HB 247
OIL & GAS TAX CREDIT REFORM FEBRUARY 2016 PRESENTATIONS BY DEPARTMENT OF REVENUE (FILE 2)

<TARGET><BILL>HB 247</BILL><SUBJECT>HB 247 OIL and GAS TAX CREDIT REFORM - FEBRUARY 2016 PRESENTATIONS BY DEPARTMENT OF REVENUE (FILE 2)</SUBJECT><COMM>HRES29</COMM></TARGET>

NEW SUSTAINABLE
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Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform

HB247

Presentation to House Resources Committee

February 3, 2016

Bill Title

"An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments on estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative ta credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition of "qualified capital expenditures"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payment for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments, and providing for an effective date." *(273 words)*

Suggested Informal Short Title

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

Work Done Since Last Session

- Governor's line-item veto capped FY16 spending at $500 million
- Temporary liquidity crisis; many meetings with industry and others to help reassure lenders
- Multiple presentations with history, current practice, and possible changes
  - Joint Resources in Kenai, June 17
  - Three "regional" presentations to Senate Working Group September through November
  - All presentations on BASIS; we're prepared to go through similar information for the committee
- Development of reform legislation including plan for transition from current system

History of Oil and Gas Production Tax Credits

- First "modern" Oil and Gas credit was the Alternative Credit for Exploration (AS 43.55.025) passed in 2003 while Alaska still had the "Economic Limit Factor" (ELF) Gross Tax
- Several credits added in 2006 with passage of the "Petroleum Production Tax" (PPT) and switch to net profits-based taxation. Included Cook Inlet tax caps as well as the first "state repurchase" provisions
- Credits substantially modified with passage of "Alaska's Clear and Equitable Share" (ACES) in 2007; state repurchase made more open-ended
- Cook Inlet Recovery Act and related legislation in 2010
- Frontier Basin credits added in 2012
- SB 21 passed in 2013, dramatically changed North Slope credits, replacing "spending" with "production" focus

History of Oil and Gas Production Tax Credits

- Credits initially added to encourage certain desired behaviors, tied to anxiety over declining production and a need for new investment
- Later credits were added as core components / offsets of the net profits system
- At times credits were layered on top of each other, creating unanticipated circumstances
- Credits can either be used against tax liability, or cashed out ("repurchased") by the state
- Per AS 43.55.028(e)(4), a company producing over 50,000 bbl / day can not have their credits repurchased by the state

History of Oil and Gas Production Tax Credits

Major Credits Available (current law):

- **.023(b) Net Operating Loss (25-45%)**
  This is the main refundable credit on the North Slope and the largest statewide credit. "Stackable"
- **.024(i&j) Per-Taxable Barrel ($0 to $8)**
  Only on North Slope
  Only can be used against tax liability
- **.023(a&l) Capital and Well Expend (20-40%)**
  Only outside North Slope, usually refunded
- **.025(var) Exploration Credit (30-40%)**
  Expires 7/16 in North Slope and Cook Inlet
  Extended in Interior / Frontier Areas until 2022
- **.024(c) Small Producer Credit (up to $12 mil)**
  Closed to new applicants in 5/16

History of Oil and Gas Production Tax Credits

FY 2007 thru 2015, $7.4 Billion in Credits

North Slope

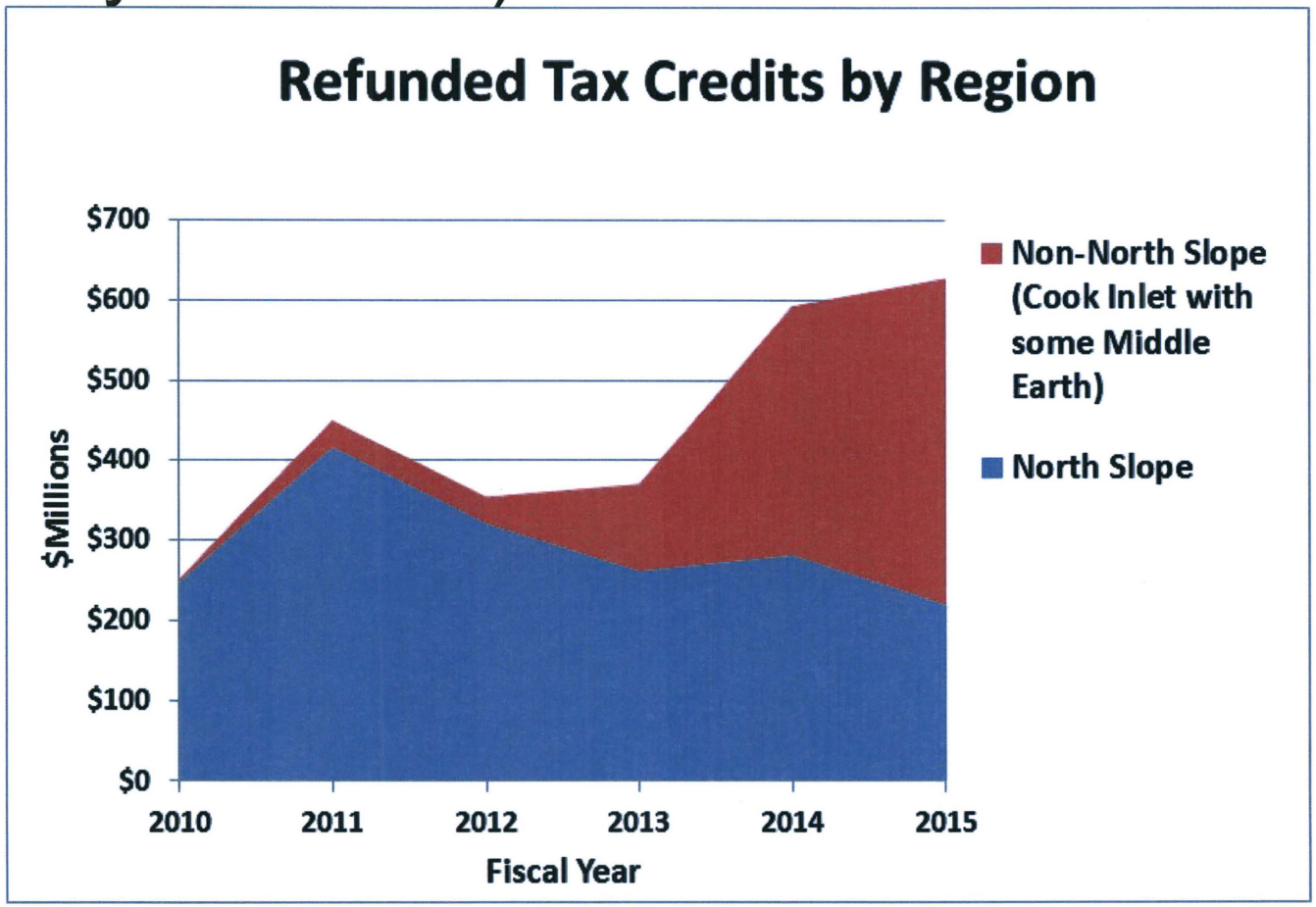
- $4.3 billion credits against tax liability
  - Major producers; mostly 20% capital credit in ACES and per-taxable-barrel credit in SB21
- $2.1 billion refunded credits
  - New producers and explorers developing new fields

Non-North Slope (Cook Inlet & Middle Earth)

- $100 million credits against tax liability
  - Another $500 to $800 million Cook Inlet tax reductions (through 2013) due to the tax cap still tied to ELF
- $900 million refunded credits (most since 2013)

History of Oil and Gas Production Tax Credits

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



History of Oil and Gas Production Tax Credits

Of the $3 billion in state-refunded credits through the end of FY15:

- $1.45 billion went to six North Slope projects that now have production
- $650 million went to 13 North Slope projects that do not have any production. Some of these are abandoned, and some are in process
- $450 million went to six non-North Slope projects that have production
- $450 million went to eight non-North Slope projects that do not have any production

History of Oil and Gas Production Tax Credits

Of the $500 million in authorized credit repurchases for FY16:

- About $472 million has already been paid
  - About $200 million from North Slope and $272 million from Cook Inlet / Interior
  - 58% non-North Slope, similar to FY15 data
- Nearly all are 2014 NOL's and Cook Inlet Drilling
- Still expect $700 million total demand, but
  - Most of the applications DOR has in-hand don't need to be issued until next July

History of Minimum Production Tax "Floor"

- During gross tax era, there was a minimum "cents per barrel" tax. In 2005 it was 60 to 80 cents adjusted for API gravity
- AS 43.55.011(f) added as part of "PPT" bill to ensure a minimum level of revenue as part of compromise with transition to Net Profits tax
- Sliding scale from zero to 4% of Gross Value, based on the price of oil. For all prices above $25 is 4%
- Under PPT and ACES, the floor could be "pierced" by many credits including the primary 20% capital expenditure credit

History of Minimum Production Tax "Floor"

- Under SB21, strengthened for "legacy" oil meaning the North Slope per-taxable-barrel credit cannot reduce taxes below the "floor"
- Several other current credits can reduce payments below the "floor"
  - Net Operating Loss; Small Producer Credit; Various Exploration Credits; Per-Taxable-Barrel credit for "new" oil eligible for the Gross Value Reduction (GVR)
- Provision was never broadly triggered until the fall 2014 price collapse
- Most North Slope production taxes throughout 2015 were at the "minimum tax" level

Major Bill Themes

1. Reduce the state's annual cash outlay;
2. Protect Net Operating Loss credits as a playing field leveler between legacy producers and newcomers;
3. Limit repurchases;
4. Strengthen the minimum tax;
5. Be more open and transparent;
6. Honor and pay credits earned to date and through any transition period.

Recommendations of Senate Working Group

1. Gradual implementation
   - ✓ $1 billion transition fund for existing and future liability
2. Consider Timeline / Sector Impacts
   - ✓ Maintains future cash support for Operating Loss credits
3. Protect local venders at bankruptcy
   - Not addressed in this bill but this is an important and timely issue

Recommendations of Senate Working Group

4. Protect Minimum Tax "Floor"
   - ✓ Prevents credits from reducing payments below the minimum; increases rate to 5%
5. Protect Frontier Basin Tax Breaks
   - ✓ Continuation of exploration credits in these areas maintains state support at up to 65%
6. Enhance Reporting Requirements
   - ✓ Limited confidentiality waiver so Alaskans know what their money is being spent on

Exploration Credits

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

Cook Inlet Drilling Credits

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

Repurchase Limits

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

Remove Exceptions / Loopholes

- Provisions that artificially inflate net operating losses
  - **Can't use GVR (new oil value reduction) to increase the size of a Net Operating Loss** (has led to credits greater than 100% of loss)
  - If a municipal entity owns production and sells only a portion of that production to an outside party, only the pro-rata share of expenses can be deducted against revenue

Strengthen Minimum Tax

- **Can't use an operating loss credit,** small producer credit, or exploration credits **to reduce payments below the 4% floor**
  - We see these in the forecast coming out for rest of FY16, as one or more major producers will show a net operating loss for 2015
  - This one provision is retroactive to 1/1/16
- Extend 4% floor to GVR-eligible "new" oil
- Prevent per-taxable-barrel credits earned in one month from being used against another month's taxes at true-up
- **Increase from 4% (at prices above $25) to 5%**

Other Provisions

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

Bill Impact: Example Scenarios

North Slope Major Producer

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

Bill Impact: Example Scenarios

North Slope New or Smaller Producer

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

Bill Impact: Example Scenarios

North Slope New Project Developer

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

Bill Impact: Example Scenarios

Cook Inlet Existing Producer

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

Bill Impact: Example Scenarios

Cook Inlet New Field Developer

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

Bill Impact: Example Scenarios

Interior / Frontier Area Explorer

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

Revenue Impact

FY17 Impact Est. $500 Million / year

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

Revenue Impact

In subsequent years, the estimated budget savings per the DOR Fiscal Note is reduced

- This is largely tied to a decline in estimated tax credits in DOR's official revenue forecast
- Our credit forecast only includes "known" projects and is typically revised upwards from year to year
- Credit projections use the same conservative methodology as DOR's production forecast
- Most "new" projects would add to the amount of projected credits

Implementation Cost

Transition

- Bill is being written with an effective date of 7/1/16 for nearly all changes
- "Honoring Existing Credits" means:
  - Roughly $200 million FY2016 "overhang"
  - Estimated $425 million credits based on spending in CY2015, which will largely be paid in early FY2017
  - Credits earned in first half of CY2016 prior to the effective date
  - Total equals about $1 billion which will be paid via an appropriation to the .028 Tax Credit Fund

Implementation Cost

- The changes anticipated in this bill will require somewhat substantial reprogramming of the Tax Revenue Management System (TRMS) and Revenue Online (ROL) which allows a taxpayer to file a return online and update the current tax return forms
- We have requested an estimate from the software developer, and currently assume a one-time cost of about $1.5 million to accomplish this
- We do not anticipate any additional costs to administer the tax program
- There will also be a need for substantial amendments to existing regulations to fully implement the changes

Closing the Budget Gap

	(Millions)
FY16 Budget	**$ 5,200**
FY17 Baseline Revenue (after proposed legislation)	
AK Permanent Fund Protection Act (annual draw)	$ 3,300
Revenue from existing taxes and fees	$ 850
Earnings on Savings	$ 135
	$ 4,285
FY17 Spending Reductions	
Continue Cuts	$ 140
Reform O&G Tax Credits	***$ 400***
Net Priority Investments	($ 40)
	$ 500

Closing the Budget Gap

New Revenue Components (estimated)	**(Millions)**
Mining (starting in FY 2018)	$ 6
Fishing	$ 18
Tourism	$ 15
Motor Fuel	$ 49
Alcohol	$ 40
Tobacco	$ 29
Oil and Gas (strengthening minimum tax)	***$ 100***
Income Tax (half in FY17; first full year is FY18)	$ 200
	$ 457
Total with reductions and new revenue	**$ 5,242**

Sectional Analysis

Sec. 1-5. Conforming language related to the repeal of AS 41.09 in Sec. 40 of the bill. The repeal is a currently unused exploration incentive credit program.

Sec. 6. Conforming language related to changes to reporting requirements and confidentiality rules in Sec. 8 of the bill.

Sec. 7. Changes the interest rate for delinquent taxes from 3 percent above the Federal Reserve Discount Rate to 7 percent above. This would currently result in an interest rate of about 8%; about halfway between the current 4% and the 11% that was in place before the passage of SB21 in 2013.

If the state were to begin using earnings from our major savings account, the Permanent Fund, to fund government operations, there would be an "opportunity cost" that comes from unpaid taxes. Our interest rate on these unpaid taxes should reflect the expected rate of earnings on our savings.

Sectional Analysis (continued)

Sec. 8. Provides an exception to the general taxpayer confidentiality statutes, so that the name of each company claiming credits, the amount they claim, and a general description of their activities can be made public.

Sec. 9-11. Amends the Gas Storage Facility, LNG Facility, and In-State Refinery Tax Credits so that these cannot be paid if the taxpayer has any outstanding liability to the state. Currently this is restricted to only a tax liability.

Sec. 12. Increases the minimum tax rate in AS 43.55.011(f) to 5% at all oil prices. Currently it is 4% at any oil price above $25 per barrel, stepping down at lower prices. The minimum tax applies only to production from the North Slope.

Sec. 13. Changes the description of monthly installment payments in AS 43.55.020(a), to conform with the higher minimum tax rate in Sec. 12. *(long technical section)*

Sectional Analysis (continued)

Sec. 14-16. Conforming language related to the repeal of AS 43.55.020(a)(1) and (2) in Sec. 40 of the bill. The repeal is obsolete installment payment language related to production prior to 2014.

Sec. 17. Strengthens the minimum tax in two distinct ways:

(b) Prevents several credits that currently can be used to reduce payments below the 4% level from being used for this purpose. Those credits would be carried-forward until the taxpayer had sufficient tax liability against which to use them.

(c) Prevents the circumstance in which per-taxable-barrel credits that could not be used in the month in which they were earned, because of the limitations of the minimum tax, could be claimed at annual tax true-up. This effectively turns the per-taxable-barrel credit into a monthly rather than an annual calculation. Currently if there is substantial price volatility within a year it could result in large tax refunds.

Sectional Analysis (continued)

Sec. 18. Modifies the carried-forward annual loss credit in AS 43.55.023(b) so that, for "new" oil production eligible to receive the Gross Value Reduction (GVR), the GVR cannot be used to increase the size of an annual loss. Thus, if a company has oil production but is operating at a loss, their loss credit is limited to the actual size of the loss. Currently there are circumstances in which a company could receive credit refunds for amounts in excess of 100% of their loss.

Sec. 19. Amends AS 43.55.023 so that credits in that section cannot reduce tax liability below the minimum tax, rather than zero as in current statute. Also establishes a sunset when certain credits must be carried forward instead of being cashed out; in these circumstances the credits can only be carried forward for 10 years.

Sectional Analysis (continued)

Sec. 20. Establishes a sunset in which credit certificates can only be held for 10 years before they expire.

Sec. 21. Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" credit outside of the North Slope.

Sec. 22. New language adding the notice and data sharing requirements that are currently part of the alternative credit for exploration, and applying them to other credits. This will enable DNR to continue to receive seismic and downhole information after the sunset of the exploration credits.

Sec. 23. Amends AS 43.55.024 so that the small producer credit cannot be used to reduce tax liability below the minimum tax. Although this credit will be closed to new recipients in May of 2016, some companies will continue to receive this benefit until approximately 2024.

Sectional Analysis (continued)

Sec. 24. Amends AS 43.55.024 so that the $5 per-taxable-barrel credit received by GVR-eligible North Slope oil production cannot reduce tax liability below the minimum tax. Currently this can be reduced to zero; only the sliding-scale credit for non-GVR oil is limited by the minimum tax.

Sec. 25. Amends AS 43.55.025 so that exploration credits cannot reduce tax liability below the minimum tax.

Sec. 26. Amends AS 43.55.028(e) to add limitations on which companies can receive refunded tax credits versus which must hold their certificates and use them against tax liability:

(2) Companies with any liability to the state are ineligible to receive payment for their tax credit certificates. Currently this is restricted to only a tax liability.

(5) Limits cash repurchase to only companies whose gross revenues in the previous year were less than $10 billion.

(6) Limits annual per-company repurchase to $25 million.

Sectional Analysis (continued)

Sec. 27. Adds a new limitation to a company's ability to receive a cash repurchase of their tax credits. The state can only repurchase that percentage of a certificate that equals that company's percentage of Alaska resident hire in the previous calendar year.

Sec. 28-30. Conforming language related to the repeal of AS 43.55.023(a) and / or (l) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" and "well lease expenditure" credits outside of the North Slope.

Sec. 31. New section specifying that the Gross Value at the Point of Production, defined as sales price less eligible transportation costs, may not be less than zero

Sec. 32. Conforming language related to the repeal of AS 43.55.165(j) and (k) in Sec. 40 of the bill. The repeal is the "standard deduction" limitation on lease expenditure inflation that expired in 2010.

Sectional Analysis (continued)

Sec. 33-36. Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" credit outside of the North Slope.

Sec. 37. In the case where a municipal entity has an interest in oil and gas production, and sells only a portion of that production to an outside party, their ability to deduct lease expenditures and claim credits is limited in proportion to their taxable production.

Sec. 38. Adds a definition for "qualified capital expenditure" to the general definitions section of AS 43.55. This replicates the definition that was in AS 43.55.023 which is repealed because the .023 "qualified capital expenditure" credit is also being repealed in Sec. 40. Most of the conforming sections that currently reference AS 43.55.023(a) use this definition.

Sectional Analysis (continued)

Sec. 39. Adds a definition for "outstanding liability to the state." This conforms with the changes made in Sections 9, 10, 11, and part (2) of 26.

Sec. 40. Repeals multiple sections. All of these have been specifically referenced elsewhere in this analysis or are technical repeals that conform with other repealed statutes.

Sec. 41. Applicability section with multiple sub-parts. In general, ensures that the changes only apply to production after the effective date. Also provides that applications that come in later for credits related to expenditures before the effective date are protected under the former program. Clarifies the timing related to the new 10-year sunset for carried-forward annual loss credits.

Sectional Analysis (continued)

Sec. 42-43. Transition language enabling DOR and DNR to draft regulations to implement the changes in this Act, and establishing that regulations may be retroactive to the effective date if they are finalized after the effective date.

Sec. 44. Section 17 is retroactive to January 1, 2016. This is the key floor-hardening provision preventing certain credits from being used against the minimum tax, and is related to the specific concern that one or more major producers could have an operating loss in 2015 and use the carried-forward credit to reduce 2016 tax payments below the minimum tax to zero.

This is the only provision of the bill for which we are seeking this retroactivity.

Sec. 45. Immediate effective date for the transition and regulatory language.

Sec. 46. Effective date of July 1, 2016 for the rest of the Act.

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Thank You!

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Oil and Gas Tax Credit Reform- HB247

Department of Revenue

"Additional Modeling and Scenario Analysis - Part 1"

Presentation to the House Resources Committee

February 22, 2016

What We Will 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 government take
- Gas supply issues in Cook Inlet

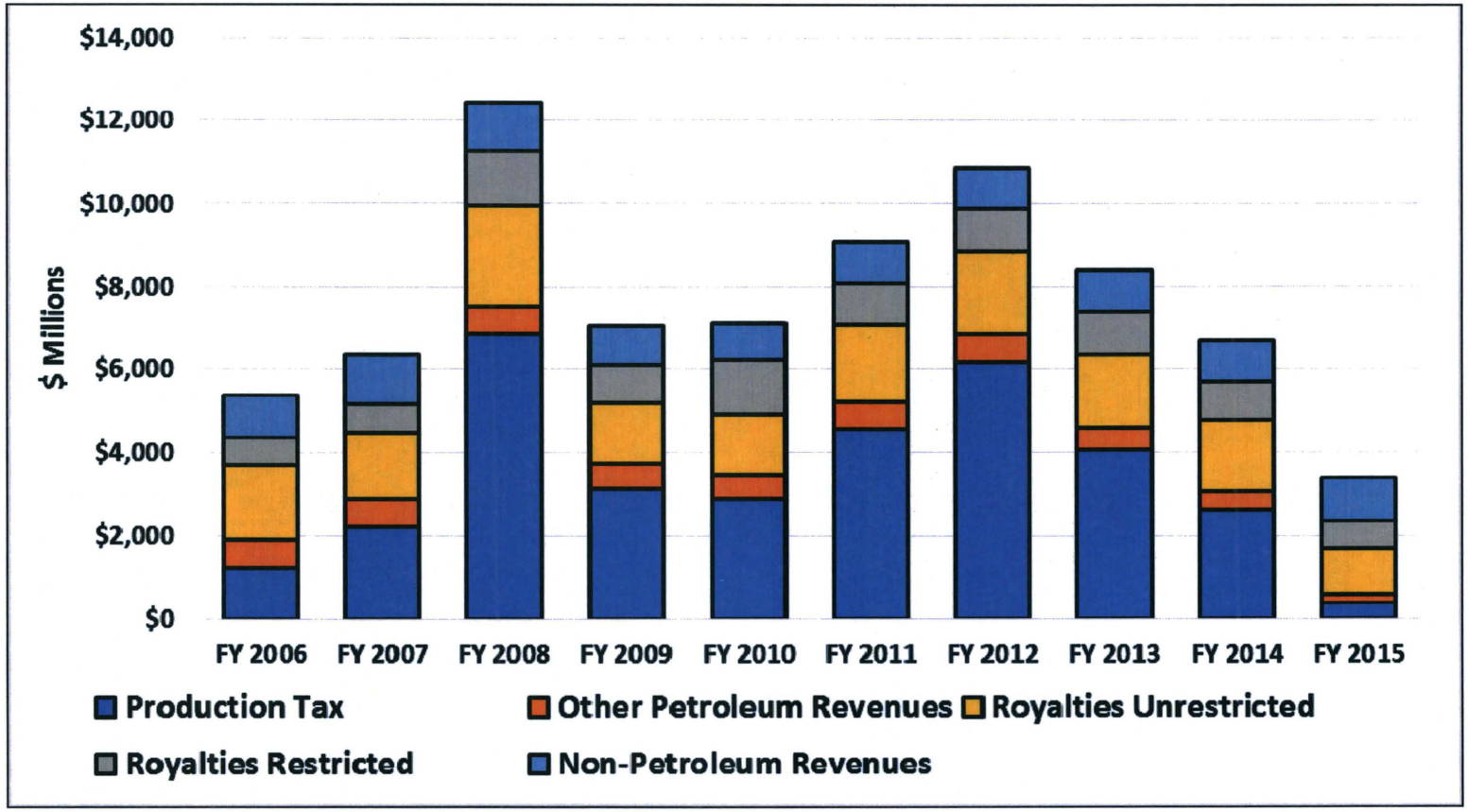
Overview of Revenue and Production

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



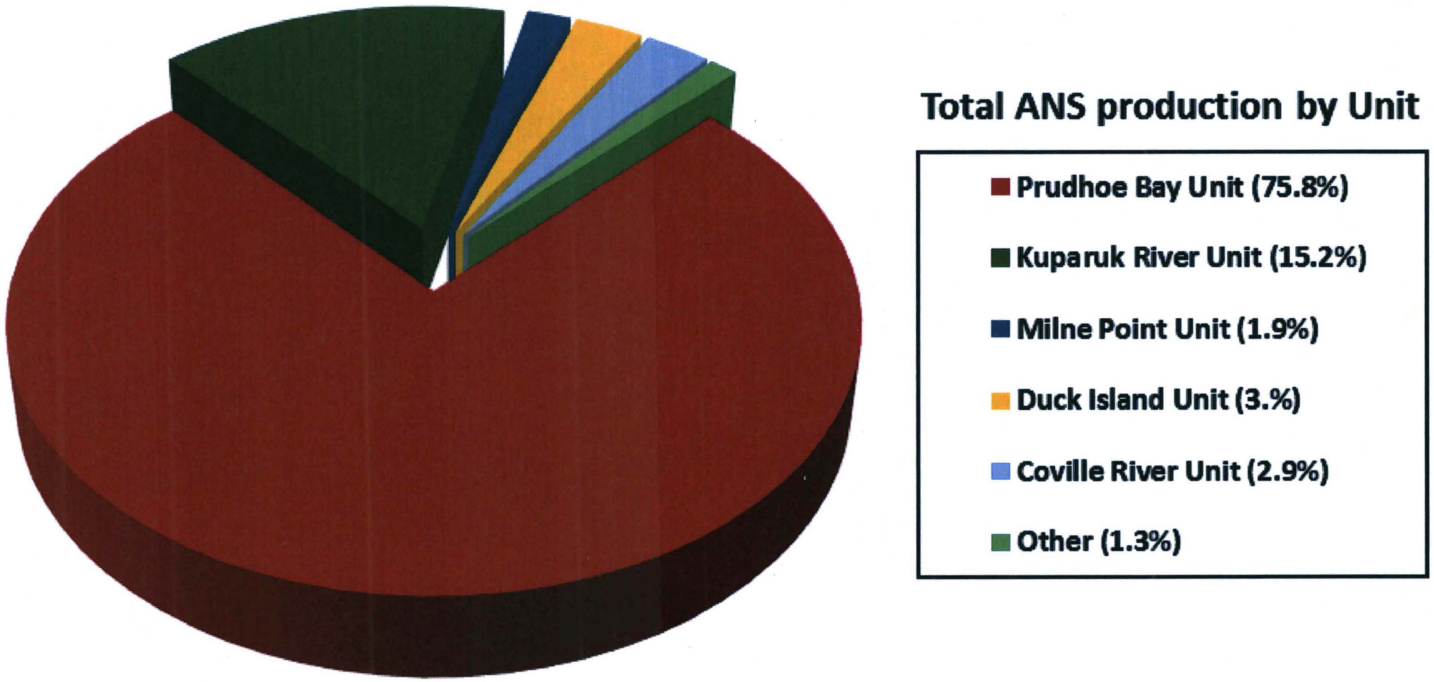
Source: Fall 2015 Revenue Sources Book Back-up

Overview of Revenue and Production

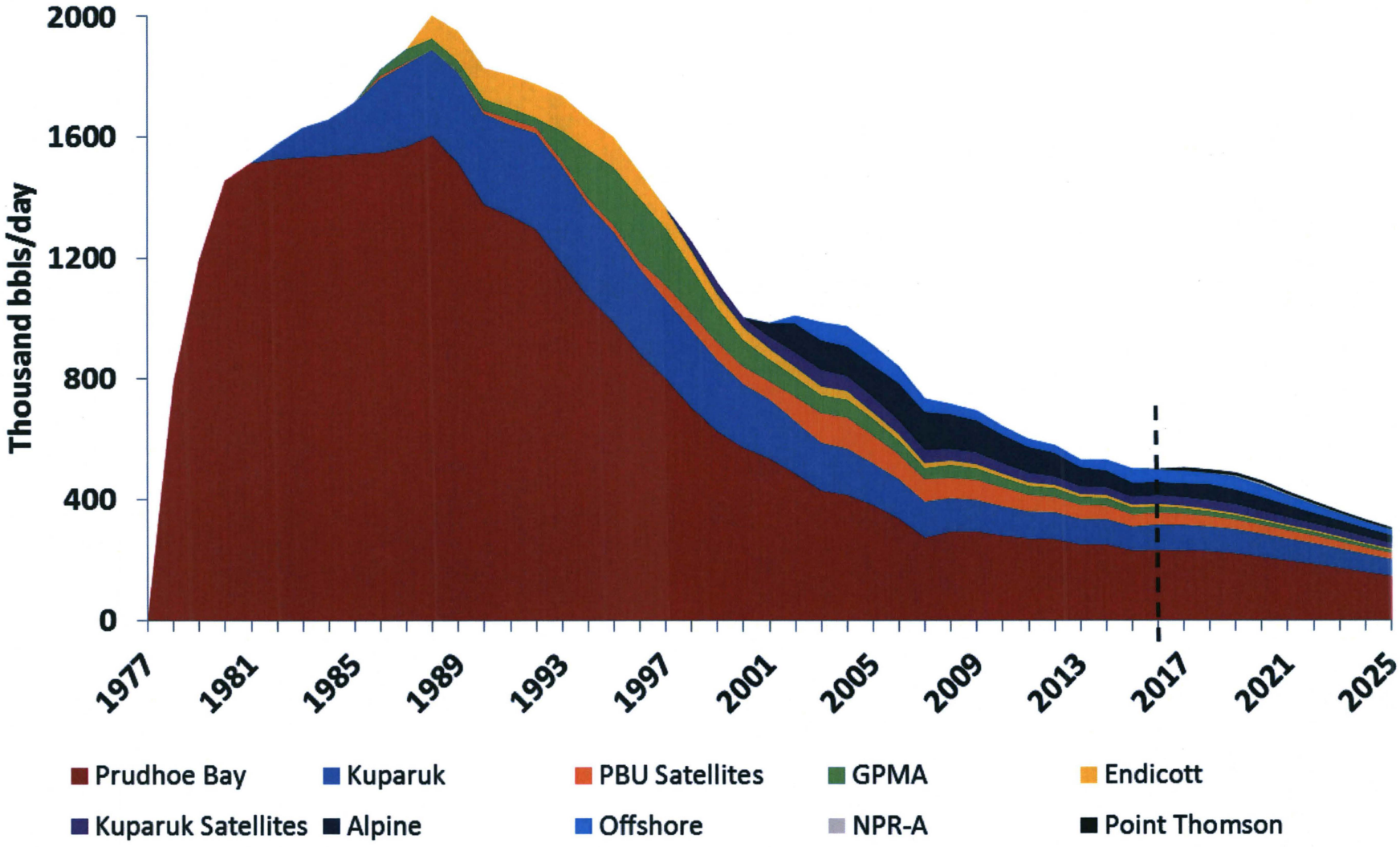
The North Slope has produced approximately 17 billion barrels of crude oil since 1977

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

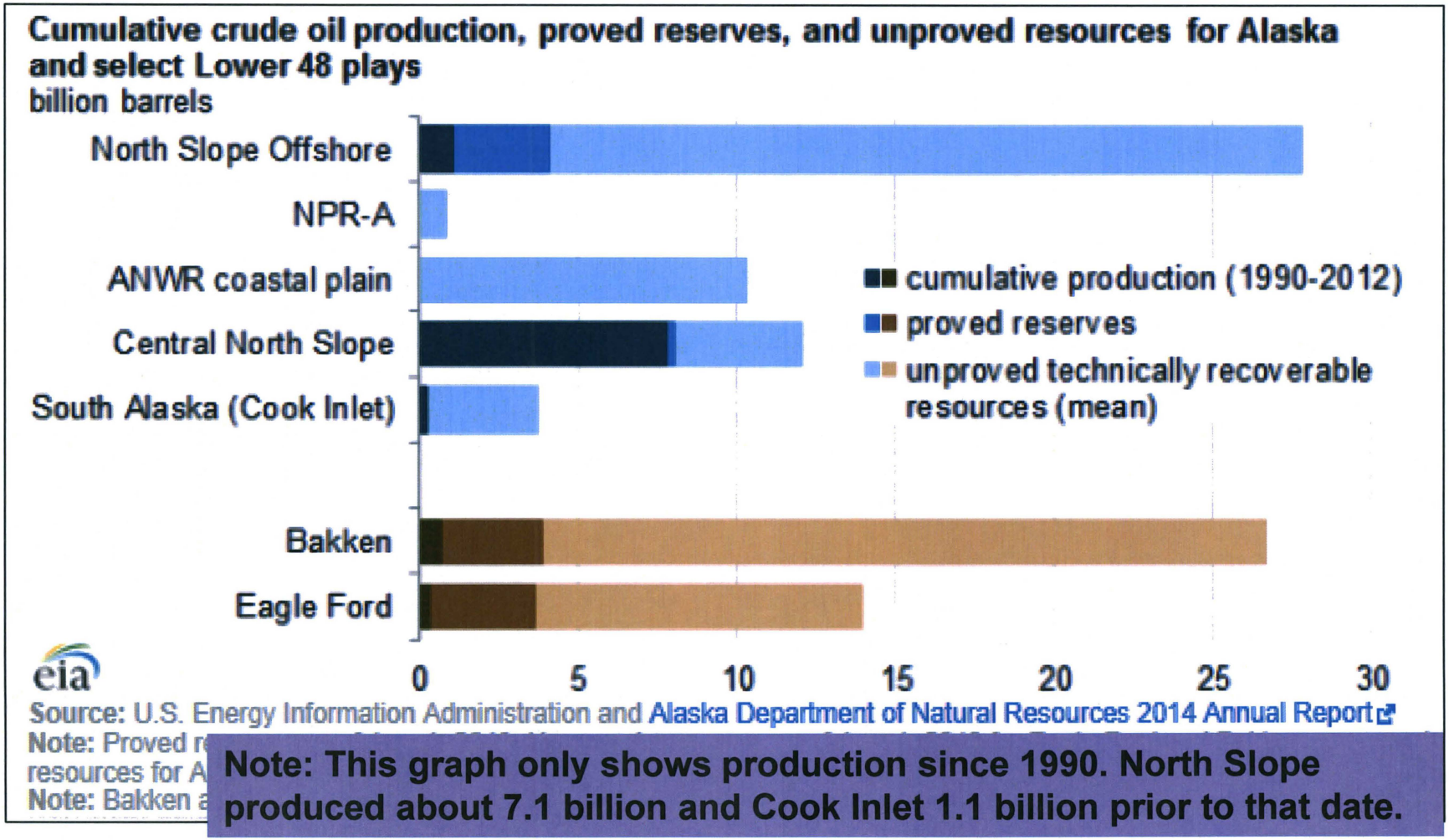


Source: Fall 2015 Revenue Sources Book, Figure 4-D

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.

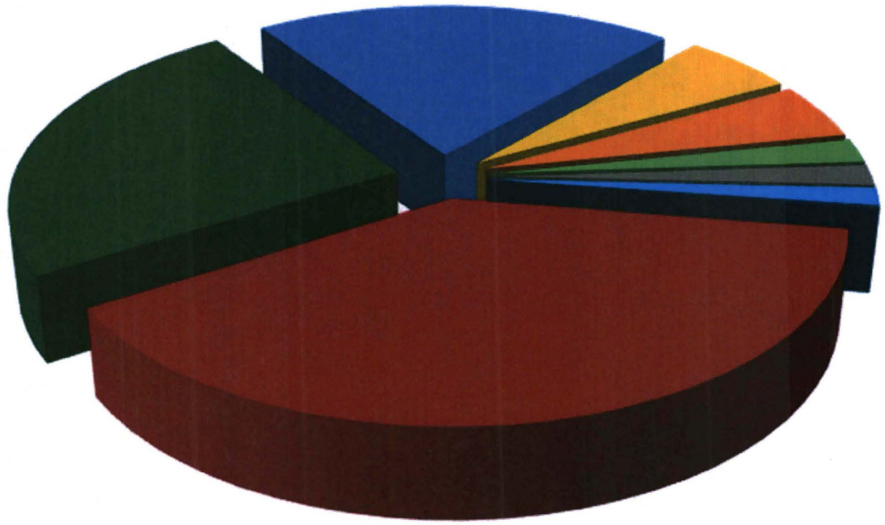


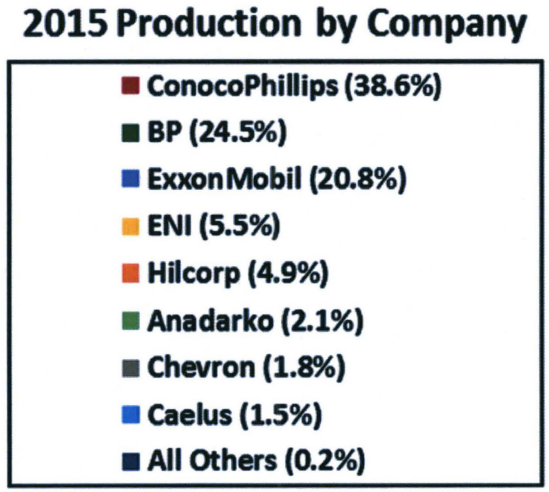
Note: This graph only shows production since 1990. North Slope produced about 7.1 billion and Cook Inlet 1.1 billion prior to that date.

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**

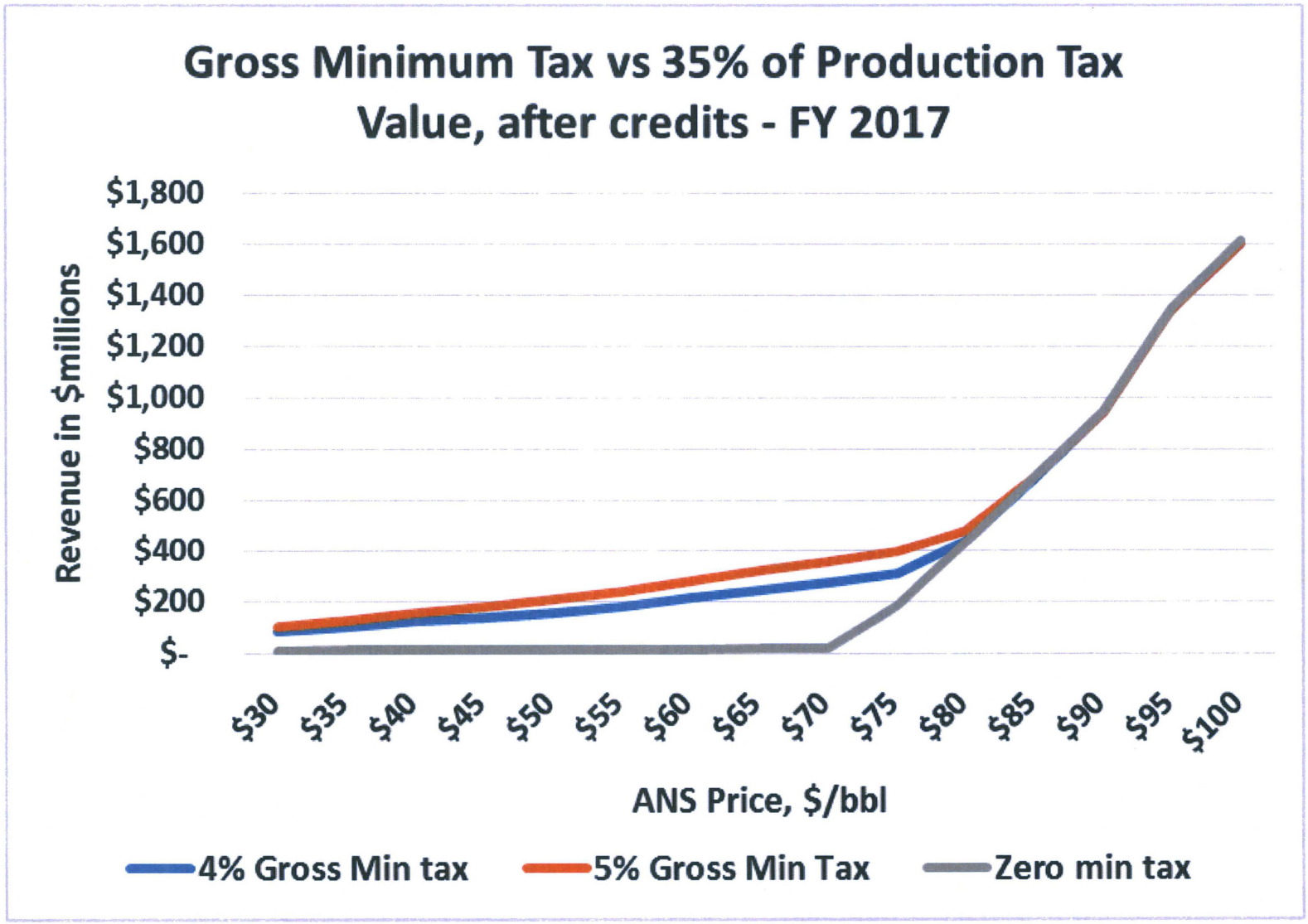
*Does not account for potential changes in Federal Reserve rate

*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 not 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

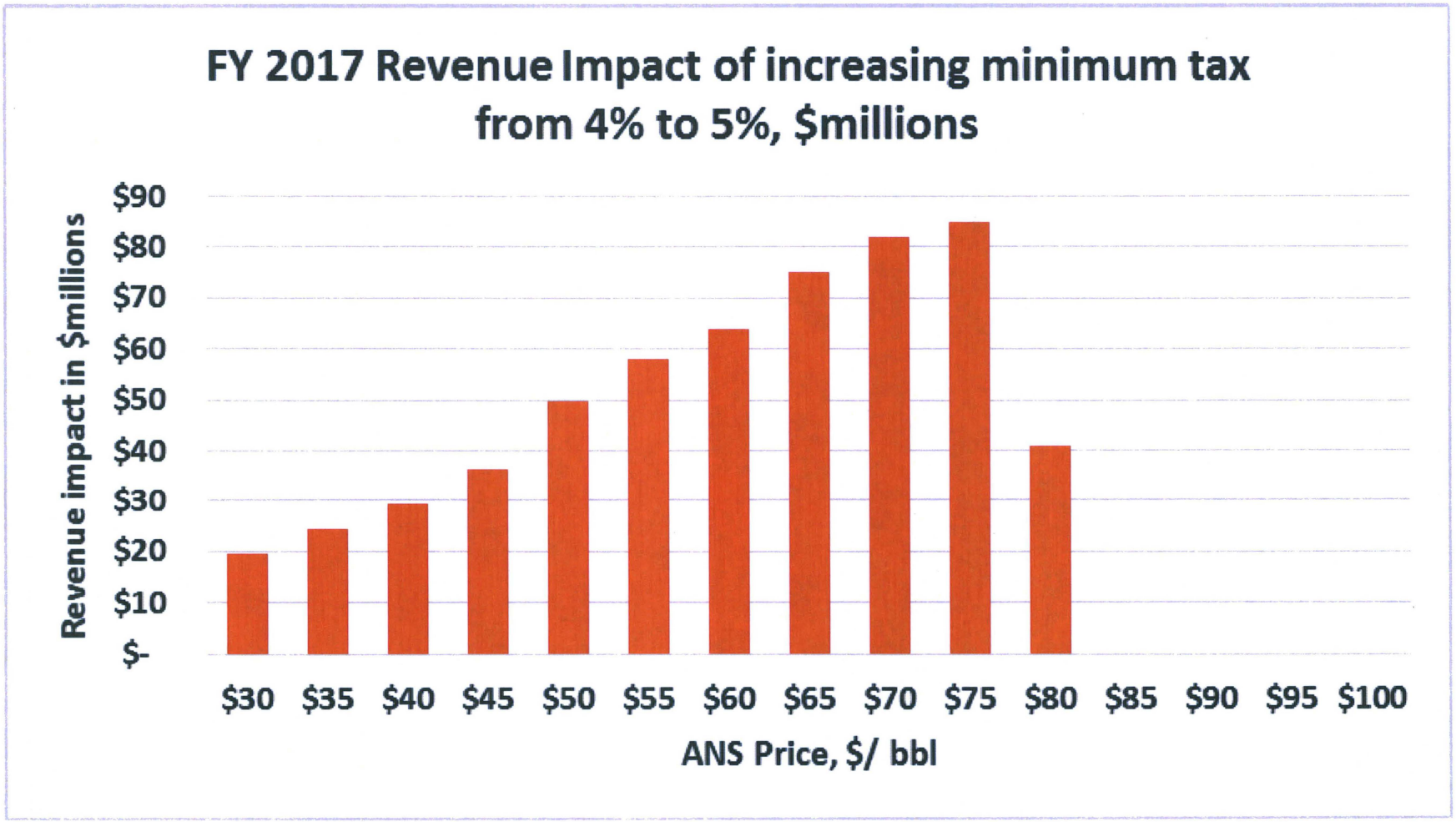
Dollars per Taxable Barrel

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.

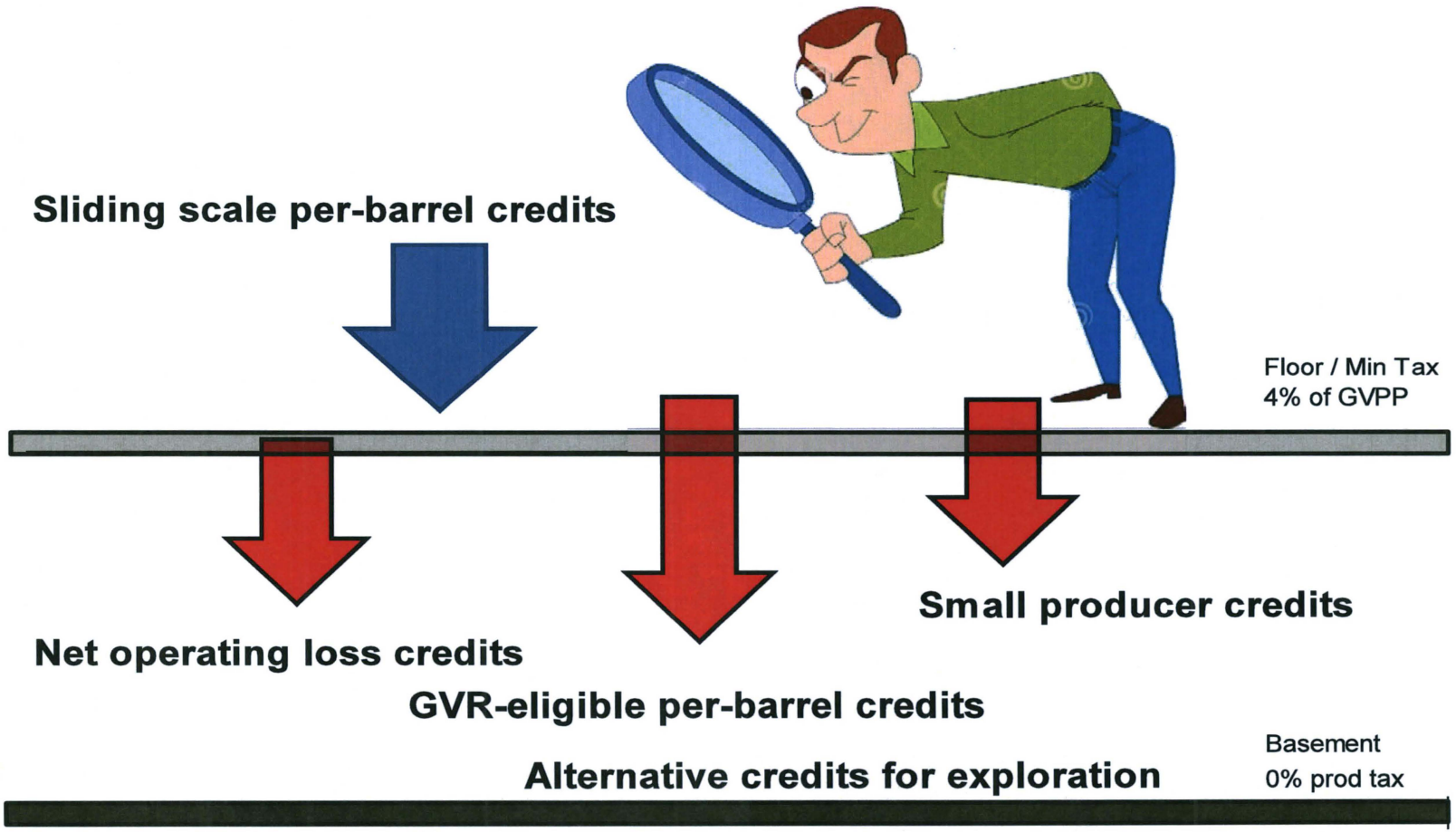
Section 12: Increase Minimum Tax



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**

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

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

Section 17(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

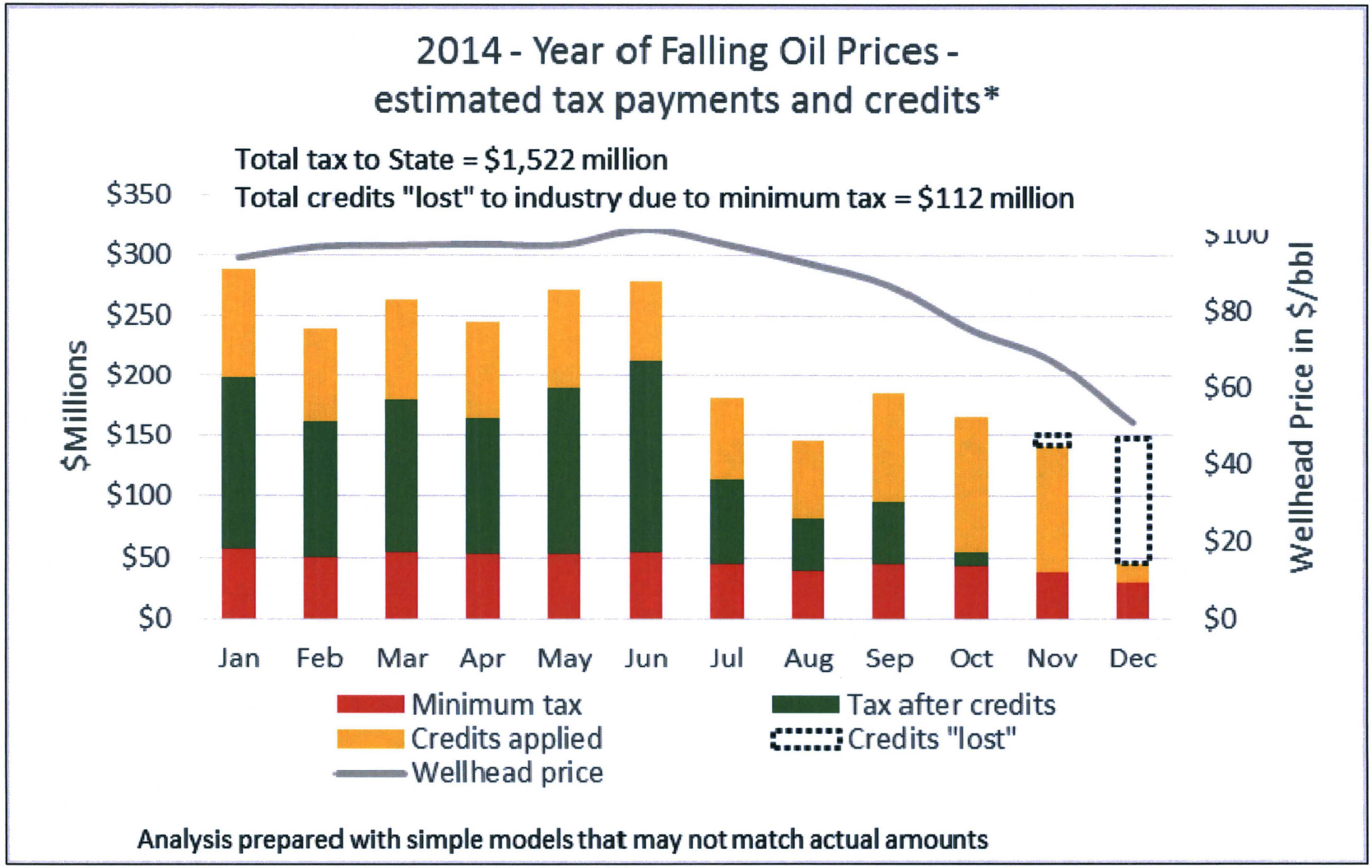
Section 17(c): Strengthen the Minimum Tax

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 monthly calculation with no annual true-up
- If sliding scale credits were intended to be a form of "reverse progressivity," then the calculation should be monthly with no annual true-up

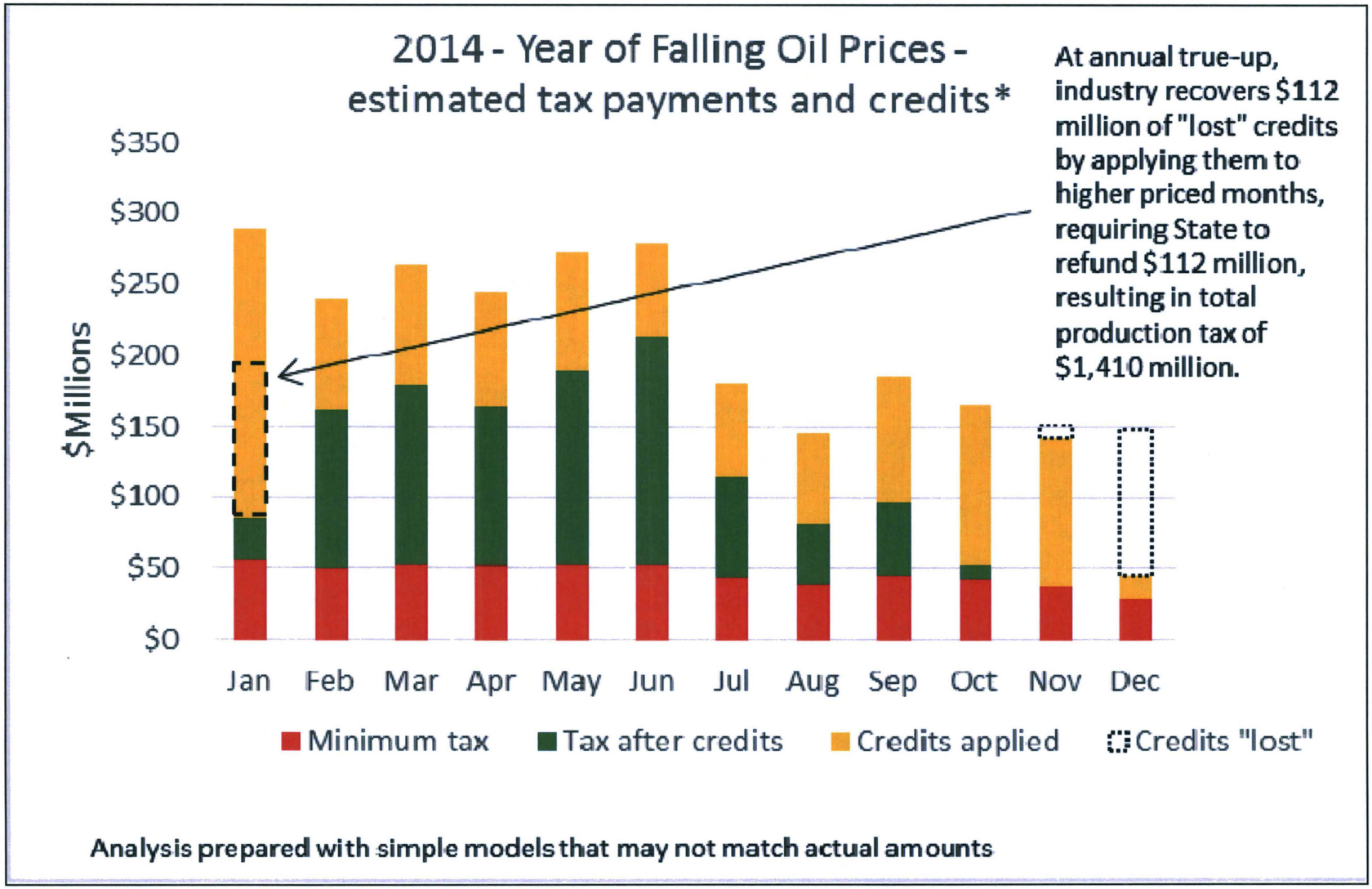
Section 17(c): Strengthen the Minimum Tax

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



Section 17(c): Strengthen the Minimum Tax

"Lost" credits recovered at annual true-up

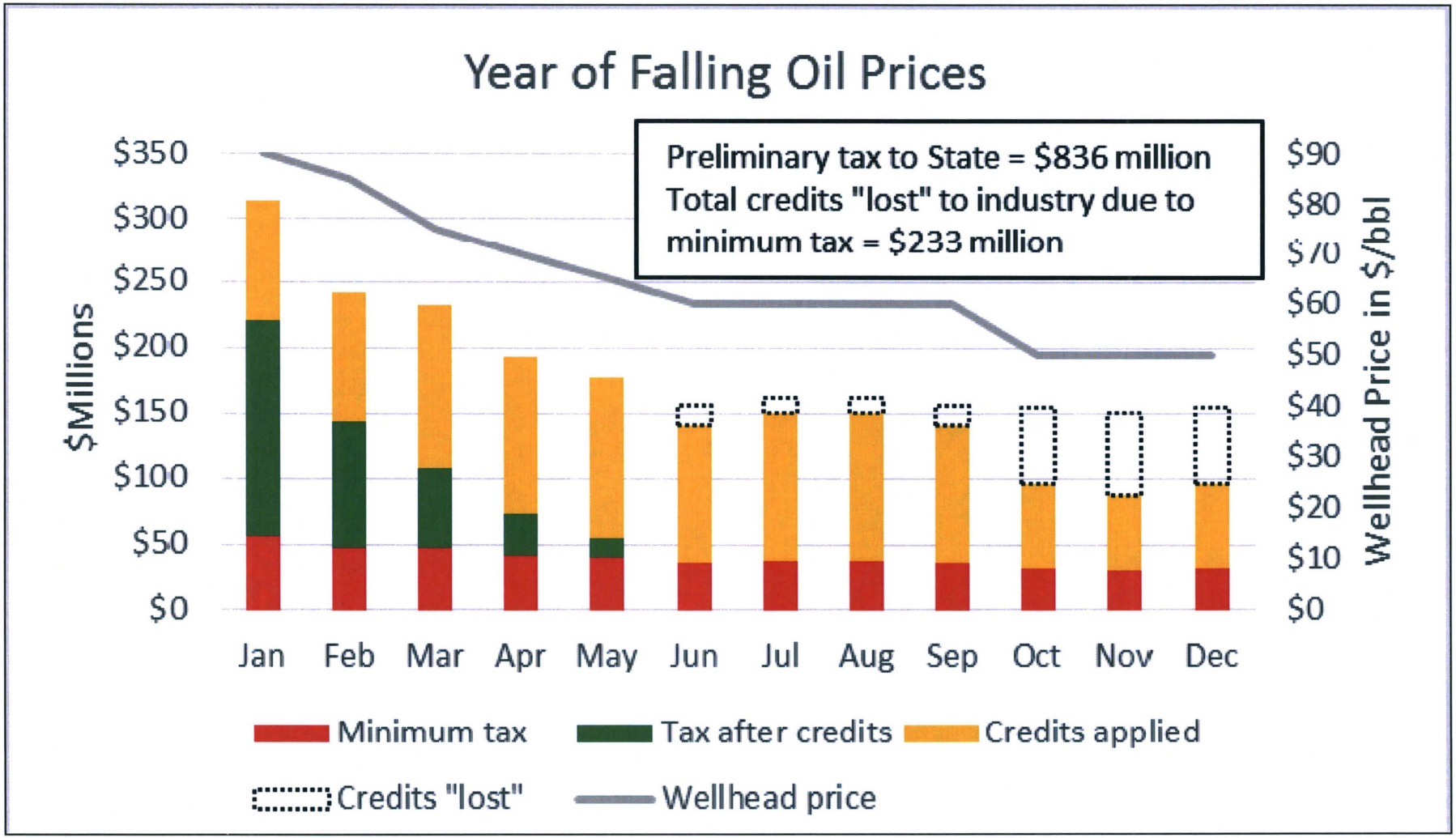


Section 17(c): Strengthen the Minimum Tax

- 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

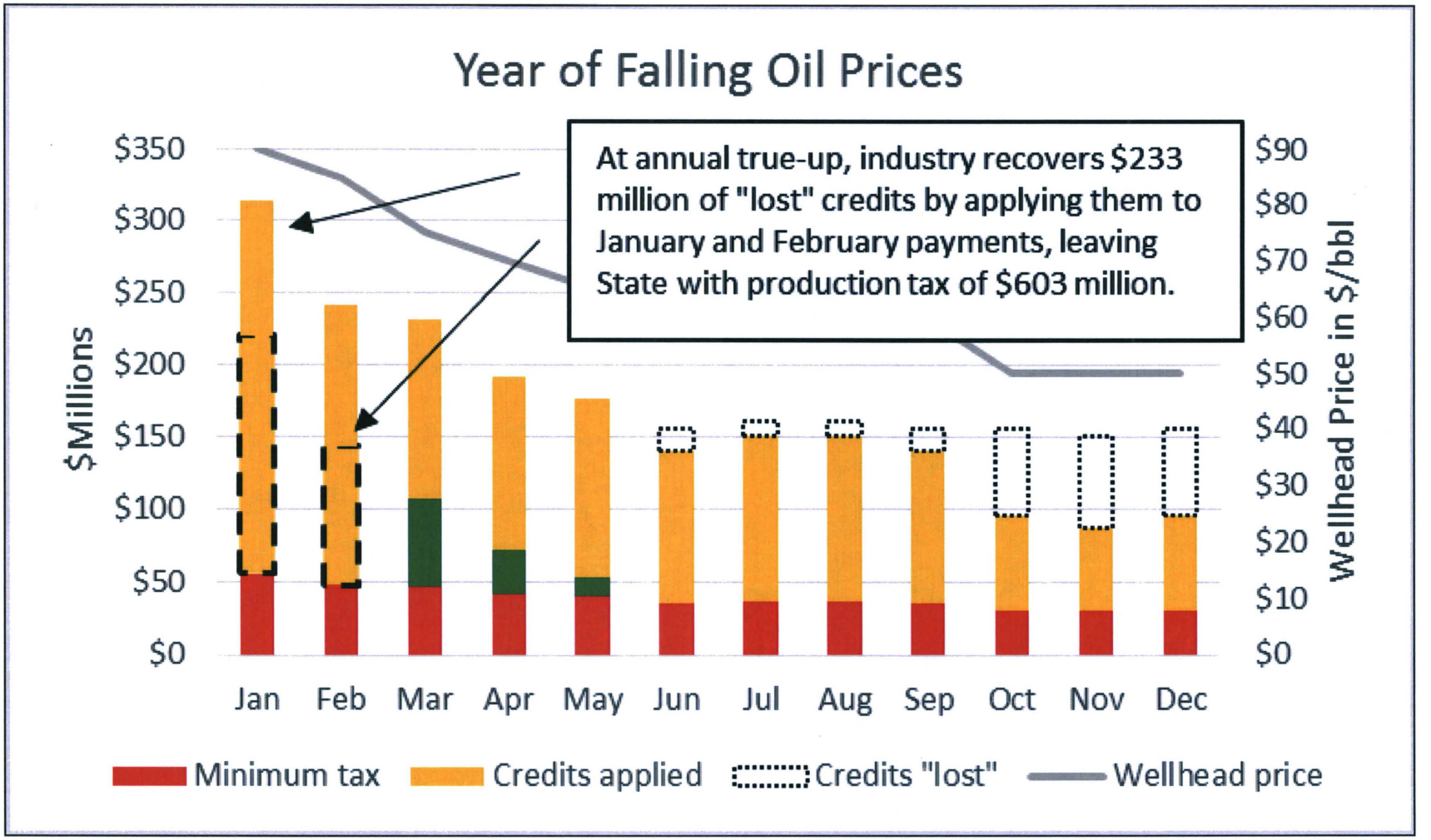
Section 17(c): Strengthen the Minimum Tax

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 Not 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 Not 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 Not 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 Not 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 cannot 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 cannot 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	**Milne Point Unit Tariffs**	$0.24	Kup - Milne Connection
	$1.78	Badami Pipeline		$1.44	Milne Pt Pipeline
	$6.13	TAPS		$6.13	TAPS
Badami Unit Tariffs	**$9.32**	**Total**	**Milne Point Unit Tariffs**	**$7.81**	**Total**
Colville River Unit Tariffs	$0.32	Kuparuk Pipeline	**Pt Thomson Unit Tariffs**	$1.41	Badami Connection
	$0.94	Alpine Tariff		$1.78	Badami Pipeline
				$19.17	Pt Thomson Pipeline
	$6.13	TAPS		$6.13	TAPS
Colville River Unit Tariffs	**$7.39**	**Total**	**Pt Thomson Unit Tariffs**	**$28.49**	**Total**
Duck Island Unit Tariffs	$2.22	Endicott Pipeline	**Northstar Unit Tariffs**	$1.09	Northstar Pipeline
	$6.13	TAPS		$6.13	TAPS
Duck Island Unit Tariffs	**$8.35**	**Total**	**Northstar Unit Tariffs**	**$7.22**	**Total**
Kuparuk River Unit Tariffs	$0.32	Kuparuk Pipeline			
	$6.13	TAPS			
Kuparuk River Unit Tariffs	**$6.45**	**Total**			

Source: Alaska Department of Natural Resources

Section 31: Gross Value cannot 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**

Coming in Part 2

Scenario Analysis:

Analysis of Projects Before and After Proposed Changes

Coming in Part 2

Cook Inlet Gas Supply Issues

NEW SUSTAINABLE
ALASKA
PLAN

Pulling Together to Build Our Future

Thank You!

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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

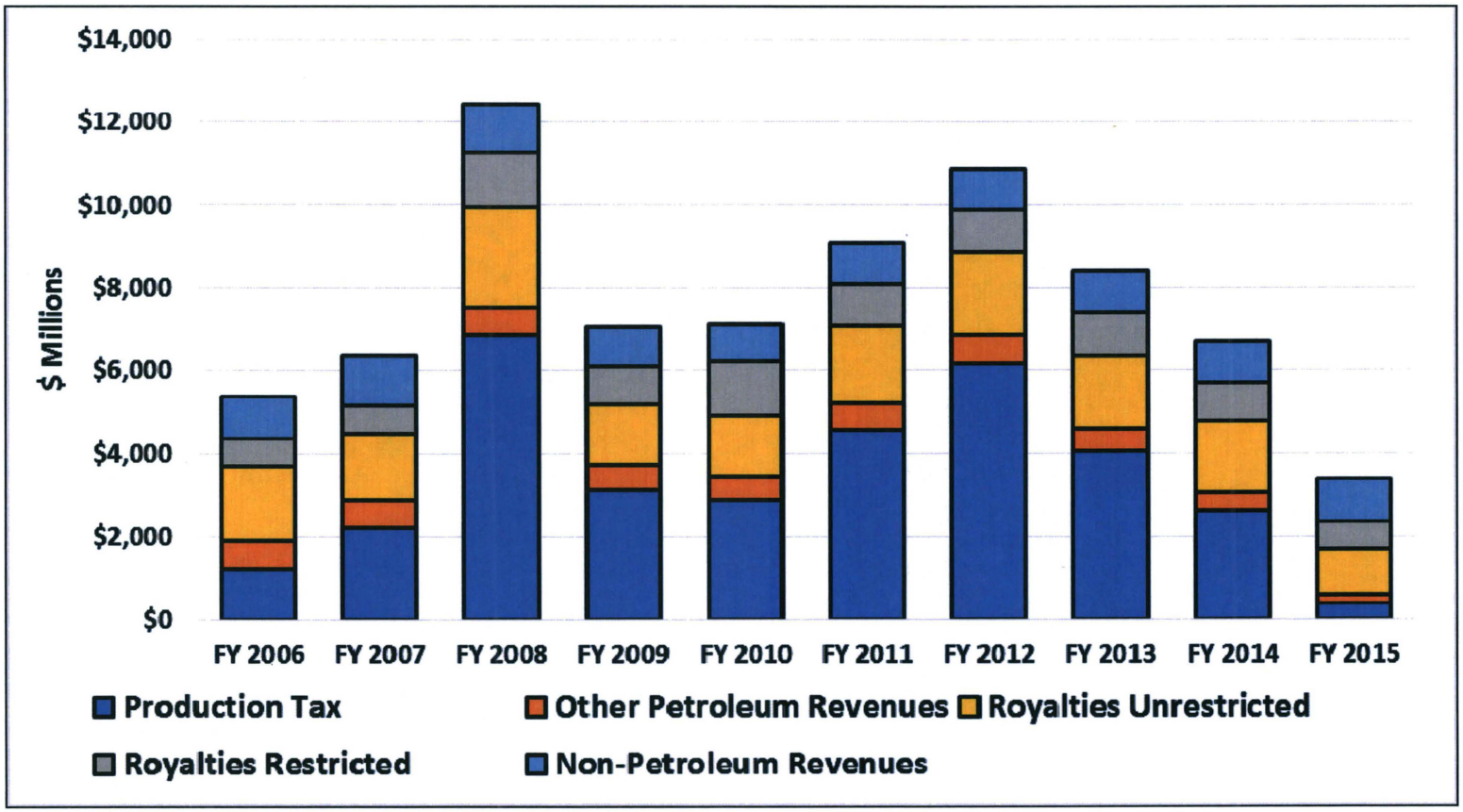
Overview of Revenue and Production

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



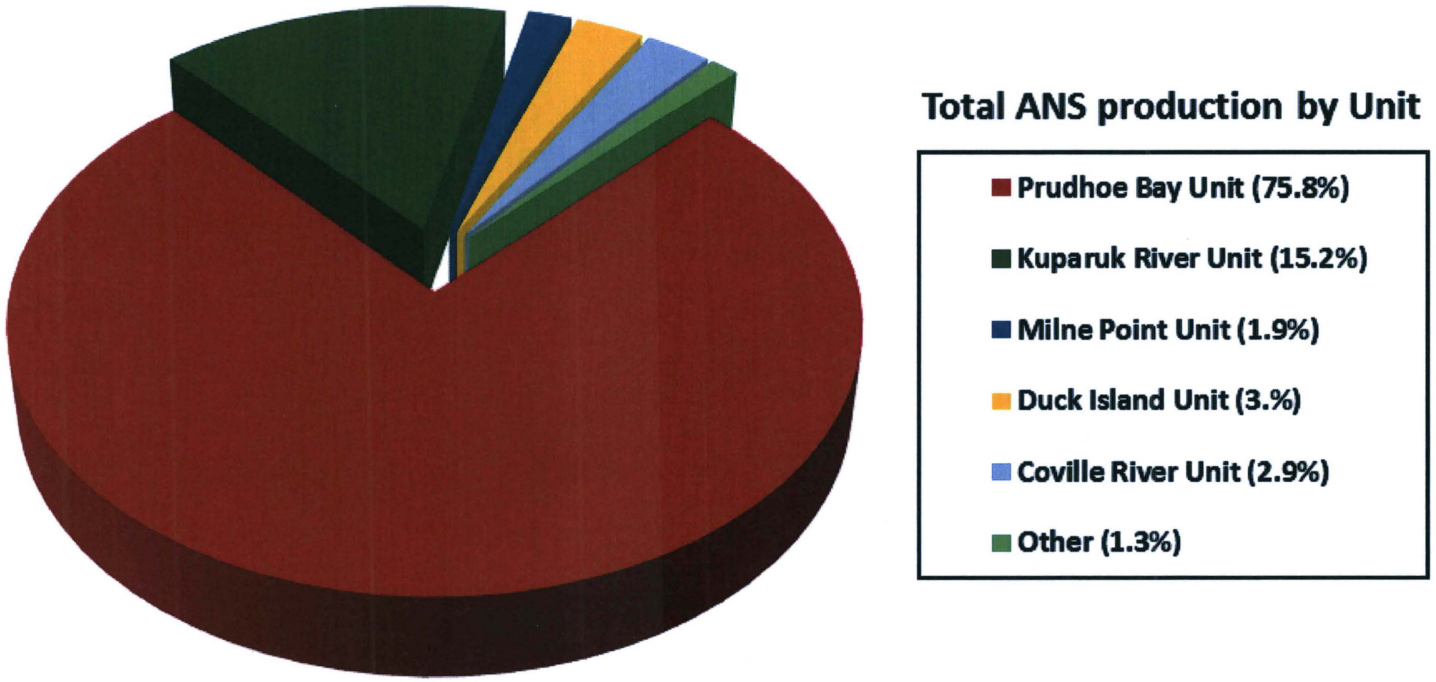
Source: Fall 2015 Revenue Sources Book Back-up

Overview of Revenue and Production

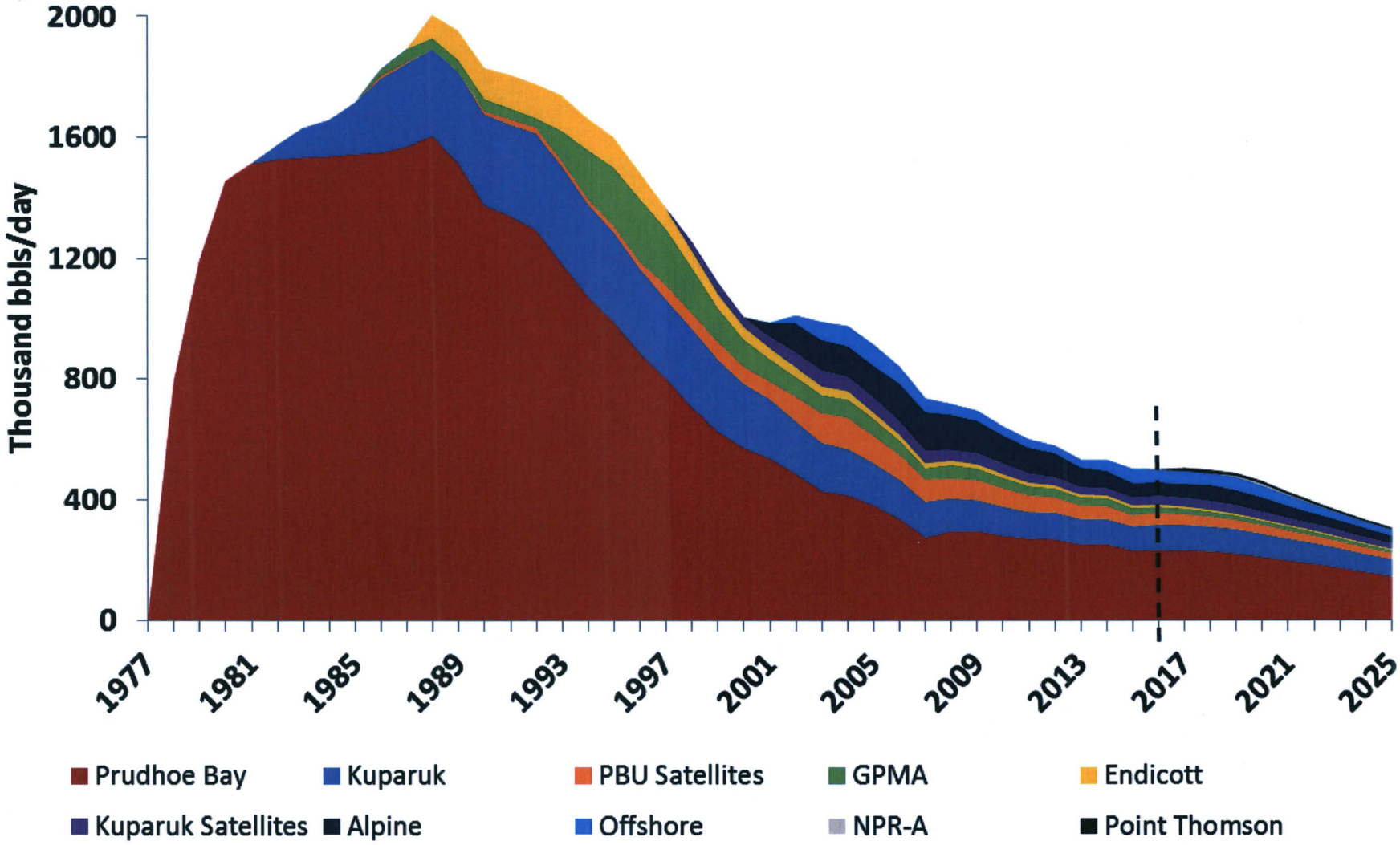
The North Slope has produced approximately 17 billion barrels of crude oil since 1977

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

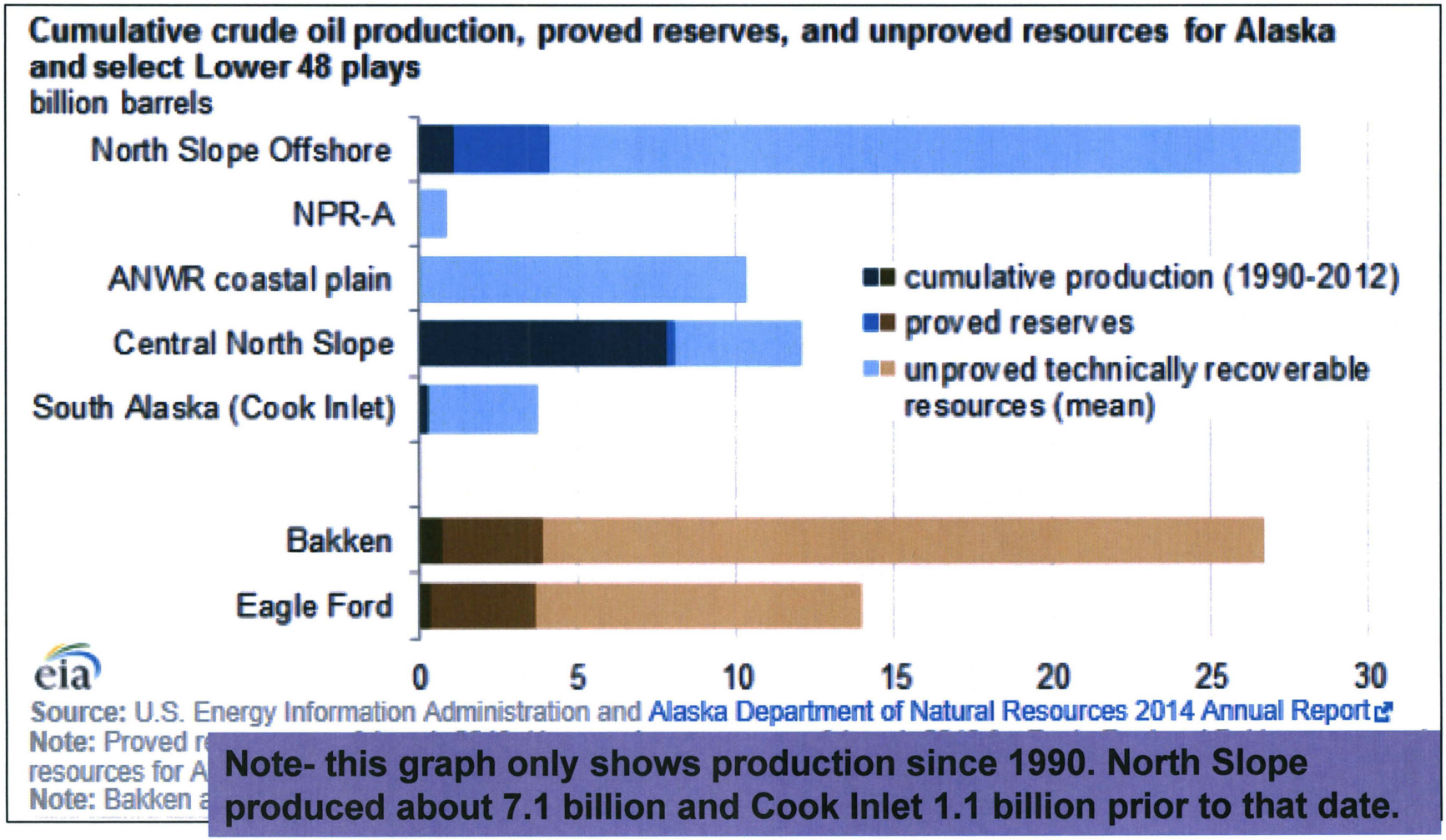


Source: Fall 2015 Revenue Sources Book, Figure 4-D

Note: Offshore includes Northstar, Oooguruk, and Nikaitchuq

Overview of Revenue and Production

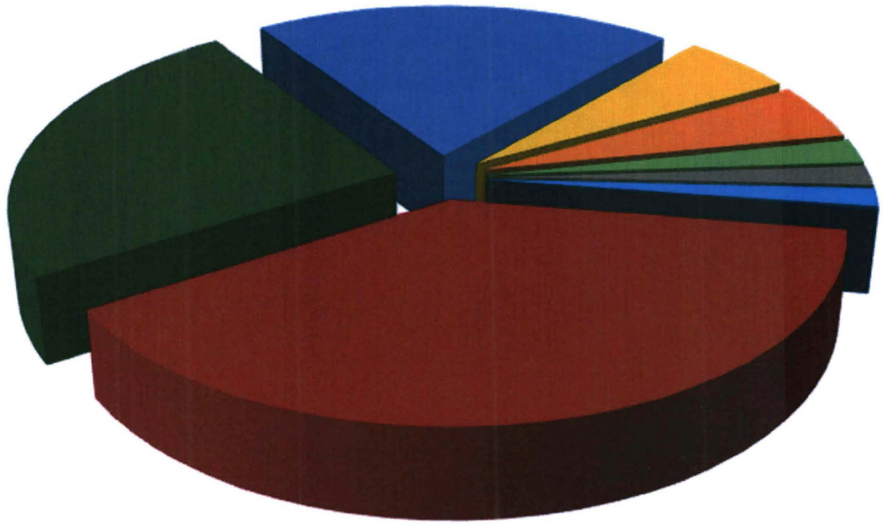
Many North Slope fields are now at mature stages. However, there is still a lot of untapped potential for new development, especially offshore.

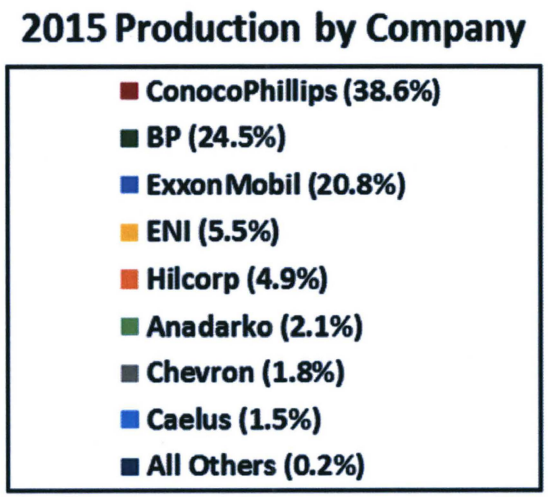


Overview of Revenue and Production

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**

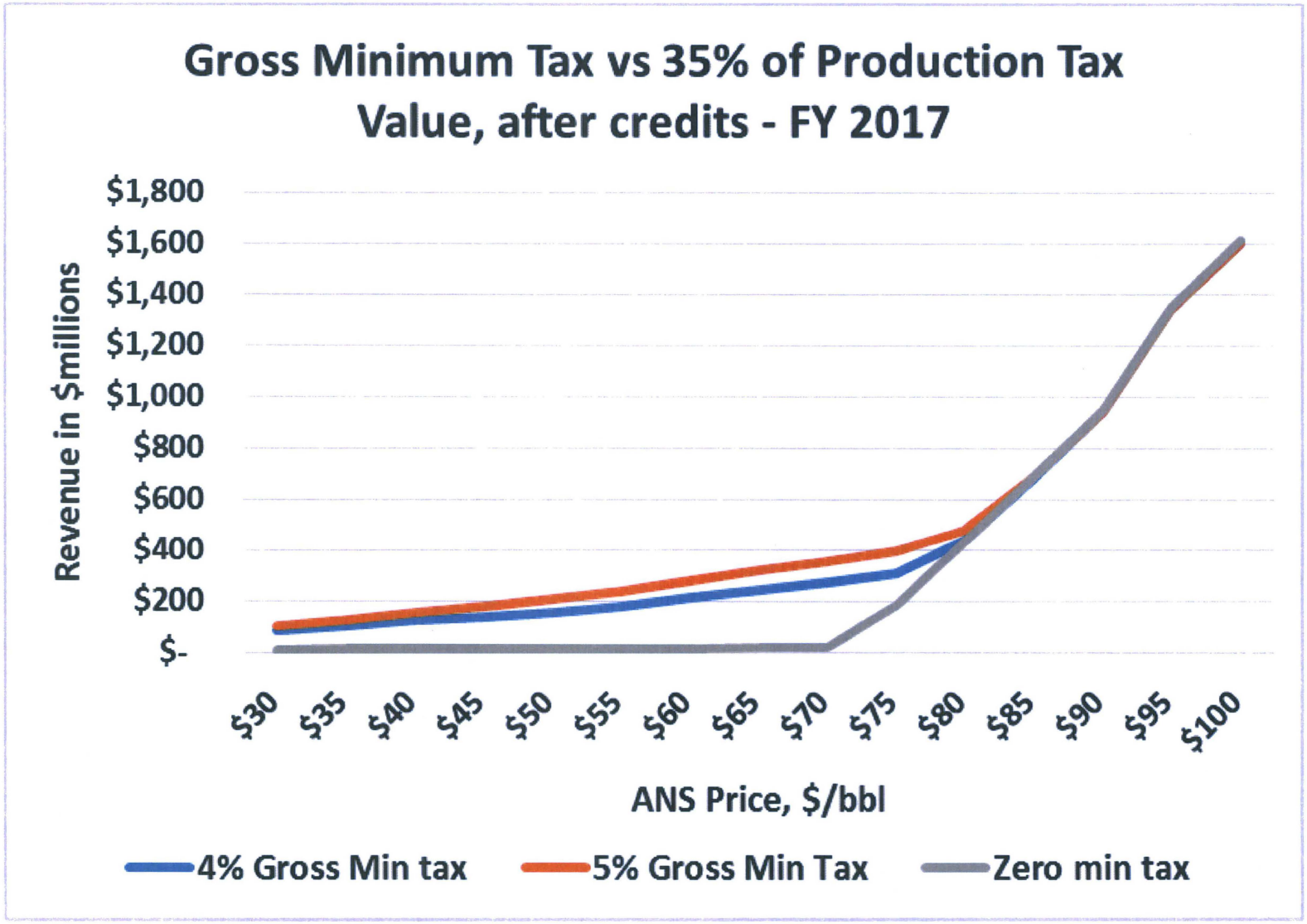
*Does not account for potential changes in Federal Reserve rate

*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

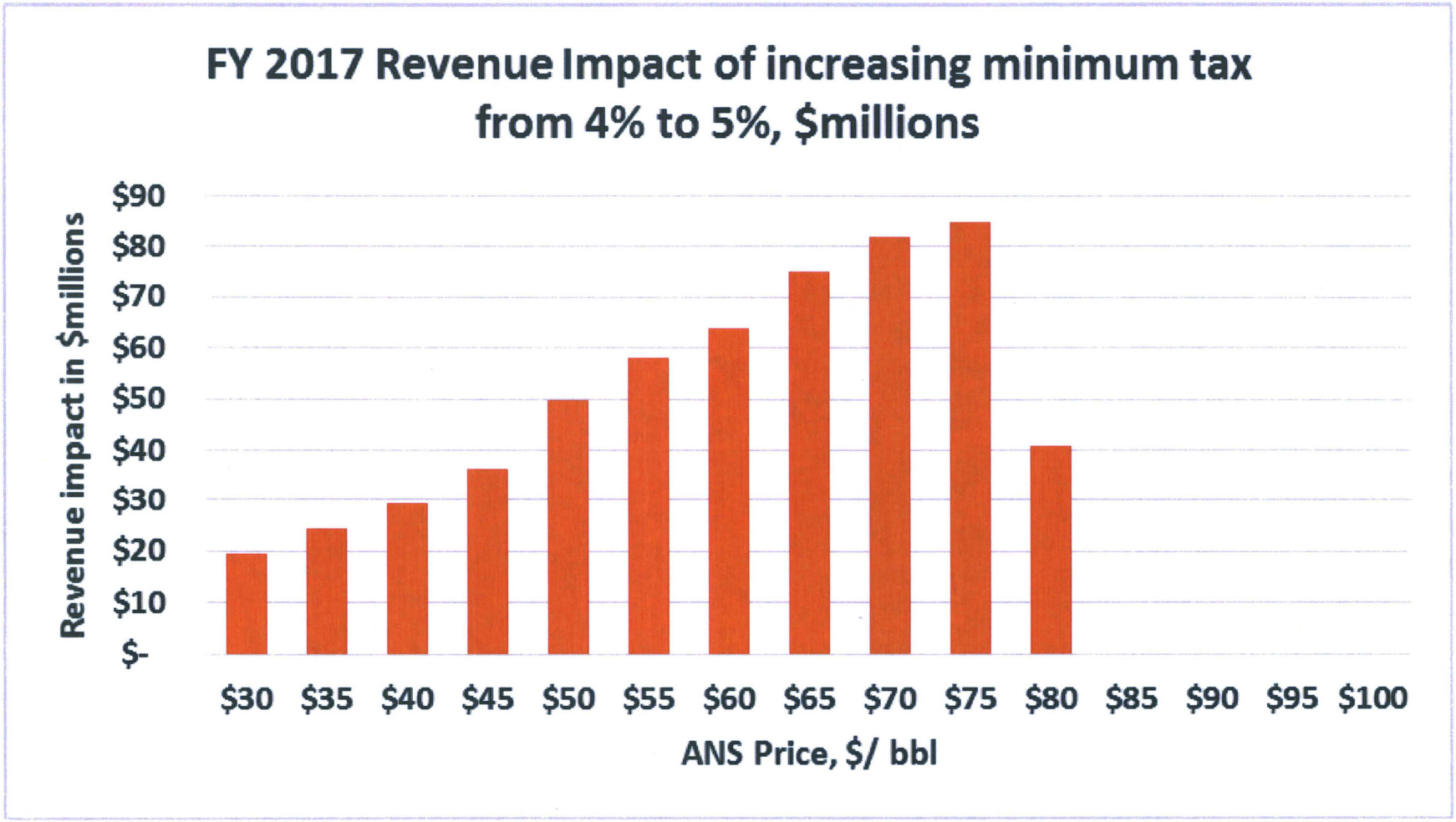
Section 12: Increase Minimum Tax

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.

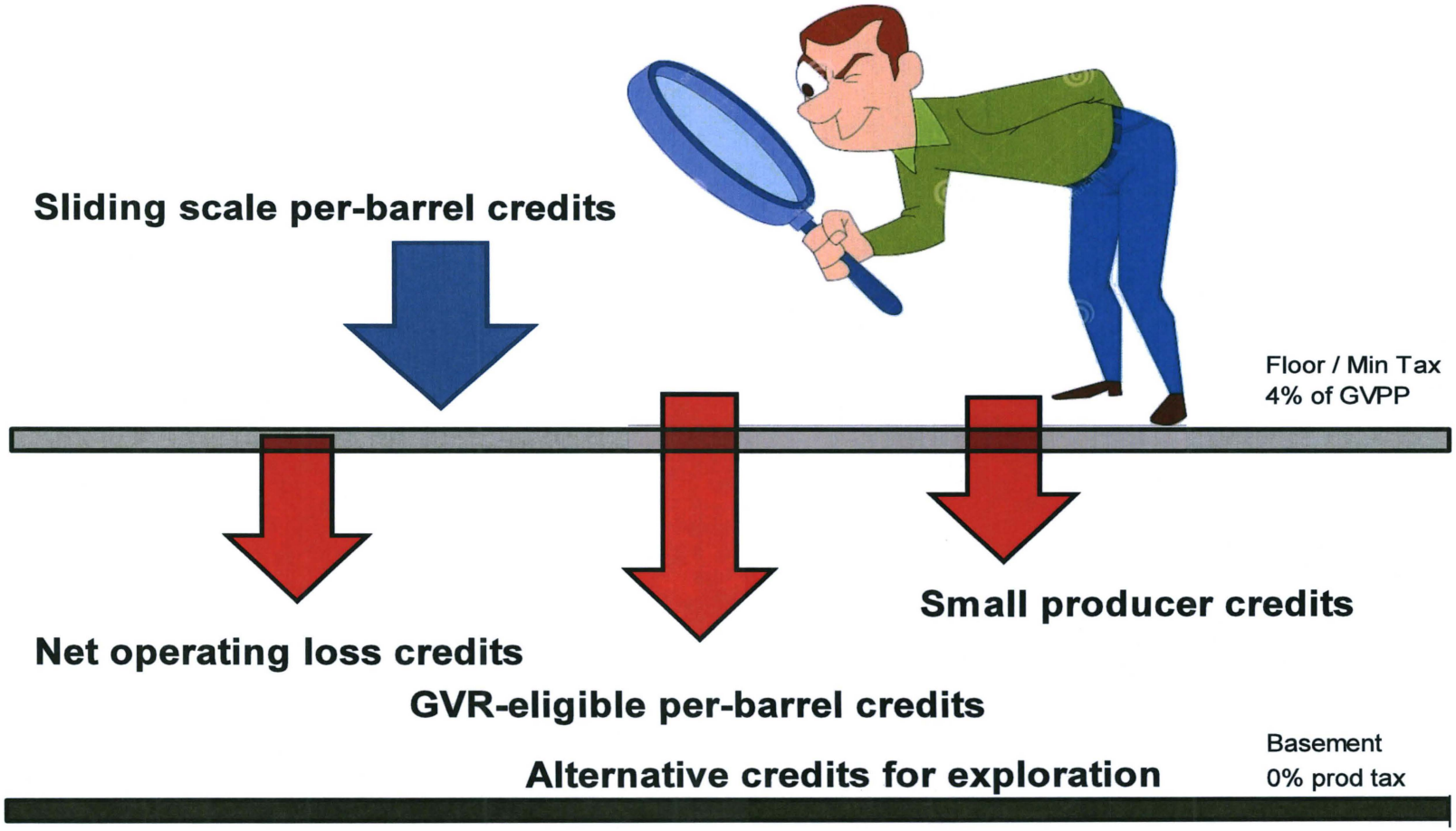
Section 12: Increase Minimum Tax



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**

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

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

Section 17(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

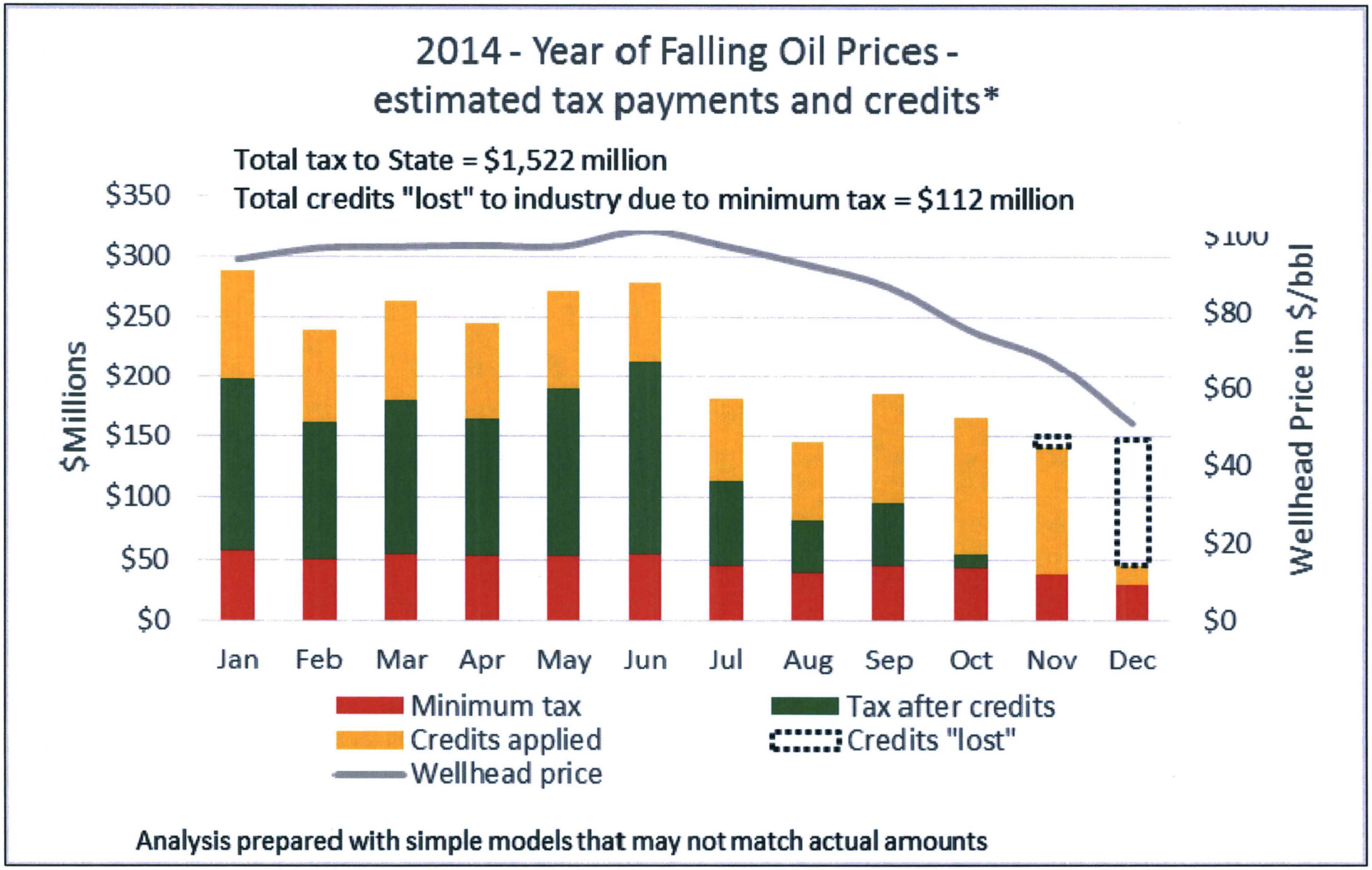
Section 17(c): Strengthen the Minimum Tax

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 monthly calculation with no annual true-up
- If sliding scale credits were intended to be a form of "reverse progressivity," then the calculation should be monthly with no annual true-up

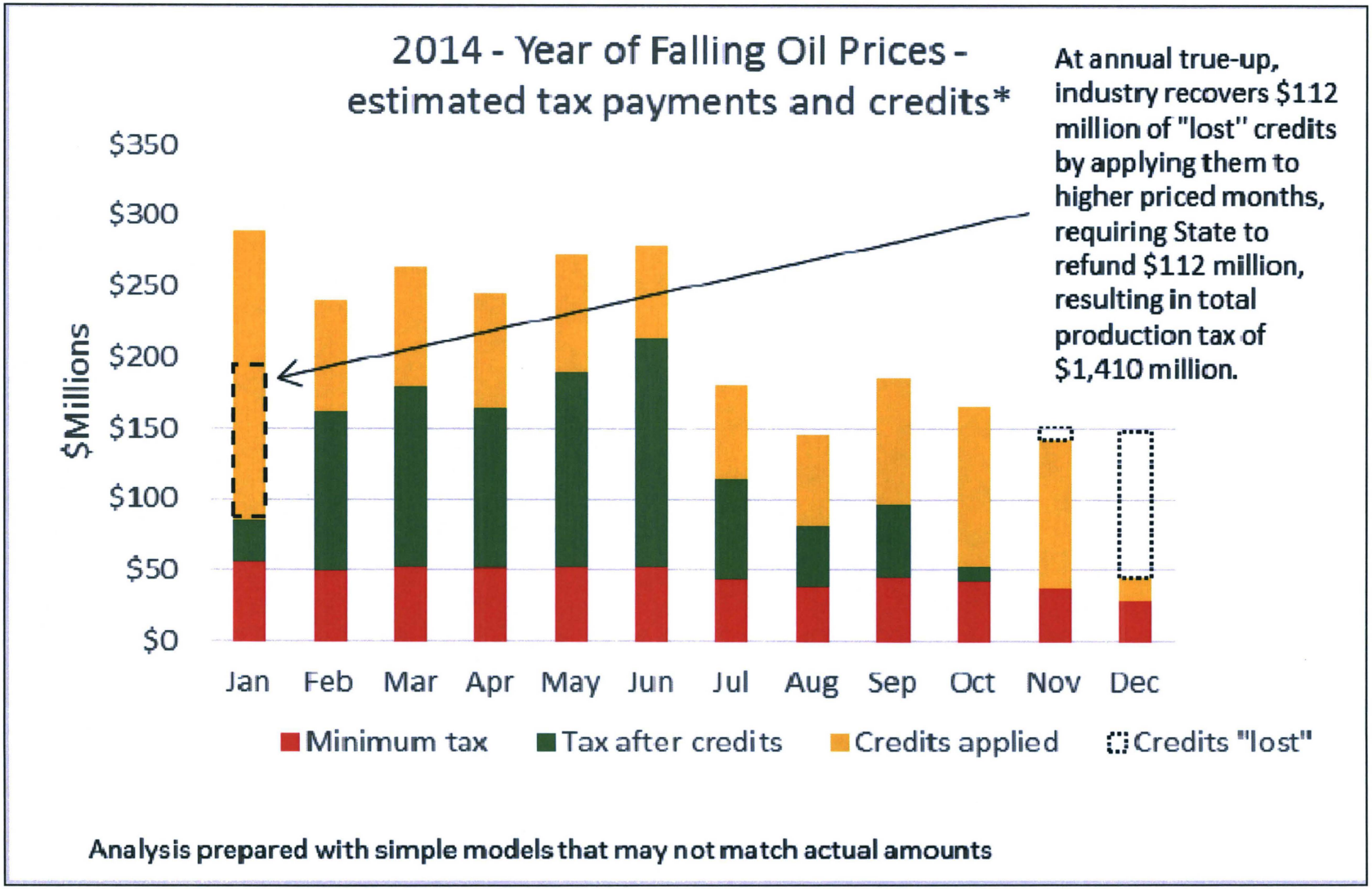
Section 17(c): Strengthen the Minimum Tax

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



Section 17(c): Strengthen the Minimum Tax

"Lost" credits recovered at annual true-up

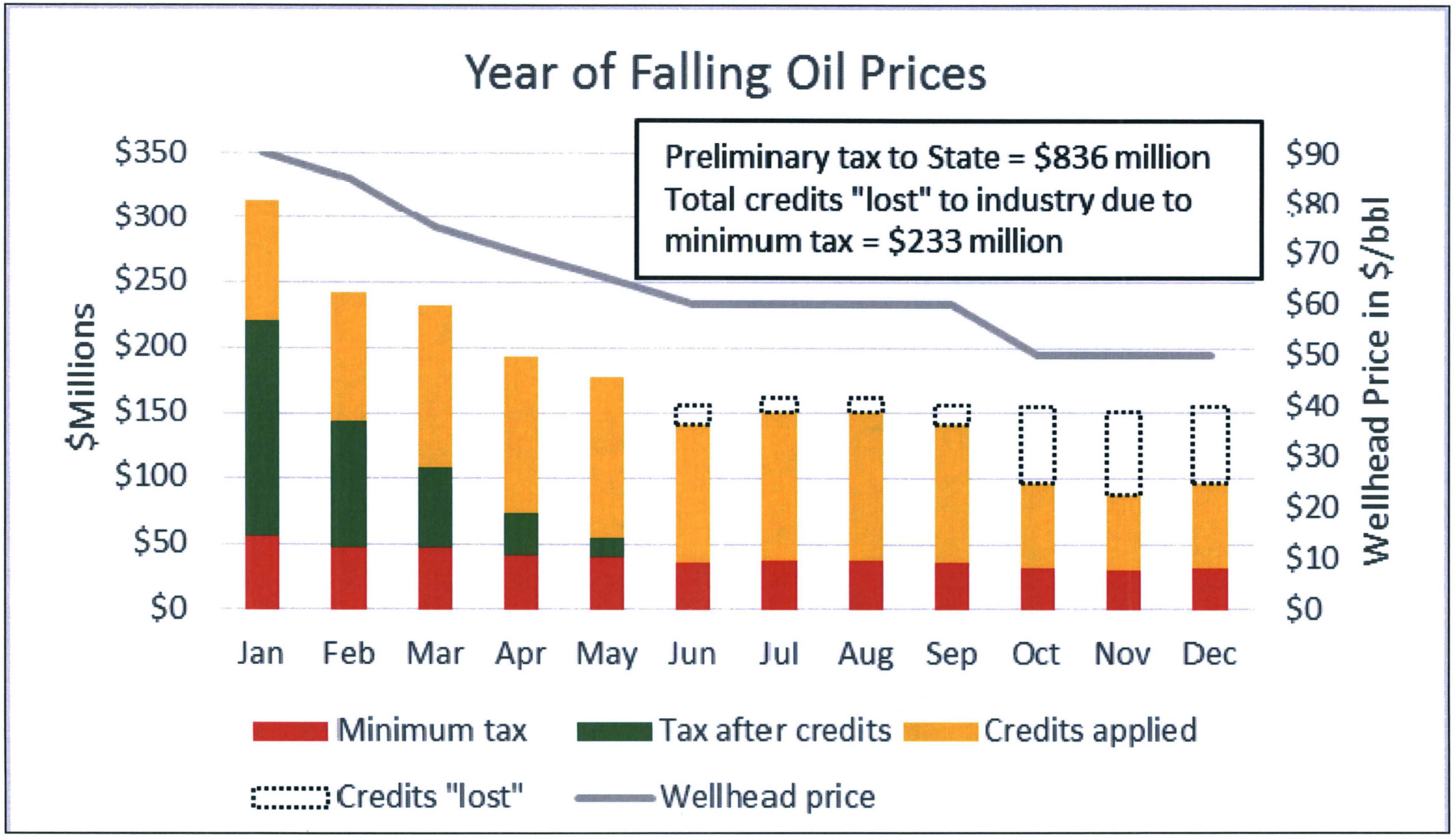


Section 17(c): Strengthen the Minimum Tax

- 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

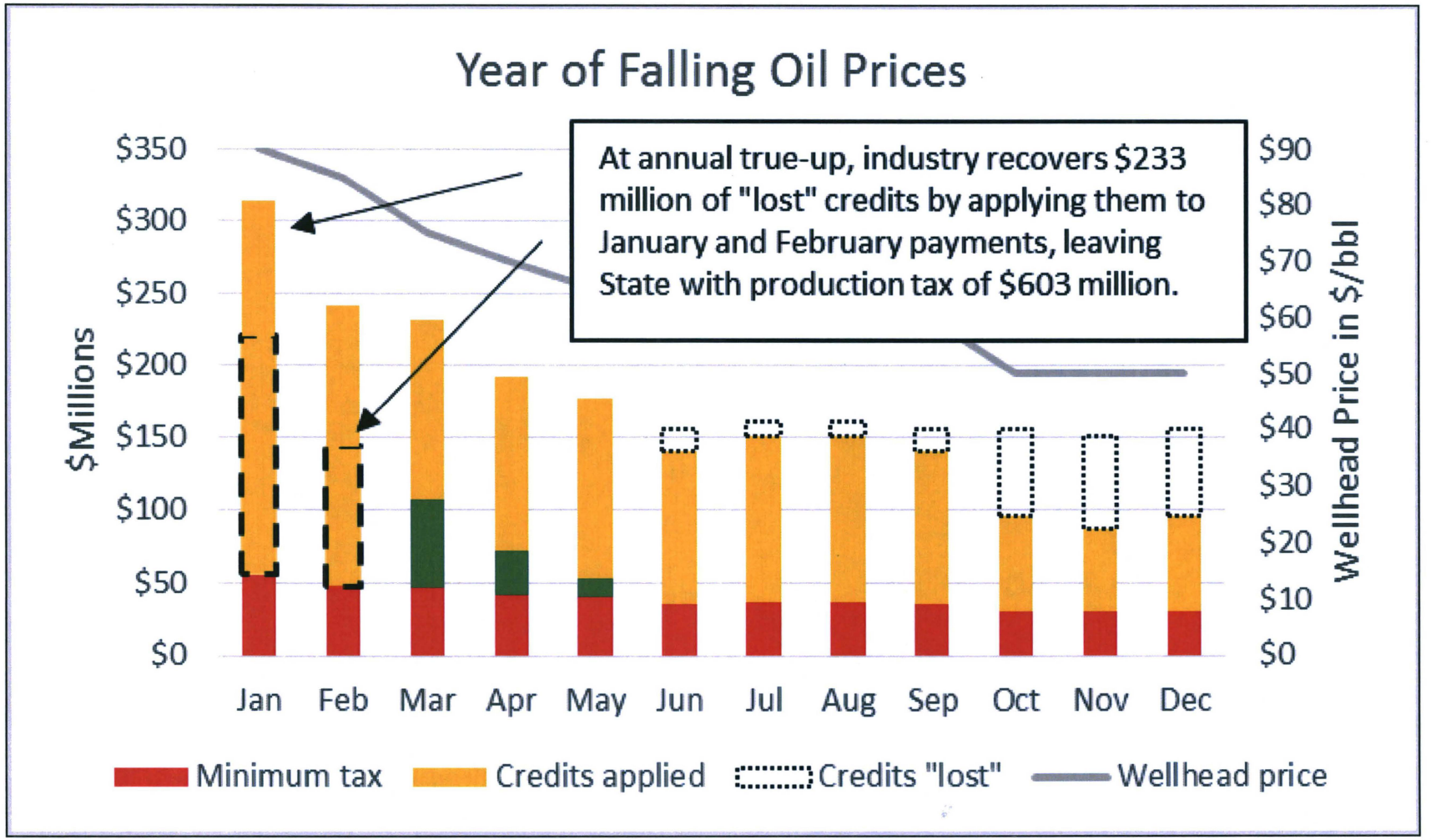
Section 17(c): Strengthen the Minimum Tax

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	**Milne Point Unit Tariffs**	$0.24	Kup - Milne Connection
	$1.78	Badami Pipeline		$1.44	Milne Pt Pipeline
	$6.13	TAPS		$6.13	TAPS
Badami Unit Tariffs	**$9.32**	**Total**	**Milne Point Unit Tariffs**	**$7.81**	**Total**
Colville River Unit Tariffs	$0.32	Kuparuk Pipeline	**Pt Thomson Unit Tariffs**	$1.41	Badami Connection
	$0.94	Alpine Tariff		$1.78	Badami Pipeline
				$19.17	Pt Thomson Pipeline
	$6.13	TAPS		$6.13	TAPS
Colville River Unit Tariffs	**$7.39**	**Total**	**Pt Thomson Unit Tariffs**	**$28.49**	**Total**
Duck Island Unit Tariffs	$2.22	Endicott Pipeline	**Northstar Unit Tariffs**	$1.09	Northstar Pipeline
	$6.13	TAPS		$6.13	TAPS
Duck Island Unit Tariffs	**$8.35**	**Total**	**Northstar Unit Tariffs**	**$7.22**	**Total**
Kuparuk River Unit Tariffs	$0.32	Kuparuk Pipeline			
	$6.13	TAPS			
Kuparuk River Unit Tariffs	**$6.45**	**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 supply cases ranging from 1,183 (2P reserves in legacy fields) to 1,600 BCF (2P legacy reserves + new field developments)

Consider 3 gas demand 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 supply vs demand 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., Updated engineering evaluation of remaining Cook Inlet gas reserves, Alaska Division of Oil and Gas, 148 p.

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

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

Bradner, T, 2015, BlueCrest set for April production at Cosmo, 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

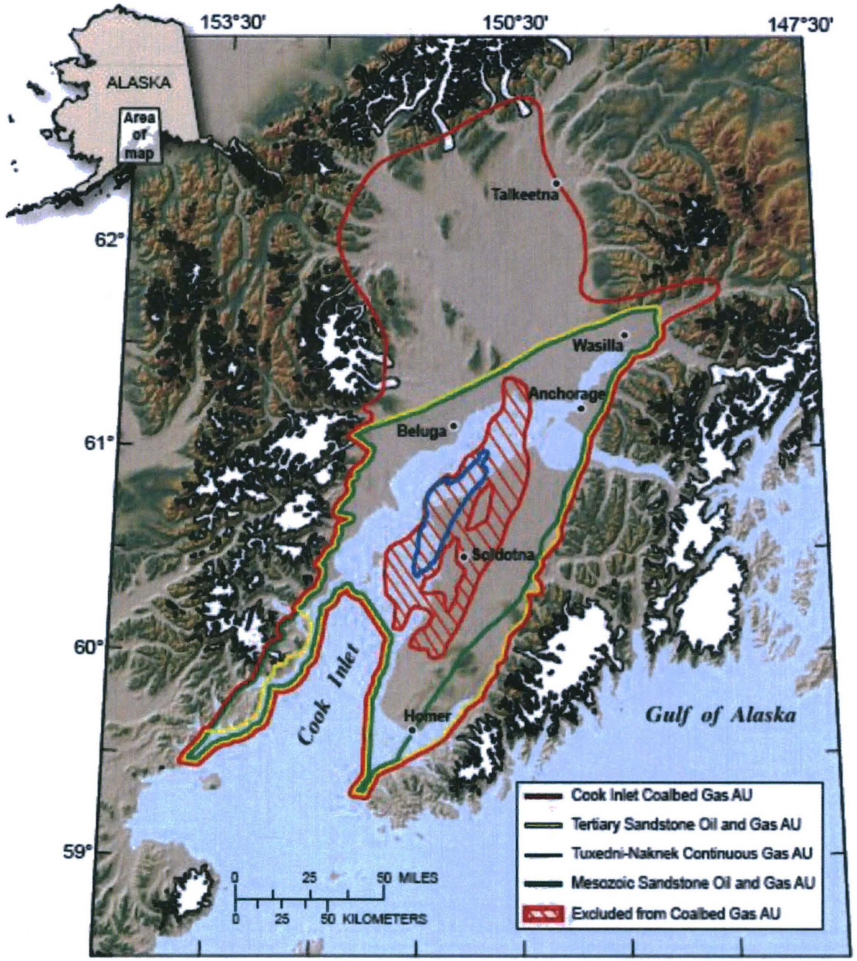
  (Demand Case 2 + 24Bcf Agrium)

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

NEW SUSTAINABLE
ALASKA
PLAN

Pulling Together to Build Our Future

Thank You!

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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 2a"

Presentation to the House Resources Committee

February 27, 2016

What We'll Be Discussing

Part 1: February 22-24-25 Presentation

- Overview of Revenue and Production
- Credits- what worked, what didn't?
- Credit cost in perspective
- Bill Details- how pieces work
- Gas supply issues in Cook Inlet

Part 2: This Presentation

- Scenario Analysis- economics of changes
  - Impact of minimum tax changes on current production
  - Life cycle analysis of possible new fields- North Slope
  - Life cycle analysis of possible new fields- Cook Inlet
  - Summary slides

North Slope Production Tax Snapshot With Impact of Minimum Tax Changes

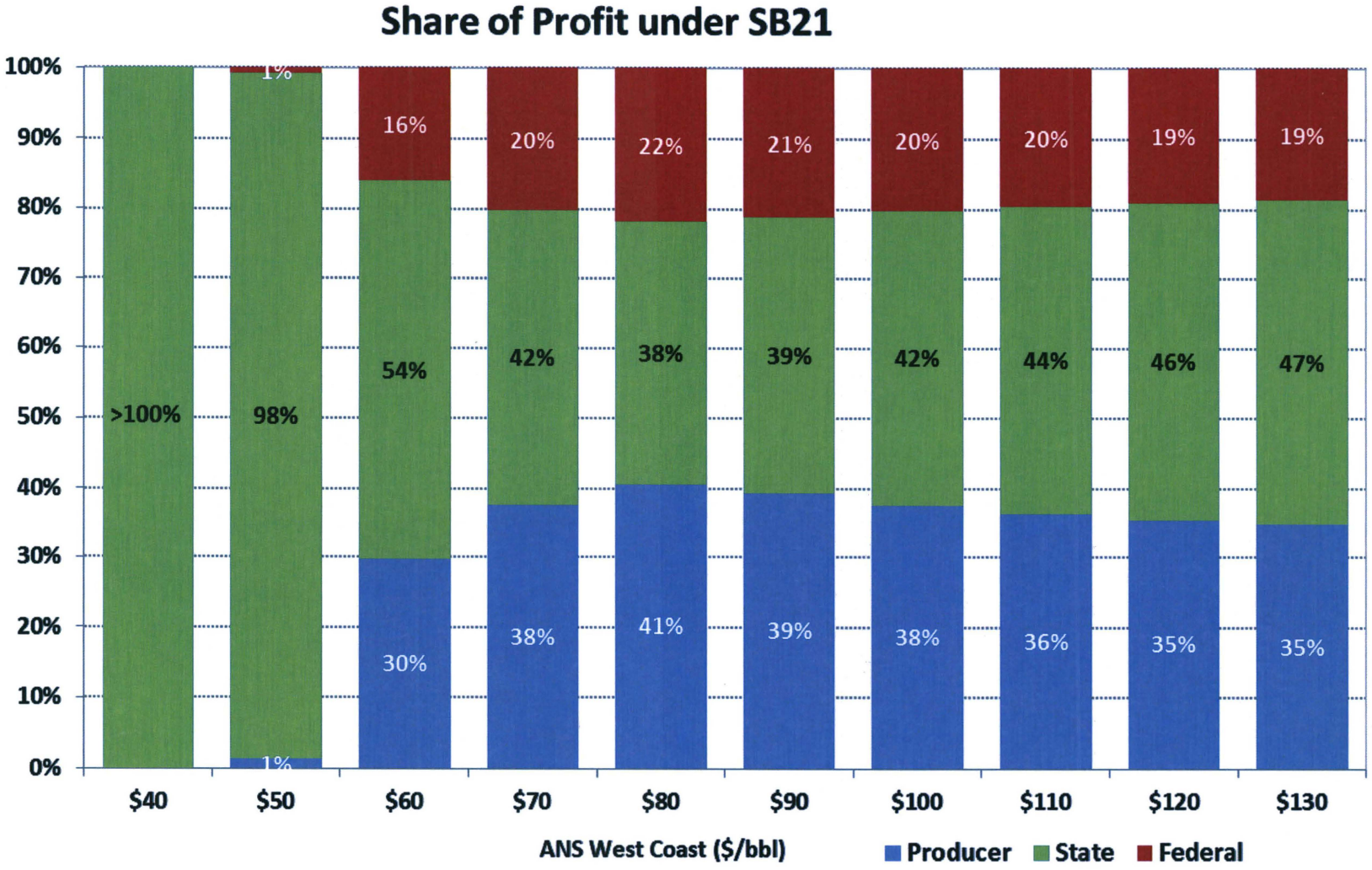
Assumptions

- Charts were produced using DOR "Snapshot" model
- Assumes a single company with all deductible costs
- Transportation costs, production, and lease expenditures, and other assumptions from Fall 2015 forecast for FY 2017

Transportation Costs ($/bbl)	$11.16
Royalty Rate	12.5%
State CIT Rate	6.50%
Federal CIT Rate	35.00%
Deductible Upstream CAPEX ($/ total bbl)*	$15.25
Deductible Upstream OPEX ($/ total bbl)*	$16.37
Total Upstream Costs ($/ bbl)*	$31.62
Daily Production (1,000 bbls / day)	504.9
Property Tax ($/bbl)	1.25

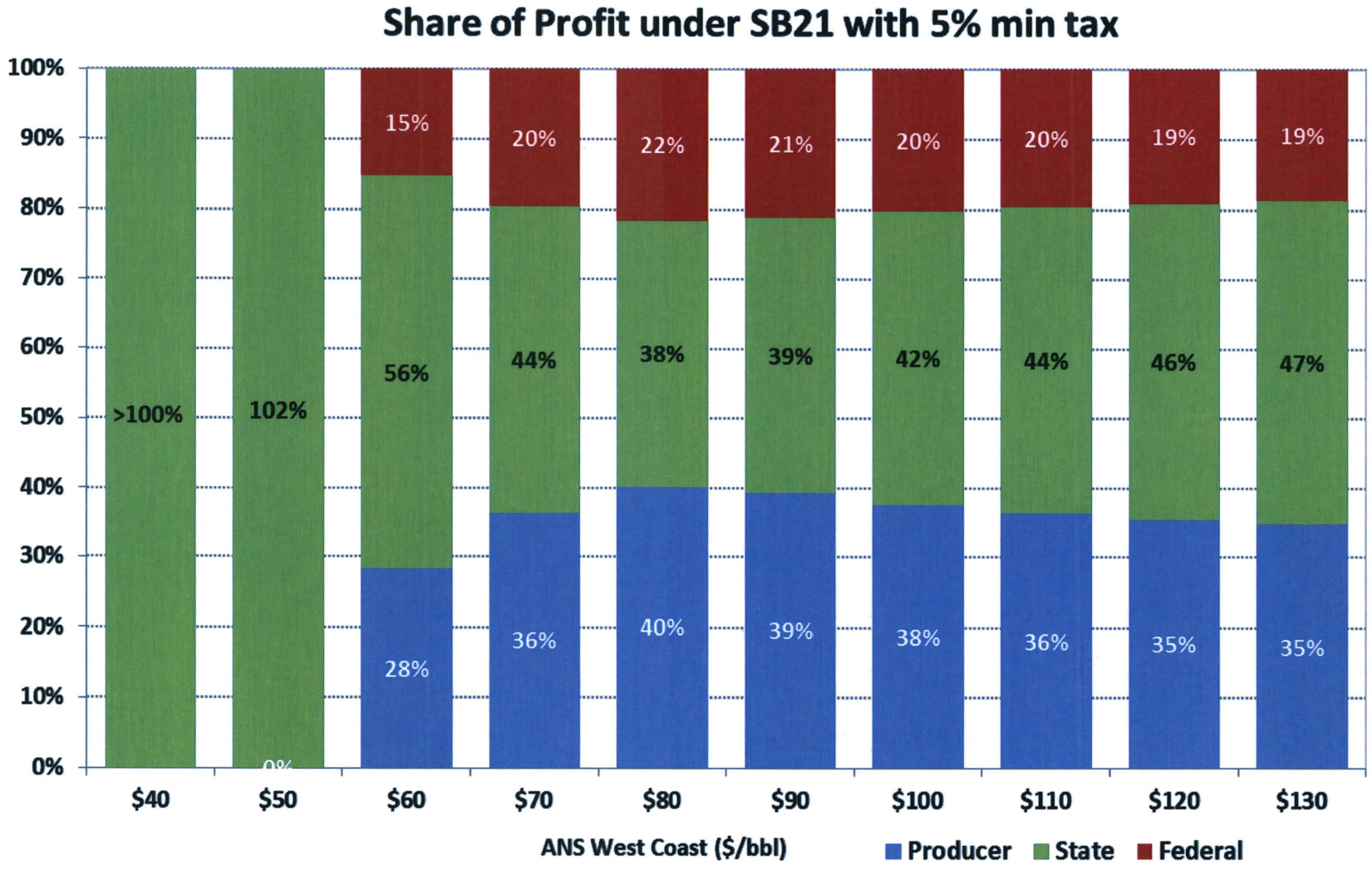
** Upstream cost in this analysis is calculated per each barrel produced including royalty barrels. Costs represent total estimated deductible costs for FY 2017.*

FY 2017 snapshot (legacy oil)



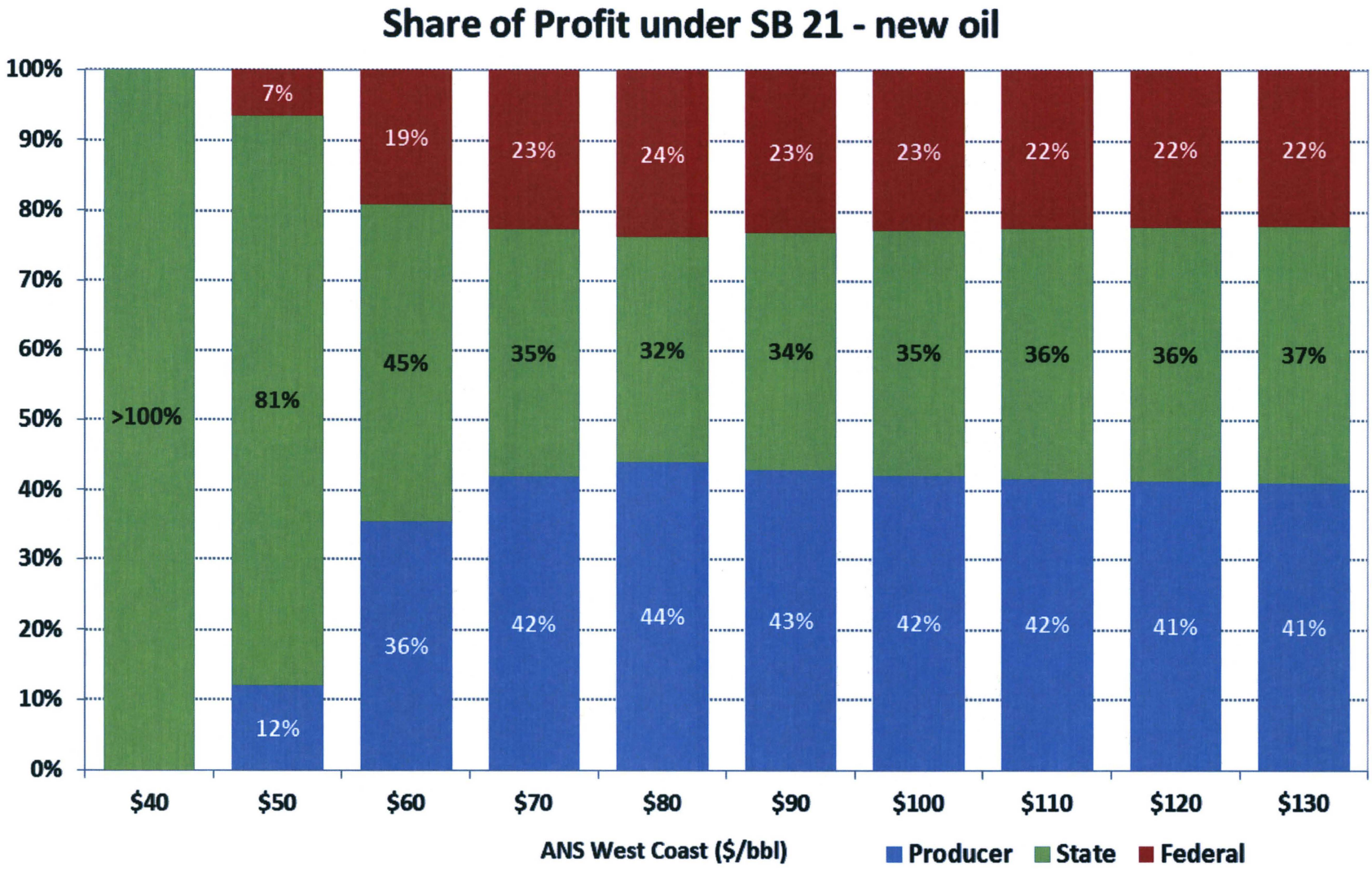
Source: Fall 2015 aggregate assumptions for FY 2017. Assumes non-GVR eligible oil and a single producer.
At $40 and below, "share of profit" is shown as >100%; there is no "profit" but state still receives revenue.
Does not include any NOL credits applied against tax liability or small producer credits.

FY 2017 snapshot (legacy oil) with 5% min. tax



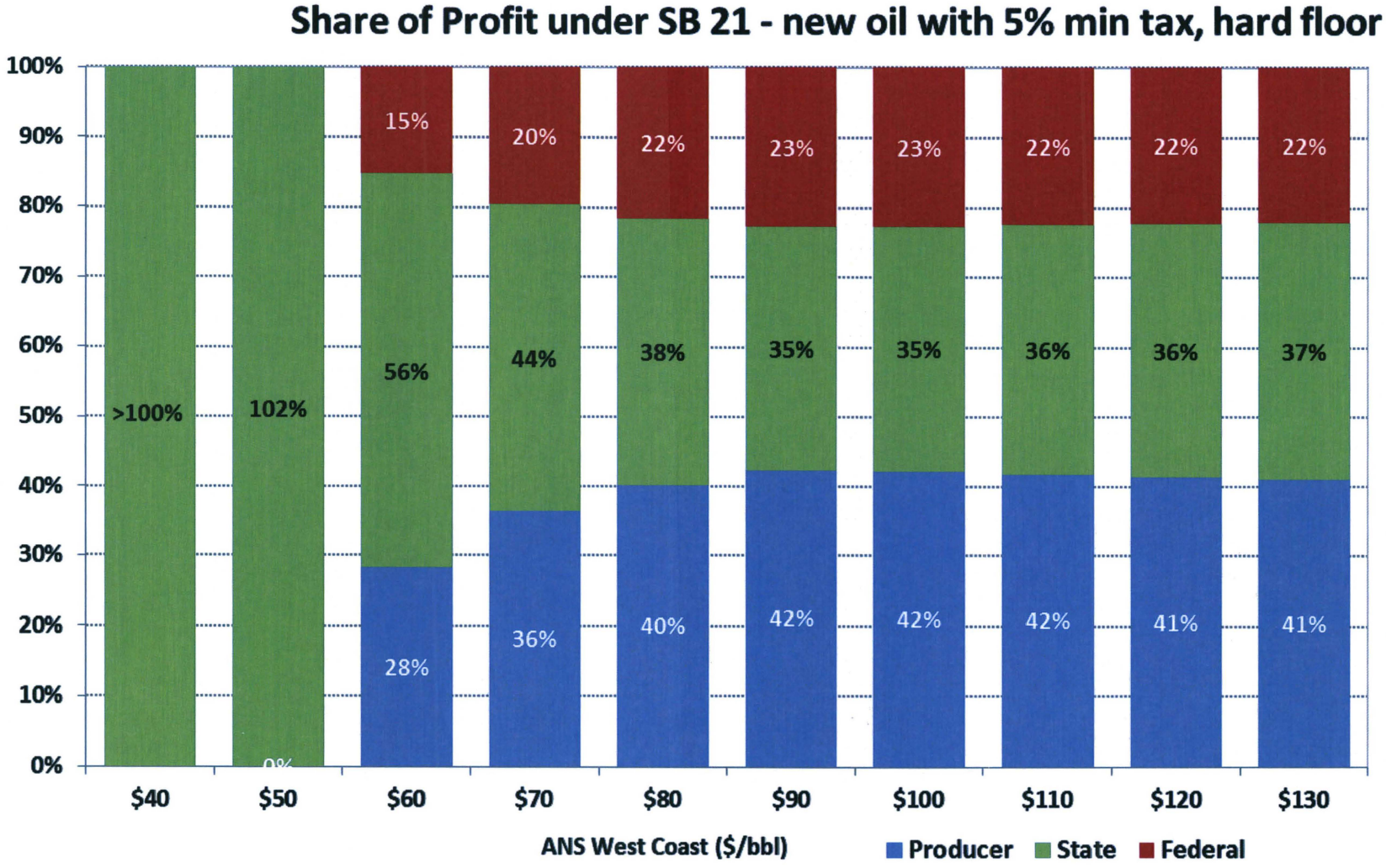
Source: Fall 2015 aggregate assumptions for FY 2017. Assumes non-GVR eligible oil and a single producer.
At $40 and below, "share of profit" is shown as >100%; there is no "profit" but state still receives revenue.
Does not include any NOL credits applied against tax liability or small producer credits.

FY 2017 snapshot (new oil)



Source: Fall 2015 aggregate assumptions for FY 2017. Assumes GVR eligible oil and a single producer.
At $40 and below, "share of profit" is shown as >100%; there is no "profit" but state still receives revenue.
Does not include any NOL credits applied against tax liability or small producer credits.

FY 2017 snapshot (new oil) with 5% min. tax and hard floor

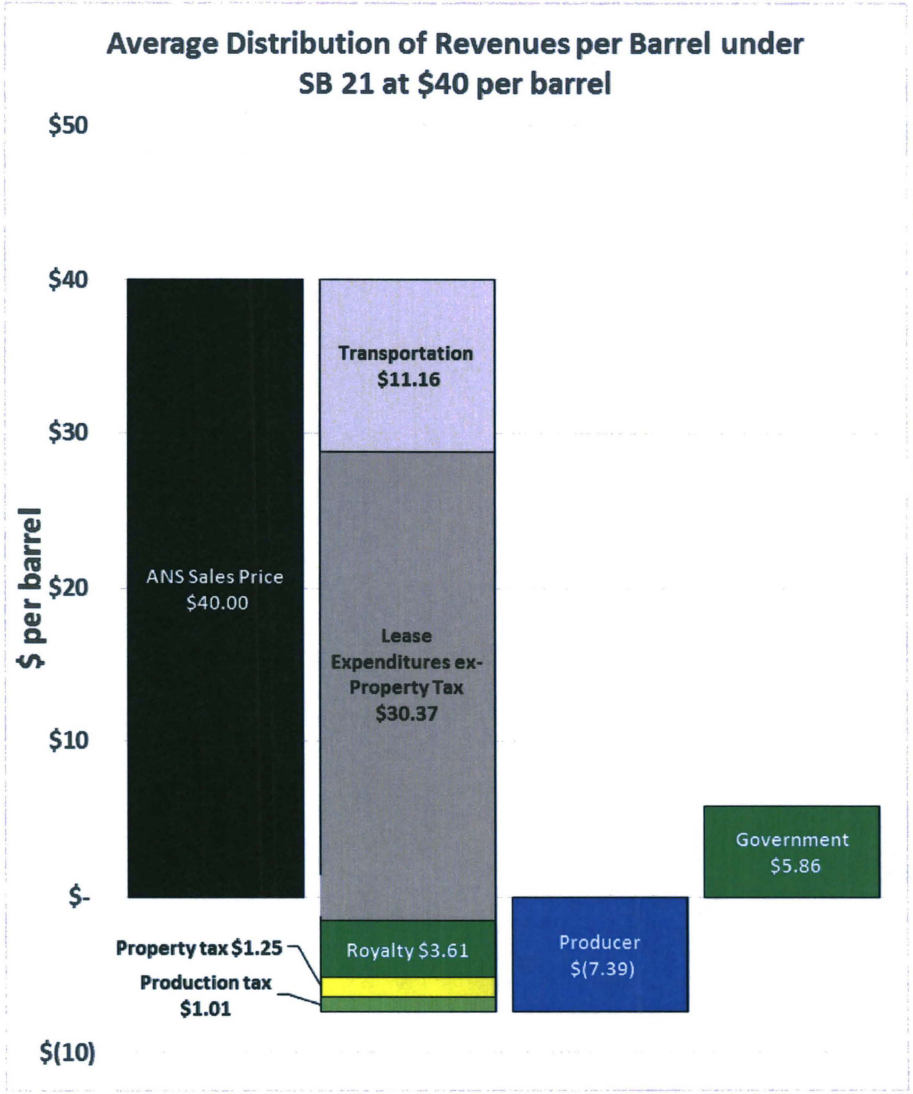


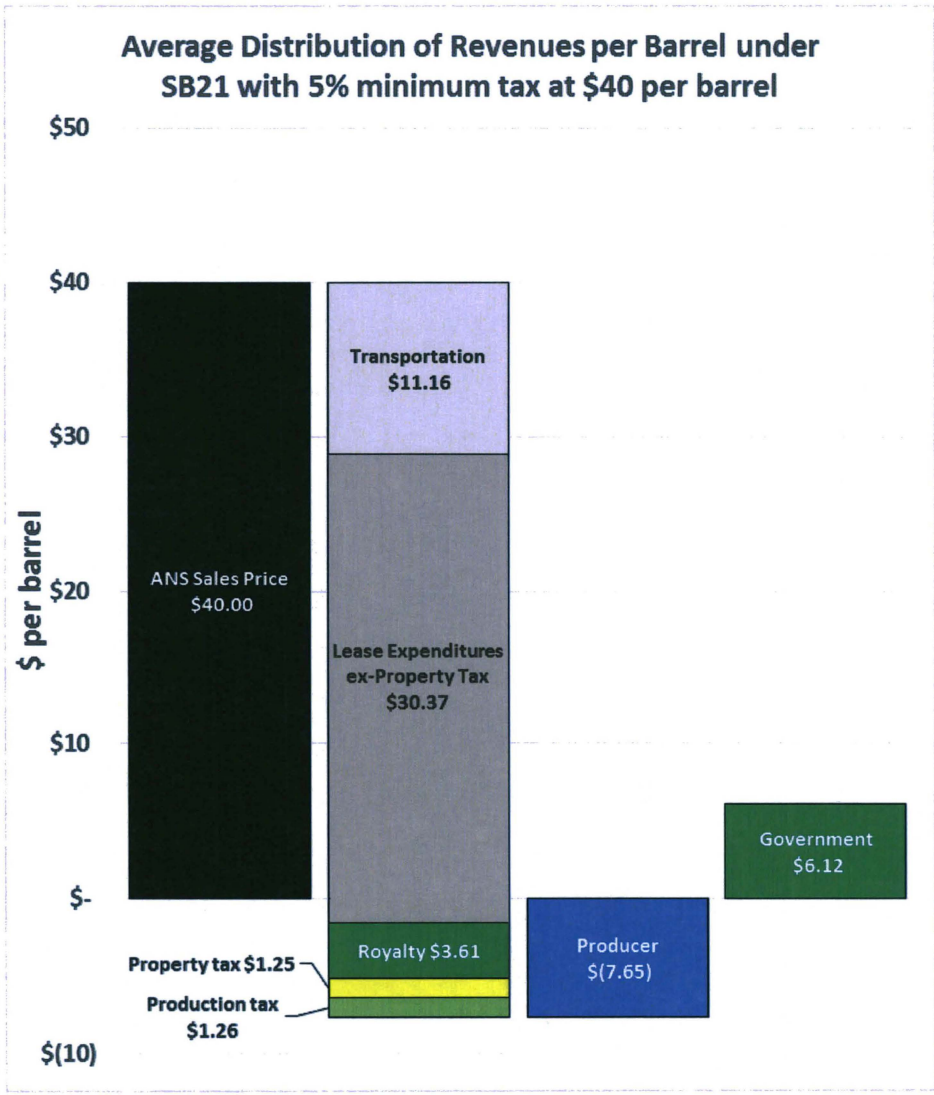
Source: Fall 2015 aggregate assumptions for FY 2017. Assumes GVR eligible oil and a single producer.
At $40 and below, "share of profit" is shown as >100%; there is no "profit" but state still receives revenue.
Does not include any NOL credits applied against tax liability or small producer credits.

Distribution of Revenues:

North Slope Production with Minimum Tax Changes

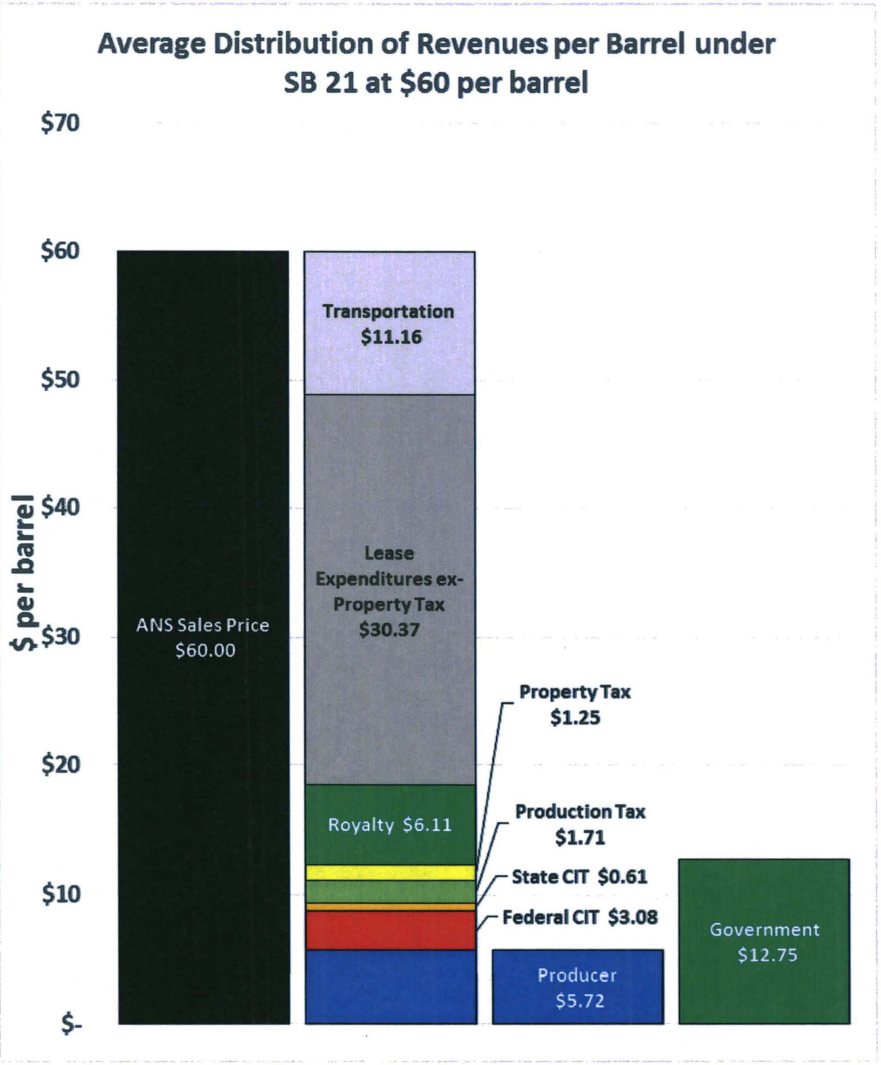
Distribution of Revenues for Legacy Oil, $40

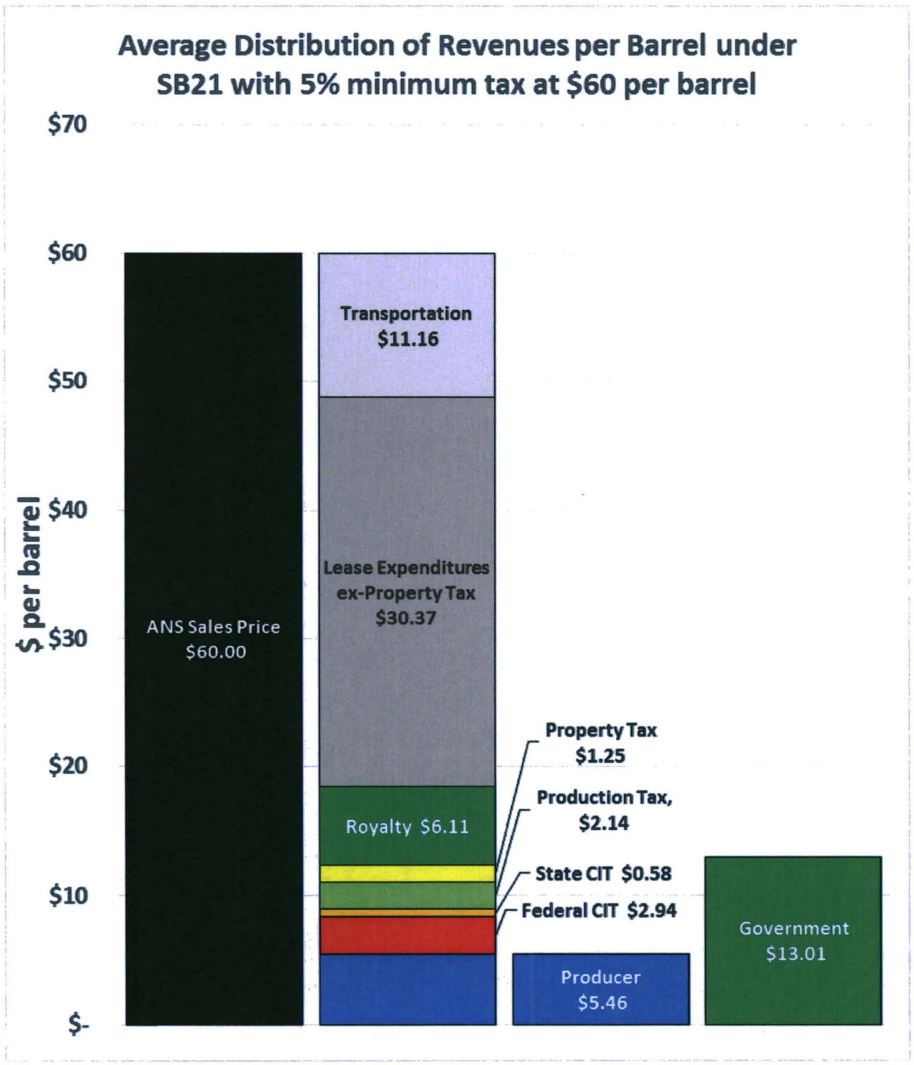




Source: Fall 2015 aggregate assumptions for FY 2017. Assumes non-GVR oil and a single producer. Does not include any NOL credits applied against tax liability or small producer credits.

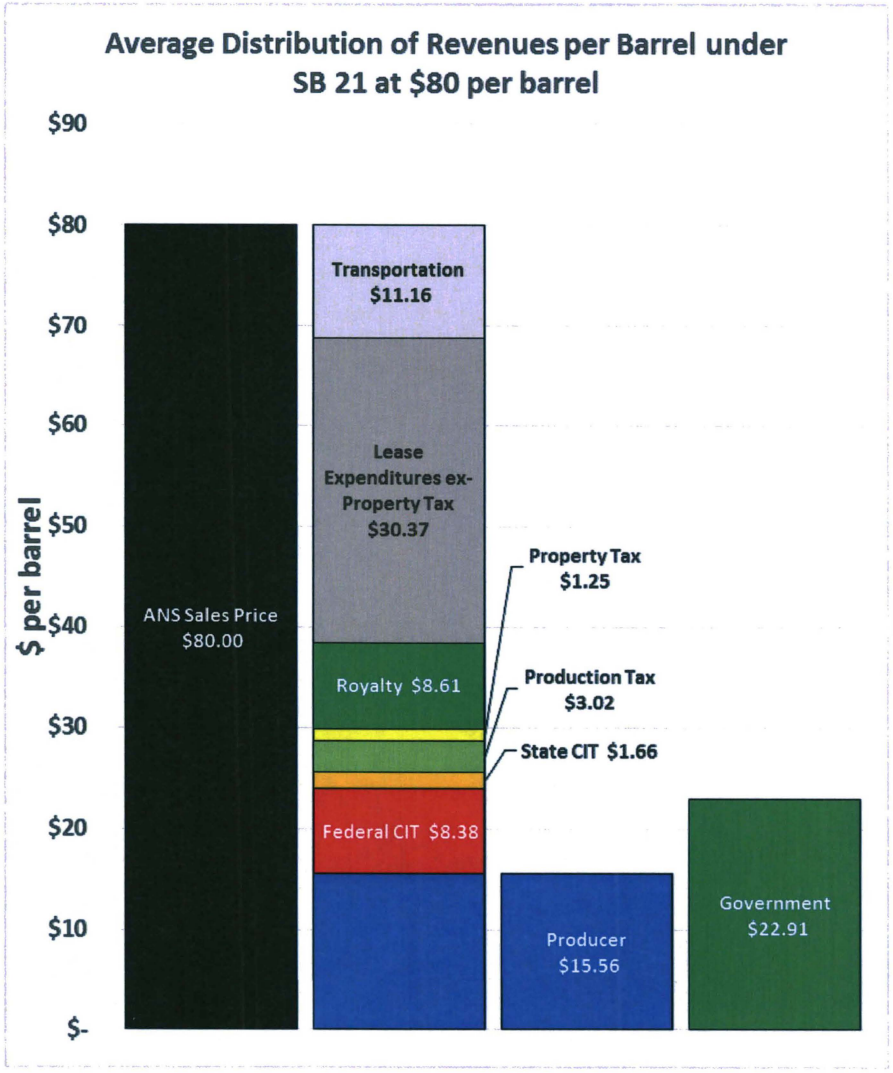
Distribution of Revenues for Legacy Oil, $60

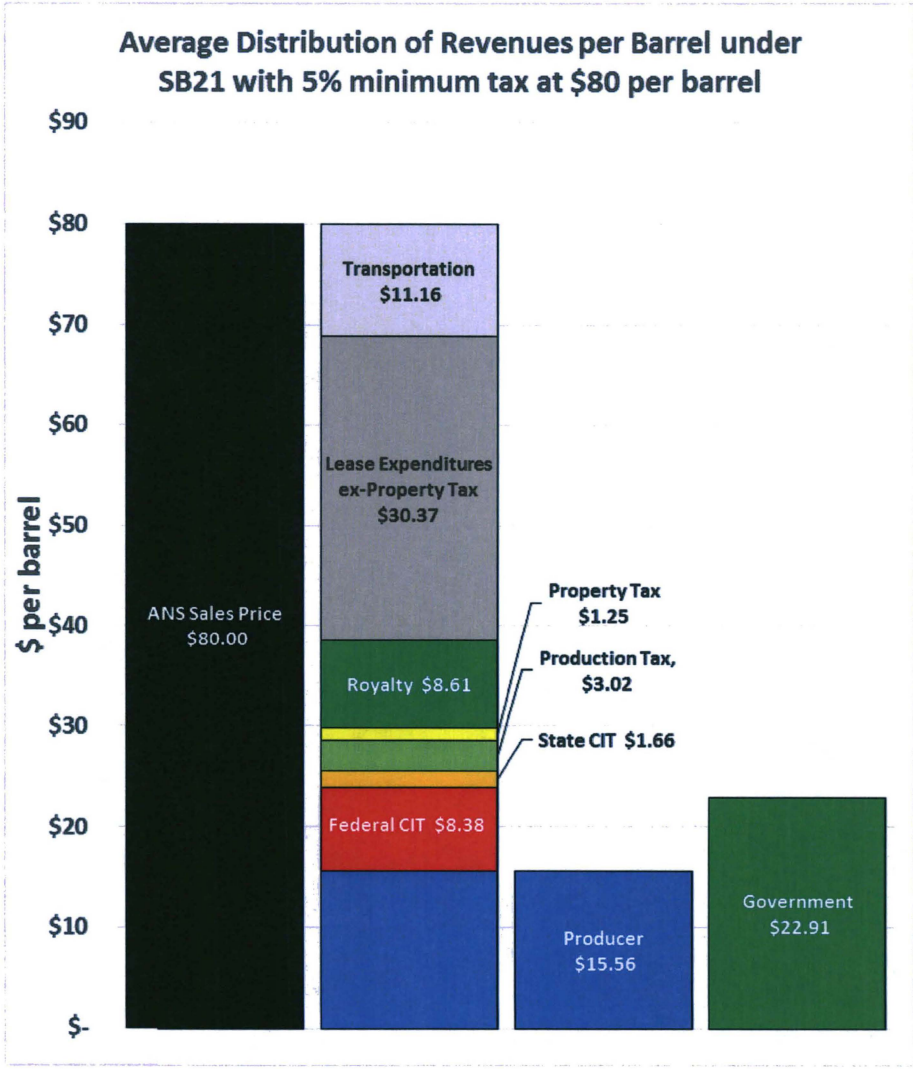




Source: Fall 2015 aggregate assumptions for FY 2017. Assumes non-GVR oil and a single producer. Does not include any NOL credits applied against tax liability or small producer credits.

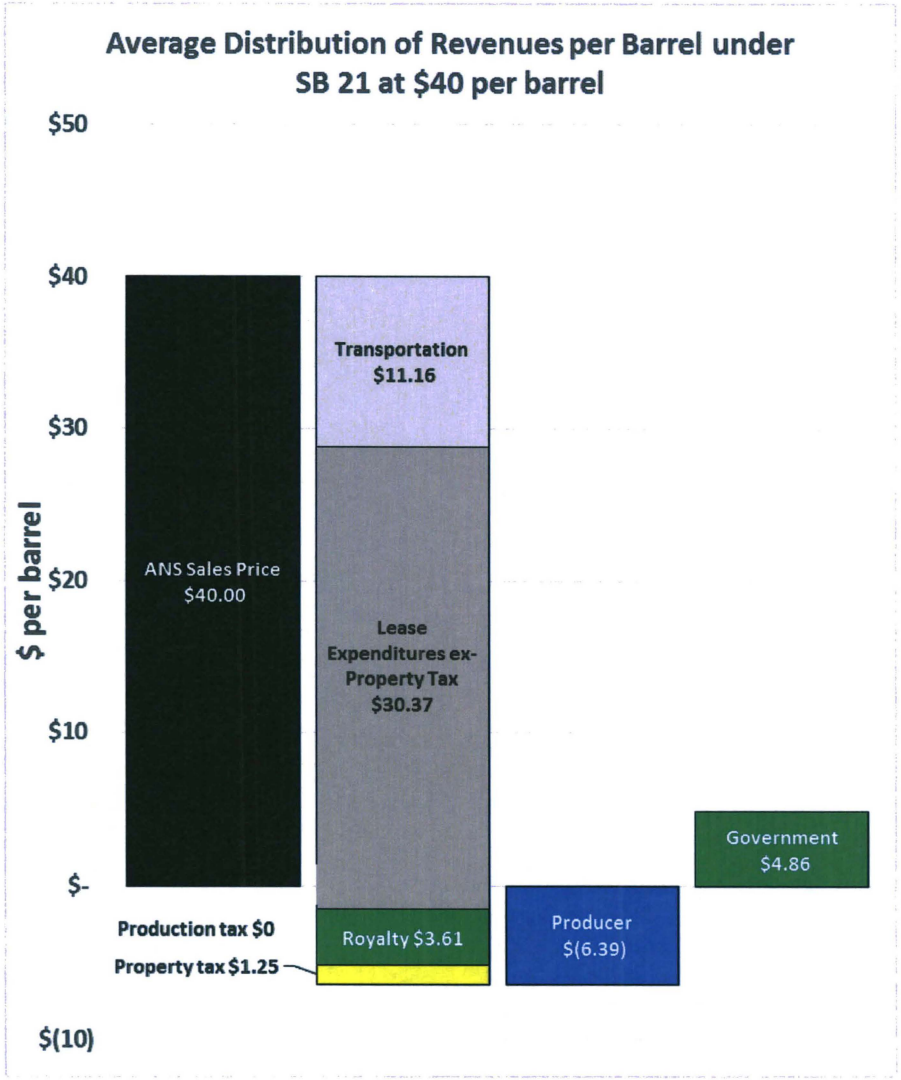
Distribution of Revenues for Legacy Oil, $80

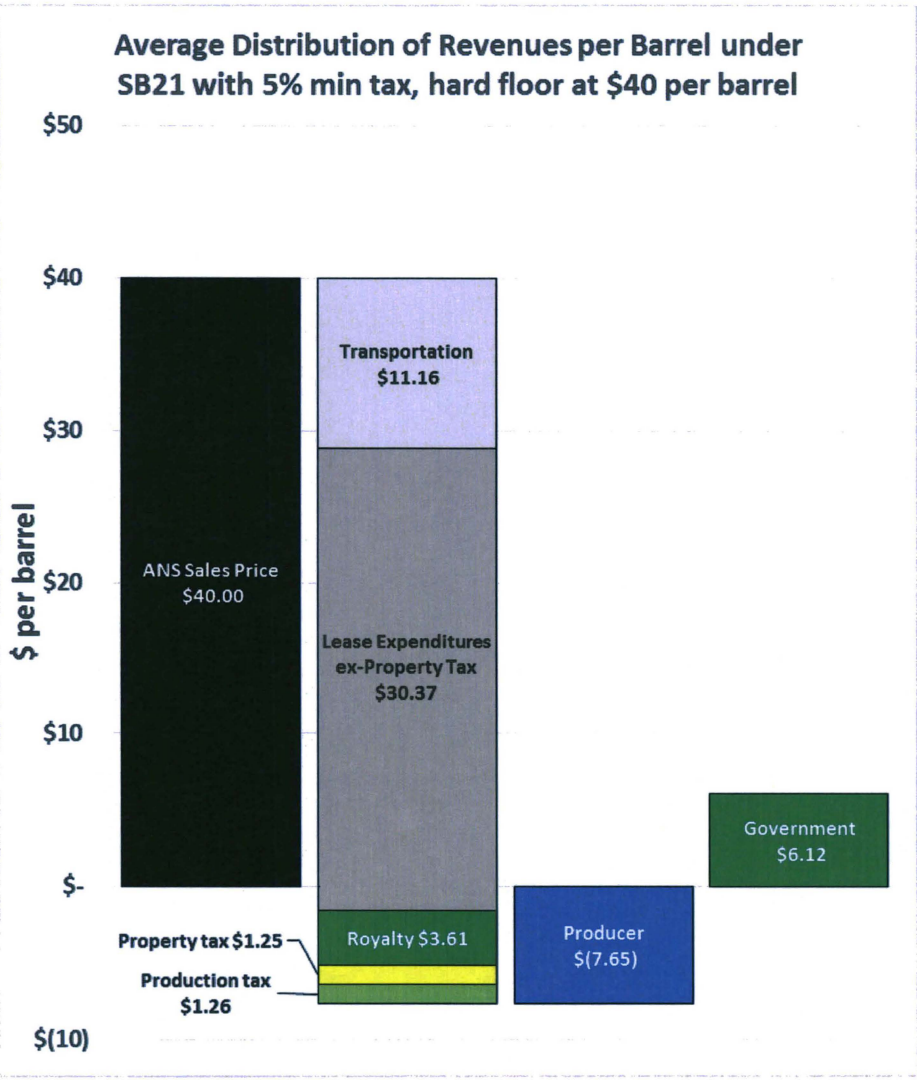




Source: Fall 2015 aggregate assumptions for FY 2017. Assumes non-GVR oil and a single producer. Does not include any NOL credits applied against tax liability or small producer credits.

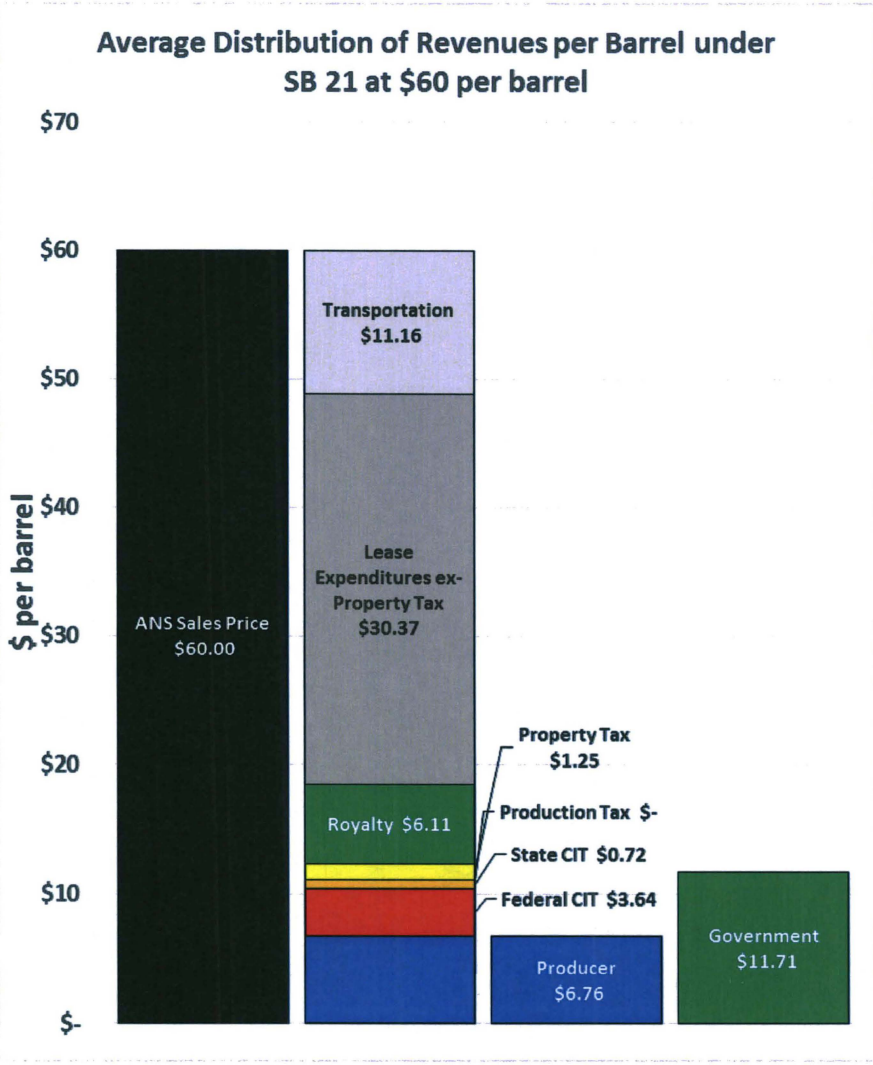
Distribution of Revenues for New Oil, $40

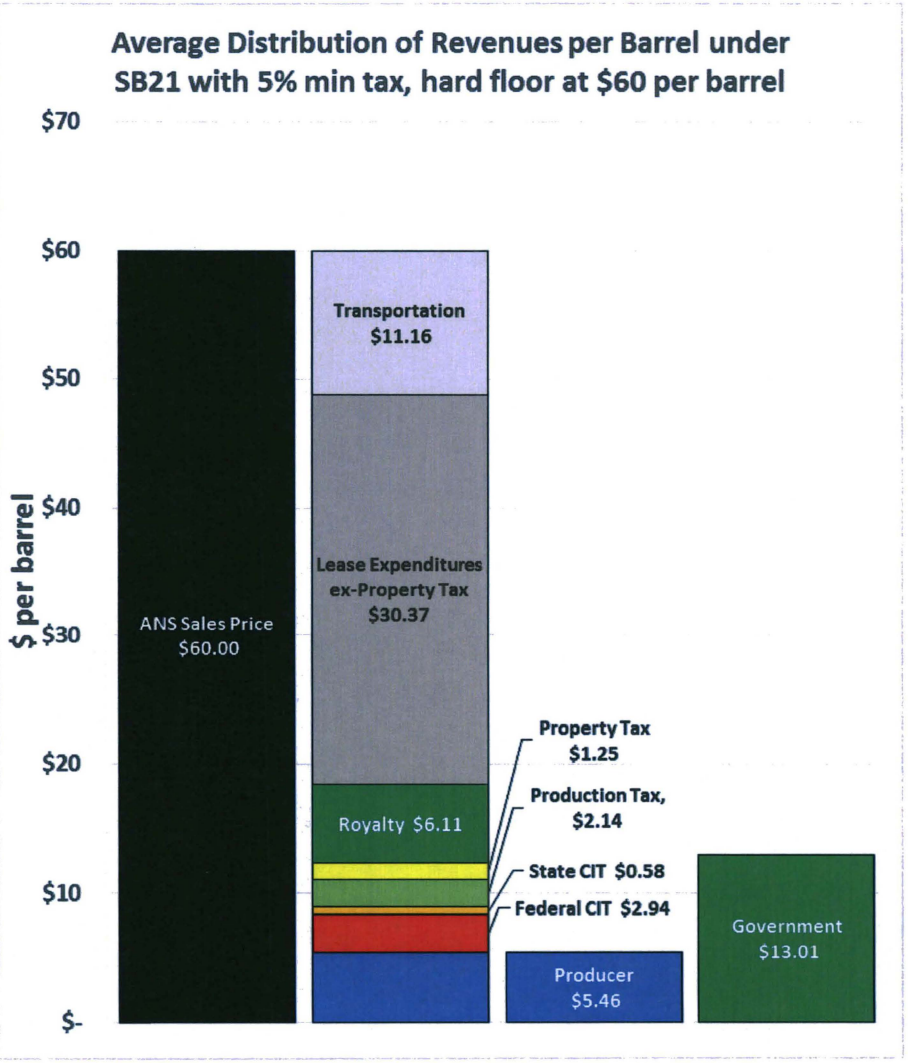




Source: Fall 2015 aggregate assumptions for FY 2017. Assumes GVR-eligible oil and a single producer. Does not include any NOL credits applied against tax liability or small producer credits.

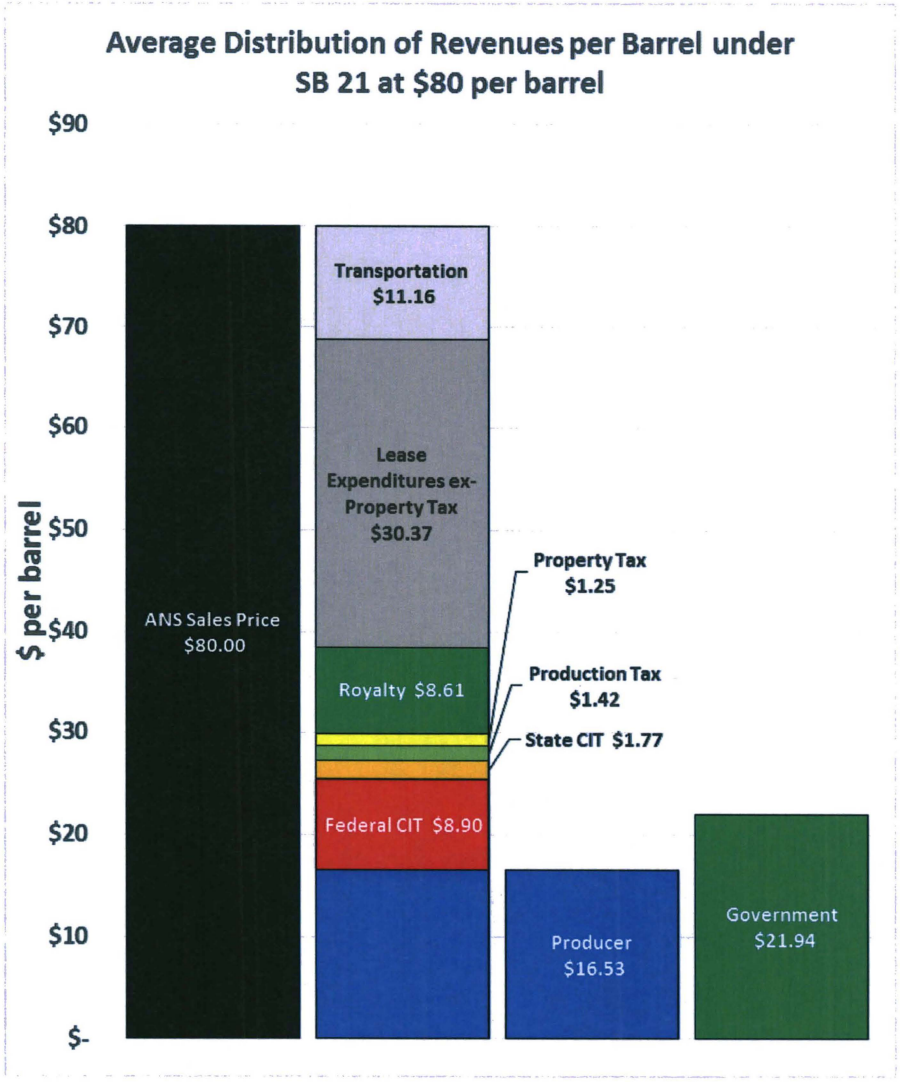
Distribution of Revenues for New Oil, $60

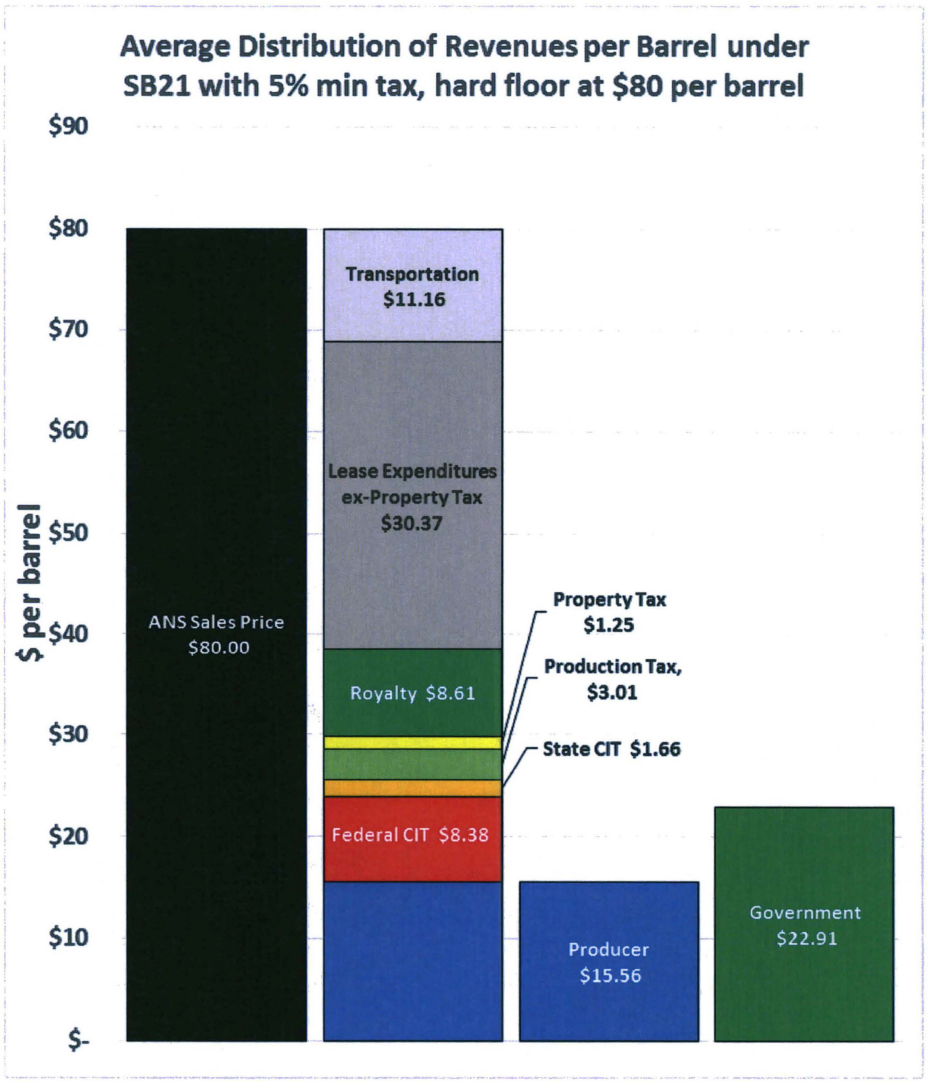




Source: Fall 2015 aggregate assumptions for FY 2017. Assumes GVR-eligible oil and a single producer. Does not include any NOL credits applied against tax liability or small producer credits.

Distribution of Revenues for New Oil, $80





Source: Fall 2015 aggregate assumptions for FY 2017. Assumes GVR-eligible oil and a single producer. Does not include any NOL credits applied against tax liability or small producer credits.

Field Life Cycle Modeling: North Slope

North Slope Life Cycle Modeling Assumptions

- Field sizes of 50 mmbo field and 750 mmbo field
- Two types of producers
  - New producer eligible for cash refunds
  - Non-incumbent producer not eligible for cash refunds due to $10 billion worldwide revenue limit
- Four Oil prices modeled – all in real uninflated $
  - $40, $60, and $80 held static through life of field
  - Fall 2015 forecast prices in real, uninflated $ extending through life of field
- Two tax systems modeled
  - Status quo (new fields qualify for 20% GVR)
  - HB247 (increase & harden minimum tax; limit credits/refunds by dollar amount, worldwide revenues and years to expiration; and GVR not being able to increase NOL)
  - We can provide modeling for some or all features in combination

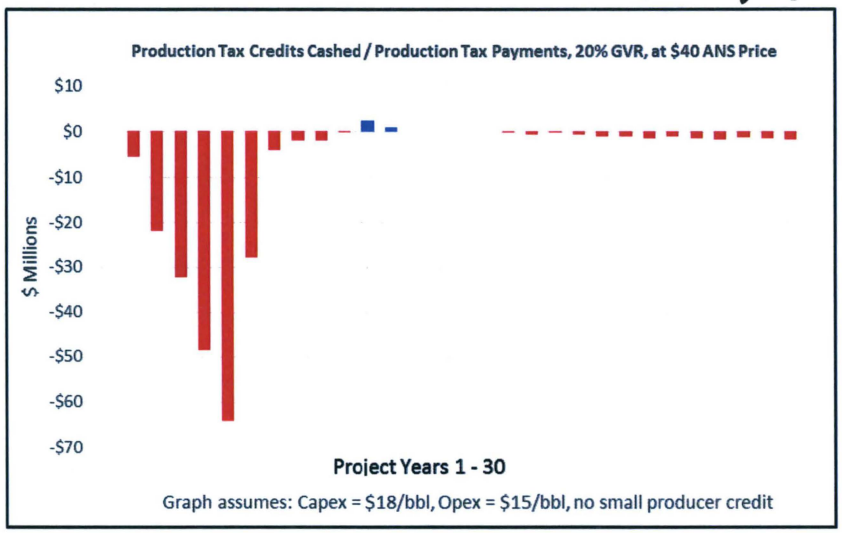
North Slope Life Cycle Modeling Assumptions

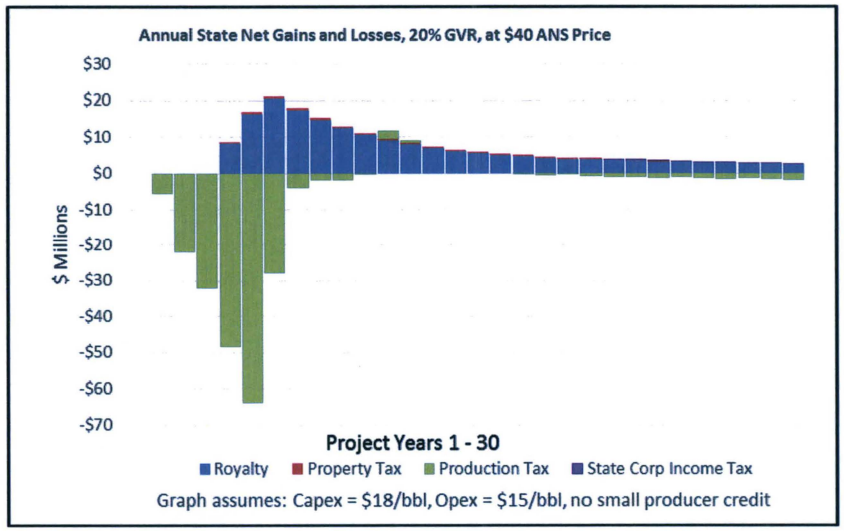
50 mmbo field assumptions

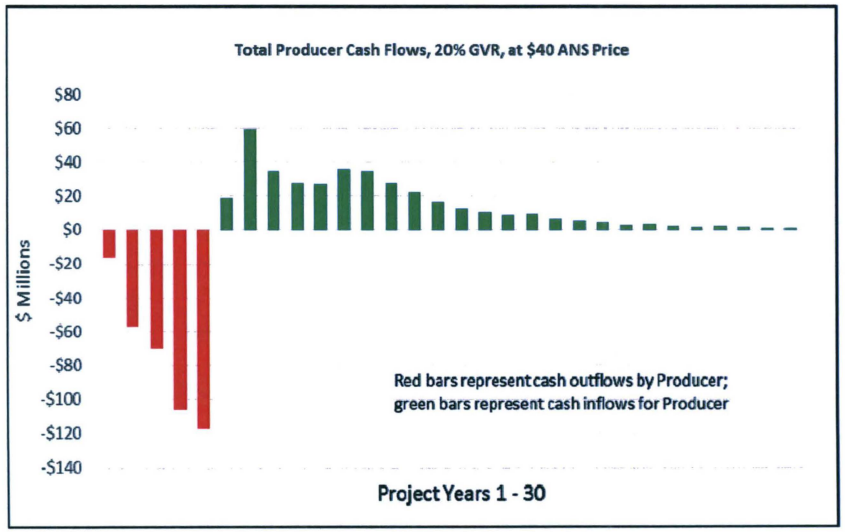
Life of Field	30 years
Peak oil Production	15,000 barrels /day
Transport / barrel	$10 / barrel
Royalty Rate	12.50%
Capex / barrel	$18 / barrel
Opex / barrel	$15 / barrel
Property Tax / barrel	$1.25 / barrel
State Corp Income Tax Rate	6.5% of PTV after Prod Tax
Fed Corp Income Tax Rate	35% of PTV after SCIT

North Slope Life Cycle Modeling

50 mmbo Status Quo, $40/bbl



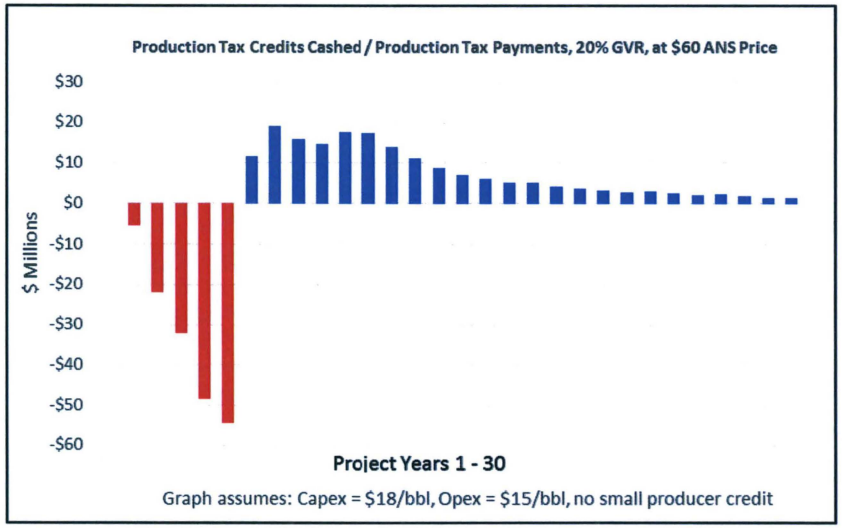


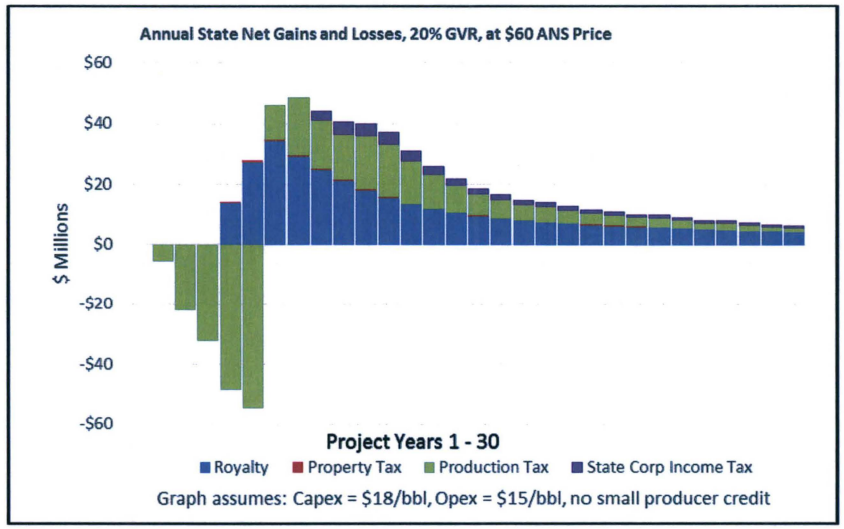


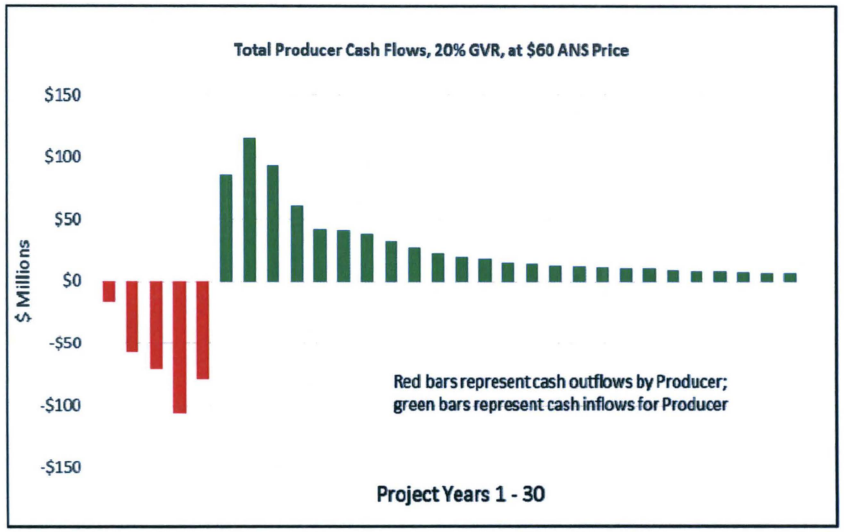
Life Cycle Totals	$Millions
Production Tax Credits Cashed	221
Production Tax Paid	3
Net Production Tax	-217
Production Tax NPV 6.15%	-153
Total Annual State Losses	153
Total Annual State Gains	129
Net State Gain (Loss)	-24
State NPV 6.15%	-58
Total Producer Cash Out	365
Total Producer Cash In	384
Net Producer Cash Flow	19
Producer Cash NPV 6.15%	-99

North Slope Life Cycle Modeling

50 mmbo Status Quo, $60/bbl



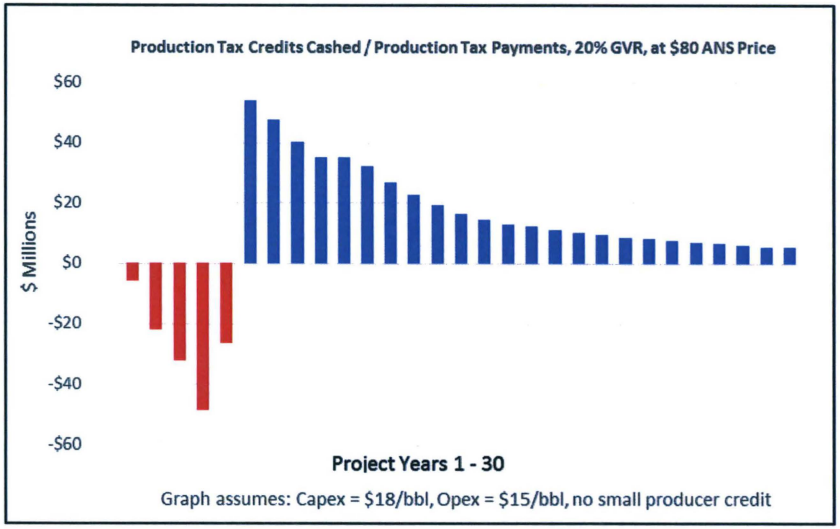


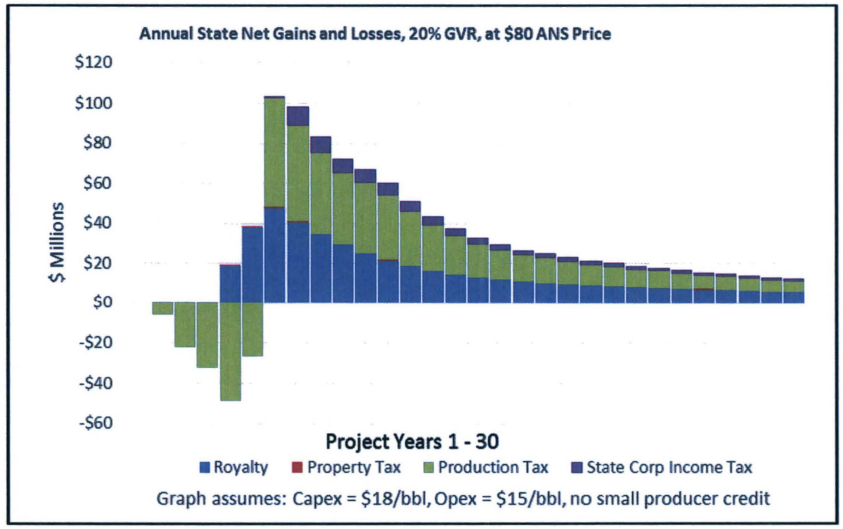


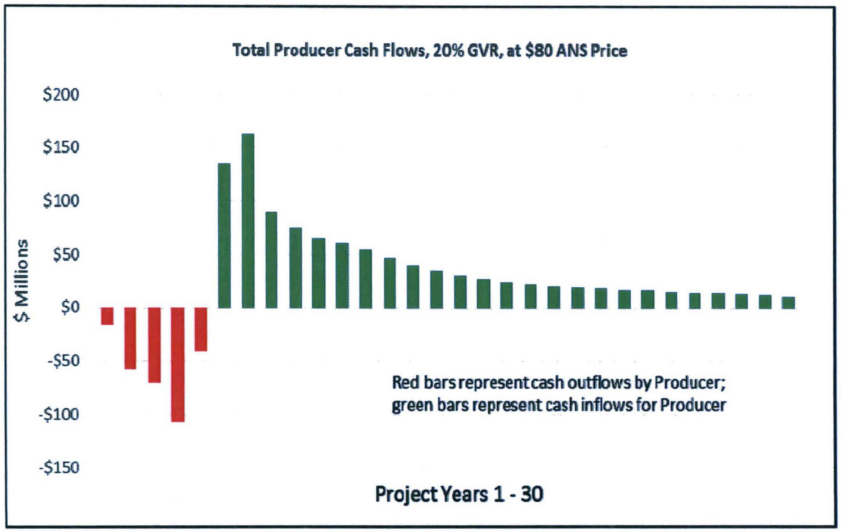
Life Cycle Totals	$Millions
Production Tax Credits Cashed	162
Production Tax Paid	183
Net Production Tax	21
Production Tax NPV 6.15%	-37
Total Annual State Losses	121
Total Annual State Gains	501
Net State Gain (Loss)	380
State NPV 6.15%	136
Total Producer Cash Out	327
Total Producer Cash In	731
Net Producer Cash Flow	404
Producer Cash NPV 6.15%	112

North Slope Life Cycle Modeling

50 mmbo Status Quo, $80/bbl



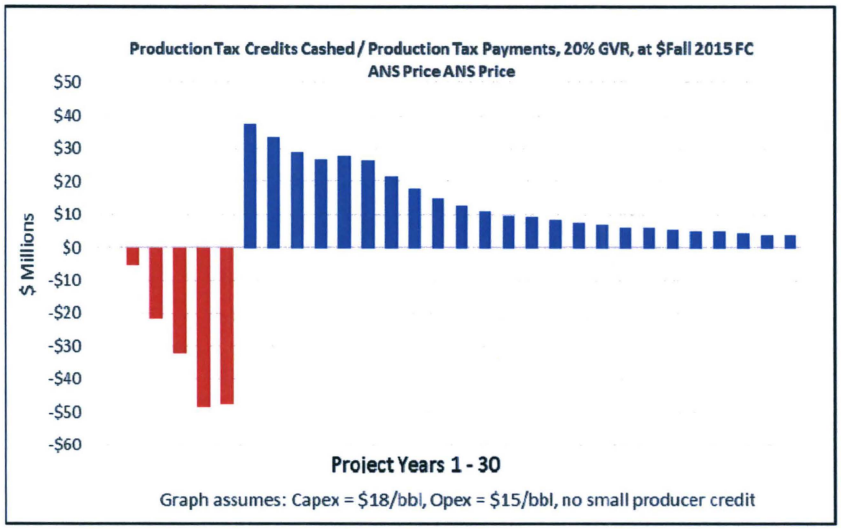


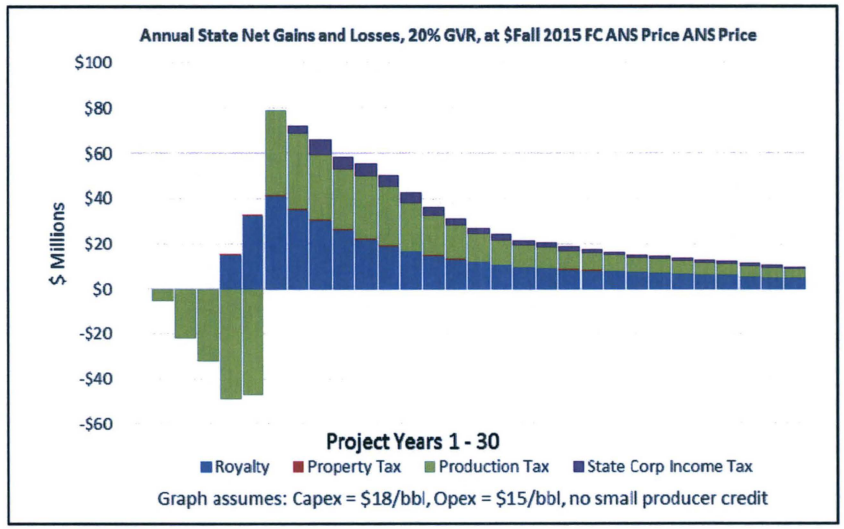


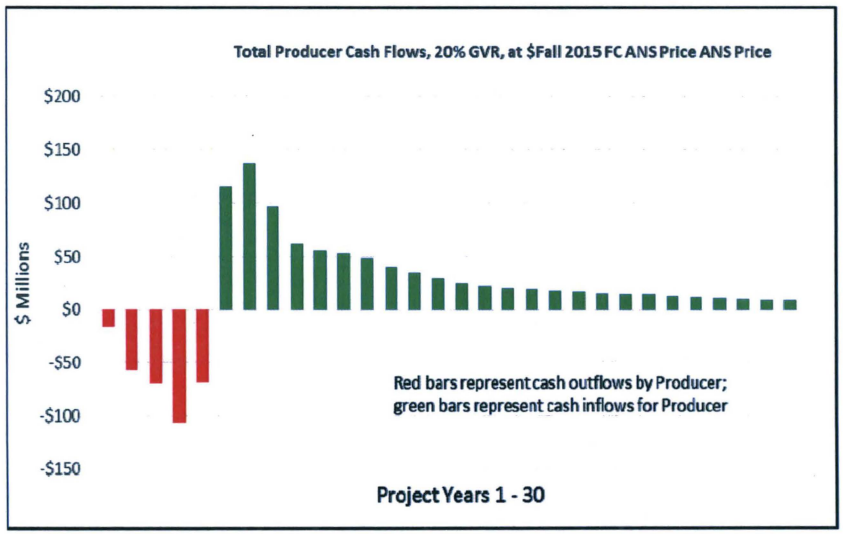
Life Cycle Totals	$Millions
Production Tax Credits Cashed	134
Production Tax Paid	457
Net Production Tax	323
Production Tax NPV 6.15%	110
Total Annual State Losses	88
Total Annual State Gains	932
Net State Gain (Loss)	844
State NPV 6.15%	364
Total Producer Cash Out	289
Total Producer Cash In	1,040
Net Producer Cash Flow	751
Producer Cash NPV 6.15%	289

North Slope Life Cycle Modeling

50 mmbo Status Quo, Fall 2015 FC Prices



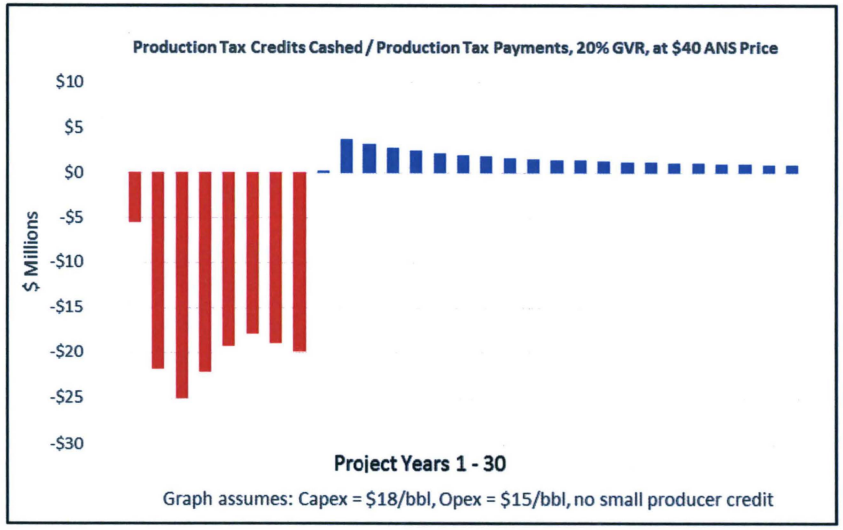


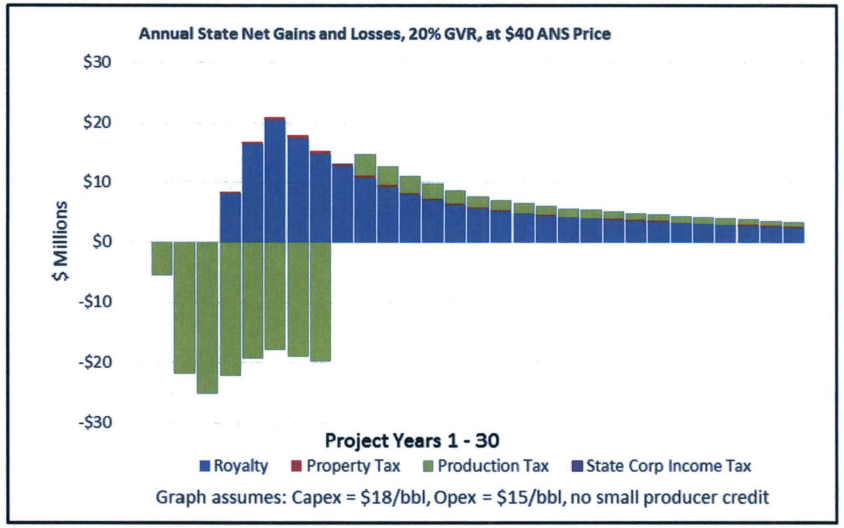


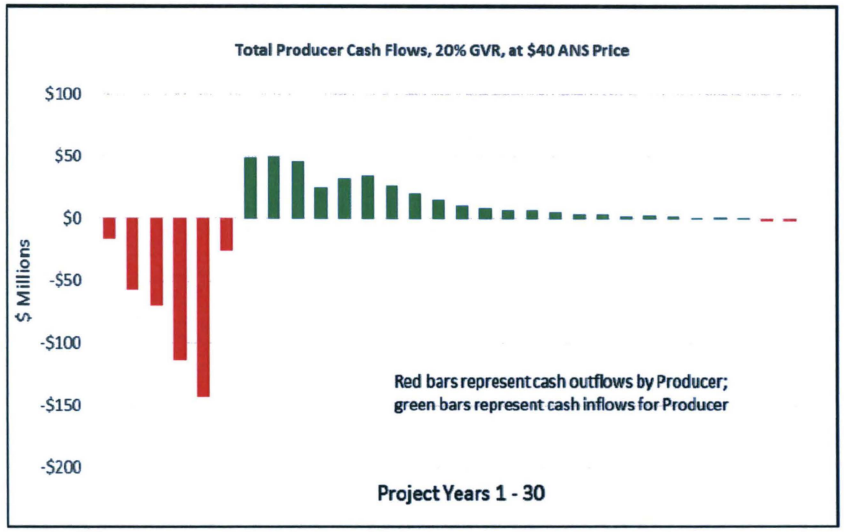
Life Cycle Totals	$Millions
Production Tax Credits Cashed	155
Production Tax Paid	339
Net Production Tax	183
Production Tax NPV 6.15%	40
Total Annual State Losses	107
Total Annual State Gains	736
Net State Gain (Loss)	629
State NPV 6.15%	255
Total Producer Cash Out	317
Total Producer Cash In	906
Net Producer Cash Flow	588
Producer Cash NPV 6.15%	203

North Slope Life Cycle Modeling

50 mmbo HB 247, $40 / bbl



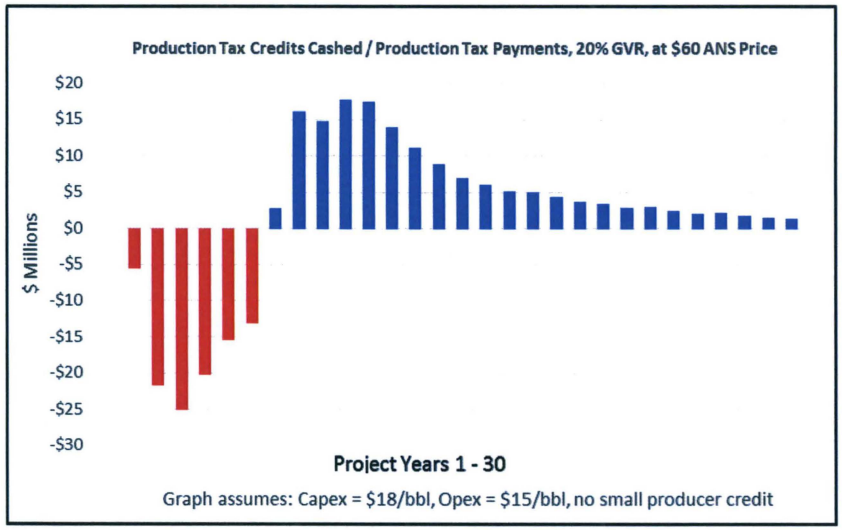


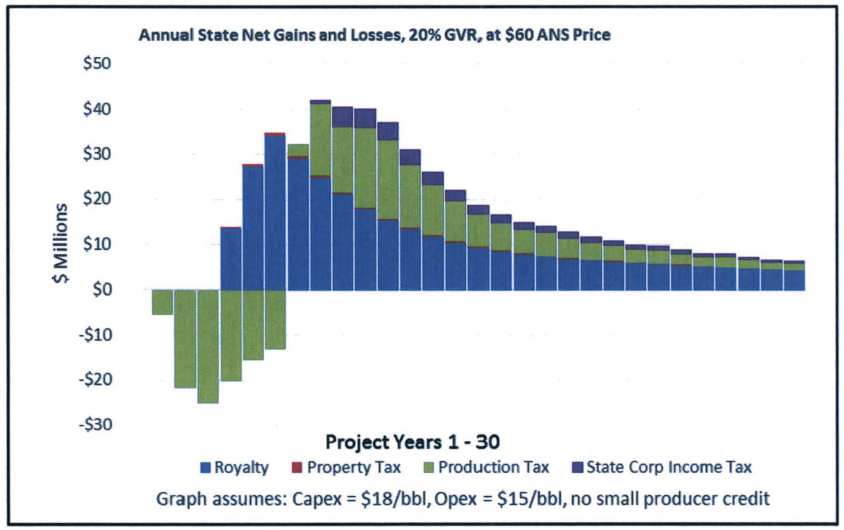


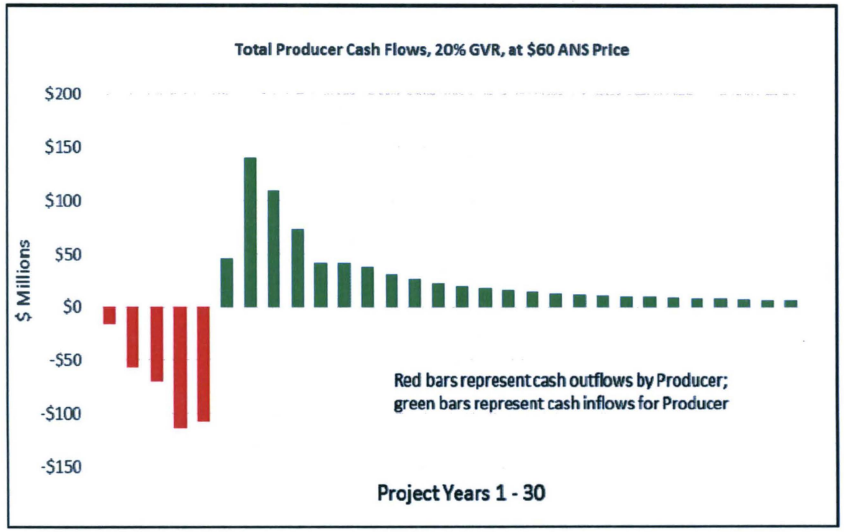
Life Cycle Totals	$Millions
Production Tax Credits Cashed	150
Production Tax Paid	34
Net Production Tax	-116
Production Tax NPV 6.15%	-95
Total Annual State Losses	74
Total Annual State Gains	150
Net State Gain (Loss)	76
State NPV 6.15%	-1
Total Producer Cash Out	425
Total Producer Cash In	354
Net Producer Cash Flow	-71
Producer Cash NPV 6.15%	-155

North Slope Life Cycle Modeling

50 mmbo HB 247, $60 / bbl



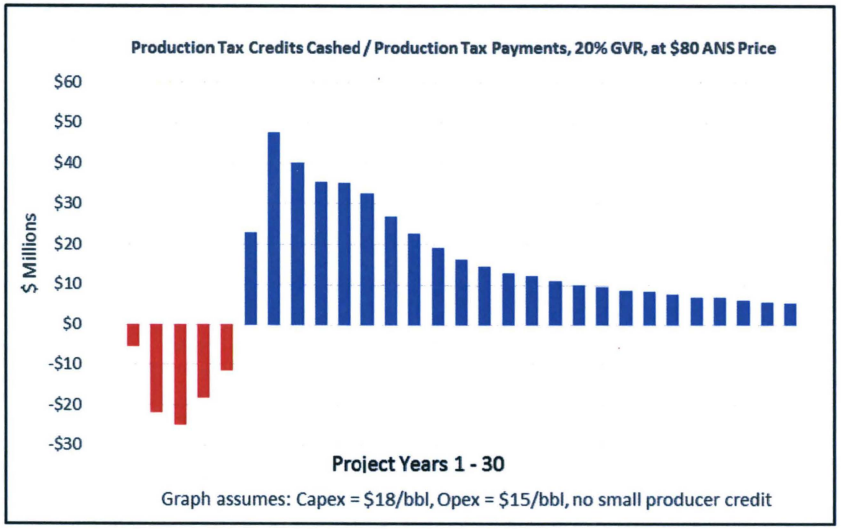


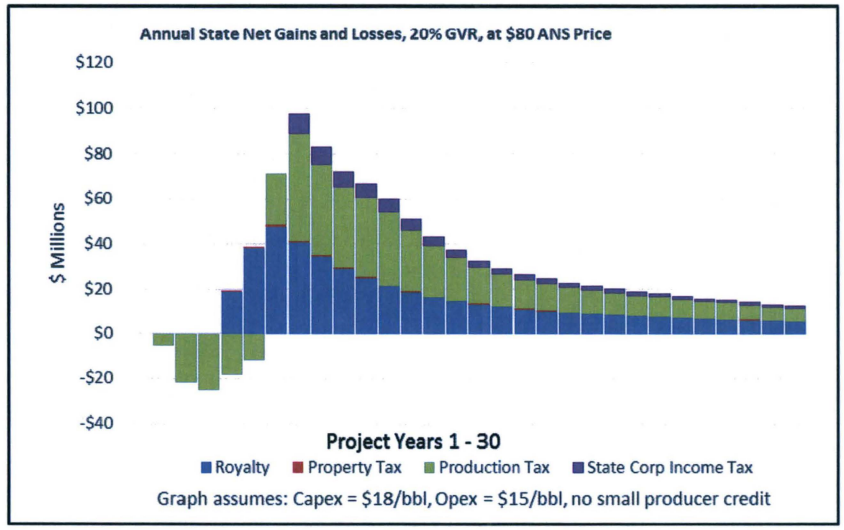


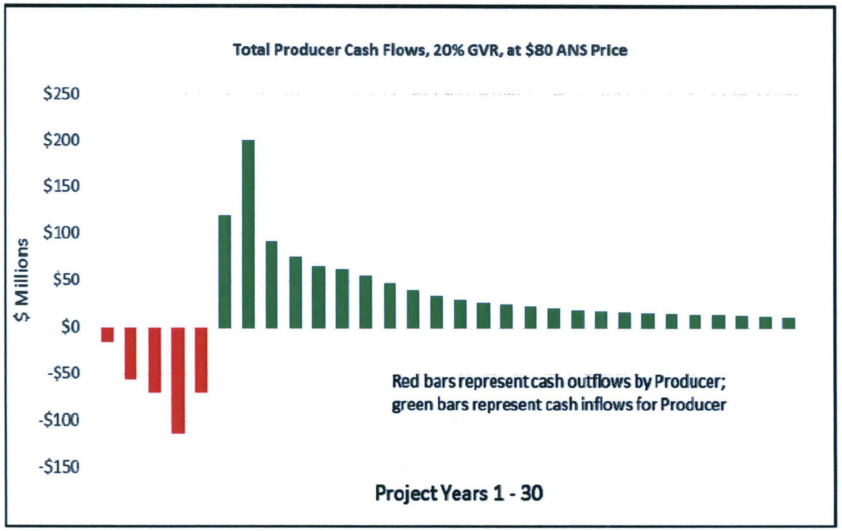
Life Cycle Totals	$Millions
Production Tax Credits Cashed	101
Production Tax Paid	155
Net Production Tax	54
Production Tax NPV 6.15%	-10
Total Annual State Losses	59
Total Annual State Gains	470
Net State Gain (Loss)	412
State NPV 6.15%	163
Total Producer Cash Out	362
Total Producer Cash In	746
Net Producer Cash Flow	384
Producer Cash NPV 6.15%	93

North Slope Life Cycle Modeling

50 mmbo HB 247, $80 / bbl



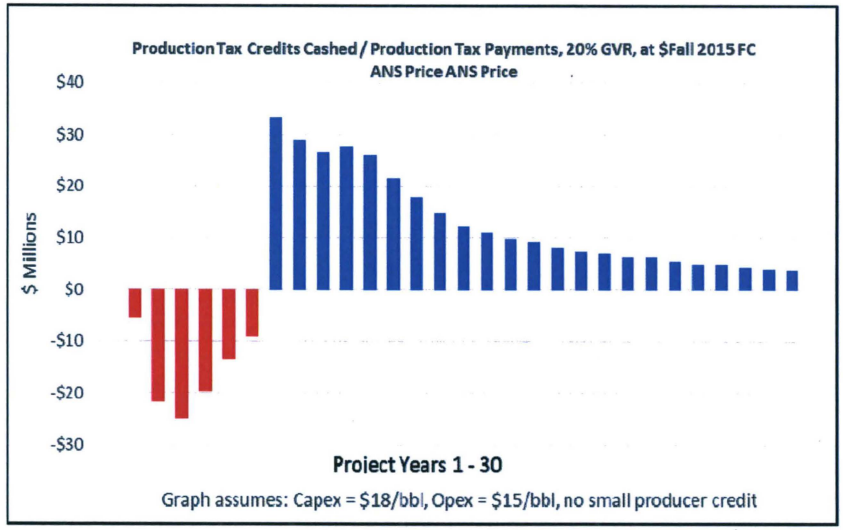


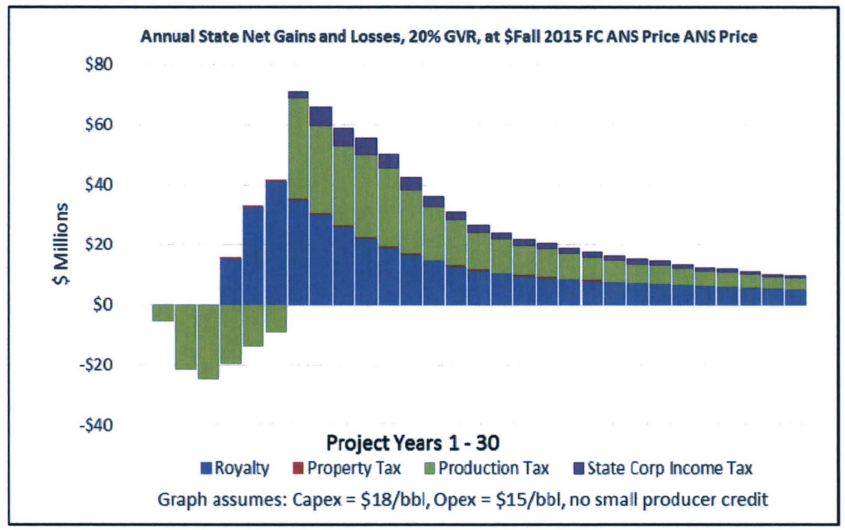


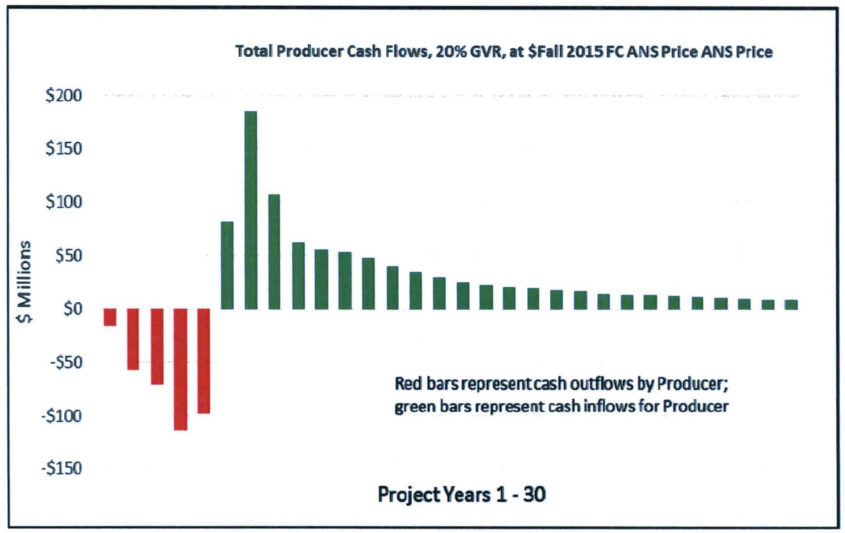
Life Cycle Totals	$Millions
Production Tax Credits Cashed	82
Production Tax Paid	426
Net Production Tax	344
Production Tax NPV 6.15%	128
Total Annual State Losses	52
Total Annual State Gains	916
Net State Gain (Loss)	863
State NPV 6.15%	380
Total Producer Cash Out	326
Total Producer Cash In	1,064
Net Producer Cash Flow	738
Producer Cash NPV 6.15%	277

North Slope Life Cycle Modeling

50 mmbo HB 247, Fall 2015 FC Prices







Life Cycle Totals	$Millions
Production Tax Credits Cashed	95
Production Tax Paid	301
Net Production Tax	207
Production Tax NPV 6.15%	60
Total Annual State Losses	57
Total Annual State Gains	707
Net State Gain (Loss)	651
State NPV 6.15%	274
Total Producer Cash Out	353
Total Producer Cash In	928
Net Producer Cash Flow	574
Producer Cash NPV 6.15%	189

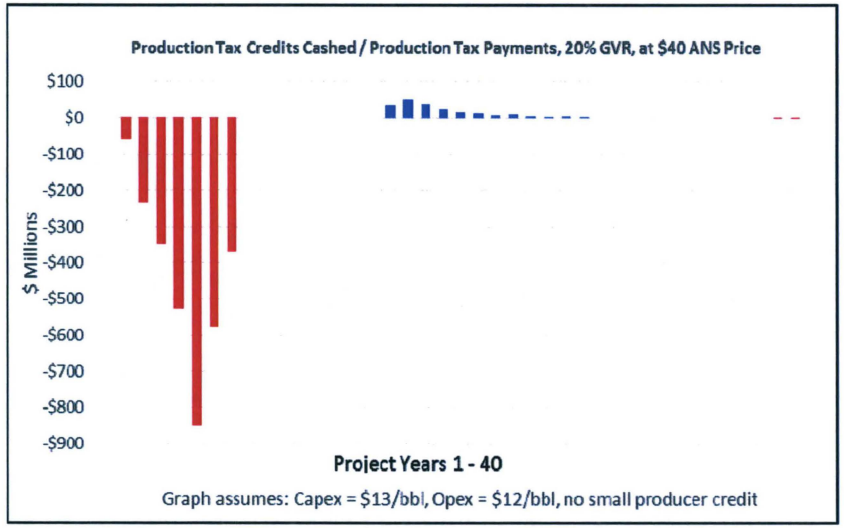
North Slope Life Cycle Modeling Assumptions

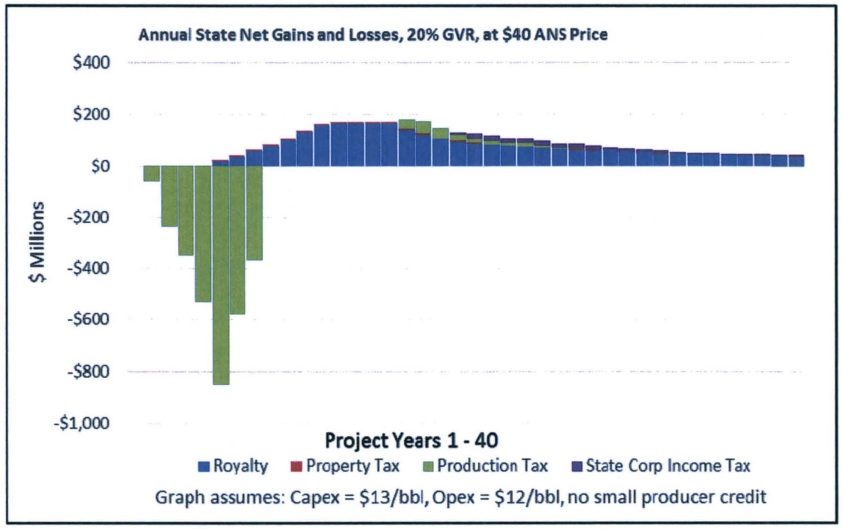
750 mmbo field assumptions

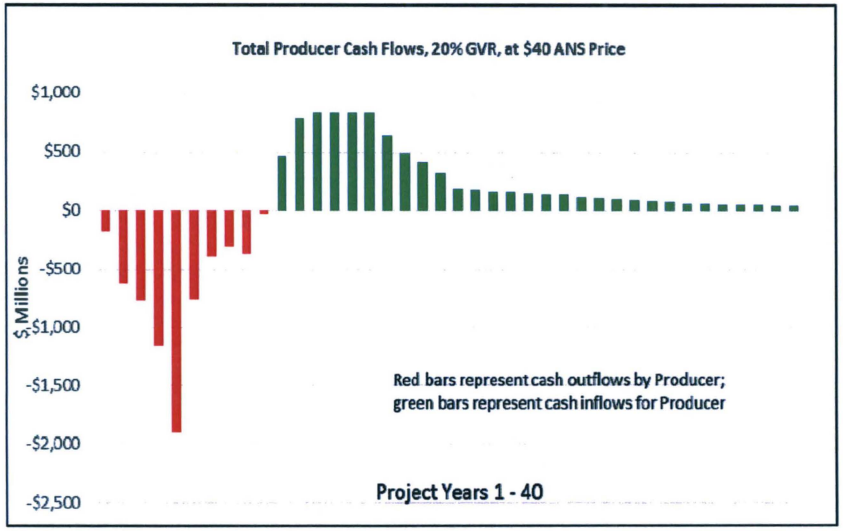
Life of Field	40 years
Peak oil Production	120,000 barrels / day
Transport / barrel	$10 / barrel
Royalty Rate	12.50%
Capex / barrel	$13 / barrel
Opex / barrel	$12 / barrel
Property Tax / barrel	$1.25 / barrel
State Corp Income Tax Rate	6.5% of PTV after Prod Tax
Fed Corp Income Tax Rate	35% of PTV after SCIT

North Slope Life Cycle Modeling

750 mmbo Status Quo, $40/bbl



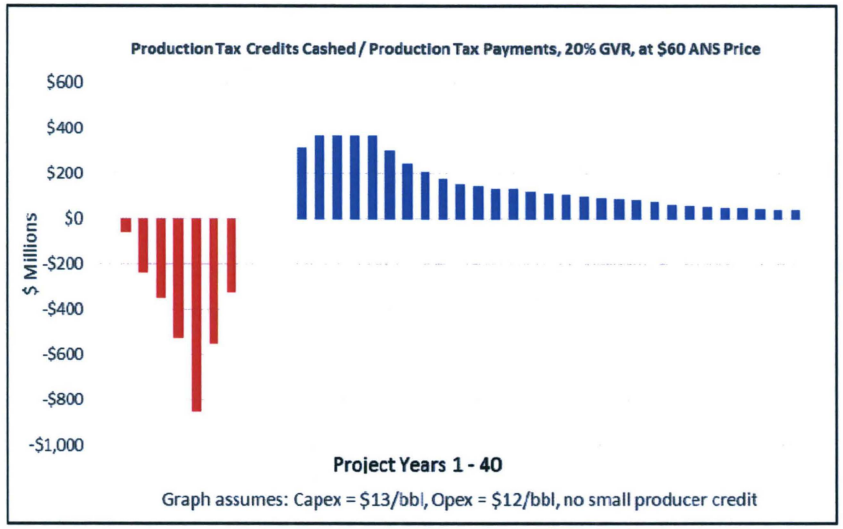


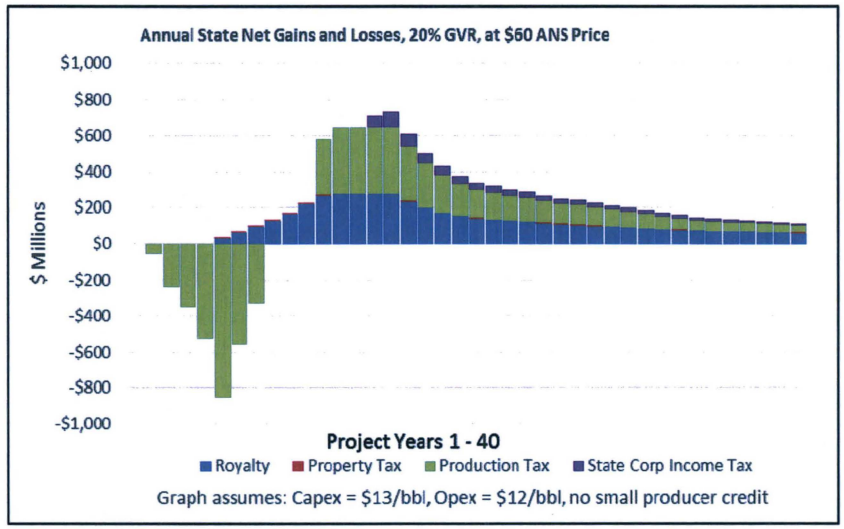


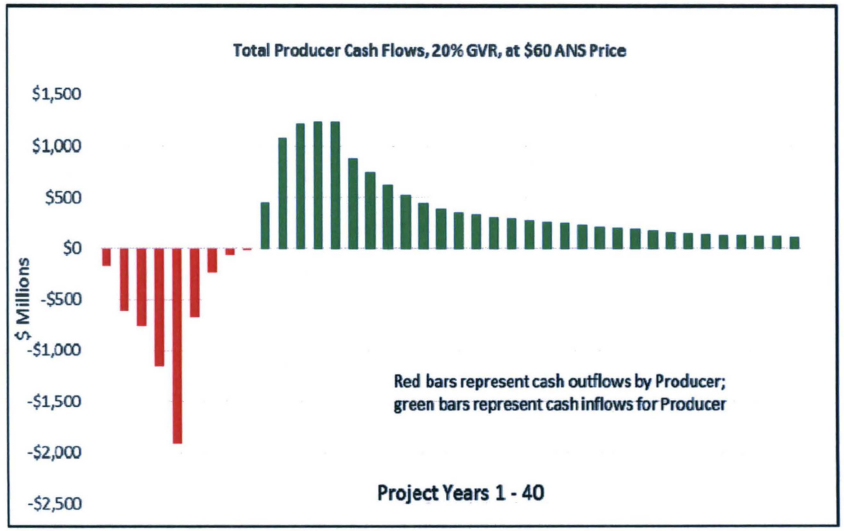
Life Cycle Totals	$Millions
Production Tax Credits Cashed	2,967
Production Tax Paid	228
Net Production Tax	-2,738
Production Tax NPV 6.15%	-2,047
Total Annual State Losses	2,844
Total Annual State Gains	3,211
Net State Gain (Loss)	367
State NPV 6.15%	-1,016
Total Producer Cash Out	6,429
Total Producer Cash In	8,561
Net Producer Cash Flow	2,131
Producer Cash NPV 6.15%	-1,768

North Slope Life Cycle Modeling

750 mmbo Status Quo, $60/bbl



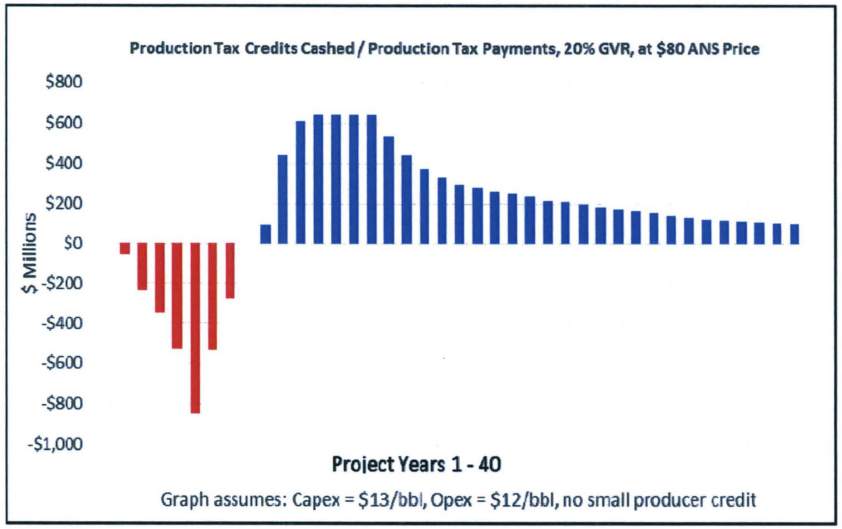


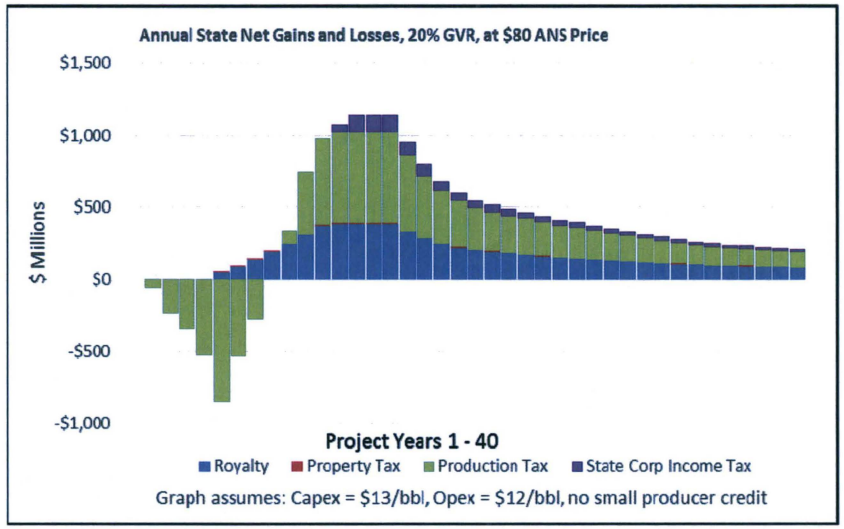


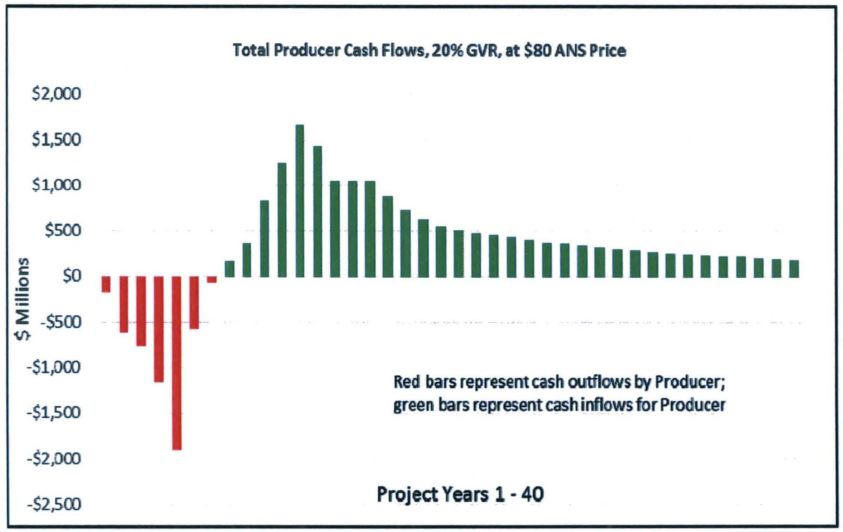
Life Cycle Totals	$Millions
Production Tax Credits Cashed	2,897
Production Tax Paid	4,465
Net Production Tax	1,568
Production Tax NPV 6.15%	-642
Total Annual State Losses	2,699
Total Annual State Gains	9,814
Net State Gain (Loss)	7,115
State NPV 6.15%	1,197
Total Producer Cash Out	5,562
Total Producer Cash In	13,037
Net Producer Cash Flow	7,475
Producer Cash NPV 6.15%	312

North Slope Life Cycle Modeling

750 mmbo Status Quo, $80/bbl



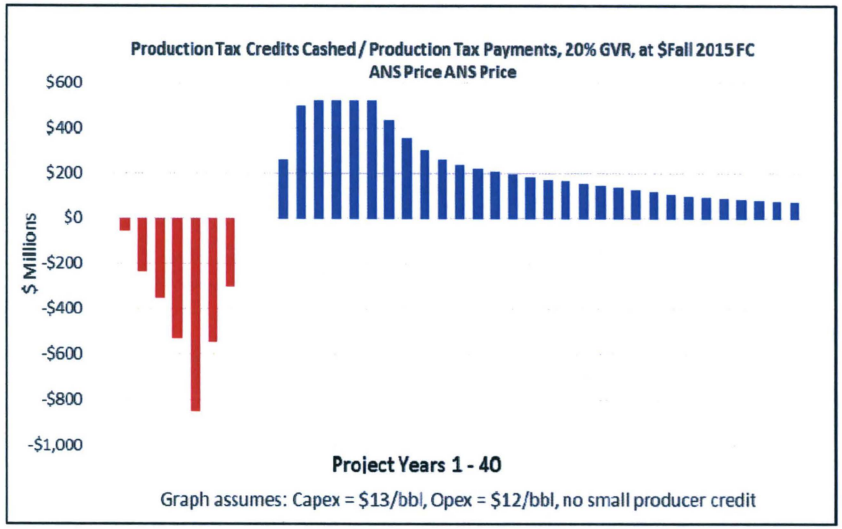


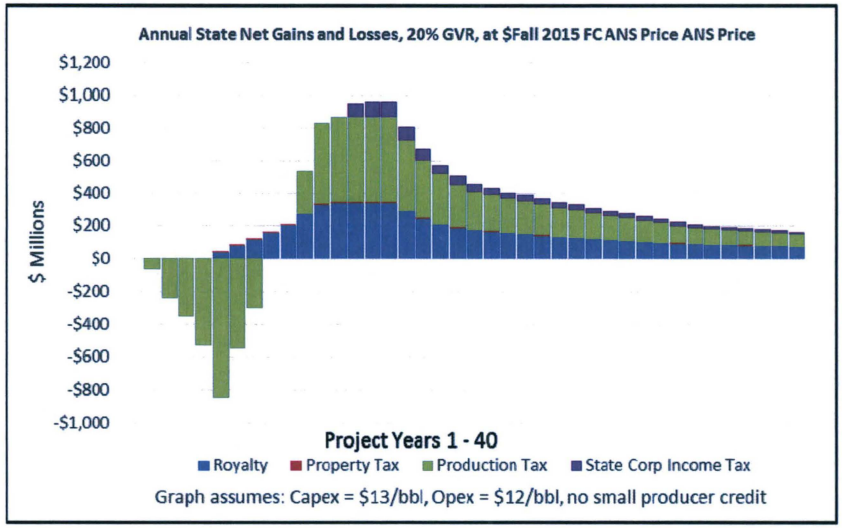


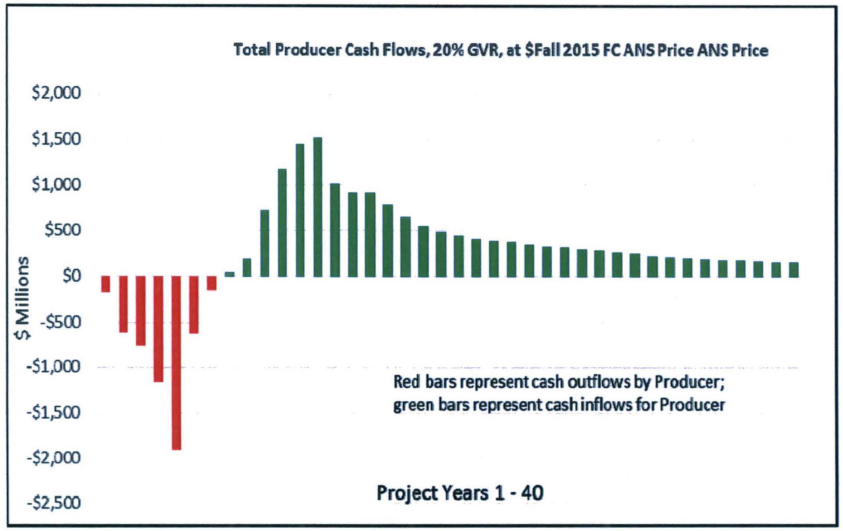
Life Cycle Totals	$Millions
Production Tax Credits Cashed	2,830
Production Tax Paid	8,923
Net Production Tax	6,093
Production Tax NPV 6.15%	869
Total Annual State Losses	2,553
Total Annual State Gains	16,623
Net State Gain (Loss)	14,069
State NPV 6.15%	3,527
Total Producer Cash Out	5,247
Total Producer Cash In	17,933
Net Producer Cash Flow	12,686
Producer Cash NPV 6.15%	2,216

North Slope Life Cycle Modeling

750 mmbo Status Quo, Fall 2015 FC Prices



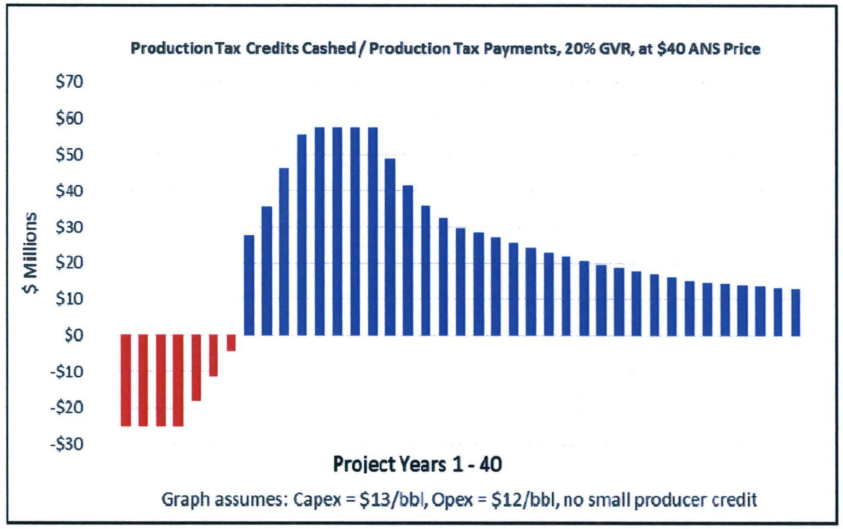


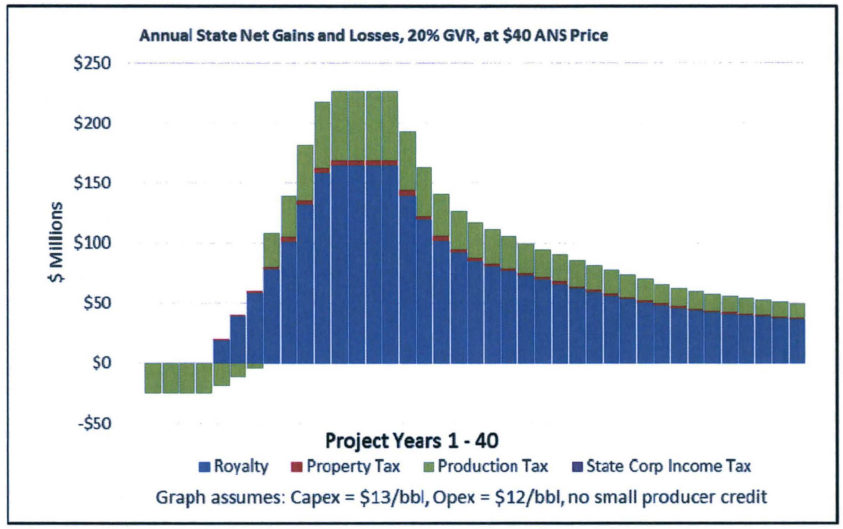


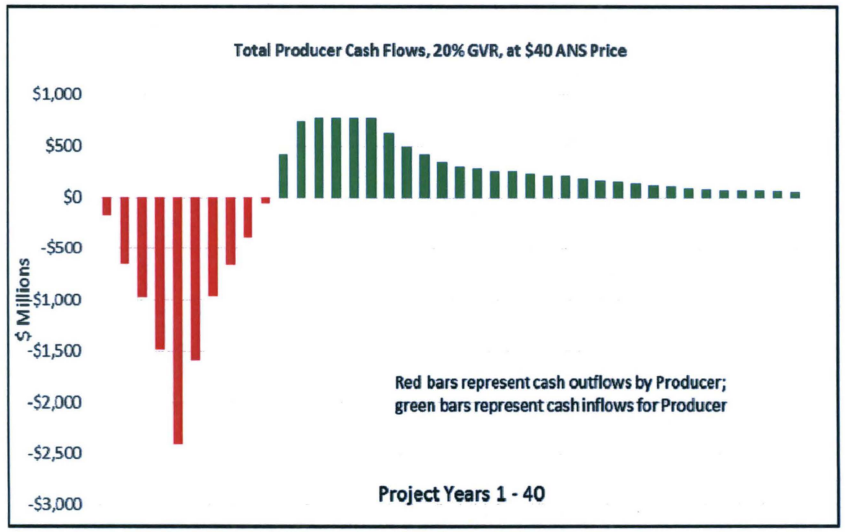
Life Cycle Totals	$Millions
Production Tax Credits Cashed	2,864
Production Tax Paid	6,999
Net Production Tax	4,135
Production Tax NPV 6.15%	206
Total Annual State Losses	2,627
Total Annual State Gains	13,696
Net State Gain (Loss)	11,069
State NPV 6.15%	2,509
Total Producer Cash Out	5,374
Total Producer Cash In	15,833
Net Producer Cash Flow	10,458
Producer Cash NPV 6.15%	1,401

North Slope Life Cycle Modeling

750 mmbo HB247, $40 / bbl



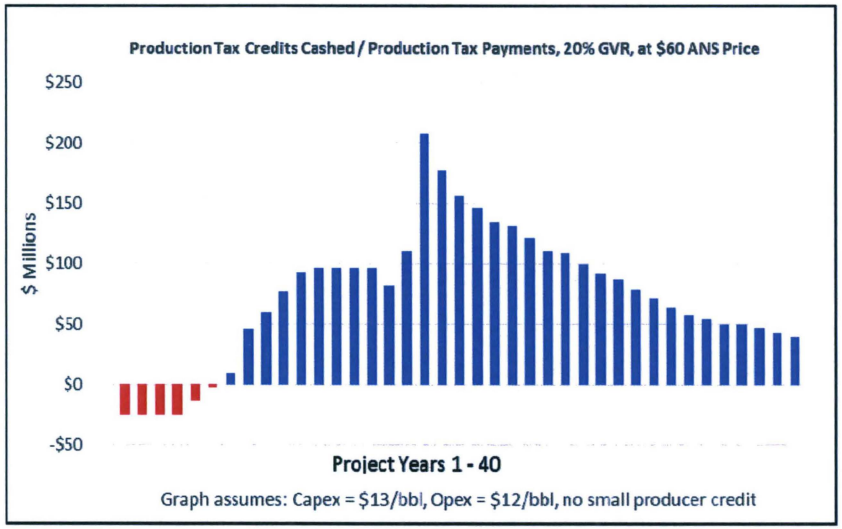


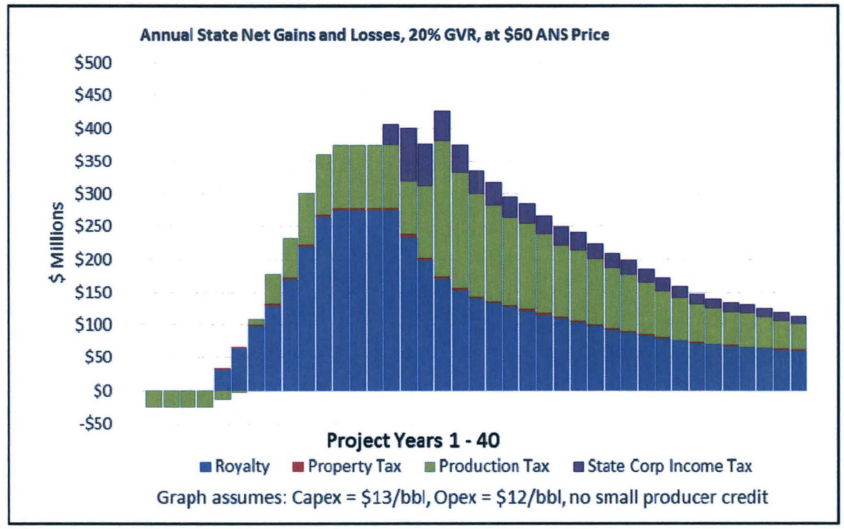


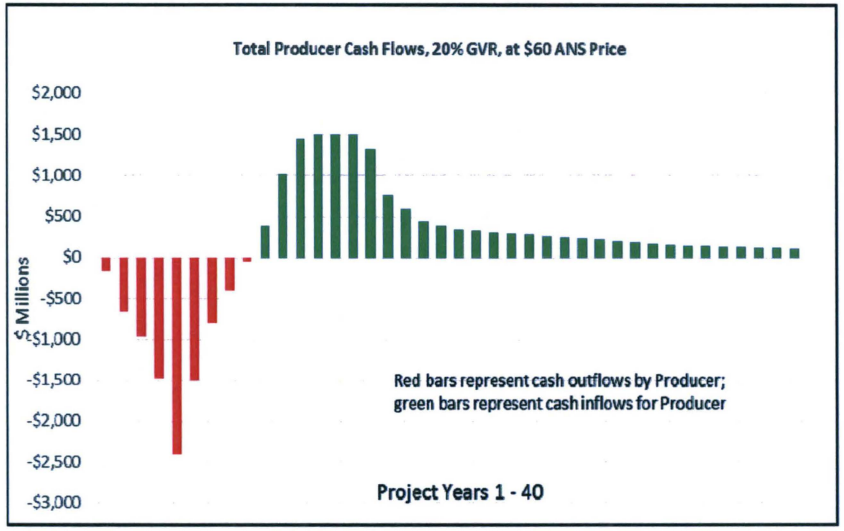
Life Cycle Totals	$Millions
Production Tax Credits Cashed	134
Production Tax Paid	941
Net Production Tax	807
Production Tax NPV 6.15%	206
Total Annual State Losses	100
Total Annual State Gains	3,785
Net State Gain (Loss)	3,685
State NPV 6.15%	1,192
Total Producer Cash Out	9,323
Total Producer Cash In	9,284
Net Producer Cash Flow	-39
Producer Cash NPV 6.15%	-3,744

North Slope Life Cycle Modeling

750 mmbo HB247, $60 / bbl



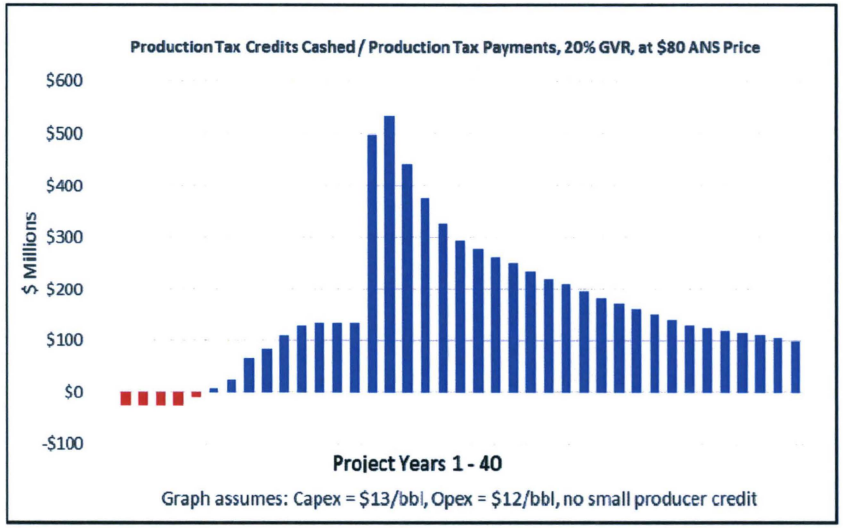


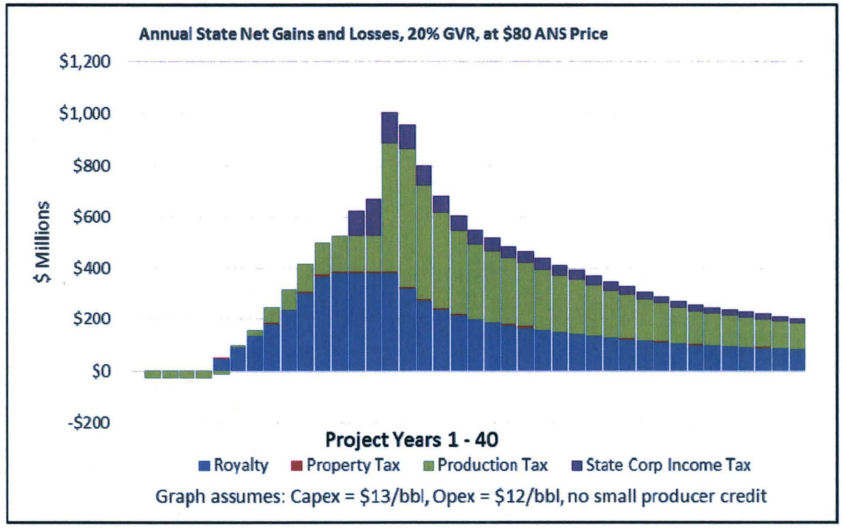


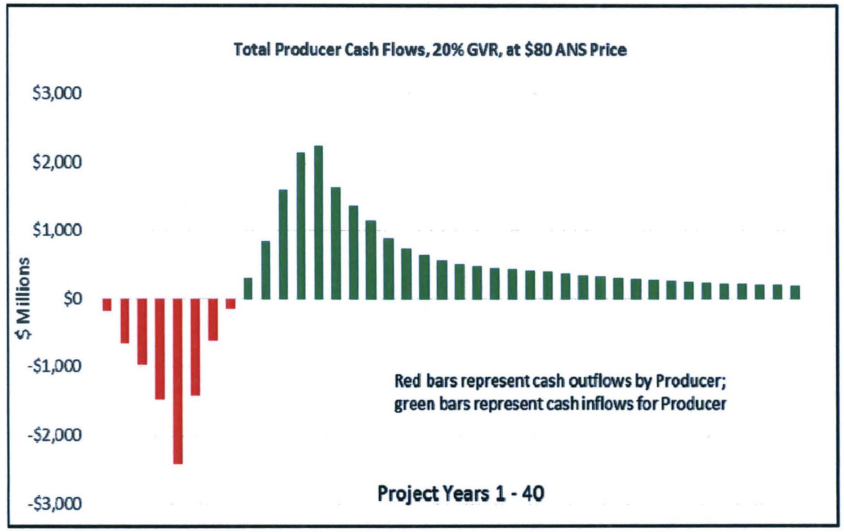
Life Cycle Totals	$Millions
Production Tax Credits Cashed	116
Production Tax Paid	2,983
Net Production Tax	2,867
Production Tax NPV 6.15%	749
Total Annual State Losses	100
Total Annual State Gains	8,431
Net State Gain (Loss)	8,331
State NPV 6.15%	2,553
Total Producer Cash Out	8,398
Total Producer Cash In	15,084
Net Producer Cash Flow	6,686
Producer Cash NPV 6.15%	-870

North Slope Life Cycle Modeling

750 mmbo HB 247, $80 / bbl



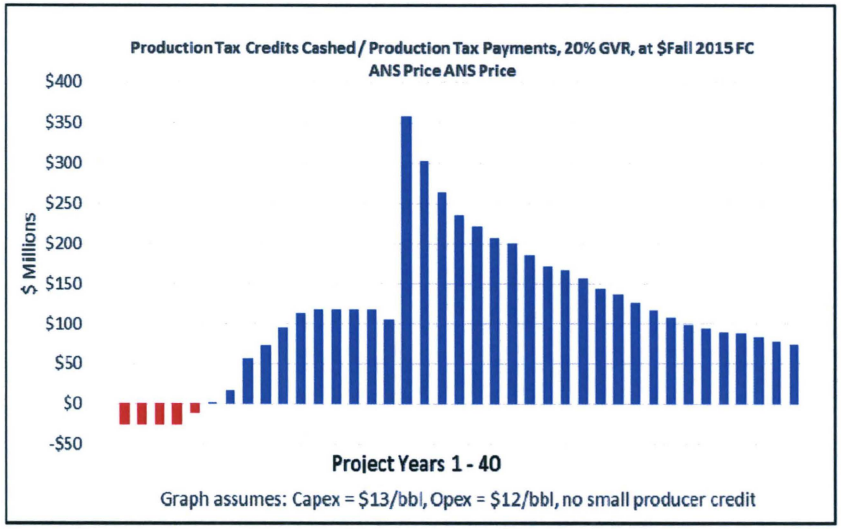


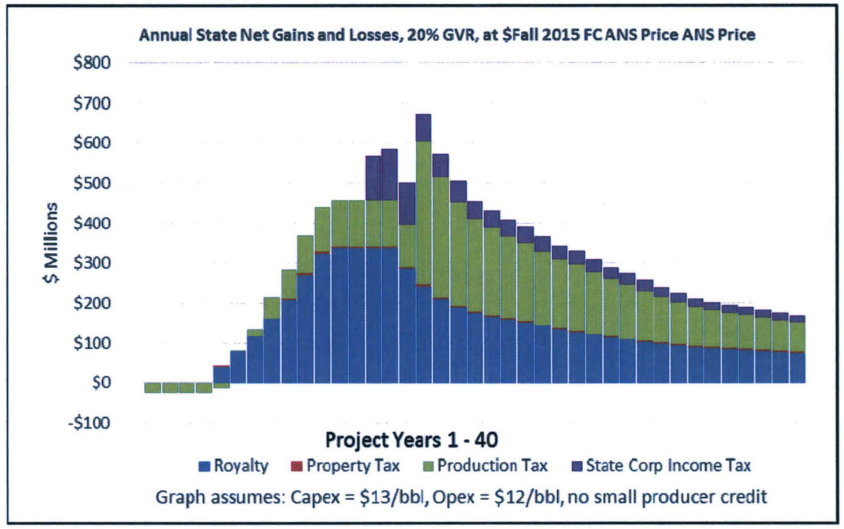


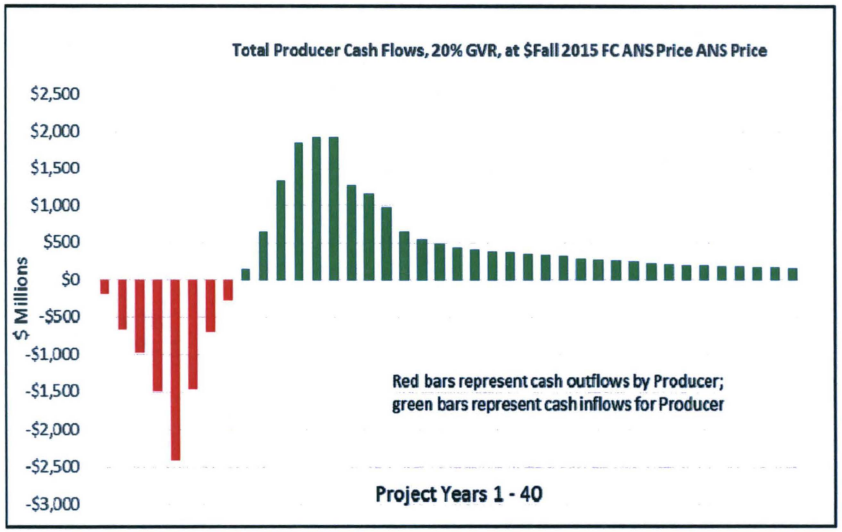
Life Cycle Totals	$Millions
Production Tax Credits Cashed	109
Production Tax Paid	6,533
Net Production Tax	6,424
Production Tax NPV 6.15%	1,743
Total Annual State Losses	100
Total Annual State Gains	14,479
Net State Gain (Loss)	14,379
State NPV 6.15%	4,388
Total Producer Cash Out	7,832
Total Producer Cash In	20,317
Net Producer Cash Flow	12,485
Producer Cash NPV 6.15%	1,415

North Slope Life Cycle Modeling

750 mmbo HB 247, Fall 2015 FC Prices



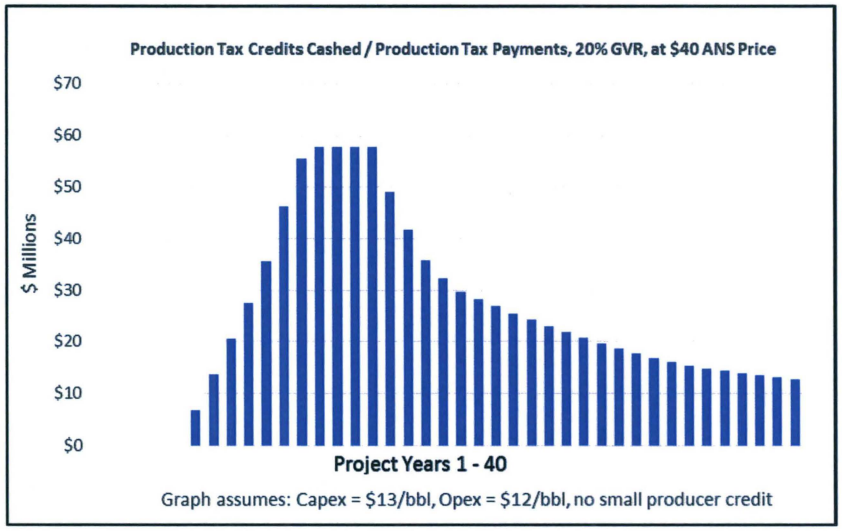


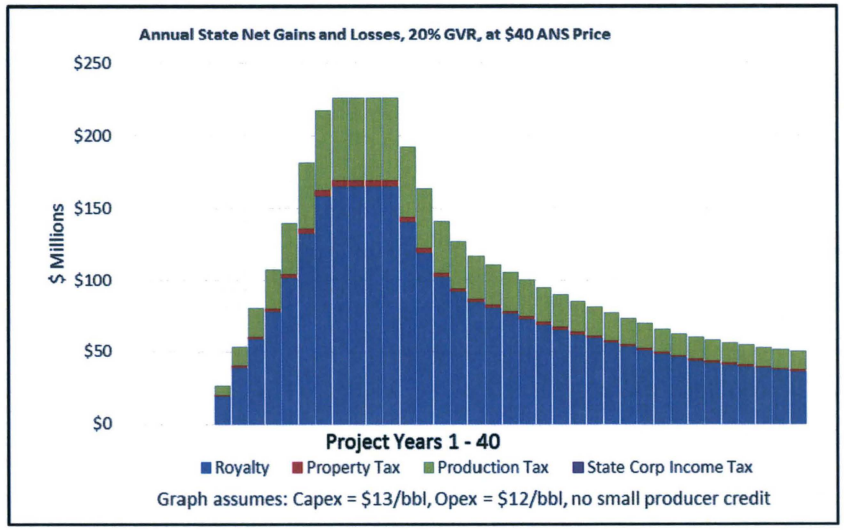


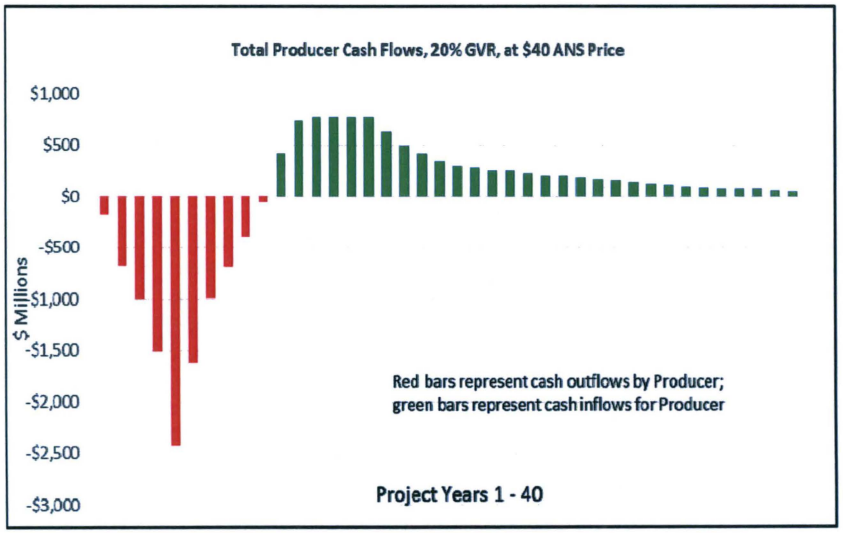
Life Cycle Totals	$Millions
Production Tax Credits Cashed	111
Production Tax Paid	4,634
Net Production Tax	4,523
Production Tax NPV 6.15%	1,172
Total Annual State Losses	100
Total Annual State Gains	11,533
Net State Gain (Loss)	11,433
State NPV 6.15%	3,461
Total Producer Cash Out	8,094
Total Producer Cash In	18,316
Net Producer Cash Flow	10,222
Producer Cash NPV 6.15%	520

North Slope Life Cycle Modeling

750 mmbo HB 247, $40/bbl, Co. w/ > $10 billion revenue



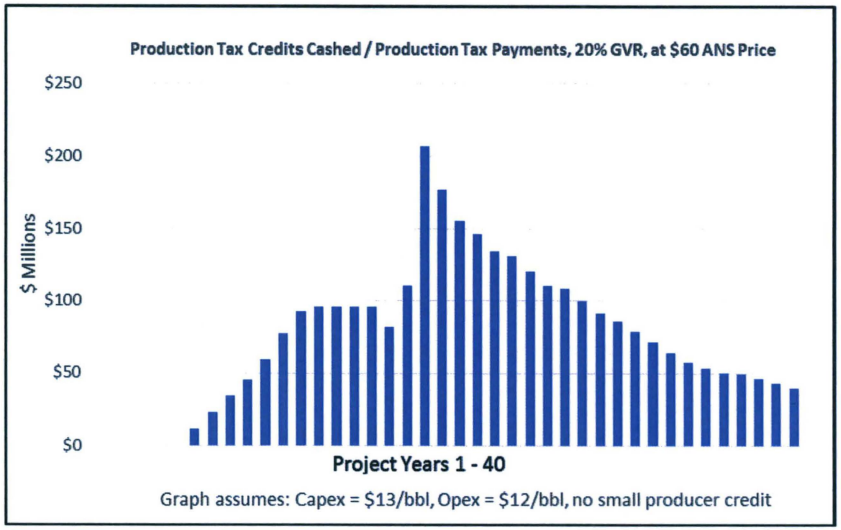


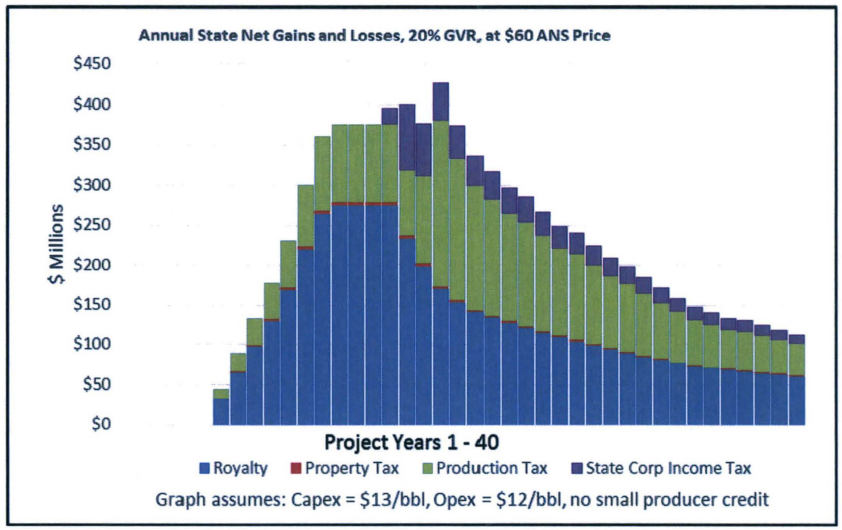


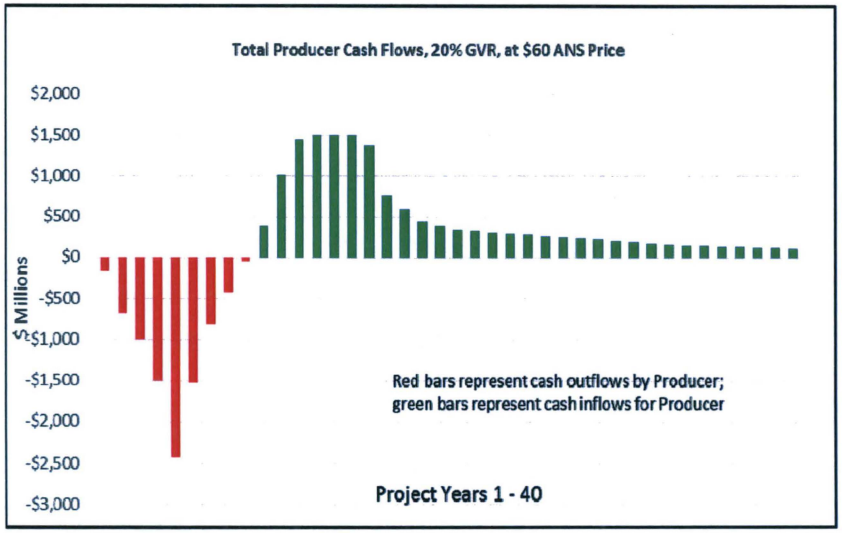
Life Cycle Totals	$Millions
Production Tax Credits Cashed	0
Production Tax Paid	982
Net Production Tax	982
Production Tax NPV 6.15%	337
Total Annual State Losses	0
Total Annual State Gains	3,860
Net State Gain (Loss)	3,860
State NPV 6.15%	1,322
Total Producer Cash Out	9,498
Total Producer Cash In	9,284
Net Producer Cash Flow	-214
Producer Cash NPV 6.15%	-3,875

North Slope Life Cycle Modeling

750 mmbo HB 247, $60/bbl, Co. w/ > $10 billion revenue



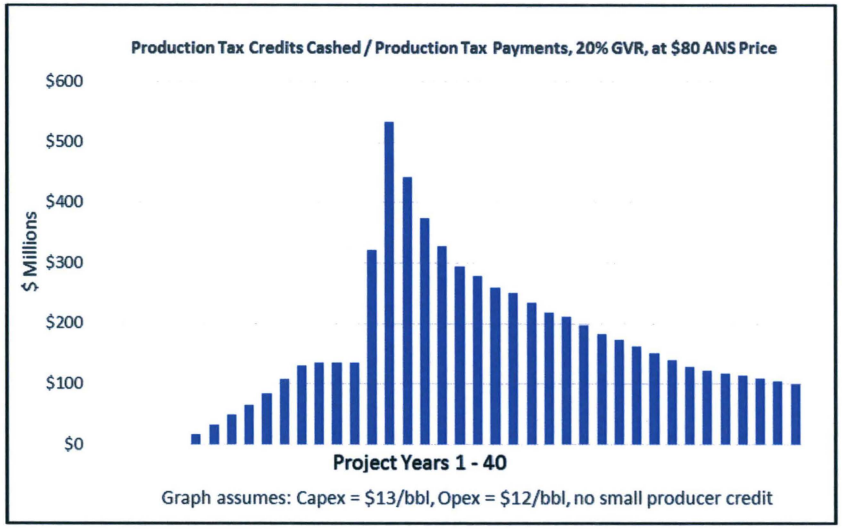


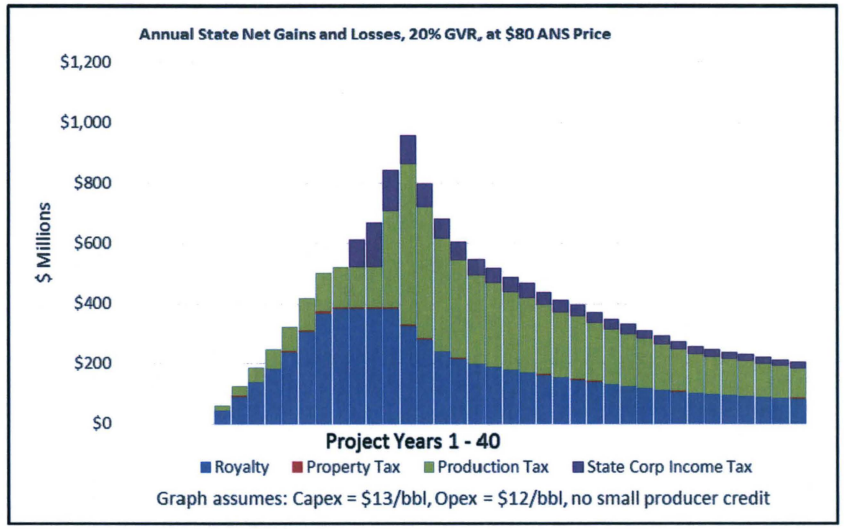


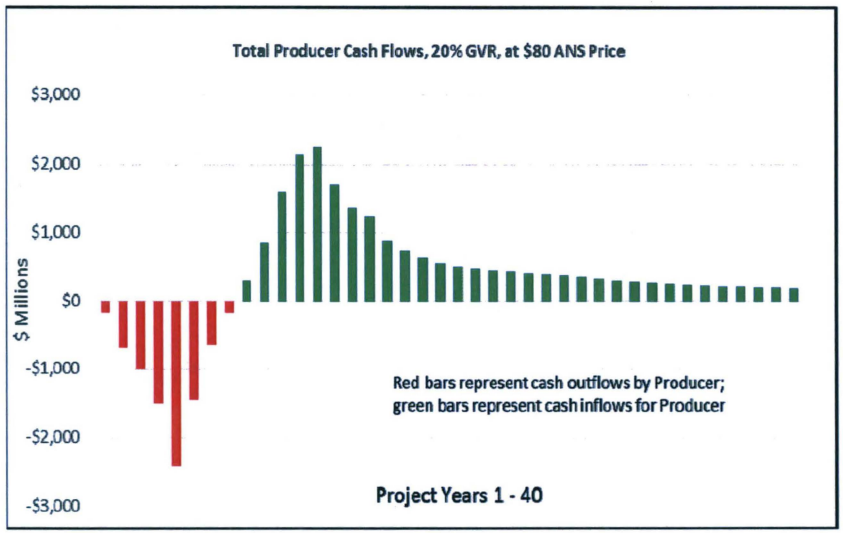
Life Cycle Totals	$Millions
Production Tax Credits Cashed	0
Production Tax Paid	3,042
Net Production Tax	3,042
Production Tax NPV 6.15%	879
Total Annual State Losses	0
Total Annual State Gains	8,494
Net State Gain (Loss)	8,494
State NPV 6.15%	2,679
Total Producer Cash Out	8,573
Total Producer Cash In	15,152
Net Producer Cash Flow	6,579
Producer Cash NPV 6.15%	-974

North Slope Life Cycle Modeling

750 mmbo HB 247, $80/bbl, Co. w/ > $10 billion revenue



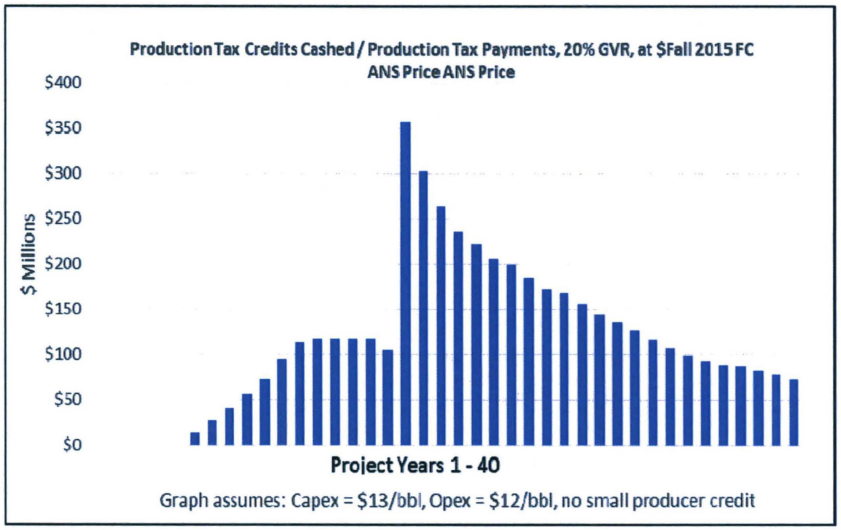


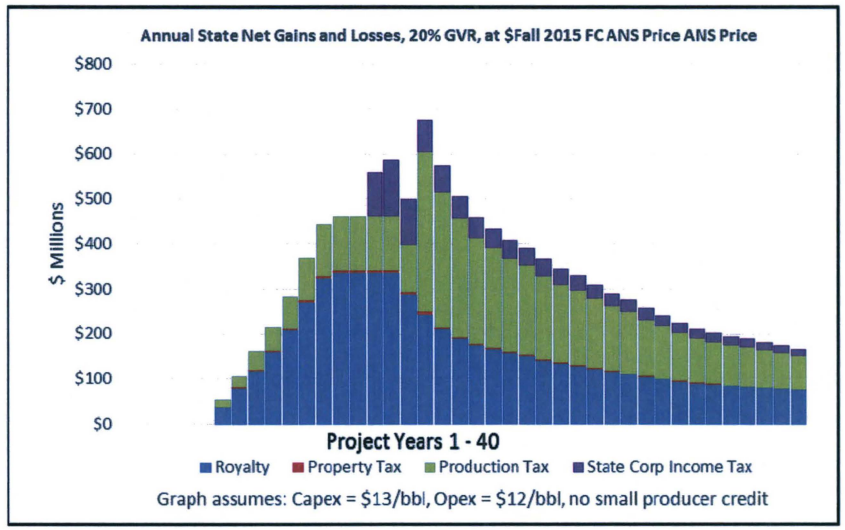


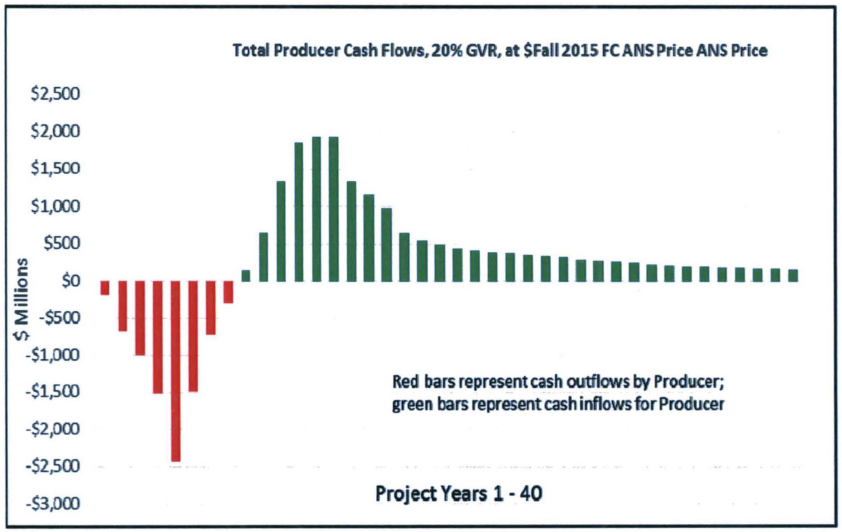
Life Cycle Totals	$Millions
Production Tax Credits Cashed	0
Production Tax Paid	6,424
Net Production Tax	6,424
Production Tax NPV 6.15%	1,806
Total Annual State Losses	0
Total Annual State Gains	14,379
Net State Gain (Loss)	14,379
State NPV 6.15%	4,451
Total Producer Cash Out	8,007
Total Producer Cash In	20,492
Net Producer Cash Flow	12,485
Producer Cash NPV 6.15%	1,355

North Slope Life Cycle Modeling

750 mmbo HB 247, Fall 2015 FC price, > $10 billion rev.







Life Cycle Totals	$Millions
Production Tax Credits Cashed	0
Production Tax Paid	4,698
Net Production Tax	4,698
Production Tax NPV 6.15%	1,303
Total Annual State Losses	0
Total Annual State Gains	11,596
Net State Gain (Loss)	11,596
State NPV 6.15%	3,587
Total Producer Cash Out	8,269
Total Producer Cash In	18,385
Net Producer Cash Flow	10,116
Producer Cash NPV 6.15%	417

Field Life Cycle Modeling: Cook Inlet

Cook Inlet Life Cycle Modeling Assumptions

- Field size of 50 mmbo
- New producer eligible for cash refunds
  - (Modeling also applies for an incumbent producer not eligible for cash refunds who can apply credits to other North Slope fields)
- Four Oil prices modeled – all in real uninflated $
  - $40, $60, and $80 held static through life of field
  - Fall 2015 forecast prices (2025 extended through life of field)
- Two tax systems modeled
  - Status quo (new fields qualify for 20% GVR)
  - HB247 elements:
    - Limit tax refunds to $25 million per company per year
    - Repeal of Qualified Capital Expenditure and Well Lease Expenditure credits
    - 10-year limit on carry-forward of NOL credits
- Alternatives for Cook Inlet tax regime, with current tax cap of zero expiring in 2022 or extended indefinitely

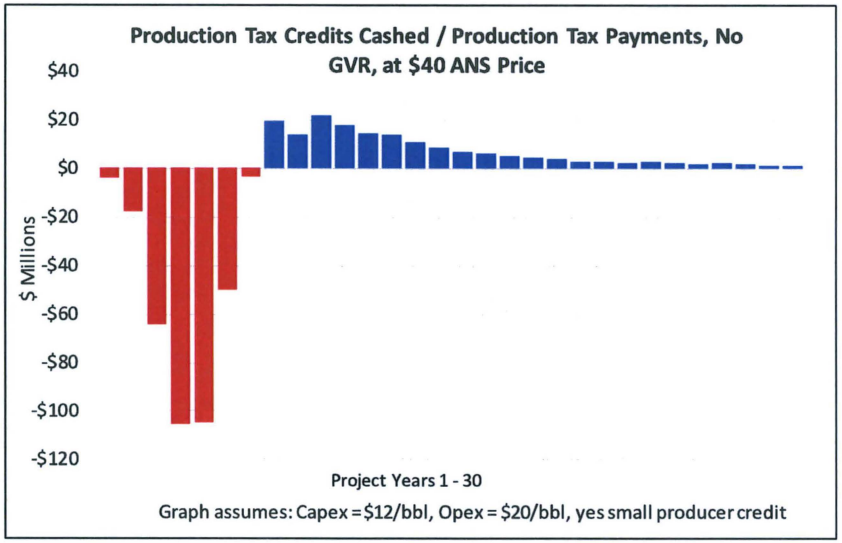
Cook Inlet Life Cycle Modeling Assumptions

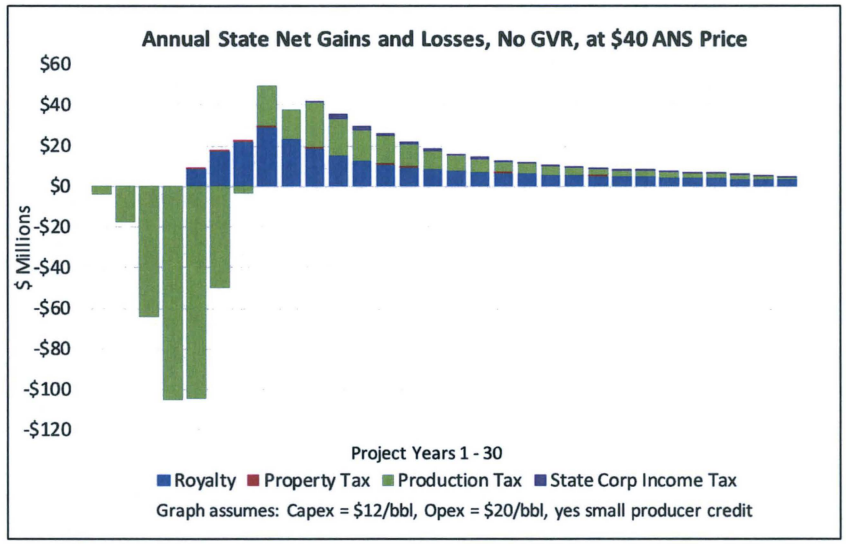
50 mmbo field assumptions

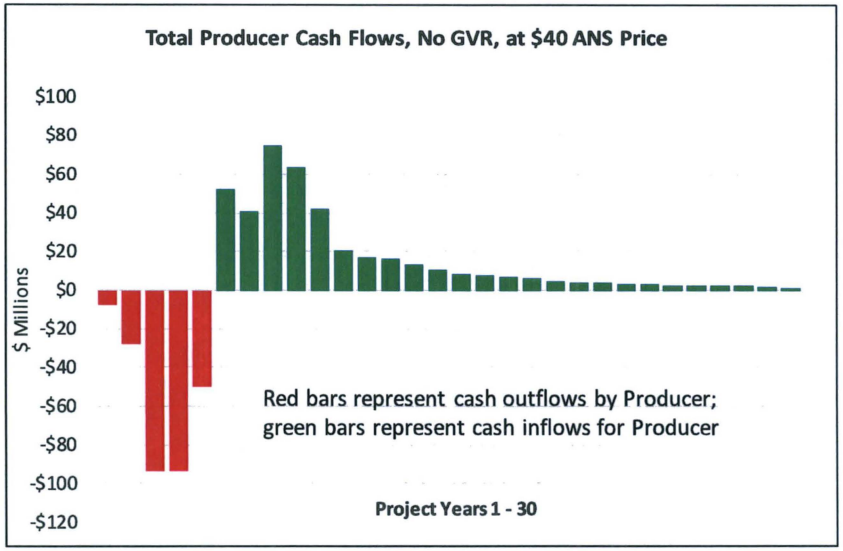
Life of Field	30 years
Peak oil Production	17,000 barrels / day
Transport / barrel	$2 / barrel
Royalty Rate	12.50%
Capex / barrel	$12 / barrel
Opex / barrel	$20 / barrel
Property Tax / barrel	$1.25 / barrel
State Corp Income Tax Rate	6.5% of PTV after Prod Tax
Fed Corp Income Tax Rate	35% of PTV after SCIT

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, 2022 Tax Caps expire, $40/bbl



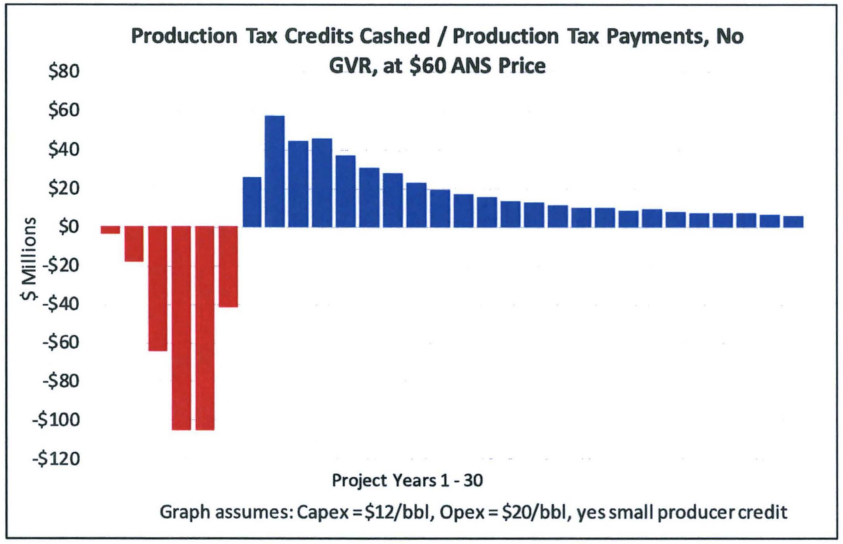


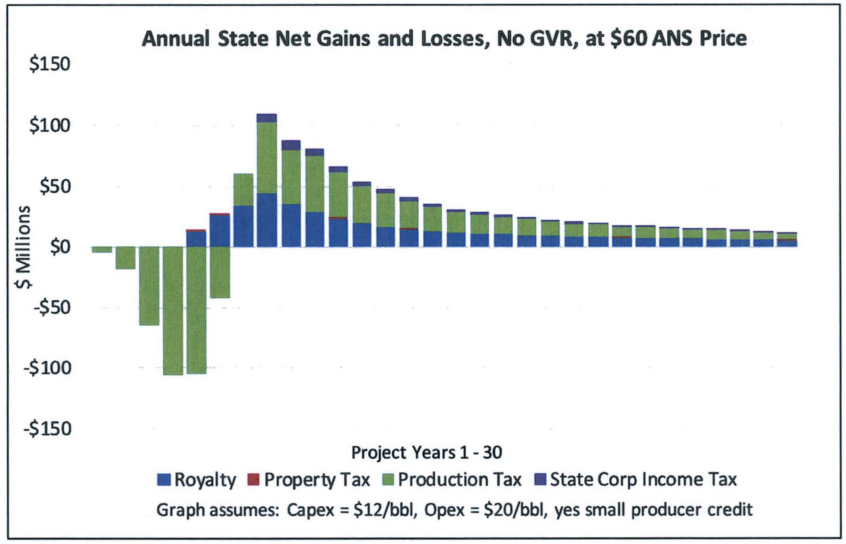


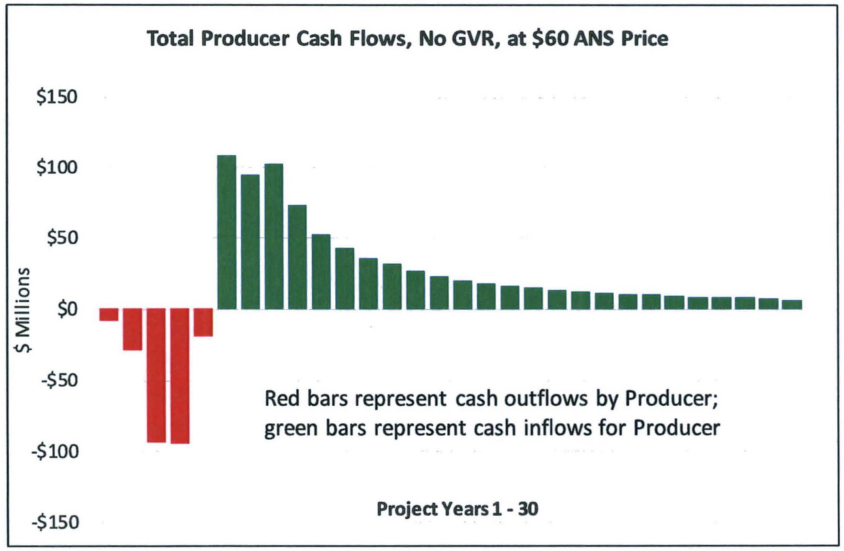
Life Cycle Totals	$Millions
Production Tax Credits Cashed	349
Production Tax Paid	172
Net Production Tax	-177
Production Tax NPV 6.15%	-192
Total Annual State Losses	319
Total Annual State Gains	418
Net State Gain (Loss)	99
State NPV 6.15%	-59
Total Producer Cash Out	273
Total Producer Cash In	412
Net Producer Cash Flow	139
Producer Cash NPV 6.15%	3

Cook Inlet Life Cycle Modeling

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



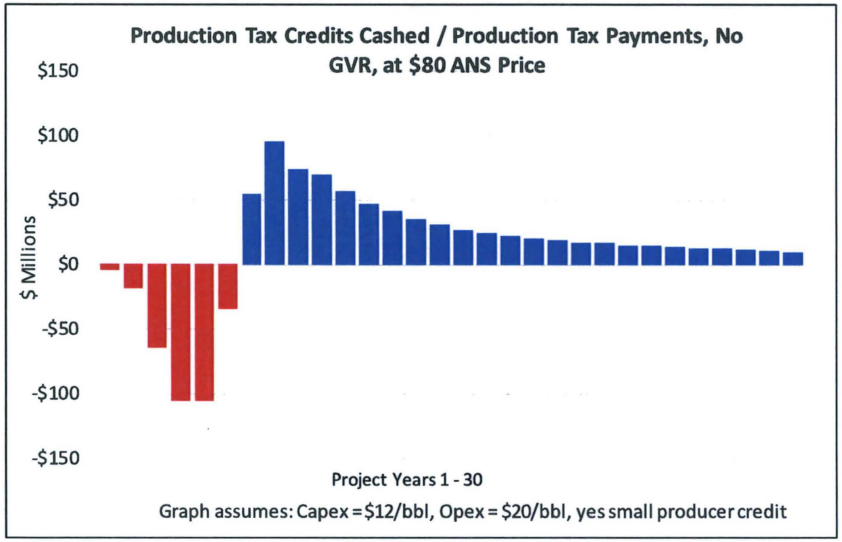


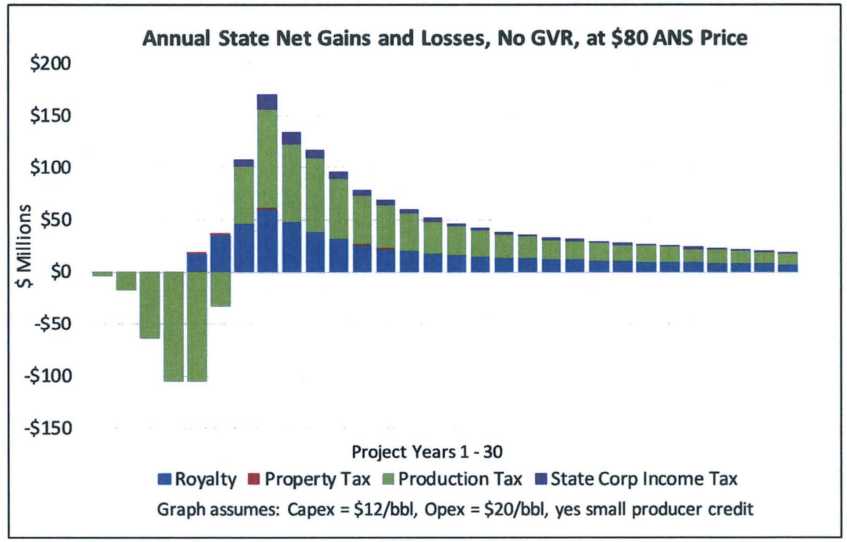


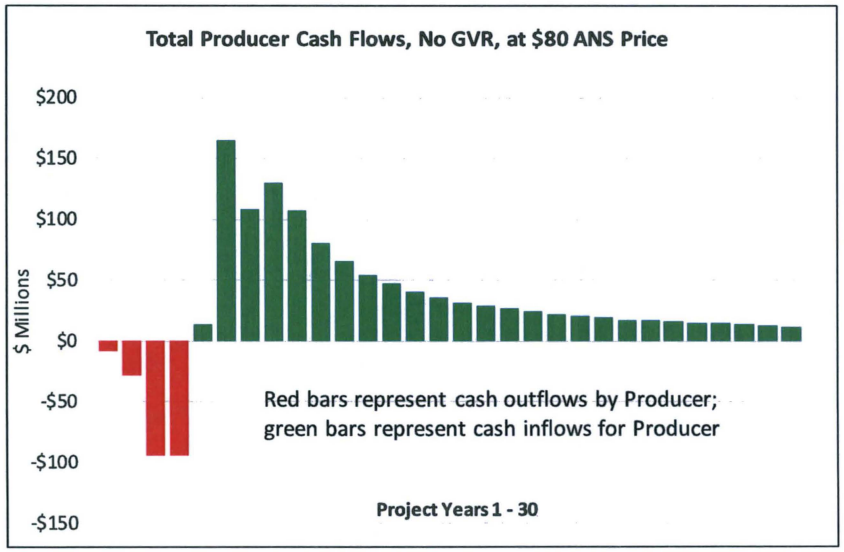
Life Cycle Totals	$Millions
Production Tax Credits Cashed	337
Production Tax Paid	465
Net Production Tax	128
Production Tax NPV 6.15%	-50
Total Annual State Losses	297
Total Annual State Gains	877
Net State Gain (Loss)	579
State NPV 6.15%	167
Total Producer Cash Out	241
Total Producer Cash In	768
Net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

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, 2022 Tax Caps expire, $80/bbl



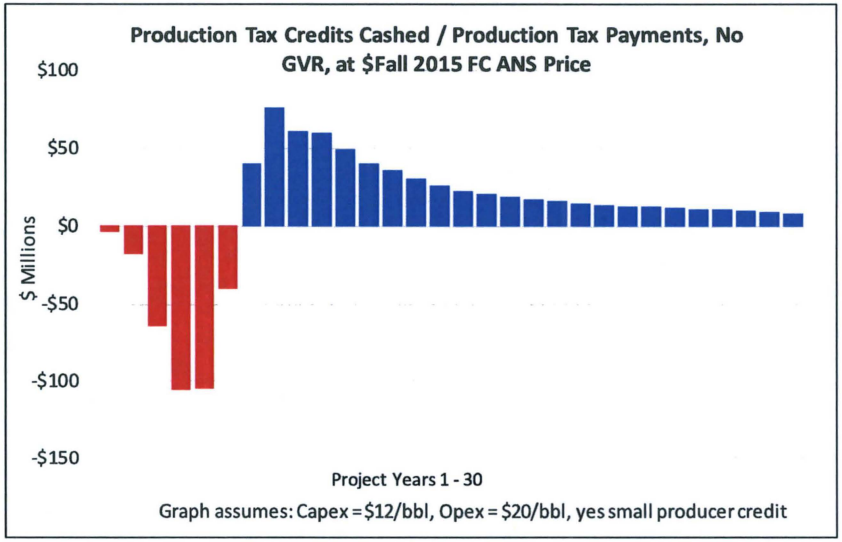


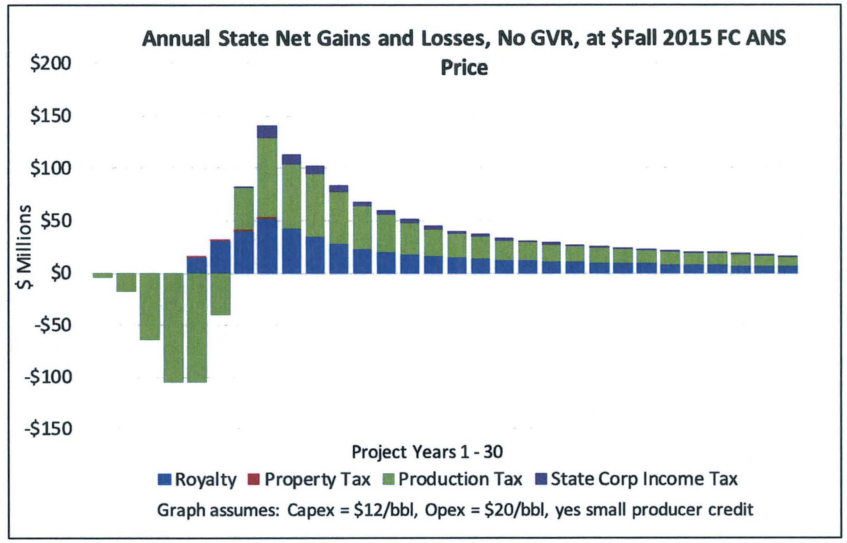


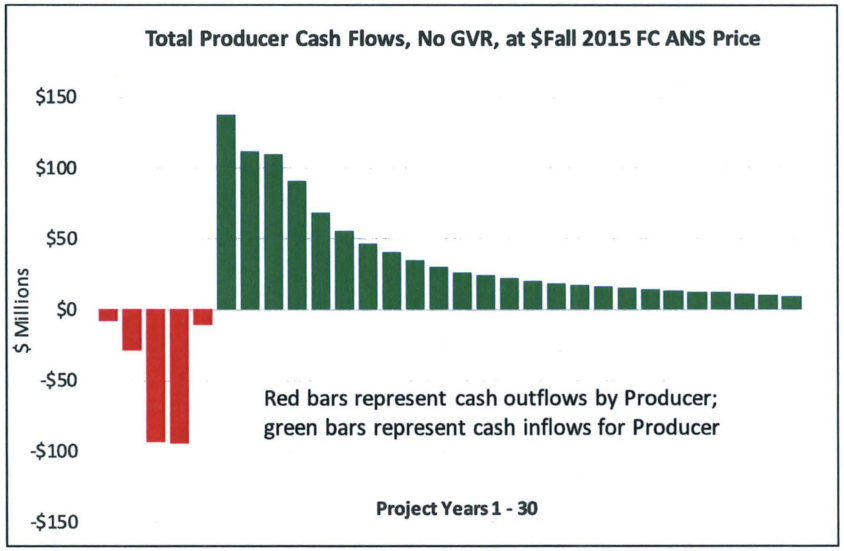
Life Cycle Totals	$Millions
Production Tax Credits Cashed	329
Production Tax Paid	761
Net Production Tax	432
Production Tax NPV 6.15%	92
Total Annual State Losses	278
Total Annual State Gains	1,338
Net State Gain (Loss)	1,060
State NPV 6.15%	395
Total Producer Cash Out	223
Total Producer Cash In	1,138
Net Producer Cash Flow	915
Producer Cash NPV 6.15%	396

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, 2022 Tax Caps expire, Fall 2015 FC Price



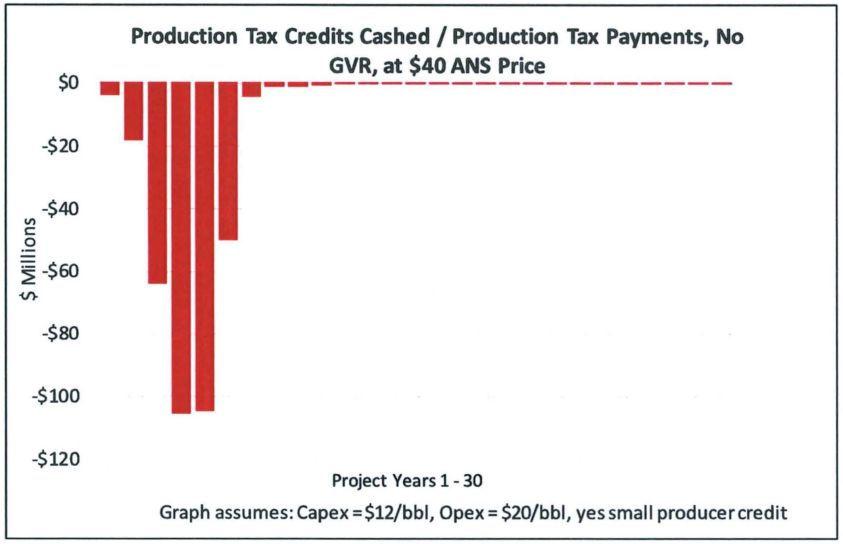


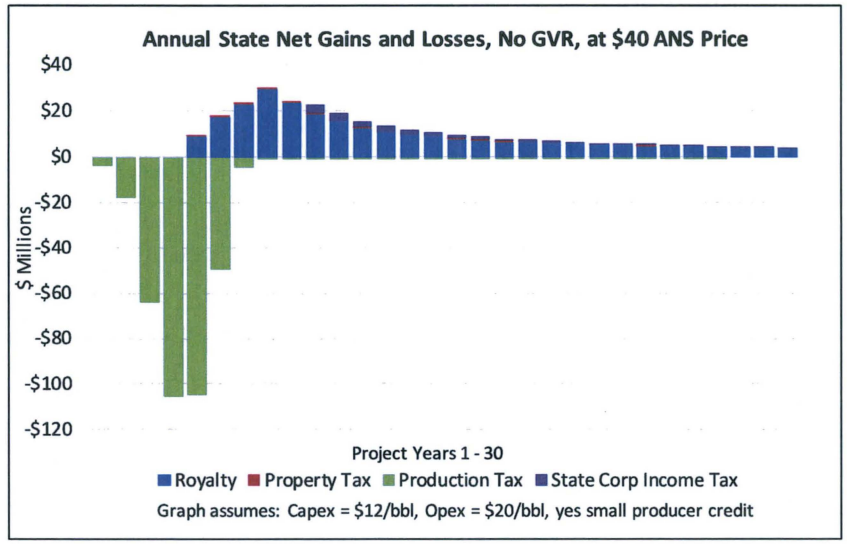


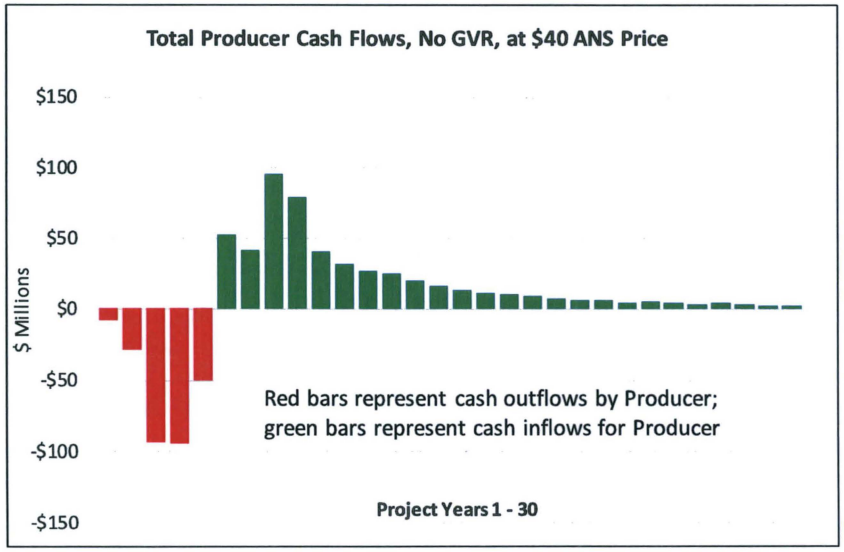
Life Cycle Totals	$Millions
Production Tax Credits Cashed	335
Production Tax Paid	629
Net Production Tax	294
Production Tax NPV 6.15%	26
Total Annual State Losses	290
Total Annual State Gains	1,130
Net State Gain (Loss)	840
State NPV 6.15%	288
Total Producer Cash Out	233
Total Producer Cash In	968
Net Producer Cash Flow	735
Producer Cash NPV 6.15%	303

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, Tax Caps extended, $40/bbl



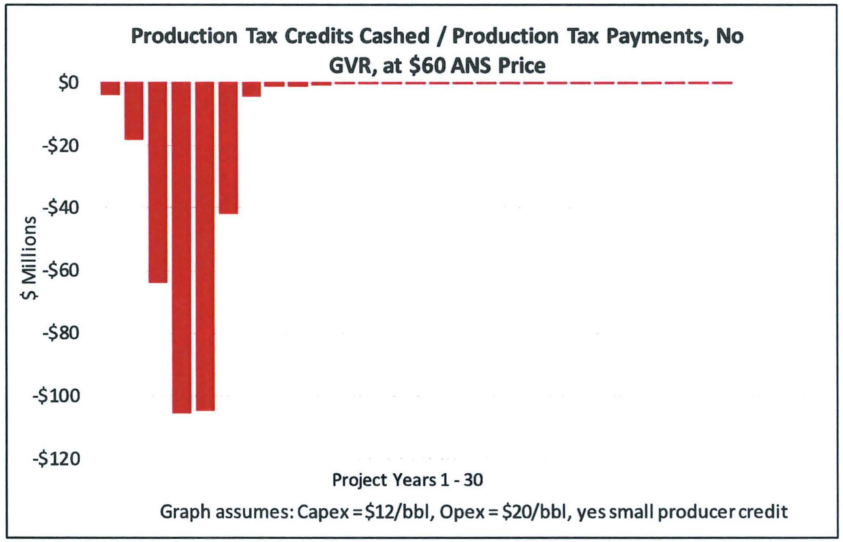


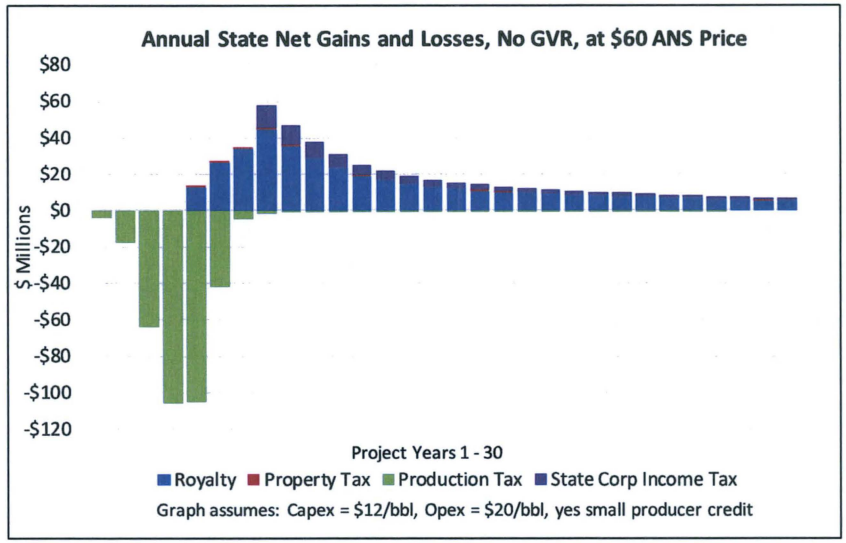


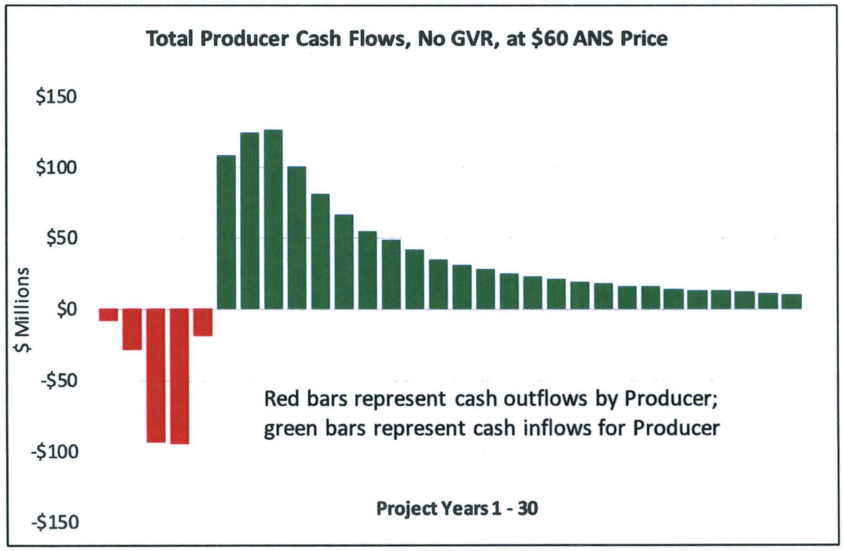
Life Cycle Totals	$Millions
Production Tax Credits Cashed	357
Production Tax Paid	0
Net Production Tax	-357
Production Tax NPV 6.15%	-275
Total Annual State Losses	319
Total Annual State Gains	249
Net State Gain (Loss)	-70
State NPV 6.15%	-137
Total Producer Cash Out	273
Total Producer Cash In	522
Net Producer Cash Flow	249
Producer Cash NPV 6.15%	54

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, Tax Caps extended, $60/bbl



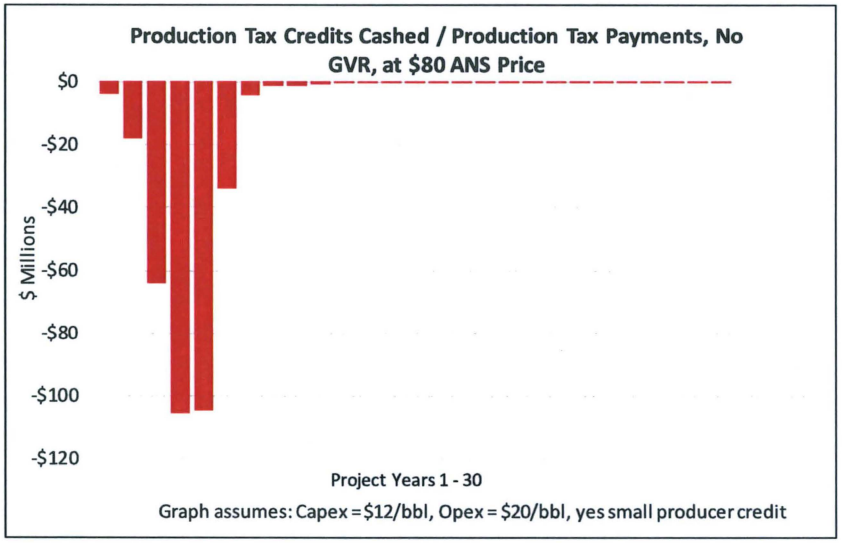


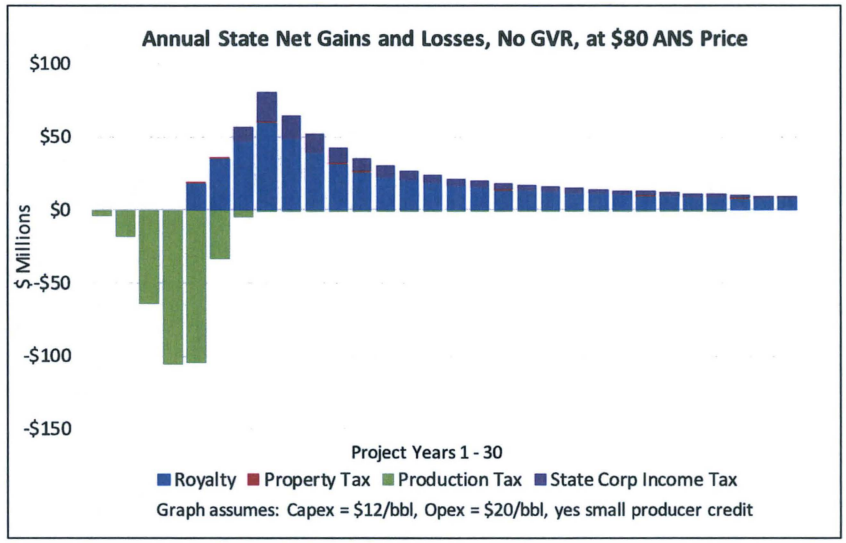


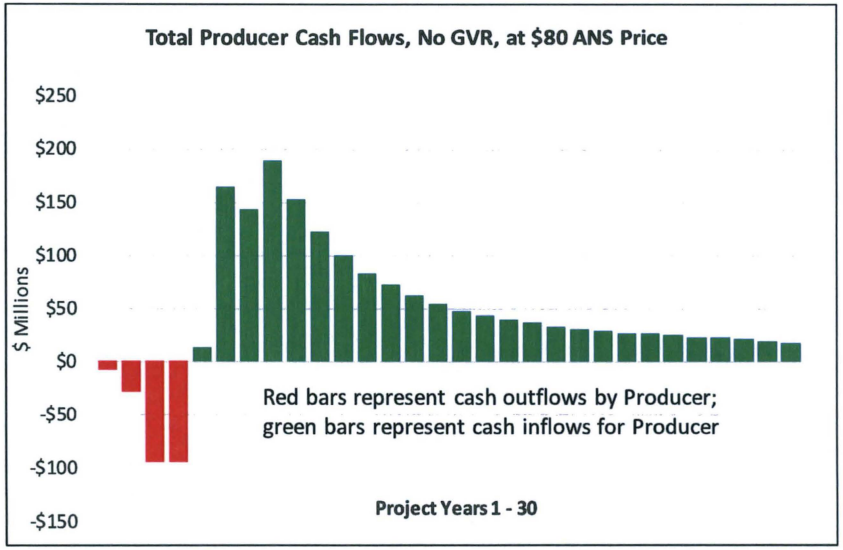
Life Cycle Totals	$Millions
Production Tax Credits Cashed	349
Production Tax Paid	0
Net Production Tax	-349
Production Tax NPV 6.15%	-269
Total Annual State Losses	297
Total Annual State Gains	431
Net State Gain (Loss)	134
State NPV 6.15%	-37
Total Producer Cash Out	241
Total Producer Cash In	1,058
Net Producer Cash Flow	817
Producer Cash NPV 6.15%	335

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, Tax Caps extended, $80/bbl



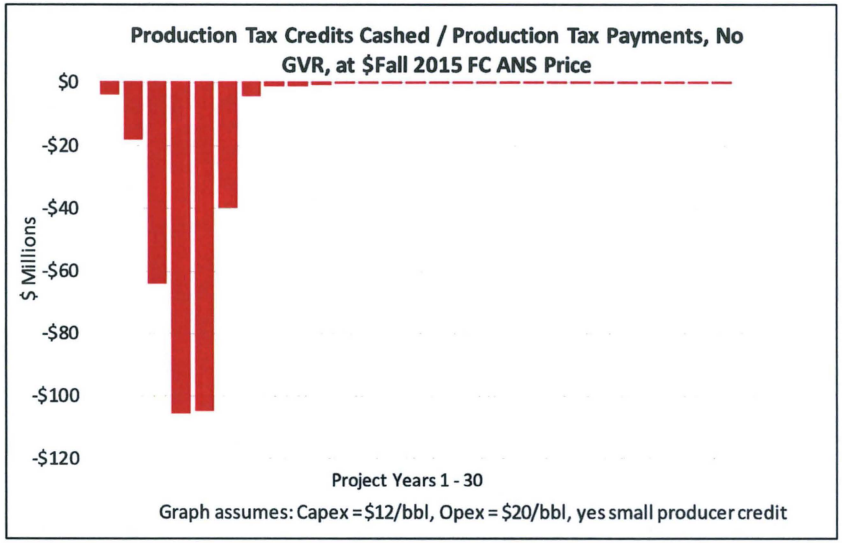


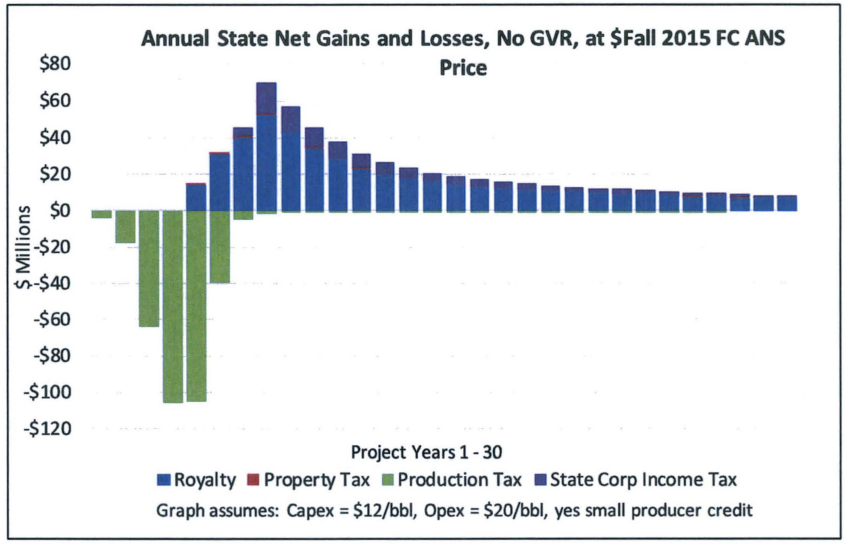


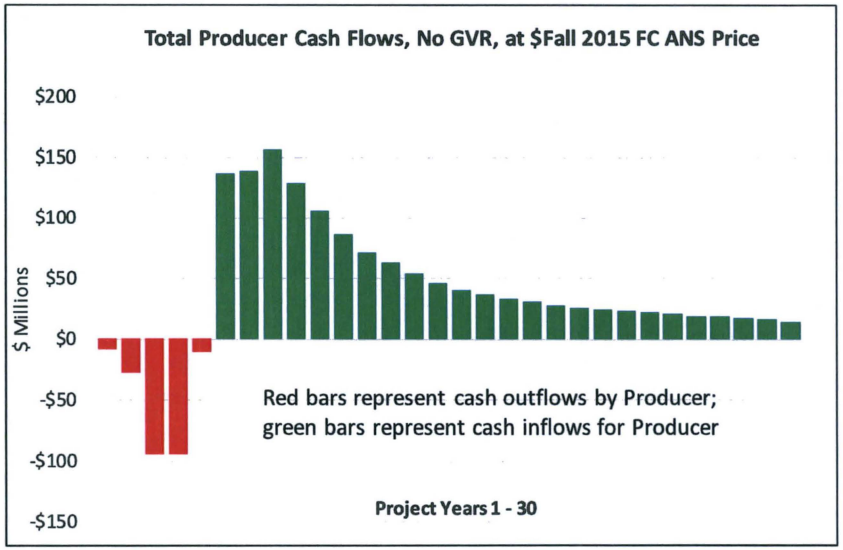
Life Cycle Totals	$Millions
Production Tax Credits Cashed	341
Production Tax Paid	0
Net Production Tax	-341
Production Tax NPV 6.15%	-263
Total Annual State Losses	278
Total Annual State Gains	615
Net State Gain (Loss)	337
State NPV 6.15%	63
Total Producer Cash Out	223
Total Producer Cash In	1,608
Net Producer Cash Flow	1,385
Producer Cash NPV 6.15%	612

Cook Inlet Life Cycle Modeling

50 mmbo Status Quo, Tax Caps extended, Fall 2015 FC Price



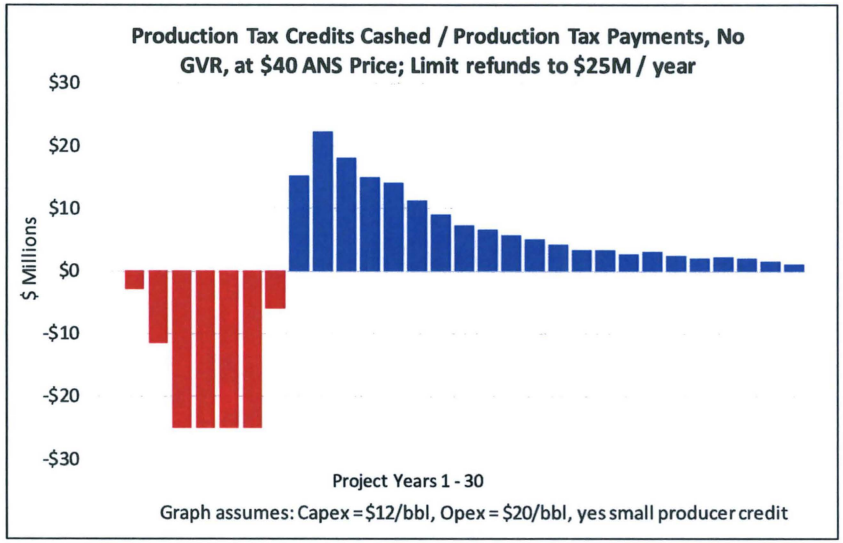


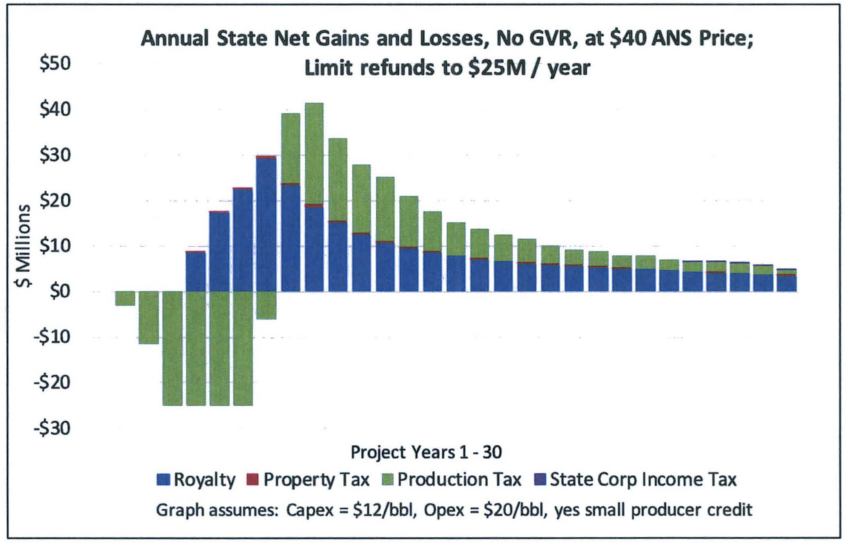


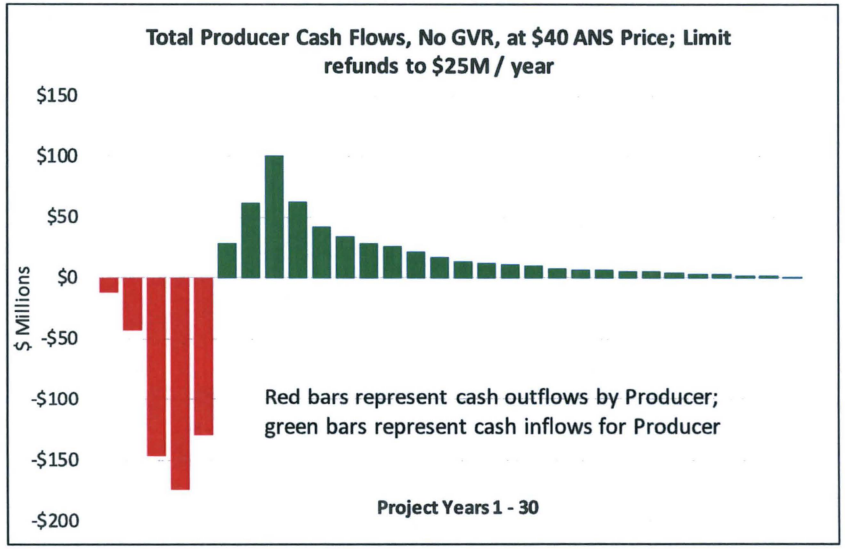
Life Cycle Totals	$Millions
Production Tax Credits Cashed	347
Production Tax Paid	0
Net Production Tax	-347
Production Tax NPV 6.15%	-268
Total Annual State Losses	290
Total Annual State Gains	531
Net State Gain (Loss)	241
State NPV 6.15%	14
Total Producer Cash Out	233
Total Producer Cash In	1,357
Net Producer Cash Flow	1,124
Producer Cash NPV 6.15%	481

Cook Inlet Life Cycle Modeling

50 mmbo HB247, 2022 Tax Caps expire, $40/bbl



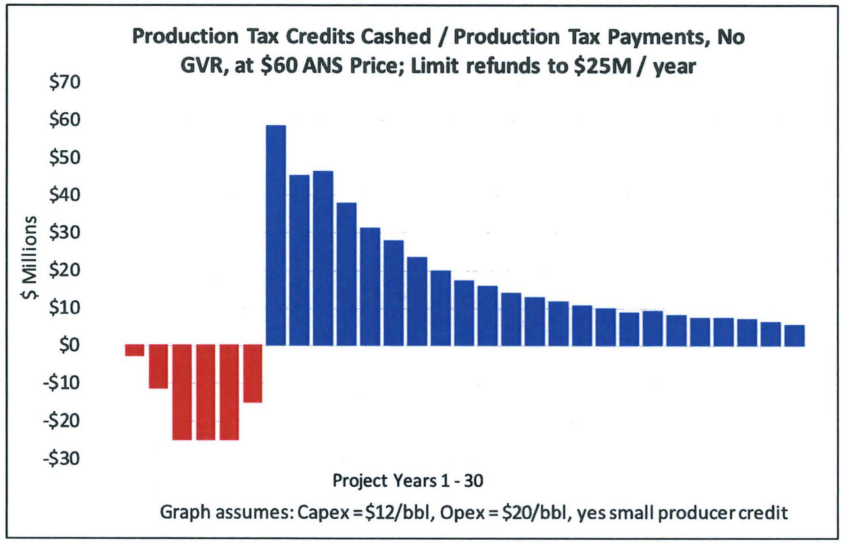


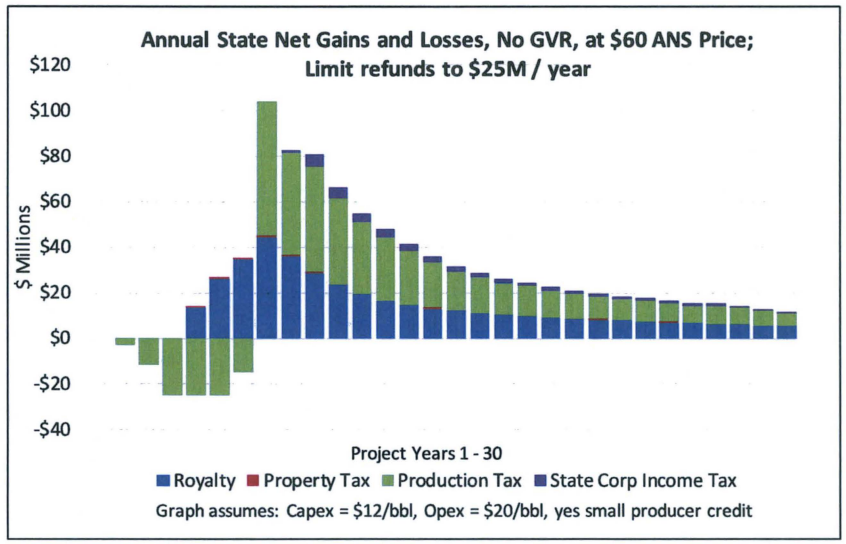


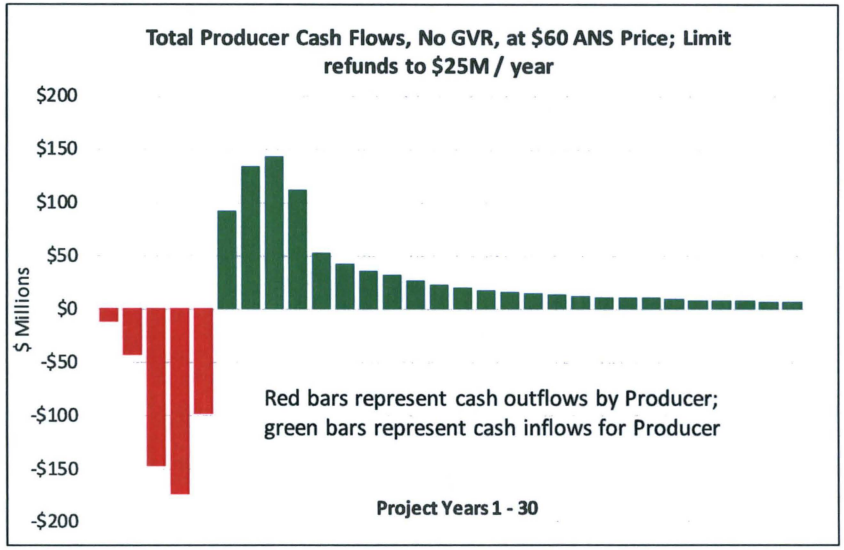
Life Cycle Totals	$Millions
Production Tax Credits Cashed	120
Production Tax Paid	159
Net Production Tax	38
Production Tax NPV 6.15%	-19
Total Annual State Losses	65
Total Annual State Gains	365
Net State Gain (Loss)	300
State NPV 6.15%	108
Total Producer Cash Out	505
Total Producer Cash In	513
Net Producer Cash Flow	9
Producer Cash NPV 6.15%	-135

Cook Inlet Life Cycle Modeling

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



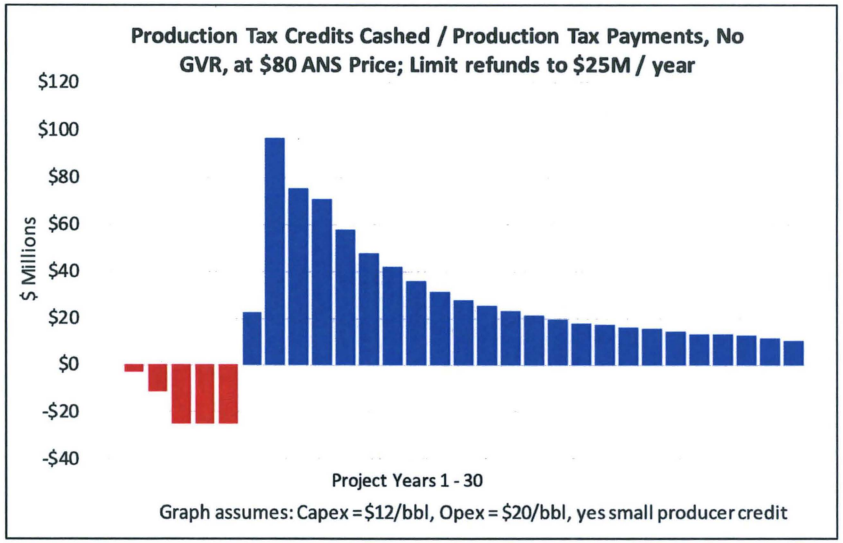


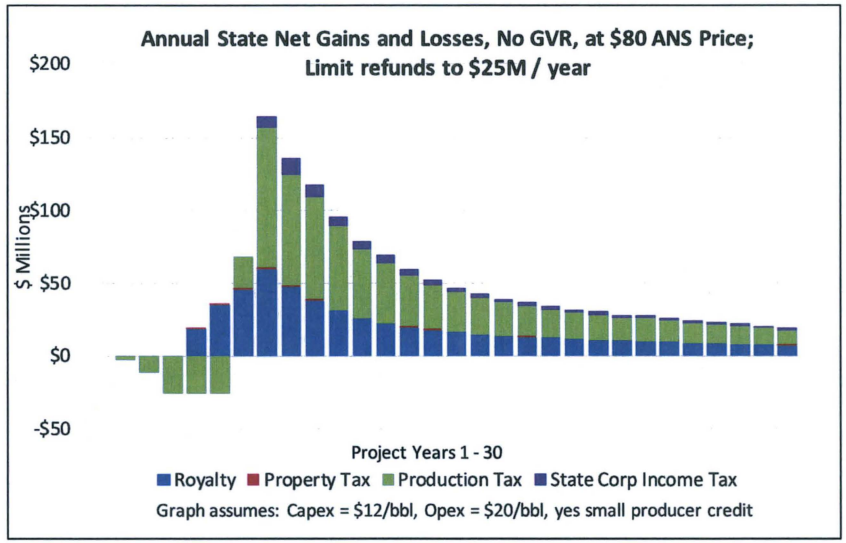


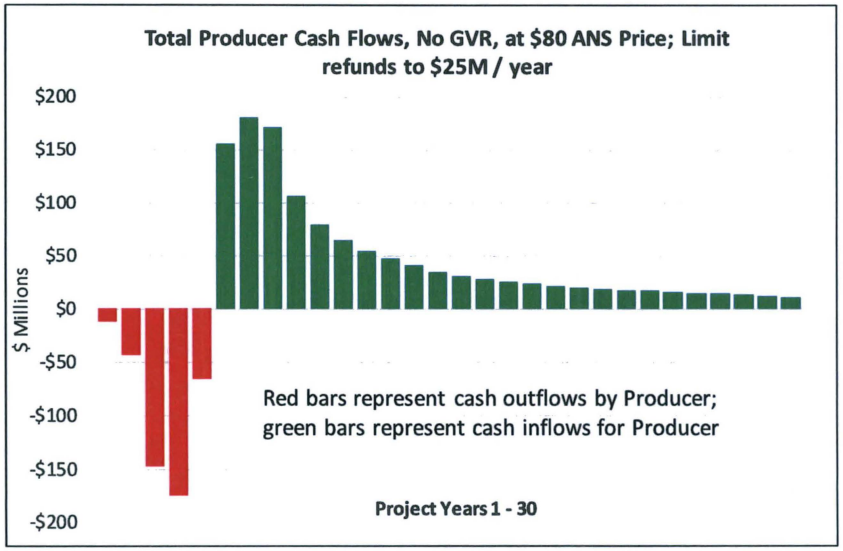
Life Cycle Totals	$Millions
Production Tax Credits Cashed	104
Production Tax Paid	447
Net Production Tax	343
Production Tax NPV 6.15%	121
Total Annual State Losses	51
Total Annual State Gains	831
Net State Gain (Loss)	780
State NPV 6.15%	331
Total Producer Cash Out	473
Total Producer Cash In	869
Net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

Cook Inlet Life Cycle Modeling

50 mmbo HB247, 2022 Tax Caps expire, $80/bbl



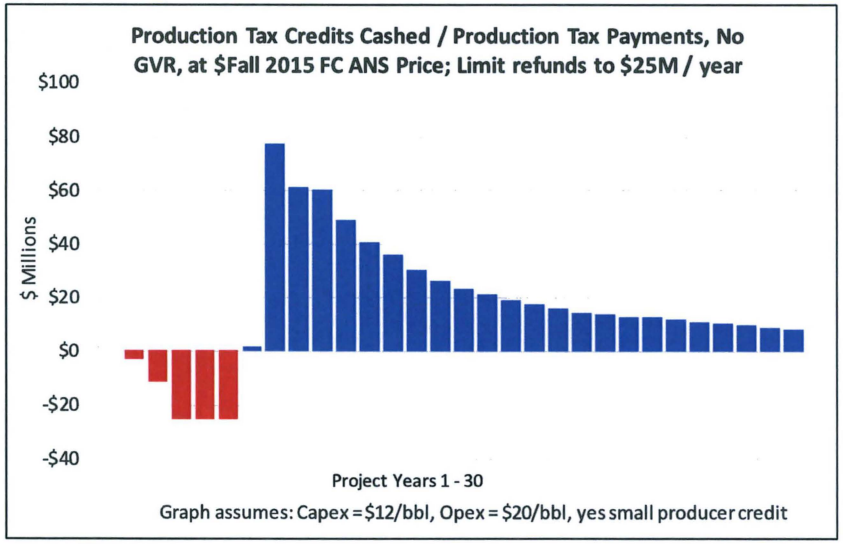


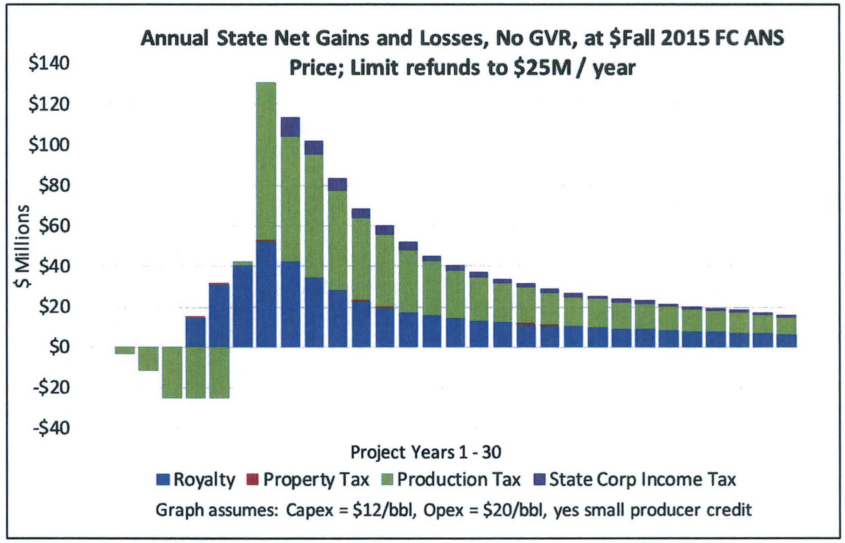


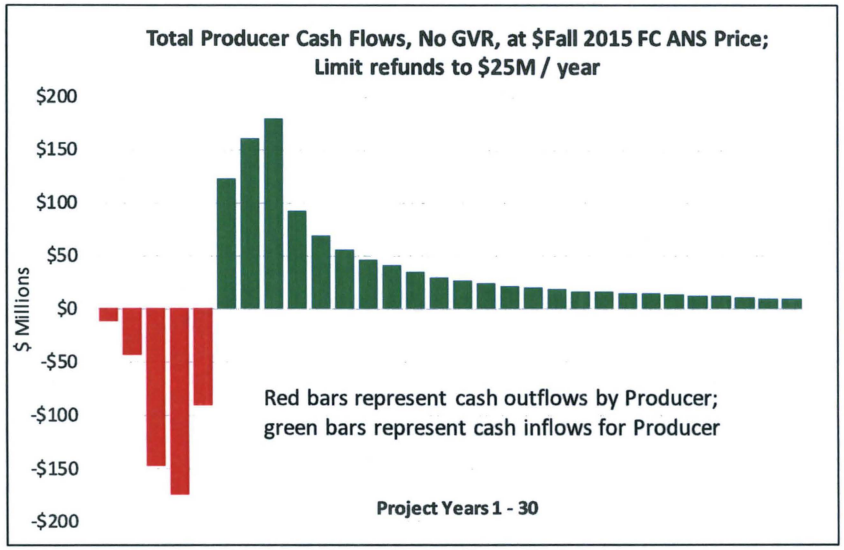
Life Cycle Totals	$Millions
Production Tax Credits Cashed	89
Production Tax Paid	736
Net Production Tax	647
Production Tax NPV 6.15%	263
Total Annual State Losses	46
Total Annual State Gains	1,307
Net State Gain (Loss)	1,261
State NPV 6.15%	557
Total Producer Cash Out	441
Total Producer Cash In	1,225
Net Producer Cash Flow	784
Producer Cash NPV 6.15%	278

Cook Inlet Life Cycle Modeling

50 mmbo HB247, 2022 Tax Caps expire, Fall 2015 FC Price



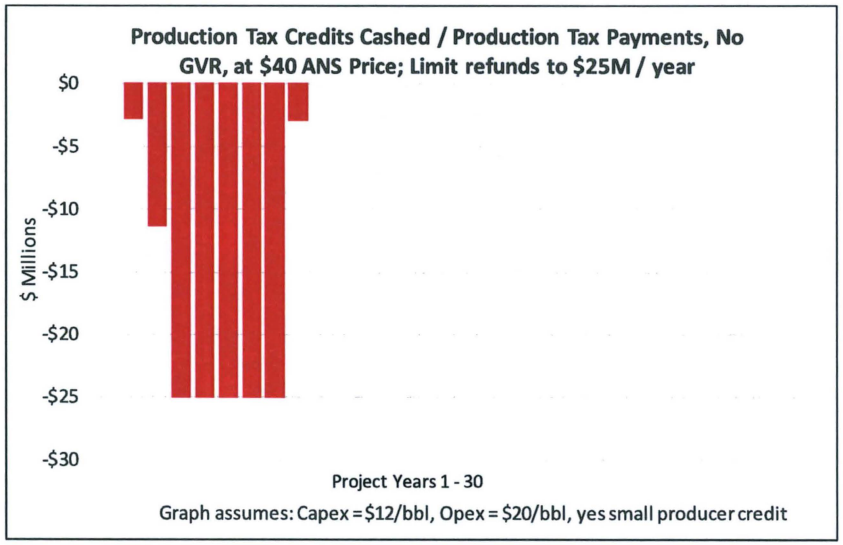


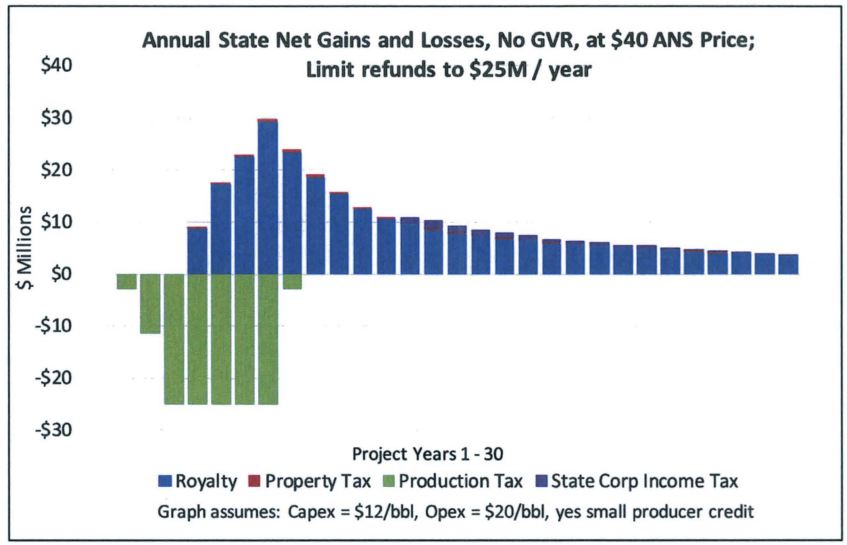


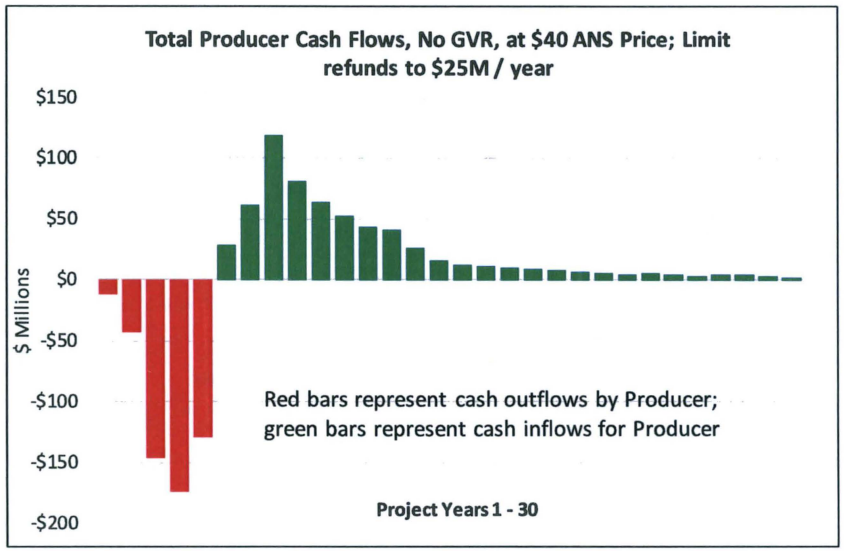
Life Cycle Totals	$Millions
Production Tax Credits Cashed	89
Production Tax Paid	598
Net Production Tax	509
Production Tax NPV 6.15%	197
Total Annual State Losses	50
Total Annual State Gains	1,091
Net State Gain (Loss)	1,041
State NPV 6.15%	451
Total Producer Cash Out	465
Total Producer Cash In	1,069
Net Producer Cash Flow	604
Producer Cash NPV 6.15%	183

Cook Inlet Life Cycle Modeling

50 mmbo HB247, Tax Caps extended, $40/bbl



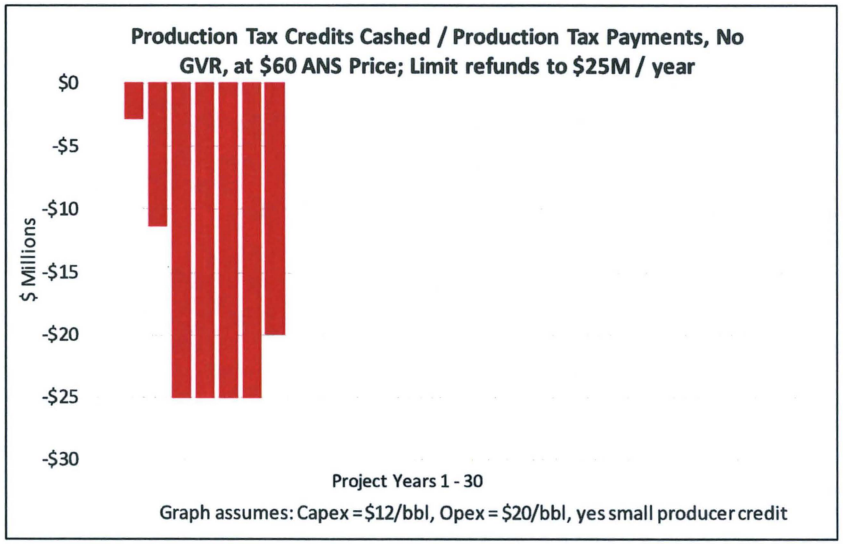


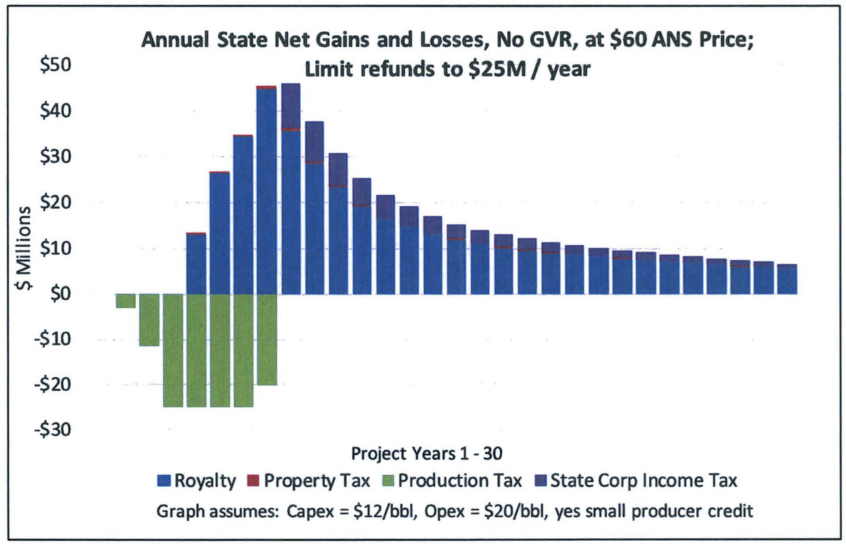


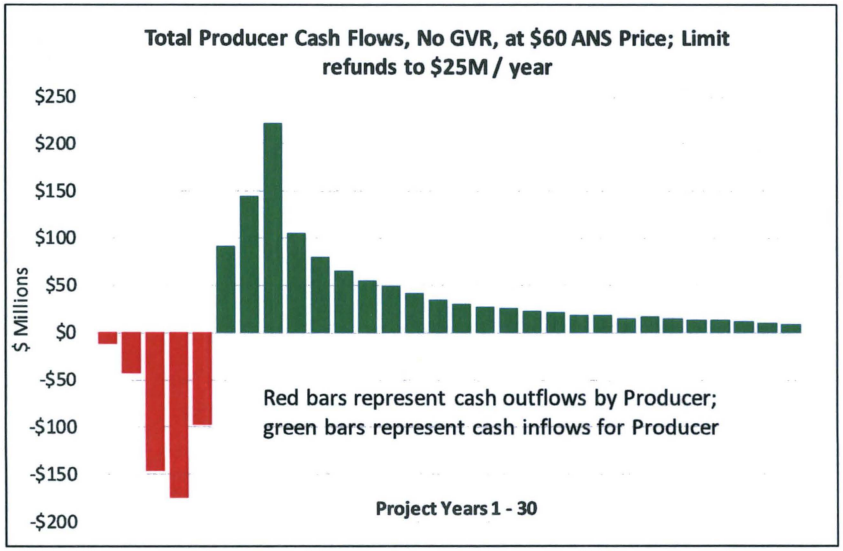
Life Cycle Totals	$Millions
Production Tax Credits Cashed	142
Production Tax Paid	0
Net Production Tax	-142
Production Tax NPV 6.15%	-101
Total Annual State Losses	65
Total Annual State Gains	196
Net State Gain (Loss)	131
State NPV 6.15%	29
Total Producer Cash Out	505
Total Producer Cash In	623
Net Producer Cash Flow	118
Producer Cash NPV 6.15%	-76

Cook Inlet Life Cycle Modeling

50 mmbo HB247, Tax Caps extended, $60/bbl



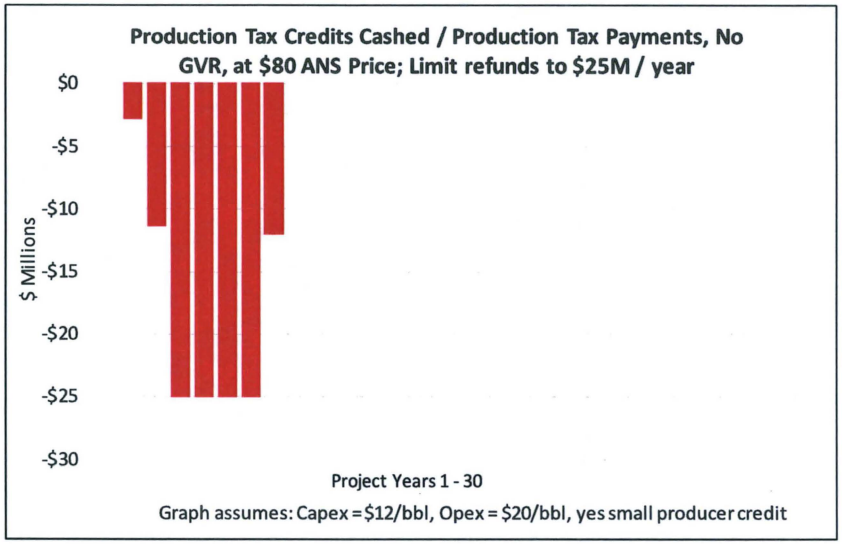


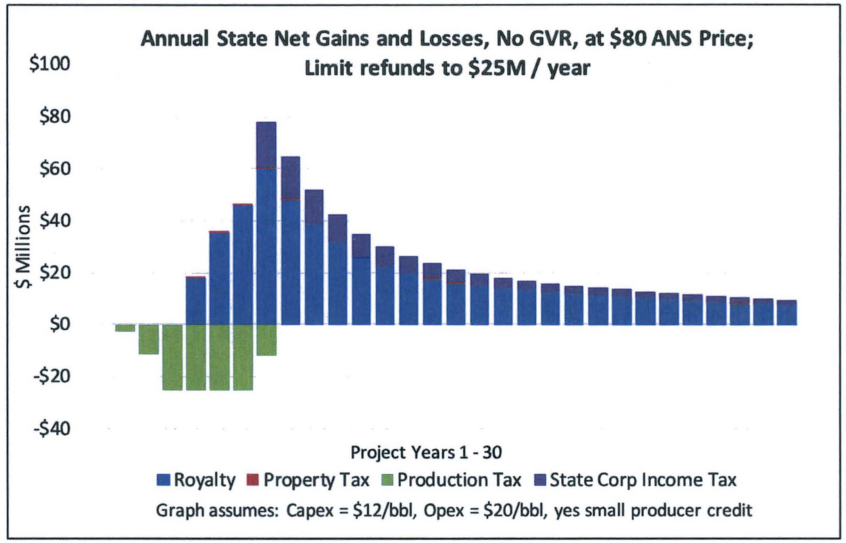


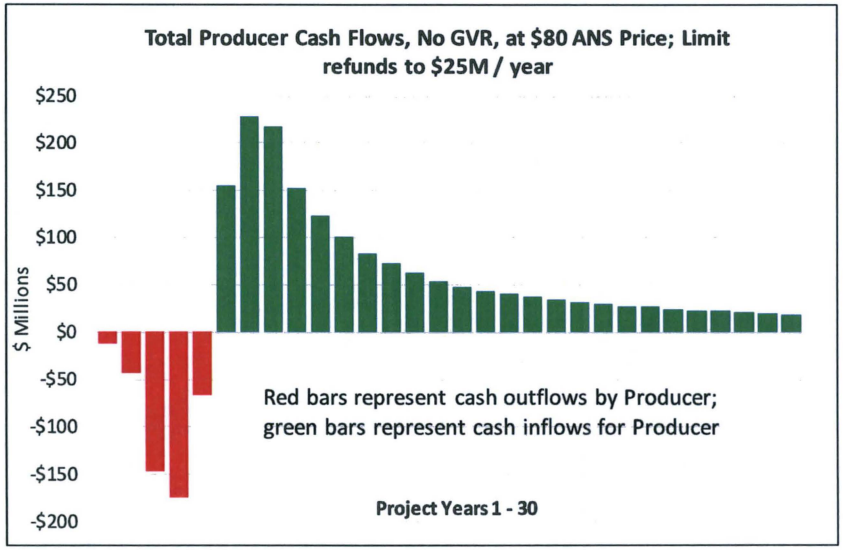
Life Cycle Totals	$Millions
Production Tax Credits Cashed	134
Production Tax Paid	0
Net Production Tax	-134
Production Tax NPV 6.15%	-97
Total Annual State Losses	51
Total Annual State Gains	385
Net State Gain (Loss)	335
State NPV 6.15%	126
Total Producer Cash Out	473
Total Producer Cash In	1,159
Net Producer Cash Flow	686
Producer Cash NPV 6.15%	214

Cook Inlet Life Cycle Modeling

50 mmbo HB247, Tax Caps extended, $80/bbl



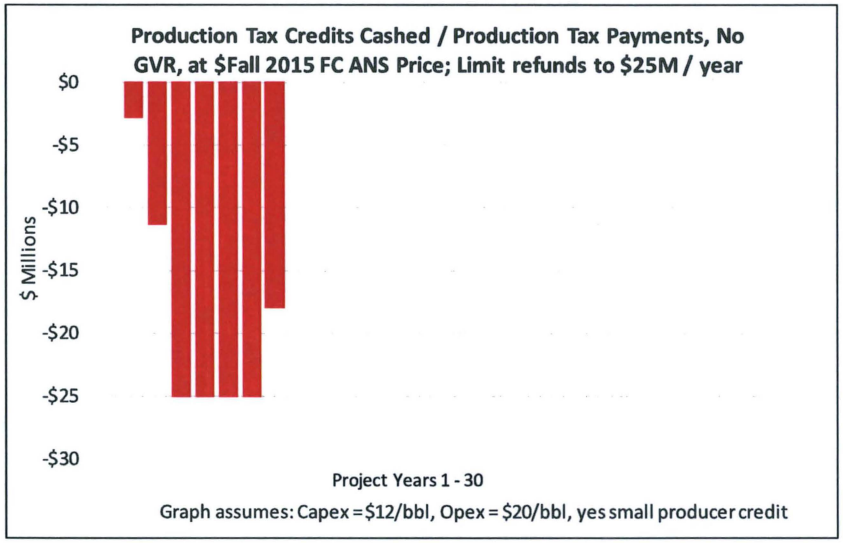


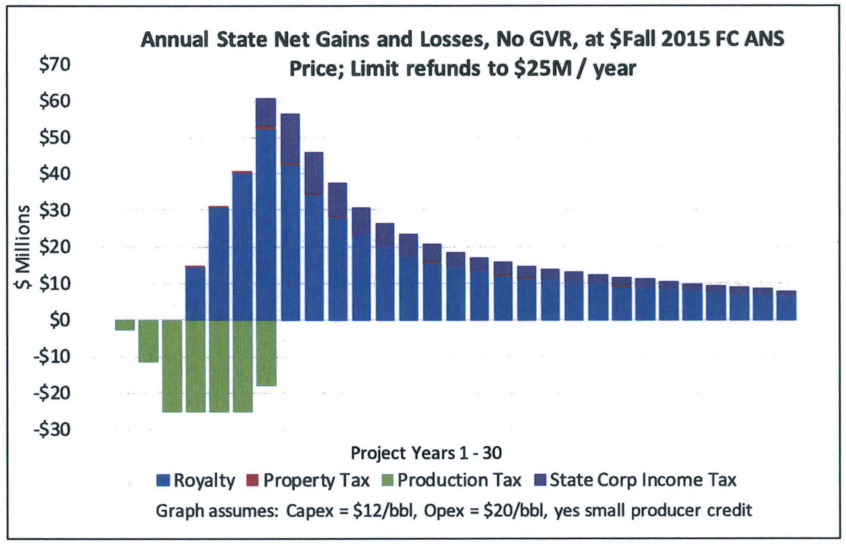


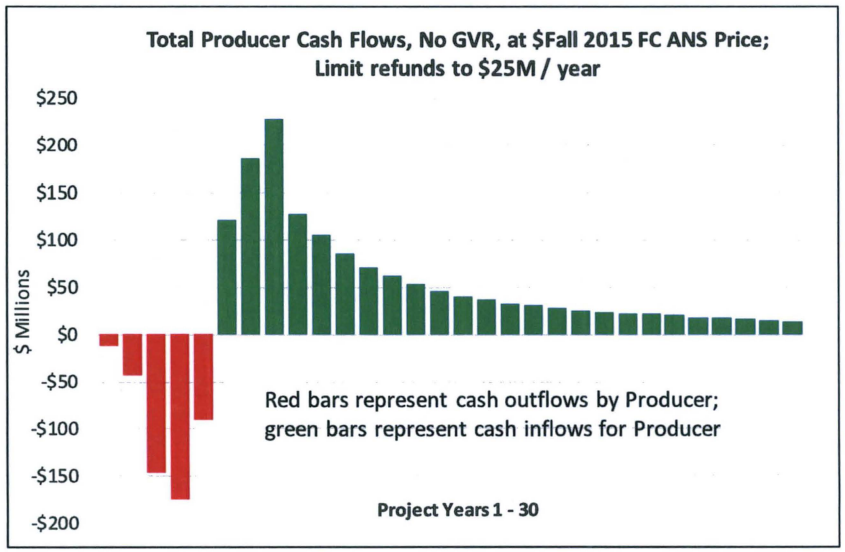
Life Cycle Totals	$Millions
Production Tax Credits Cashed	126
Production Tax Paid	0
Net Production Tax	-126
Production Tax NPV 6.15%	-92
Total Annual State Losses	46
Total Annual State Gains	584
Net State Gain (Loss)	538
State NPV 6.15%	225
Total Producer Cash Out	441
Total Producer Cash In	1,695
Net Producer Cash Flow	1,254
Producer Cash NPV 6.15%	494

Cook Inlet Life Cycle Modeling

50 mmbo HB247, Tax Caps extended, Fall 2015 FC Price







Life Cycle Totals	$Millions
Production Tax Credits Cashed	132
Production Tax Paid	0
Net Production Tax	-132
Production Tax NPV 6.15%	-95
Total Annual State Losses	50
Total Annual State Gains	492
Net State Gain (Loss)	442
State NPV 6.15%	177
Total Producer Cash Out	465
Total Producer Cash In	1,458
Net Producer Cash Flow	994
Producer Cash NPV 6.15%	362

Summary Tables

Summary Table- North Slope

Field Size (million bbl)	Tax Regime	Producer Size (>$10 billion revenue)	Oil Price	Credits Paid ($millions)	Net Production Tax Paid ($millions)	Production Tax NPV 6.15% ($millions)	Net State Gain (Loss) ($millions)	State NPV 6.15% ($millions)	Producer Cash Flow ($millions)	Producer NPV 6.15% ($millions)
50	Status Quo	n/a	$40	$221	($217)	($153)	($24)	($58)	$19	($99)
50	Status Quo	n/a	$60	$162	$21	($37)	$380	$136	$404	$112
50	Status Quo	n/a	$80	$134	$323	$110	$844	$364	$751	$289
50	Status Quo	n/a	Fall 15 FC	$155	$183	$40	$629	$255	$588	$203
50	HB 247	small	$40	$150	($116)	($95)	$71	($1)	($71)	($155)
50	HB 247	small	$60	$101	$54	($10)	$412	$163	$384	$93
50	HB 247	small	$80	$82	$344	$128	$863	$380	$738	$277
50	HB 247	small	Fall 15 FC	$95	$207	$60	$651	$274	$574	$189
750	Status Quo	n/a	$40	$2,967	($2,738)	($2,047)	$367	($1,016)	$2,131	($1,768)
750	Status Quo	n/a	$60	$2,897	$1,568	($642)	$7,115	$1,197	$7,475	$312
750	Status Quo	n/a	$80	$2,830	$6,093	$869	$14,069	$3,527	$12,686	$2,216
750	Status Quo	n/a	Fall 15 FC	$2,864	$4,135	$206	$11,069	$2,509	$10,458	$1,401
750	HB 247	small	$40	$134	$807	$206	$3,685	$1,192	($39)	($3,744)
750	HB 247	small	$60	$116	$2,867	$749	$8,331	$2,553	$6,686	($870)
750	HB 247	small	$80	$109	$6,424	$1,743	$14,379	$4,388	$12,485	$1,415
750	HB 247	small	Fall 15 FC	$111	$4,523	$1,172	$11,433	$3,461	$10,222	$520
750	HB 247	large	$40	$0	$982	$337	$3,860	$1,322	($214)	($3,875)
750	HB 247	large	$60	$0	$3,084	$879	$8,494	$2,679	$6,579	($974)
750	HB 247	large	$80	$0	$6,424	$1,806	$14,379	$4,451	$12,485	$1,355
750	HB 247	large	Fall 15 FC	$0	$4,683	$1,303	$11,596	$3,587	$10,116	$417

Summary Table- Cook Inlet

Field Size (million bbl)	Tax Regime	Tax Caps Sunset?	Oil Price	Credits Paid ($millions)	Net Production Tax Paid ($millions)	Production Tax NPV 6.15% ($millions)	Net State Gain (Loss) ($millions)	State NPV 6.15% ($millions)	Producer Cash Flow ($millions)	Producer NPV 6.15% ($millions)
50	Status Quo	yes	$40	$349	($177)	($192)	$99	($59)	$139	$3
50	Status Quo	yes	$60	$337	$128	($50)	$579	$167	$527	$202
50	Status Quo	yes	$80	$329	$432	$92	$1,060	$395	$915	$396
50	Status Quo	yes	Fall 15 FC	$335	$294	$26	$840	$288	$735	$303
50	Status Quo	no	$40	$357	($357)	($275)	($70)	($137)	$249	$54
50	Status Quo	no	$60	$349	($349)	($269)	$134	($37)	$817	$335
50	Status Quo	no	$80	$341	($341)	($263)	$337	$63	$1,385	$612
50	Status Quo	no	Fall 15 FC	$347	($347)	($268)	$241	$14	$1,124	$481
50	HB 247	yes	$40	$120	$38	($19)	$300	$108	$9	($135)
50	HB 247	yes	$60	$104	$343	$121	$780	$331	$397	$80
50	HB 247	yes	$80	$89	$647	$263	$1,261	$557	$784	$278
50	HB 247	yes	Fall 15 FC	$89	$509	$197	$1,041	$451	$604	$183
50	HB 247	no	$40	$142	($142)	($101)	$131	$29	$118	($76)
50	HB 247	no	$60	$134	($134)	($97)	$335	$126	$686	$214
50	HB 247	no	$80	$126	($126)	($92)	$538	$225	$1,254	$494
50	HB 247	no	Fall 15 FC	$132	($132)	($95)	$442	$177	$994	$362

NEW SUSTAINABLE
ALASKA
PLAN

Pulling Together to Build Our Future

Thank You!

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