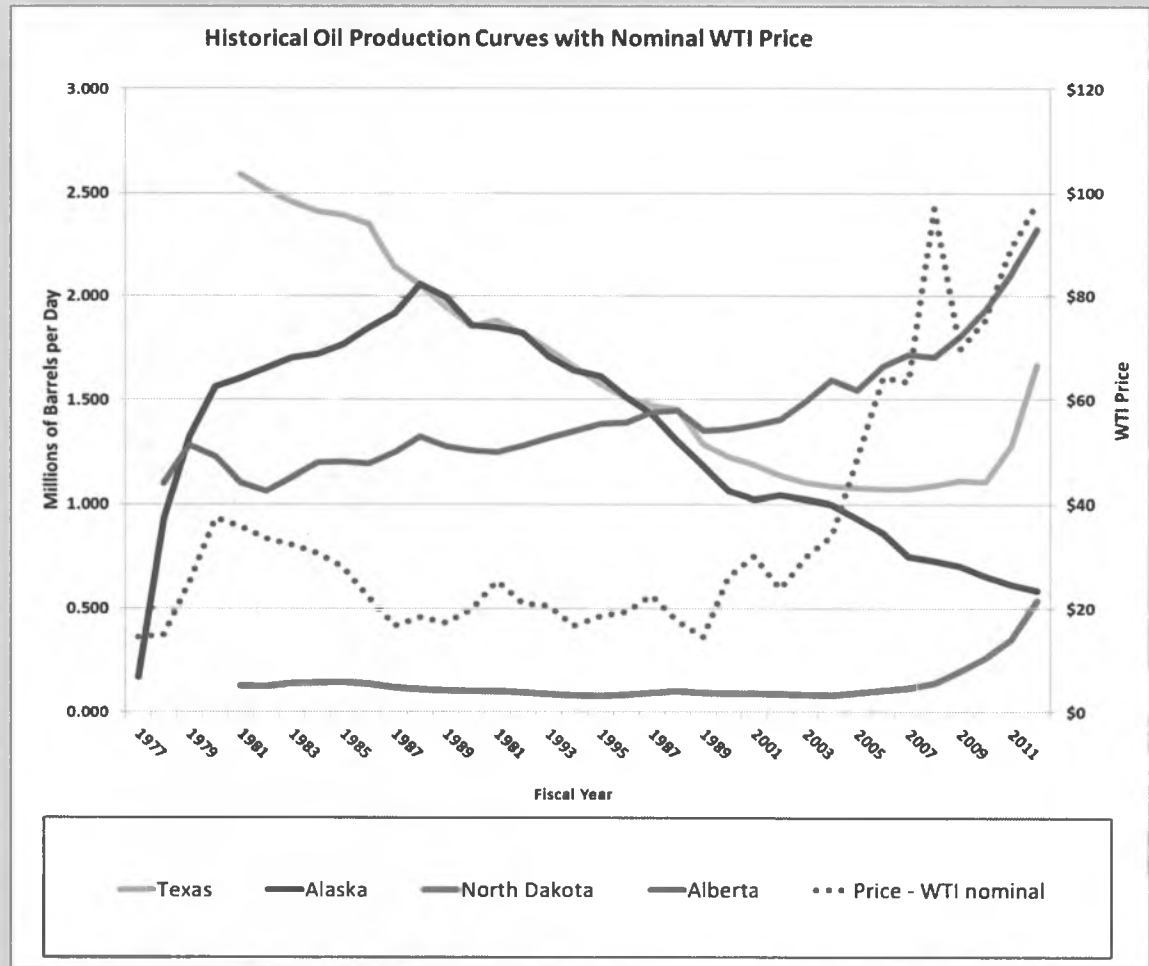
- USGS estimates that Alaska's North Slope has more oil than any other Arctic nation
 - **OIL:** Est. 40 billion barrels of conventional oil (*USGS & BOEMRE*)
 - **GAS:** Est. over 200 trillion cubic feet of conventional natural gas (*USGS*)
- Alaska has world-class unconventional resources, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates
- Alaska's North Slope has already produced more than 16 billion barrels of oil to date
- At year-end 2010, the Energy Information Agency (EIA)(federal Department of Energy) put remaining North Slope reserves at 3.7 billion barrels of oil

Compared to most hydrocarbon basins, Alaska is relatively underexplored, with 500 exploration wells on the North Slope, compared to Wyoming's 19,000.

OTHER BASINS HAVE TURNED DECLINE AROUND

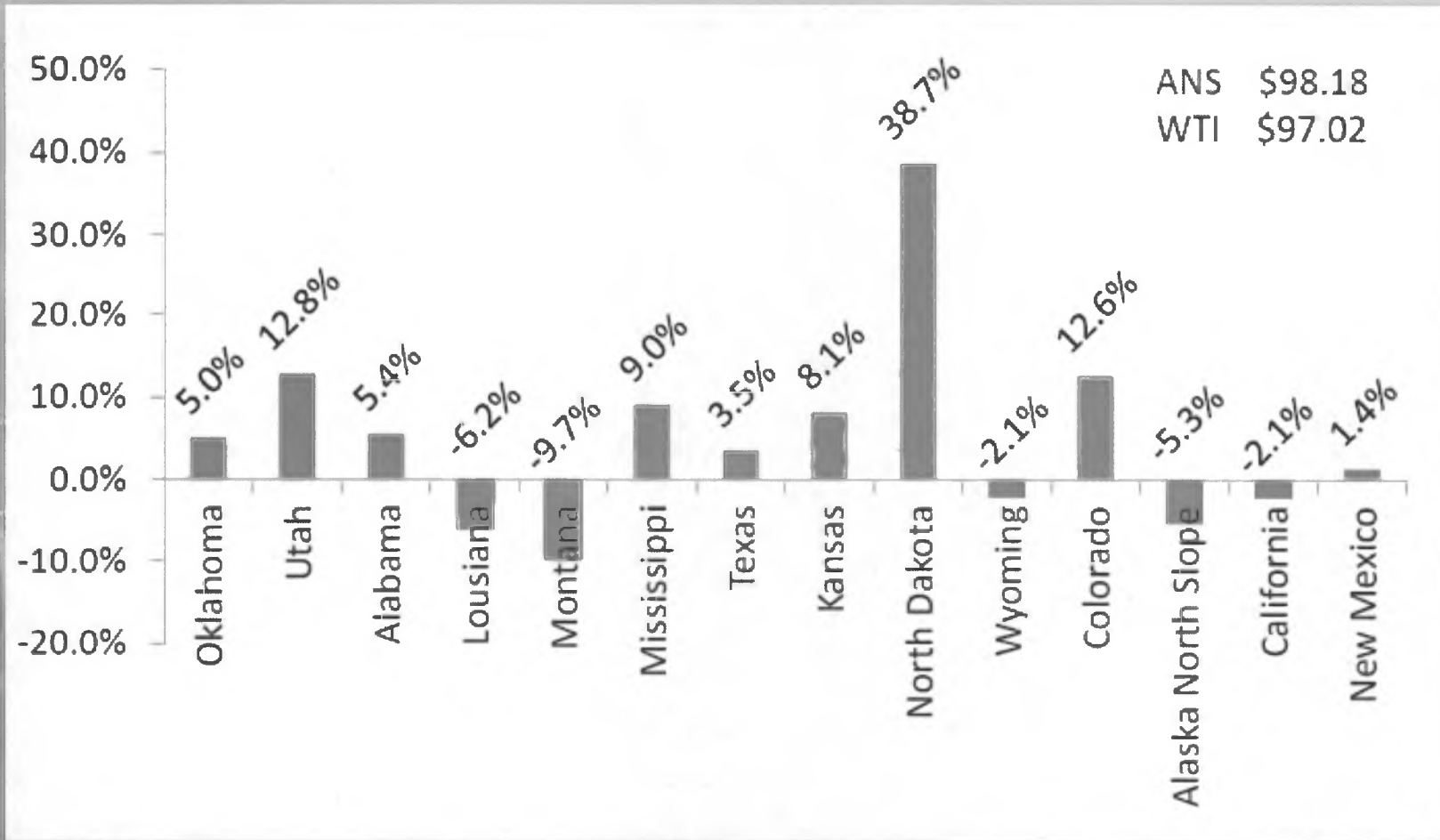
- HISTORICAL OIL PRODUCTION -

How Did Our
Competition Fare
When Prices Spiked?



CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2007-2008

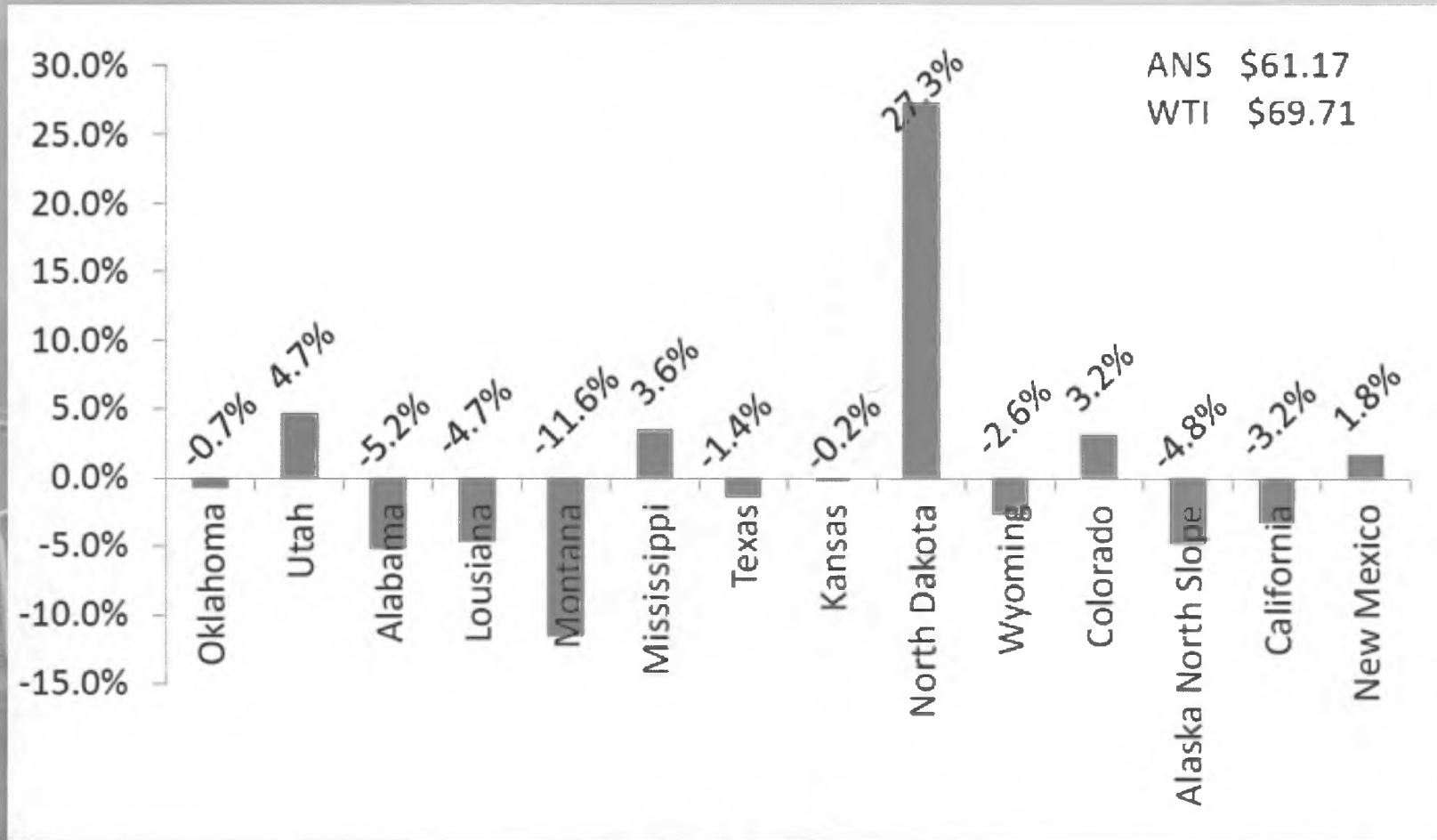
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2008-2009

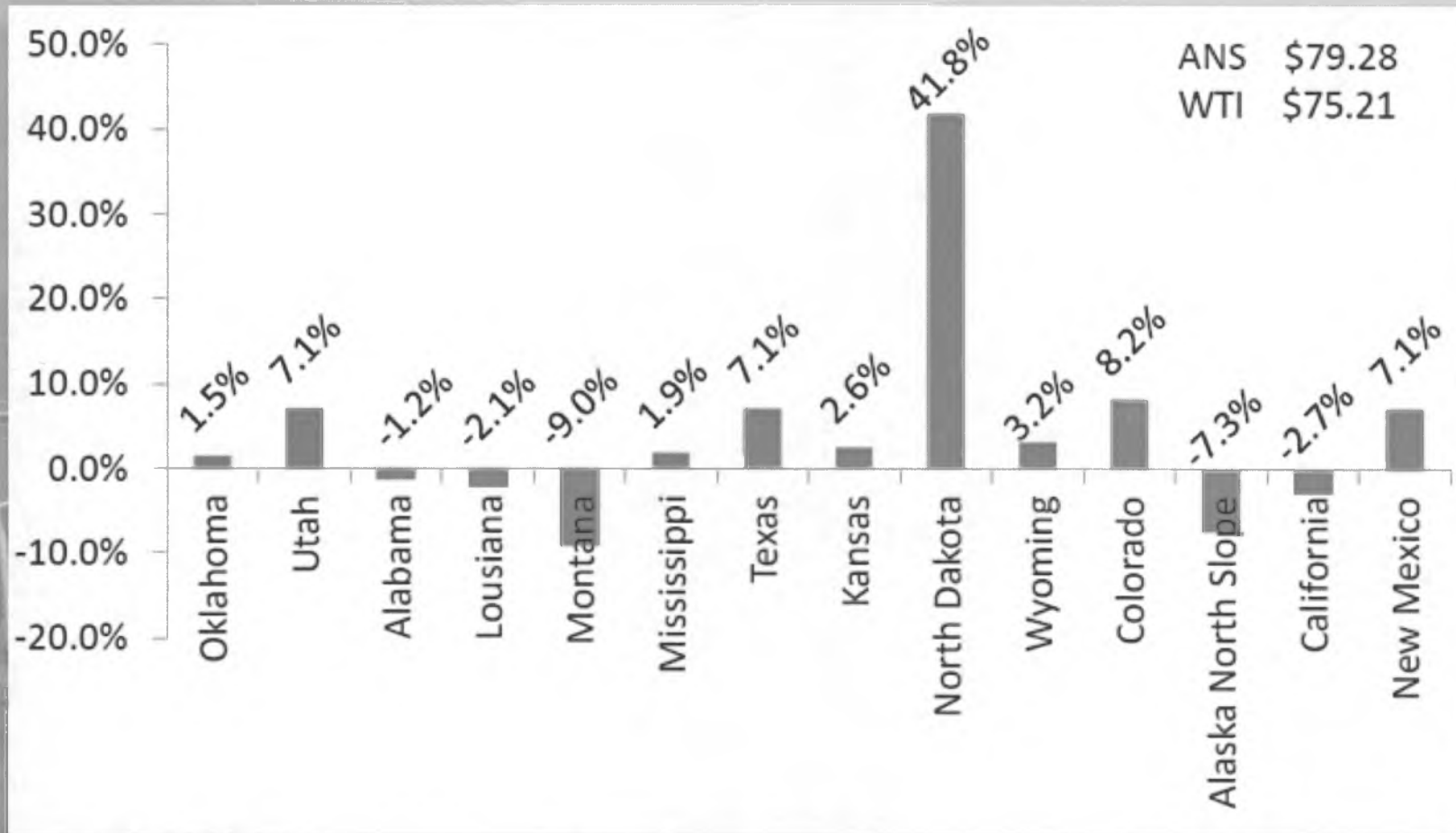
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2009-2010

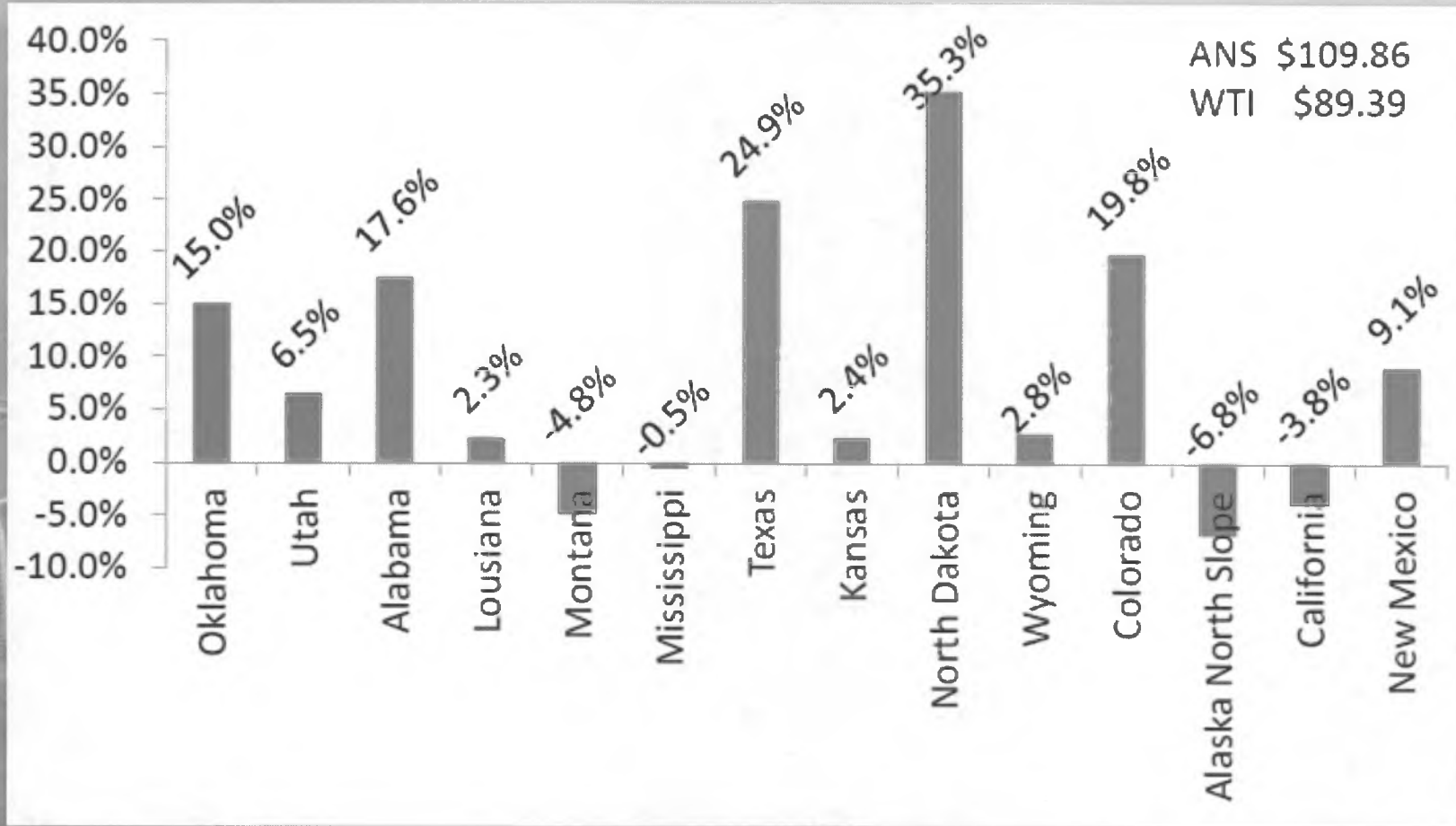
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2010-2011

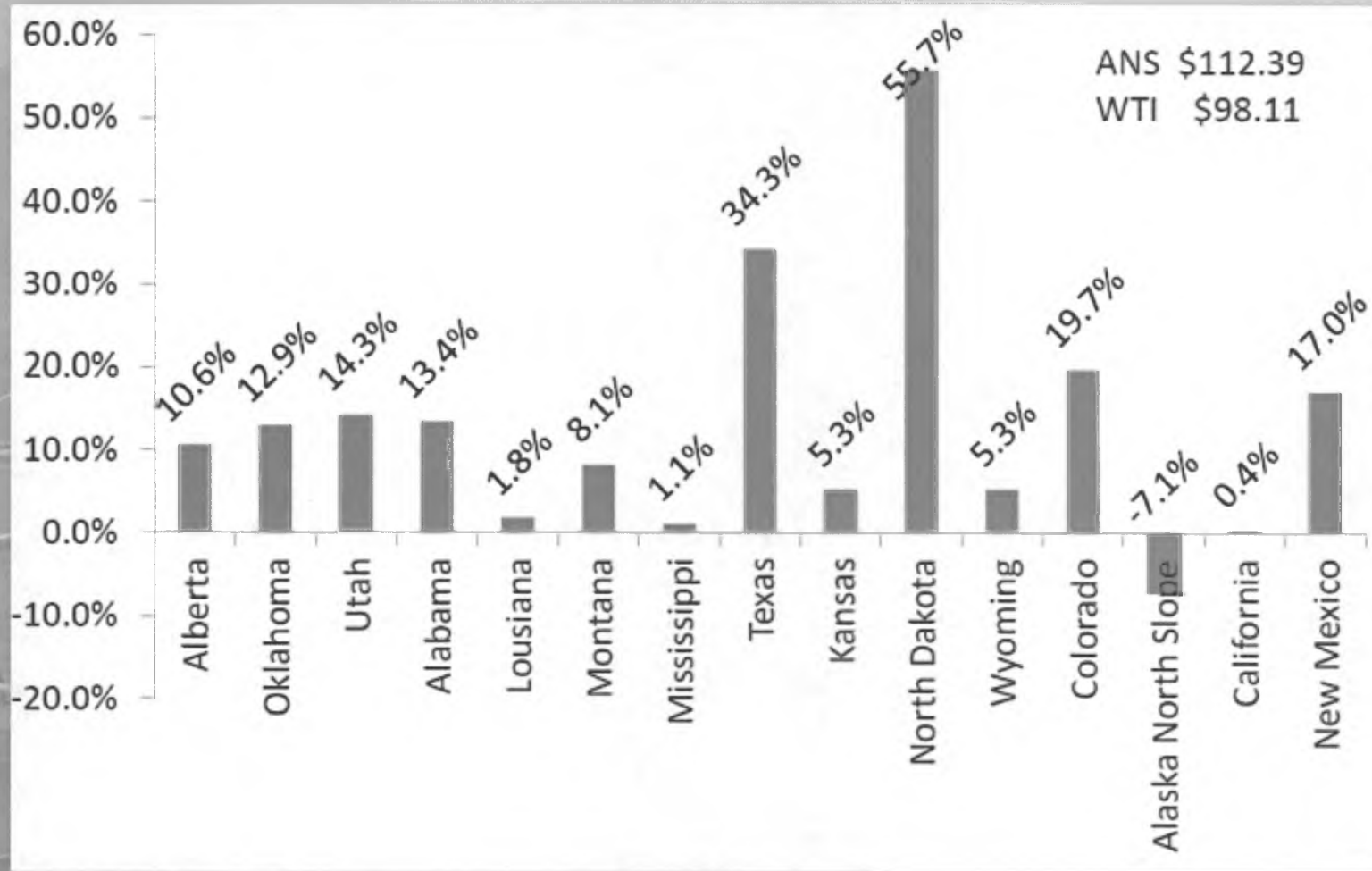
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2011-2012

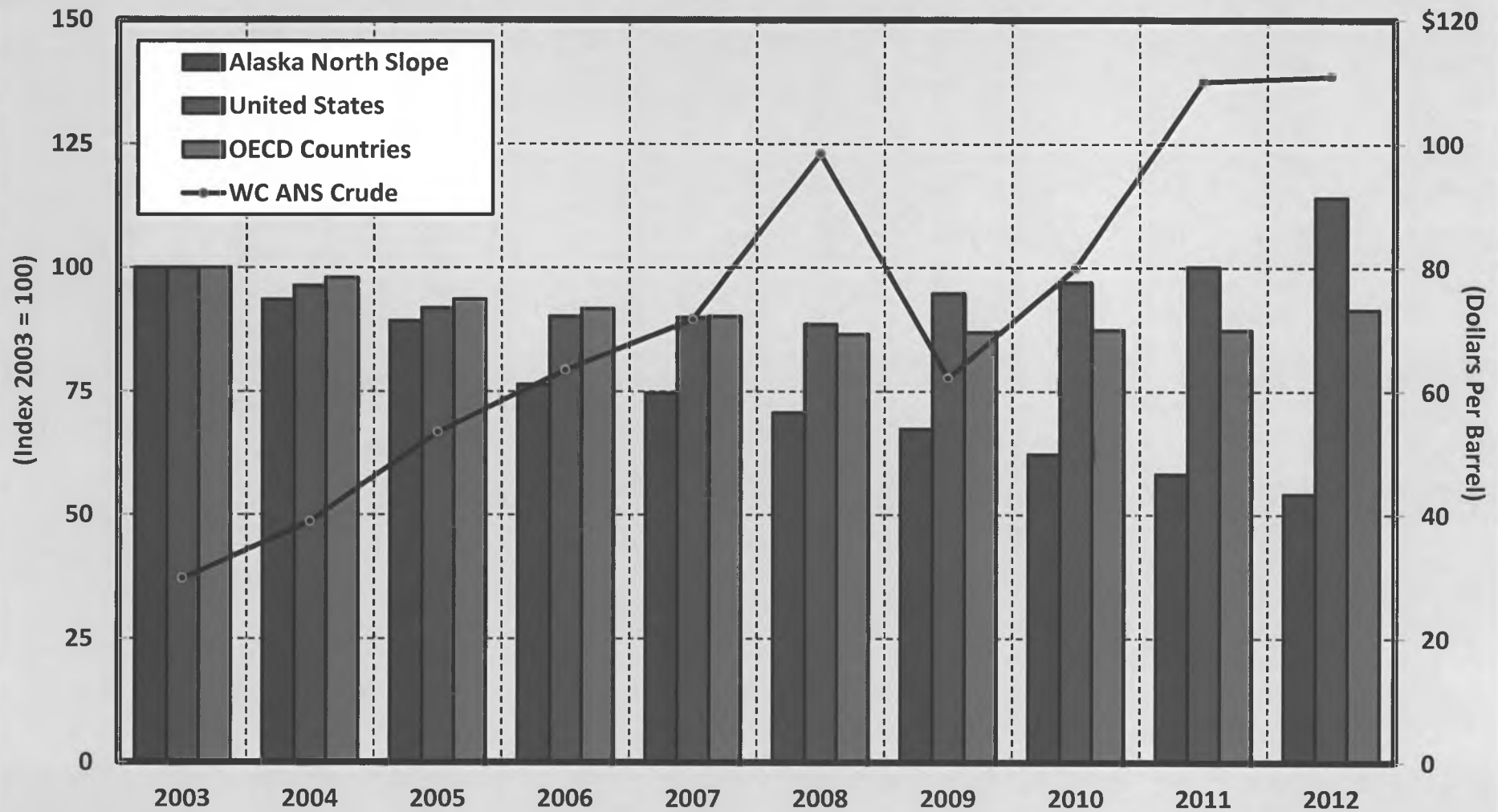
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

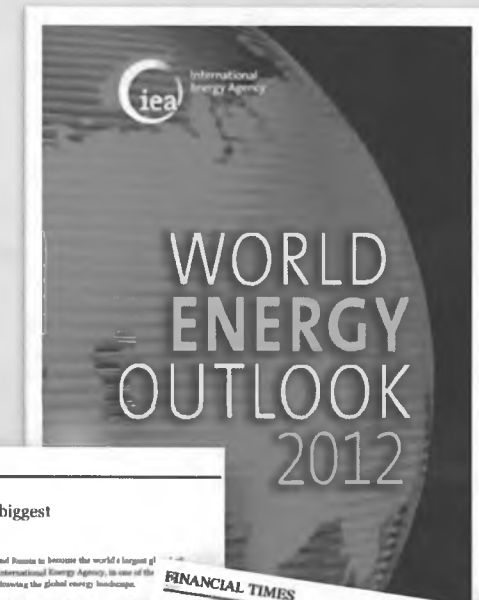
CRUDE OIL PRODUCTION:

AK NORTH SLOPE VS. U.S. & OECD COUNTRIES, 2003-2012

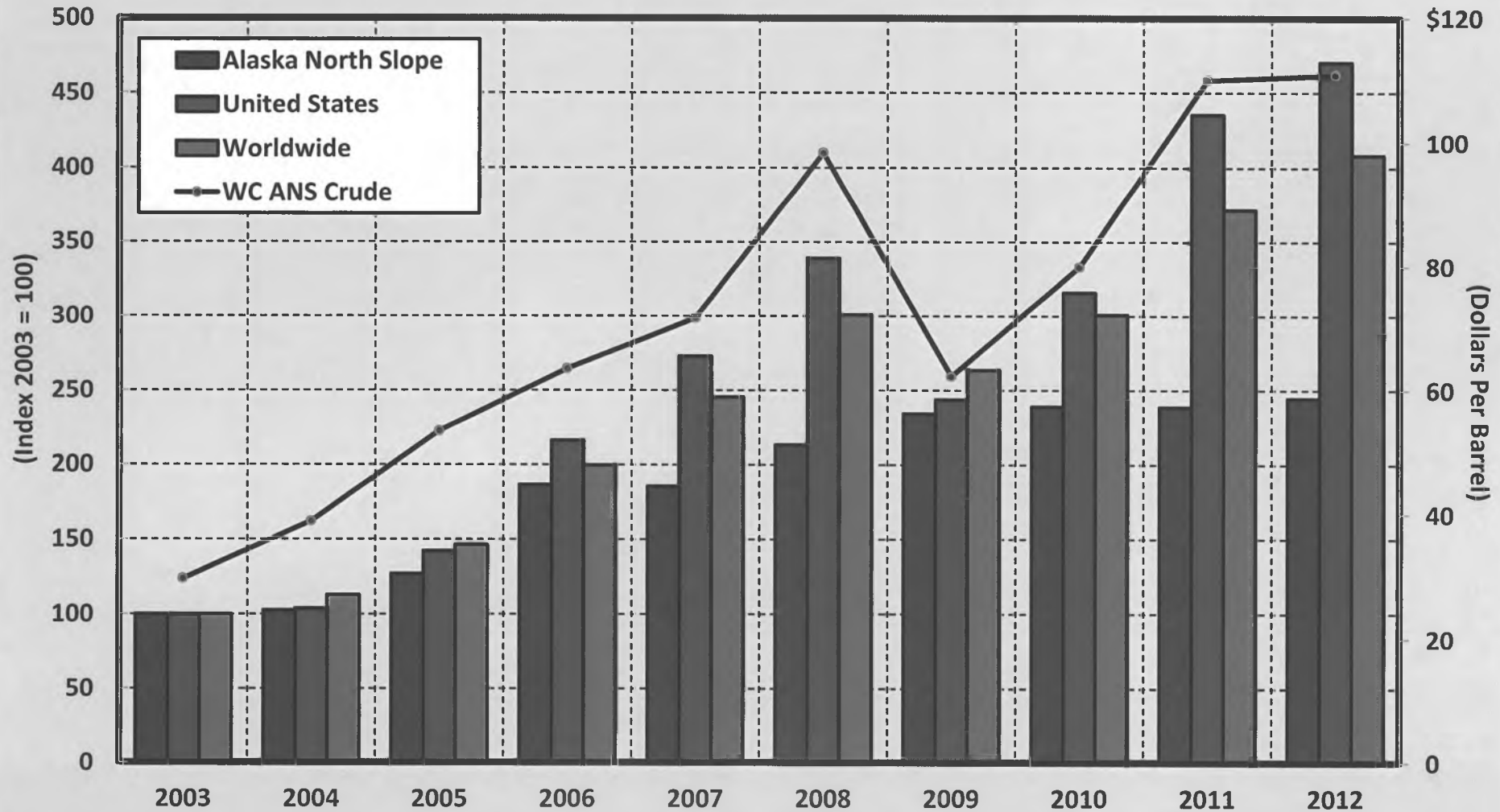


CAPITAL INVESTMENT & THE U.S. ENERGY RENAISSANCE

- Global and U.S. hydrocarbon boom
- IEA World Energy Outlook 2012 – U.S. to overtake Saudi Arabia and Russia to become the world's largest global oil producer by the second half of this decade
 - Congressional Research Service report found that since 2007, all increases in U.S. oil and gas production occurred outside federally controlled areas, with oil and gas production on federal lands decreasing by 7% and 33% respectively
- Financial Times, November 12, 2012 – *“U.S. set to become biggest oil producer”*
- Financial Times, December 27, 2012 – *“Oil and gas – hey big spenders”*
 - 2012 - \$600 billion on exploration and production in oil and gas industry
 - 2013 projected - \$650 billion on exploration and production in oil and gas industry
 - Alaska - one of the world's great hydrocarbon basins – accounted approximately half of 1% of these expenditures in 2012



EST. CAPITAL SPENDING FOR EXPLORATION & DEVELOPMENT: AK NORTH SLOPE VS. U.S. & WORLD SPENDING*, 2003-2012



* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

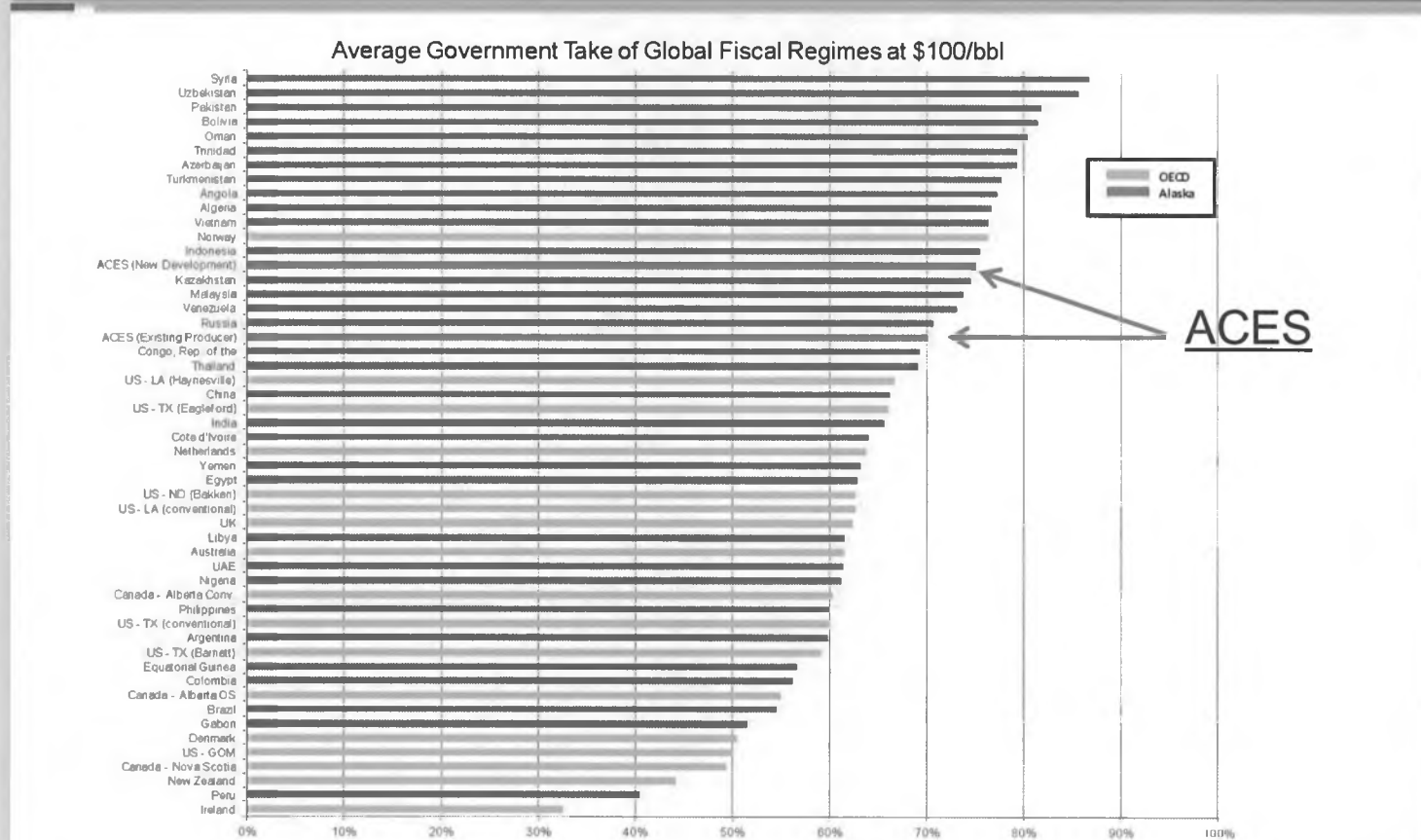
PART II



**Is the Current Tax System
Working for Alaskans?**

AVERAGE GOVERNMENT TAKE AT \$100/BBL

Regime Competitiveness: Average Government Take at \$100/bbl



CURRENT SYSTEM IS NOT WORKING FOR ALASKANS

Examples of the Real Giveaway

- ACES has taken away most of the incentive to produce more barrels and more profit at higher prices
 - In FY08, North Slope oil averaged \$96.51 per barrel and the total production tax collected was \$6.8 billion
 - By next fiscal year (FY14), prices are forecasted to be \$13 higher at \$109.61, but the total production tax collected is estimated to be \$3.8 billion – a decrease of more than \$3 billion in unrestricted general fund revenue
- The Ultimate Giveaway:
 - Comparing year-end 2011 and year-end 2012, there were ~40,000 fewer barrels of oil per day flowing through TAPS
 - Approximately 14.6 million barrels a year = \$1.46 billion in lost economic activity and value

NEW ENTRANTS IN ALASKA'S CURRENT TAX SYSTEM

- *Secure Alaska's Future—Oil* is the State's comprehensive strategy to increase TAPS throughput to one million barrels a day
 - I. Enhance Alaska's global competitiveness and investment climate
 - II. Ensure the permitting process is structured and efficient
 - III. Facilitate and incentivize the next phases of North Slope development
 - IV. Promote Alaska's resources and positive investment climate to world markets*

- **Governor Parnell's 2013 State of the State: "Our problem is not below the ground. Our problem is above the ground."**
 - The missing piece is meaningful tax reform
 - "Our state's prosperity has always rested on natural resources. Tonight, that foundation is at risk, not because we are running out of oil, but because we are running behind the competition."



NEW ENTRANTS IN ALASKA'S CURRENT TAX SYSTEM

- REPSOL EXAMPLE -



Excerpts from
March 6, 2013,
letter to the
Senate Finance
Committee



- We came to the North Slope in 2011, after many years of reviewing numerous opportunities and turning them down. We considered the North Slope to be an especially promising area that has been shown to be oil rich and with lower exploratory risk than other regions.
- Offsetting these positive aspects were the extreme climate, and a short exploration season in a remote, expensive and environmentally sensitive area with little established infrastructure. **The biggest negative factor, however, was a tax system that did not encourage long-term investment.**
- With regards to investment in onshore state lands, we found that in all but the best scenarios, **the progressive nature of the ACES petroleum tax structure did not allow for returns that were competitive with opportunities in the lower forty-eight states or other parts of the world.**
- This view changed in early 2011 when it appeared that serious reform of the ACES tax structure would be enacted... [Repsol was] convinced that the State of Alaska was serious about providing the necessary incentives for new investment. We were also convinced that if we waited for meaningful tax reform to be enacted, we would risk being lost in the rush of companies to Alaska to invest in North Slope exploration and development projects.

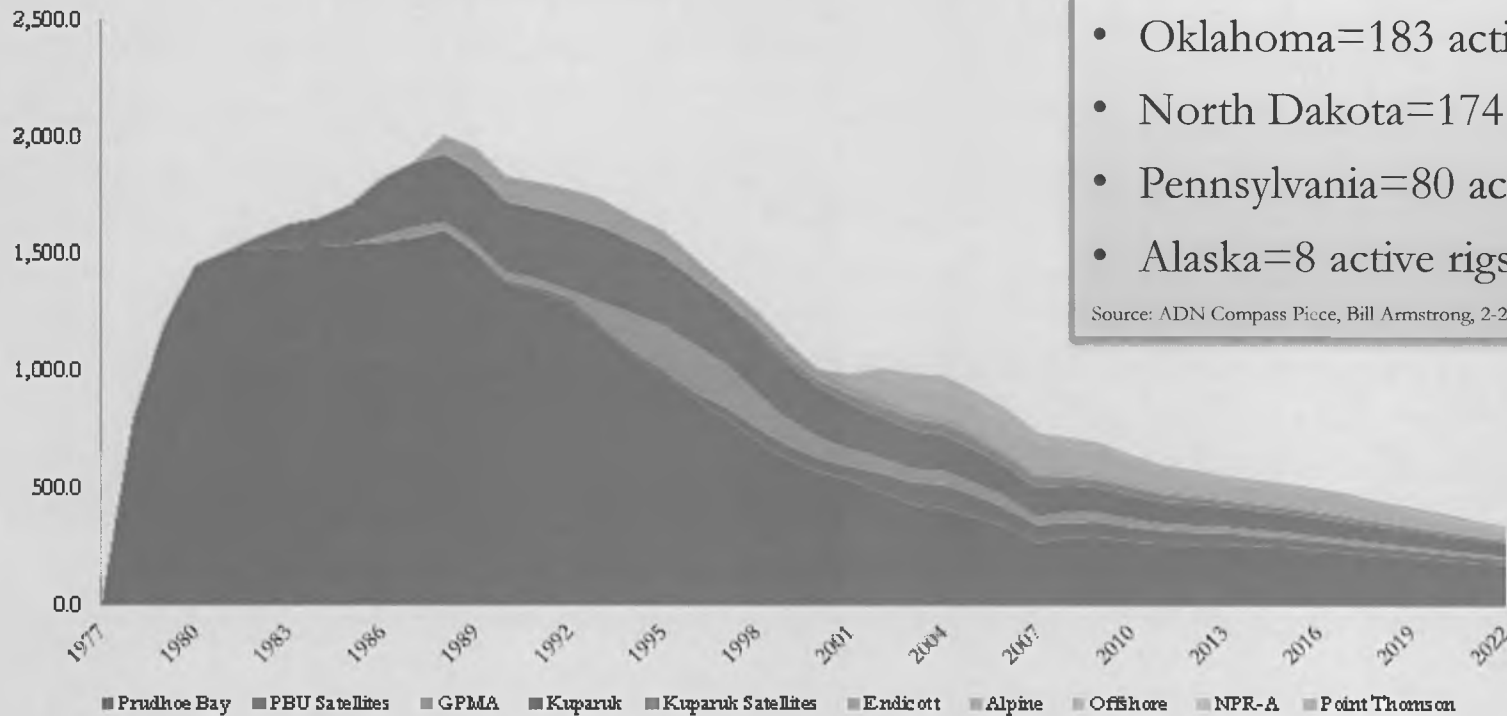
PART III



**Production, Production,
Production**

PRODUCTION HISTORY

ANS Production



2013 Rig Count:

- Texas=830 active rigs
- Oklahoma=183 active rigs
- North Dakota=174 active rigs
- Pennsylvania=80 active rigs
- Alaska=8 active rigs

Source: ADN Compass Piece, Bill Armstrong, 2-20-13

Source: Alaska Department of Revenue Fall 2012 Revenue Sources Book: <http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2682f>

CS SB21(FIN)'S MAJOR COMPONENTS ARE FOCUSED ON INCENTIVIZING PRODUCTION

ACES

- Qualified Capital Credit
 - Based on 20% of qualified capital expenditures
 - To generate an additional \$100 million in capital credits a company must spend \$500 million
 - $\$500 \text{ mm} \times 20\% = \100 mm

CS SB21(FIN)

- Per Barrel Credit
 - Based on taxable production
 - To generate an additional \$100 million in credits a company must produce an additional 20 million barrels
 - $20 \text{ mm} \times \$5 = \100 mm
- Gross Value Reduction
 - GVR is limited to new participating areas, either in a legacy unit or outside a legacy unit

STATUS QUO OF CONTINUED DECLINE IS UNACCEPTABLE

- This is about Alaskans' future— present citizens and future generations
- We clearly have the resource base to turn our oil production decline around
- The status quo of continued decline when there is a global investment boom and literally every other basin in the United States is increasing production is unacceptable
- ACES, although well-intentioned, is significantly contributing to our production decline as well as discouraging potential new entrants.
- As production continues to decline, the strain on the state will only grow
- Tax reform must focus on incentivizing production
- “The ANCSA Regional Association is calling on state leaders to continue moving on an oil tax reform bill. Tax reform for the oil and gas industry that results in increased production will give communities across the state access to important economic opportunities. Association members stress the importance of new and increased production with long-term benefits to Alaskans.” – March 28, 2013

House Resources Committee Comments on SB 21

“Perspectives Of An Alaska Exploration Company”

Investors: AVCG (Alaska Venture Capital Group)

Operator: Brooks Range Petroleum

Ken Thompson
AVCG Co-Owner/Investor
Former President, ARCO Alaska, Inc.

March 27, 2013

AVCG LLC

Why Consider Our Company's Perspectives ?



- 1) Most active exploration company exploring and developing solely on North Slope state lands
 - a) Drilled 10 of 36 exploration wells on state lands in 2007-12 (more than COP, BP, XOM, ENI, Repsol, Armstrong combined)
 - b) 105,000 leased acres in 3 core areas in JV partnership with Ramshorn Exploration (affiliate of large Nabors Industries)
- 2) ~ \$200 MM invested to date in Alaska North Slope projects...3 discoveries, acquired discovery
- 3) Mustang development project under construction...\$577 MM capital, 44 MMBO, 15,000 BOPD...
future level of capital spending/yr same as Pioneer Natural Resources and one-third the level of COP capital spending
- 4) Three other development projects in permitting/conceptual engineering stages...> \$1.5 B capital
- 5) First production and cash flow to state and our companies...startup of Mustang in 3Q 2014
- 6) On investment of \$200 MM, received refunded tax credits totaling \$69 MM but State will receive back this amount+ in the first year of Mustang production...and \$1.2 billion over field life
 - a) All credits have been redeployed on the North Slope for new drilling or seismic to find, develop oil...none sent Outside
 - b) Credits redeployed has allowed in some years the drilling of 3 exploration wells instead of 2...or 2 wells instead of only 1
 - c) Payment of credits in cash versus just an allowance against taxes critical to AVCG which has no current production
- 7) Experience in bringing other independents to Alaska and in raising capital for Alaska
 - a) Seeking additional capital for Mustang and 3-5 year exploration program...started fundraising 18 months ago, Sept 2011
 - b) Sent materials to 210 firms, but only 19 wanted to consider Alaska...and after further review, only 2 firms remain interested
 - c) Biggest hurdles we heard: 1) complex and high gov't take of AK fiscal regime, 2) flow of capital to Lower 48 source rocks
 - d) In final negotiations...belief in our confidence that Legislature will make positive change in 2013

North Slope Drilling Results And Success



Tofkat Unit

- ~ 40 MMBO Kup C, ~ 20 MMBO Jurassic
- Offset Alpine & Nanuq fields
- Ran 3D after drilling indicates Kup C may extend into Nanuq field
- 3 delineation wells drilled
- Returning to delineate in Q1 2014
- COP drilled 4 wells into Jurassic at Nanuq
- Less than 1 mile to Alpine CC pipeline
- Upside defined in Brookian, new leases Nov 2012
- **FIRST OIL 2015 or 2016**

Beechey Point Unit

- ~ 26 MMBO Kup C & Ivishak
- Adjacent to Prudhoe Bay and Midnight Sun
- 3-D definition on traps
- 3 discovery wells
- Substantial commercial opportunities within drilling reach
- East Shore prospect analog is Midnight Sun
- Lease block win Nov 2011 increases resource expectations
- **FIRST OIL 2016**

Kachemach Unit

3-D seismic evaluation
Exploration drilling planning

S. Miluveach Unit – Mustang / Appaloosa

- 44 MMBO Kup C Mustang, ~ 37 MMBO Appaloosa
- Extension to KRU field
- N Tarn well penetrated reservoir 2011, re-entered & tested 2012 (20+ Kup C discovery)
- N Tarn #1A confirmed quality C sand 10+ ft. oil test
- Drilled confirmation Mustang #1 2012 20+ ft.
- Confirmed communication with KRU 2M
- Common carrier pipeline 700' from production pad
- 200 sq. miles proprietary 3D + 240 WBA license 3D
- **FIRST OIL 2014**

Telemark Discovery...Badami Unit Expansion

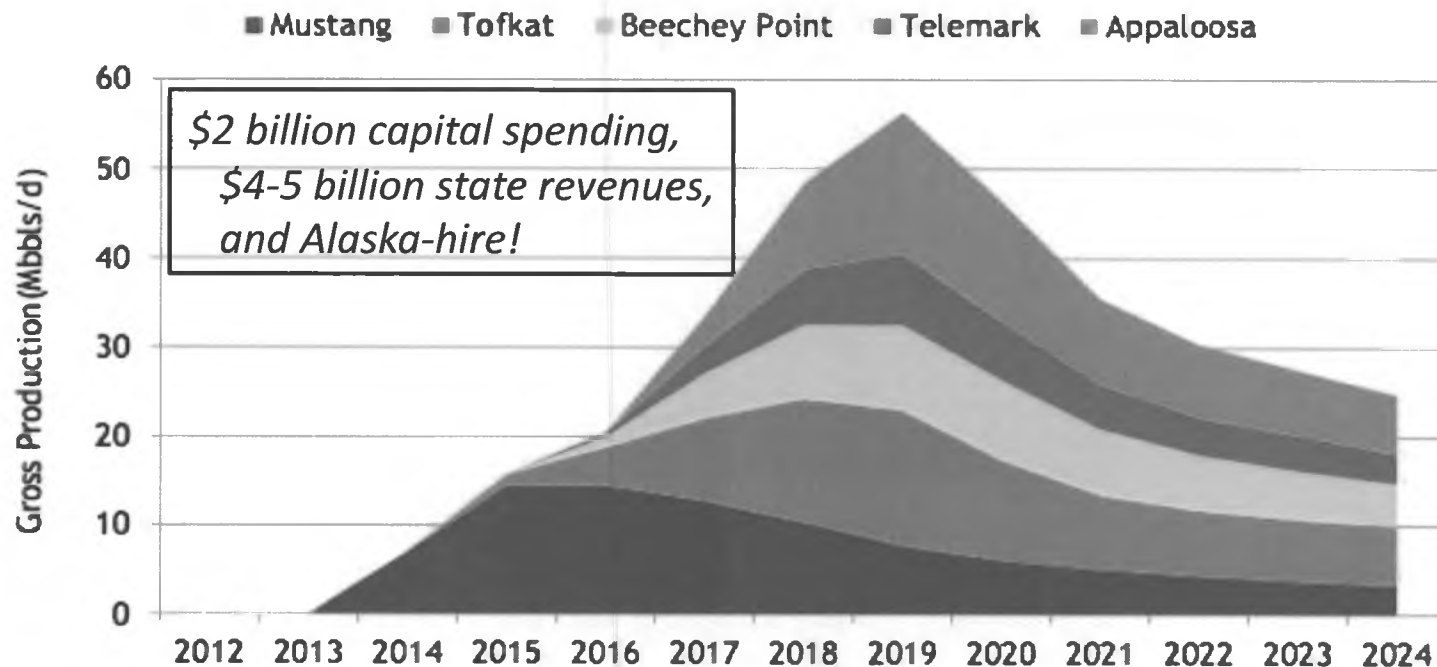
- ~ 16 MMBO Flaxman Sst
- Project area located between Badami & Pt. Thomson
- E Mikkelson #1 tested 250 BOPD un-stimulated
- Improved reservoir setting to Badami
- Horizontal development strategy
- Facilities and pipeline capacity in close proximity- no need to build facilities
- Pt. Thomson sand upside
- **FIRST OIL 2015 or 2016**

What Difference Can Our Company Make?



Production Profile (Mbbbls/d)

"New work in existing fields to increase production above their existing declines will not – by itself – level AK's oil production. Production from exploration discoveries are needed also. Alaska still needs E&P...not just P!" ...Ken Thompson



*Between 2012 and 2011, North Slope oil production declined 50,768 BOPD. Developments such as the above, if repeated, could help in replacing production fall off...**AND ACHIEVE "NO DECLINE!"***

Note: Mustang delineated and development underway. Tokfat, Beechey Point, Telemark, Appaloosa require delineation before sanctioning...not risked.

We See Positives In SB 21 But Have Competitive Suggestions



- 1) Eliminates progressivity factor, increases base tax rate from 25% to 35% but provides \$5/bbl produced bbl credit
 - ✓ *POSITIVE: Eliminating progressivity simplifies tax calculation and will be a public relations plus for AK*
 - X *NEGATIVE: Increase in base tax rate from 25% to 35% not expected...suggest compromise at 30%*
 - ✓ *POSITIVE: \$5 produced bbl credit better balances relative state/producer takes at low oil prices but "retest" economics*

- 2) Increases "Carry Forward Loss Credit (CFL)" from 25% to 35% and interest on unused credits (NOLCF)
 - ✓ *POSITIVE: incrementally more future cash flow to re-deploy into facilities & drilling*

- 3) SB 21 originally extended "Small Producers" Credits from 2016 to 2022...reduces small producers' tax bill by \$12 MM/yr...but latest version now sunsets this credit in 2016; originally intended to assist companies for 9 years
 - X *NEGATIVE: Small producer like BRPC with first production in 4Q 2014 has not been able to utilize, but included in economics*
 - ✓ *POSITIVE: IF REINSTATED...more cash flow for small producers to re-deploy into facilities & drilling*

- 4) Specifies 20% QCE tax credit certificate payment in single year vs. 2 but does eliminate QCE on 12/31/13
 - ✓ *POSITIVE: more immediate cash to put into Mustang development facilities and drilling in 2014*
 - ✓ *NEGATIVE: goes away 12/31/13...no QCE payment in 2015 to redeploy into Mustang development drilling*
 - ✓ *POSITIVE: IF EXTENDED to 12/31/16 for at least small producers...Mustang project was sanctioned assuming QCE...and OK to limit QCE per company per year to control impact on state treasury, e.g. limit credit to \$40-50 MM per year per company*

- 5) At one point SB 21 increased "20% Gross Revenue Exclusion (GRE)" to 30% GRE and amended definition of leases that can be included for this GRE...but GRE now lowered back to 20%
 - ✓ *POSITIVE: GRE should incentivize new oil production on more leases, also help during low oil price cycles*
 - X *NEGATIVE: this applies to new oil which is what the state wants...reconsider increasing GRE to 30% or at least to 25%*

- 6) SB 21 originally had a 30% "Exploration Incentive Credit" for NS exploration wells drilled that target new oil discoveries regardless of location...please re-instate this at least for small producers/explorers through 12/31/18
 - X *HUGE NEGATIVE FOR EXPLORERS: Doesn't matter to legacy field owners, but a huge negative for small exploration companies like ours to omit an exploration credit*
 - ✓ *HUGE POSITIVE FOR EXPLORERS: IF YOU REINSTATE this credit, but to minimize impact on state treasury, allow only for small producers and limit to \$25 MM credit per year per company...for five years through 2018 then "retest" effectiveness*



limit to outside of units establish after effective date of bill

Photos: Mustang Development Project Underway - \$1.2 B State Revenues





House Resources Committee

Testimony re: CS SB 21(FIN) am (efd fld)

March 27, 2013

J. Patrick Foley

Land and External Affairs Manager

Incoming President, Pioneer Natural Resources, Alaska



NYSE: PXD
www.pxd.com



Pioneer Natural Resources, Alaska

Forward Looking Statements

Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, international operations and associated international political and economic instability, litigation, the costs and results of drilling and operations, availability of equipment, services and personnel required to complete the Company's operating activities, access to and availability of transportation, processing and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.

Presentation Overview

- Pioneer at a glance
- Competitive environment
- CS SB 21(FIN) am(efd lfd)
- Incentives for Alaskan investments
- Closing thoughts and 'wish list'



Corporate overview:

- \$19 Billion enterprise value
- Member of the S&P 500
- Investment grade rating
- ~3,500 employees
- \$3 Billion capital budget
- \$2 Billion cash flow from operations
- Leading performer in peer group

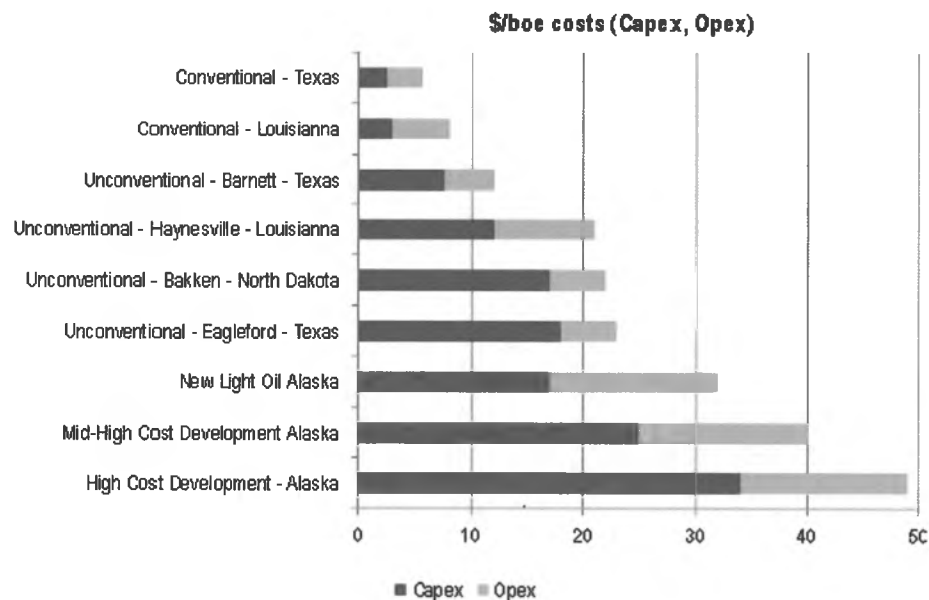
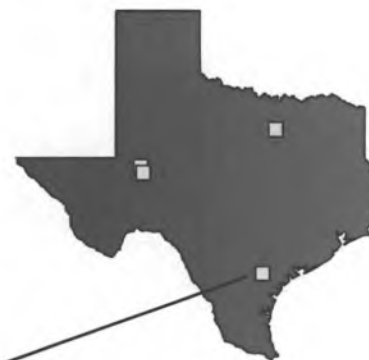


Alaska Operations Overview:

- 1st independent operator on North Slope
- 70+ full-time Alaska employees
- \$14+ million in annual wages (employees)
- 150 - 300 Alaska contract workers
- ~\$180 million 2013 capital budget
- ~6,000 BOPD gross production
- Net investor in Alaska
- Nuna project sanction decision 2013

Eagle Ford Operators and Companies

■Abraxas Petroleum ■Alta Mesa Holdings ■Anadarko ■Apache Corp. ■Aruba Petroleum ■Aurora resources ■Austin Exploration (Aus-Tex Expl.) ■BHP Billiton ■BP ■Cabot Oil & Gas ■Carrizo Oil & Gas ■Chaparral Energy ■Chesapeake Energy ■Cinco Resources ■Clayton Williams Energy ■Comstock Resources ■ConocoPhillips – (Burlington Resources) ■CNOOC (China National Offshore Oil Corporation) ■Crimson Exploration ■Devon Energy ■Eagle Ford Oil & Gas Corp. ■El Paso ■Enduring Resources ■Enerjex Resources ■EOG Resources ■Escondido Resources ■Espada Operating ■Exxon-XTO ■Forest Oil ■GAIL (Gas Authority of India Limited) ■GeoResources Inc. ■Goodrich Petroleum ■Global Petroleum ■Hess Corporation ■Hilcorp Resources ■Hunt Oil ■Jadela Oil ■Japan Petroleum Exploration ■KNOC (Korea National Oil Corporation) ■Laredo Energy ■Lewis Energy Group (BP Partner) ■Lonestar Resources ■Lucas Energy ■Magnum Hunter Resources ■Marathon Oil ■Marubeni Corporation (Hunt Oil Partner) ■Matador Resources ■Mitsui ■Murphy Oil ■Newfield Exploration ■NFR Energy ■Penn Virginia Corp ■Peregrine Petroleum ■PetroHawk ■PetroQuest ■Pioneer Natural Resources ■Plains Exploration & Production ■Redemption Oil & Gas ■Reliance Industries ■Riley Exploration ■Rock Oil Company ■Rosetta Resources ■San Isidro Development (Acquired by Chesapeake) ■Sanchez Energy ■Sandstone Energy, LLC ■Saxon Oil Company ■Shell ■SM Energy (St. Mary Land & Exploration) ■Statoil ■Strand Energy ■Strike Energy ■Swift Energy ■Talisman Energy ■Texon Petroleum ■Tidal Petroleum ■TXCO Resources (Now, Newfield & Anadarko) ■Unit Corporation ■U.S. Energy Corp. ■Weber Energy ■WEJCO E&P ■ZaZa Energy



Source: Alaska Discussion Slides, PFC Energy 2012, February 11, 2013

Governor's Guiding Principles

- Tax policy must be fair to Alaskans
- Any changes to oil taxes should, when taken together, be geared to foster new production
- Changes should result in a more simple tax system and restore balance to our fiscal system
- Tax policy must make Alaska competitive for the long-term

■ Positives:

- Elimination of progressivity
- Gross revenue exclusion (GRE)
- Loss carry-forward monetization
- \$5/bbl credit

■ Negatives:

- Loss of capital credits
- Increased base tax rate

■ Benefits to State

- Credits directly encourage activity in Alaska
 - Jobs, direct and indirect (9x multiplier)
 - More wells
 - More oil
 - More royalties, taxes and throughput

■ Benefits to Developer

- Reduces investor risk
- Improves small project economics
- Improves financial performance
 - Doesn't increase debt
- Builds healthy industry
- Strengthens competitiveness

Purpose of Tax Credit Provisions:

“The fiscal impact of the tax credits was an investment incentive that state must offer to secure a ‘long-term stream of oil.’”

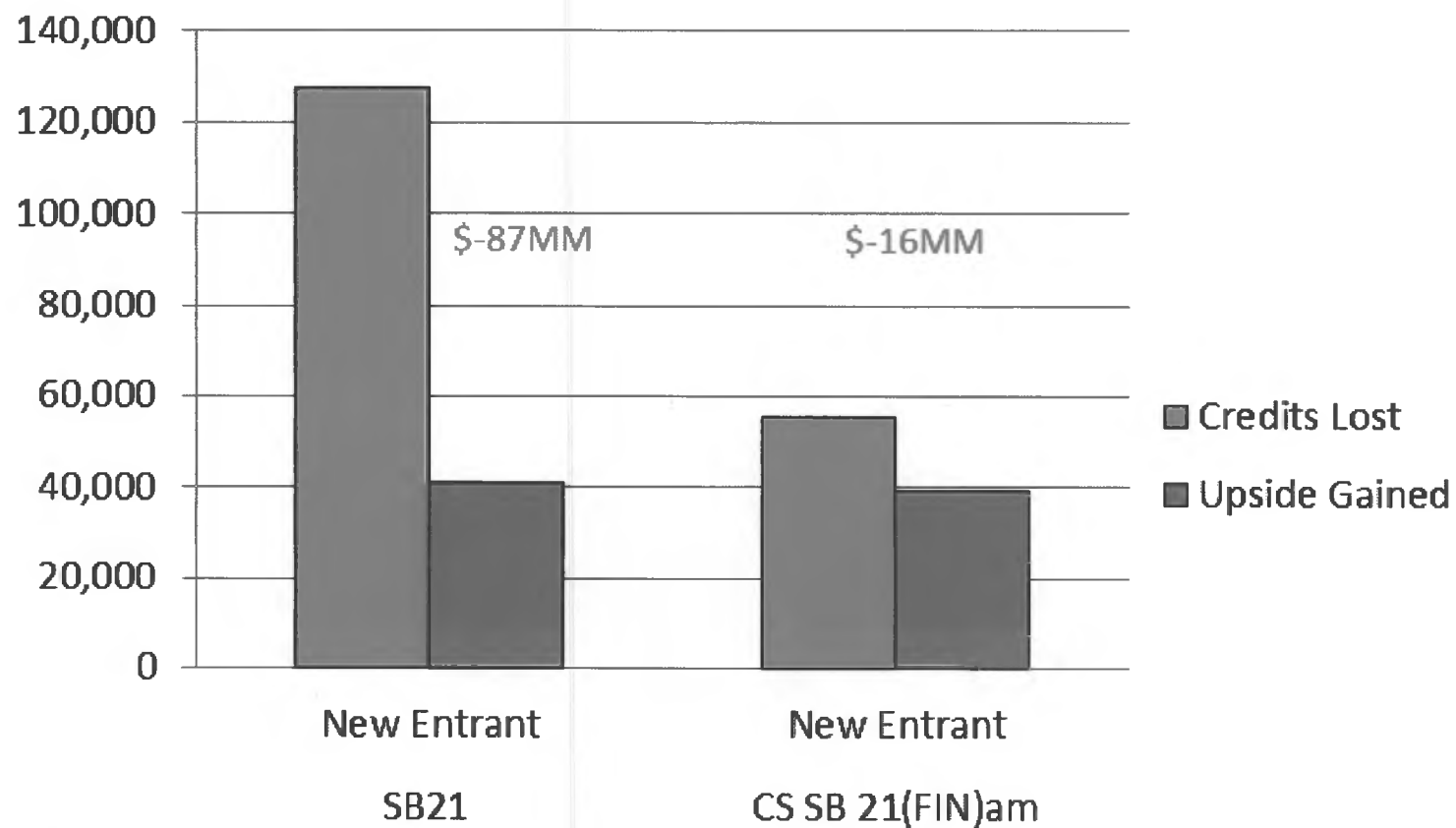
- Senate Finance Committee 5/13/2003

Source: DOR Presentation to Senate Resources Committee 2/13/2012

“Recommend targeted tax credits as being preferable [vs GRE], they provide incentive to invest.”

- Roger Marks, Senate Finance Committee 03/04/2013

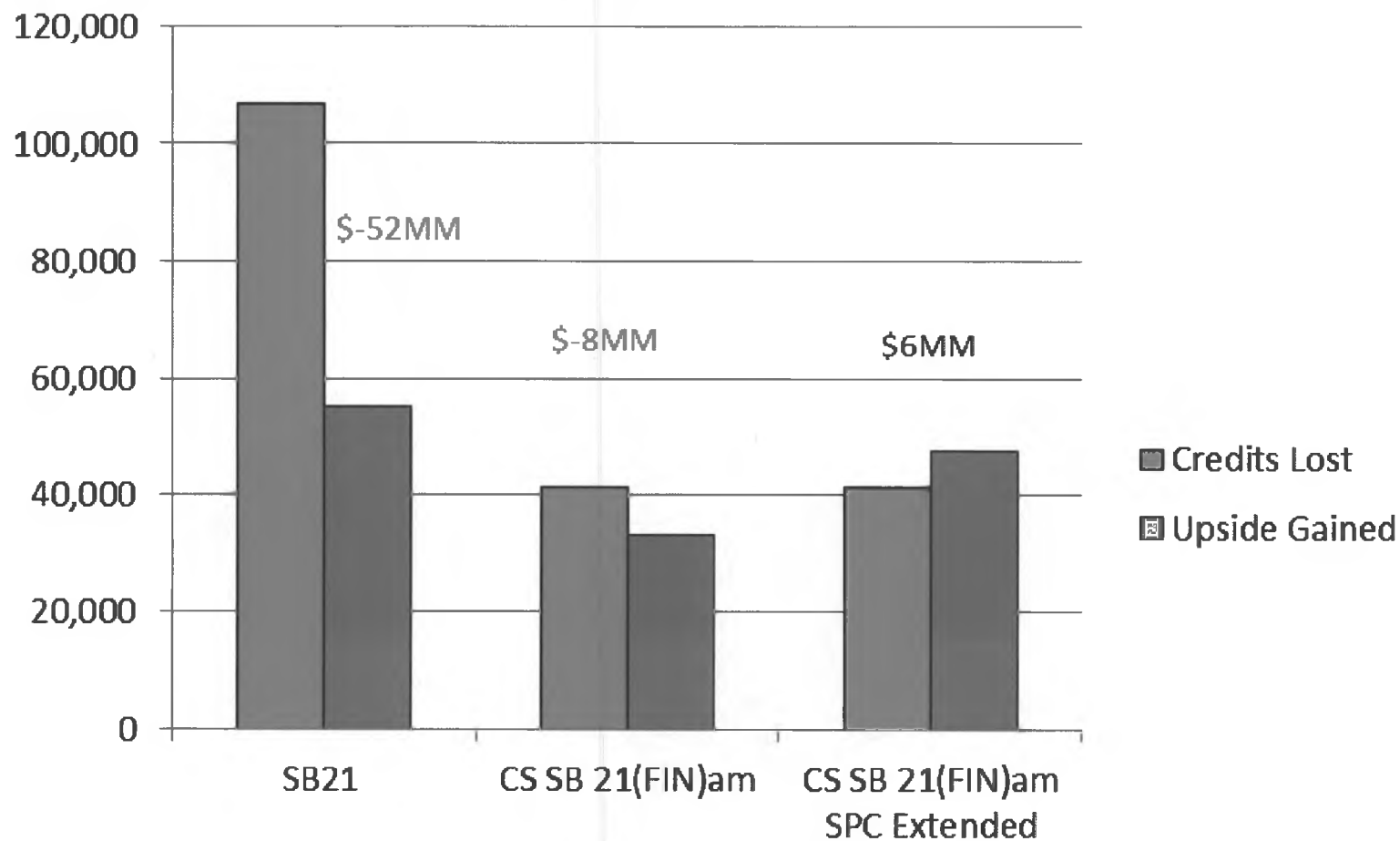
New Entrant Comparison



Field assumptions:

- 50 MMBO field
- \$1 Billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast (Nominal)
- NPV-10

Mid-Sized Producer Comparison



Field assumptions:

- 50 MMBO field
- \$1 Billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast (Nominal)
- NPV-10

CS SB 21(FIN) am(efd fld) Closing Thoughts

■ Pros

- 35/5 bbl. keeps tax rate flat across price ranges
- GRE tax reduction for new oil
- Loss carry-forward credit monetization
 - Rewards investment in Alaska

■ Cons

- Elimination of credits increases investor risk
 - Requires more upfront capital
- Increased base tax rate

■ CS SB 21(FIN) am(efd fld) 'wish list'

- Extend small producer credit to 2022
 - Adds additional value to projects
- Increase GRE to 25%
- Add targeted credits for facilities/well related costs
- 2 – Allow credits to be taken against any payment to the state
 -

→ for above curve wells
for those with no
previous liability



Savant Alaska, LLC
7501 Village Square Dr.
Suite 102
Castle Rock, CO 80108
Phone: 720-328-7186
Fax: 720-328-7183

SAVANT
ALASKA

VIA Email

March 26, 2013

Honorable Eric Feige
House Resources Co-Chair
State Capitol, Room 126
Juneau, AK 99801

Dear Representative Feige,

Thank you for allowing Savant Alaska LLC ("Savant") to offer this written testimony regarding SB 21 Oil & Gas Production Tax.

Savant first began investing in North Slope state leases in May of 2006. In the winter of 2008, after licensing some 200 square miles of 3D seismic data, Savant drilled its first exploration well, a dry hole, from remote, man-made, ice island in the Beaufort Sea. In the winter of 2009, Savant, with its working interest partner ASRC Exploration LLC ("AELLC"), began actively drilling and exploring in the Badami Unit as a result of a commercial agreement with BP Exploration (Alaska) Inc. ("BP"). In the winter of 2010, Savant made its first discovery in a secondary Killian sand exploration target located within the Badami Unit. The primary horizon in this well was dry. During that same winter ice road season, Savant notably drilled the first horizontal well in the Badami Sands pool. Later that year, Savant and AELLC elected to restart the then dormant Badami processing plant and pipeline to resume production from some of the wells in the Badami Sands PA, the new horizontal well, and from the Killian Sands discovery well.

In January 2012, Savant succeeded BP as the Badami Unit operator and became just the fifth production operator on the North Slope of Alaska. The Badami Unit has produced over 1.1 million barrels of oil at an average of 1279 barrels of oil per day since production was resumed and new oil was brought on line in November of 2010. The Badami Unit continues to produce at about the same level today.

The Badami Unit, with low production and high operating cost, is a marginal oil project by any standard. There is no gravel road access from the main North Slope infrastructure, drilling activities are limited to winter when ice road access is available, open water barging operations only offer some minor well services support in summer, and air transport must be relied upon at all other times. Even so, production from the Badami Unit employs approximately 45 contractors and Savant employees, the majority of whom are residents of Alaska, to operate the Badami Unit. Without the herculean efforts of its contractors and employees, and the various tax credits available under the original ACES legislation, Savant and its

working interest partner, AELLC, could not have accomplished what they have to date at the Badami Unit.

The proposed SB 21 Oil & Gas Production Tax legislation will negatively impact Savant's ability to maintain or grow existing production, both in the Badami Unit and on its leasehold outside of the Badami Unit, for the following reasons:

1. The elimination of "a credit for a qualified capital expenditure incurred to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude" after December 31, 2013 will cause Savant to invest less of its capital in the marginal exploration and development opportunities in the Badami Unit.
2. The Gross Revenue Exclusion (GRE) not being allowed for new oil within the existing Badami Sands PA will cause Savant to invest less of its capital in the marginal development opportunities within the Badami Sands PA.
3. By not extending the Small Producer Credit under AS 43.55.024 to 2022, Savant, a very small producer, will be less likely to explore for and develop any oil and gas deposits on its leasehold outside of the Badami Unit.
4. Removal of the modification of the Exploration Tax Credit (ETC) that eliminated the 3-mile buffer for drilling and extended the deadline for ETC's to 7/1/2022 removes any incentive for Savant to explore the small, one-well, marginal exploration targets within the Badami Unit not associated with any current production and on its leasehold outside of the Badami Unit.

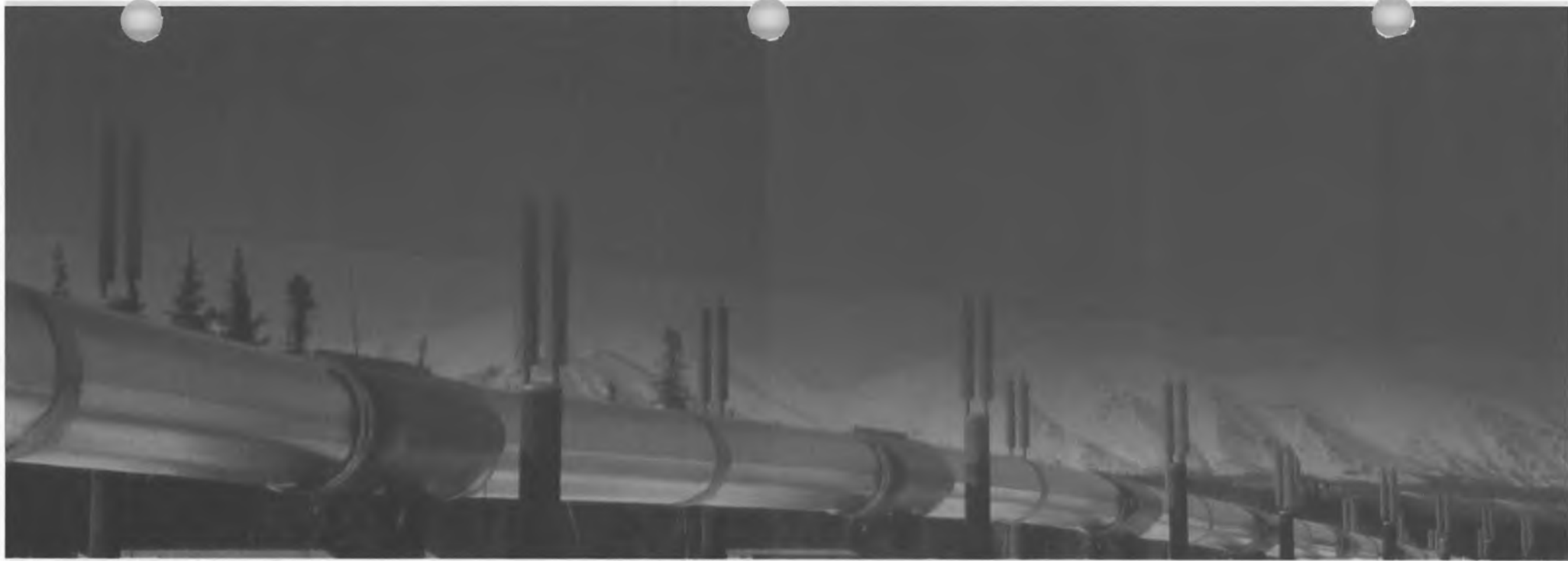
In closing, Savant urges the House Resources Committee to consider certain changes to the proposed SB 21 to provide further incentives for small producers to continue to explore and develop the smaller marginal targets, in and outside of existing units, on the North Slope of Alaska.

Thank you again for allowing Savant to submit this written testimony.

Very Truly Yours,



Greg Vigil, President



AOGA

OIL & GAS:

**FUELING
ALASKA'S
ECONOMY**

**House Resources
Committee**
CSSB21 (FIN) am(efd fld)
March 27, 2013
Kara Moriarty, Executive Director

AOGA Member Companies

PIONEER
NATURAL RESOURCES ALASKA



Apache



Hilcorp Alaska, LLC

ExxonMobil.



TESORO



bp



petroleum

Chevron

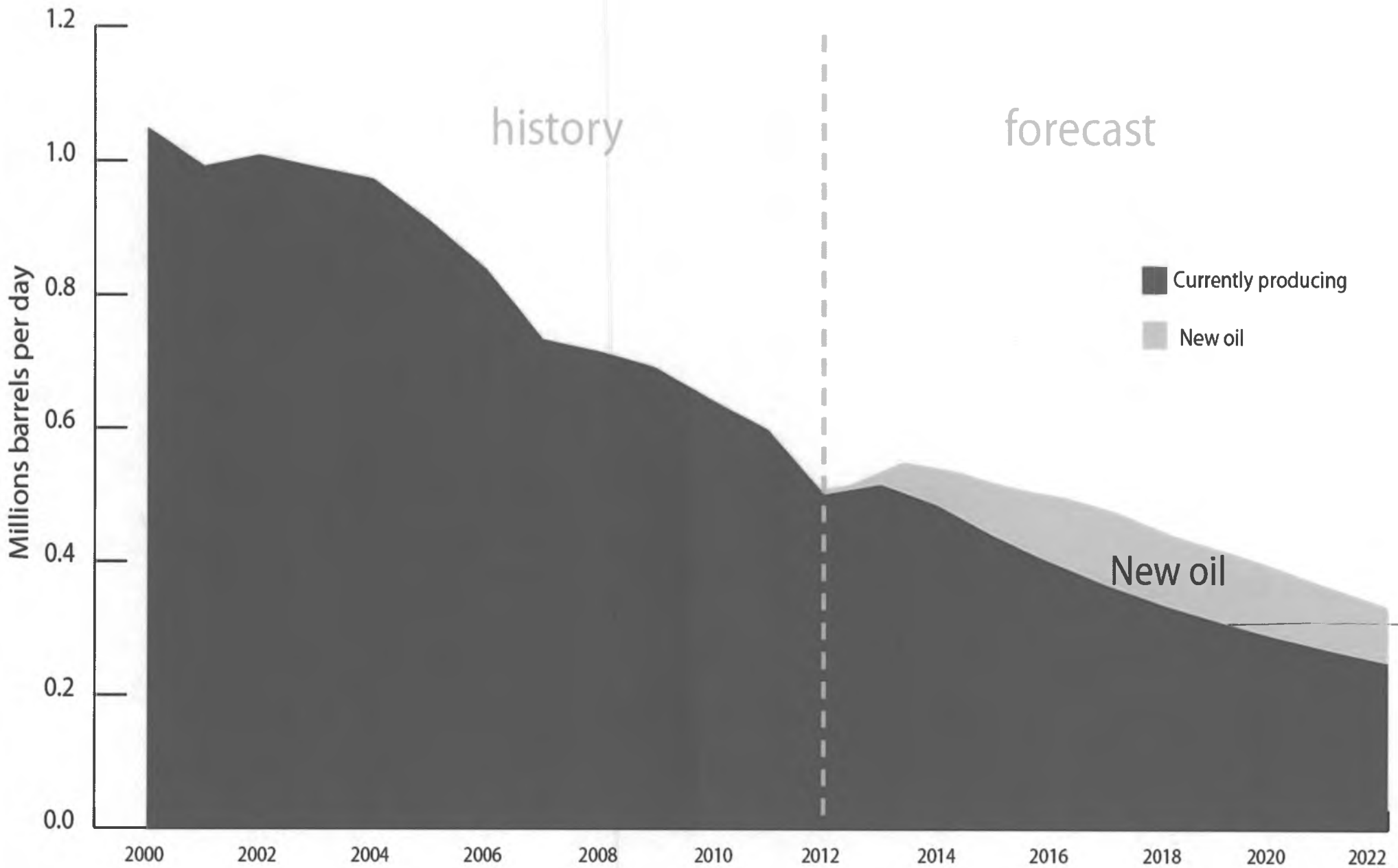


FLINT HILL
RESOURCES
Alaska



Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



Governor Lays out Principles for Oil Tax Reform

Anchorage Daily News, Jan. 6, 2013:

Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature

Governor Lays out Principles for Oil Tax Reform

Anchorage Daily News, Jan. 6, 2013:

Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature
- *AOGA Recommendation: Avoid changes that artificially creates “winners & losers”*

CSSB21 (FIN) am(efd fld) Component: Progressivity

- *AOGA supports the elimination of progressivity*
 - 1) Progressivity is the single most influential component of Alaska's tax structure negatively impacting investment decisions.
 - 2) Progressivity brings extraordinary complexity to the tax.
 - 3) The repeal of progressivity is consistent with all of the Governor's core principles.

CSSB21 (FIN) am(efd fld) Component: Increasing the Base Tax Rate

- *AOGA does not endorse increasing the base tax rate to 35%*
 - 1) Increasing the base tax rate burdens every investment case with a higher tax rate.
 - 2) Increasing the base tax rate is contrary to the Governor's second principle. It would not encourage new production.

CSSB21 (FIN) am(efd fld) Component: Tax Credits

*There is no tax credit liability for the State until
the investor invests here*

- 1) *AOGA does not support the repeal of Qualified
Capital Expenditure Credits (QCE)*
 - a) Elimination of QCE would undo significant part of
competitive environment
 - b) Repeal likely creates “winners & losers”
 - c) Consider expanding the scope of the “well lease
expenditure” tax credit

CSSB21 (FIN) am(efd fld) Component: Tax Credits

2) AOGA is concerned that the potential benefit of a \$5/bbl tax credit will be offset by other burdens

a) Weight of the benefit in respect to other changes is hard to measure.

b) Applaud the concept of tying incentives to the goal of increased production.

CSSB21 (FIN) am(efd fld) Component: Tax Credits

***3) AOGA supports amending CSSB 21 to extend
Small-producer & exploration tax credits***

a) Attracts new players to Alaska

**b) From testimony...has made a material
difference for some companies**

**c) Exploration credits bring about
exploration in a timely fashion**

CSSB21 (FIN) am(efd fld) Component: Tax Credits

4) AOGA supports the transferability of “Loss Carry Forward” credits

- a) New companies are many times not yet producing or producing only small volumes of oil/gas and have little to no tax liabilities.
- b) Maintaining the ability to transfer their losses to others allows companies to monetize the investments they have already made.

CSSB21 (FIN) am(efd fld) Component: Tax Credits

5) AOGA supports the new proposed manufacturing credit

a) May not have great impact on the reduction of the production decline.

b) Step in the right direction in creating more Alaska jobs and investment.

CSSB21 (FIN) am(efd fld) Component: Gross Revenue Exclusion (GRE)

AOGA supports concept, but concerned about breadth of applicability

- 1) CSSB 21 attempts to expand GRE to 80-90% of the potential development on North Slope in legacy fields.
- 2) Current language causes concerns due to uncertain nature of the applicability.
- 3) Companies won't know if they qualify for GRE until after investment is made, so they won't be able to use the GRE as a factor when determining economics.

AOGA Recommendation:

Need additional clarity and certainty surrounding GRE for legacy fields

CSSB21 (FIN) am(efd fld) Component: Competitiveness Review Board

*AOGA does not support the concept of a
Competitiveness Review Board*

1) Does not meet Governor's principle for durability

2) Tax certainty is in jeopardy with each annual report

? 3) Confidentiality concerns

CSSB21 (FIN) am(efd fld) Component: Statutory Interest Rate

AOGA supports the lowering of the statutory interest rate

- 1) Because the current Federal Reserve rate is very low, the current statutory interest rate is 11% APR.
- 2) When coupled with a six year, statute of limitations, the current interest rate adds uncertainty for taxpayers.
- 3) Lowering the interest rate provides some certainty to taxpayers.

Components Not Addressed in CSSB 21 (FIN) am(efd fld)

1) Minimum Tax

- *AOGA Recommendation: Minimum Tax should be repealed.*

2) Joint Interest Billings

- *AOGA Recommendation: Restore language specifically authorizing DOR to rely on joint-interest billings if it chooses to do so.*

AOGA Supports Components of CSSB 21 (FIN) am(efd fld)

Cornerstone for significant and crucial tax reform

- Support the elimination of progressivity
- Support the concept of gross revenue exclusions
- Support the transferability of loss carry forward credits
- Support the manufacturing credit
- Support lower statutory interest rate

AOGA Concerns with CSSB 21 (FIN) am(efd fld)

- Base tax rate is too high
- Serious concerns with how the bill addresses tax credits (QCE elimination, no extension of small producer and exploration credits)
- Does not support the Competitiveness Review Board
- Gross Revenue Exclusions for legacy fields needs clarity and certainty.
- Identified other ways to improve policy (repeal minimum tax, and allow DOR to use joint-interest billings)

Alaska Oil and Gas Association

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907) 221-1481 Fax: (907) 279-8114

**ALASKA OIL AND GAS ASSOCIATION
TESTIMONY ON COMMITTEE SUBSTITUTE SENATE BILL 21(FIN) am(efd fld)
TO THE HOUSE RESOURCES COMMITTEE
March 27, 2013**

Good afternoon. My name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding Senate Bill 21, and specifically Committee Substitute Senate Bill 21 (FIN) am(efd fld), have been reviewed by all members and have been approved unanimously.

In short Mr. Chairman, my members believe the proposed Committee Substitute represents a base for significant and crucial tax structure reform of ACES that will help move the State's fiscal policy toward Governor Parnell's four "core principles". While we are encouraged by the Committee Substitute and the efforts by the Legislature and the Administration thus far to try and significantly improve Alaska's overall global attractiveness, AOGA believes additional changes are still needed for the bill to truly change investment behaviors to the benefit of Alaskans.

The industry's greatest challenge today, which we share with the State is the decline of oil production from the North Slope. A healthy oil and gas industry is one that sees the economic benefits of continuing to invest in projects in Alaska and keeping its employees here, where they volunteer their time, talent and treasure to make Alaska a better place to live for us all. Corrections to the ACES tax regime will remove impediments to development and exploration and assist the industry in investing in projects that could both extend the life of TAPS and open up new resources to long term development. We want to create developments that will last for decades more, creating jobs for our children and opportunities for our communities to flourish.

If a restructuring and tax rate reduction make investments here more competitive, or better yet, “attractive”, companies will want to make more investments here for that upside. Deciding to make long term investments in Alaska’s North Slope requires the industry to see potential upside to their investments and assessing that the essential risks of those investments are offset by the opportunities afforded in success. Without that potential opportunity in Alaska, investment dollars will be spent elsewhere, where risks are less and opportunity is greater.

Core Principles to Address North Slope Production Decline

Throughout my testimony today, I will reference Governor Parnell’s four “core principles” so it is important to restate them here as they offer an excellent cornerstone for you as you consider potential solutions to the challenge production decline creates for Alaska:

- “First, tax reform must be fair to Alaskans.”
- “Second, it must encourage new production.”
- “Third, it must be simple, so that it restores balance to the system.”
- “Fourth, it must be durable for the long term.”

We believe the addition of a fifth such principle would be required to meet Alaska’s goals, because the challenge is not that there are too many companies pursuing opportunities, but that there are too few. Alaska should therefore avoid tax changes that artificially create “winners” and “losers.”

Our goal today is to offer insights into how the CSSB21 impacts industry and we have ideas of how the current tax structure can be modified to better suit the needs of the State.

1. Repealing Progressivity.

AOGA endorses the elimination of progressivity.

Impact of Progressivity as part of the ACES tax rate in industry investment decision making is the single most influential component of Alaska’s tax structure negatively impacting investment decisions related to Alaskan projects. Taxes are paid by the industry in virtually every jurisdiction in which we function and so we are very familiar with how they work. But the uniformity and consistency in the application of tax impacts as they relate to investment decision making found in almost every jurisdiction is missing in Alaska. As my member companies have testified in the past, investment decisions are driven by combining high and low case scenarios where costs and revenues are estimated and best case cash flows and worst case cash flows are measured, risked and analyzed. Each potential project, in every jurisdiction, is measured and compared and only some are funded. As one of the

legislative consultants, Roger Marks, pointed out recently, the international investment climate is characterized by plenty of opportunities, fluid capital, but finite capital. To choose what they can and cannot fund, companies have compared each potential project, no matter the jurisdiction, by application of a uniform investment decision measuring formula. When Alaska's tax system is quantified and added to this measure for proposed Alaskan projects the best cases are always burdened with an excessively high tax rate and as the assumed high cases get better, the burden only increases. We can find almost no other jurisdiction that so burdens investment return where the better the cases assumed for the decision, the higher the tax burden that applies.

And as I have testified to before, progressivity brings extraordinary complexity to the tax, not only in calculating what the tax is, but also in analyzing what the amount of the progressivity is for any particular item that affects a taxpayer's Production Tax Value (PTV).

The repeal of progressivity is consistent with all the principles outlined above. Its removal improves fairness because operators that increase margins through efficiency would no longer be automatically penalized. Its removal encourages new production because it reduces the tax burden on investment, as discussed above. Its removal is a significant step toward simplicity. And, lastly, its removal enhances durability because it satisfies the three preceding core principles.

2. Increasing the base tax rate from 25 to 35%.

AOGA does not endorse increasing the base tax rate to 35%.

Let's go back to the industry investment decision process again. Increasing the base tax rate, burdens every investment case with a higher tax rate. The burden of a 35% versus a 25% rate is easy to envision as every middle case and every worst case scenario is burdened with an additional 10% tax rate. This assumed cost will negatively impact the potential returns deemed available for any Alaskan project and drive investments to be made elsewhere. Increasing the base tax rate is contrary to the second core principle; there is not any reasonable argument that suggests increasing the base tax rate would encourage new production. Indeed, using the progressivity formula as a benchmark, the ten percentage point increase in the base tax rate could be viewed as equivalent to a sustained reduction in oil price of \$25 per barrel, all else being equal.¹

¹ In other words, a sustained \$25 per barrel price change would be needed under progressivity to get the same 10% change in the base tax rate. Under progressivity, each \$1 increase in PTV (or price, all else equal) per barrel would result in a 0.4% increase in the tax rate surcharge. Thus, a 10 percentage point change in the tax rate under progressivity would be equivalent to a \$25 change in PTV or price because $25 = 10\% \text{ divided by } 0.4\%$.

3. Tax Credits

Industry makes investments to seek returns. In general, tax credits, because they act to offset a part of the costs of certain investments when the expenditure is made are an important tool in reducing the deemed risks of those expenditures.

It is important to reinforce that there is no tax credit liability for the State at all until an investor invests here. So it costs the State nothing to offer the credit until the investment is made and at that point the tax credit has already succeeded in what it is supposed to do – namely to attract investment dollars here.

A. Repeal of the Qualified Capital Expenditure (“QCE”) Tax Credit.

AOGA does not support the repeal of the Qualified Capital Expenditure Tax Credit.

Even while the elimination of progressivity would improve the competitiveness of Alaskan investments from the present ACES tax, the elimination of the QCE Credit would claw back one important financial incentive and a part of ACES that actually acts to improve the competitive environment. The QCE Credit depends entirely on how much is invested here, and provides benefits for investments even when oil prices are lower. While the benefit from ending progressivity, which depends on the price of oil relative to a producer’s lease expenditures, helps when oil prices are higher the QCE provides benefits across all price levels. At low to mid-range of oil prices the loss of QCE Credit would outweigh the benefit from the end of progressivity.

Repeal of the QCE credit is contrary to the second core principle. Furthermore, because every producer’s costs are different and prices will impact them differentially, AOGA fears the repeal of the QCE Credit is worse than creating “winners” and “losers” because it only creates “losers” artificially among producers, and we see no sound tax policy justification for doing so.

For these reasons, AOGA believes the elimination of the QCE tax credits would not serve to attract new business to Alaska. Instead of that, one possibility might be to expand the scope of the “well lease expenditure” tax credit under AS 43.55.023(l) so it is available to producers on the North Slope. This credit has several meaningful advantages. First, it focuses investment incentives on subsurface intangible-drilling expenditures, which are a reasonable proxy for direct spending on well activity and, in turn, production. Second, the credit is clear because it uses already established concepts in the federal Internal Revenue Code. Third, it is fair because it applies equally to well-related spending in all areas of the state, without creating winners and losers merely on the basis of geography.

B. The \$5 dollar per barrel tax credit.

AOGA is concerned that the potential benefit of a \$5 dollar per barrel tax credit under AS 43.55.024(i) will be offset by other burdens.

There are multiple issues to balance when taking in the numerous proposed changes found in CSSB21. The removal of progressivity, the increase in base rate, elimination of the QCE credit all create interrelated issues and while a \$5 dollar per barrel tax credit would provide benefits both in real tax costs and in investment decision making, the weight of the benefit in respect to the other changes is hard to measure. AOGA applauds the concept of tying incentives to the goal of increased production and as such allowing a tax credit per barrel.

C. Small-Producer and Exploration Credits.

AOGA supports amending CSSB21 to extend the small-producer tax credit under AS 43.55.024 and exploration tax credits under AS 43.55.025 from the present sunset dates in 2016 to a later date.

The State had sound policy reasons for creating these small producer and exploration tax credits, and those reasons are just as valid today as they were then. The current CSSB21 does not extend the sunset dates beyond 2016, even though AOGA believes these credits have increased the likelihood of participation by new industry players and act to increase the opportunities that could be found by expanding exploration. The purpose of the small-producer tax credit was to attract new players to Alaska who might otherwise have been deterred from coming here by presumptions of increased risks and of higher-than-average costs and expenses. The success of the credit in attracting new participants is a fact that cannot be denied. AOGA sees this success in its own membership, and in other companies that have come here and are now active. Smaller producers often have a different perspective about the opportunities around them, and as such can bring with them new ideas and opportunities. New participants with new ideas can only strengthen and improve the Alaskan petroleum industry and help the state stem the decline in production. We know from testimony that the small-producer tax credit has made a material difference in individual companies' decisions to do business and invest in Alaska.

The purpose and justification for the exploration tax credits under AS 43.55.025 are equally clear. Huge parts of this state remain unexplored or underexplored. Again, these tax credits are only earned when actual expenditures for exploration occur. The credits tangibly reduce the risks faced by an explorer and as such incentivize them to go out and search for oil and gas that is much needed.

Increased exploration leads to increased development and these credits act to increase exploration and should be extended as well. Just as with the QCE credits for capital investments, there is no exploration tax credit without real money having first been spent on exploration work that qualifies for these tax credits.

D. Maintaining transferability of “carried-forward annual loss” tax credits.

AOGA supports the transferability of these losses.

We applaud that the CSSB21 maintains the transferability of the current “carried-forward annual loss” tax credits under AS 43.55.023(b). New participants and new explorers are many times not yet producing in the state or only producing small volumes of oil and gas and as such have little or no production tax liabilities. The ability to transfer their losses to others allows them to monetize the investments they have already made, both reducing their cost exposure on the original expenditure and hopefully at the same time acquiring additional capital for more investment.

E. New credit for Manufacturing

AOGA supports the new proposed manufacturing credit.

Although this credit is directed to the incentivizing of development and manufacture of drilling and exploration methods and materials, it may not have a great impact on the reduction of the current production decline. However, it is a step in the right direction to incentivize jobs and additional investment, and having more jobs and investment in Alaska is never a bad thing.

4. Gross Revenue Exclusion.

AOGA endorses the proposed 20% gross revenue exclusion or GRE, but has concerns on breadth of applicability.

The GRE would, in calculation of the taxable Production Tax Value, exclude 20% of the Gross Value at the Point of Production of what we’ll call “non-legacy” production, and attempts to apply to new oil within legacy fields. AOGA supports the concept of a GRE, and initially we were concerned that it was too narrowly focused because it would have only applied to those areas outside existing Units.

The Governor’s second “core principle” for tax legislation is that “it must encourage new production.” But, in order to get results from such encouragement, the tax legislation must incentivize the best opportunities that Alaska has for getting results. The current CSSB21 attempts to expand the application of the GRE and tries to include legacy fields, which is where at least 80 – 90 percent of the 3

billion-barrel opportunity in the central North Slope that Econ One identified as economically recoverable earlier this session.

However, the current language causes concern because of the uncertain nature of the applicability and the problem that companies won't know if they get the GRE until after the investment is made, so in essence, companies cannot utilize the GRE in modeling economics of future projects in legacy fields. Additionally, we have concerns that the determination methodology will be defined after the bill is passed and be placed in future regulations.

AOGA believes our concerns can be addressed by additional language to provide clarity and certainty so the GRE is effective for industry.

Oil and Gas Competitiveness Review Board

AOGA does not support the formation of the Competitiveness Review Board.

The proposed Board provides an oversight and review process that we believe would be burdensome to the industry and contravenes the Governor's principles relating durability in the long term. The perspective that the proposed changes found in the Bill would provide a long term solution to problems we know exist are placed in jeopardy because the very certainty that is required for sound investment decision making would be placed in question with each annual report of the Board. Instead of moving forward with projects that might help stem decline, industry resources would be used to assist the Board in collecting and understanding complex information of long term consequence. Finally, the documentation and information the Board might request or require is of the highest proprietary value to oil and gas companies and confidentiality concerns and related complexities would hinder the efforts of the industry as well as the Board. While we appreciate the ability to represent industry on the proposed board, our concerns cause AOGA to question both the viability and the effectiveness of the proposed Board and as such we cannot support its proposed formation.

Reduction in Statutory Interest Rate

AOGA supports the lowering of the statutory interest rate.

As we have testified to in the past, the statute of limitations under AS 43.55.075(a) is six years from the date when the tax return was filed for the tax being audited, while the limitations period for other taxes under AS 43.05.260(a) is three years from the filing date of the tax return. Under both statutes, the period may be extended by mutual consent of the taxpayer and the Department of Revenue

(DOR).

The current statutory rate of interest under AS 43.05.225(1) for tax underpayments is “five percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter[.]” Currently the Federal Reserve rate is very low, so 11% APR is the applicable rate.

A lower statutory interest rate is very much supported by industry, because it provides some certainty to taxpayers.

Issues that the current draft does not address.

There are several significant problems in the present ACES tax that are not addressed in CSSB21, and I will address a few of them this morning.

A. Minimum tax for North Slope production. AS 43.55.011(f) sets a minimum tax that is targeted solely against North Slope production. That tax is based on the gross value of that production instead of the regular tax based on “net” Production Tax Value. The rationale for adopting it was to protect the State against low petroleum revenues when prices are low.

The minimum tax only complicates potential new investors’ analyses of what their tax would be if they invest here instead of someplace else, and consequently it has, if anything, driven investments away. AS 43.55.011(f) should be repealed or consideration given to significantly reducing the rate of the minimum tax.

B. Joint-interest billings. Instead of starting with the joint-interest billings that participants in a unit or other joint operation receive from the operator, DOR regulations reflect an assumption that each non-operating participant has information, in addition to the operator’s billings to them, that allows them to determine which expenditures are deductible as allowed “lease expenditures” under AS 43.55.165 and which are not. Instead of one audit of the expenses by a joint venture for any given period, the Department audits each participant separately for its respective share of the same pool of expenses.

We are not asking for legislation to put the Department’s regulations on a different track. But there are some in the Department who believe that the repeal by the 2007 ACES legislation of AS 43.55.165(c) and (d) — which specifically authorized the Department to rely on joint-interest billings — means the Department cannot legally rely on them now. While we disagree with this position (which is

also at odds with what the Department testified to during the enactment of the 2007 ACES legislation), we do think it would be appropriate to restore language specifically authorizing the Department to rely on joint-interest billings if it chooses to do so.

Conclusion.

If I leave you with one thing today, it would be the word “enormous”. While AOGA believes that Alaska’s potential is enormous we are grounded by the reality that our competition is enormous as well, and they are just starting to heat up. It is estimated that the fields of South and West Texas alone could produce over FOUR MILLION barrels of oil equivalent per day by 2020. That’s more than some OPEC countries. Alaska should ask themselves if they really believe a “middle of the pack” policy for the state will attract new investment capital against that type of competition.

We believe it is up to you, and the Governor, to shape an attractive oil fiscal policy that is supported by strong principles that will win additional capital, arrest North Slope production decline and will lead Alaska towards a prosperous future for the long-term.

As I mentioned at the beginning of our testimony, overall, AOGA’s members believe the Bill represents a base for significant and crucial tax structure reform that move toward Governor Parnell’s four “core principles” — fairness for Alaskans, encouraging new production, simplicity with balance, and durability for the long term, but as I have outlined today, AOGA members believe additional changes should be included for this bill to truly change investment behaviors to the benefit of Alaskans. You have a difficult task ahead and AOGA stands ready to assist you throughout this process.



March 27, 2013

Representative Eric Feige
Co-Chair
House Resources Committee
Alaska State Legislature
State Capitol Building
Barnes 124
Juneau, AK 99801

Representative Dan Saddler
Co-Chair
House Resources Committee
Alaska State Legislature
State Capitol Building
Barnes 124
Juneau, AK 99801

Dear Co-Chairs Feige and Saddler:

On behalf of Arctic Slope Regional Corporation, I am writing to share with you ASRC's position on oil tax reform, specifically SB 21. Thank you for your leadership on this issue and for the opportunity to weigh-in on this important piece of legislation.

By way of background, ASRC is the largest Alaskan-owned company with approximately 10,000 employees worldwide, with approximately 5,000 employees in Alaska. ASRC represents the business interests of 11,000 Iñupiat shareholders who primarily reside within the boundaries of the North Slope.

The ASRC enterprise is heavily invested in this state. In Alaska we provide quality services to the oil and gas industry through our subsidiary ASRC Energy Services; we draw crude from the Trans Alaska Pipeline System to process through our refineries in North Pole and Valdez- supplying marine, jet and home heating fuel and ultra-low sulfur diesel to the Alaskan market through our subsidiary Petro Star, Inc.; we are involved in commercial construction projects through our subsidiary ASRC Construction Holding Company; and, we are a resource owner, developer and explorer in this state.

Some of our ownership interests are subject to Section 7(i) of the Alaska Native Claims Settlement Act, and our ability to explore, develop and produce on those lands benefit every region in this state. The absence of a stable tax regime and positive investment climate for the oil industry has a material negative impact on how we develop or not develop those lands.

I submit our comments from the perspective of an employer and a company with an enterprise involved in the value chain of oil development in this state, from exploration through refining product and all services in-between.

There are some positive aspects to SB 21, and areas in need of improvement. Here are some areas of the bill ASRC wishes to highlight:

- The community sharing provision is a good start, and we encourage the Legislature to continue to consider linking it to a percentage of the tax, versus the current language of a legislative appropriation. We feel this is a more objective approach to sharing revenues with Alaskan communities.
- We support the 35% Loss Carry Forward (LCF) Credits, as currently written. They enable explorers, small producers, majors and organizations like ASRC to receive carry-forward loss credit, through a transfer, refund or tax deduction. This flexibility is attractive to ASRC.
- We support the \$5 per barrel tax credit for producers of oil.
- We support the 10% service credit because it stimulates the economy within the service industry. Our subsidiary, ASRC Energy Services, employs thousands of Alaskans, and this credit could help us revamp our fabrication and construction services in the state.
- As currently written, we are concerned that this legislation will negatively impact our ability as a small producer, through our subsidiary, ASRC Exploration LLC, and the ability of other small producers, to maintain or grow existing production for the following reasons:
 1. The elimination of “a credit for a qualified capital expenditure incurred to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude” after December 31, 2013 would cause small producers to invest less of their capital in marginal exploration and development opportunities in their leaseholds. It is not good for new investment.
 2. As currently written, the Gross Revenue Exclusion (GRE) does not allow for new oil within the existing small producer units or PA’s. This will cause the small producer to invest less of its capital in marginal development opportunities within their units or PA’s.
 3. By not extending the Small Producer Credit under AS 43.55.024 to 2022, current small producers would be less likely to explore for and develop any oil and gas deposits on leaseholds outside of their units that could add new production to their unit positions.
 4. Deletion of the proposed modification of the Exploration Tax Credit (ETC) that eliminated the 3-mile buffer for drilling and extended the deadline for ETC’s to 7/1/2022 would remove any incentive for a small producer to add new production to its unit or create other opportunities for new production.



- With respect to gross revenue exclusions (GRE), while we feel the base tax rate of 35% is too high, we could support it if it were coupled the following changes:
 1. Remove language contained in **Section 29** that currently requires the well to be “accurately metered and measured to the satisfaction of the Commissioner of the Department of Revenue.” It is unclear what “to the satisfaction of the Commissioner” means, and it creates ambiguity at a time when we need certainty. This language implies that there is an absence of this practice, and ASRC, as a small producer, stands by its metering and measuring practices, which are currently monitored by the AOGCC. Further, in its current form, producers do not have certainty that a new well will be eligible for the 20% GRE. If the State wants new oil, then any new well should count for that exclusion.

Layering on an addition approval process between ADOR and ADNDR for “new oil” would be onerous and inefficient. We support having new wells eligible for the GRE. Removing this language would eliminate the dual approval process obligation and give incentives for new production, thus making investments that grow production more attractive.

2. Remove the language also contained in **Section 29** that creates a requirement that the producer “demonstrates to the Department of Revenue the volume of oil or gas produced from that well.” This requirement would be burdensome, expand State bureaucracy, and would inhibit oil and gas investment. If a well is drilled and it produces oil or gas, simply put, it should qualify.

This has been a long and challenging process. I sincerely believe we all want what is best for Alaska, our economy and the industry on which our state is dependent. As an employer, service provider, resource owner, explorer, producer and developer, ASRC is in a unique position to provide comments. While some may be looking at this issue through a narrow lens, we have the fortune to see this issue from several important viewpoints. ASRC strategically plans for a sustainable future in Alaska and we support a healthy and robust oil industry here. Again, thank you for your leadership on this issue and for the opportunity for input into the process.

Respectfully,
ARCTIC SLOPE REGIONAL CORPORATION



Richard K. Glenn
Executive Vice President
Lands and Natural Resources





BP Testimony to House Resources

Damian Bilbao
Head of Finance

March 26, 2013

SB 21 makes Alaska more competitive



What it does well:

- Elimination of progressivity is a game changer
 - Puts Alaska “back in the game” of competition for investment
- Gross Revenue Exclusion could have a positive impact on economics
 - Application to legacy fields targets most reliable source of new oil
- Simplifies Alaska’s fiscal system
 - Removes many inefficient elements of administering ACES

What it could do better:

- Base rate presents a challenge below \$100/bbl for all players
 - 2010 prices averaged \$80/bbl
- More certainty on criteria for receiving Gross Revenue Exclusion

House Resources Committee

CSSB21

Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

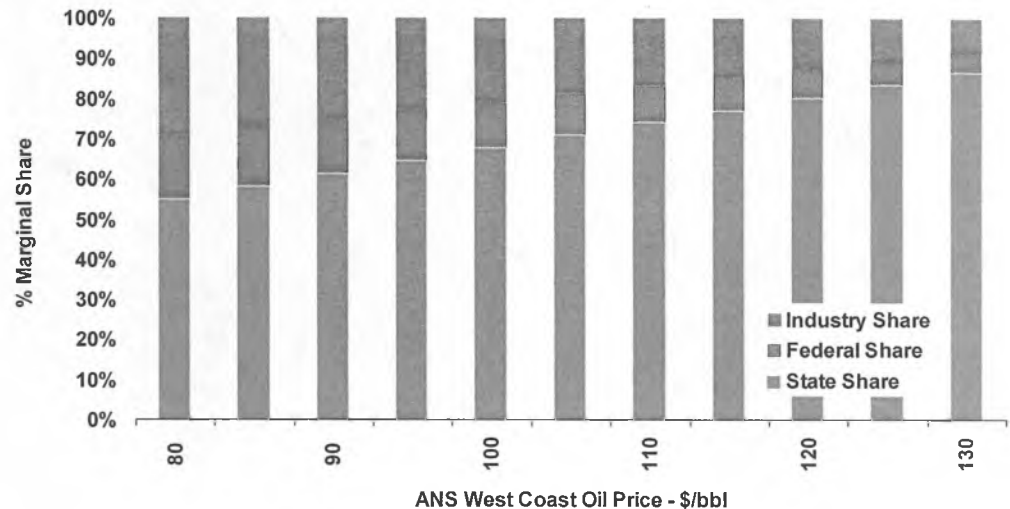
March 26, 2013

North Slope Investment Challenges

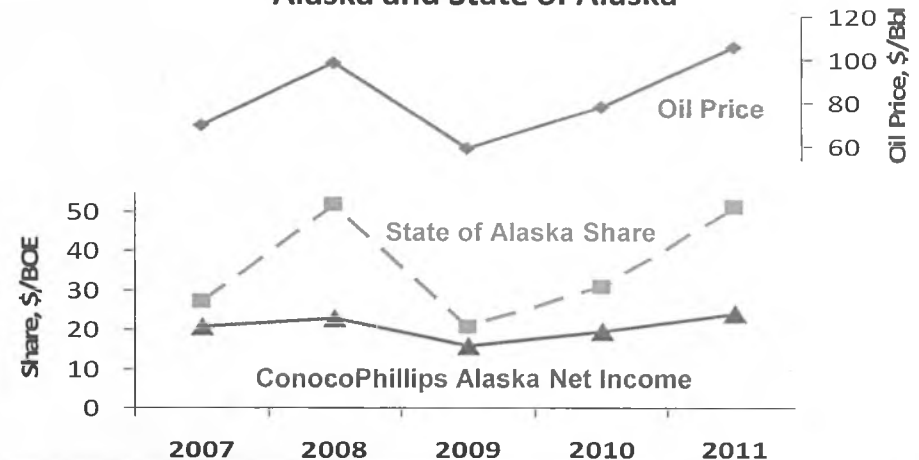
- Challenged oil remains
 - Complex, high cost wells
 - Smaller reserve targets
 - Fault blocks, flank oil
 - Satellites, viscous oil
 - Facilities handling ~ three times as much water as oil
 - Significant resource

- ACES tax structure
 - High average & marginal tax rates
 - Progressivity eliminates upside
 - Tax credits attempt to offset high tax rates and high costs. Apply to both new and legacy fields

Government and Industry Marginal Share in Alaska




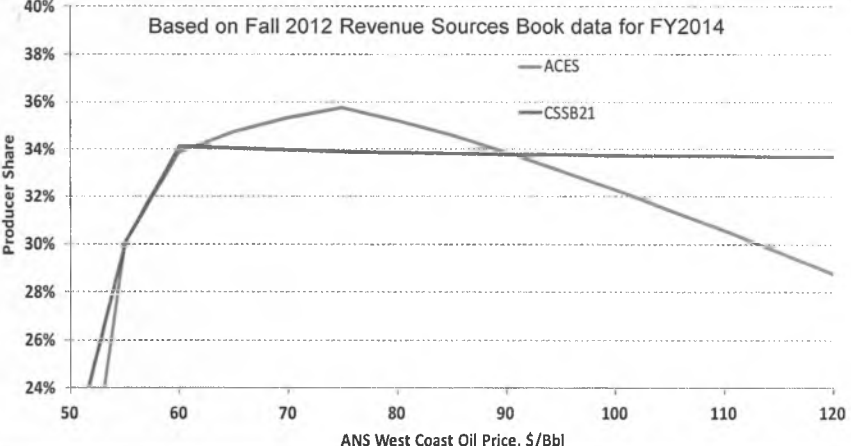
Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska



Upper right plot based on Fall 2012 Revenue Sources Book data for FY2014

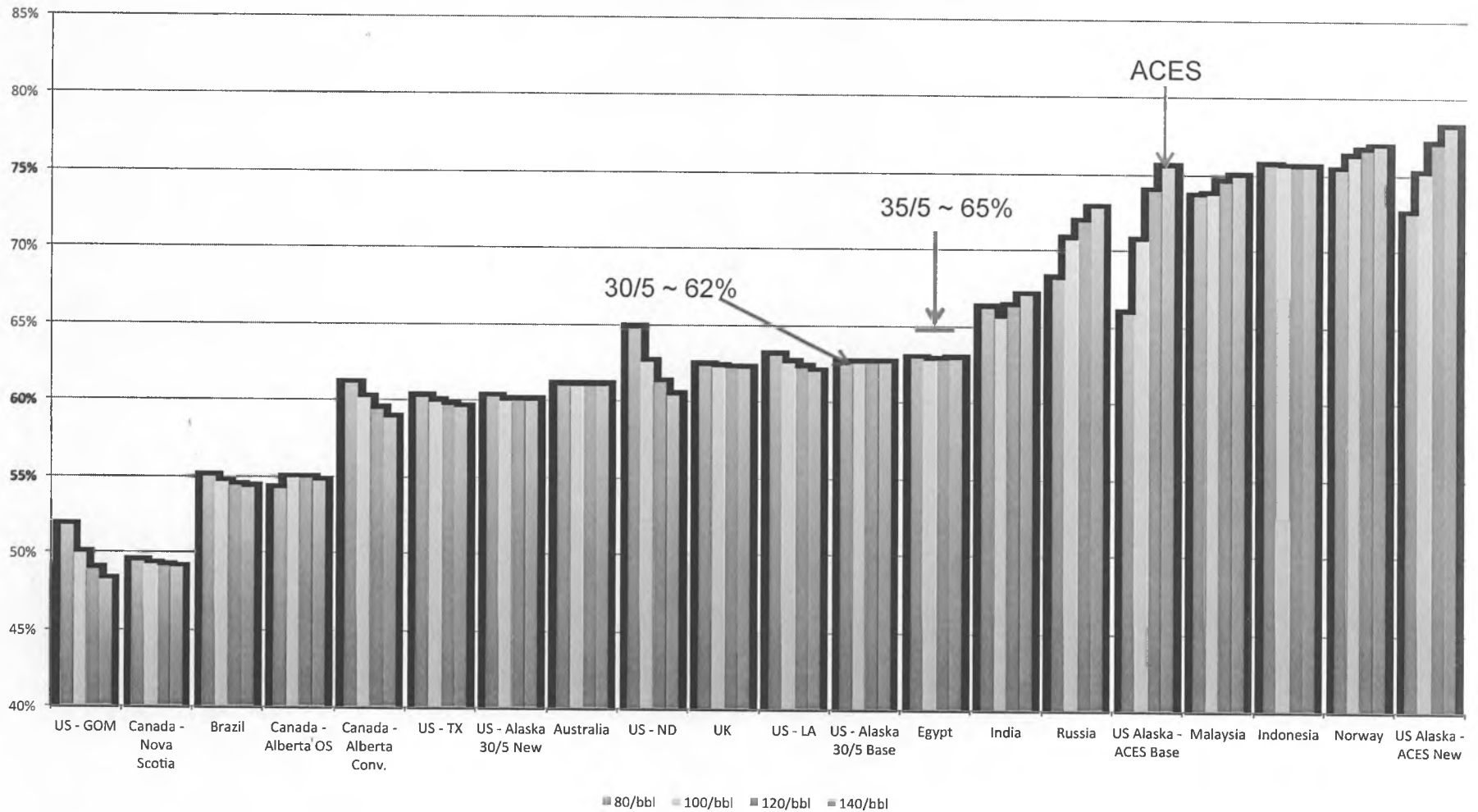
Lower right plot based on ConocoPhillips 2007 – 2011 10-K reports; State share is royalties (estimated), production tax, ad valorem tax and state income tax; oil prices are ConocoPhillips average realized prices on the West Coast

Changes to ACES to Improve Alaska's Investment Climate

Change	CSSB21																											
<ul style="list-style-type: none"> Eliminate progressivity 																												
<ul style="list-style-type: none"> Create a flatter tax rate over a broad range of prices <ul style="list-style-type: none"> ➤ Producer and State share proportionately as prices fluctuate and margins change 	 <p>Based on Fall 2012 Revenue Sources Book data for FY2014</p> <table border="1"> <caption>Approximate data from the graph</caption> <thead> <tr> <th>ANS West Coast Oil Price (\$/Bbl)</th> <th>ACES Producer Share (%)</th> <th>CSSB21 Producer Share (%)</th> </tr> </thead> <tbody> <tr> <td>50</td> <td>24.5</td> <td>24.5</td> </tr> <tr> <td>60</td> <td>34.0</td> <td>34.0</td> </tr> <tr> <td>70</td> <td>35.5</td> <td>34.0</td> </tr> <tr> <td>80</td> <td>35.0</td> <td>34.0</td> </tr> <tr> <td>90</td> <td>33.5</td> <td>34.0</td> </tr> <tr> <td>100</td> <td>31.5</td> <td>34.0</td> </tr> <tr> <td>110</td> <td>29.5</td> <td>34.0</td> </tr> <tr> <td>120</td> <td>28.5</td> <td>34.0</td> </tr> </tbody> </table>	ANS West Coast Oil Price (\$/Bbl)	ACES Producer Share (%)	CSSB21 Producer Share (%)	50	24.5	24.5	60	34.0	34.0	70	35.5	34.0	80	35.0	34.0	90	33.5	34.0	100	31.5	34.0	110	29.5	34.0	120	28.5	34.0
ANS West Coast Oil Price (\$/Bbl)	ACES Producer Share (%)	CSSB21 Producer Share (%)																										
50	24.5	24.5																										
60	34.0	34.0																										
70	35.5	34.0																										
80	35.0	34.0																										
90	33.5	34.0																										
100	31.5	34.0																										
110	29.5	34.0																										
120	28.5	34.0																										
<ul style="list-style-type: none"> Establish a tax structure creating an attractive investment climate <ul style="list-style-type: none"> ➤ Competitive tax rate ➤ Provide the incentives to balance Alaska's high cost environment ➤ Incentives for both legacy and new field investments 	<ul style="list-style-type: none"> Base rate too high <ul style="list-style-type: none"> ➤ Tax increase at lower prices ➤ Overall tax rate high GRE appears to have minimal applicability to legacy fields 																											

Government Take Competitiveness

Alaska Government Take Competitiveness - Comparable Regimes



Gross Revenue Exclusion (GRE)

- 20% GRE with no time limitation provides incentive

- Qualifying for a GRE is problematic for legacy field investments
 - Criteria for GRE would appear to exclude legacy fields
 - “Accurately metered and measured ” is a potential issue *

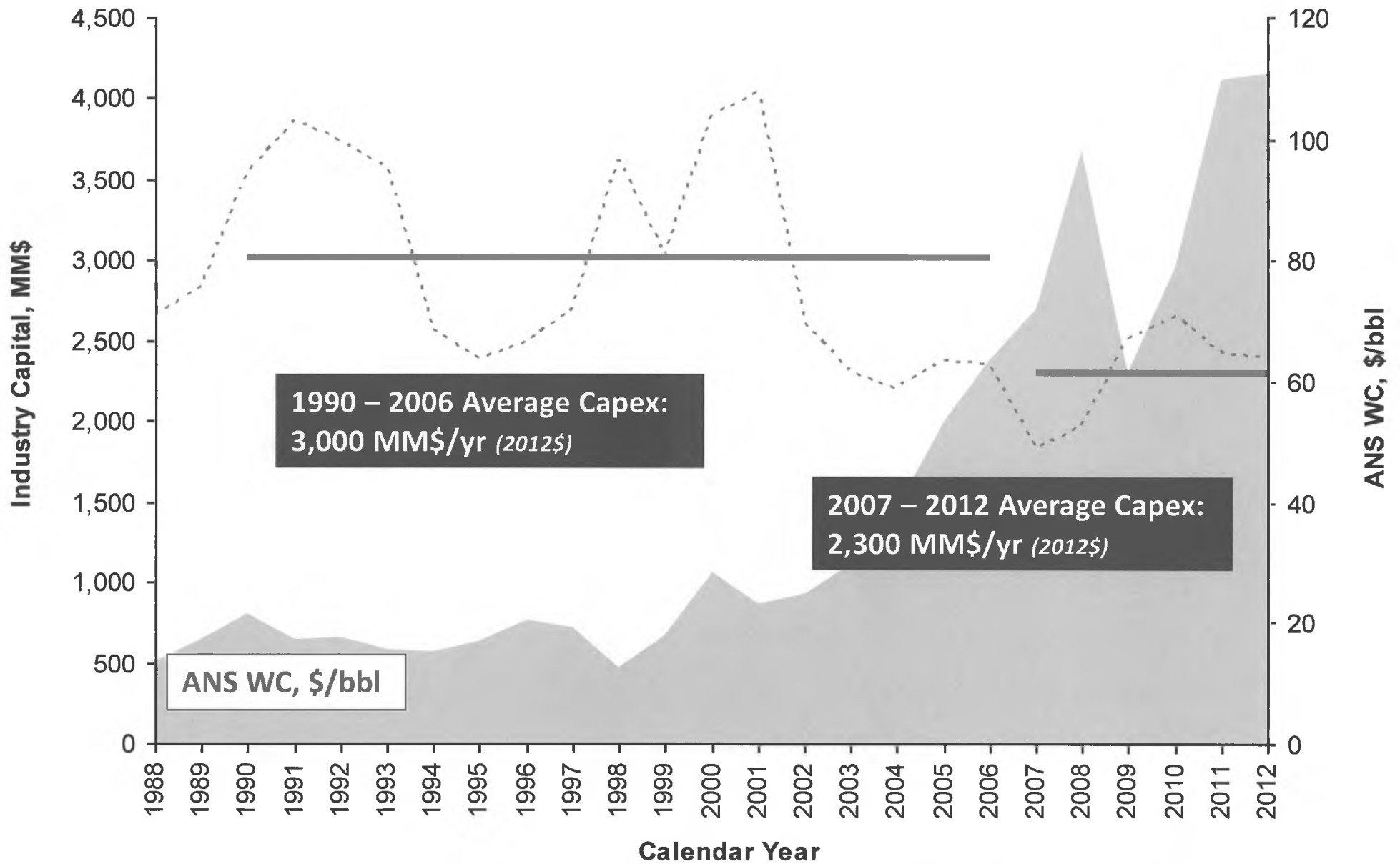
- Suggested changes to GRE
 - ➔ ▪ Production from any new well (sidetrack, CTD, grass roots well, etc.) that meets the criteria for qualified capital receives the GRE
 - Utilize current allocation methodologies to determine production from GRE qualified wells
 - Simple and clear

Summary

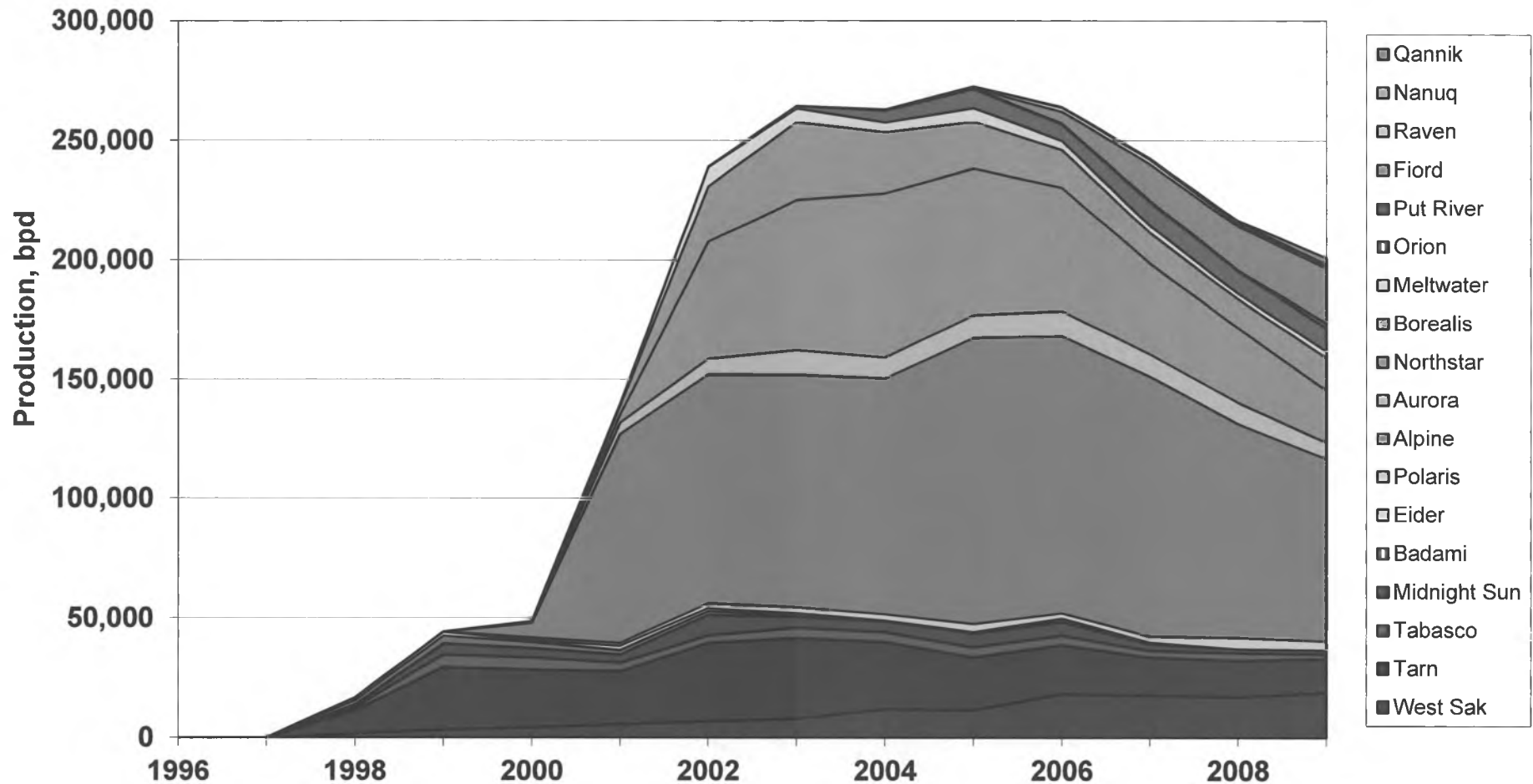
- CSSB21 an improvement over ACES
 - Provides relatively flat tax rate with slightly progressive nature over a broad price range
 - Elimination of progressivity solves the high marginal tax problem
 - Makes Alaska more attractive for investment at \$100+ prices
 - Concept of GRE positive

- CSSB21 changes for an attractive investment climate
 - Reduce base tax rate
 - Modify GRE to create incentives for both new and legacy fields

Historical North Slope Investment (Adjusted to 2012 Dollars)



Production Under ELF – New Field Production since 1997





House Resources Committee

Alaska Fiscal System Discussion Slides

March 25 2013
Janak Mayer
Manager, Upstream
PFC Energy

PFC Energy

ACES and SB21: Issues and Aims

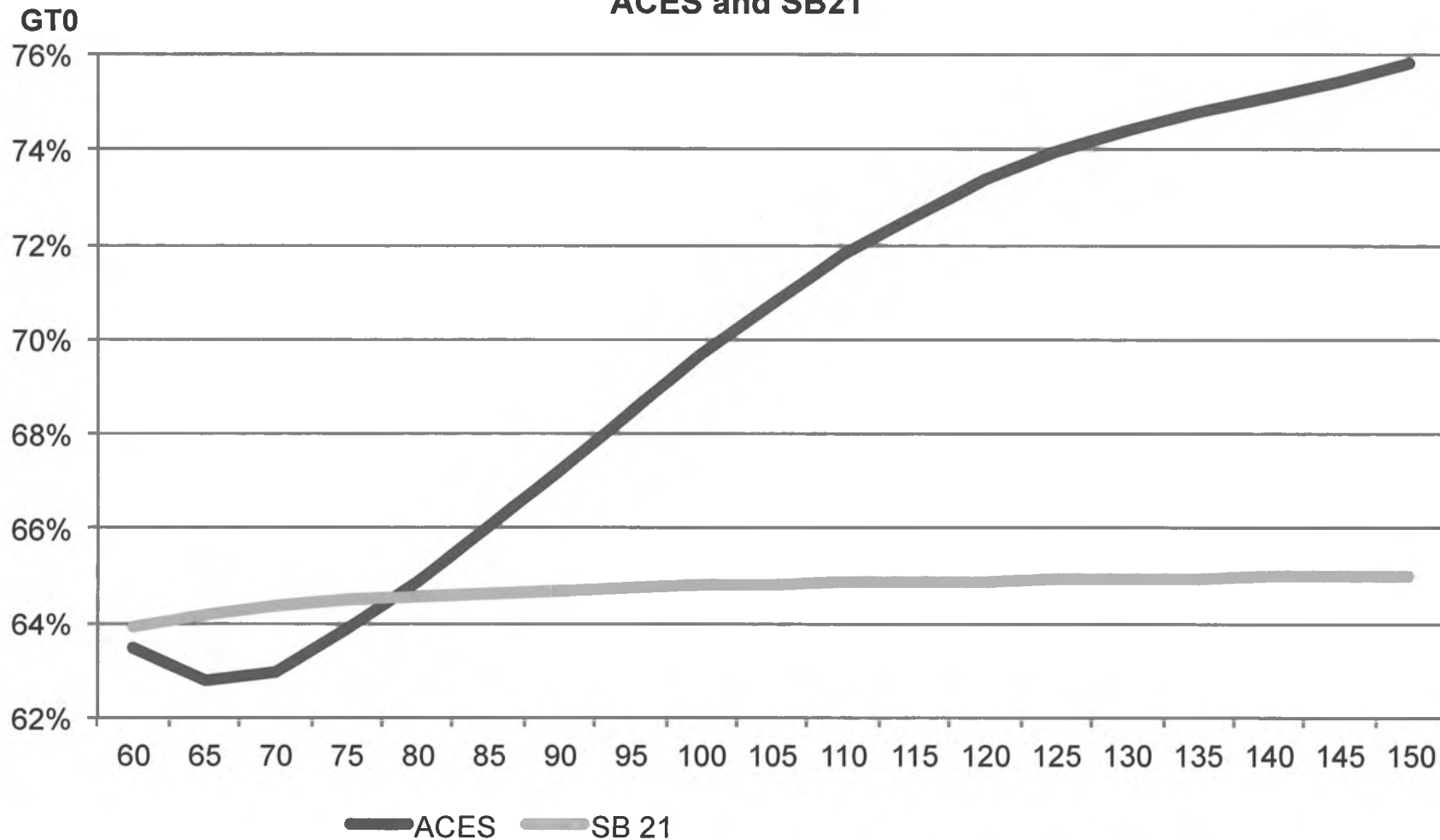
ACES - Issues	SB21 - Aims
<ul style="list-style-type: none"> High Government Take and high degree of progressivity means uncompetitive for investment at current prices 	<ul style="list-style-type: none"> Overall neutrality at a competitive level of Government Take, while further improving competitiveness for new projects
<ul style="list-style-type: none"> Credits create significant downside exposure to state in low price environments, for high cost projects, and projects not on state lands 	<ul style="list-style-type: none"> Limit downside risk to state from credits
<ul style="list-style-type: none"> “Buydown” effect means incremental and standalone economics very different – with very different impacts for incumbent vs new producer 	<ul style="list-style-type: none"> Balance system with even impacts for incumbent vs new producer
<ul style="list-style-type: none"> High marginal rates mean little incentive for producer efficiency 	<ul style="list-style-type: none"> Neutral regime creates low, constant marginal rates – strong incentive for producer efficiency
<ul style="list-style-type: none"> Complex system, with often counter-intuitive effects 	<ul style="list-style-type: none"> Simplify the fiscal system

ACES and SB21: Key Changes

	ACES	SB21
Base Tax Rate	25%	35%
Progressivity	0.4 % per dollar of per barrel-PTV from \$30 to \$92.50; 0.1% per dollar of per barrel-PTV above \$92.50	None – although \$/bbl allowance creates an implicit 'reverse' progressivity that counteracts regressive nature of royalty, leading to overall neutrality
Maximum Tax Rate	75%	35%
Incentives for New Production	None	Gross Revenue Exclusion (GRE): In calculating the PTV, a producer's 20% of gross revenues from eligible production are excluded. Oil is from new PA, PA expansions, and areas in legacy fields not previously contributing to production.
\$/bbl Allowance	None	\$5
Capital Credit	20% of all qualified capital expenditures	Eliminated after Dec 31 for North Slope
NOL Credit	25% for Carry-Forward Annual Loss Credit, monetizable for small producer over 2 years	35% for Carry-Forward Annual Loss Credit, monetizable for small producer over one year
Small Producer Credit	Expires 2016	Expires 2016
Exploration Credit	Expires 2016	Expires 2016

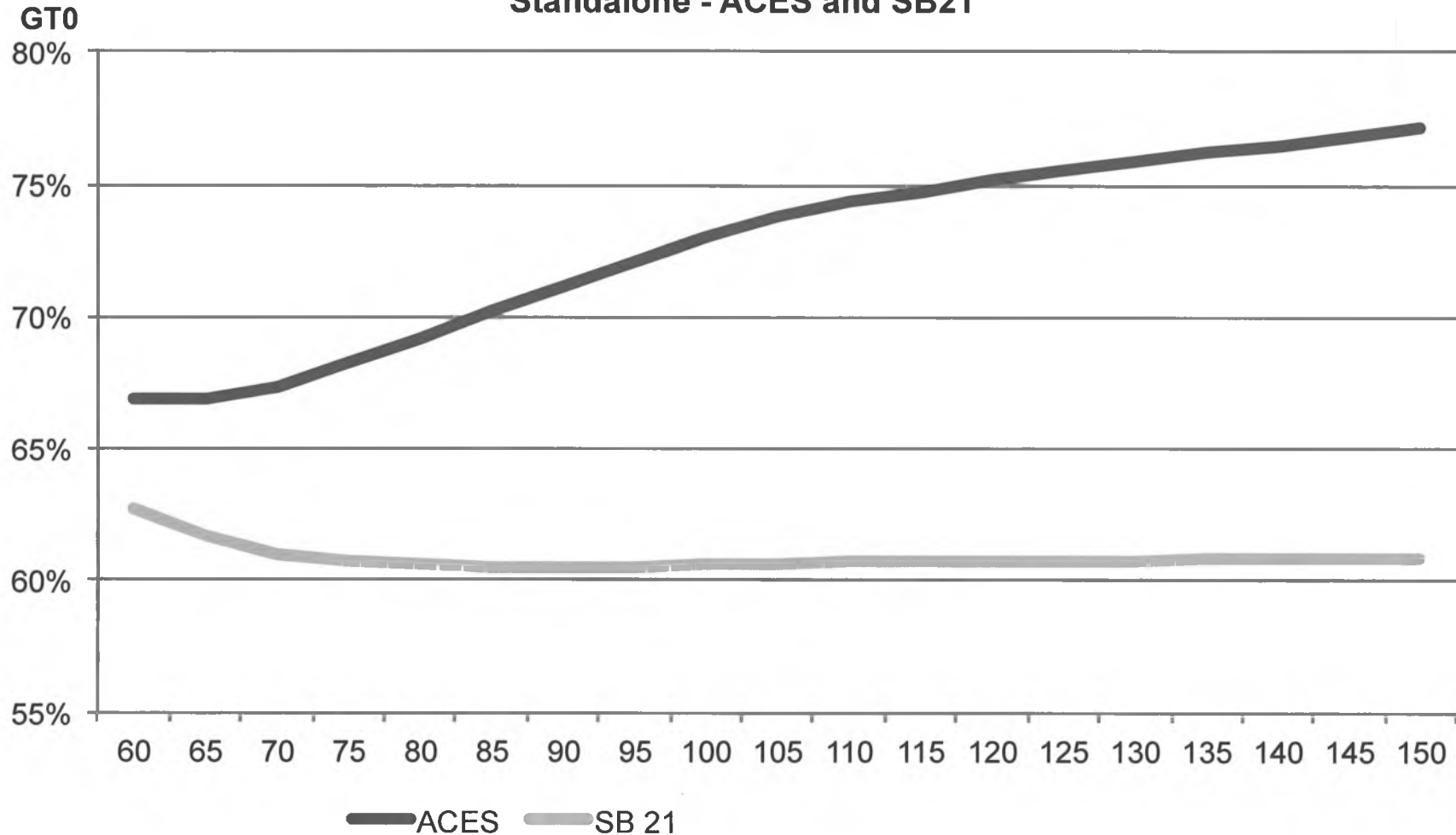
ACES and SB21: Government Take Comparison Base Production

Undiscounted Government Take for Existing Production
ACES and SB21



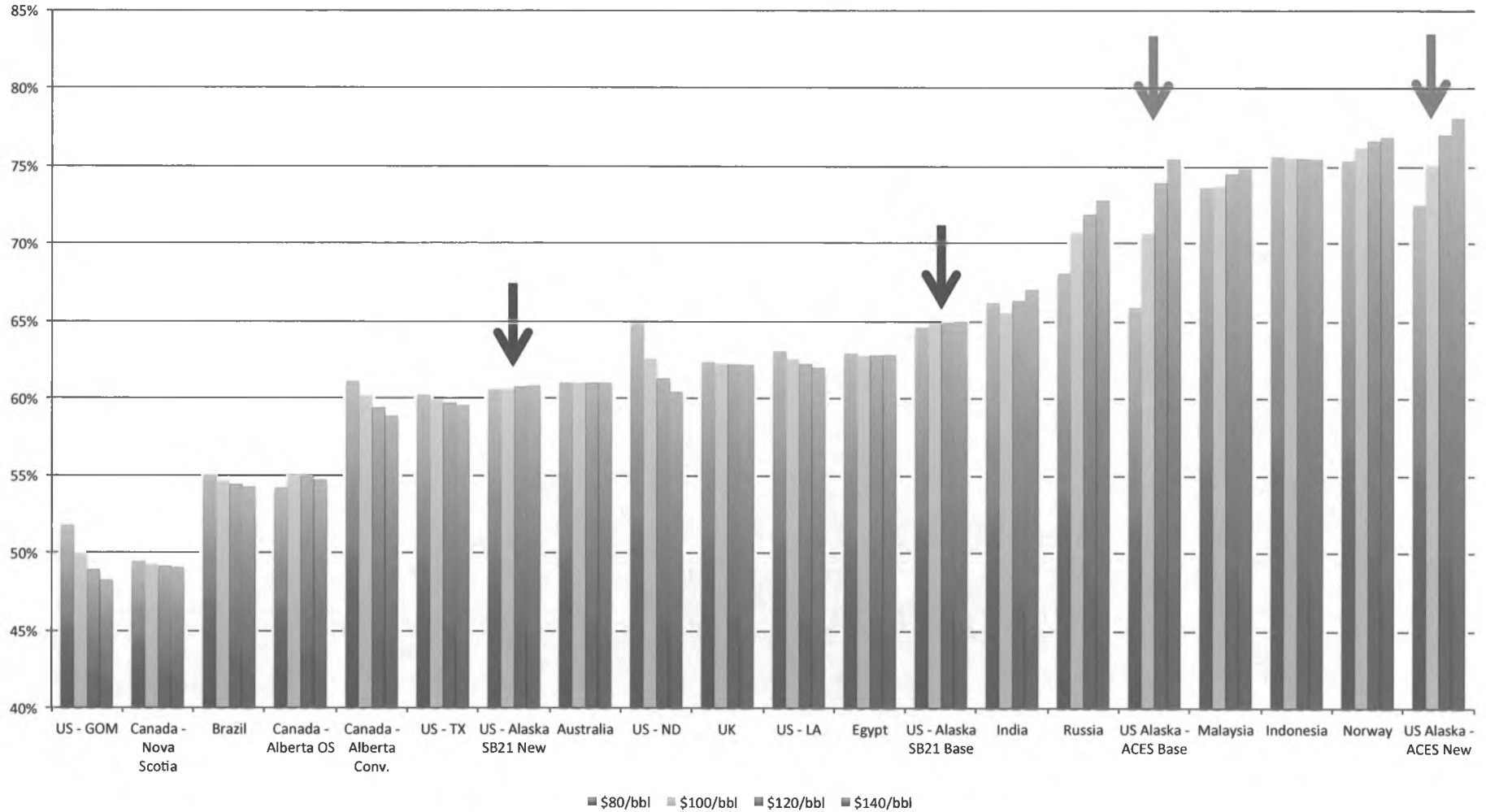
ACES and SB21: Government Take Comparison \$18/bbl New Development, Standalone

Undiscounted Government Take for new \$18/bbl Development,
Standalone - ACES and SB21



Government Take Competitiveness

Alaska Government Take Competitiveness - Comparable Regimes

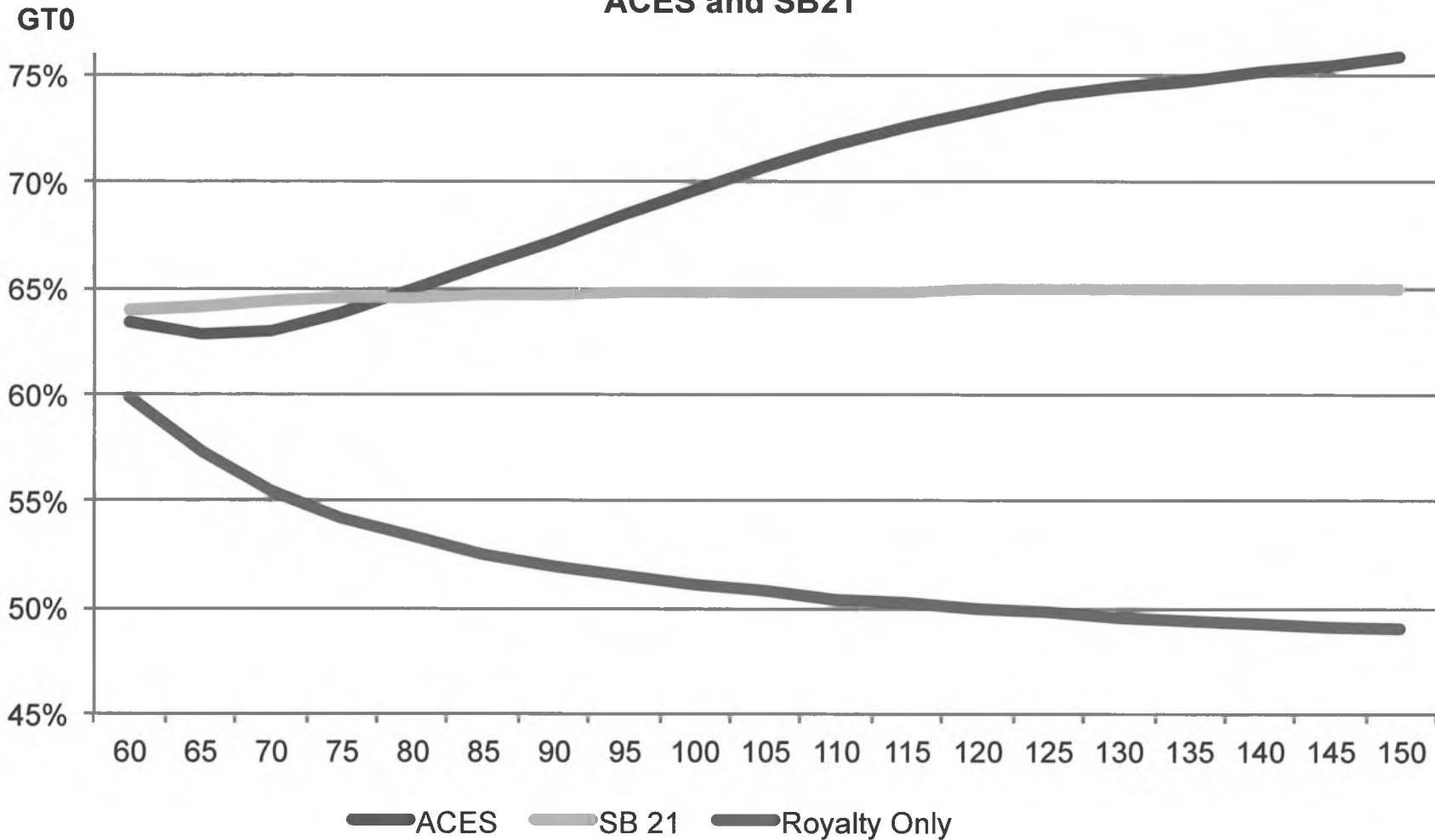


Regressive and Progressive Regimes

- 2 potential reasons to desire a progressive element in Alaska's fiscal regime:
 - To counteract regressive elements in the regime to achieve something close to **neutrality**
 - To go beyond neutrality, to ensure a **higher level of take** for the state in **high price environments**
- Regressive and Progressive regimes imply a very different outlooks on risk and reward, for government and the private sector:
 - **Regressive regimes limit risk to the state**, placing large downside risk on the private sector, protecting the state in low price or high cost environments
 - In return, regressive regimes offer outsized returns in high price environments
 - **Progressive regimes** involve the **state bearing more price and cost risk**, in return for a higher share of returns in good times
- Perhaps the single biggest problem with Alaska's current fiscal regime is that it involves elements that are **both strongly regressive and strongly progressive**.
 - It seeks to place downside risk on the private sector, while taking most of the returns in high price environments.
 - It is this combination that makes it particularly unattractive from an investment perspective

Regressivity, Progressivity, Neutrality

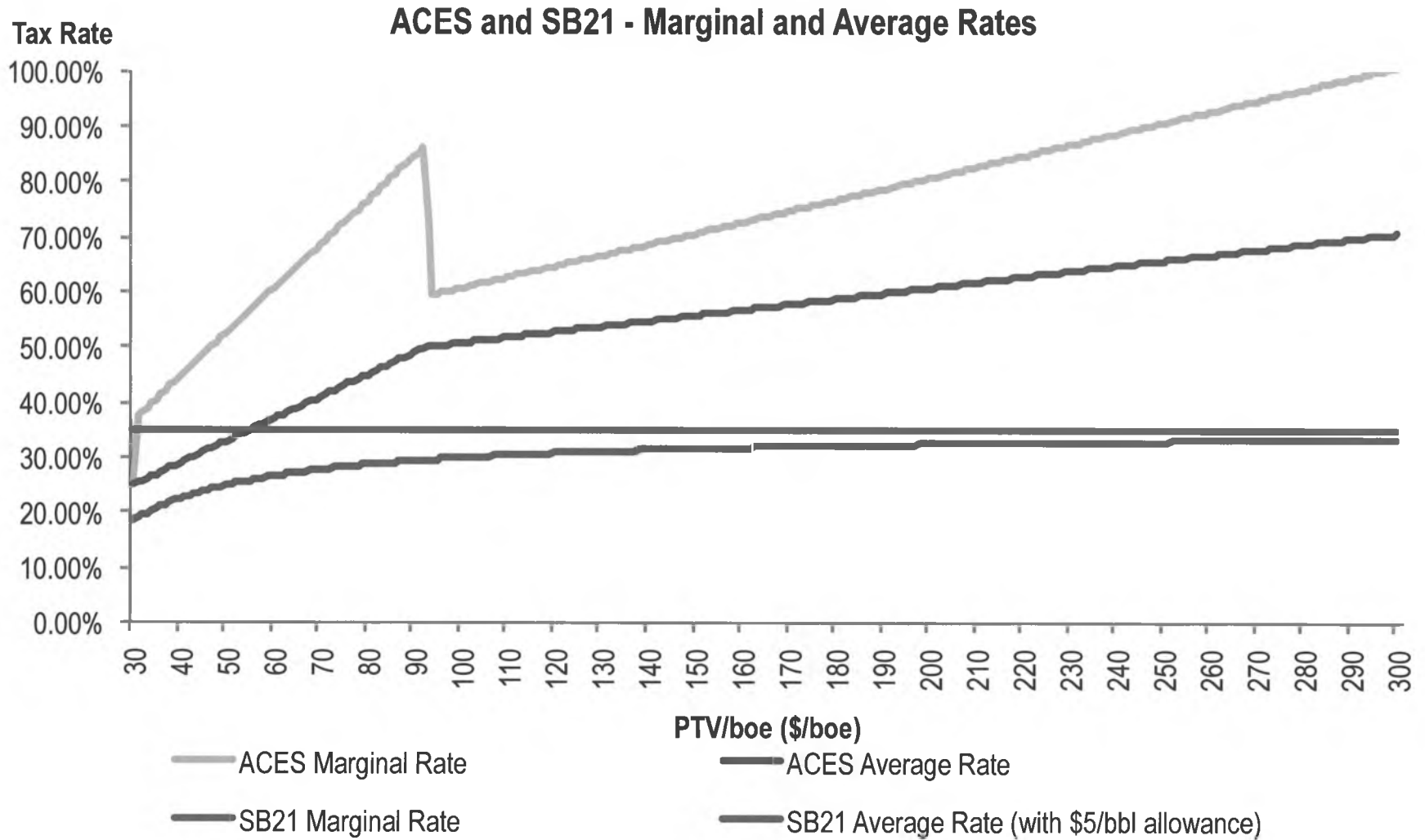
Undiscounted Government Take for Existing Production ACES and SB21



\$5 production allowance is like reverse progressivity, to counteract effect of royalty

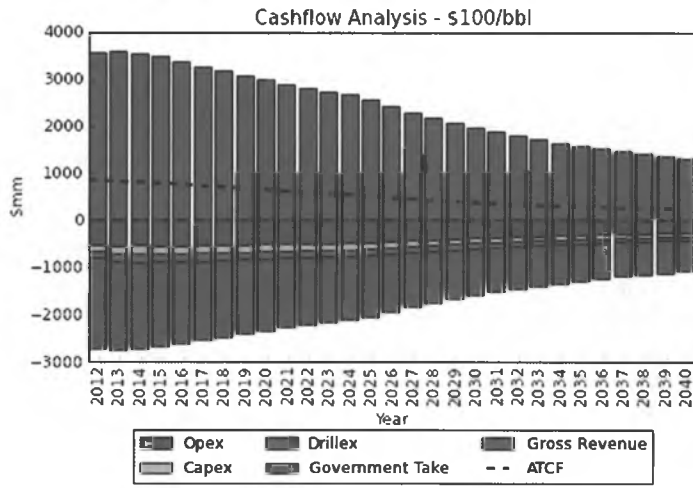
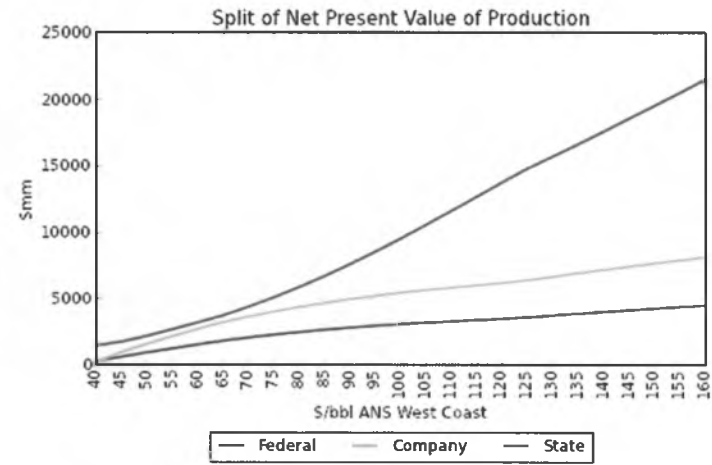
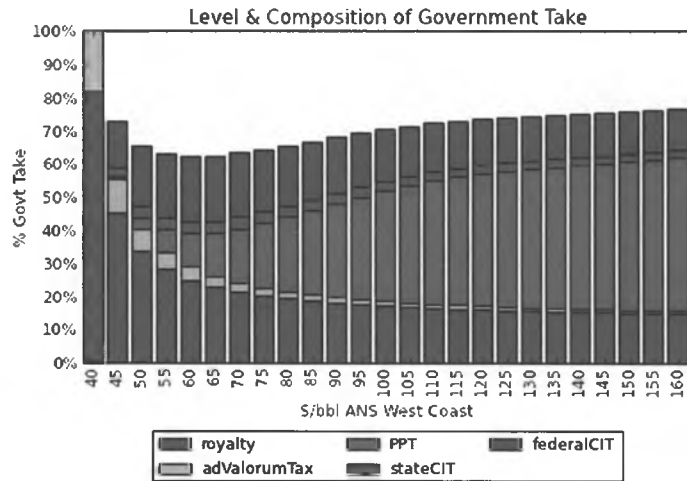
Taxable Production	50,000,000	50,000,000	50,000,000	50,000,000
ANS West Coast	60	80	120	140
Transportation	10	10	10	10
Gross Value at Point of Production	2,500,000,000	3,500,000,000	5,500,000,000	6,500,000,000
Lease Expenditures	1,500,000,000	1,500,000,000	1,500,000,000	1,500,000,000
GVPP/bbl	50	70	110	130
Lease Expenditures / bbl	30	30	30	30
PTV	1,000,000,000	2,000,000,000	4,000,000,000	5,000,000,000
PTV/bbl	20	40	80	100
Production Tax without Allowance	350,000,000	700,000,000	1,400,000,000	1,750,000,000
Production Allowance	250,000,000	250,000,000	250,000,000	250,000,000
Production Tax	100,000,000	450,000,000	1,150,000,000	1,500,000,000
Nominal Tax Rate	35%	35%	35%	35%
Rate after Allowance	10.0%	22.5%	28.8%	30.0%
Progressive Tax Rate Deduction	25.0%	12.5%	6.3%	5.0%

Marginal and Average Rates



ACES – Base Production

ACES, 12.5% Royalty, Base Production

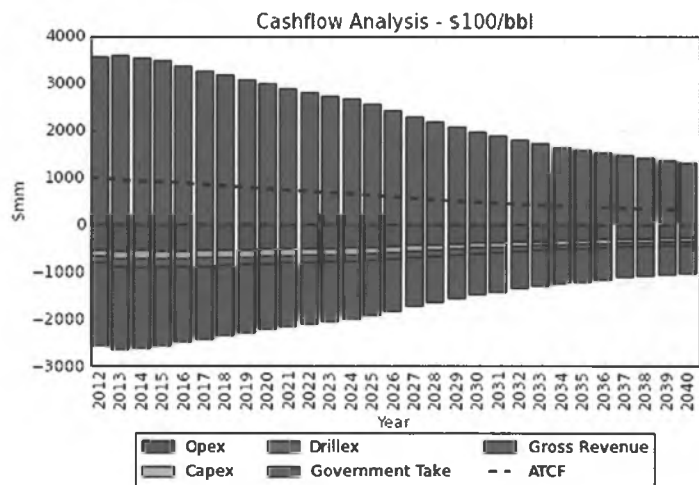
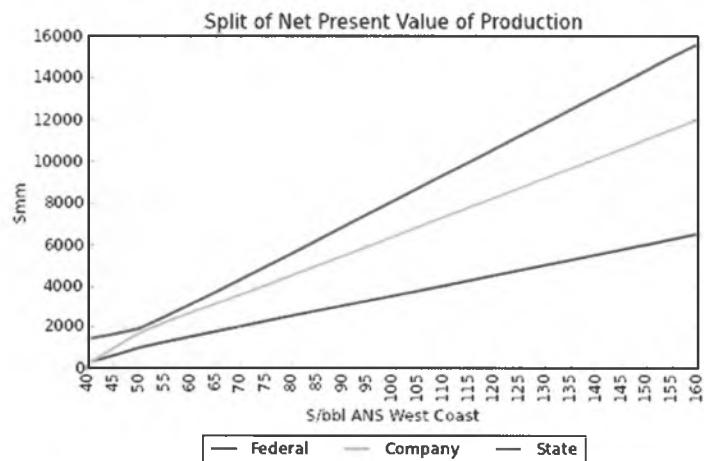
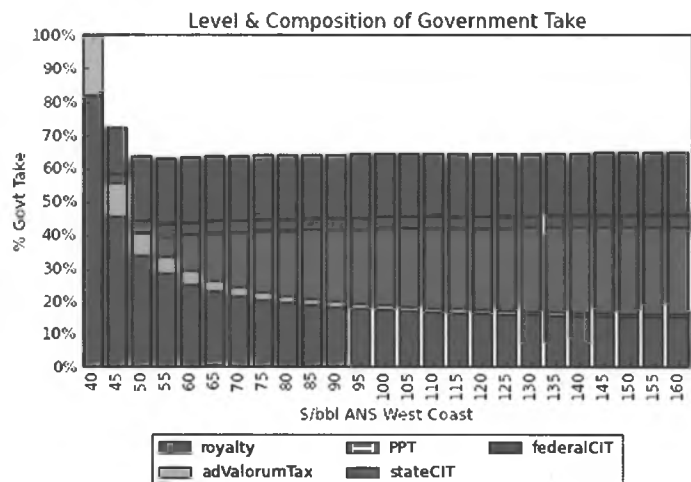


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	65.89%	4.18		19.04
\$100/bbl	70.65%	5.26		23.92
\$120/bbl	73.92%	6.0		27.09
\$140/bbl	75.46%	6.97		31.89

SB21 Base Production

SB 21, 12.5% Royalty, Base Production



Economic Summary

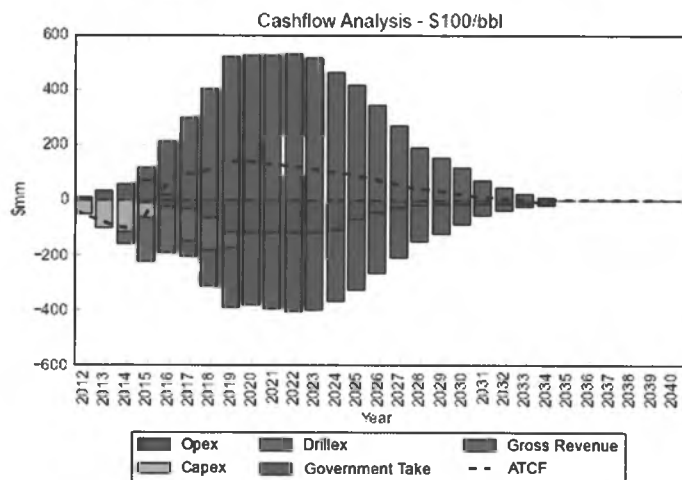
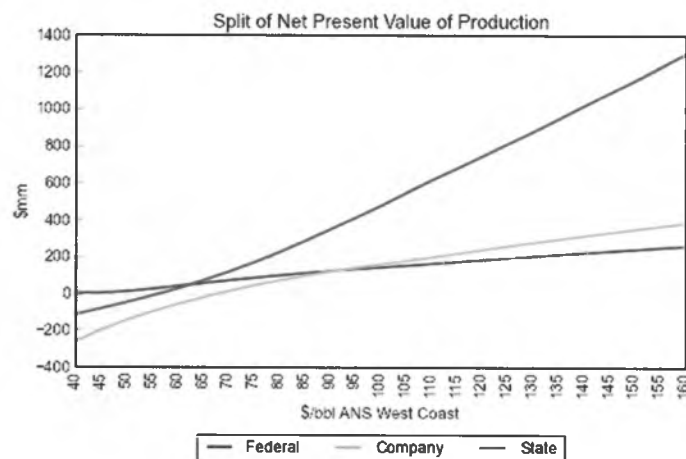
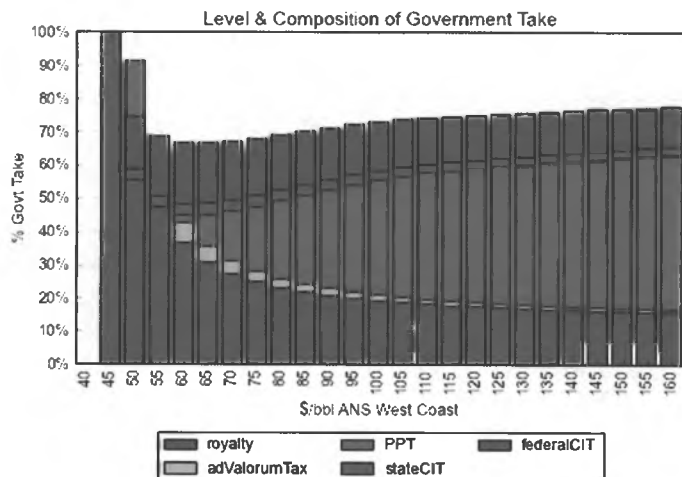
	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.22%	4.37		19.77
\$100/bbl	64.54%	6.18		28.11
\$120/bbl	64.71%	8.0		36.45
\$140/bbl	64.81%	9.82		44.78

GRE increases the price level at which production tax, and 'progressivity', apply

Taxable Production		50,000,000	50,000,000	50,000,000	50,000,000
ANS West Coast		60	80	120	140
Transportation		10	10	10	10
Gross Value at Point of Production		2,500,000,000	3,500,000,000	5,500,000,000	6,500,000,000
Lease Expenditures		1,500,000,000	1,500,000,000	1,500,000,000	1,500,000,000
GVPP/bbl		50	70	110	130
Lease Expenditures / bbl	30	30	30	30	30
PTV before GRE		1,000,000,000	2,000,000,000	4,000,000,000	5,000,000,000
Prod tax without GRE		350,000,000	700,000,000	1,400,000,000	1,750,000,000
GRE	30%	750,000,000	1,050,000,000	1,650,000,000	1,950,000,000
PTV		250,000,000	950,000,000	2,350,000,000	3,050,000,000
PTV/bbl		20	40	80	100
Production Tax without Allowance		87,500,000	332,500,000	822,500,000	1,067,500,000
Production Allowance	\$ 5.00	250,000,000	250,000,000	250,000,000	250,000,000
Production Tax		-	82,500,000	572,500,000	817,500,000
Nominal Tax Rate	35%	35%	35%	35%	35%
Rate after Allowance and GRE		0.0%	4.1%	14.3%	16.4%
Progressive Tax Rate Deduction		35.0%	30.9%	20.7%	18.7%

ACES - \$18/bbl New Development, Standalone

ACES, 12.5% Royalty, \$18/bbl New Development, Standalone



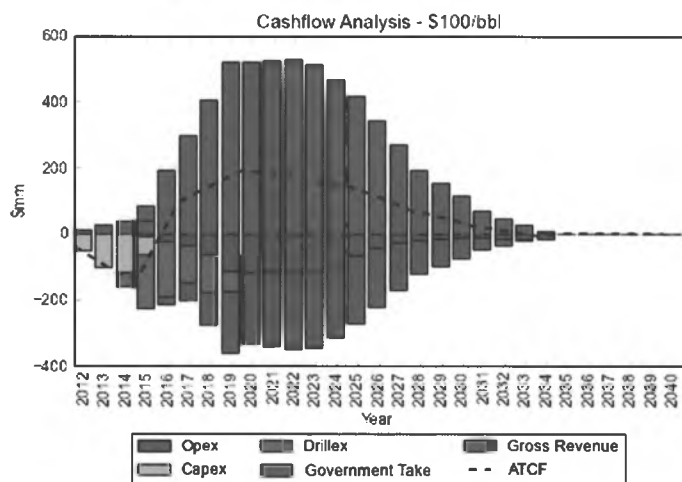
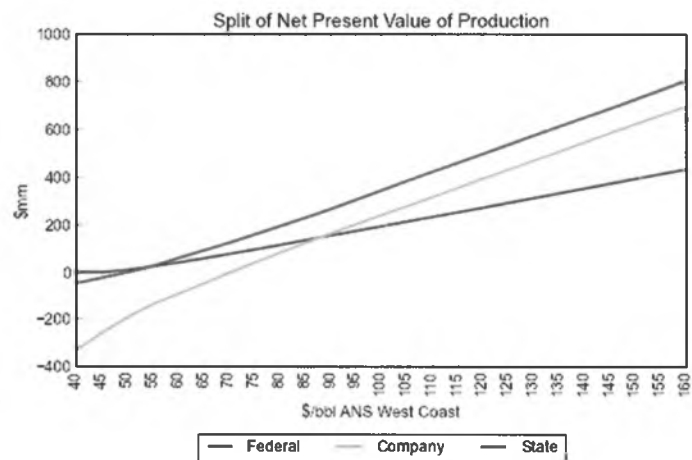
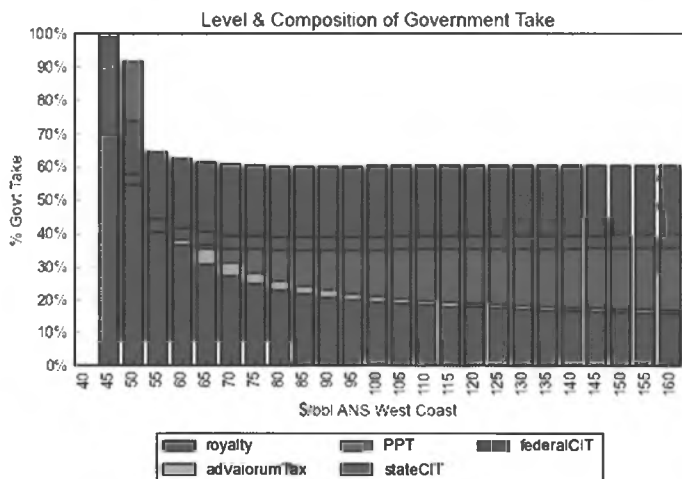
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	69.25%	1.44	16.15%	22.21
\$100/bbl	73.03%	3.21	20.95%	27.06
\$120/bbl	75.13%	4.78	24.84%	30.63
\$140/bbl	76.52%	6.27	28.18%	34.71

CS SB21

\$18/bbl New Development, Standalone, with GRE

SB21, 12.5% Royalty, \$18/bbl New Development, Standalone



Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	60.56%	1.67	15.83%	26.56
\$100/bbl	60.60%	4.83	22.23%	35.76
\$120/bbl	60.76%	7.89	27.63%	44.59
\$140/bbl	60.81%	10.95	32.47%	53.36

Credits – NOL, Exploration & Small Producer

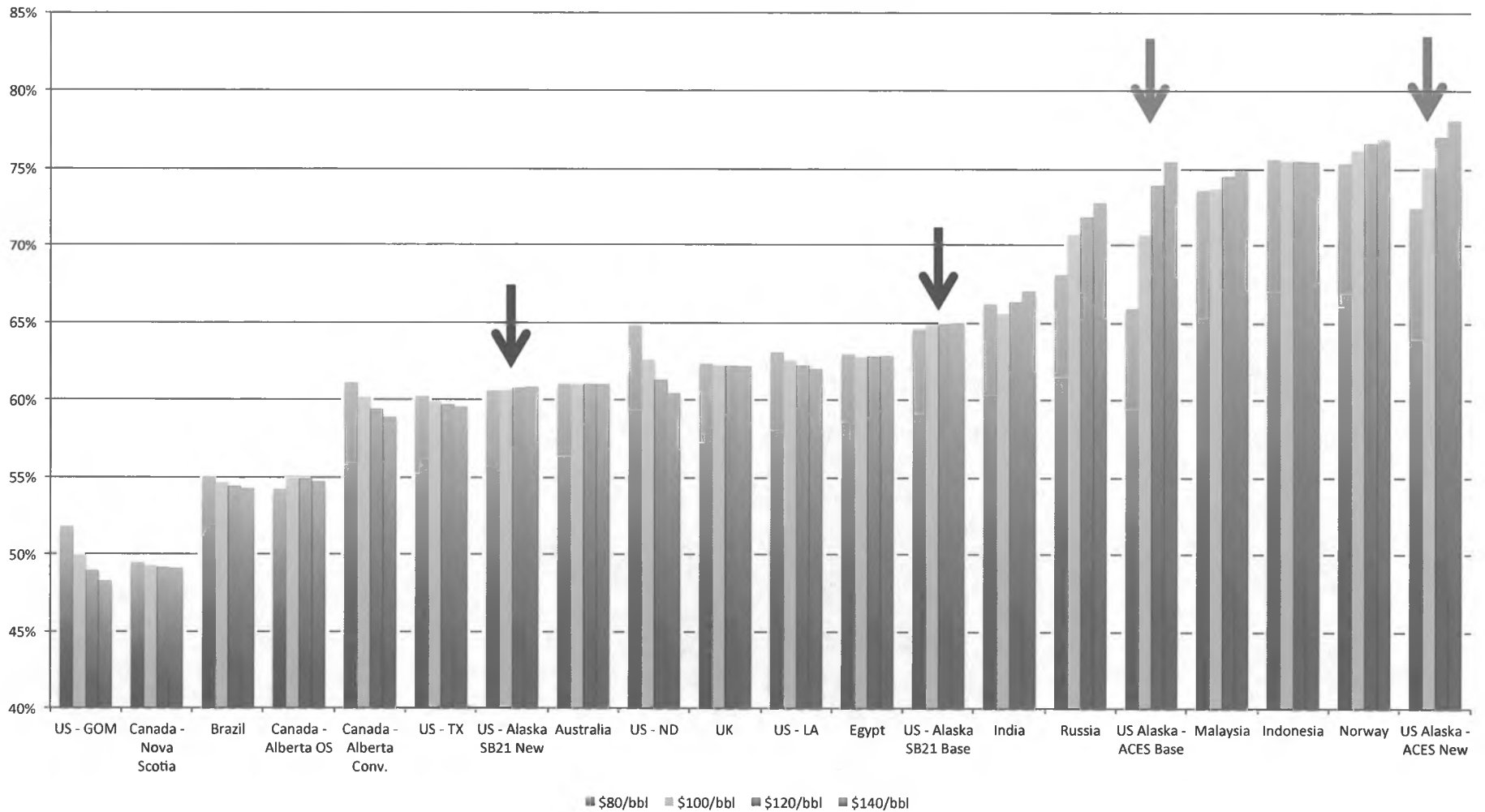
- Impact of ACES on project economics is very different for an incumbent vs a new producer
 - At current prices, incumbent experiences experiences impact of ‘buydown’ effect, with new spending reducing tax rate from levels above 25% (plus also impact of capital credit)
 - New producer receives only impact of 25% NOL credit (plus capital credit)
- Fully monetizable NOL credit for small producers evens this playing field
 - All producers receive effective 35% government support for spending, whether new or incumbent
 - Flat, low marginal rate maintains strong incentive for efficiencies and cost control
 - No undue exposure to the state from higher cost projects at low prices
- Aim is to even the playing field and limit the level of support for exploration as well as other forms of spending
 - Allowing the Exploration credit to sunset, but having the fully monetizable 35% NOL credit means 35% government support for exploration spending
 - Again, even impact between incumbent vs new producer
- When the impacts of the system are even between incumbent vs new producer, strong argument that extending ‘small producer’ credit is less warranted
- Overall impact is to significantly simplify the system

ACES and SB21: Issues and Aims

ACES - Issues	SB21 - Aims
<ul style="list-style-type: none"> High Government Take and high degree of progressivity means uncompetitive for investment at current prices 	<ul style="list-style-type: none"> Overall neutrality at a competitive level of Government Take, while further improving competitiveness for new projects
<ul style="list-style-type: none"> Credits create significant downside exposure to state in low price environments, for high cost projects, and projects not on state lands 	<ul style="list-style-type: none"> Limit downside risk to state from credits
<ul style="list-style-type: none"> “Buydown” effect means incremental and standalone economics very different – with very different impacts for incumbent vs new producer 	<ul style="list-style-type: none"> Balance system with even impacts for incumbent vs new producer
<ul style="list-style-type: none"> High marginal rates mean little incentive for producer efficiency 	<ul style="list-style-type: none"> Neutral regime creates low, constant marginal rates – strong incentive for producer efficiency
<ul style="list-style-type: none"> Complex system, with often counter-intuitive effects 	<ul style="list-style-type: none"> Simplify the fiscal system

Government Take Competitiveness

Alaska Government Take Competitiveness - Comparable Regimes



Notice

This material is protected by United States copyright law and applicable international treaties including, but not limited to, the Berne Convention and the Universal Copyright Convention. Except as indicated, the entire content of this publication, including images, text, data, and look and feel attributes, is copyrighted by PFC Energy. PFC Energy strictly prohibits the copying, display, publication, distribution, or modification of any PFC Energy materials without the prior written consent of PFC Energy.

These materials are provided for the exclusive use of PFC Energy clients (and/or registered users), and may not under any circumstances be transmitted to third parties without PFC Energy approval.

PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED “AS IS” WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

© PFC Energy, Inc. License restrictions apply. Distribution to third parties requires prior written consent from PFC Energy.

PFC Energy Locations and Contact Information

NORTH AMERICA

PFC Energy, Washington
1300 Connecticut Avenue, NW
Suite 800
Washington, DC 20036, USA
Tel +1 202 872 1199
Fax +1 202 872 1219

PFC Energy, Houston
2727 Allen Parkway, Suite 1300
Houston, Texas 77019, USA
Tel +1 713 622 4447
Fax +1 713 622 4448

EUROPE

PFC Energy, France
19 rue du Général Foy
75008 Paris, France
Tel +33 1 4770 2900
Fax +33 1 4770 5905

RUSSIA

PFC Energy, Moscow
10 Vozdvizhenka Street
Voentorg building, Suite 341
Moscow, 125009
Russian Federation
Tel +7 (495) 797 3733

ASIA

PFC Energy, Kuala Lumpur
Level 27, UBN Tower #21
10 Jalan P. Ramlee
50250 Kuala Lumpur, Malaysia
Tel +60 3 2172 3400
Fax +60 3 2072 3599

PFC Energy, China
89 Jianguo Road
China Central Place # 4-1602
Chaoyang District, Beijing 100025, China
Tel +86 10 6530 7010
Fax +86 10 6530 5093

PFC Energy, Singapore
15 Scotts Road
Thong Teck Building, #08-04
Singapore 228218
Tel +65 6736 4317

www.pfcenergy.com | info@pfcenergy.com

ACES, SB21/HB72 and CS SB21 (FIN) Analysis for House Resources Committee

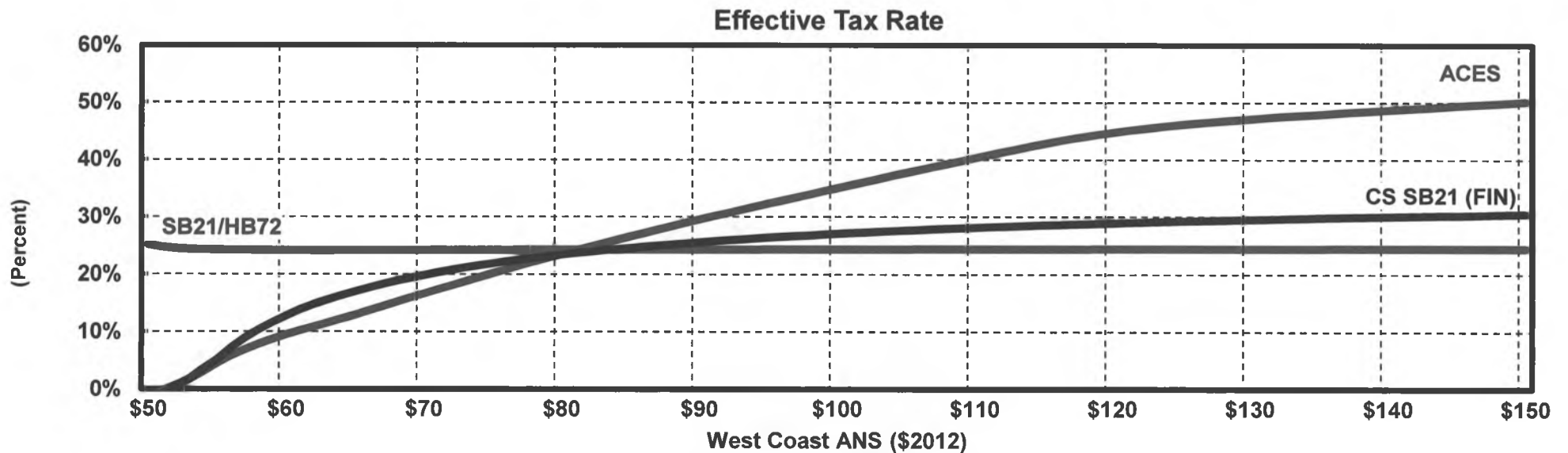
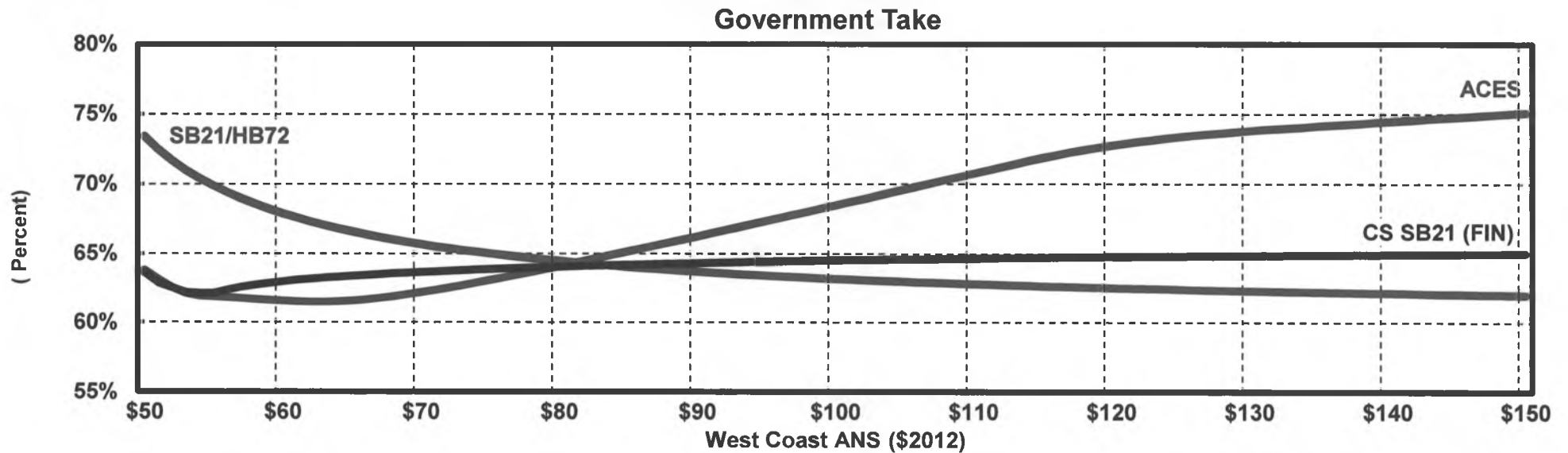
**Barry Pulliam
Managing Director
Econ One Research, Inc.**

March 25, 2013

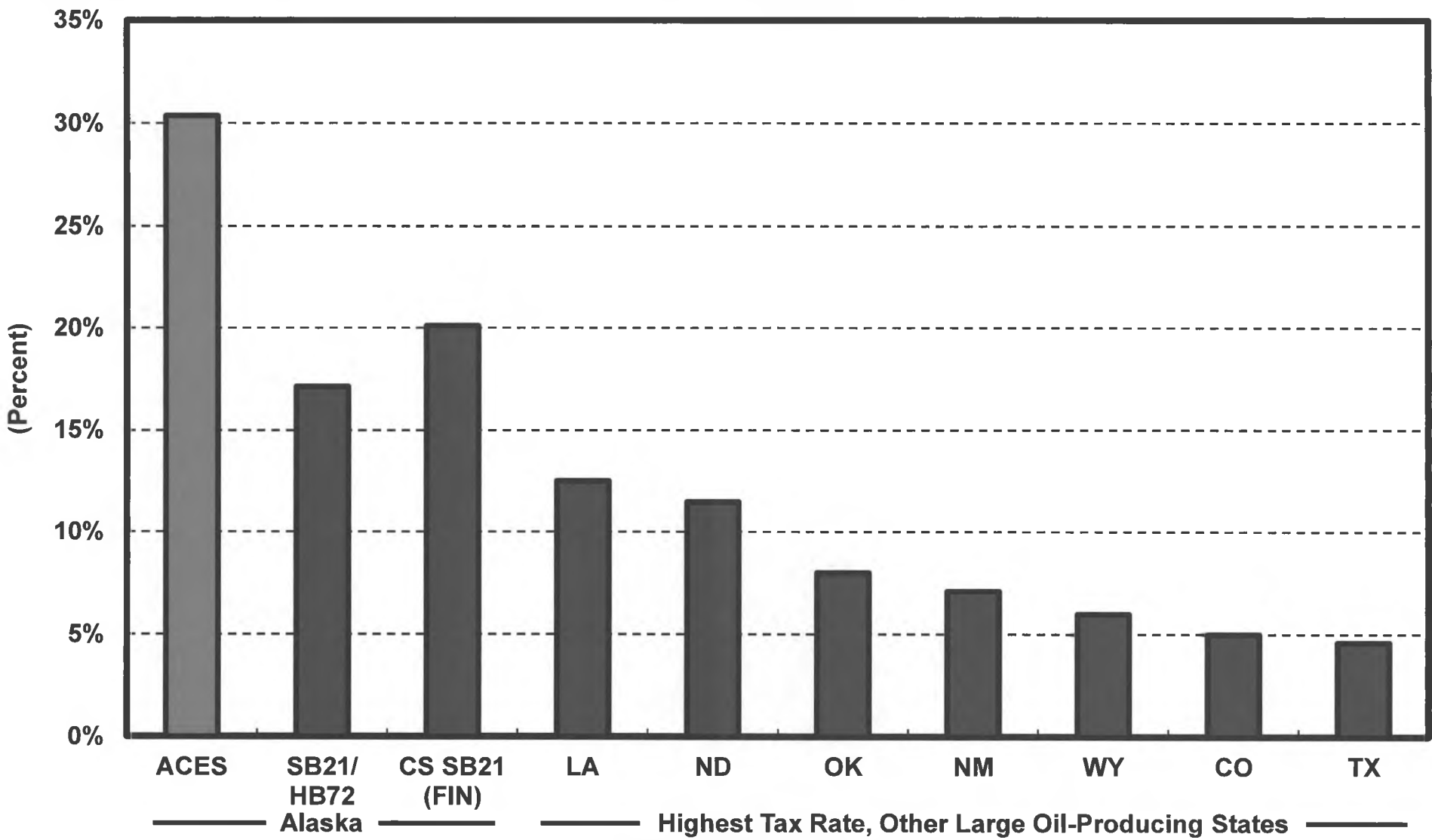
Comparison of Key Features of CS SB21 (FIN) With SB21/HB72

	<u>SB21/HB72</u>	<u>CS SB21 (FIN)</u>
Base Tax Rate	25%	35%
Credits	None	\$5/Bbl
Monetization of NOLs	No	Yes
GRE Rate	20%	20%
Applicability	Post 2003 Units; Post 2012 PAs	Post 2003 Units; Post 2012 PAs; Certified New Oil From Existing Fields
Small Producer Credit Extended	Yes (2022)	No (2016)

Average Government Take and Effective Tax Rate ACES v. SB21/HB72 and CS SB21 (FIN) for All Existing Producers (FY2015-FY2019)



Effective Tax Rates on Gross Value for Legacy Production ACES vs. SB21/HB72, CS SB21 (FIN) and Other Large Oil-Producing States With Production Taxes at \$100 Wellhead Value (\$2012)



Note: California and Federal Offshore properties are not subject to a severance tax.

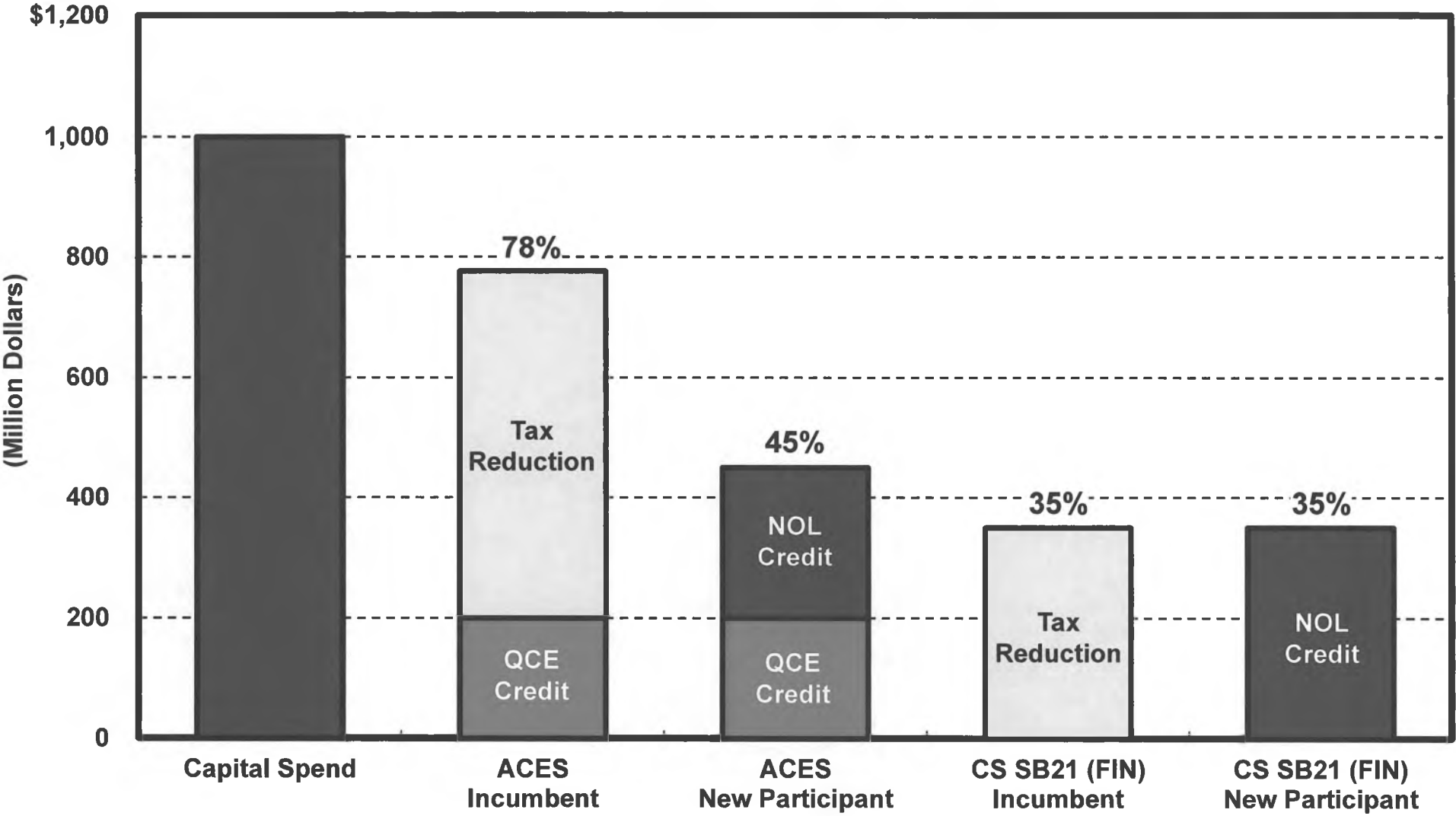
Calculation of Tax Under CS SB21 (FIN) Production Not Qualifying for GRE

	<u>\$80 West Coast ANS</u>		<u>\$100 West Coast ANS</u>		<u>\$120 West Coast ANS</u>	
Gross Barrels		100,000		100,000		100,000
Royalty Barrels	-	12,500	-	12,500	-	12,500
Taxable Barrels	=	87,500	=	87,500	=	87,500
West Coast Value (\$/Bbl)		\$80.00		\$100.00		\$120.00
Transportation Costs (\$/Bbl)	-	10.00	-	10.00	-	10.00
Wellhead Value (\$/Bbl)	=	\$70.00	=	\$90.00	=	\$110.00
Lease Expenses (\$/Bbl)	-	30.00	-	30.00	-	30.00
Taxable Value (\$/Bbl)	=	\$40.00	=	\$60.00	=	\$80.00
Production Tax Value (\$)		\$3,500,000		\$5,250,000		\$7,000,000
Tax Rate (%)	35%	\$1,225,000	35%	\$1,837,500	35%	\$2,450,000
Production Credit (\$/Bbl)	\$5.00 -	437,500	\$5.00 -	437,500	\$5.00 -	437,500
Tax Due (\$)	=	\$787,500	=	\$1,400,000	=	\$2,012,500
Tax as % of Net Value of Production		22.5%		26.7%		28.8%
Tax as % of Gross Value of Production		12.9%		17.8%		20.9%

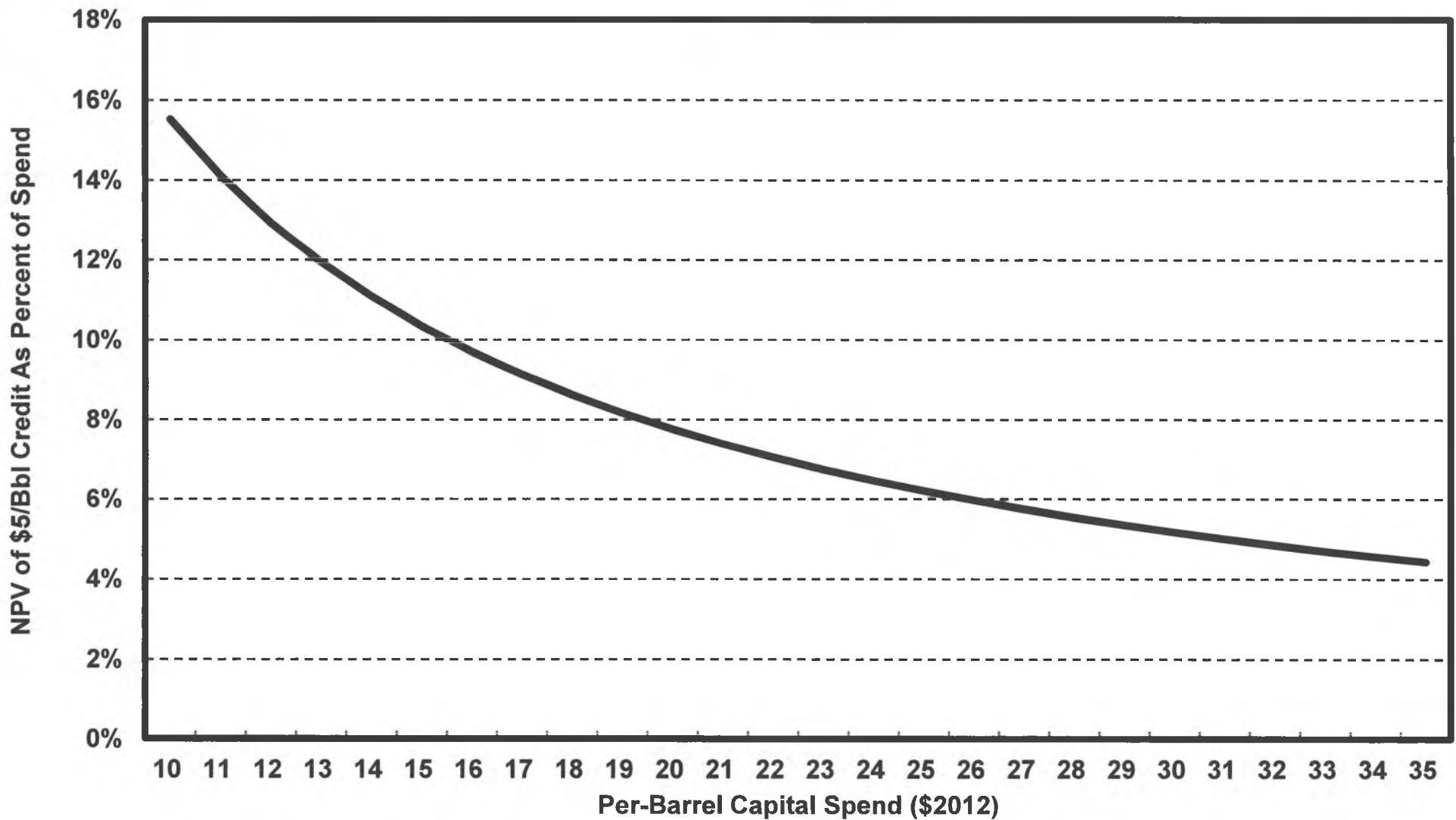
Calculation of Tax Under CS SB21 (FIN) Production Qualifying for GRE

	\$80 West Coast ANS		\$100 West Coast ANS		\$120 West Coast ANS	
Gross Barrels		100,000		100,000		100,000
Royalty Barrels	-	12,500	-	12,500	-	12,500
Taxable Barrels	=	87,500	=	87,500	=	87,500
West Coast Value (\$/Bbl)		\$80.00		\$100.00		\$120.00
Transportation Costs (\$/Bbl)	-	10.00	-	10.00	-	10.00
Wellhead Value (\$/Bbl)	=	\$70.00	=	\$90.00	=	\$110.00
Gross Revenue Exclusion (%)	20% -	14.00	20% -	18.00	20% -	22.00
Lease Expenses (\$/Bbl)	-	30.00	-	30.00	-	30.00
Taxable Value (\$/Bbl)	=	\$26.00	=	\$42.00	=	\$58.00
Production Tax Value (\$)		\$2,275,000		\$3,675,000		\$5,075,000
Tax Rate (%)	35%	\$796,250	35%	\$1,286,250	35%	\$1,776,250
Production Credit (\$/Bbl)	\$5.00 -	437,500	\$5.00 -	437,500	\$5.00 -	437,500
Tax Due (\$)	=	\$358,750	=	\$848,750	=	\$1,338,750
Tax as % of Net Value of Production		15.8%		23.1%		26.4%
Tax as % of Gross Value of Production		5.9%		10.8%		13.9%

State Support for Capital Spending Under ACES and CS SB21 (FIN) at \$100 West Coast ANS (\$2012)



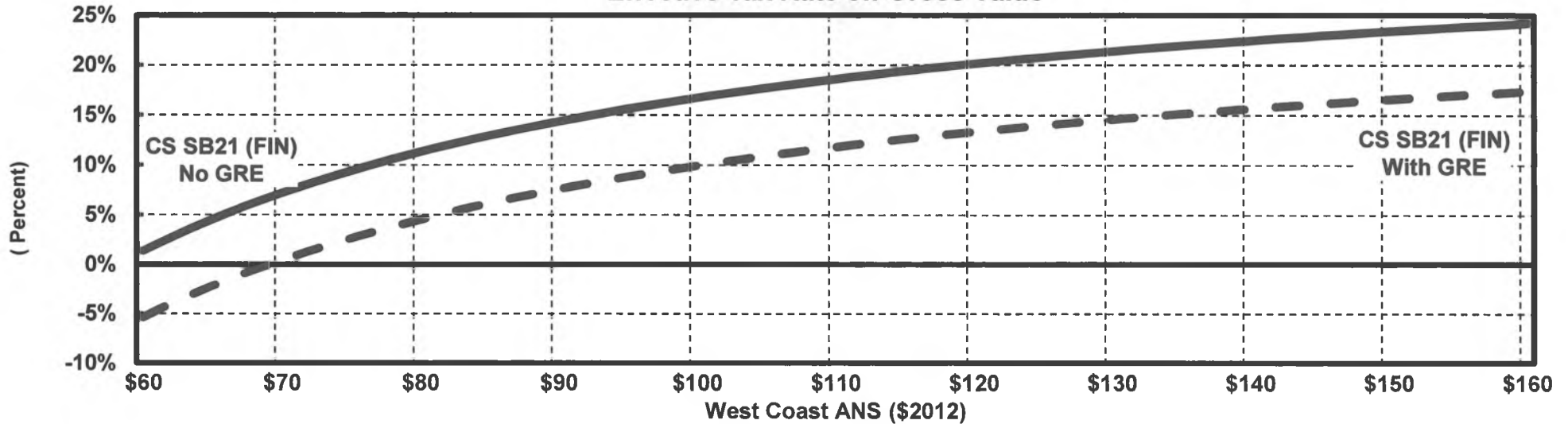
NPV Equivalence of \$5/Bbl Production Credit As Percent of Capital Spend



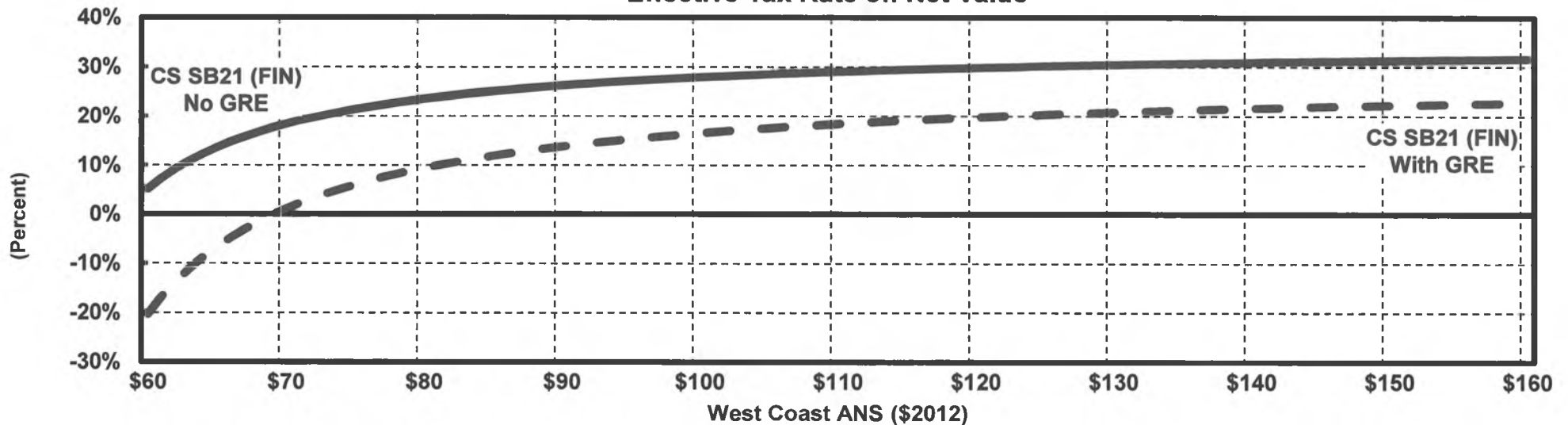
Effective Tax Rate on Gross and Net Value for New Participant Under CS SB21 (FIN): 20% GRE v. No GRE

Mid-Range Cost 50 MMBO Alaska Oil Development

Effective Tax Rate on Gross Value



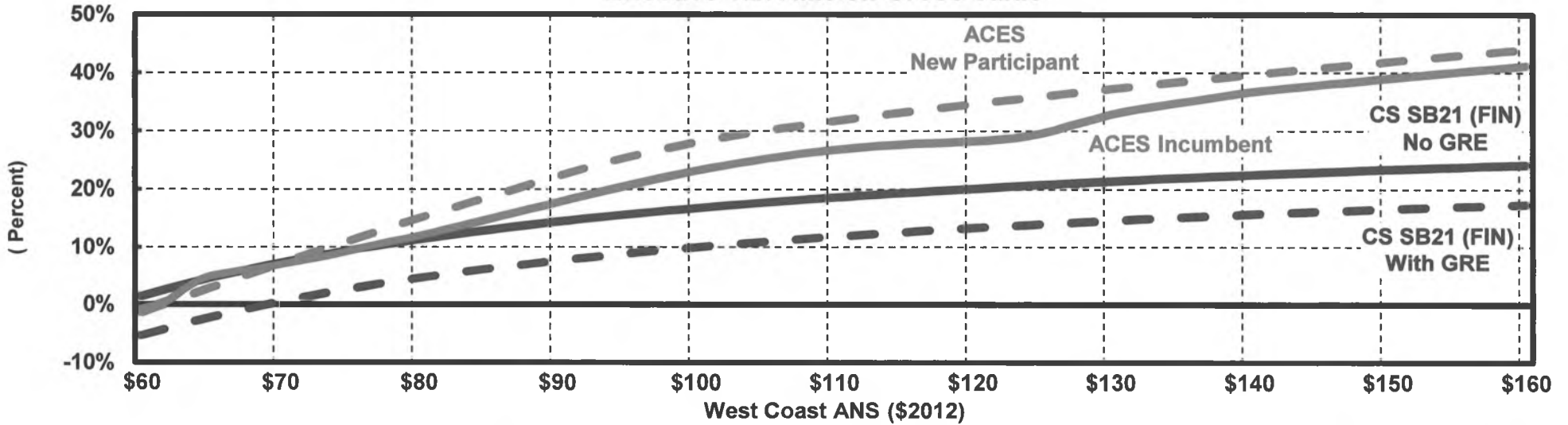
Effective Tax Rate on Net Value



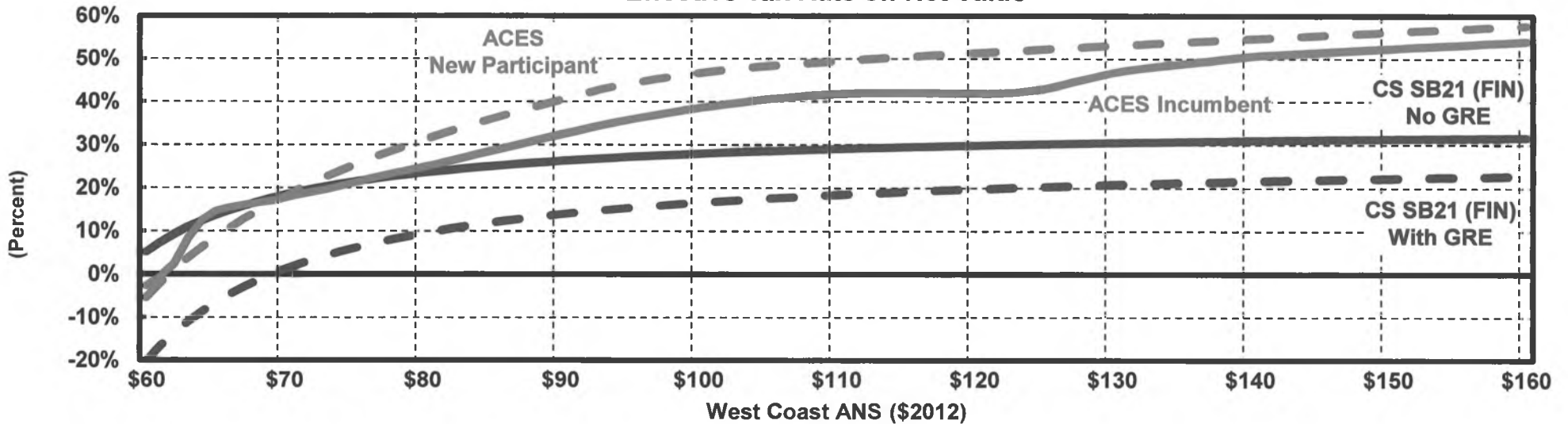
Effective Tax Rate on Gross and Net Value for New Participant Under ACES and CS SB21 (FIN) Mid-Range Cost 50 MMBO Alaska Oil Development



Effective Tax Rate on Gross Value



Effective Tax Rate on Net Value



Summary of Investment Measures for New Participant Mid-Range Cost 50 MMBO Alaska Oil Development ACES and CS SB21 (FIN) v. Benchmark Areas



Real \$2012 West Coast ANS Price	Alaska Project Qualifying for GRE				Unconventional Lower-48 Eagle Ford	Bakken	Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom	
	12.5% Royalty Rate		16.67% Royalty Rate							Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
	ACES	CS SB21 (FIN)	ACES	CS SB21 (FIN)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$1.72	\$2.65	\$1.30	\$2.07	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$3.09	\$5.93	\$2.61	\$5.20	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$4.80	\$9.22	\$4.23	\$8.33	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.10	1.16	1.08	1.12	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.19	1.36	1.16	1.31	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.29	1.56	1.26	1.50	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	16.3%	17.7%	15.3%	16.5%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	19.5%	24.0%	18.4%	22.6%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	23.3%	29.7%	22.0%	28.2%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$28.08	\$33.33	\$26.94	\$31.72	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$31.19	\$42.44	\$29.97	\$40.40	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$35.74	\$51.54	\$34.22	\$49.07	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	68.4%	58.6%	70.9%	62.1%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	74.2%	59.7%	76.1%	62.6%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	75.9%	60.2%	77.5%	62.9%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$4.43	\$3.02	\$5.08	\$3.90	-	-	-	-	-	-	-
\$100	\$10.98	\$6.60	\$11.71	\$7.73	-	-	-	-	-	-	-
\$120	\$17.00	\$10.19	\$17.87	\$11.56	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.
Cost Assumptions: \$20/Bbl. Development Capex and \$14/Bbl. Opex.

Summary of Investment Measures for Incumbent Mid-Range Cost 50 MMBO Alaska Oil Development ACES and CS SB21 (FIN) v. Benchmark Areas



Real \$2012 West Coast ANS Price	Alaska Project Qualifying for GRE				Unconventional Lower-48 Eagle Ford	Bakken	Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom	
	12.5% Royalty Rate		16.67% Royalty Rate							w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
	ACES	CS SB21 (FIN)	ACES	CS SB21 (FIN)							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$3.17	\$2.63	\$2.73	\$2.05	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$6.01	\$5.92	\$5.54	\$5.18	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$9.07	\$9.20	\$8.53	\$8.31	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.19	1.16	1.16	1.12	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.36	1.36	1.33	1.31	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.55	1.56	1.51	1.50	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	21.8%	17.6%	20.6%	16.5%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	35.2%	23.9%	33.7%	22.6%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	56.7%	29.7%	54.8%	28.2%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$26.56	\$33.26	\$25.35	\$31.66	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$29.63	\$42.37	\$28.35	\$40.33	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$33.80	\$51.48	\$32.27	\$49.01	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	65.6%	58.7%	68.1%	62.2%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	70.3%	59.8%	72.1%	62.7%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	71.2%	60.3%	72.8%	62.9%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$2.21	\$3.04	\$2.88	\$3.93	-	-	-	-	-	-	-
\$100	\$6.49	\$6.63	\$7.20	\$7.76	-	-	-	-	-	-	-
\$120	\$10.42	\$10.21	\$11.25	\$11.58	-	-	-	-	-	-	-

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

* Brownfield Allowance applied to 100 MMBOE development.

Cost Assumptions: \$20/Bbl. Development Capex and \$14/Bbl. Opex.

Summary of Investment Measures for New Participant Lower Cost 50 MMBO Alaska Oil Development ACES and CS SB21 (FIN) v. Benchmark Areas



Real \$2012 West Coast ANS Price	Alaska Project Qualifying for GRE				Unconventional Lower-48 Eagle Ford	Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom		
	12.5% Royalty Rate		16.67% Royalty Rate						Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*	
	ACES	CS SB21 (FIN)	ACES	CS SB21 (FIN)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$3.01	\$4.13	\$2.59	\$3.55	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$4.37	\$7.42	\$3.89	\$6.68	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$6.08	\$10.70	\$5.51	\$9.81	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.23	1.31	1.20	1.27	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.33	1.56	1.29	1.50	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.46	1.81	1.42	1.74	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	21.0%	22.6%	19.8%	21.3%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	24.8%	29.9%	23.5%	28.3%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	29.2%	36.5%	27.7%	34.8%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$27.11	\$32.37	\$25.96	\$30.76	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$30.22	\$41.48	\$28.99	\$39.44	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$34.76	\$50.59	\$33.25	\$48.11	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	68.3%	58.7%	70.6%	62.0%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	73.9%	59.7%	75.6%	62.5%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	75.5%	60.3%	77.1%	62.8%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$5.96	\$4.24	\$6.61	\$5.13	-	-	-	-	-	-	-
\$100	\$12.52	\$7.83	\$13.24	\$8.96	-	-	-	-	-	-	-
\$120	\$18.52	\$11.41	\$19.40	\$12.78	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.
Cost Assumptions: \$16/Bbl. Development Capex and \$14/Bbl. Opex.

Summary of Investment Measures for Incumbent Lower Cost 50 MMBO Alaska Oil Development ACES and CS SB21 (FIN) v. Benchmark Areas



Real \$2012 West Coast ANS Price	Alaska Project Qualifying for GRE							Canada		United Kingdom	
	12.5% Royalty Rate		16.67% Royalty Rate		Unconventional Lower-48		Offshore	Oil Sands		Pre-1993	Post-1993
	ACES	CS SB21 (FIN)	ACES	CS SB21 (FIN)	Eagle Ford	Bakken	GOM	SAGD	Norway	w/ Brownfield Allowance*	w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$4.17	\$4.11	\$3.73	\$3.53	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$6.64	\$7.40	\$6.17	\$6.66	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$9.37	\$10.69	\$8.82	\$9.80	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.31	1.31	1.28	1.27	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.50	1.56	1.47	1.50	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.71	1.81	1.67	1.74	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	27.7%	22.6%	26.2%	21.2%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	42.9%	29.9%	41.1%	28.3%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	67.2%	36.5%	64.8%	34.8%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$25.59	\$32.31	\$24.38	\$30.70	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$28.66	\$41.41	\$27.37	\$39.37	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$32.83	\$50.52	\$31.29	\$48.05	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	66.3%	58.8%	68.7%	62.1%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	71.2%	59.8%	72.8%	62.6%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	72.2%	60.3%	73.7%	62.8%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$4.18	\$4.27	\$4.85	\$5.16	-	-	-	-	-	-	-
\$100	\$9.03	\$7.85	\$9.74	\$8.98	-	-	-	-	-	-	-
\$120	\$13.47	\$11.44	\$14.31	\$12.81	-	-	-	-	-	-	-

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

* Brownfield Allowance applied to 100 MMBOE development.

Cost Assumptions: \$16/Bbl. Development Capex and \$14/Bbl. Opex.

Summary of Investment Measures for New Participant Higher Cost 50 MMBO Alaska Oil Development ACES and CS SB21 (FIN) v. Benchmark Areas



Real \$2012 West Coast ANS Price	Alaska Project Qualifying for GRE				Unconventional Lower-48 Eagle Ford	Bakken	Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom	
	12.5% Royalty Rate		16.67% Royalty Rate							Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
	ACES	CS SB21 (FIN)	ACES	CS SB21 (FIN)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$0.11	\$0.79	(\$0.31)	\$0.22	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$1.49	\$4.08	\$1.01	\$3.35	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$3.19	\$7.37	\$2.62	\$6.48	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.01	1.04	0.99	1.01	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.07	1.20	1.05	1.16	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.15	1.36	1.13	1.31	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	12.2%	13.4%	11.4%	12.4%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	15.0%	18.9%	14.1%	17.7%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	18.2%	23.8%	17.2%	22.5%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$29.30	\$34.53	\$28.15	\$32.92	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$32.41	\$43.63	\$31.18	\$41.59	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$36.95	\$52.74	\$35.44	\$50.27	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	68.6%	58.4%	71.3%	62.3%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	74.7%	59.6%	76.7%	62.8%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	76.3%	60.2%	78.0%	63.0%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$2.53	\$1.48	\$3.18	\$2.37	-	-	-	-	-	-	-
\$100	\$9.06	\$5.07	\$9.79	\$6.20	-	-	-	-	-	-	-
\$120	\$15.09	\$8.65	\$15.96	\$10.03	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.
Cost Assumptions: \$25/Bbl. Development Capex and \$14/Bbl. Opex.

Summary of Investment Measures for Incumbent Higher Cost 50 MMBO Alaska Oil Development ACES and CS SB21 (FIN) v. Benchmark Areas



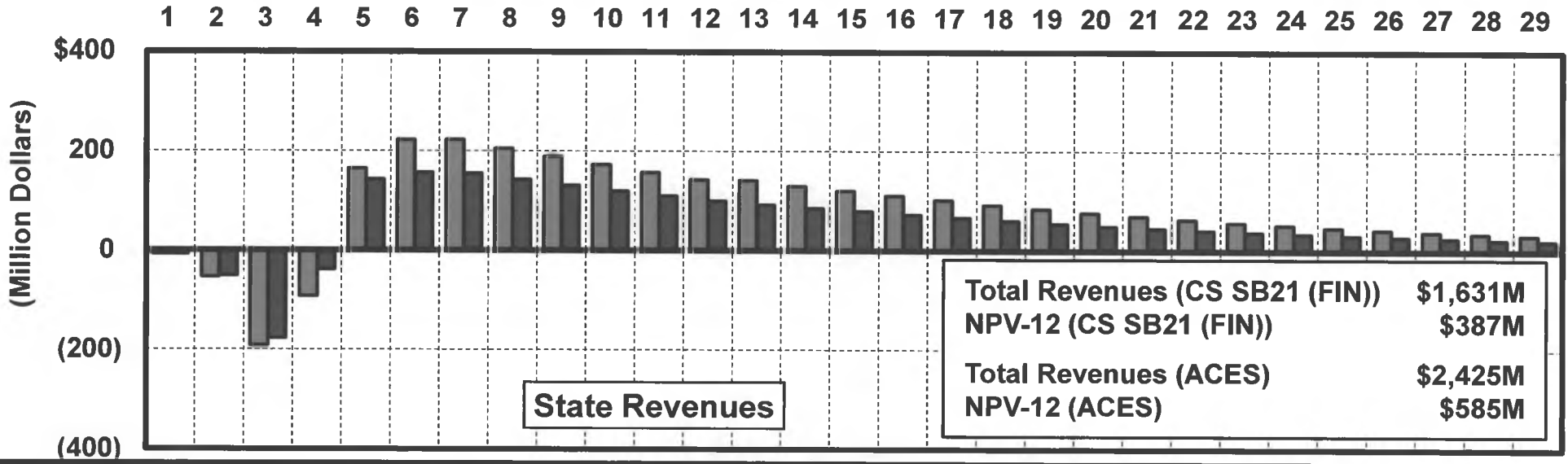
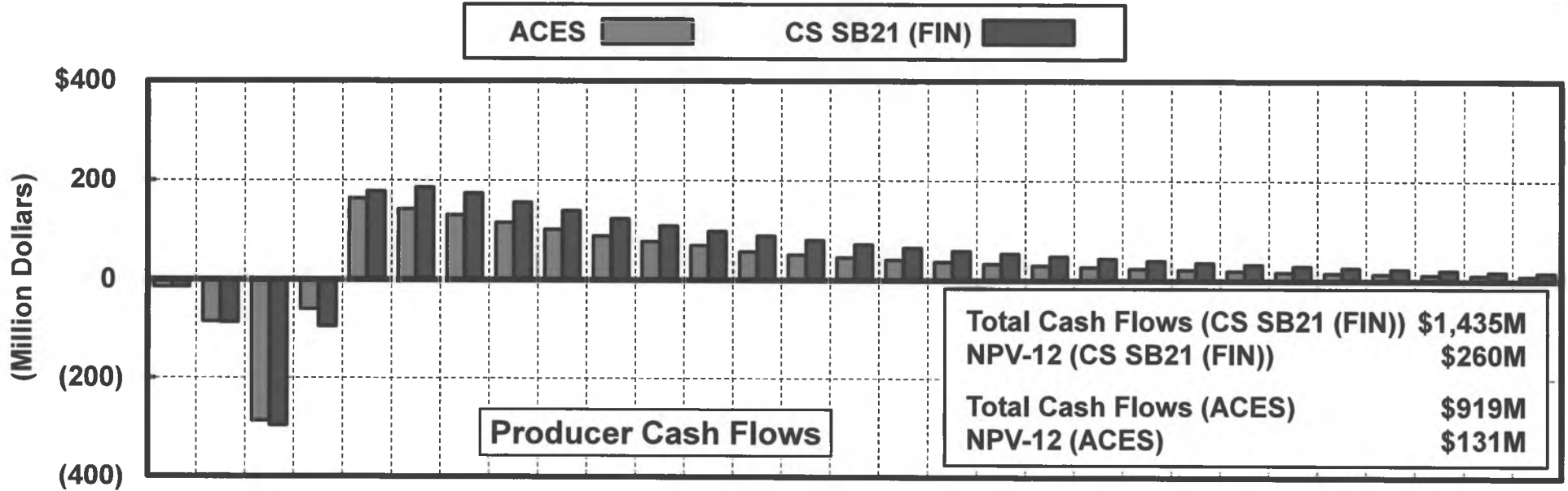
Real 2012 West Coast ANS Price	Alaska Project Qualifying for GRE				Unconventional Lower-48 Eagle Ford	Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom		
	12.5% Royalty Rate		16.67% Royalty Rate						Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*	
	ACES	CS SB21 (FIN)	ACES	CS SB21 (FIN)							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$1.78	\$0.78	\$1.34	\$0.20	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$5.16	\$4.06	\$4.70	\$3.33	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$8.65	\$7.35	\$8.11	\$6.46	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.09	1.04	1.06	1.01	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.25	1.20	1.23	1.16	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.42	1.35	1.39	1.31	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	16.5%	13.4%	15.4%	12.4%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	28.5%	18.8%	27.2%	17.7%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	47.5%	23.8%	45.8%	22.5%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$27.78	\$34.46	\$26.57	\$32.86	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$30.85	\$43.57	\$29.56	\$41.53	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$35.02	\$52.68	\$33.48	\$50.20	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	64.8%	58.5%	67.6%	62.4%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	69.2%	59.7%	71.1%	62.8%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	69.9%	60.3%	71.6%	63.1%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	(\$0.03)	\$1.51	\$0.64	\$2.40	-	-	-	-	-	-	-
\$100	\$3.41	\$5.10	\$4.12	\$6.23	-	-	-	-	-	-	-
\$120	\$6.69	\$8.68	\$7.51	\$10.05	-	-	-	-	-	-	-

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

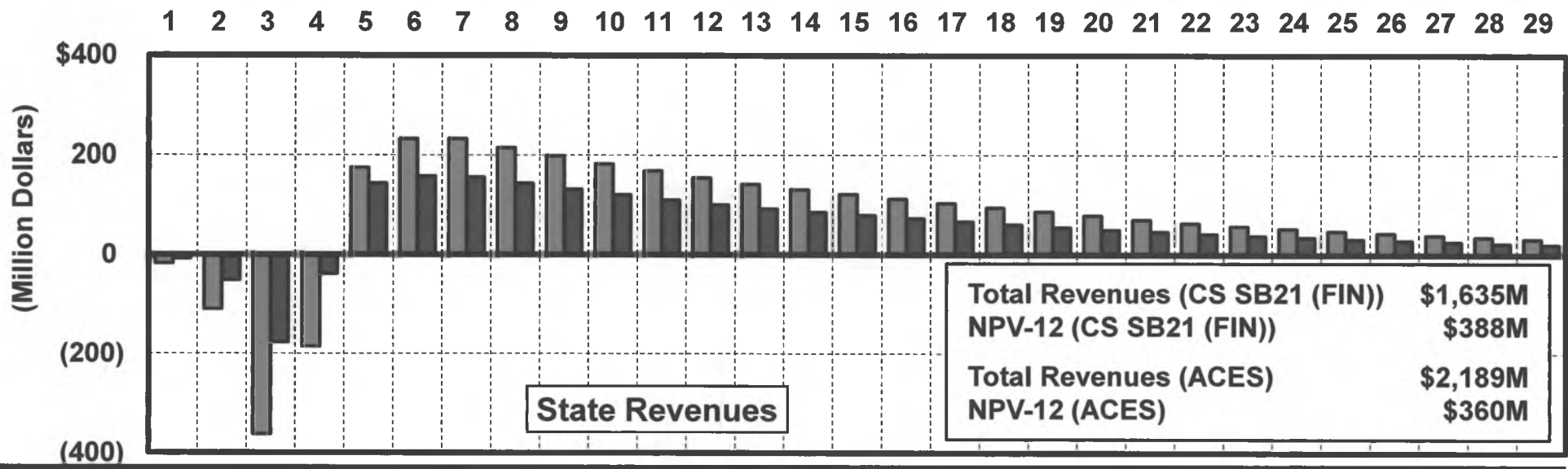
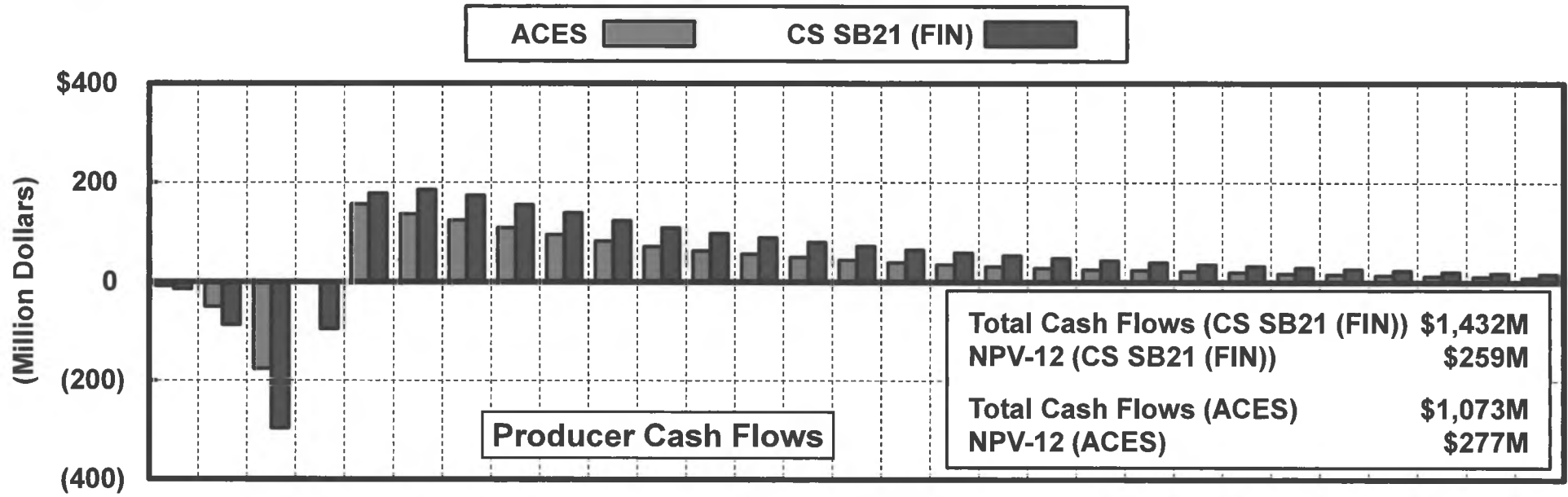
* Brownfield Allowance applied to 100 MMBOE development.

Cost Assumptions: \$25/Bbl. Development Capex and \$14/Bbl. Opex.

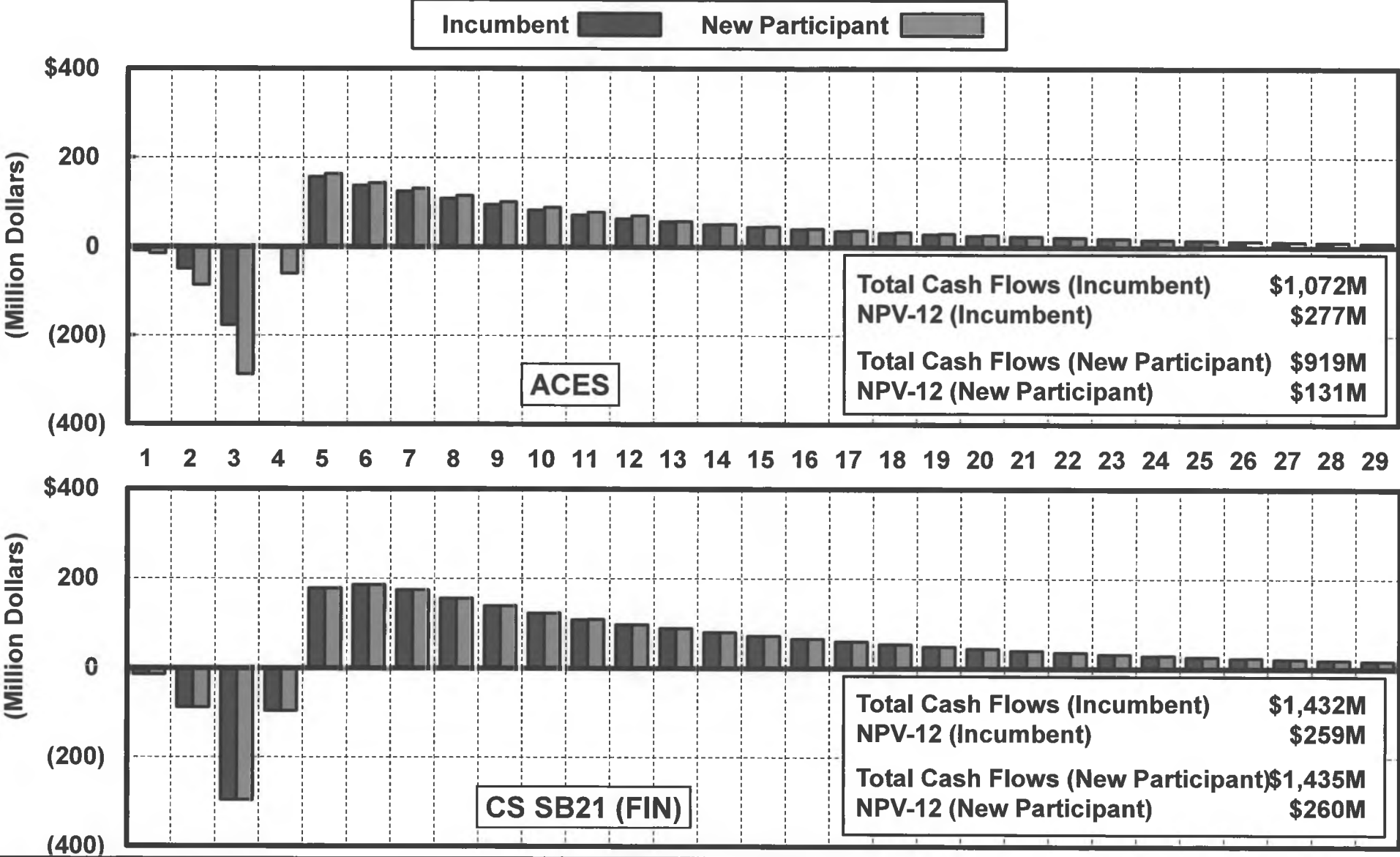
Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) Mid-Range Cost 50 MMBO Alaska Oil Development New Participant in Alaska



**Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012)
Mid-Range Cost 50 MMBO Alaska Oil Development
Incumbent Participant in Alaska**



Annual Producer Cash Flows at \$100 West Coast ANS (\$2012) Mid-Range Cost 50 MMBO Alaska Oil Development



Additional Volumes Need to Offset Projected Fiscal Impact of CS SB21 (FIN) (FY2014 - FY2043)



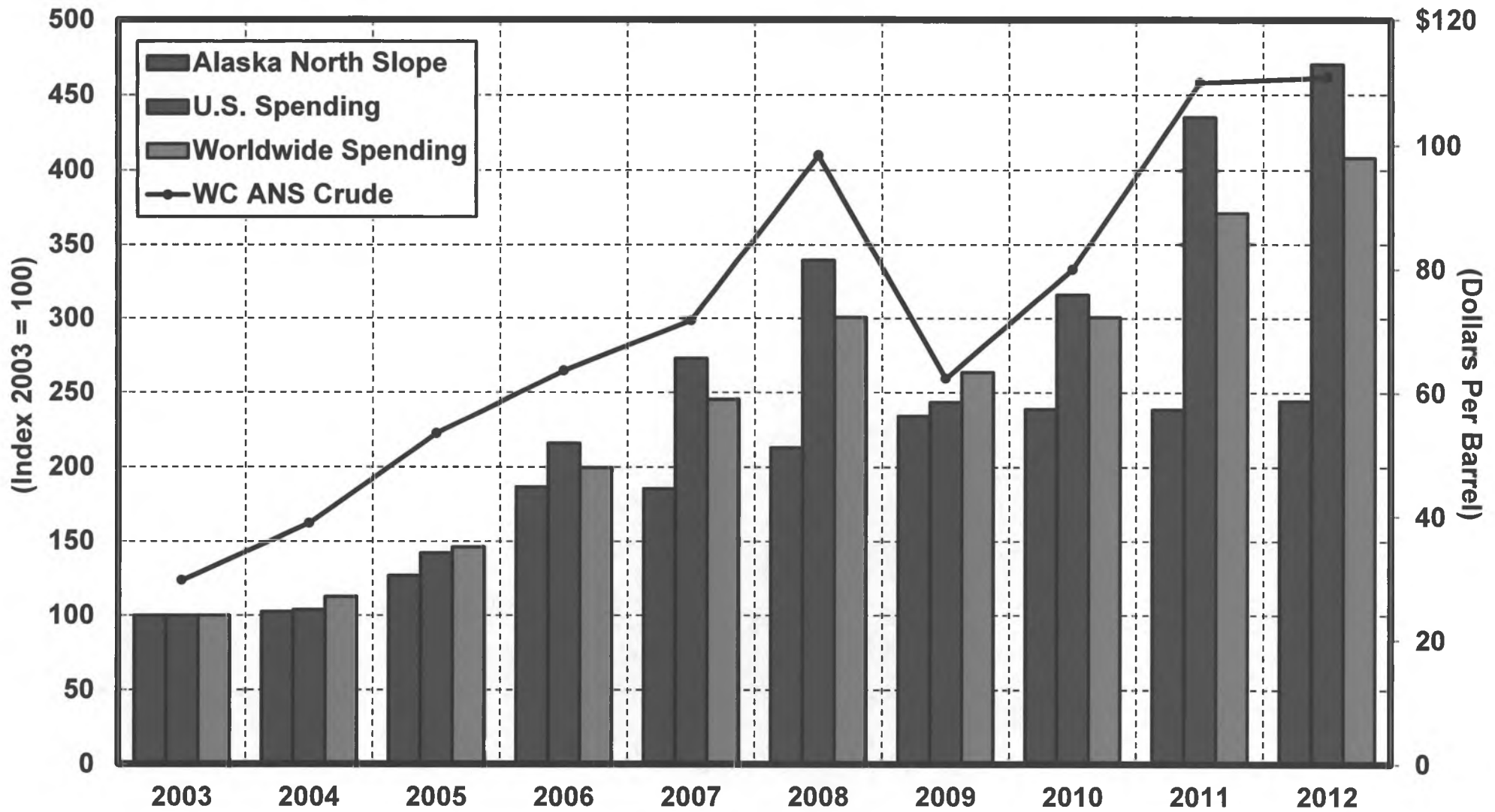
**Assumptions: \$20/Bbl Development Cost
Price = \$105/Bbl West Coast ANS Price (\$2012)
Taxes Per Senate Finance CS SB21: 35% Base Rate, \$5/Bbl Credit, 20% GRE**

	<u>16.67% Royalty</u>	<u>12.5% Royalty</u>
State Revenue Per Barrel Developed (No Tariff Impact)		
Nominal Dollars	\$35.50	\$32.00
2012 Dollars	\$25.75	\$23.00
Additional State Revenue From Tariff Reduction (\$2012)	\$3.50	\$3.50
30-Year Breakeven		
Nominal Dollars	\$17,200	\$17,200
2012 Dollars	\$12,900	\$12,900
Total Barrels Needed to Develop (MMBO)	441	487
Annual Barrels Needed (MMBO)	15	16
Daily Barrels Needed (BPD)	40,000	44,000
Central North Slope Undiscovered Conventional Economically Recoverable Resources	3,000 <i>MMBOE</i>	3,000
% of Resources Required Annually	0.5%	0.5%

Testing Reasonableness of Achieving Breakeven Development Capital Required (\$2012)

Annual Development Required (Barrels)		15,000,000
\$/Bbl Development Costs	x	\$20
Annual Capital Required (Dollars)	=	<u>\$300,000,000</u>
2012 Capital Spending (Dollars)		\$2,400,000,000
Additional Capital Required as Percent of 2012 Spending Level		12.5%

Estimated Capital Spending for Exploration and Development Alaska North Slope vs. U.S. and Worldwide Spending* 2003 - 2012



* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

Testing Reasonableness of Achieving Breakeven Development Capital Spending Increase at Worldwide Pace

Worldwide Capital Spending Growth 2003-2012 (Percent)		400%
Alaska Capital Spending in 2003 (Dollars)		\$1,000,000,000
Alaska Capital Spending in 2012 with Growth at Worldwide Pace (Dollars)		\$4,000,000,000
Actual 2012 Capital Spending (Dollars)	-	2,400,000,000
Worldwide Pace vs Actual (Dollars)	=	\$1,600,000,000
Percentage Over Actual 2012 Spending (Percent)		67%
Potential Development @ \$20/Bbl (Barrels)		80,000,000
Breakeven Volume (Barrels)		15,000,000
Difference (Barrels)		65,000,000

Testing Reasonableness of Achieving Breakeven Development

Gerking, et al. Study of Sensitivity of Drilling to Tax Rates

Drilling Change Due to Reduction in Gross Severance Tax By 5.3 Percentage Points (From 10.6% to 5.3%)		23.0%
Change Per 1% Change in Severance Tax Rate		4.3%
Change in Alaska Tax Rate (Gross Equivalent) (10 Percentage Points)	x	10%
Implied Impact on Drilling Starts (Percent)	=	43.4%
2012 Well Starts in Alaska with Production	x	60
Implied Increase in Drilling Starts	=	26
Expected First Year Recovery (Barrels) (Assumes 80% in-field wells with initial production of 1,000 b/d; 20% new field drilling with initial production of 2,000 b/d)		11,388,000
Total Expected Recovery (Barrels) (Assumes 15% Annual Decline)		72,800,000
Breakeven Volume (Barrels)	-	15,000,000
Amount Over Breakeven (Barrels)	=	57,800,000

Testing Reasonableness of Achieving Breakeven Development

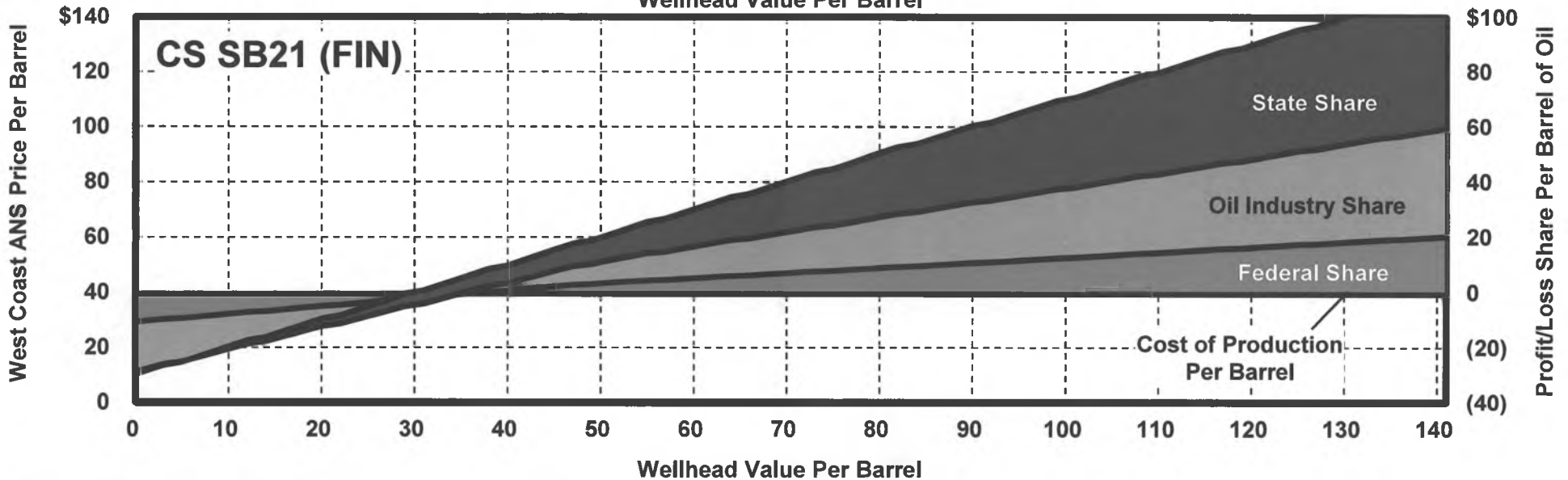
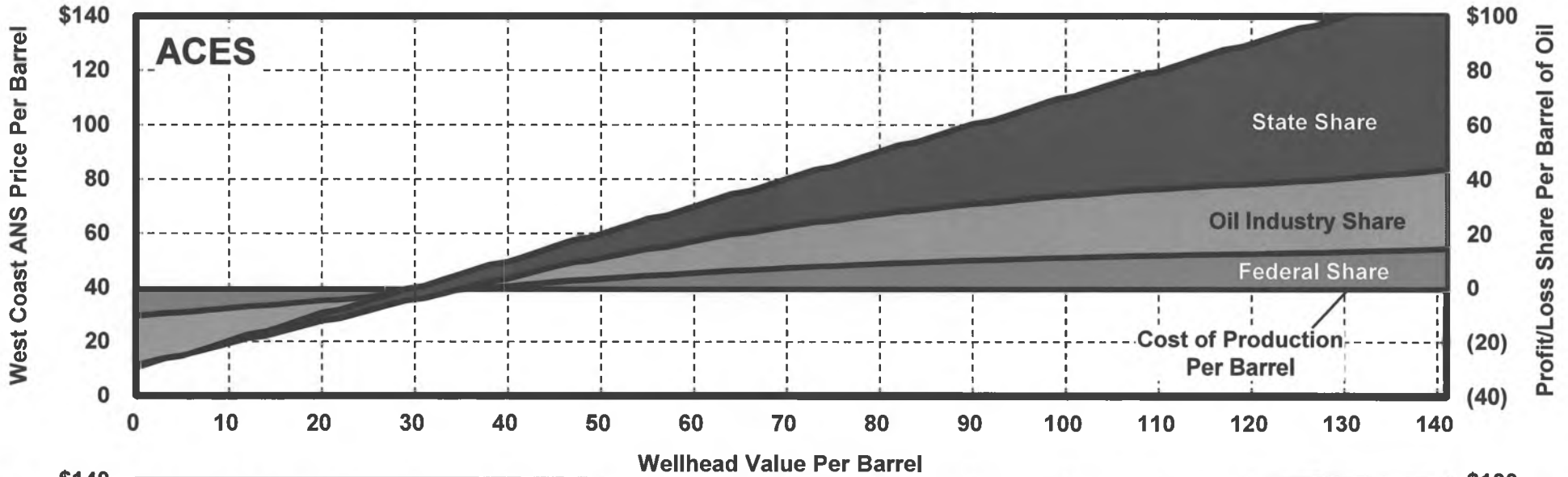
Gerking, et al. Study of Sensitivity of Drilling to Tax Rates

Limited Impact Sensitivity



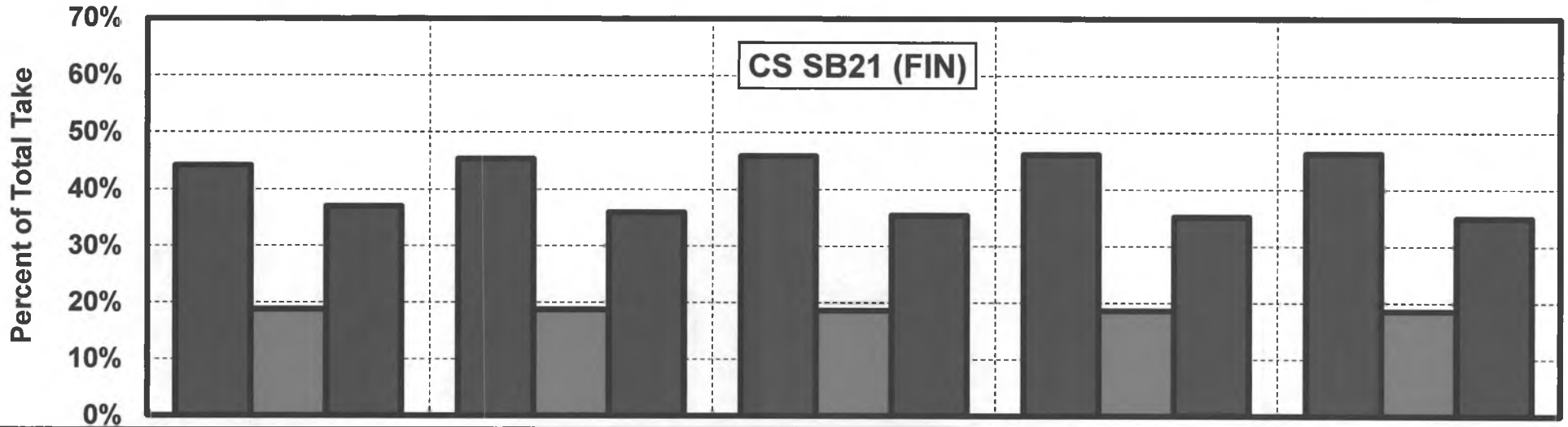
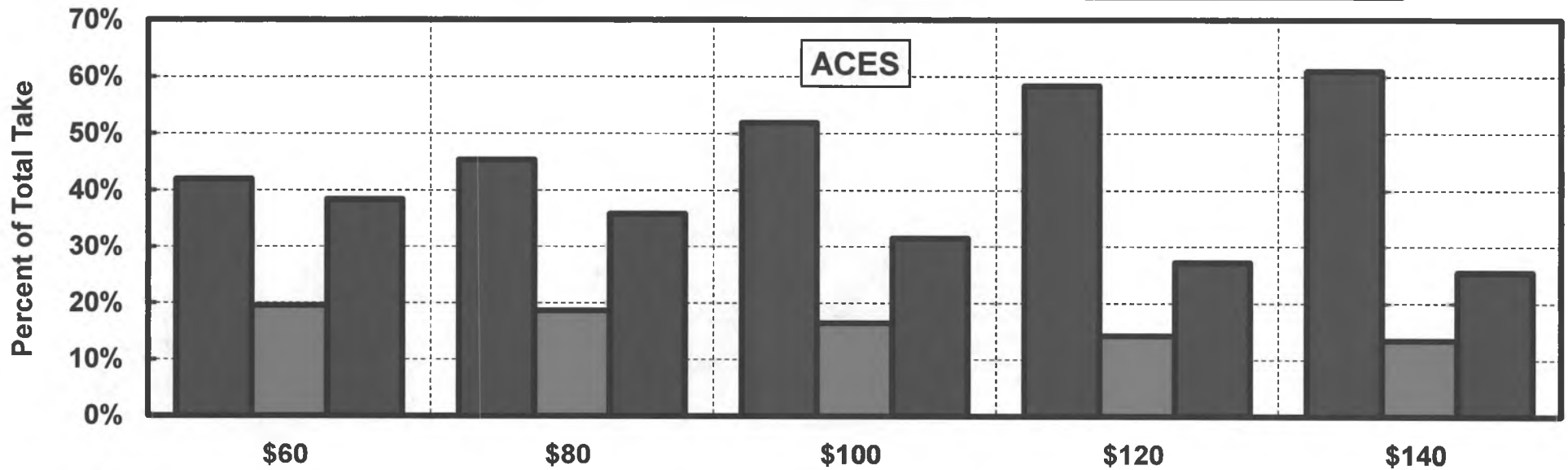
Drilling Change Due to Reduction in Gross Severance Tax By 5 Percentage Points (From 10.6% to 5.3%)		23.0%
Change Per 1% Change in Severance Tax Rate		4.3%
Change in Alaska Tax Rate (Gross Equivalent) (10 Percentage Points)	x	10%
Implied Impact on Drilling Starts (Percent)	=	43.4%
50% of Implied Drilling Starts (Percent)		21.7%
2012 Well Starts in Alaska with Production	x	60
Implied Increase in Drilling Starts	=	13
Expected First Year Recovery (Barrels) (Assumes 80% in-field wells with initial production of 1,000 b/d; 20% new field drilling with initial production of 2,000 b/d)		5,694,000
Total Expected Recovery (Barrels) (Assumes 15% Annual Decline)		36,400,000
Breakeven Volume (Barrels)	-	15,000,000
Amount Over Breakeven (Barrels)	=	21,400,000

Shares of Per-Barrel Values Under ACES and CS SB21 (FIN) for All Producers (FY 2015 - FY 2019)



State, Federal and Producer Take at Various \$2012 WC ANS Prices for All Producers (FY 2015 - FY 2019)

ACES and CS SB21 (FIN)



STATE TAXATION, EXPLORATION, AND PRODUCTION
IN THE U.S. OIL INDUSTRY*

Mitch Kunce
Department of Economics and Finance
University of Wyoming
Laramie, WY 82071-3985
mkunce@uwyo.edu

Shelby Gerking
Department of Economics
University of Central Florida
Orlando, FL 32812-1400
sgerking@bus.ucf.edu

William Morgan
Department of Economics and Finance
University of Wyoming
Laramie, WY 82071-3985
wemorgan@uwyo.edu

Ryan Maddux
University of Wyoming
Laramie, WY 82071-3985

November 26, 2001

* This research was partially supported by an appropriation from the Wyoming Legislature (1999 Wyoming Session Laws, Chapter 168, Section 3). However, this paper may or may not reflect the views of public officials in the State. Gerking acknowledges the hospitality of CentER, Tilburg University, where portions of this paper were completed, as well as support from visiting grant B46-386 from the Netherlands Organization for Scientific Research (NWO). Maddux acknowledges the support of a student EPSCoR research fellowship from the University of Wyoming. We thank Laura Marsiliani and John Livernois for a number of constructive suggestions on earlier drafts.

STATE TAXATION, EXPLORATION, AND PRODUCTION IN THE U.S. OIL INDUSTRY

Abstract

How do firms in nonrenewable resource industries respond to changes in state taxes? This paper employs state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, affect little change in reserve additions and future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil activity.

1. Introduction

How do firms in nonrenewable resource industries respond to changes in state taxes? It may be tempting to look for answers to this question in the empirical literature on effects of state taxation (see, for example, Bartik 1985, Helms 1985, Papke 1991, 1994, and Holmes 1998). These papers focus on firms with mobile capital that choose where to locate on the basis of factors affecting revenues and costs. This perspective, however, is not particularly relevant when looking at the behavior of firms extracting nonrenewable natural resources. Such firms cannot change location because they are tied to a geographically immobile reserve base that makes up a key component of their capital stock. On the other hand, extractive firms can and probably do alter the timing of their activities when state taxes and other public policies change. Yet, little is known about the extent to which they do this even though commercially valuable deposits of natural resources are found in most U.S. states and some states such as Texas, Oklahoma, Louisiana, Wyoming, and Alaska rely heavily on taxation of oil, gas, and/or coal production to fund public services.

This paper uses state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. It is arguably superior to and more comprehensive than previous efforts to develop econometric and/or simulation models of taxation and natural resource exploration and production. For example, Deacon, DeCanio, Frech, and Johnson (1990)

and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes. Simulation studies conducted by Yucel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production, but do not consider interactions between tax bases claimed by different levels of government. Additionally, these studies do not allow for possible interstate differences in exploration and extraction costs and are aimed mainly at assessing the generality of theoretical results obtained in more limited settings (see, for example, Burness 1976, Conrad and Hool 1980, and Heaps 1985) rather than analyzing possible outcomes of changes in state tax policies.

Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes so deadweight losses from altering these taxes are likely to be small. As a consequence, state officials may consider raising production tax rates as a way to increase revenue. It is worth noting in this context that because state production taxes are deductible against federal corporate income tax liabilities, increases in production tax rates increase state revenues partly at the expense of federal tax collections. These points are more fully discussed in Section 3 after developing the framework for the simulation model in the next section.

2. *The Simulation Model*

This section shows how Pindyck's (1978) model of nonrenewable resource development is adapted to simulate effects of state production tax changes. The

discussion begins with a brief overview of the Pindyck model and then discusses estimation of key equations and tax parameters.

Conceptual Model

The model assumes that perfectly competitive producers maximize the discounted present value of future operating profits from the sale of resources and because one such firm is chosen to represent the industry, the common pool problem and well-spacing regulations are not considered (see McDonald 1994 for discussion of these issues). The firm's problem is to take the future time path of output prices and taxes as given and then choose optimal time paths for exploration and production. This approach is similar to that taken in previously cited econometric studies of effects of changes in state tax policy on state economic growth and ignores the possibility that choices of tax bases and rates are endogenous (i.e., that governments consider the firm's objective function in choosing taxes that maximize community welfare). Also, the model defines exploration to include resource development, although the two activities clearly are not the same (Adelman 1990). The aim of exploration is to add to the reserve base, which as indicated in the introduction, is a form of geographically immobile capital.

The firm's maximization problem is

$$\max_{q, w} \Omega = \int_0^{\infty} [qp - C(q, R) - D(w) - \gamma R] e^{-\rho t} dt \quad (1)$$

subject to

$$\dot{R} = \dot{x} - q \quad (2)$$

$$\dot{x} = f(w, x) \quad (3)$$

$$q \geq 0, w \geq 0, R \geq 0, x \geq 0 \quad (4)$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(\cdot)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels (R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of all tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(\cdot)$ denotes the production function for gross reserve additions (\dot{x}), and \dot{R} denotes reserve additions net of production (q).¹ In this formulation, the net-of-tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a tax policy parameter such that $0 < \alpha_p < 1$.

Correspondingly, $C(q, R) = \alpha_c C^*(q, R)$ and $D(w) = \alpha_D D^*(w)$, where α_c and α_D also are tax policy parameters that lie on the unit interval. These tax policy parameters are discussed more fully later on in this section.

Model Implementation

To implement the model, equations for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) are estimated and then substituted into the model along with estimates of the tax parameters α_p , α_c , α_D , and γ . Effects of tax changes then are obtained by simulation. Estimates of the tax parameters are described first followed by discussion of estimates of equations for D^* , f , and C^* .

Tax Parameters

General considerations in developing estimates of the four tax policy parameters for major oil producing states are briefly outlined below and technical details are described in Appendix A. Among major oil producing states, tax structures vary considerably and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy production taxes against the value of output. Production taxes dominate other forms of local taxation in Alaska, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Within states, counties apply their own mill levies to compute property taxes on equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are ignored below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail

interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is ignored.

The myriad of state-specific special features described above creates considerable complexity in tracking tax law over time. Rather than itemize tax code details, effective tax rates are used to translate dynamic tax policy into a tractable form. Effective rates can be expressed as the ratio of taxes (or royalties) collected from a particular tax to the value of production. Thus, the calculation of specific effective tax rates fully account for exemptions, incentives, different tax bases, and frequent changes in tax law both at the state and federal level. For a detail account of the taxation of the oil industry see Gerking, Morgan, Kunce, and Kerkvliet (2000), Chapter 2.

Marginal Cost of Reserve Additions

The before-tax marginal cost of reserve additions (D_w^*/f_w) is computed from estimates of equations for drilling costs and for the production of reserve additions. Drilling costs are assumed to be proportional to drilling effort as shown in equation (5)

$$D^*(w) = \phi w e^u \tag{5}$$

where ϕ is the parameter to be estimated and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2 . The production function for reserve additions is specified as

$$f(w, x) = A w^\rho e^{-\beta \cdot x} e^v \tag{6}$$

where A , ρ , and β are parameters to be estimated and the disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2 . Equation (6) is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate.

Estimation used annual data from the 15 U.S. states for which complete information on variables needed could be assembled for the period 1970-98.² These states accounted for 96.5% of total U.S. oil production over this time period. Drilling costs are measured by total real costs (both tangible and intangible) of each well completed, including dry holes.³ Nominal cost values were deflated using the 1995 GDP deflator. Oil reserve additions are defined as extensions, new field discoveries and new reservoir discoveries in old fields. The total number of wells drilled for each state since 1859 (when the first oil well was drilled in Pennsylvania) is used as a proxy for x . Data sources and sample means of variables used in the analysis are presented in Table 1.

Equation (5) and equation (6) were estimated in natural logarithms. Both equations used an instrument for the number of wells drilled because w is an endogenous variable in the model presented in Section 2. The instrument was obtained from the predicted values from a regression of the number of wells on cumulative drilling and the wellhead price as shown in Appendix A. Estimates of the drilling cost equation, equation (5), are obtained by regressing drilling cost per well on dummy variables for states and years. Coefficients of state and year dummies are jointly significant at the 1% level and the R^2 is 0.90. The idea behind using this approach is to get state- and time-specific estimates of ϕ . This parameter is expected to vary across states because of differences in

geologic conditions, geographic remoteness of on-shore oil resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. State-specific estimates of ϕ test different from each other, except Texas and Oklahoma, at the 5% level.

Estimates of equation (6), shown below in equation (7), allow for state-specific intercept terms (time-specific effects were jointly insignificant), common slope coefficients across states, and are corrected for first-order serial correlation ($\rho = 0.431$).

$$\ln (ADDED\ RESERVES) = \ln A + 0.69 * \ln (PREDWELLS) - 0.000006 * CWELLS . \quad (7)$$

(t) (5.33) (-1.37)

State-specific estimates of A are jointly significant at the 1% level and $R^2 = 0.40$.⁴ These results show that the marginal product of drilling (f_w) decreases with wells drilled as well as with cumulative drilling, although the coefficient of cumulative drilling is insignificant at conventional levels.

Estimates of equations (5) and (6) combined show that the marginal cost of reserve additions (D_w^* / f_w) increases with drilling activity. As w increases, the marginal cost of drilling is constant, but the marginal product of drilling in finding new reserves (f_w) falls. Table 2 reports values of D_w^* , f_w , and D_w^* / f_w by state for seven major oil producing states. These estimates use 1998 values for numbers of wells drilled and cumulative drilling and are corrected for conversion from logarithms (see Greene 1997, p. 279). Estimates of D_w^* and f_w reflect considerable variation across the seven states. Estimates of marginal drilling cost range from \$127,943 in Kansas to \$1,218,758 in Louisiana. Marginal reserve additions from drilling (f_w) range from 7,460 barrels in Kansas to 64,862 barrels in Louisiana. Thus, while drilling in Louisiana is relatively

more expensive than in Kansas, Louisiana experiences a greater payoff from these more costly exploration and development efforts. Values of D_w^*/f_w for the seven states range from a low of \$17.15 per barrel in Kansas to a high of \$26.04 in Texas.

Extraction Costs

Because data on oil extraction costs are weak, $C(q, R)$ could not be econometrically estimated. Instead, this equation was calibrated for each state with a Cobb-Douglas functional form using methods described in Deacon (1993). Cost parameter calibration specifics are described in Appendix A. Results show that the 1998 marginal extraction costs range from a low of \$4.89 per barrel in Kansas to a high of \$8.81 per barrel in Louisiana. Additionally, the Cobb-Douglas form implies that extraction costs rise without limit as reserves approach zero and that a positive level of reserves will remain at any terminal time T . Thus, boundary conditions used in the simulations reported in Section 3 allow production to continue after incentives for further exploration vanish so that the terminal date for the exploration/production program must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3. *Simulation Results*

The model presented in Section 2 can be simulated to obtain responses of exploration and production to changes in various types of taxes in any of 15 oil producing states. Simulations presented below focus on production tax changes in Wyoming. The production tax is the most important tax levied on the oil industry by oil producing states (see Section 2) and changes in production taxes turn out to have quite similar effects in all major oil producing states so results from one state are used to represent the others

(for results of tax changes in other major oil producing states, see Gerking, Kuncie, Morgan, and Kerkvliet 2000). Also, simulations reported are based on the assumption that tax changes in one state do not affect the wellhead price of oil seen by operators in other states. This assumption probably is not unreasonable in view of the fact that oil prices are internationally determined and even the largest producing U.S. state (Texas) accounts for only a small percentage (4.2% from 1970-98) of world output.⁵ Moreover, as shown below, tax changes considered lead to comparatively small changes in output, so these interstate effects are not likely to be important in any case.

Simulations for Wyoming were performed using the instrumental variable estimates of equations (5) and (6), the calibrated production cost function and the tax parameters, both derived in Appendix A. The discount rate, r , was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at \$23.00 per barrel each year reflecting the real sample mean for all 15 states. Other price trajectories were simulated, but the alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled were fixed to year-end 1998 levels at 550 million barrels and 40,439 wells, respectively. To obtain numerical solutions for the optimal time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in exploratory effort (\dot{w}), production (\dot{q}), and for the state variable evolution equations (2) and (3). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is then solved recursively by iterating over the initial values of the control variables, q and w , until transversality conditions are satisfied. Under these base conditions, exploratory effort approaches zero

after approximately 40 years, thus the terminal time is set to 40 periods. The solver algorithm in Microsoft Excel was used to generate numerical solutions.

Before the simulation results are discussed, a historical analysis of Wyoming's oil experience is warranted. Figure 1 depicts the actual time paths of real price, drilling, production, and reserves for Wyoming from 1970-98. In this figure, the vertical axis shows price per bbl (dotted line) in $\$1995 \times 10$, drilling (dashed line) in total wells, production (solid line) in $\text{bbls} \times 10^5$, and reserves (bold line) in millions of barrels (MMbbls). In reviewing these data, several observations are noteworthy. Historical drilling appears sensitive to price. Total wells drilled increases markedly during the high price period of the early 1980s. Extraction activity, however, appears to map the declining proved reserve level in the state. In fact, oil production continued to decline during the late 1970s and early 1980s even though real prices increased $2 \frac{1}{2}$ fold. The increased drilling experienced in the early to mid 1980s failed to replenish the depleting oil reserve in the state and production closely followed the reserve decline.

This apparent historical insensitivity of production to changes in price raises an interesting policy question: If severance tax changes are reflected in net price (as modeled in section 2), what are the effects of a severance tax increase? Many oil states, as previously described — including Wyoming, rely heavily on production taxes to fund local public goods and officials may have incentives to raise production taxes for the revenue. The inherent trade off to severance tax increases is the purported loss of economic activity generated by the industry within the state. To examine this, the first simulation conducted shows the effects of *doubling* Wyoming's effective state severance tax rate for the full 40-year program. Results detailing the simulated differences in the

timing of drilling, production, and discounted severance tax revenue for the full tax interaction model (outlined above) are presented in the top section of Table 3.

Comparative individual program year results, divided into 10-year increments, show that doubling the state severance tax markedly decreases early period drilling. Drilling decreases by 19.4% in the first year of the simulated program and this difference converges to zero by year 40. Interestingly, 10 year fractional results show that 63.8% of the total 1208 well decrease occurs in the first 20 years of the program. Figure 2 graphically compares the effects of the tax increase (dotted line) to the base drilling solution (bold line). With less drilling in the early years of the program, fewer new reserves are identified and, as shown in Figure 3, future production of oil slightly diverges downward from the base solution. Production results presented in Table 3 show this gradual divergence — a 2.4% drop in year one falling to an 11.8% decline in year 40. Through the life of the program, doubling the state severance tax decreases total production by about 48 MMbbls or 5.7% below the base solution.

The largest change associated with doubling the state oil severance tax appears to come from discounted severance tax collections. As shown in Table 3, the tax increase results in an increase in the present value of Wyoming severance tax collections from \$609 million to \$1165 million, an increase of over 91%. The majority (87.6%) of this \$556 million increase occurs in the first half of the simulated program due to the relatively small production loss generated by the tax increase and discounting. Because severance taxes are deductible in computing federal corporate income tax liabilities, discounted tax payments to the federal government decrease by \$60 million or about 11% below the base simulation. Also, the severance tax increase transfers local government

revenue to the state because of the production decline. Discounted local production taxes decrease by \$34 million or 5% below the base solution. The same can be said for discounted public land royalties which decrease by 4.6% (\$50 million) because of the decrease in future production.

The tax interactions described above highlight a key feature of the model developed here — oil producers do not face the full effect of an increase in the severance tax rate. As shown, tax base and rate interactions partially offset the pure-effect of the severance tax rate increase. To illustrate this clearly, counterpart simulations were conducted where all tax effects, other than state level production tax rates, were effectively *zeroed out*. The lower section of Table 3 presents the counterpart Wyoming results. When all tax interactions are ignored, doubling the state severance tax decreases relative drilling by 32.8% and production by 11.2%, a decrease in activity roughly 2 times larger than found in the full tax interaction model examined above. Timing effects are similar to the full tax interaction model results. Because the severance tax increase now invokes a larger production loss, discounted state severance taxes increase by 83% as compared to the 91% increase in the full tax interaction model. Analyzing taxes individually appears to overstate the affects on exploration and production by ignoring potential offsets and tax base interactions. These results suggest that taxes should not be analyzed independently without careful reference to the entire tax structure applied by all levels of government.

General results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. This inelastic response may provide incentives for state officials to substantially increase these taxes risking little in the way of reduced

industry activity while gaining much needed tax revenue. State severance tax increases clearly reduce the net price faced by producers but it is reserves, not net price, that drives production in this industry. Moreover, the effects of increased state severance taxes are partially offset by reduced tax collections by all other levels of government.

4. *Conclusions*

This paper has adapted Pindyck's (1978) model of nonrenewable natural resource production to take account of taxation at the federal and state-local government levels. Equations of the model are estimated from panel data on production, exploration and reserve additions for 15 states over the period 1970-98. The model is designed so that effects of changes in existing state production tax rates on the timing and evolution of exploration and production can be simulated into the mid-21st century. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, invoke little change in reserve additions and subsequently future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil activity.

Endnotes

¹Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987), and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ . The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are ignored in the analysis below because of severe data constraints on estimating the extraction cost function.

²The Energy Information Administration and the American Petroleum Institute report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 16 smallest producing states. The 15 states included in the panel are Alaska, Alabama, California, Colorado, Kansas, Louisiana, Michigan, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, and Wyoming.

³Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).

⁴Corrected (see Greene 1997, p. 279) state-specific intercept terms (and t-statistics) for 7 major producing states are: CA 0.17(2.01), KS 0.06(1.06), LA 0.57(2.21), NM 0.19(1.68), OK 0.07(1.94), TX 0.01(1.11), WY 0.29(2.03). Equation (6) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β . This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.

⁵Source of world oil production for 1970-98, www.eia.doe.gov/emeu/international/petroleu.html.

References

- Adelman, Morris A. 1990. "Mineral Depletion, with Special Reference to Petroleum," Review of Economics and Statistics 72: 1-10.
- American Petroleum Institute. Basic Petroleum Data Book. Annual. Washington, D.C.
- American Petroleum Institute. Joint Association Survey on Drilling Costs. Annual. Washington, D.C.
- American Petroleum Institute. Petroleum Facts and Figures. 1971 ed. Washington, D.C.: 16-23.
- Bartik, Timothy J. 1985. "Business Location Decisions in the United States: Estimates of the Effects of Unionization, Taxes, and Other Characteristics of States," Journal of Business and Statistics 3:14-22.
- Burness, H. Stuart. 1976. "On the Taxation of Nonreplenishable Natural Resources," Journal of Environmental Economics and Management, 3:289-311.
- Conrad, Robert F. and B. Hool. 1980. "Resource Taxation with Heterogeneous Quality and Endogenous Reserves," Journal of Public Economics, 16.
- Deacon, Robert, Stephen DeCanio, H.E. Frech III, M. Bruce Johnson. 1990. Taxing Energy: Oil Severance Taxation and the Economy. New York: Holmes & Meier.
- Deacon, Robert T. 1993. "Taxation, Depletion, and Welfare: A Simulation Study of the U.S. Petroleum Resource," Journal of Environmental Economics and Management, 24:159-87.
- Gerking, S., W. Morgan, M. Kunce, and J. Kerkvliet. 2000. Mineral Tax Incentives, Mineral Production and the Wyoming Economy. Report to the State of Wyoming. <http://w3.uwyo.edu/~mkunce/StateReport.pdf>
- Greene, William H. 1997. Econometric Analysis. 3rd Edition. Saddle River, New Jersey: Prentice Hall.
- Heaps, Terry. 1985. "The Taxation of Nonreplenishable Natural Resources Revisited," Journal of Environmental Economics and Management, 12:14-27.
- Helms, L. Jay. 1985. "The Effect of State and Local Taxes on Economic Growth: A Time-Series Cross Section Approach," Review of Economics and Statistics 67:574-82.

- Holmes, Thomas J. 1998. "The Effect of State Policies on the Location of Manufacturing: Evidence from State Borders," Journal of Political Economy, 106:667-705.
- Kunce, M., S. Gerking, and W. E. Morgan. 2001. "Environmental Policy and the Timing of Drilling and Production in the Oil and Gas Industry," *in* Recent Advances in Environmental Economics. (John A. List & Aart de Zeeuw, Eds.) Edward Elgar Publishing. Forthcoming.
- Livernois, John L. 1987. "Empirical Evidence on the Characteristics of Extractive Technologies: The Case of Oil," Journal of Environmental Economics and Management, 14: 72-86.
- Livernois, John L. 1988. "Estimates of Marginal Discovery Costs for Oil and Gas," Canadian Journal of Economics, 21: 379-93.
- Livernois, John L. and Russell S. Uhler. 1987. "Extraction Costs and the Economics of Nonrenewable Resources," Journal of Political Economy 95: 195-203.
- McDonald, Stephen L. 1994. "The Hotelling Principle and In-Ground Values of Oil Reserves: Why the Principle Over-Predicts Actual Values," The Energy Journal 15: 1-17.
- Moroney, John R. 1997. Exploration, Development, and Production: Texas Oil and Gas, 1970-95. Greenwich, Connecticut: JAI Press.
- Papke, Leslie E. 1991. "Interstate Business Tax Differentials and New Firm Location," Journal of Public Economics 45:47-68.
- Papke, Leslie E. 1994. "Tax Policy and Urban Development," Journal of Public Economics 54:37-49.
- Pesaran, M. Hashem. 1990. "An Econometric Analysis of Exploration and Extraction of Oil in the U.K. Continental Shelf," Economic Journal, 100:367-90.
- Pindyck, Robert S. 1978. "The Optimal Exploration and Production of Nonrenewable Resources," Journal of Political Economy, 86:841-61.
- Swierzbinski, Joseph E. and Robert Mendelsohn. 1989. "Exploration and Exhaustible Resources: The Microfoundations of Aggregate Models," International Economic Review 30:175-86.

- Uhler, Russel S. 1976. "Costs and Supply in Petroleum Exploration: The Case of Alberta," Canadian Journal of Economics, 29:72-90.
- U.S. Department of Energy. Energy Information Administration. Cost indices for domestic oil field equipment and production operations. Annual. Washington, D.C.
- U.S. Department of Energy. Energy Information Administration. U.S. crude oil, natural gas, and gas liquids reserves. Annual. Washington, D.C.
- U.S. Department of Treasury. Statistics of Income. 1996-98. Washington D.C.
- Yücel, Mine K. 1989. "Severance Taxes and Market Structure in an Exhaustible Resource Industry," Journal of Environmental Economics and Management. 16:134-48.

Table 1
 Variable Definitions, Data Sources, and Sample Means
 (Excludes federal OCS activity.)

<u>Variable</u>	<u>Definition</u>	<u>Source</u>	<u>Mean</u>
<i>TRCOST</i>	Total drilling cost in millions of 1995 dollars, by state and year.	American Petroleum Institute, <i>Joint Association Survey on Drilling Costs</i> . Annual.	427.6
<i>ADDED RESERVES</i>	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	US Energy Information Administration, <i>U.S. Crude Oil, Natural Gas and Gas Liquids Reserves Annual Report</i> . Annual	42.0
<i>WELLS</i>	Oil wells drilled in a state by year.	American Petroleum Institute, <i>Joint Association Survey on Drilling Costs</i> . Annual.	943
<i>CWELLS</i>	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute, <i>Petroleum Facts & Figures</i> . 1971 Ed.	1.07E+5
<i>PRICE</i>	Average well head oil price, by state and year, in 1995 dollars per barrel.	American Petroleum Institute, <i>Basic Petroleum Data Book</i> . Annual.	22.80
<i>PRICE2</i>	Average real price per barrel squared.	--	656.3
<i>CWELLS2</i>	Cumulative oil wells squared.	--	4.3E+10
<i>PRICE * CWELLS</i>	Interaction of real price and cumulative wells.	--	2.5E+6

Table 2
 Pre-Tax Marginal Drilling Cost, Marginal Reserve Additions,
 and Pre-Tax Marginal Cost of Reserve Additions for 7 Major Producing States

<u>State</u>	<u>D_w^* (in \$)</u>	<u>f_w (in bbls)^a</u>	<u>D_w^* / f_w^a</u>
California	274,675	11,464	23.96
Kansas	127,943	7,460	17.15
Louisiana	1,218,758	64,862	18.79
New Mexico	485,698	22,148	21.93
Oklahoma	345,706	15,223	22.71
Texas	342,266	13,144	26.04
Wyoming	593,162	34,627	17.13

^a Assumes wells drilled at the actual 1998 count. State-specific cumulative wells total is set to actual 1998 values in all calculations.

Table 3
Timing of Drilling, Production,
and Discounted Severance Tax Revenue

<u>Full Tax Interaction Model</u>	Individual Program Year:					
	Year 1	Year 10	Year 20	Year 30	Year 40	Total
Drilling (Base Solution, in wells)	211	203	187	132	2	6274
Drilling (Double Tax)	170	165	152	116	2	5066
Change from Base	-19.4 %	-18.7 %	-18.7 %	-12.1 %	0.0 %	-19.2 %
Production (Base, in MMbbls)	57.7	27.0	15.9	12.1	7.6	834.3
Production (Double Tax)	56.3	25.9	14.7	10.8	6.7	786.6
Change from Base	-2.4 %	-4.1 %	-7.5 %	-10.7 %	-11.8 %	-5.7 %
Severance Tax Revenue (Base, \$MM)	66.6	21.3	8.2	4.2	1.9	608.6
Severance Tax Revenue (Double Tax)	130.2	41.0	15.2	7.4	3.3	1165.2
Change from Base	95.5 %	92.5 %	85.4 %	76.2 %	73.7 %	91.5 %
10 Year Fractions of Total Change from Base Solution:						
	Years 1-10	Years 11-20	Years 21-30	Years 31-40		
Drilling	33.0 %	30.8 %	25.9 %	10.3 %		
Production	21.2 %	24.8 %	27.0 %	27.0 %		
Severance Tax Revenue	67.2 %	20.4 %	8.4 %	4.0 %		
<hr/>						
<u>No Tax Interaction Model</u>	Individual Program Year:					
	Year 1	Year 10	Year 20	Year 30	Year 40	Total
Drilling (Base Solution, in wells)	283	271	249	175	1	8363
Drilling (Double Tax)	189	183	168	119	1	5624
Change from Base	-33.1 %	-32.6 %	-32.4 %	-32.0 %	0.0 %	-32.8 %
Production (Base, in MMbbls)	59.6	28.8	18.0	14.2	9.0	911.0
Production (Double Tax)	57.0	26.4	15.3	11.4	7.2	809.3
Change from Base	-4.4 %	-8.3 %	-15.0 %	-19.7 %	-20.1 %	-11.2 %
Severance Tax Revenue (Base, \$MM)	75.6	24.9	10.2	5.3	2.5	714.3
Severance Tax Revenue (Double Tax)	144.7	45.9	17.4	8.6	3.9	1307.8
Change from Base	91.4 %	84.3 %	70.6 %	62.3 %	56.0 %	83.1 %
10 Year Fractions of Total Change from Base Solution:						
	Years 1-10	Years 11-20	Years 21-30	Years 31-40		
Drilling	33.2 %	30.9 %	25.9 %	10.0 %		
Production	21.0 %	25.1 %	26.9 %	27.0 %		
Severance Tax Revenue	68.1 %	20.1 %	8.0 %	3.8 %		

Figure 1. Wyoming Oil, 1970-98

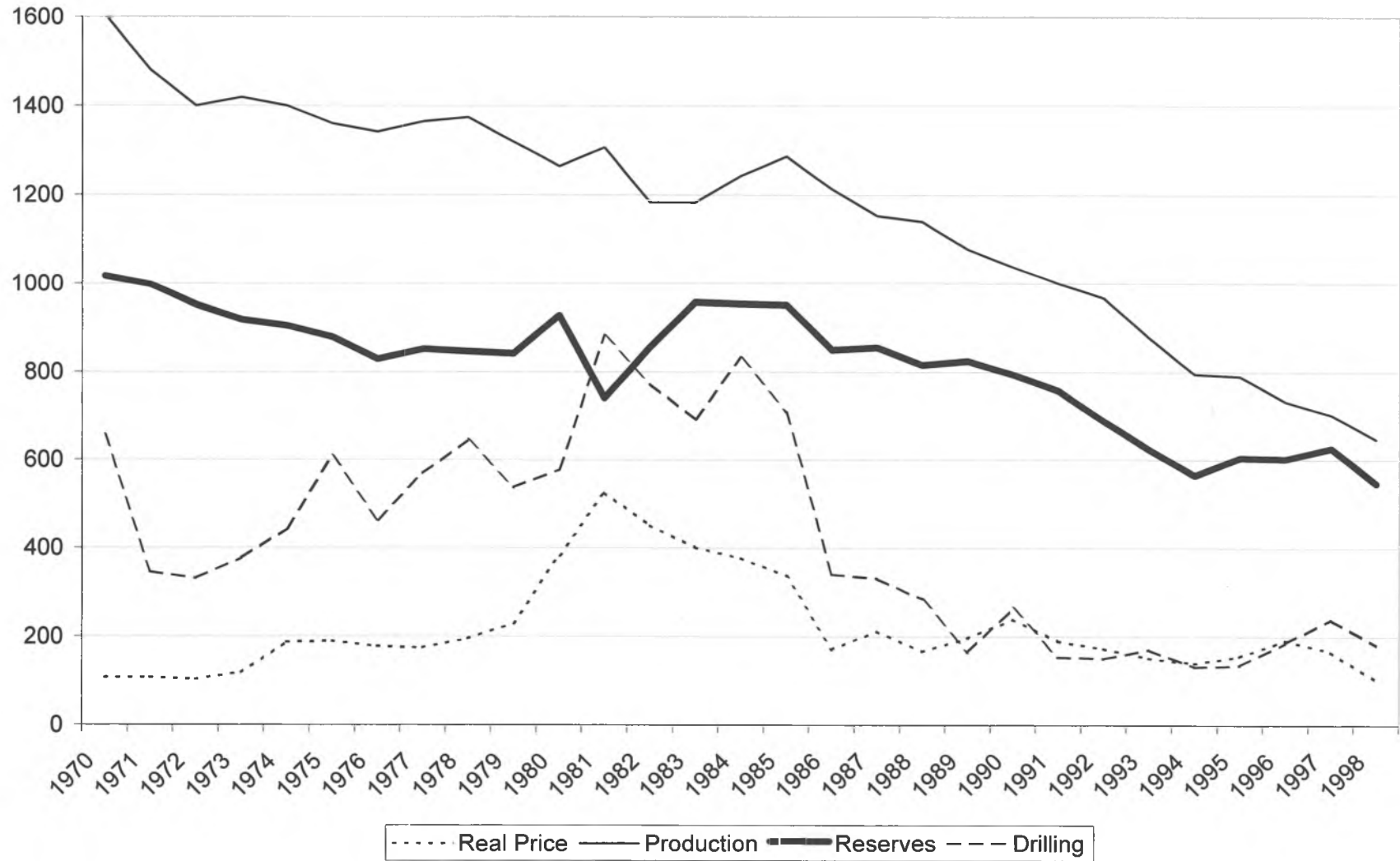


Figure 2. Wyoming Drilling

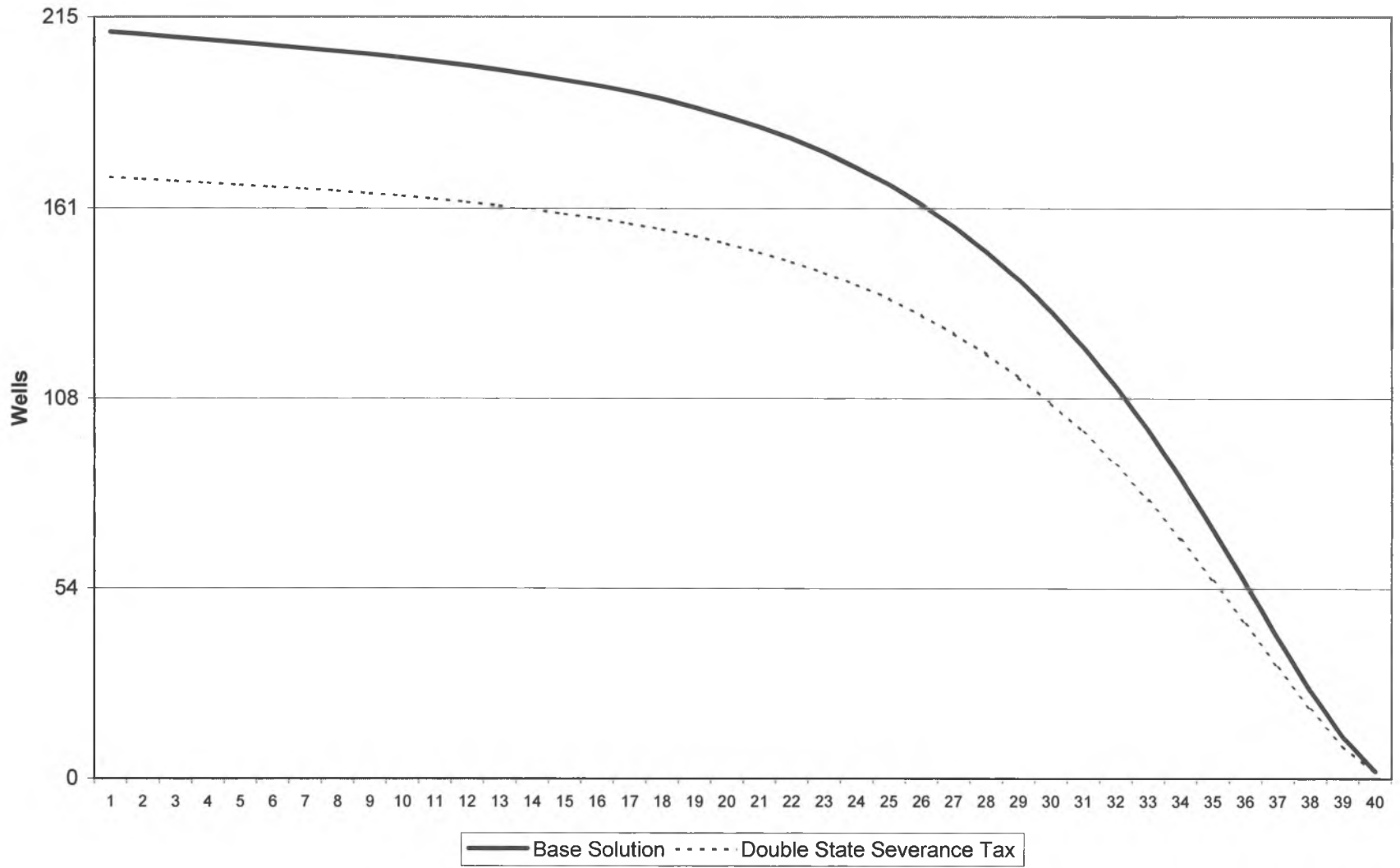
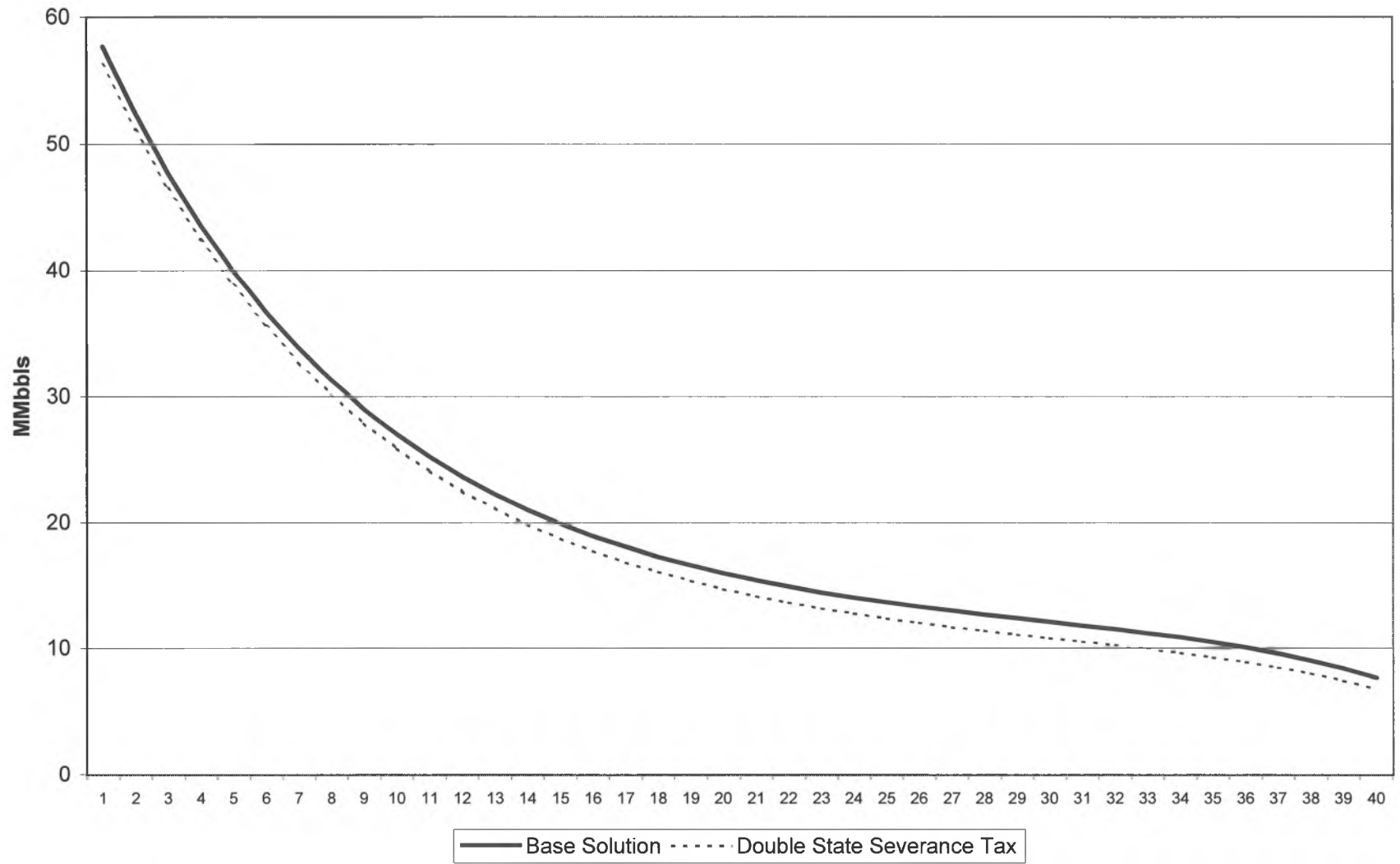


Figure 3. Wyoming Production



Appendix A

Tax Policy Parameters

For most states in most years, γ and α_j ($j=p,c,D$) can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating equations (A.1)-(A.4).

$$\gamma = \{(1 - \tau_{us})(1 - \tau_s)\tau_R\} \quad (\text{A.1})$$

$$\alpha_p = \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} \quad (\text{A.2})$$

$$\alpha_c = \{(1 - \tau_{us})(1 - \tau_s)\} \quad (\text{A.3})$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_s)\eta\} \quad (\text{A.4})$$

A derivation of equations (A.1)-(A.4) can be found in Gerking, Morgan, Kunce, and Kerkvliet (2000), Appendix C. In (A.1)-(A.4), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct

(tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well. In the illustration at hand, equations (A.1)-(A.4) can be simplified because Wyoming does not have a state corporate income tax ($\tau_s=0$) and does not levy a property tax against reserves in the ground ($\tau_R=0$).

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in text section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) or Deacon, DeCanio, Frech, and Johnson (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (A.1)-(A.4) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state (see Gerking, Morgan, Kuncze, and Kerkvliet 2000, Chapter 2). In developing the *base*

solution for Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9% for oil in the late 1990s. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the prior year's gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this one-year-lagged net value of production. The sum of the two average effective rates in the late 90's totaled approximately 11.9% (local 6.7% and state 5.2%). At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1997-1998) for the oil and gas sector show that federal corporate taxes paid averaged about 10% of *net operating* income in 1998. Also, the current nominal percentage depletion rate of 15% applied to about 58% of Wyoming oil producers in 1998, thus $\delta = 8.7\%$. Also, the expensed portion of current period drilling costs is approximately 40% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r+(q/R))$, assuming that the ratio of production to reserves is constant (Deacon 1993). Wyoming's mean value of q/R was approximately 8% for the sample period 1996-1998, therefore $\eta = 0.40 + (1 - 0.4)*(0.08 / (0.04 + 0.08)) = 0.8$. The base tax policy parameters for Wyoming are $\alpha_p = 0.73$, $\alpha_c = 0.90$, $\alpha_D = 0.72$, $\gamma = 0$.

Estimate of an Instrument for WELLS

An instrument for the natural logarithm of *WELLS* was used as an explanatory variable in estimating both text equations (5) and (6) with *CWELLS* entering equation (6) as the proxy for x . Instrumental variable estimation is appropriate because w is an endogenous variable in the model presented in Section 2. An instrument for w was

obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table A.1. Time-specific effects tested insignificant at conventional levels and $R^2 = 0.91$. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2*, *CWELLS2*, and *PRICE*CWELLS* were included to account for non-linearities expected in light of relationships in the model (see Table 1 for descriptions). All estimated coefficients are significantly different from zero except the interaction term *PRICE*CWELLS*. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of $\ln(WELLS)$ and the corresponding predicted values, $\ln(PREDWELLS)$, is 0.96.

Table A.1
Construction of Instrument $\ln(PREDWELLS)$

<u><i>Explanatory Variable</i></u>	<u><i>Coefficient</i></u> <u>(t-statistic)</u>
<i>PRICE</i>	0.064 (6.49)
<i>PRICE2</i>	-0.45E-3 (-2.90)
<i>CWELLS</i>	-0.22E-4 (-5.19)
<i>CWELLS2</i>	0.15E-10 (4.17)
<i>PRICE*CWELLS</i>	0.18E-7 (1.51)

Extraction Cost Function

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA

for the period 1970-1998. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb-Douglas function,

$$C(q, R) = \kappa q^\varepsilon R^{1-\varepsilon}, \quad (\text{A.5})$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant value that drives the production cost modeled to an average level of *lifting costs* representative of the 1998 DOA/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Kunce, Gerking, and Morgan 2001 for specific calibration methods). Marginal extraction costs per barrel using 1998 data for 7 major producing states are: CA \$6.12, KS \$4.89, LA \$8.81, NM \$6.27, OK \$6.89, TX \$6.71, and WY \$6.43. The 1998 calibrated oil production cost parameters for Wyoming are $\varepsilon = 2.93$ and $\kappa = 141$.

Departments of Revenue and Law:

Sectional Review

CSSB 21(FIN)

28-GS1647\R.A

March 22, 2013

House Resources Committee

Main Provisions

- **Interest Rate for Delinquent Tax Payments and Refunds of Overpayments of Taxes**

- Decreased to 3% points above the annual rate charged by the 12th Federal Reserve District

- **Corporate Income Tax Credit for Qualified Oil and Gas Service Industry Expenditures**

- **Production Tax Rate**

- Establishes a 35% flat tax rate
- Repeals progressivity.

- **Tax Credits**

- Eliminates current 20% capital expenditure tax credit for North Slope after December 31, 2013.
- Increases tax credit for carried-forward annual losses to 35% for the North Slope after December 31, 2013.
- Establishes a \$5 per barrel of oil tax credit.

- **Gross Revenue Exclusion**

- Establishes 20 % exclusion from the gross value at the point of production for oil and gas produced from
 - 1) new units,
 - 2) new participating areas in existing units and,
 - 3) metered wells subject to demonstration by the producer of certain conditions to the Department of Natural Resources and the Department of Revenue.

- **Oil and Gas Competitiveness Review Board**

- **Hold Cook Inlet and Middle Earth harmless**

Sec. 4 – Interest Rate for Delinquent Taxes

- **Amends AS 43.05.225(1).**
- **Sets the interest rate at 3% points above the annual rate charged member banks for advances by the 12th Federal Reserve District compounded quarterly.**
 - Currently, the interest rate is the greater of either 5% points above the annual rate charged member banks for advances by the 12th Federal Reserve District OR the annual rate of 11% compounded quarterly.
- **Eliminates the 11% alternate annual rate.**
- **Applies to many tax types.**
- **Applies against the State for refunds of overpayments of taxes.**
- **12 % interest rate under AS 43.05.225(2) is unchanged.**

Sec. 7 - Qualified Oil and Gas Industry Service Expenditure Tax Credit

- **Amends AS 43.20, the Alaska Net Income Tax Act, by adding a new section, AS 43.20.049.**
- **Provides a tax credit for the lesser of 10 % of qualified oil and gas industry service expenditures incurred in the state or \$10,000,000.**
- **Applies against tax liability, may be carried-forward for no more than 5 tax years after the expenditures were incurred.**
- **Qualified oil and gas service industry expenditure must be directly attributable to the in-state manufacture or modification of tangible personal property that has a useful life of 3 years or more used in the exploration, development, or production of oil or gas.**

Sec. 9 - Tax Rate

- **AS 43.55.011(e) is amended to levy an annual flat tax rate of 35%.**
- **AS 43.55.011(g), the monthly progressivity tax, is repealed.**
- **Applies to oil and gas produced after December 31, 2013.**

Sec. 2- Community Revenue Sharing Fund

- Amends AS 29.60.850(b) to eliminate the reference to AS 43.55.011(g), progressivity, to conform to the repeal of progressivity.**
- Provides guidelines for the amount the legislature may appropriate to the community revenue sharing fund.**
- No change to the eligibility determinations for community revenue sharing payments to communities.**

Sec. 15 - Qualified Capital Expenditure Tax Credit

- **AS 43.55.023(a)(3) is a new provision limiting the 20% qualified capital expenditure tax credit for expenditures incurred to explore for, develop, or produce oil and gas deposits on the North Slope to expenditures incurred before January 1, 2014.**
- **Tax credits for expenditures incurred to explore for, develop, or produce oil and gas deposits south of the North Slope are not impacted.**
- **The full amount of a tax credit certificate may be issued in a single year.**

16
Sec. ~~9~~ - Carried-Forward Tax Credit
AS 43.55.023(b)

- Amends AS 43.55.023(b) to retain a tax credit of 25% for a carried-forward annual loss for adjusted lease expenditures incurred outside of the North Slope.
- Provides a tax credit of 35% for a carried-forward annual loss for adjusted lease expenditures incurred after December 31, 2013 on the North Slope.
- A carried forward annual loss is the amount of a producer's or explorer's lease adjusted lease expenditures that were not deductible in calculating the annual production tax values for that year.

Sec. 22 - \$5 Per Oil Barrel Tax Credit

AS 43.55.024(i)

- **Amends AS 43.55.024 by adding a new a tax credit of \$5 for each barrel of oil subject to tax under AS 43.55.011(e)**
- **Applicable to the producer's tax liability for the year the oil was produced.**
- **The tax credit is not transferable.**
- **Any unused portion may not be carried forward for use in a later calendar year**
- **May not be applied to reduce the producer's tax liability to below zero.**

Sec. 29 - Gross Revenue Exclusion for North Slope Oil and Gas

- **Provides that for the determination of the annual production tax value of oil and gas produced north of 68 degrees North latitude, that the gross value at the point of production is reduced by 20 percent for the oil or gas:**
 - 1) **Produced from a lease or property that does not contain a lease that was within a unit as of January 1, 2003;**
 - 2) **Produced from a participating area established after December 31, 2011 that was within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir previously established in a participating area;**

Sec. 29 - Gross Revenue Exclusion for North Slope Oil and Gas

3) Produced from a well that

- has been accurately metered and measured by the operator to the satisfaction of the Commissioner of the Department of Revenue, and
 - the producer demonstrates to the Department of Revenue that the well is producing from a reservoir that the Department of Natural Resources has certified was not contributing to production before January 1, 2013, and
 - the producer demonstrates to the Department of Revenue the volume of oil or gas produced from that well.
- **May not apply 20 percent exclusion to reduce the gross value at the point of production below zero.**
 - **Participating area defined a reservoir or portion of a reservoir producing or contributing to production as approved by the Department of Natural Resources.**

Sec. 33 - Oil and Gas Competitiveness Review Board

AS 43.98.040-070

- **AS 43.98.040 , establishes a 9 member board**
 - Governor designates chair every 2 years. Governor may replace and remove members.
 - Members serve 6 year terms, may be reappointed.
 - Board meets once a year
- **AS 43.98.050 details the duties of the Board, including annual written findings and recommendations to the Legislature**
- **AS 43.98.060 relates to information provided to the Board**
- **AS 43.98.070 defines the board**
- **The Board sunsets December 31, 2022.**

GROSS REVENUE EXCLUSION

House Resources Committee

March 22, 2013

Department of Natural Resources

- Joe Balash, Deputy Commissioner



HOW DOES PRODUCTION QUALIFY FOR THE GRE?

- **Three ways to qualify:**
 1. Production from a Unit formed after 2003
 - Nikaitchuq Unit, Oooguruk Unit
 2. Production from a PA formed after 2012 which is in a unit formed prior to 2003
 - New PA at Prudhoe Bay
 3. Production from a portion of a reservoir in any existing PA that has been shown to DNR as not previously contributing to production from that PA.
 - Kuparuk River Unit, Kuparuk PA, Shark's Tooth

WHAT *is* a PARTICIPATING AREA (PA)?

**A set of tracts within a Unit, overlying a reservoir
which is on sustained production**

- North Slope: 18 State Units, 38 PAs
- A unit may have multiple reservoirs at different depths – each PA is defined vertically as well as horizontally
- Leases approved for inclusion into a PA may not be severed
- PA provides mechanism to allocate costs and revenues

Regulations

- 11 AAC 83.351 PA Formation, Expansion, Contraction
- 11 AAC 83.343 Plans of Development
- 11 AAC 83.371 Allocation of Production and Costs
- 11 AAC 83.303 Protect all parties

NORTH SLOPE PAS

Nikaitchuq

2011 Nikaitchuq
Schrader Bluff

Oooguruk

2008 Oooguruk Kuparuk
2008 Oooguruk Nuiqsut
2010 Oooguruk Torok

Northstar

2001 Northstar
2008 Northstar Fido
(pending)

Colville

2000 Alpine
2006 F Kuparuk
2006 Nanuq Kuparuk
2006 F Nechelik
2006 Nanuq Nanuq
2008 Quannik

Badami

1998 Badami Sands

1977

1980

1985

1990

1995

2000

2005

2010

Duck Island

1987 Endicott
1989 Sag Delta North

1998 Eider

Milne Point

1985 Kuparuk 1991 Schrader Bluff

2005 Sag River

KRU

1981 Kuparuk

2000 Aurora
1998 Tarn
1998 Tabasco
1997 West Sak
2001 Meltwater

2008 KRU News

1998 Midnight Sun

1999 Polaris

Prudhoe

1977 IPA Oil
Rim/Gas Cap

1983 Lisburne

1993 Pt McIntyre

1993 West Beach

1993 N Prudhoe Bay

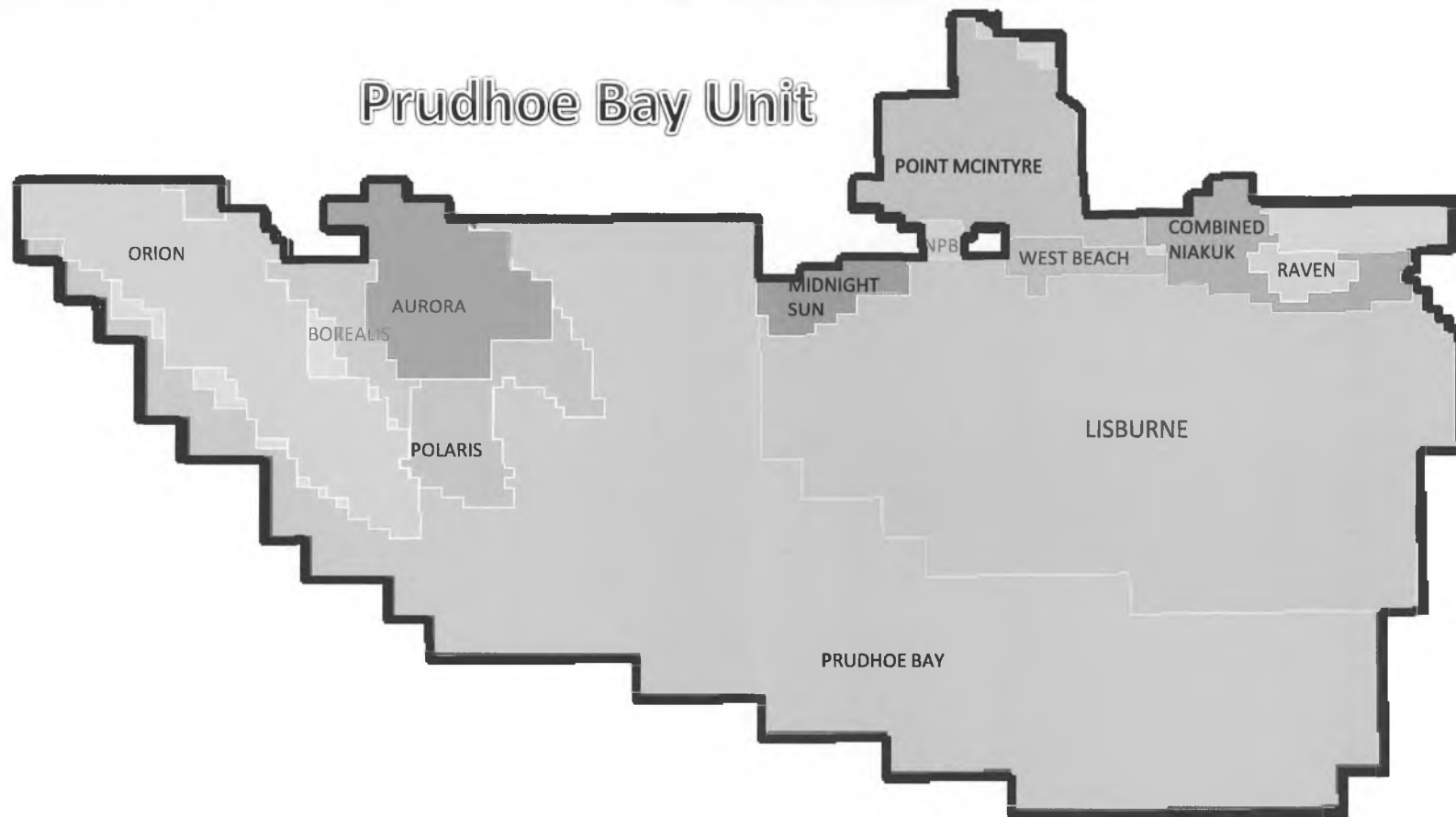
1994 Combined Niakuk

2001 Borealis

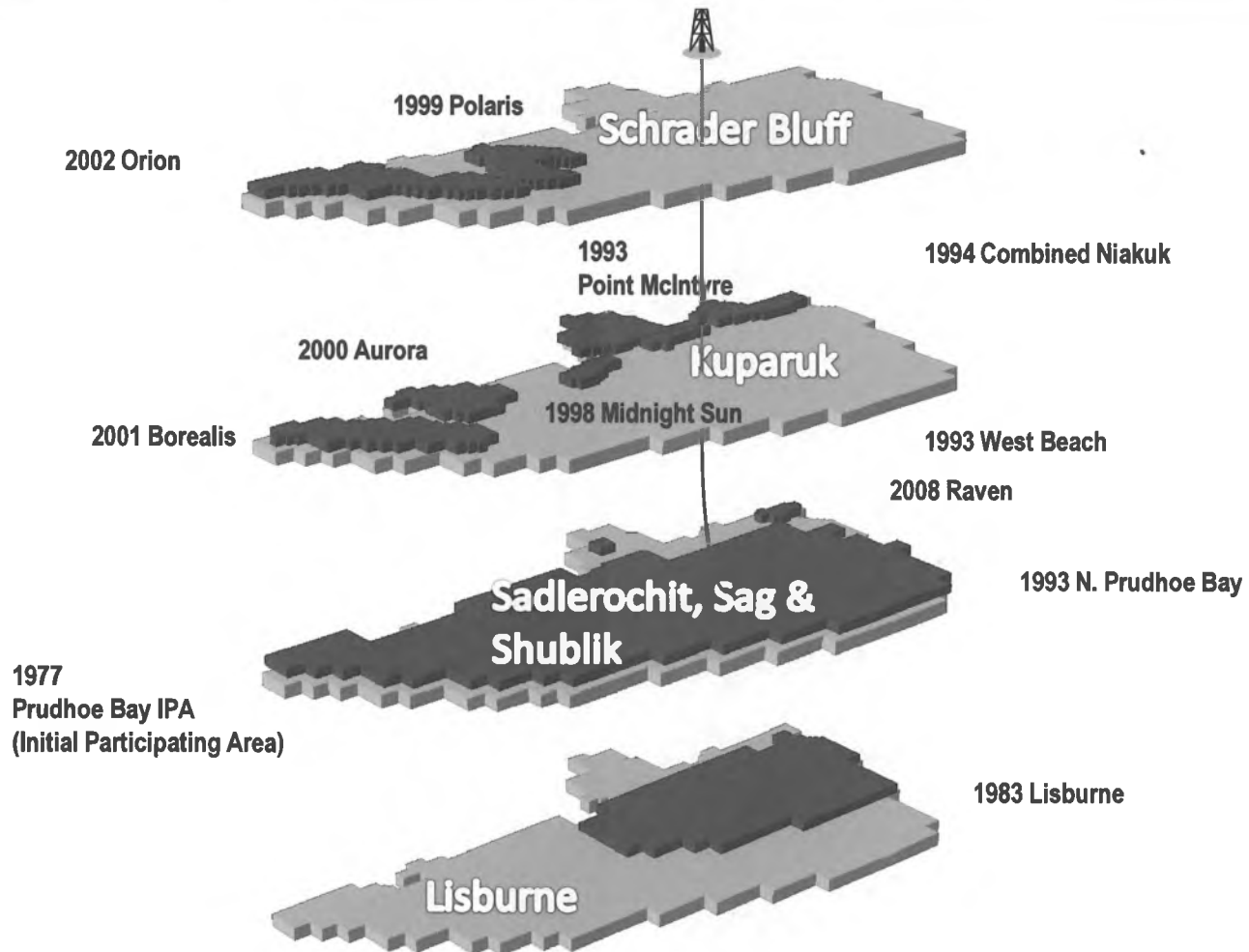
2002 Orion

2008 Raven

PRUDHOE BAY UNIT



PRUDHOE BAY UNIT



EVALUATION *and* APPROVAL of PAS

11 AAC 83.351: PA Formation, Expansion, Contraction

- PA may include only the land capable of producing or contributing to production of hydrocarbons in paying quantities
- PA must be contracted to exclude acreage incapable of contributing to production of hydrocarbons in paying quantities

11 AAC 83.303 Criteria

- Promote conservation
- Prevent waste
- Protect all parties

EVALUATION *and* APPROVAL of PAS

PA application has no regulatory deadline as with unit applications

- **Operator submits application no later than 90 days prior to sustained production**
- **Submittal includes Exhibits C and D, legal description with allocation factors, and map**
 - Allocation factors allocate production to each tract
- **Must include Exhibits E and F if Net Profit Share (NPS) leases included**
 - NPS leases require accounting of costs and revenues to determine “pay out”. Exhibits E and F provides methodology and basis for cost allocation, used by Royalty Accounting and Audit

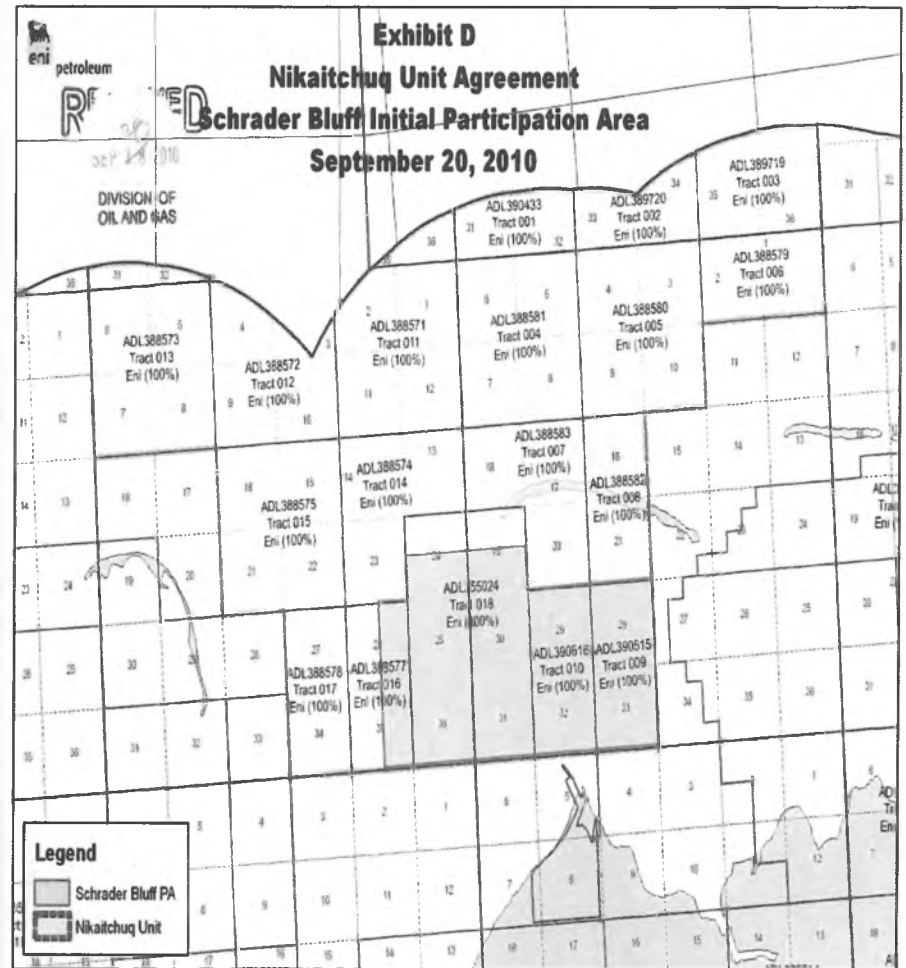
PA EXHIBITS C and D

NIKAITCHUQ UNIT AGREEMENT: Exhibit C SCHRADER BLUFF PARTICIPATING AREA Nikaitchuq Unit Area

September 20, 2010

Lease No. / Unit Tract Number	Lessors / Royalty Donee / Lease Serial No.	Unit Area / Borehole / Participating Area	Regulatory / Rules	OPR Owners	Operating Rights / Interest	Working Interest / Current Percentage Working Interest	Unit/Tract Production / Basis of Surface Area
9 300915 TYN, R.E.E., UMIAT MERIDIAN Sec. 29 Porcupine, A1 Sec. 33 Porcupine, A1		64-030	0-1807	GM Exploration North Saskatchewan Company, LLC	1-1333	En 100%	20.15%
		56-233		GM Exploration John V. Sommer Edgar Mer Jeffrey A. Lytle Parce M. Head Matthew K. Furr Stuart W. Gaultier Dexter E. Pire	2-2097 0-22-07 0-22-07 0-22-07 0-22-07 0-22-07 0-22-07		
10 300916 TYN, R.E.E., UMIAT MERIDIAN Sec. 29 Porcupine, A1 Sec. 33 Porcupine, A1		64-030	0-1807	GM Exploration North Saskatchewan Company, LLC	1-1333	En 100%	20.15%
		56-233		GM Exploration John V. Sommer Edgar Mer Jeffrey A. Lytle Parce M. Head Matthew K. Furr Stuart W. Gaultier Dexter E. Pire	2-2097 0-22-07 0-22-07 0-22-07 0-22-07 0-22-07 0-22-07		
11 388577 TYN, R.E.E., UMIAT MERIDIAN Sec. 28 Porcupine, E1 and Subsequent Areas, E2 Sec. 33 Porcupine, E1 and Subsequent Areas, E2		32-002	0-1507	Cinco Petroleum	4-2074	En 100%	10.26%
		38-002			4-2074		
12 33-263 TYN, R.E.E., UMIAT MERIDIAN Segment 2 Sec. 24 Porcupine, S2 Sec. 25 Porcupine, A1 Sec. 33 Porcupine, A1 TYN, R.E.E., UMIAT MERIDIAN Sec. 19 Porcupine, S2 Sec. 33 Porcupine, A1 Sec. 31 Porcupine, A1		32-000	0-1500	Cinco Petroleum	3-1674	En 100%	49.62%
		64-030	30% OPS	BP	2-2574		
		64-030	Each	Each	4-2074		
		308-000	0-1500	0-1500	4-2074		
		338-000	0-1500	0-1500	4-2074		
		338-000	0-1500	0-1500	4-2074		
		338-000	0-1500	0-1500	4-2074		
		338-000	0-1500	0-1500	4-2074		
		338-000	0-1500	0-1500	4-2074		
		338-000	0-1500	0-1500	4-2074		
Total State Land		616-030					
Total BLP Land		0-000					
Total Unleased Land		6-351-50					

RECEIVED
SEP 28 2010
DIVISION OF OIL AND GAS



PA PLAN *of* DEVELOPMENT

- **Once development activities commence and/or a PA is formed, A Plan Of Development (POD) is required under 11 AAC 83.343**
 - Describes plans to develop the reservoir
 - Development activities: facilities, pipelines, offshore production islands, gathering lines, and permanent drill sites.
 - POD is submitted annually for review and approval
 - If POD deemed insufficient for approval, DNR may propose modifications. If Operator agrees to modification, POD approved
 - If modifications not accepted by Operator and reviewed POD not approved, current POD may expire.

TRACT ALLOCATION FACTORS

11 AAC 83.371

- **Approval of PA includes approval of Allocation Factors (Tract Factors, or TF) to protect all parties**
 - Exhibit C designates each PA tract a TF
 - Bases for calculating TF proscribed in Operating Agreement sometimes Unit Agreement or approval decision
 - Acreage
 - Original Oil in Place (OOIP)
 - Recoverable
 - Value Based
- **Working Interest Owners receive revenue based on TF**
 - Equity negotiations
- **State of Alaska receives royalties based on TF**
 - Commercial interest evaluation

REVISIONS *to* DIVISION *of* INTEREST: REALLOCATIONS

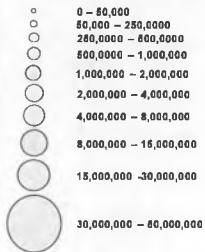
- **Production is reallocated**
 - As PA expands of contracts
 - Development wells identified and committed to in Plan of Development
 - Expansion of Milne Point Unit Sag River PA
 - Contraction of Milne Point Unit Sag River PA
 - As basis for allocation changes
 - Field matures, more technical information gathered and evaluated, production is reallocated
 - Revised Exhibit C designates each PA tract a TF
 - Bases for calculating TF proscribed in Operating Agreement sometimes Unit Agreement or approval decision
 - Acreage, OOIP, Recoverable, Value Based
 - Resource Evaluation, Commercial, Royalty Accounting, Audit Sections
 - Evaluation of protection of State's Interest
 - Protection of all parties

KUPARUK RIVER UNIT (KRU)

KRU Boundary

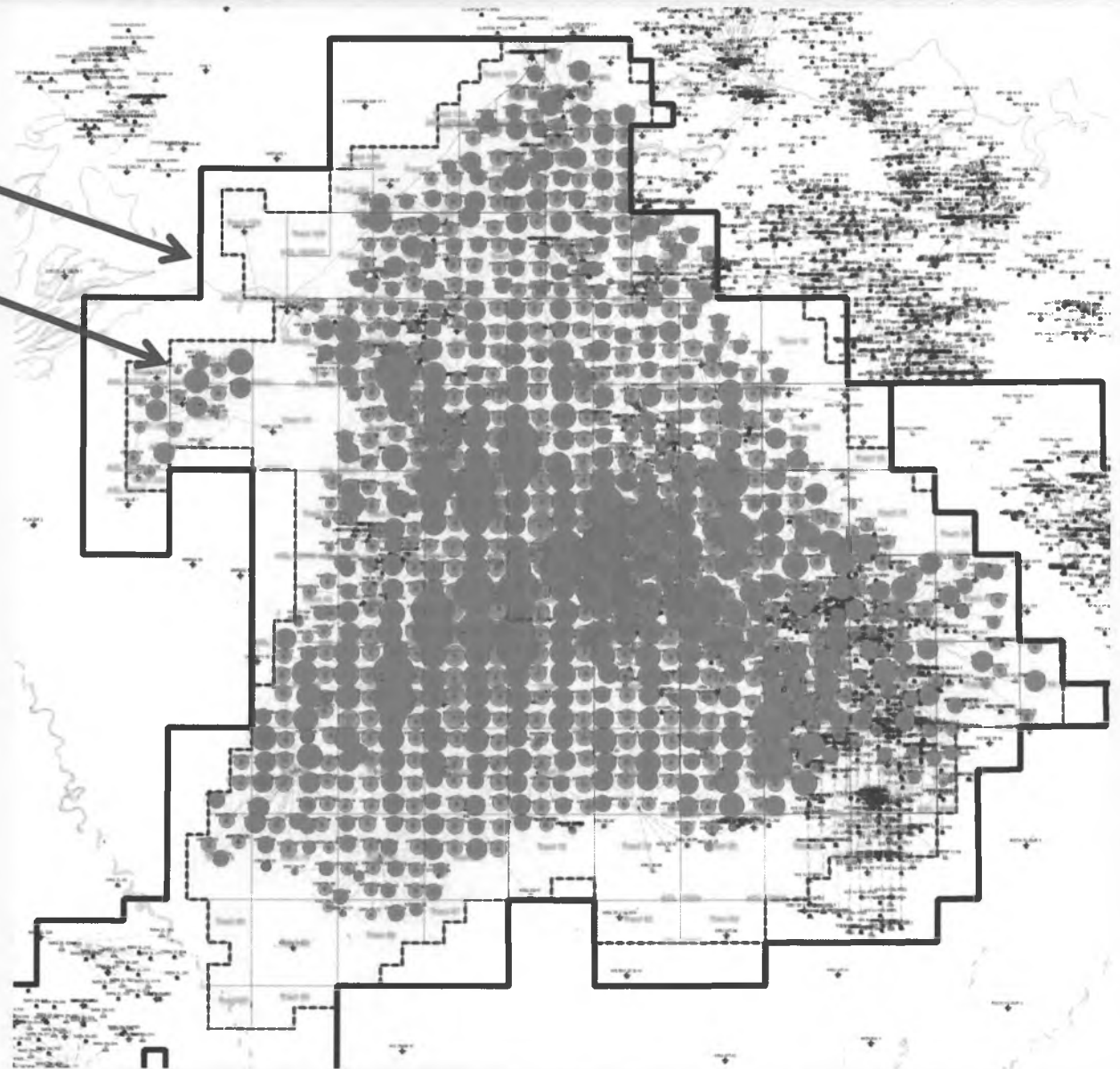
Kuparuk PA Boundary

Cumulative Barrels (KPA)



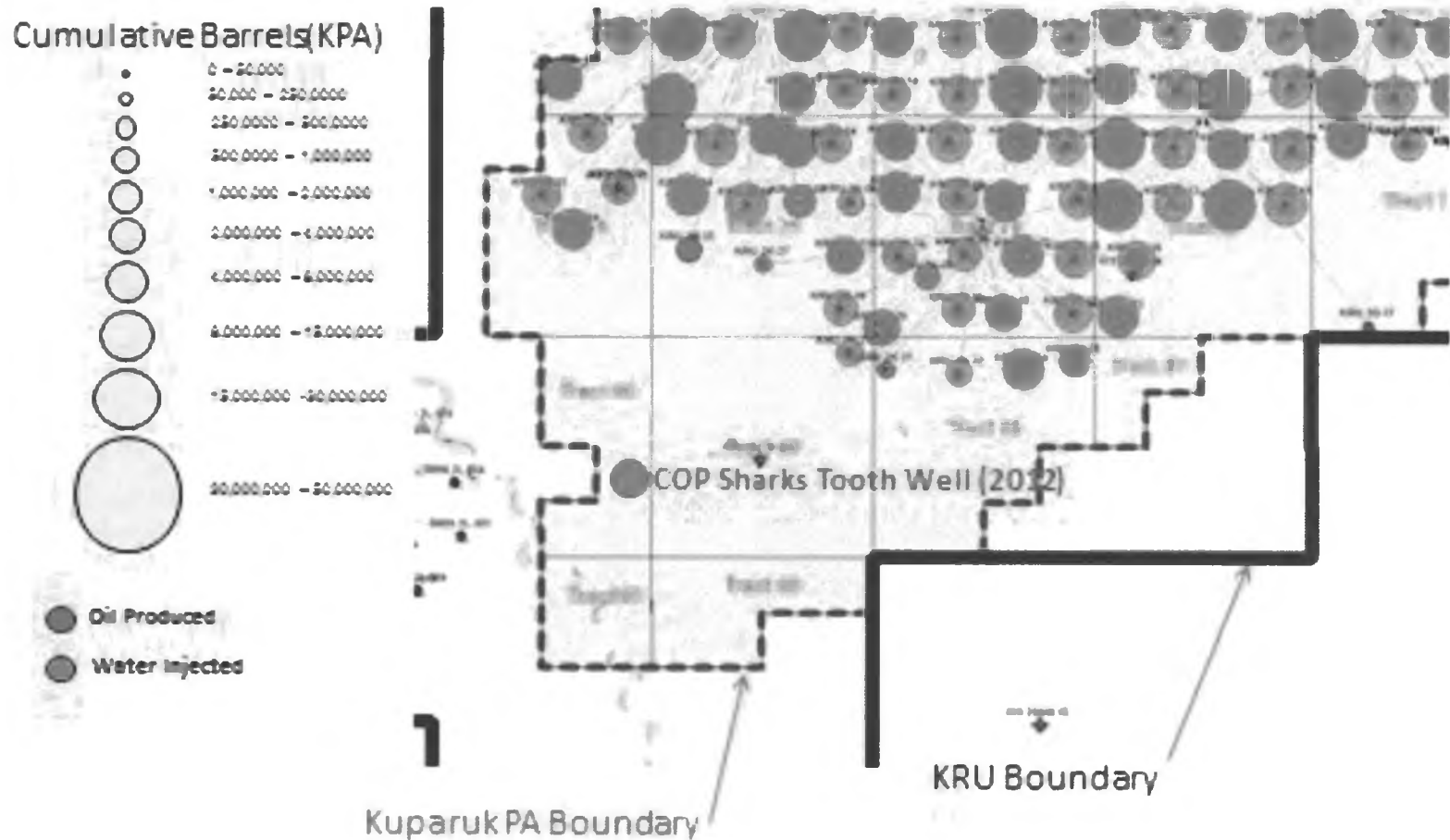
● Oil Produced

● Water Injected



KUPARUK RIVER UNIT (KRU)

Southwest Portion Kuparuk River Unit (KRU)



QUESTIONS?

Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: SB 21
Fiscal Note Number: _____
() Publish Date: _____

Identifier: SB021CS(FIN)amS-DOR-TAX-03-21-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: H Resources

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)

	FY2014	Included in	Out-Year Cost Estimates				
	Appropriation Requested	Governor's FY2014 Request	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
OPERATING EXPENDITURES	FY 2014	FY 2014					
Personal Services							
Travel							
Services	100.0						
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	100.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

1004 Gen Fund	100.0						
Total	100.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

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

Estimated SUPPLEMENTAL (FY2013) cost: 0.0

Estimated CAPITAL (FY2014) cost: 0.0

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? 01/01/14

Why this fiscal note differs from previous version:

This version updates the fiscal note for the bill that passed the Senate.

Prepared By: Cherie Nienhuis, Ed King and Dan Stickel
Division: Tax Division
Approved By: Bryan D. Butcher, Commissioner
Department of Revenue

Phone: (907)269-1019
Date: 03/21/2013 01:00 PM
Date: 03/21/13

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. CSSB 21(FIN) am S

Analysis

Operating expenditures: This bill makes changes to the tax credits under the production tax system. For leases or properties that contain land that is north of 68 degrees North latitude, the following changes are made: (1) Credits for qualified capital expenditures are limited to expenditures incurred before January 1, 2014; (2) Beginning January 1, 2014, the rate for credits earned for net operating losses increases to 35% of the loss. The operating portion of the long-term fiscal plan anticipates an average of \$400 million in refundable credits through 2023. It is anticipated that the changes in this bill would impact those future appropriations, beginning in FY 2015.

The change to the interest rate for delinquent taxes is expected to require changes to the department's tax accounting systems to accommodate the changes. It is estimated that this change will require a one-time appropriation of \$100,000 in FY14 for contractor costs.

Regulations: The bill does not direct DOR to adopt new regulations to implement its provisions, but existing regulations may need to be amended to conform to changes in eligibility for redeemable tax credits, and to account for repeal of some sections. There may be additional regulations required, but not before January 1, 2014.

*****The revenue impact of this bill is an estimate based on the Fall 2012 Forecast.**

This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed separately below. The effective date of each of the bill's provisions listed below is January 1, 2014, with the exception of provision 6, which is effective for expenditures beginning January 1, 2013.

1. The progressive portion of the production tax at AS 43.55.011(g) is repealed. Based on our Fall 2012 forecast, this change decreases production tax revenue over the forecast period analyzed. Please see detailed summary table on page 4 of this fiscal note.

2. The production tax rate under AS 43.55.011(e) has been increased to a tax rate of 35% of production tax value. Based on our Fall 2012 forecast, this change increases production tax revenue over the forecast period analyzed from this portion of the tax. Please see detailed summary table on page 4 of this fiscal note.

3. Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 on leases or properties that contain land north of 68 degrees North latitude. Based on our Fall 2012 forecast, this change increases production tax revenue annually over the forecast period analyzed. Please see detailed summary table on page 4 of this fiscal note.

4. Companies that incur net losses from leases or properties that contain land north of 68 degrees North latitude will earn a credit of 35% of those losses. These losses are transferable and eligible for refund by the state. The impact of this provision is on the operating budget and is expected to increase credit refunds appropriated through the operating budget by approximately \$40 million per year over the amount anticipated under current law.

5. A gross revenue exclusion (GRE) of 20% of the gross value at the point of production is applicable to production from certain areas. The GRE applies to oil or gas production from wells north of 68 degrees North Latitude that meet one or more of the following criteria: (1) is produced within a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) is produced within a participating area established after December 31, 2011, in a unit formed before January 1, 2003, if the participating area does not contain a reservoir that had been in a participating area established before December 31, 2011; or (3) is produced from a well that has been accurately metered and measured and the producer demonstrates to the department that the metered well drains a reservoir or portion of a reservoir that DNR has certified was not contributing to production before January 1, 2013. Please see detailed summary table on page 4 of this fiscal note for revenue impacts of this provision.

(Analysis continued on following pages)

Analysis Continued

6. The provision requiring that credits be taken over two years is eliminated. This provision would result in companies using credits earlier than they would without this change, and except for the time value of money impact, it is revenue neutral. This provision applies to expenditures after December 31, 2012.

7. The community revenue sharing fund is amended to allow the legislature to make an appropriation from any source as opposed to tying the appropriation to revenue collected under AS 43.55.011(g). This provision has no revenue impact under our Fall 2012 forecast.

8. A credit of \$5 per taxable barrel may be applied against a producer's production tax liability. The credit is not transferable, cannot be carried forward, and cannot reduce the producer's tax liability to less than zero. The credit is applicable statewide, but we expect that over the time horizon of this fiscal note, the revenue impact will be limited to the North Slope. Please see detailed summary table on page 4 of this fiscal note for the revenue impact of this provision.

9. A credit of 10% of qualified oil and gas industry service expenditures may be applied to tax liabilities under AS 43.20 in amounts up to \$10 million per taxpayer per year. The credit applies to qualified oil and gas service expenditures that are for in-state manufacture or in-state modification of oil and gas tangible personal property with a service life of 3 years or more. The credit is not transferable, however, any amount of the credit that exceeds the taxpayer's liability under AS 43.20 may be carried forward for up to five years. We have no data with which to quantify the revenue impact of this provision, although it is possible that the impact may be as high as -\$25 million per year. The revenue impact of this provision is indeterminate.

10. The interest rate on delinquent taxes is changed from the greater of 5 percentage points above the annual rate of interest charged by the 12th Federal Reserve District or 11 percent, to 3 percentage points above the annual rate of interest charged by the 12th Federal Reserve District. There will be one-time contractor costs to implement this change in our accounting system. Over the past five fiscal years (FY 2008-FY 2012), interest on delinquent taxes and refunds has resulted in a net positive revenue to the state. The average annual net revenue to the state in these years was \$26 million in revenue to the General Fund and \$71 million in revenue to the Constitutional Budget Reserve Fund. The Department of Revenue does not forecast interest on taxes. Over the time horizon of this fiscal note, this provision is estimated to impact state revenues in amounts up to -\$25 million per year. The impact will increase over time as more delinquent taxes are calculated under the new interest rates established with this provision. Our fiscal impact estimates do not take into account changes in taxpayer behavior as a result of this reduction in interest rate.

Analysis Continued

Provisions in CSSB21(FIN) am S and their Estimated Fiscal Impact as compared to Fall 2012 Forecast (\$millions)¹

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-\$800	-\$1,500	-\$1,700	-\$1,800	-\$1,750	-\$1,650
2. Base tax rate changed to 35% of production tax value	\$550	\$1,075	\$1,100	\$1,075	\$1,025	\$975
3. Limitation of credits for qualified capital expenditures for North Slope	\$300	\$700	\$650	\$550	\$475	\$400
4. Net operating loss credit rate increased to 35%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
	\$0 to	-\$25 to	-\$25 to	-\$50 to	-\$25 to	-\$50 to
5. Gross revenue exclusion for certain areas and certain new wells	-\$50	-\$175	-\$225	-\$250	-\$225	-\$250
6. Provision requiring credits be taken over 2 years eliminated ²	-\$250					
7. Amendment to the community revenue sharing fund	\$0	\$0	\$0	\$0	\$0	\$0
8. Allowance of \$5 per taxable barrel	-\$425	-\$825	-\$775	-\$750	-\$700	-\$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -\$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -\$25 million annually, increasing over time)					
	-\$625 to	-\$575 to	-\$750 to	-\$975 to	-\$975 to	-\$1000 to
Total Revenue Impact	-\$725	-\$775	-\$1000	-\$1225	-\$1225	-\$1250
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-\$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit	\$150					
Impact on Operating Budget of increase in Net Operating Loss credits	-\$40					
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production³	-\$775 to -\$875	-\$465 to -\$665	-\$640 to -\$890	-\$865 to -\$1115	-\$865 to -\$1115	-\$890 to -\$1140

¹The impacts listed are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between \$109.61 and \$118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is \$400 million, with \$250 million taken against tax liability as a revenue impact and \$150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

³NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. CSSB 21(FIN) am S

Analysis Continued

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

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

At Forecasted Production

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$75	\$325	\$250	\$75	-\$25	-\$25
\$100	-\$100	\$50	-\$50	-\$225	-\$300	-\$300
\$120	-\$625	-\$925	-\$975	-\$1,150	-\$1,175	-\$1,100

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

Additional Production Scenario A

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

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$75	\$325	\$250	\$100	\$0	\$0
\$100	-\$100	\$50	-\$50	-\$200	-\$275	-\$250
\$120	-\$625	-\$925	-\$975	-\$1,125	-\$1,150	-\$1,075

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

Additional Production Scenario B

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

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$100	\$450	\$475	\$400	\$475	\$400
\$100	-\$50	\$225	\$250	\$175	\$275	\$200
\$120	-\$550	-\$650	-\$575	-\$625	-\$450	-\$475

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be \$20 million. One half of this oil is assumed to qualify for the GRE under the provisions of this bill.

Additional Production Scenario C

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

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$0	\$300	\$425	\$500	\$1,075	\$975
\$100	-\$150	\$100	\$250	\$350	\$1,000	\$900
\$120	-\$625	-\$700	-\$475	-\$275	\$475	\$450

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of \$5 billion, all of which is assumed to qualify for the GRE. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new field.

Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: SB 21
Fiscal Note Number: _____
() Publish Date: _____

Identifier: SB021CS(FIN)amS-DNR-DOG-3-22-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Senate Finance

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

Expenditures/Revenues

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

	FY2014	Included in	Out-Year Cost Estimates				
	Appropriation Requested	Governor's FY2014 Request	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
OPERATING EXPENDITURES	FY 2014	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None							
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

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

Estimated SUPPLEMENTAL (FY2013) cost: 0.0

Estimated CAPITAL (FY2014) cost: 0.0

ASSOCIATED REGULATIONS

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

Why this fiscal note differs from previous version:

The committee substitute adopted by the Senate Finance Committee, which was amended on the Senate Floor. No changes were made that affect the Department of Natural Resources except for references to bill sections.

Prepared By: William C. Barron
Division: Oil and Gas
Approved By: Daniel S. Sullivan, Commissioner
Department of Natural Resources

Phone: (907)269-8800
Date: 03/21/2013 04:00 PM
Date: 03/22/13

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. CSSB21(FIN)amS

Analysis

CSSB21(FIN)amS reforms the oil and gas production tax system in Alaska. This bill will not result in any procedural changes in how the Division of Oil and Gas operates and therefore the Department of Natural Resources (DNR) does not anticipate any fiscal impact to the Department's operating budget.

CSSB21(FIN)amS proposes to improve Alaska's competitiveness and encourage producers to invest more by simplifying the oil and gas production tax system. First, this bill repeals the progressive tax structure, which will help encourage the type of long-term planning and investment needed to promote new investment in new production in Alaska. Further, this bill attempts to shift incentives away from spending and provides new incentives to reward new production.

Section 29 amends the gross revenue exclusion (GRE) from 30% of the gross value at the point of production to 20% of the gross value at the point of production for 10 years following the commencement of production from the well. The GRE applies to production from leases or properties containing land that is north of 68 degrees North latitude and meets one or more of the three criteria: (1) is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) is produced from a participating area established after December 31, 2011, in a unit formed before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before December 31, 2011; (3) is produced from a well that has been accurately metered and measured by the operator to the satisfaction of the commissioner, and the producer demonstrates to DNR that the well drains a reservoir or portion of a reservoir that DNR has certified was not contributing to production before January 1, 2013 and the producer demonstrates that the volume produced was subject to certification by DNR. This section also clarifies that the GRE may not reduce the gross value at the point of production below zero.

At forecasted price ranges, overall government take and marginal tax rates are reduced materially. To the extent that investments are made as a consequence of these changes to the tax regime, royalty revenue may rise. The fiscal impact on royalty revenue is an indeterminate positive.

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. CSSB21(FIN)amS

Analysis Continued

**Differences in Royalty Revenues from
New Production Scenarios in \$Millions***

*Note: These scenarios are based on Department of Revenue modeling.

At Forecasted Production							
	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	
\$	120	\$0	\$0	\$0	\$0	\$0	\$0
\$	100	\$0	\$0	\$0	\$0	\$0	\$0
\$	90	\$0	\$0	\$0	\$0	\$0	\$0

Additional Production Scenario A

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

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	
\$120	\$0	\$0	\$0	\$12	\$24	\$35	
\$100	\$0	\$0	\$0	\$10	\$20	\$29	
\$90	\$0	\$0	\$0	\$9	\$17	\$26	

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	
\$120	\$57	\$106	\$147	\$181	\$212	\$179	
\$100	\$47	\$87	\$120	\$148	\$173	\$146	
\$90	\$42	\$77	\$107	\$132	\$154	\$130	

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day and declining at a rate of 15% per year. Development costs for each well assumed to be \$20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	
\$120	\$111	\$213	\$307	\$433	\$557	\$533	
\$100	\$91	\$174	\$251	\$354	\$455	\$435	
\$90	\$81	\$155	\$223	\$314	\$404	\$386	

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of \$5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: CSSB 21(FIN)
Fiscal Note Number: 7
(S) Publish Date: 3/18/13

Identifier: SB021CS(FIN)-DOR-COMM-03-14-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Senate Resources

Department: Department of Revenue
Appropriation: Administration and Support
Allocation: Commissioner's Office
OMB Component Number: 123

Expenditures/Revenues

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

	FY2014	Included in	Out-Year Cost Estimates				
	Appropriation Requested	Governor's FY2014 Request	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
OPERATING EXPENDITURES	FY 2014	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Personal Services		157.8	157.8	157.8	157.8	157.8	157.8
Travel	4.6		4.6	4.6	4.6	4.6	4.6
Services							
Commodities	30.0		20.0	20.0	20.0	20.0	20.0
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	34.6	157.8	182.4	182.4	182.4	182.4	182.4

Fund Source (Operating Only)

1004 Gen Fund	34.6	157.8	182.4	182.4	182.4	182.4	182.4
Total	34.6	157.8	182.4	182.4	182.4	182.4	182.4

Positions

Full-time		1.0	1.0	1.0	1.0	1.0	1.0
Part-time							
Temporary							

Change in Revenues							

Estimated SUPPLEMENTAL (FY2013) cost: 0.0

Estimated CAPITAL (FY2014) cost: 0.0

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:

Senate Finance Committee Substitute added language requiring an updated fiscal note from Revenue.

Prepared By: Jerry Burnett, Director
Division: Administrative Services
Approved By: Bryan D. Butcher, Commissioner
Department of Revenue

Phone: (907)465-2312
Date: 03/14/2013 09:15 AM
Date: 03/14/13

FISCAL NOTE ANALYSIS #7

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. CSSB 21(FIN)

Analysis

The bill establishes a nine member Oil and Gas Competitiveness Review Board, in the Department of Revenue, which is charged with establishing and maintaining a salient collection of information related to oil and gas exploration, development, and production in the state and related to tax structures, rates, and credits in other regions with oil and gas resources; evaluating and suggesting changes to state laws and regulations reviewing historical, current, and potential levels of investment in the state's oil and gas sector; identifying factors that affect investment in oil and gas exploration, development, and production in the state, including tax structure, rates, and credits; royalty requirements; infrastructure; workforce availability; and regulatory requirements; reviewing the competitive position of the state to attract and maintain investment in the oil and gas sector in the state as compared to the competitive position of other regions with oil and gas resources. The Board is required to meet once per year to provide a report by December 1 of each year regarding means for increasing the state's ability to attract and maintain investment in, and development of, the state's oil and gas resources.

To accomplish these tasks the Department would use existing professional staff, primarily the Oil and Gas Program Coordinator currently in the Commissioner's Office, and funding to provide board meeting and travel, space and overhead costs associated with the data room.

The fiscal note assumes one board meeting per year.