NEW SUSTAINABLE
ALASKA
PLAN
Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform- HB247

Department of Revenue

"Additional Modeling and Scenario Analysis - Part 1a"

Presentation to the House Resources Committee

February 22-24, 2016

What We'll Be Discussing

- Overview of Revenue and Production
- Credits- what worked, what didn't?
- Credit cost in perspective
- Bill Details- how pieces work
- Scenario Analysis- economics of changes
  - Project NPV for both producer and state
  - Total gov't take
- Gas supply issues in Cook Inlet

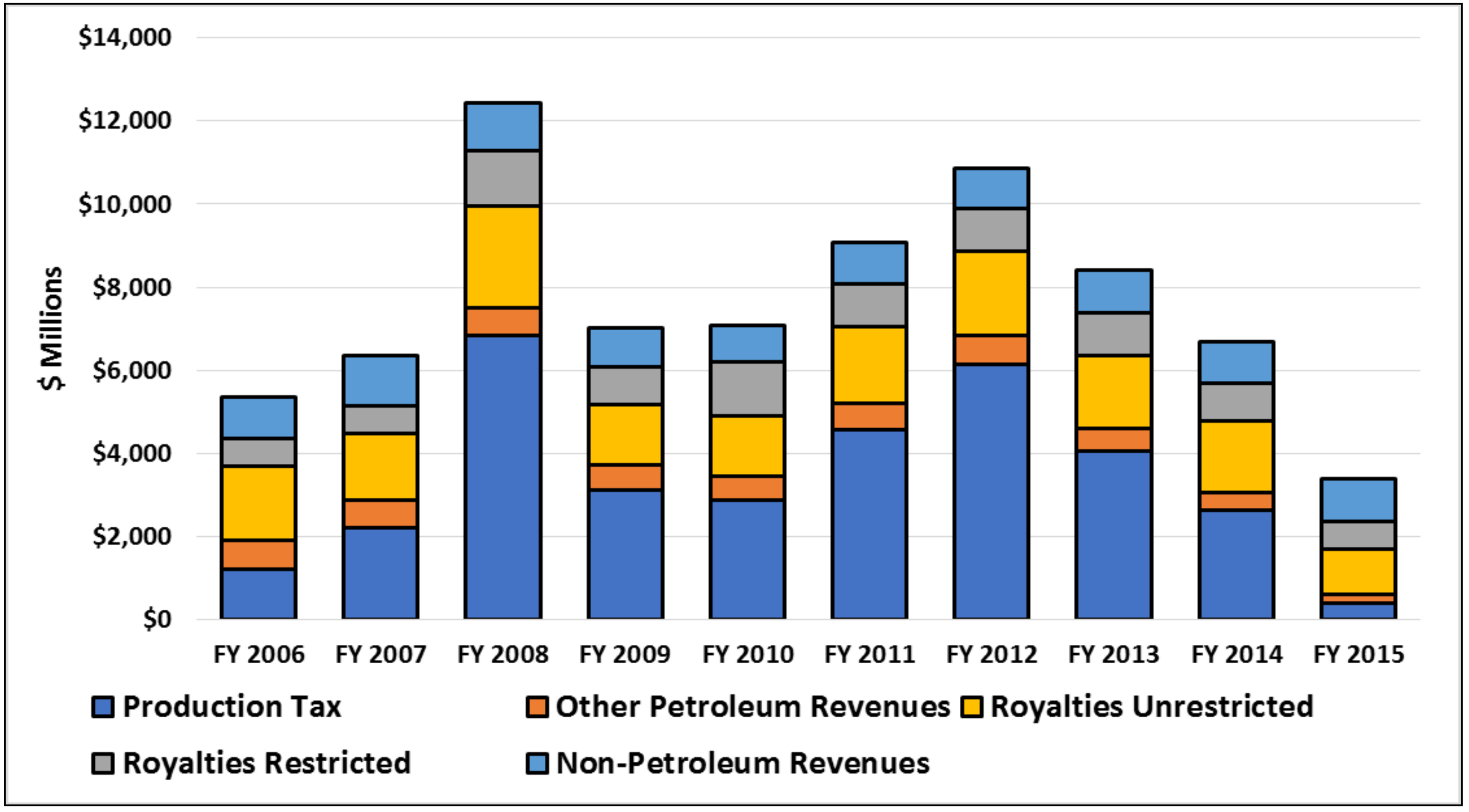
Overview of Revenue and Production

Overview of Revenue and Production

Impact of Petroleum on State Revenues FY 2006-2015

Total State Revenues excluding Federal and Investment

- Production taxes accounted for 17% of petroleum revenues in FY 2015, down from 62% in FY 2012



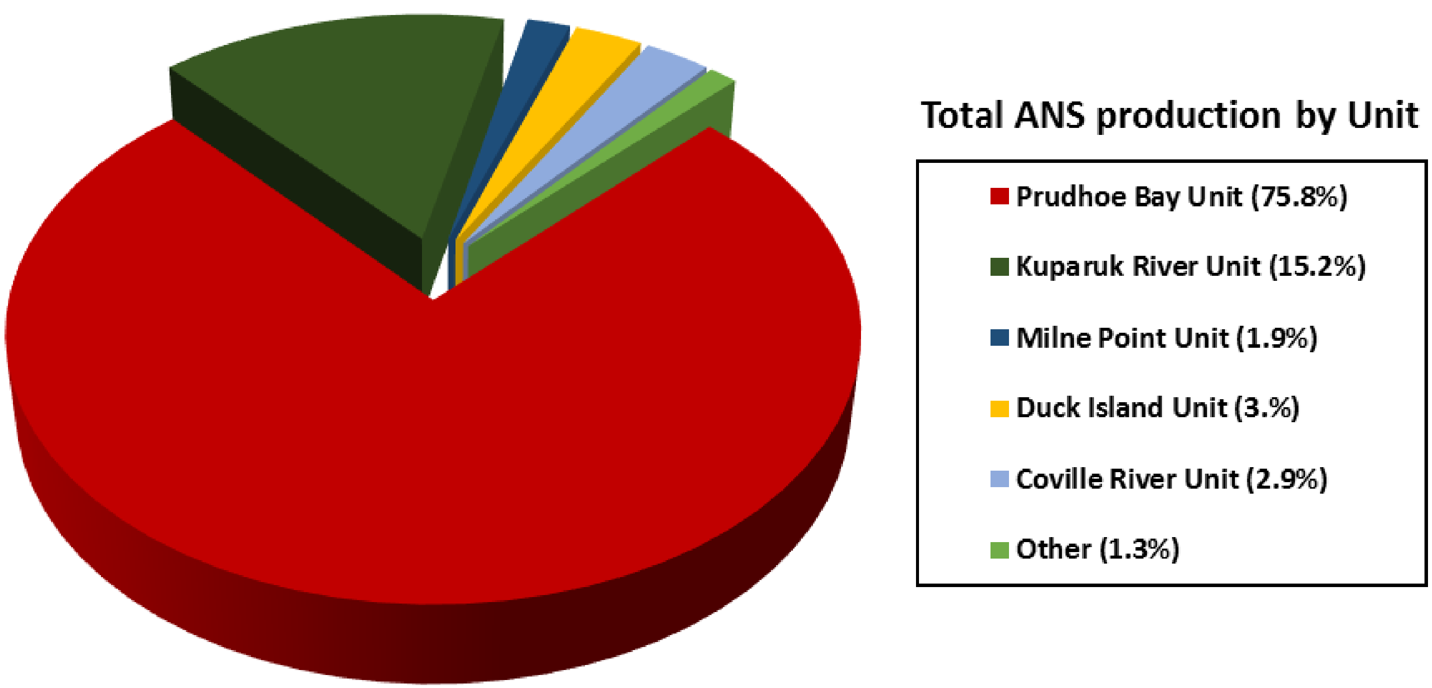
Source: Fall 2015 Revenue Sources Book Back-up

Overview of Revenue and Production

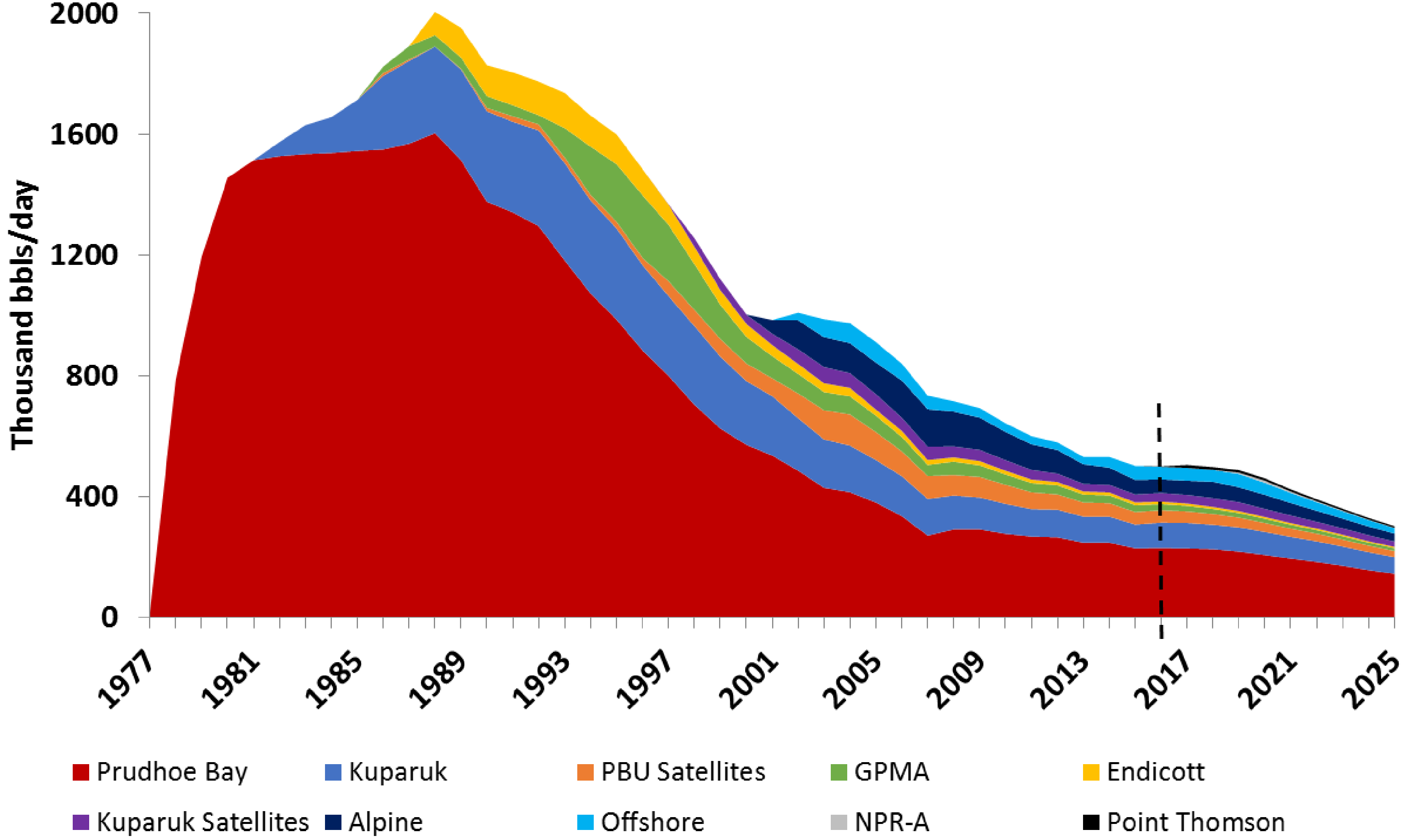
The North Slope has produced approximately 17 billion barrels of crude oil since 1977

The vast majority has come from two giant “legacy” fields: Prudhoe Bay and Kuparuk (both discovered in the 1960s).

- Production from these two fields is naturally declining over time, though the decline has been partially offset by the addition of smaller discoveries and infield work.



Overview of Revenue and Production

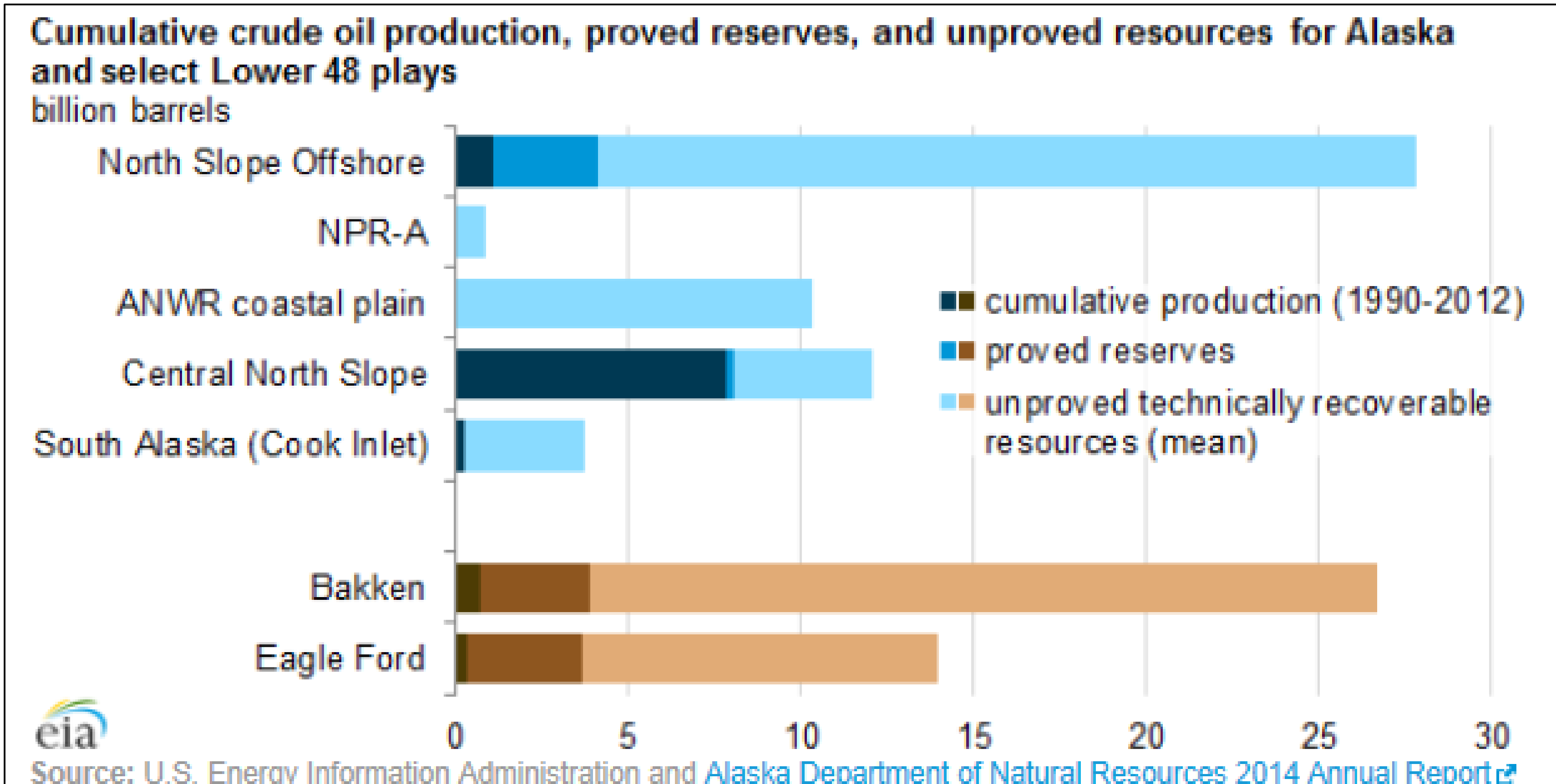


Source: Fall 2015 Revenue Sources Book, Figure 4-D

Note: Offshore includes Northstar, Oooguruk, and Nikaitchuq

Overview of Revenue and Production

Many North Slope fields are now at mature stages. However, there is still a lot of untapped potential for new development, especially offshore.

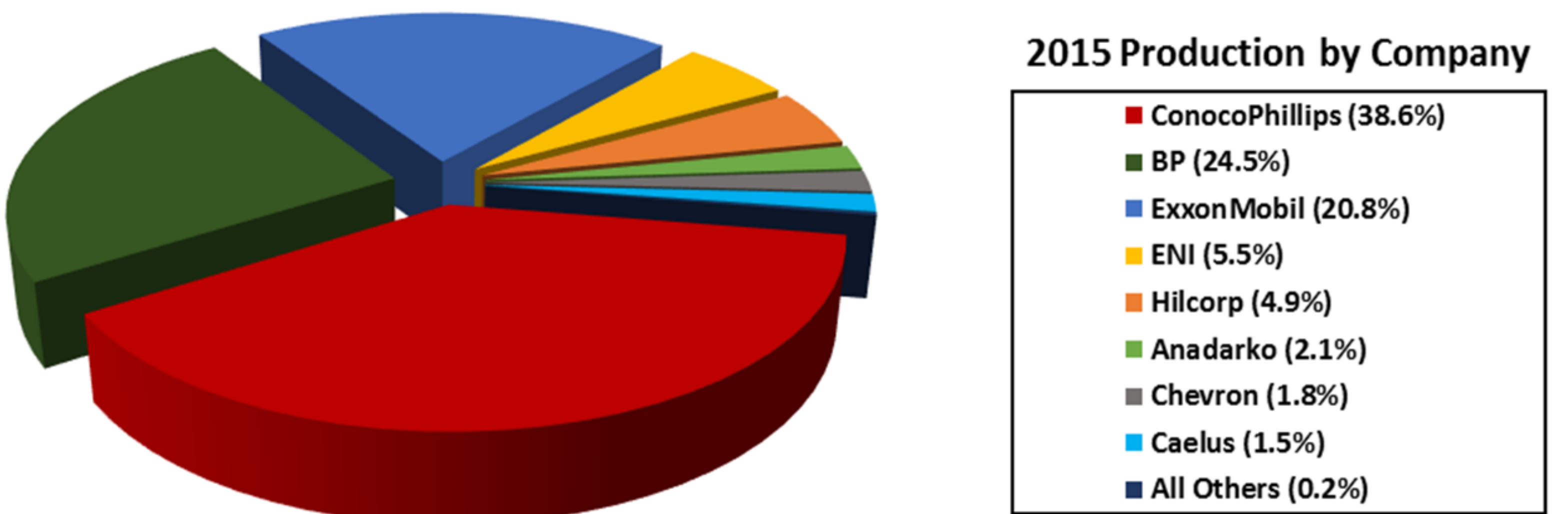


Note- this graph only shows production since 1990. North Slope produced about 7.1 billion and Cook Inlet 1.1 billion prior to that date.

Overview of Revenue and Production

Three large producers account for most of the state's current production. However, in recent years, Alaska has attracted a number of new participants, with several developing and operating fields of their own.

The Majors	Other Producers	Explorers
BP	Chevron	Brooks Range / Mustang
ConocoPhillips	Hilcorp	Repsol / Armstrong
Exxon Mobil	ENI	Great Bear Petroleum
	Anadarko	Furie
	Caelus	Bluecrest



Credits: What Worked, What Didn't?

Credits- What Worked, What Didn't?

Some Credits have Never Been Claimed

- Middle Earth "New Areas" $6 million Credit
  (AS 43.55.024(a); part of HB3001/PPT, 2006)
- Cook Inlet "Jack Up Rig" 100% Credit
  (AS 43.55.025(m); part of SB309, 2010)
- Frontier Basin 80% Drilling Credit
  (AS 43.55.025(n); part of SB23, 2012)

Companies did some of the activities incentivized by these, but were able to get better results from "stacking" other credits

All of these programs are sunsetting in 2016

Credits- What Worked, What Didn't?

Credits sunsetting and phasing out

- **North Slope Exploration Credits**
  Exact total not available due to confidentiality, but:
  - Refunded credits $125-200 million (thru FY15)
  - Credits Against Liability $150-$200 million (the great majority of these used before FY11)
- **Non-North Slope Exploration Credits**
  Exact total not available due to confidentiality, but:
  - Refunded credits $25-75 million, all refunded

With increase to NOL credit in 2014, North Slope exploration credits led to state rebates up to 85%

With addition of 40% well credit in 2010, Cook Inlet exploration credits became somewhat redundant

Credits- What Worked, What Didn't?

Credits sunsetting and phasing out (contd.)

- **Small Producer Credits**
  These can only be used against liability
  Exact total not available due to confidentiality, but:
  - North Slope $250-$400 million (thru FY15)
    Additional $257 million projected
  - Cook Inlet $50-$100 million
    Additional $15 million projected
- **Cook Inlet Gas Storage Credit**
  (AS 43.20.046; part of HB280, 2010)
  - Only the single $15 million credit allowed in statute
  - Paid to CINGSA in FY14
    (this credit has a specific confidentiality waiver)

Credits- What Worked, What Didn't?

Credits Repealed In HB247

- **Qualified Capital Expenditure (20%) and Well Lease Expenditure (40%) outside the North Slope**
  - The Capital credit was repealed for the North Slope with the passage of SB21, in 2013

  Exact total not available due to confidentiality, but:
  - Total between $500-$800 million, with over 85% of the total since FY13 (est. $150-$200 million / year)
  - A substantial portion of this has been spent on oil drilling and well workovers
  - Cook Inlet gas supply issues are much less problematic than in 2010, which will be shown later

Credits- What Worked, What Didn't?

Credits Remaining If HB247 Passes

- **Carried-Forward Annual Loss Credit** (also called "net operating loss")
  - 35% on North Slope and 25% in Cook Inlet and elsewhere
- **Exploration Credits outside North Slope and Cook Inlet** ("middle earth exploration")
  - 30-40% depending on location
  - Sunset January 1, 2022
- **Cook Inlet Tax Caps**
  - Oil tax of zero, gas tax averages 17 cents / mcf
  - Sunset January 1, 2022

Credits- What Worked, What Didn't?

Credits Remaining If HB247 Passes (contd.)

- **Middle Earth Tax Caps**
  - 4% of gross value (first seven years of production that begins before 2027)
- **LNG Storage Facility Credit**
  - Lesser of 50% of cost or $15 million
- **Refinery Infrastructure Credit**
  - 40% of cost up to $10 million / year, before 2020

Credit Cost in Perspective

Credit Cost in Perspective

North Slope Refundable Credits

- Previously said between FY07-FY15 spent $1.45 billion supporting six producing projects
- Total production through end of FY15 is 38.5 million barrels
- Total credits = **$37.30** / barrel
  - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were $4.94 billion
  - Credit support was **29%** of lease expenditures

Credit Cost in Perspective

Cook Inlet Refundable Credits

- Previously said between FY07-FY15 spent $450 million supporting six producing projects
- Total production through end of FY15 is 55.9 million BOE (much of this was gas)
- Total credits = **$7.80** / BOE or about **$1.30** / mcf
  - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were $1.09 billion
  - Credit support was **40%** of lease expenditures

Credit Cost in Perspective

Cook Inlet Tax Caps

- Estimated value to industry \$550-\$850 over the years 2007-2013
- Total Production Estimate
  - Gas: ~ 250 million cubic feet / day for seven years = 640 BCF of gas or 106 million BOE
  - Oil: ~ 10,000 barrels / day for seven years = 26 million BOE
  - Total Production = 132 BOE
- Using midpoint \$700 million estimate, value of caps = **\$5.30** / barrel or **\$0.88** / mcf

Bill Details & Calculations
Analysis of Complex Sections

Section 7: Interest Rate Compounding

Evolution of the interest rate language in SB21:

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

Section 7: Interest Rate Compounding

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

Page 2, lines 23 - 25:

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

Section 7: Interest Rate Increase

Middle ground tied to opportunity cost

- We believe the current rate (4% this quarter) may create incentives to delay & contest tax payments. Companies expect to earn much higher returns
- The former (pre 2014) rate, 11%, was too high especially with multiple years of compound interest
- **Currently, each dollar of tax not paid is another dollar out of savings**
- When this tax is eventually paid, it should compensate for what would have earned had it stayed in savings
- Current Permanent Fund estimate (Callan & Assoc.) is about 7%

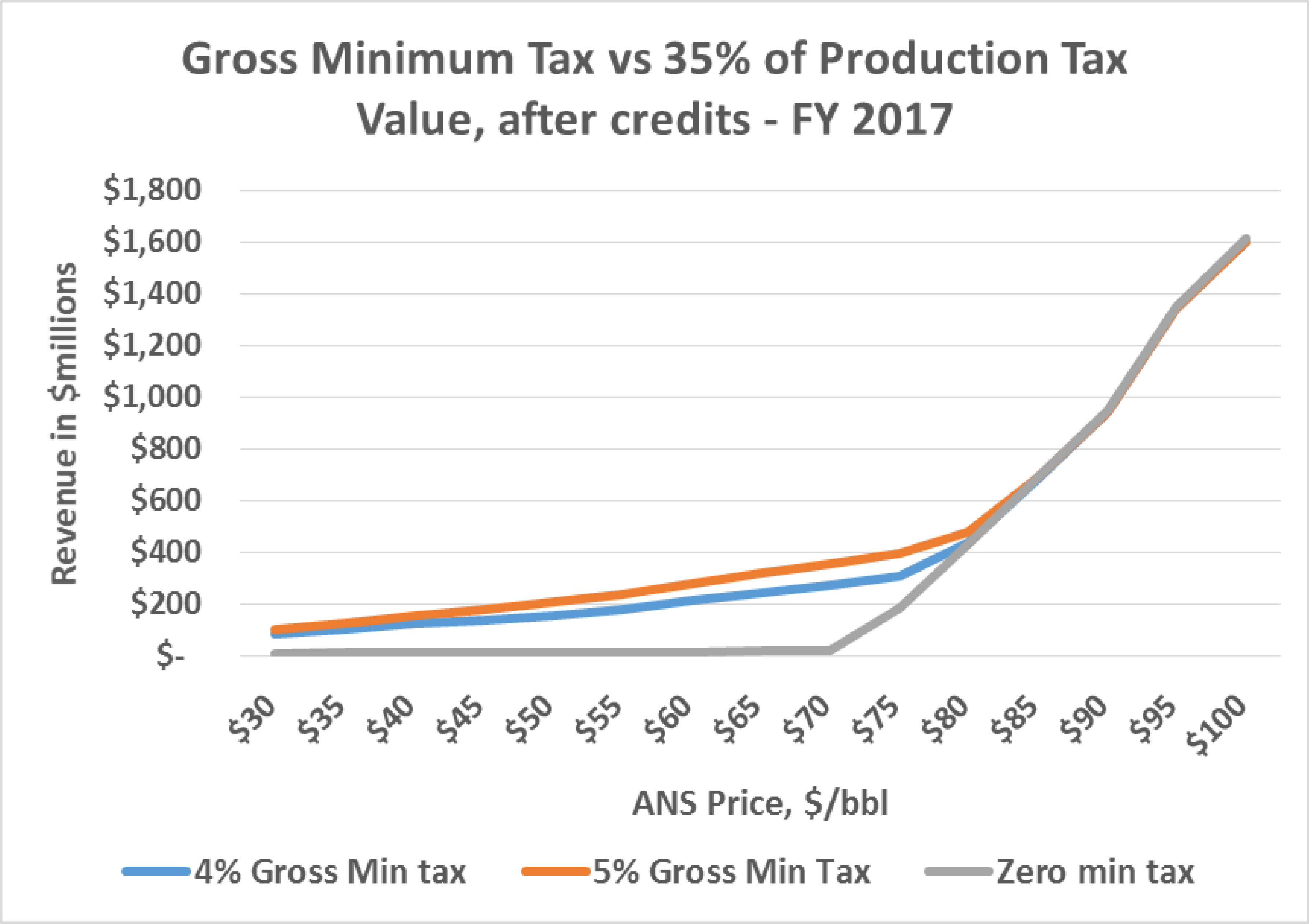
Section 7: Interest Rate Increase

Illustration: $1 million assessment to a tax due 12/31/15, and assessed 6/30/17						
Current Law						
	Q1 2016	**Q2 2016**	**Q3 2016**	**Q4 2016**	**Q1 2017**	**Q2 2017**
Pricipal	$ 1,000,000	$ 1,010,000	$ 1,020,000	$ 1,030,000	$ 1,040,000	$ 1,050,000
Subject to interest	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**
Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Interest	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**
					Total Due 6/30/17	**$ 1,060,000**
HB 247						
	Q1 2016	**Q2 2016**	**Q3 2016**	**Q4 2016**	**Q1 2017**	**Q2 2017**
Principal	$ 1,000,000	$ 1,010,000	$ 1,020,000	$ 1,040,000	$ 1,060,400	$ 1,081,208
Subject to interest	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,020,000**	**$ 1,040,400**	**$ 1,061,208**
Rate	4.00%	4.00%	8.00%	8.00%	8.00%	8.00%
Interest	**$ 10,000**	**$ 10,000**	**$ 20,000**	**$ 20,400**	**$ 20,808**	**$ 21,224**
					Total Due 6/30/17	**$ 1,102,432**
*Does not account for potential changes in Federal Reserve rate						
*This example would apply to either taxes due to state, or refunds payable						

Section 7: Interest Rate Increase

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

Section 12: Increase Minimum Tax



Source: DOR Fall 2015 forecast modeling

Section 12: Increase Minimum Tax

FY16 Spending Assumptions from Fall 2015 Revenue Sources Book

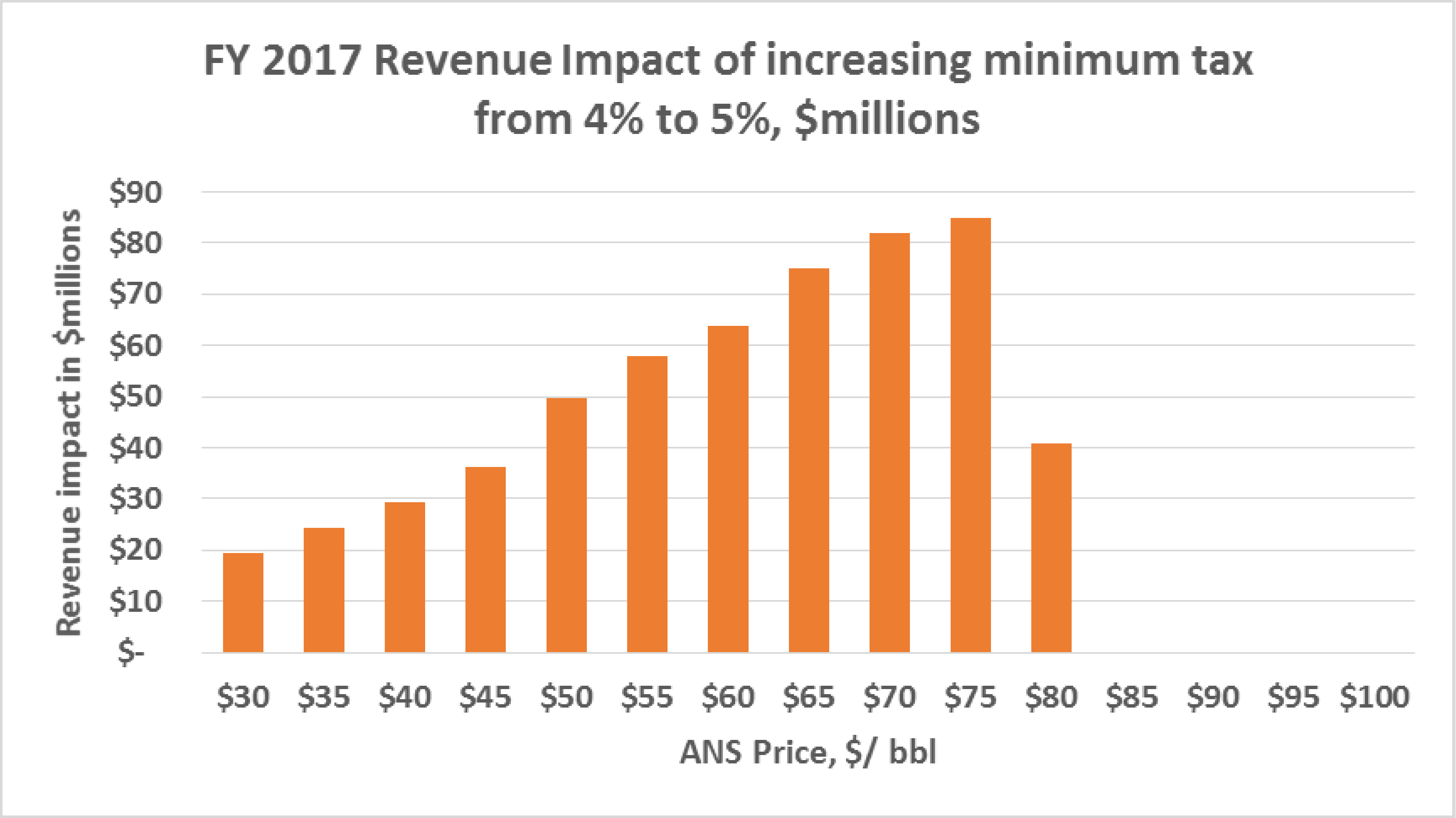
Dollars per Taxable Barrel

Legacy Production (oil not eligible for Gross Value Reduction)

Price of Oil	**$20**	**$30**	**$40**	**$50**	**$60**	**$70**	**$80**	**$90**	**$100**
Transport Cost	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)
Wellhead (Gross) Value	$10	$20	$30	$40	$50	$60	$70	$80	$90
Lease Expenditures	($36)	($36)	($36)	($36)	($36)	($36)	($36)	($36)	($36)
Net Value	**$0**	**$0**	**$0**	**$4**	**$14**	**$24**	**$34**	**$44**	**$54**
Base Tax Rate 35%	$0.00	$0.00	$0.00	$1.40	$4.90	$8.40	$11.90	$15.40	$18.90
Sliding Scale Credit	($8)	($8)	($8)	($8)	($8)	($8)	($8)	($7)	($6)
Tax After Credits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.40	$3.90	$8.40	$12.90
Minimum Tax (4%)	$0.40	$0.80	$1.20	$1.60	$2.00	$2.40	$2.80	$3.20	$3.60
Higher Of (Actual Tax)	**$0.40**	**$0.80**	**$1.20**	**$1.60**	**$2.00**	**$2.40**	**$3.90**	**$8.40**	**$12.90**
Total Production 160 million Taxable Barrels / Year (based on 500,000 bbl / day less 12.5% royalty barrels)									
Annual Revenue ($millions)*	**$64**	**$128**	**$192**	**$256**	**$320**	**$384**	**$624**	**$1,344**	**$2,064**
Revenue from 5% Minimum Tax ($millions)	$80	$160	$240	$320	$400	$480	$560	$640	$720
Increase ($millions)	**$16**	**$32**	**$48**	**$64**	**$80**	**$96**	**$0**	**$0**	**$0**

* Actual revenue will be less. Does not consider credits that currently can reduce payments below minimum tax, including small producer credit and, at very low prices, carried-forward annual loss credits. Also, about 7% of production is eligible for the Gross Value Reduction and would be outside this formula.

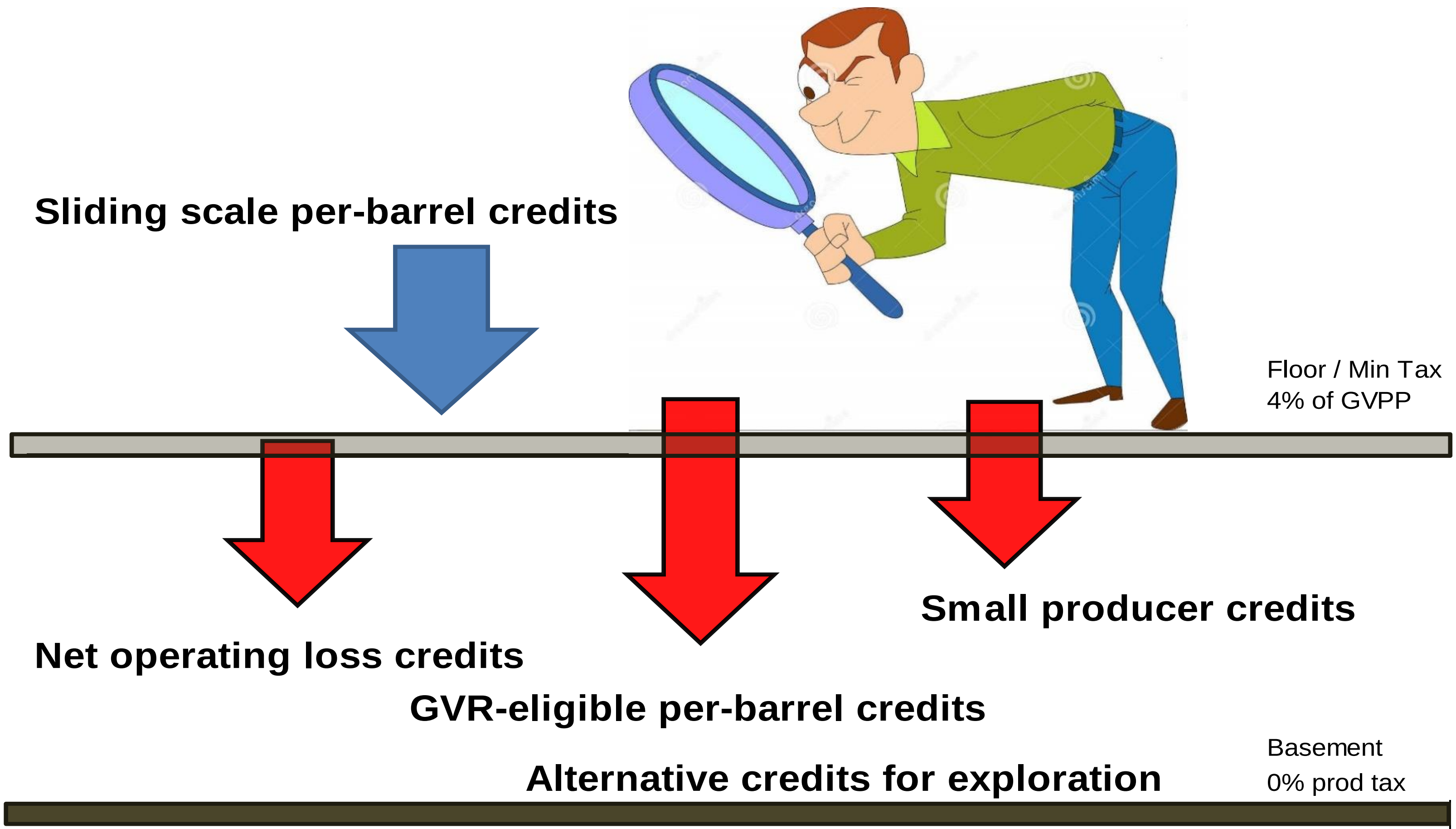
Section 12: Increase Minimum Tax



Source: DOR Fall 2015 forecast modeling

Section 17(b): Strengthen the Minimum Tax

Which credits can break through the floor under current law?



Section 17(b): Strengthen the Minimum Tax

- Current law allows all credits with the exception of the sliding scale per-barrel credits for legacy oil to reduce taxes below the minimum tax (also called the “floor”)
- HB 247 seeks to change law so that the following additional credits cannot reduce taxes below the minimum tax
  - Small producer credits
  - GVR-eligible per-barrel credits
  - Net operating loss credits
  - Alternative credits for exploration

Section 17(b): Strengthen the Minimum Tax

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

This is really three different issues / policy questions

All of these only pertain to the North Slope:

1) **Small Producer Credits**
   (should everyone, not just major producers, pay a minimum tax?)

2) **Per-Barrel Credits for GVR "New" Oil**
   (should the tax on production from new fields be allowed to go to zero?)

3) **Net Operating Loss for producers not eligible for refundable credits**
   (should the major producers ever be able to go below the floor? And should this be retroactive to Jan. 1?)

Section 17(b): Strengthen the Minimum Tax

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

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

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

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

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

Section 17(b): Strengthen the Minimum Tax

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

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

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

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

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

Section 17(b): Strengthen the Minimum Tax

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

- Net operating losses occur when a producer’s total amount of lease expenditures for the year exceed the gross value at the point of production
- In plain English, this is when a producer has negative net income (based on Alaska production tax laws)
- Net operating losses for Alaska production tax purposes are experienced on a calendar year basis, not a fiscal year basis
- At oil prices of around $50 and below, some producers will report net operating losses as early as in CY 2015

Section 17(b): Strengthen the Minimum Tax

How net operating loss (NOL) credits are earned and used – page 1

	Calendar Year 2015											
	Fiscal Year 2015						Fiscal Year 2016					
All values in $M except where noted	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Oil price in $/bbl	48.87	53.84	52.28	58.49	64.37	64.40	56.20	48.26	48.83	48.20	44.24	37.15
Production Tax Value	-78.37	-10.44	-33.16	48.96	119.52	107.16	53.94	-34.15	-34.79	-43.47	-91.79	-186.56
Tax under AS 43.55.011(e) before credits	-27.43	-3.65	-11.61	17.14	41.83	37.51	18.88	-11.95	-12.18	-15.22	-32.13	-65.30
Sliding scale credits	106.80	92.76	107.85	104.45	99.29	88.75	92.99	82.79	101.96	103.51	100.32	103.57
Tax under AS 43.55.011(e) minus credits	-134.23	-96.42	-119.46	-87.32	-57.46	-51.24	-74.12	-94.74	-114.14	-118.73	-132.45	-168.87
Minimum tax	20.90	20.45	22.94	25.46	27.12	24.25	21.22	15.61	19.51	19.48	16.89	13.77
Higher of Tax under .011(e) minus credits & Minimum tax	20.90	20.45	22.94	25.46	27.12	24.25	21.22	15.61	19.51	19.48	16.89	13.77
Minus other credits (primarily small producer)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Preliminary Production Tax after Credits	15.90	15.45	17.94	20.46	22.12	19.25	16.22	10.61	14.51	14.48	11.89	8.77
Application of carried-fwd loss credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Production Tax Paid after carried-fwd loss credits	**15.90**	**15.45**	**17.94**	**20.46**	**22.12**	**19.25**	**16.22**	**10.61**	**14.51**	**14.48**	**11.89**	**8.77**

Calendar Year 2015 Production Tax Paid ($M)	**187.6**
Calendar Year 2015 Net Operating Loss ($M)	**183.2**
Credit rate for carried-forward losses	**45%**
Calendar Year 2015 Carried-forward loss credit earned ($M)	**82.4**

Values shaded gray above cannot be negative under state law, but are shown here for illustration

Section 17(b): Strengthen the Minimum Tax

How net operating loss (NOL) credits are earned and used – page 2

	Calendar Year 2016											
	Fiscal Year 2016						Fiscal Year 2017					
All values in $M except where noted	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Oil price in $/bbl	30.22	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Production Tax Value	-212.92	-80.66	-87.00	-83.88	-86.97	-83.41	-96.79	-96.79	-93.67	-96.79	-93.67	-96.79
Tax under AS 43.55.011(e) before credits	-74.52	-28.23	-30.45	-29.36	-30.44	-29.20	-33.88	-33.88	-32.78	-33.88	-32.78	-33.88
Sliding scale credits	103.36	96.31	103.88	100.16	103.85	99.60	99.65	99.65	96.44	99.65	96.44	99.65
Tax under AS 43.55.011(e) minus credits	-177.88	-124.55	-134.33	-129.52	-134.29	-128.79	-133.53	-133.53	-129.22	-133.53	-129.22	-133.53
Minimum tax	10.16	14.18	15.29	14.74	15.29	14.66	14.37	14.37	13.91	14.37	13.91	14.37
Higher of Tax under .011(e) minus credits & Minimum tax	10.16	14.18	15.29	14.74	15.29	14.66	14.37	14.37	13.91	14.37	13.91	14.37
Minus other credits (primarily small producer)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Preliminary Production Tax after Credits	5.16	9.18	10.29	9.74	10.29	9.66	9.37	9.37	8.91	9.37	8.91	9.37
Application of carried-fwd loss credits	5.16	9.18	10.29	9.74	10.29	9.66	9.37	9.37	8.91	0.46	0	0
Production Tax Paid after carried-fwd loss credits	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8.91**	**8.91**	**9.37**

Calendar Year 2016 Production Tax Paid ($M)	**27.2**
Calendar Year 2016 Net Operating Loss ($M)	**1209.3**
Credit rate for carried-forward losses	**35%**
Calendar Year 2016 Carried-forward loss credit earned ($M)	**423.3**

Values shaded gray above cannot be negative under state law, but are shown here for illustration

Section 17(b): Strengthen the Minimum Tax

Using the scenario on the previous two slides

- The net operating loss for CY15 is estimated to be about $183 million. At a NOL credit rate of 45%, this loss will generate a credit of about $82 million
- Producers will likely apply their net operating loss credits against taxes due starting in January 2016
- If oil prices were to rise to $40 and stay at that level through CY16, using same oil production and lease expenditure assumptions, the net operating loss for CY16 could be over $1 billion for North Slope producers
- At a NOL credit rate of 35%, this loss will generate a credit in excess of $400 million, which would be applied in subsequent years

If proposed changes are made, this credit wouldn't be "lost," it would be deferred to after prices recovered

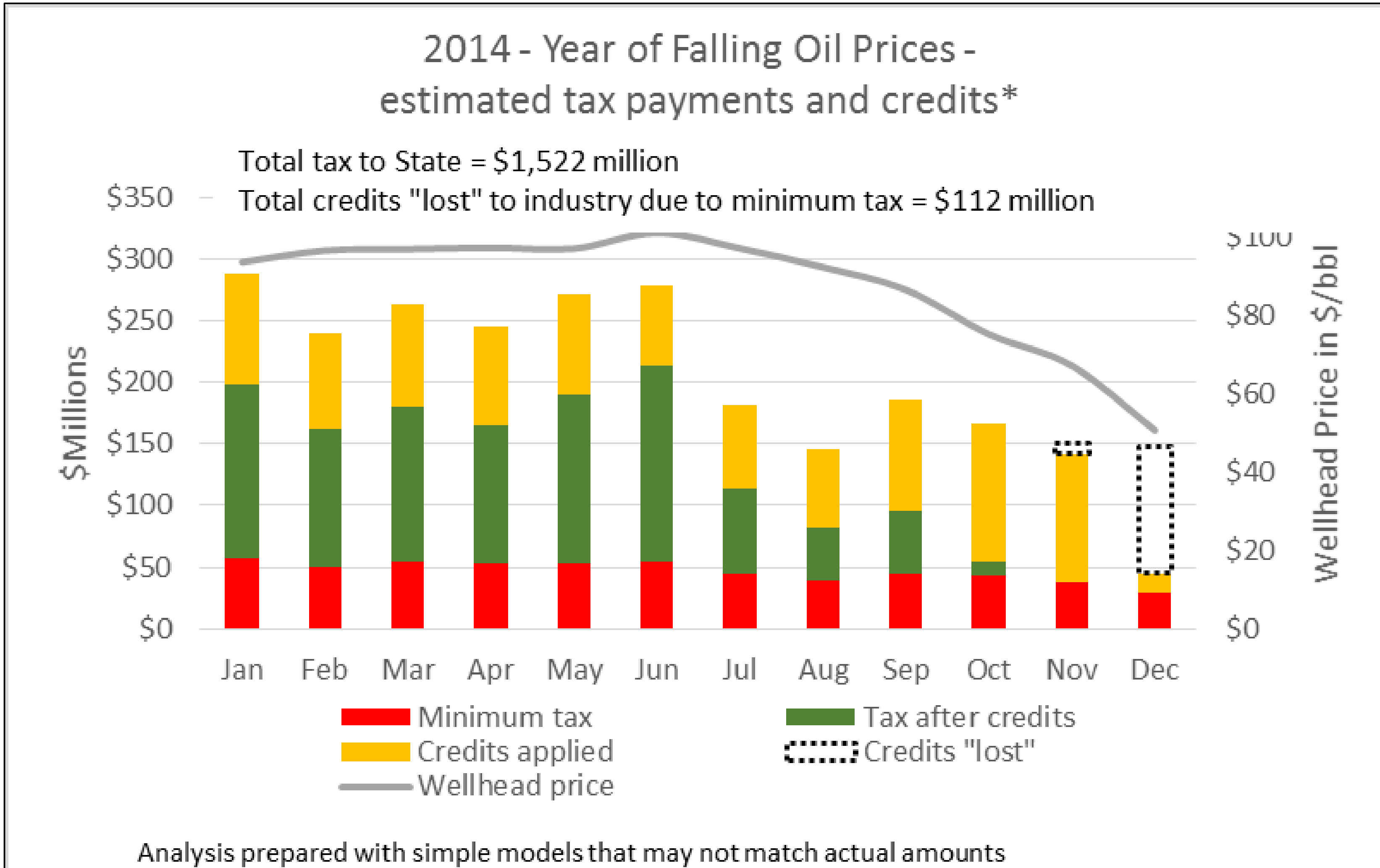
Section 17(c): Strengthen the Minimum Tax

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

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

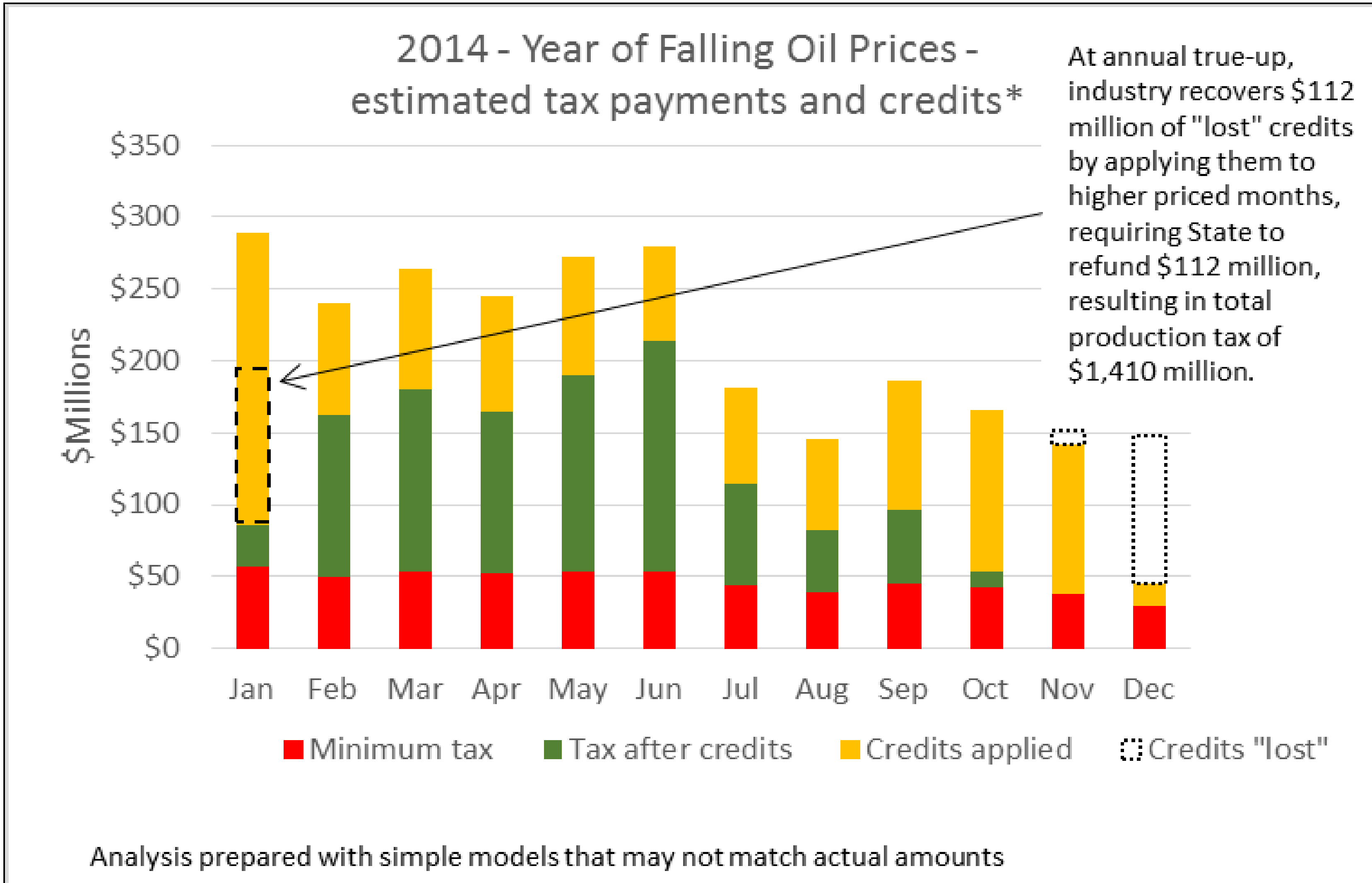
Section 17(c): Strengthen the Minimum Tax

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



Section 17(c): Strengthen the Minimum Tax

"Lost" credits recovered at annual true-up

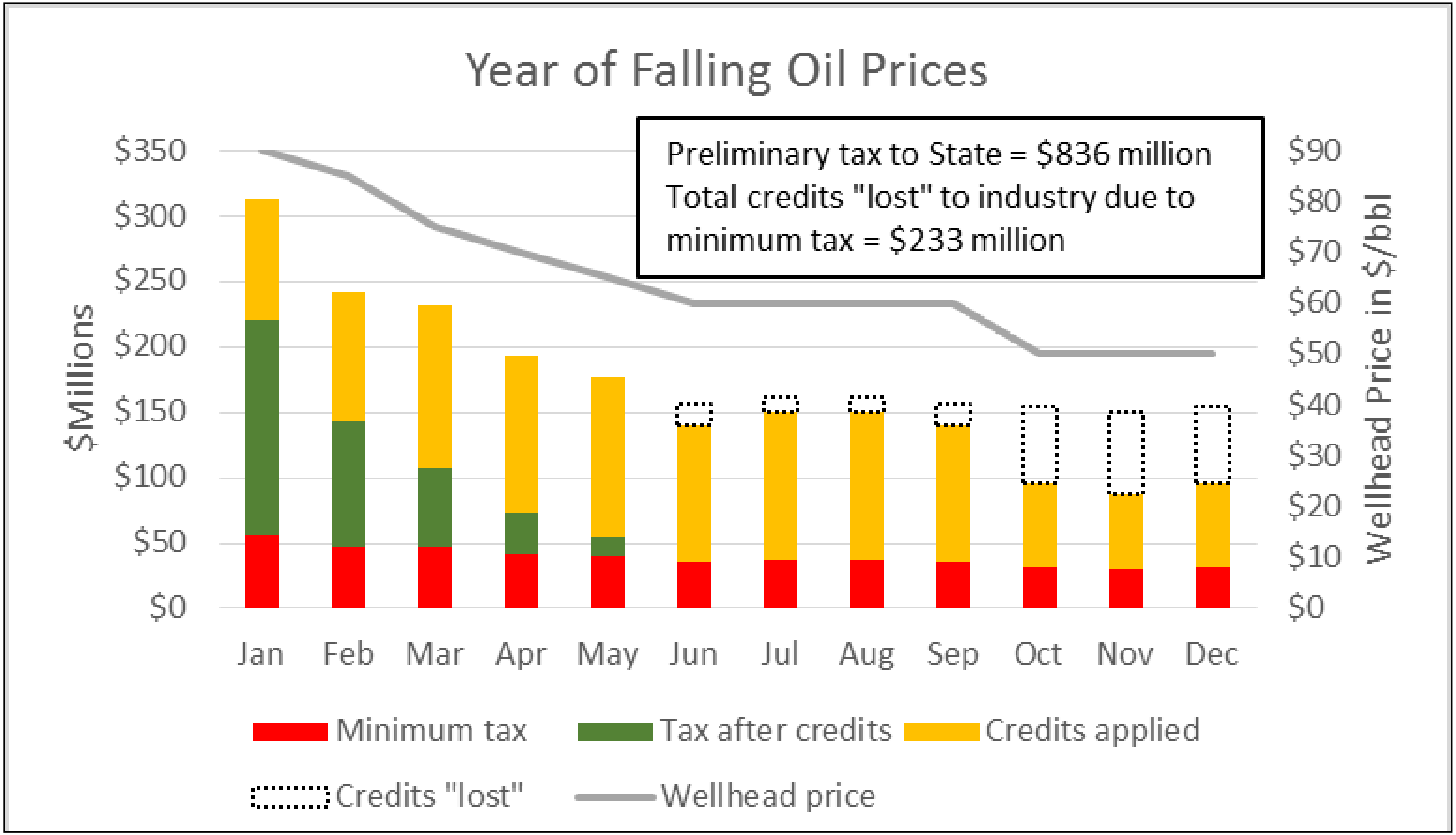


Section 17(c): Strengthen the Minimum Tax

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

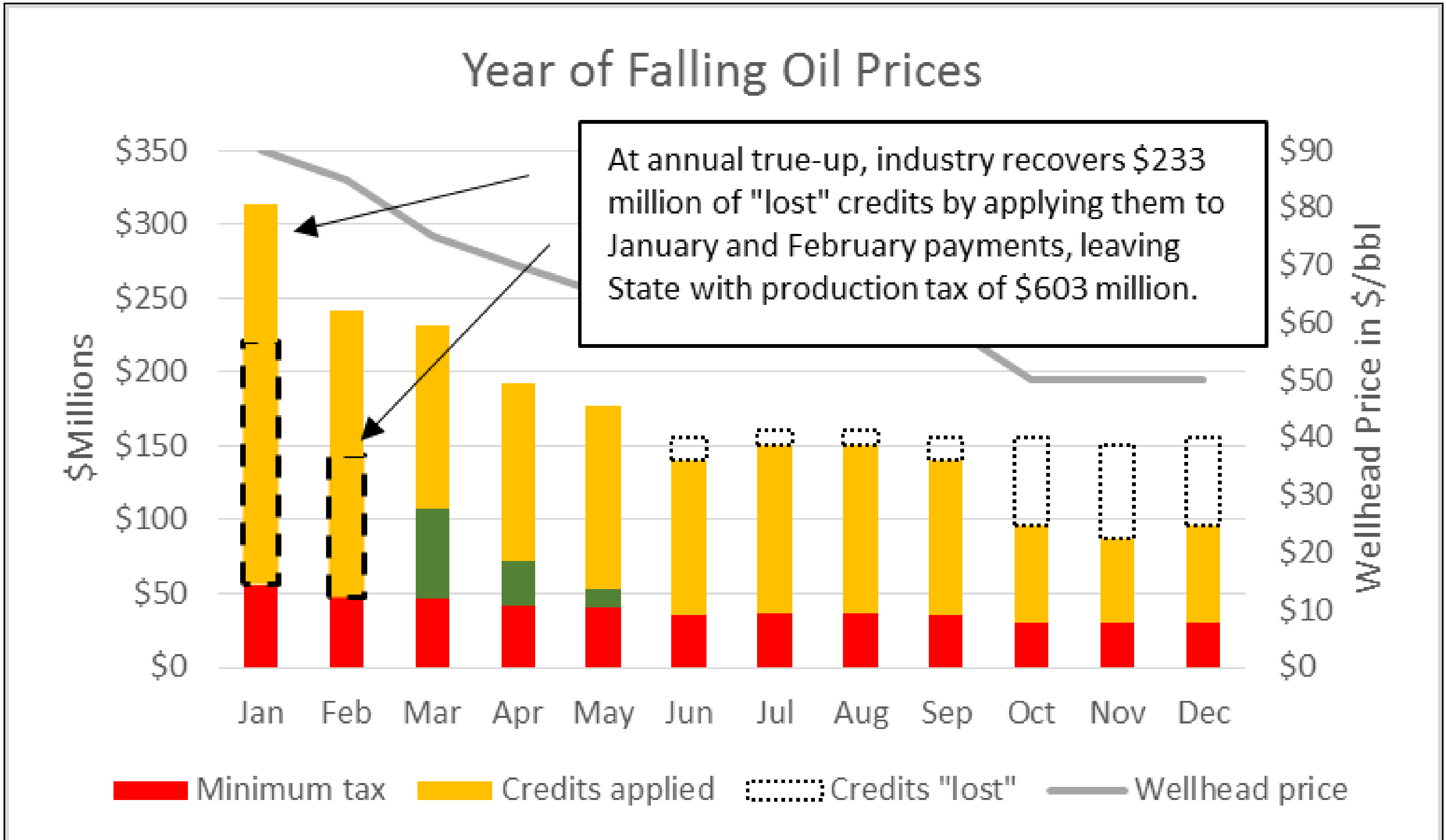
Section 17(c): Strengthen the Minimum Tax

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



Section 17(c): Strengthen the Minimum Tax

"Lost" credits recovered at annual true-up



Section 17(c): Strengthen the Minimum Tax

- Only an issue in years of oil price volatility, where some but not all months trigger the minimum tax
- Example on previous two slides showing moderate oil price volatility
  - Reduces State tax payments by close to 30%
  - Reduces effective tax rate on net from 14.5% to 10.5%
  - Results in State forfeiting some of the “upside” in years where monthly oil prices could reach $100 per barrel or more
- In the future, as tariff rates increase, wellhead values will decrease as sliding scale credits stay the same

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

- HB 247 would prohibit the gross value reduction (GVR) from being used to increase size of net operating loss and by extension, the NOL credit
- In the low oil price / low cost example shown on the next page, the net operating loss would be limited to the net value before GVR, which is $6 per barrel instead of $12 per barrel
- The resulting credit is 35% of the actual net operating loss, reducing the credit liability to the State by 50%. For a GVR-field producing 10,000 taxable barrels per day, the difference is $7.6 million

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

Current law allows GVR to increase an NOL credit

Example showing NOL due to low prices

20% GVR-Eligible Production increasing Size of Net Operating Loss and Proposed Change*	Current Law	Proposed Change
West Coast Price ($/tax bbl)	$40	$40
Transportation ($/tax bbl)	-$10	-$10
Wellhead Value ($/tax bbl)	$30	$30
Lease Expenditures ($/tax bbl)	-$36	-$36
Net Value before GVR ($/tax bbl)	-$6	-$6
Wellhead Value from above ($/tax bbl)	$30	$30
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction ($/tax bbl)	$6	$6
GVR-Adjusted Net Value ($/tax bbl)	-$12	-$12
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits ($/tax bbl)	$0.00	$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value ($/tax bbl)	$30	$30
Minimum Tax ($/tax bbl)	**$1.20**	**$1.20**
GVR Credit per-Tax-Barrel ($/tax bbl)	$5	$5
Production Tax after credits ($/tax bbl)	**$0.00**	**$0.00**
Net Operating Loss for Credit ($/tax bbl)	-$12	-$6
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit ($/tax bbl)	$4.20	$2.10
NOL per barrel times 10,000 taxable b/d	$15,330,000	$7,665,000
Difference		$7,665,000

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

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

- In the high oil price / high cost example shown on the next page, the net operating loss would be limited to the net value before GVR, which is $10 per barrel instead of $24 per barrel
- The resulting credit is 35% of the actual net operating loss, reducing the credit liability to the State by 50%. For a GVR-field producing 10,000 taxable barrels per day, the difference is close to $18 million

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

Current law allows GVR to increase an NOL credit

Example showing NOL due to higher prices with high continued investment

20% GVR-Eligible Production increasing Size of Net Operating Loss and Proposed Change*

	Current Law	**Proposed Change**
West Coast Price ($/tax bbl)	$80	$80
Transportation ($/tax bbl)	-$10	-$10
Wellhead Value ($/tax bbl)	$70	$70
Lease Expenditures ($/tax bbl)	$80	$80
Net Value before GVR ($/tax bbl)	-$10	-$10
Wellhead Value from above ($/tax bbl)	$70	$70
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction ($/tax bbl)	$14	$14
GVR-Adjusted Net Value ($/tax bbl)	-$24	-$24
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits ($/tax bbl)	$0.00	$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value ($/tax bbl)	$70	$70
Minimum Tax ($/tax bbl)	**$2.80**	**$2.80**
GVR Credit per-Tax-Barrel ($/tax bbl)	$5	$5
Production Tax after credits ($/tax bbl)	**$0.00**	**$0.00**
Net Operating Loss for Credit ($/tax bbl)	-$24	-$10
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit ($/tax bbl)	$8.40	$3.50
NOL per barrel times 10,000 taxable b/d	$30,660,000	$12,775,000
Difference		$17,885,000

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

Sections 26-27: Credit Refund Limitations

Four New Limitations on Cash Refunds:

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

This section has an estimated fiscal impact of about $150 million / year at first.

Future years will depend on actual projects

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

Section 31: Gross Value can't go below Zero

- HB 247 would prohibit the Gross Value at the Point of Production from being less than zero
- At current market oil prices of around $30 per barrel, this means that transport costs must be $30 or less
- At current prices, there are few properties that have transport costs approaching $30 per barrel
- If prices were to go lower than $20 per barrel, more properties could be affected

Section 31: Gross Value can't go below Zero

Jan. 2016 TAPS and feeder pipeline tariffs

(these are before adding the $3.37 marine transport cost)

TAPS Tariff	**$6.13**	Weighted Average

Badami Unit Tariffs	$1.41	Badami Connection
	$1.78	Badami Pipeline
	$6.13	TAPS
Badami Unit Tariffs	**$9.32**	**Total**
Colville River Unit Tariffs	$0.32	Kuparuk Pipeline
	$0.94	Alpine Tariff
	$6.13	TAPS
Colville River Unit Tariffs	**$7.39**	**Total**
Duck Island Unit Tariffs	$2.22	Endicott Pipeline
	$6.13	TAPS
Duck Island Unit Tariffs	**$8.35**	**Total**
Kuparuk River Unit Tariffs	$0.32	Kuparuk Pipeline
	$6.13	TAPS
Kuparuk River Unit Tariffs	**$6.45**	**Total**

Milne Point Unit Tariffs	$0.24	Kup - Milne Connection
	$1.44	Milne Pt Pipeline
	$6.13	TAPS
Milne Point Unit Tariffs	**$7.81**	**Total**
Pt Thomson Unit Tariffs	$1.41	Badami Connection
	$1.78	Badami Pipeline
	$19.17	Pt Thomson Pipeline
	$6.13	TAPS
Pt Thomson Unit Tariffs	**$28.49**	**Total**
Northstar Unit Tariffs	$1.09	Northstar Pipeline
	$6.13	TAPS
Northstar Unit Tariffs	**$7.22**	**Total**

Source: Alaska Department of Natural Resources

Section 31: Gross Value can't go below Zero

Example of gross value potentially going below zero

West Coast Price ($/bbl)	$30.00
Point Thomson Unit Tariffs ($/bbl)	$28.49
Marine Transportation ($/bbl)	$3.37
Wellhead Price ($/bbl)	-$1.86
Annual Oil Production (bbls)	3,650,000
Royalty Oil Production (bbls)*	456,250
Taxable Oil Production (bbls)	3,193,750
Wellhead Price from above ($/bbl)	-$1.86
Taxable Oil Production from above (bbls)	3,193,750
Gross Value at Point of Production	-$5,940,375

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

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

Section 37: Municipal Utility Limitation

- If a municipal utility owns a portion of a gas field and uses all of the gas to generate its own power, this is not taxable

However, if a portion of that gas is sold to a third party, those sales are taxable.

Current law allows all lease expenditures to be used to offset the comparably small amount of sales, potentially generating large credits. HB247 proposes to limit the lease expenditure calculation to just the pro-rata share of the expenditures equal to the proportion of the gas that was sold

	Current Law	HB247 Proposal
Daily Volume Produced (mmcf)	20	20
Volume Used By Utility (untaxable)	18	18
Volume Sold to 3rd Parties (taxable)	2	2
Sales Price / mcf	$8	$8
Annual Revenue Subject to Tax ($000)	$5,840	$5,840
Lease Expenditures per mcf produced	$3	$3
Annual Lease Expenditures ($000)	$21,900	$21,900
Allowable Lease Expenditures	$21,900	$2,190
Operating Profit (Loss)	**($16,060)**	**$3,650**
Operating Loss Credit @ 25%	**$4,015**	**n/a**

Cook Inlet Gas Supply Issues

Cook Inlet Gas Supply (data from DNR)

Q. How long can known Cook Inlet gas supplies meet regional demand?

A. It depends on how fast the known supply can be made available.

Simple approach given rapid response required:

Consider 2 gas <u>supply</u> cases ranging from 1,183 (2P reserves in legacy fields) to 1,600 BCF (2P legacy reserves + new field developments)

Consider 3 gas <u>demand</u> cases ranging from 80 BCF/year (current utility, refinery, and field use) to 140 BCF/year (current use + Donlin Gold + 2 trains Agrium)

Combine for 4 <u>supply vs demand</u> scenarios to evaluate "lifespan"* range
"Lifespan" assumes reserves and discovered undeveloped resource will be developed and available in time to meet demand, as if sitting in a bank

Data sources:

Munisteri, I., Burdick, J.D., Hartz, J.D., 2015, P.L. Decker, ed., <u>Updated engineering evaluation of remaining Cook Inlet gas reserves</u>, Alaska Division of Oil and Gas, 148 p.

Alaska Gasline Development Corp., <u>Alaska In-State Natural Gas Demand Forecast</u>, June 11, 2015. Accessed February 19, 2016.

Stokes, P., 2012, <u>Cook Inlet Gas Study – 2012 Update</u>, Petrotechnical Resources of Alaska, 78 p.

Bradner, T, 2015, <u>BlueCrest set for April production at Cosmo</u>, Alaska Journal of Commerce, November 24, 2015. Accessed February 19, 2016.

DOG estimates

Cook Inlet Gas Supply (data from DNR)

- Supply Case 1: 1,183 BCF = 2P reserves in legacy fields (DOG, 2015)

- Supply Case 2: 1,600 BCF = Legacy fields plus *ballpark estimates* for new field development of Kitchen Lights and Cosmopolitan

  *These new fields are offshore, and involve development cycles of 5 years or more. Kitchen Lights is now partially developed; Cosmo gas development has not yet begun; **full development of both remains contingent on further investment**.*

- Demand Case 1: 80 BCF/year = current South-central regional demand

  (65Bcf utilities + 10Bcf in-field use + 5Bcf Tesoro)

- Demand Case 2: 116 BCF/year = Addition of Donlin and 1 train at Agrium

  (Demand Case 1 + 12Bcf Donlin + 24Bcf Agrium)

- Demand Case 3: 140 BCF/year = Addition of second train at Agrium

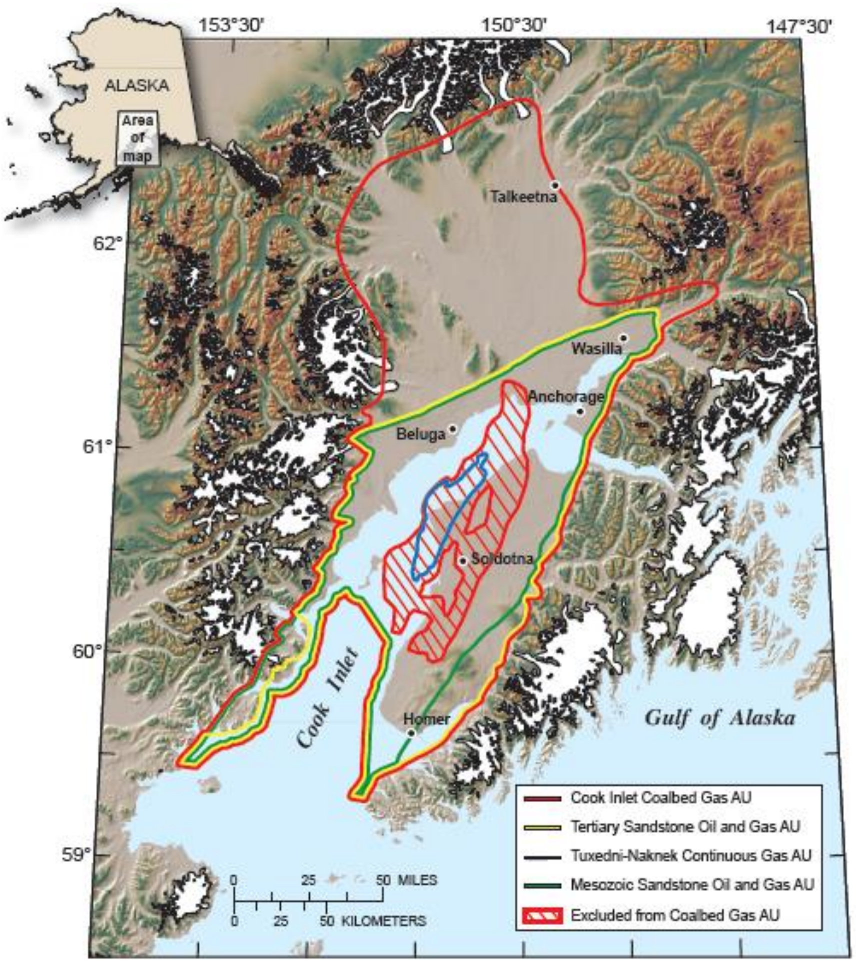
  (Demand Case 2 + 24Bcf Agrium)

Cook Inlet Gas Supply (data from DNR)

These supply "lifespan" estimates require significant continued investment to ensure reserves and discovered resources will be produced in time to meet demand.

Supply-Demand Scenario	Supply Case	Demand Case	"Lifespan"
Low-Low	1,183 BCF legacy field 2P reserves (DOG, 2015)	80 BCF/year current local demand (65 utilities + 10 in-field use + 5 Tesoro)	15 years
High-Low	1,600 BCF Add in newer fields (Kitchen Lights & Cosmo)	80 BCF/year current local demand (65 utilities + 10 in-field use + 5 Tesoro)	20 years
High-Med	1,600 BCF Add in newer fields (Kitchen Lights & Cosmo)	116 BCF/year add Donlin + 1 train Agrium (80 current + 12 Donlin + 24 Agrium)	14 years
High-High	1,600 BCF Add in newer fields (Kitchen Lights & Cosmo)	140 BCF/year add second train Agrium (80 current + 12 Donlin + 48 Agrium)	11 years

Cook Inlet Undiscovered Resources
(USGS resource assessment, 2011)



Undiscovered, Technically Recoverable Oil and Gas

- mean conventional oil 599 MMBO

372 MMBO in Tertiary Ss play

227 MMBO in Mesozoic Ss play

- mean conventional gas 13.7 TCF

12.2 TCF in Tertiary Ss play

1.5 TCF in Mesozoic Ss play

- mean unconventional gas 5.3 TCF

0.6 TCF Mesozoic tight ss play

4.7 TCF Tertiary Coalbed play

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

Coming in Part 2

Scenario Analysis:

Analysis of Projects Before and After Proposed Changes

Thank You!

Contact Information

Ken Alper
Director, Tax Division
Department of Revenue
Ken.Alper@Alaska.gov
(907) 465-8221

Cherie Nienhuis
Commercial Analyst
DOR Tax Division
Cheryl.Nienhuis@Alaska.gov
(907) 269-1019