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ARRESTING TAPS THROUGHPUT DECLINE & OIL TAX REFORM

Senate Finance

February 28, 2013

Juneau, Alaska

Dan Sullivan, Commissioner

Alaska Department of Natural Resources

Joe Balash, Deputy Commissioner

Alaska Department of Natural Resources

Bryan Butcher, Commissioner

Alaska Department of Revenue

Michael Pawlowski, Advisor, Petroleum Fiscal Systems

Alaska Department of Revenue



TAPS

- A CRITICAL STATE & NATIONAL ENERGY ASSET -

- The Trans Alaska Pipeline, 11 pump stations, several hundred miles of feeder pipelines, and the Valdez Marine Terminal constitute the Trans-Alaska Pipeline System (TAPS).
- At 800 miles long, the Trans Alaska Pipeline is one of the longest pipelines in the world; it crosses more than 500 rivers and streams and three mountain ranges as it carries Alaska's oil from Prudhoe Bay to Valdez.
- The U.S. Congress was instrumental in the approval and rapid development of TAPS. Congress approved construction of the pipeline with the Trans Alaska Pipeline Authorization Act of 1973.
- The principle focus of this Act is as relevant today as it was in 1973: *"the early development and delivery of oil and gas from Alaska's North Slope to domestic markets is in the national interest because of growing domestic shortages and increasing dependence upon insecure foreign sources."*



TAPS

- A CRITICAL STATE & NATIONAL ENERGY ASSET -

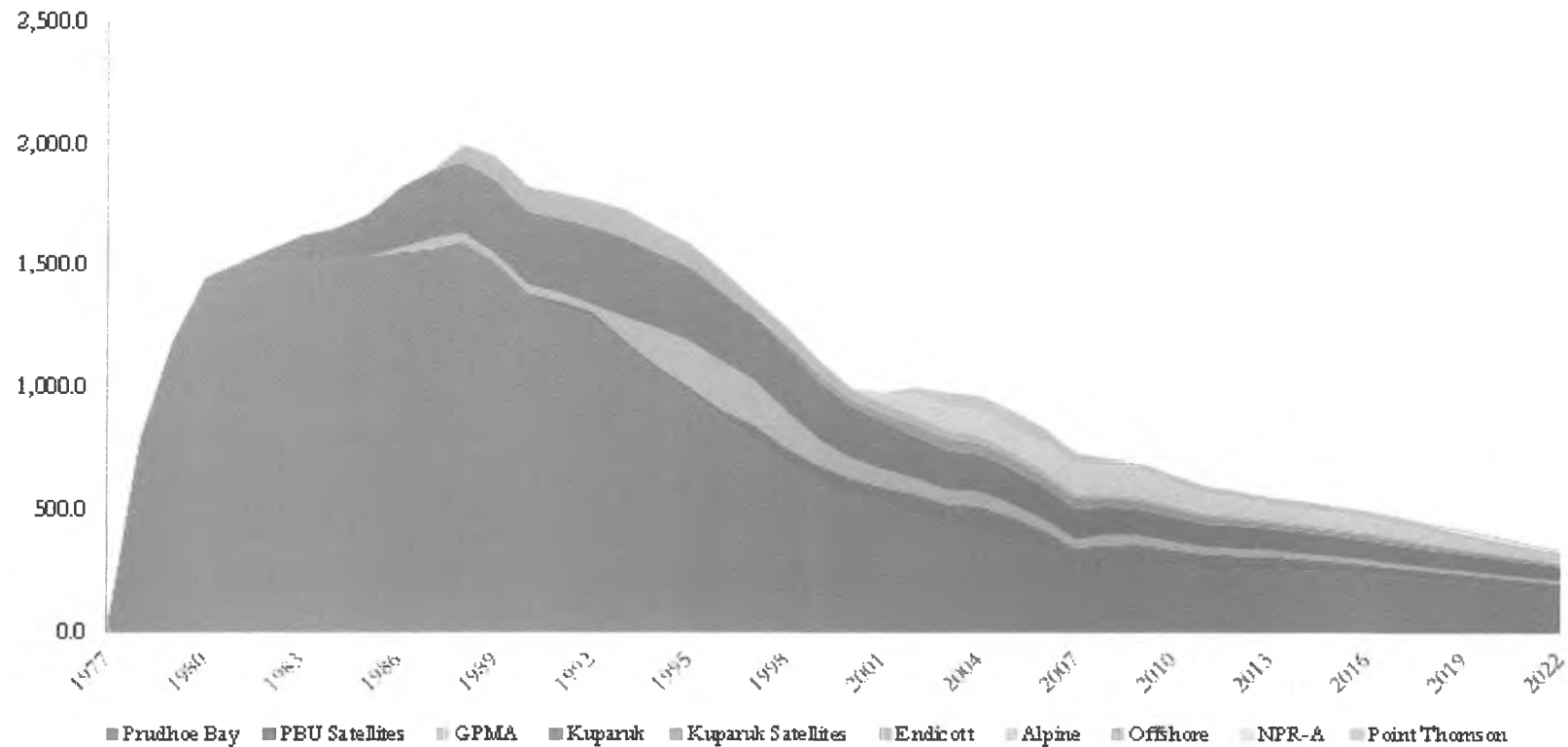


- TAPS has transported over 16.3 billion barrels of oil and natural gas liquids since June of 1977. Production peaked at 2.2 million barrels per day in the late 1980s, representing 25% of U.S. domestic production
- Since its peak, however, throughput has steadily declined; today, TAPS is 2/3 empty and declining at an average of 6% per year
- TAPS throughput decline threatens economic disruption and the very existence of our pipeline
- We must encourage industry to invest in exploration and development of conventional and unconventional resources on state and federal land, onshore and offshore
- TAPS has plenty of capacity for increased throughput
- Most near-term critical economic issue facing the state
- Less oil in the pipeline year after year takes away revenue from future generations—the ultimate giveaway
- Reconfiguration, 1.2 million barrels/day

OIL TAX REFORM

- PRODUCTION HISTORY -

ANS Production



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

TAPS

- THROUGHPUT DECLINE IS AN URGENT PROBLEM -

- TAPS throughput decline is the **MOST URGENT** issue facing the State's economic future
- January 2011 TAPS shutdown



Petroleum News, February 27, 2011:
“Jan. shutdown puts TAPS close to brink:

Alyeska executives describe efforts to prevent freezing in pipeline after pump station oil leak in era of low oil throughput”

WSJ, May 11, 2011:

“Shrinking Oil Supplies Put Alaskan Pipeline at Risk”

“Now, dwindling oil production along Alaska's northern edge means the pipeline carries less than one-third the volume it once did—and the crude takes five times as long to get to its destination.

That leisurely flow means the oil is above ground longer and more exposed to Alaska's frigid weather; the crude sometimes arrives chilled to 40 degrees. As the flow and temperature continue to drop, experts say the risks of a clog or corrosion increase, as do the odds of ruptures and spills.”

ALASKA'S NORTH SLOPE OIL & GAS POTENTIAL

- USGS estimates that Alaska's North Slope has more oil than any other Arctic nation
 - **OIL:** Est. 40 billion barrels of conventional oil (*USGS & BOEMRE*)
 - **GAS:** Est. over 200 trillion cubic feet of conventional natural gas (*USGS*)
- Alaska has world-class unconventional resources, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates
 - Positive methane hydrate test production

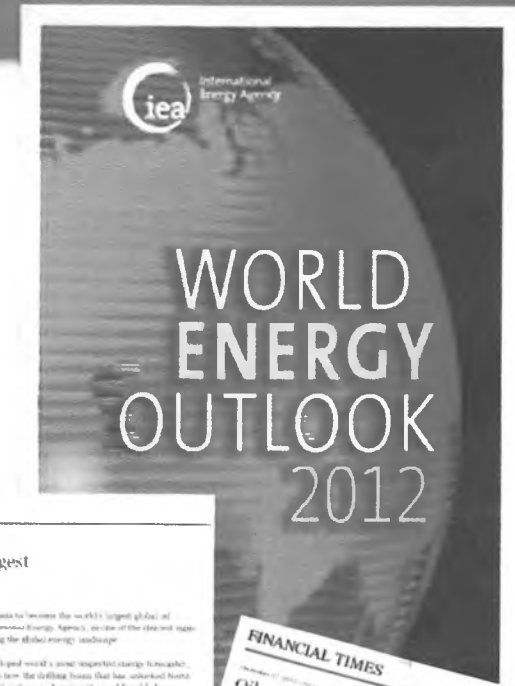


Compared to most hydrocarbon basins, Alaska is relatively underexplored, with 500 exploration wells on the North Slope, compared to Wyoming's 19,000.



U.S. ENERGY RENAISSANCE

- Global and U.S. hydrocarbon boom
- IEA World Energy Outlook 2012 – U.S. to overtake Saudi Arabia and Russia to become the world's largest global oil producer by the second half of this decade.
- **Financial Times, November 12, 2012 – “U.S. set to become biggest oil producer”**
- **Financial Times, December 27, 2012 – “Oil and gas – hey big spenders”**
 - 2012 - \$600 billion on exploration and production in oil and gas industry
 - 2013 projected - \$650 billion on exploration and production in oil and gas industry



FINANCIAL TIMES

US set to become biggest oil producer

By Sue Thomsett in China

The US will overtake Saudi Arabia and Russia to become the world's largest global oil producer by 2035, according to the International Energy Agency, on the eve of the latest round of talks for shale revolution reducing the global energy shortage.

This marks the first time the IEA, the developed world's most respected energy watchdog, has made such a prediction. It underlines how the shale boom that has shocked Saudi America's oil markets is reshaping the world's oil balance.

However, other analysts have warned that the US oil boom is still in its infancy and sustained growth to levels predicted by the IEA cannot be guaranteed.

In its fourth world energy outlook, published on Monday, the IEA said that by 2035, the US, which currently supplies around 10 per cent of its own energy needs, becomes oil that will suffice in its needs. A dramatic reversal of the trend seen in most other energy-reporting countries. It said that partly as a result of this, the direction of the international oil trade would get on towards flat.

If realized, the IEA's prediction would have significant implications for world commodity markets and the broader geopolitics of energy. Some analysts have wondered whether a that was energy independence would still part the world's critical sea lanes and rough routes in two decades. But – and it is not clear why – a role, whether China, who reliance on Middle East crude exports was growing, would decline.

The increase in US domestic production – of both oil and gas – as well as unconventional “tight” oil – comes as new hydrocarbon resources are reported on the East African seaboard are set to reduce oil demand sharply. That will see fall in oil exports into the US, which the IEA says will plunge from over 10 million barrels a day in its 2009 peak. The agency says that North America will become a net oil exporter by 2035.



OTHER BASINS HAVE TURNED DECLINE AROUND

THE  INDEPENDENT

North Sea set to create 50,000 new jobs as investment soars

Tom Bawden

Monday, 14 January 2013

North Sea employment is set to boom this year. Up to 50,000 new jobs are expected in Britain's oil and gas industry.

The jobs bonanza will support services staff in the North Sea to nearly half a million.

"There's been a lot of investment at the moment," said a source behind the research. "It's behind their life. At the same time, they've made it economically viable," he added.

Further down the line, 35,000 jobs in the next five years, the Institute of Directors.

The expansion has been set to be ploughed into the biggest creation in the North Sea for a decade. The Shetland Isles, that will be the focus.

The surge in investment in North Sea development, particularly in the Energy and Climate Change.

Although North Sea production was 4.5m barrels a day, it's down 2m barrels. On the day, it's more than twice the rate.

"The expansion has been spurred by record-breaking levels of investment, with about £40bn set to be ploughed into North Sea production in the next three years..."

"The surge in investment comes after the government relaxed the tax regime around North Sea development, prompting a record-breaking licensing round when the Department of Energy and Climate Change awarded 167 new licenses on 330 blocks last October."

"Budget 2012: North Sea oil tax reforms 'to lead to £50bn investment': An extra £50bn could be pumped into the North Sea oil and gas industry thanks to a new package of tax reforms."

Budget 2012: North Sea oil tax reforms 'to lead to £50bn investment'

An extra £50bn could be pumped into the North Sea oil and gas industry thanks to a new package of tax reforms.

The Budget was a 'turning point' for industry relations with the Treasury. Photo: Rex Features

By Emily Cozden

10.11PM GMT 23 Mar 2012

Industry body Oil & Gas UK said the Chancellor's promise of certainty on decommissioning tax relief and new tax breaks on small and deepwater fields would stimulate tens of billions of pounds of additional investment.

The Budget was a "turning point" for industry relations with the Treasury after outrage at the surprise tax rise in last year's Budget. Oil & Gas UK said. The measure means more than 2bn barrels of the UK's oil and gas reserves that would otherwise have been left in the ground will now eventually be recovered at no net cost to the Exchequer.

The Treasury estimates that the reforms could actually boost its coffers by £1bn over the next five years, due to tax on projects that would not otherwise have gone ahead.

The Chancellor confirmed that he would draw up a contract with the industry to permanently guarantee levels of tax relief on the £30bn bill for decommissioning old infrastructure, a move that Oil & Gas UK said could stimulate up to £40bn investment during the lifetime of the North Sea basin. Anxiety over whether rates might be cut has blocked some deals.

The Chancellor unveiled new 'field allowances', doubling tax breaks for developing smaller fields and introducing a £3bn allowance for some deepwater fields with significant reserves in the new exploration frontier West of Shetland. The allowances should see £10bn extra investment, the industry body said.

Malcolm Webb, Oil & Gas UK's chief executive, said the Budget was a "turning point for the UK's oil and gas industry" toward "a more stable future fostered by constructive collaboration between government and industry".

OTHER BASINS HAVE TURNED DECLINE AROUND

Tax Breaks Spur Record U.K. Oil, Gas Investment

By SELINA WILLIAMS

LONDON—Tax incentives have helped spur record levels of investment in the U.K.'s offshore oil and gas sector, which is set to recover from more than a decade of declining production and boost flagging government coffers in 2014.

Investment in offshore oil and gas projects is forecast to rise to a record level of at least £13 billion (\$19.6 billion) this year, up from £11.4 billion last year which at the time was the highest in more than 30 years, according to an annual report published Monday by industry body Oil & Gas U.K.

"This year and next we expect record levels of investment and that's a relief when you look at how much production has fallen. It will be a catch-up from a long period of underinvestment," said Mike Tholen, Oil & Gas U.K. economics and commercial director and one of the authors of the report.

North Sea oil and gas production is vital for the U.K. economy. Shutdowns at several key fields were a major reason for the 0.3% contraction of economic output in the last quarter of the year, according to the Office for National Statistics. Extractive industries, the bulk of which is oil and gas, contribute 2.4% of total U.K. gross domestic product, the ONS said.

Increasing output would also be significant for tax receipts and jobs in a sector that last year employed 440,000 people.

The 45 projects that were approved in 2011 and 2012 will over time produce more than 2 billion barrels of oil and gas and generate £100 billion for the economy and an additional £25 billion in production taxes, the report said.

The investment will also help U.K. energy security by reducing hydrocarbon imports at a time of higher international oil and gas prices.

"Too often we've been seen as part of the problem, rather than part of the solution because production output had fallen. But we're stopping the decline and increasing output and that will have a more positive impact on the U.K. economy," Mr. Tholen told The Wall Street Journal.

The higher investment in new projects and redevelopment of older fields would help bring another 500,000 barrels of oil equivalent a day onstream by 2017, taking output to as much as 2 million barrels of oil and gas a day by 2017 or earlier.

This compares to 1.55 million barrels of oil equivalent a day in 2012 and 1.45 million to 1.5 million barrels a day expected for this year, Mr. Tholen said.

THE WALL STREET JOURNAL.

Monday, February 25, 2013 As of 11:30 AM EST

"Tax Breaks Spur Record U.K. Oil, Gas Investment" – WSJ, 2/25/13

The upturn expected in 2014 is significant, as oil and gas production from the U.K. continental shelf has been declining since a peak of 4 million barrels of oil equivalent a day in 1999 to 2000 due to natural decline rates at mature fields, high development costs and a wave of punitive taxes over the past decade, most notably a surprise tax increase in 2011.

BP BP.LN +1.60% PLC's April 2010 Deepwater Horizon disaster in the Gulf of Mexico also prompted a wave of shutdowns as companies reassessed safety procedures.

Over the past year, the U.K. has introduced a raft of tax breaks in an attempt to mend bridges with the oil and gas industry after the 2011 tax increase hurt investment and raised concerns about the future of the sector.

In total, companies are planning capital investments of almost £100 billion in new projects and redevelopment of old fields. Of this, £44 billion are already approved and under development and another £30 billion have a better than 50% chance of approval over the next few years, the report said.

Investments include Statoil ASA's STL.OS +1.55% £4.3 billion Mariner field, Talisman's £1.6 billion plan to boost production at Montrose/Arbroath, GDF Suez's GSZ.FR +1.60% £1.4 billion for gas development at Cygnus gas and Dana Petroleum's £1 billion to develop its Harris/Barra fields.

Exploration for new oil and gas reserves is also expected to reverse a trend of decline with more than 130 wells forecast to be drilled over the next three years, up from about 21 wells a year from 2009-2012.

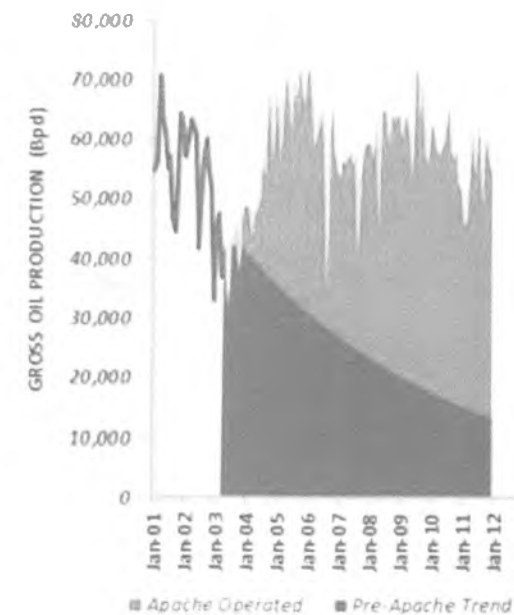
Easier access to finance and pressure to meet commitment dates set in licenses is helping to drive the higher exploration rates, Mr. Tholen said.

OTHER BASINS HAVE TURNED DECLINE AROUND

Apache Corporation: Forties Field Acquisition

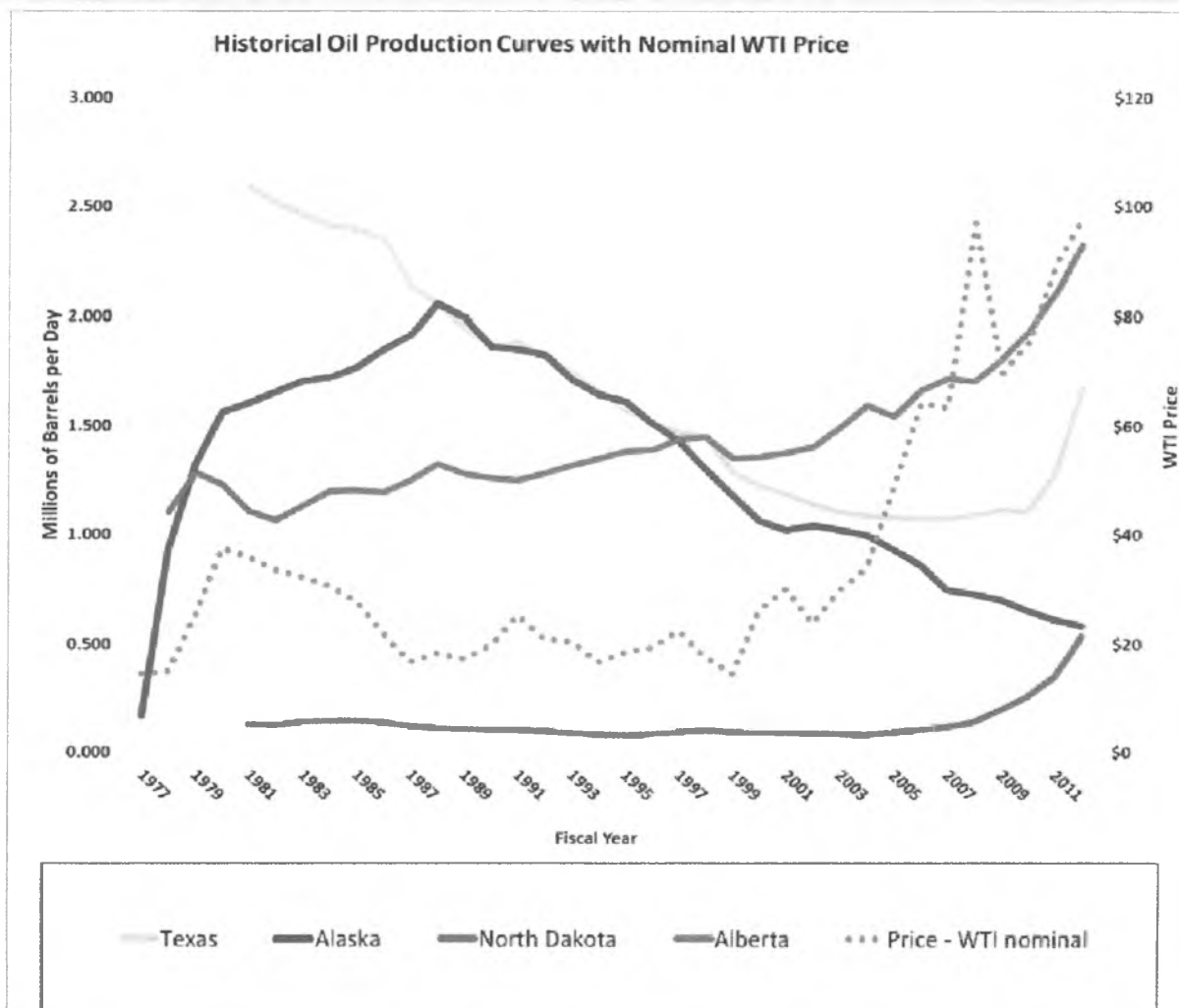
- Field discovered in early 1970s by BP; purchased by Apache in 2003
- Contains estimated 4.2 to 5.0 billion barrels of oil in place
- Production peaked at over 500,000 Bpd, but by 2003, had declined to 40,000-45,000 Bpd
- Apache has “beaten the curve” by adding reserves, production, and value
- Have returned over 400% of their original 2003 investment

BEATING THE PRODUCTION CURVE



OTHER BASINS HAVE TURNED DECLINE AROUND - HISTORICAL OIL PRODUCTION -

How Did Our Competition Fare When Prices Spiked?



SECURE ALASKA'S FUTURE—OIL

Secure Alaska's Future—Oil is the State's comprehensive strategy to increase TAPS throughput to one million barrels a day.



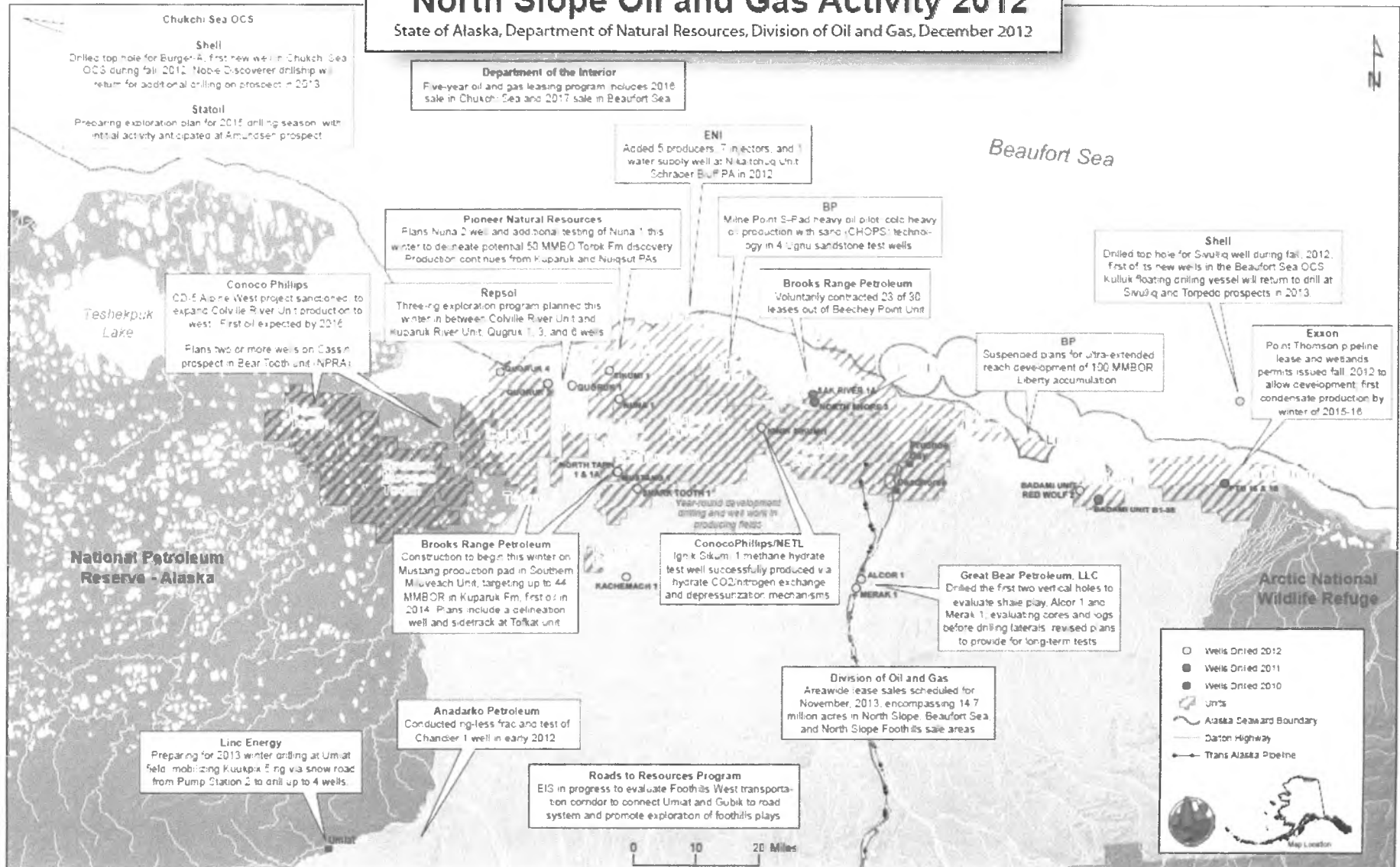
- I. Enhance Alaska's global competitiveness and investment climate
- II. Ensure the permitting process is structured and efficient
- III. Facilitate and incentivize the next phases of North Slope development
- IV. Promote Alaska's resources and positive investment climate to world markets

SECURE ALASKA'S FUTURE: OIL

- NORTH SLOPE RECENT & PROPOSED ACTIVITY FOR OIL & GAS -

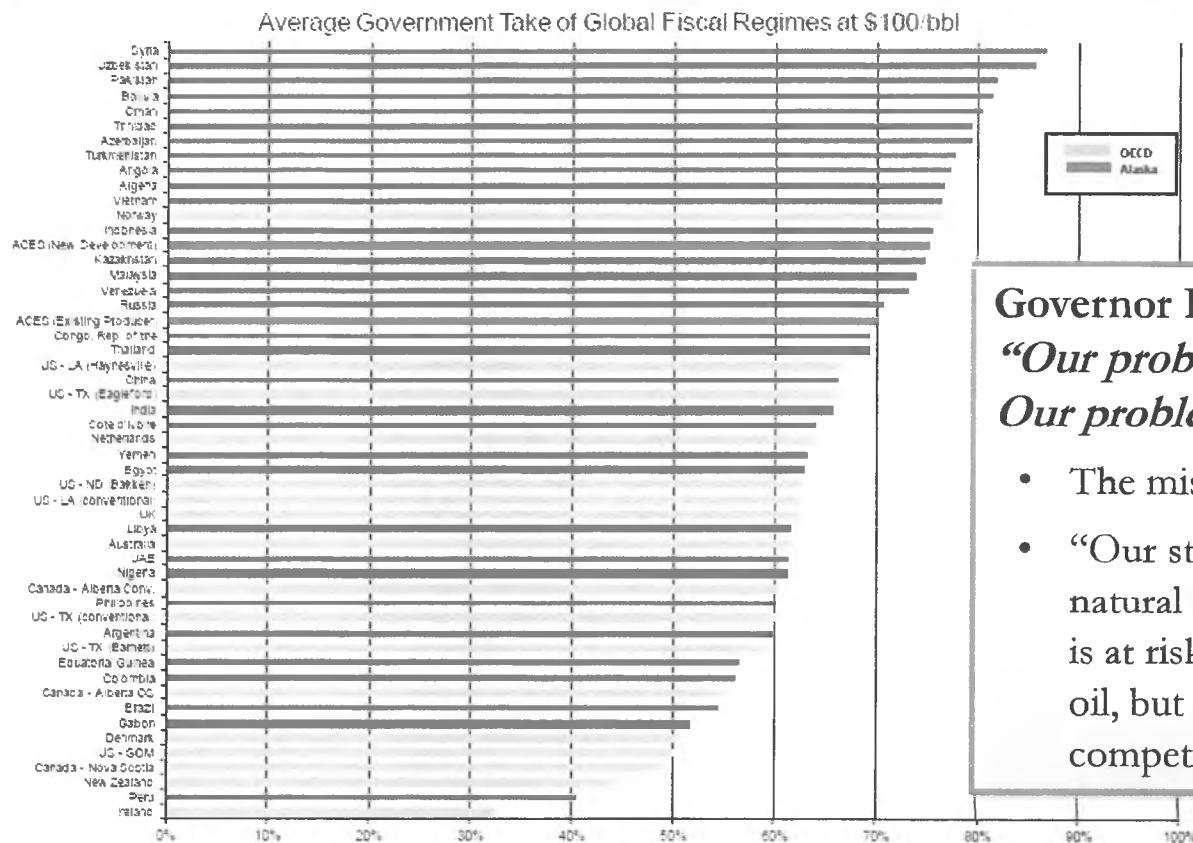
North Slope Oil and Gas Activity 2012

State of Alaska, Department of Natural Resources, Division of Oil and Gas, December 2012



RELATIVE COMPETITIVENESS

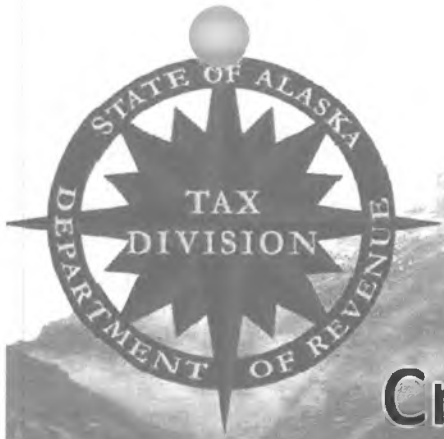
Regime Competitiveness: Average Government Take at \$100/bbl



Governor Parnell's 2013 State of the State:
"Our problem is not below the ground. Our problem is above the ground."

- The missing piece is meaningful tax reform
- "Our state's prosperity has always rested on natural resources. Tonight, that foundation is at risk, not because we are running out of oil, but because we are running behind the competition."

2



Oil Tax Reform



Creating a Durable Production Tax
System that is Competitive
for the Long term Benefit of Alaskans

*A presentation to the
Senate Finance Committee*

Feb 28, 2013



Principles of Reform



Tax reform must:

1. Be fair to Alaskans.
2. Encourage new production.
3. Be simple so that it restores balance to the system.
4. Be durable for the long-term.



Challenges in the Current Tax System



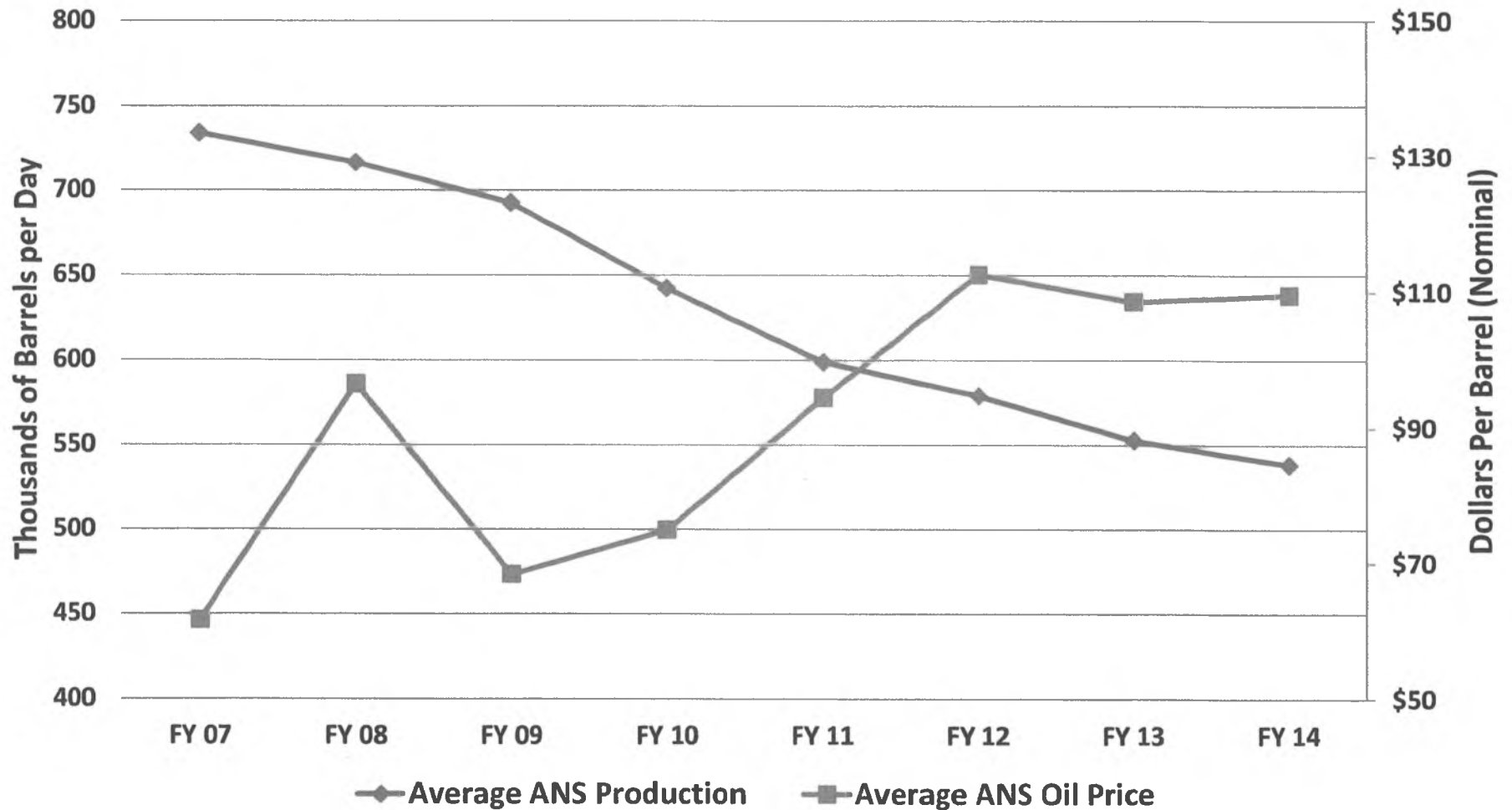
- Declining production.
- Progressivity.
- Tax Credits.



Rising Prices And Declining Production



ANS Average Daily Production and Price





Rising Prices and Declining Production



- Less production = less potential value for both the state and producers.
- In FY 2008 an ANS price of \$96.51 yielded approximately \$20.4 billion in gross value.
- By FY 14, a price that is \$13 higher will yield a bit more than \$3 billion less in gross value.

Fiscal Year	Average ANS Oil Price (Dollars per Barrel)	Modeled GVPP (Gross Value at the Point of Production in Billions of Dollars)
2007	\$61.60	\$16
2008	\$96.51	\$20.4
2009	\$68.34	\$13.2
2010	\$74.90	\$13.8
2011	\$94.49	\$16.3
2012	\$112.65	\$18.8
2013	\$108.67	\$17.2
2014	\$109.61	\$17.3



Rising Prices and Declining Production



- Higher prices and lower revenues?
- In FY 2008 an ANS price of \$96.51 yielded approximately \$6.823 billion in production tax.
- By FY 2014, a price that is \$13 higher will yield a bit more than \$3.7 billion in production tax.
- If production was the same as FY 08, revenues in FY 14 would be close to \$6.5 billion or \$2.7 billion higher than forecast.

Fiscal Year	Average ANS Oil Price (Dollars per Barrel)	Production Tax (After Credits in Billions of Dollars)
2007	\$61.60	\$2.208
2008	\$96.51	\$6.823
2009	\$68.34	\$3.112
2010	\$74.90	\$2.871
2011	\$94.49	\$4.553
2012	\$112.65	\$6.146
2013	\$108.67	\$4.353
2014	\$109.61	\$3.779



Rising Prices and Declining Production Observations



1. High prices have generally offset declining production over the past several fiscal years.
2. As production has continued to fall however, the level of production tax generated by high oil prices has fallen.
3. But, the level of production tax revenues have fallen faster than production.
4. The question is why?



Production Tax Liability =



$$[\text{Production Tax Value} * \text{Tax Rate}] - \text{Credits}$$

- Production Tax Value = (Value - Costs)
 - ❑ Value = Volume of Taxable Oil & Gas Produced * Wellhead Value
 - ❑ Costs = Operating Expenditures + Capital Expenditures
- Tax Rate = 25% + 0.4% for every \$1 per barrel that this “net income” exceeds \$30, up to \$92.50, then 0.1%
- Credits = (20% * Capital Expenditures)⁽¹⁾ + (20% * Eligible Transition Expenditures)⁽²⁾ + Small Producer Credit ⁽³⁾

(1) Spread over two years

(2) Limited to those credits earned while the PPT was in effect and could not be used

(3) Credit is for companies producing less than 100,000 bbls/day. Available up to \$12 million for North Slope and/or Cook Inlet Producers, and \$6 million for production outside of North Slope and Cook Inlet annually. Small producer credits cannot be redeemed for cash certificates or carried forward.



The Progressivity Function



- Found in AS 43.55.011 (g)
- Based on the *Production Tax Value* (PTV)
- When the PTV exceeds \$30 per barrel of oil equivalent (BOE) the tax is levied at:
 - .4% per dollar until the PTV/bbl = \$92.50
 - .1% per dollar that the PTV/bbl is greater than \$92.50
 - Maximum rate of 50% (in addition to 25% base tax)
- Calculated monthly
- A single statewide calculation on all oil and gas



Progressivity: How it is Calculated.



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000
- **GVPP = *Gross Value at the Point of Production.***
- **PTV = *Production Tax Value.***

ANS West Coast Price:	\$109.61
Transportation Costs:	-\$8.81
GVPP:	\$100.80
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$19.61
Production Tax Value (PTV):	\$64.87
Base Tax (25%):	\$16.22



Progressivity: How it is Calculated.



Calculating the Progressivity with a PTV/bbl = \$64.87

- $\$64.87 - \$30 = \$34.87$
- Because the PTV/bbl < \$92.50
- $\$34.87 \times .004 \approx 13.95\%$

The 13.95% progressive tax is then applied to the PTV/bbl of \$64.87 not to the \$34.87

$\$64.87 \times 13.95\% = \9.05 per barrel

Therefore: the \$9.05 progressive tax + \$16.22 (25%) base tax = \$25.27 production tax per barrel **before credits**.

Multiplied by the taxable production (170,262,000 bbls) = \$4,302 million



Observations



- Progressivity increases the overall tax rate as the overall profitability (before state and federal income taxes) rises.
- Remember, progressivity is company specific and each company will have a different exposure because progressivity is sensitive to:
 - The oil price.
 - Spending.
 - Production.
- Progressivity is only one part of what makes the overall system progressive; it is not a factor at low oil prices.



Example 1: New Capital Spending in Fiscal Year 2014



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000.
- Increased capital spending by \$500 million from \$3,338.6 million to \$3,836.6 million.
- CAPEX per barrel goes from \$19.61 to \$22.55 per barrel.

ANS West Coast Price:	\$109.61
Transportation Costs:	-\$8.81
GVPP:	\$100.80
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$22.55
Production Tax Value (PTV):	\$61.93
Base Tax (25%):	\$15.48



Example 1: New Capital Spending in Fiscal Year 2014



Calculating the Progressivity with a PTV/bbl = \$61.93

- $\$61.93 - \$30 = \$31.93$
- Because the PTV/bbl $< \$92.50$
- $\$31.93 \times .004 \approx 12.77\%$

The 12.77% progressive tax is then applied to the PTV/bbl of \$61.93 not to the \$31.93

$\$61.93 \times 12.77\% = \7.91 per barrel

Therefore: the \$7.91 progressive tax + \$15.48 (25%) base tax = \$23.39 production tax per barrel **before credits.**

Multiplied by the taxable production (170,262,000) = \$3,983 million

Therefore – capital spending went up \$500 million and state revenues went down \$319 million before considering the credits.



Observations



- Progressivity based on the net production tax incentivizes spending.
- The level of the incentive depends on the price of oil and the cost structure of the investor not the project's economics.
- The value of the deduction often exceeds the value of the tax credits.
- This benefit is only available to incumbent producers and doesn't create a level playing field with new entrants.



Example 2: New Capital Spending in Fiscal Year 2014 with lower oil price



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000.
- Oil Prices decline \$10 to \$99.61
- Increased capital spending by \$500 million from \$3,338.6 million to \$3,836.6 million
- CAPEX per barrel goes from \$19.61 to \$22.55 per barrel.

ANS West Coast Price:	\$99.61
Transportation Costs:	-\$8.81
GVPP:	\$90.80
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$22.55
Production Tax Value (PTV):	\$51.93
Base Tax (25%):	\$12.98



Example 2: New Capital Spending in Fiscal Year 2014 with lower oil price



Calculating the Progressivity with a PTV/bbl = \$51.93

- $\$51.93 - \$30 = \$21.93$
- Because the PTV/bbl < \$92.50
- $\$21.93 \times .004 \approx 8.77\%$

$\$51.93 \times 8.77\% = \4.56 per barrel

Therefore: the \$4.56 progressive tax + \$12.98 (25%) base tax = \$17.54 production tax per barrel **before credits.**

Multiplied by the taxable production (170,262,000) = \$2,986 million

The same equation run **without** the additional capital spending (Capital at \$19.61 / bbl) derives \$3,265 million.

Therefore the benefit of the deduction of an additional \$500 million in capital spending at an oil price of \$109.61 was **\$319 million** but at an oil price of \$99.61 was **\$279 million.**



Observations



- Since the value of a deduction is dependent on the price of oil it is very difficult for a company to predict the value of the deduction especially with long lead time projects.
- The reduction in taxes is temporary, since as soon as the spending is done the tax rate rises back to the higher rate.
- Greater incentive to spend at higher prices than at lower prices – the opposite of what is needed to make projects economic.



Example 3: Cutting Costs

- Again, based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Oil Production: 170,262,000
- Reduce the capital cost per barrel by \$5.

ANS West Coast Price:	\$109.61
Transportation Costs:	-\$8.81
GVPP:	\$100.80
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$14.61
Production Tax Value (PTV):	\$69.87
Base Tax (25%):	\$17.47



Example 3: Cutting Costs



Calculating the Progressivity with a PTV/bbl = \$69.87

- $\$69.87 - \$30 = \$39.87$
- Because the PTV/bbl $< \$92.50$
- $\$39.87 \times .004 \approx 15.95\%$

$\$69.87 \times 15.95\% = \11.14 per barrel

Therefore: the \$11.14 progressive tax + \$17.47 (25%) base tax = \$28.61 production tax per barrel **before credits.**

Before the cost savings, taxes per barrel were \$25.27

Therefore a reduction in capital cost per barrel of \$5 leads to a tax increase of \$3.34 per barrel.

With progressivity, producer keeps \$1.66 of the \$5 in cost savings (\$5-\$3.34); without progressivity, producer keeps \$3.75 of the \$5 in cost savings (\$5-\$1.25)



Observations



- When cutting costs increases taxes it creates distortions in decision making and behavior.
- Technology that improves economic value will create the same effect as cutting costs because it increases the production tax value and therefore, the progressive tax rate.
- Similarly, things that reduce the production tax value reduce the tax rate.
- Much stronger incentive to keep costs under control without progressivity – good for both producer and state.



FY 09 Monthly Tax Calculations – Monthly Oil Price Volatility Matters!



	July	August	September	October	November	December	
Oil Price	\$132.87	\$115.98	\$101.86	\$73.65	\$53.94	\$37.70	
Total barrels per month	20,174,640	17,230,458	21,197,405	23,080,737	22,846,738	22,727,030	
Royalty & Federal barrels	2,848,947	2,848,947	2,848,947	2,848,947	2,848,947	2,848,947	
Taxable barrels per month	17,325,693	14,381,511	18,348,458	20,231,790	19,997,791	19,878,083	
Wellhead value	\$126.37	\$109.48	\$95.36	\$67.15	\$47.44	\$31.20	
Gross value of taxable bbls	\$2,189,447,867	\$1,574,487,850	\$1,749,708,987	\$1,358,564,721	\$948,695,216	\$620,196,200	
Deductible Opex	\$170,833,333	\$170,833,333	\$170,833,333	\$170,833,333	\$170,833,333	\$170,833,333	
Deductible Capex	\$145,833,333	\$145,833,333	\$145,833,333	\$145,833,333	\$145,833,333	\$145,833,333	
Taxable value	\$1,872,781,200	\$1,257,821,183	\$1,433,042,320	\$1,041,898,054	\$632,028,549	\$303,529,533	
Base rate	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	
Base tax	\$468,195,300	\$314,455,296	\$358,260,580	\$260,474,514	\$158,007,137	\$75,882,383	
Taxable value per barrel	\$108.09	\$87.46	\$78.10	\$51.50	\$31.60	\$15.27	
Progressive tax rate	26.6%	23.0%	19.2%	8.6%	0.6%	-	
Progressive tax	\$497,397,040	\$289,102,592	\$275,726,004	\$89,595,168	\$4,057,416	\$0	
Tax before credits	\$965,592,340	\$603,557,888	\$633,986,584	\$350,069,682	\$162,064,553	\$75,882,383	
Credits applied	\$29,150,000	\$29,150,000	\$29,150,000	\$29,150,000	\$29,150,000	\$29,150,000	
Tax after credits	\$936,442,340	\$574,407,888	\$604,836,584	\$320,919,682	\$132,914,553	\$46,732,383	
Effective tax rate on net	50%	46%	42%	31%	21%	15%	
	January	February	March	April	May	June	Total
Oil Price	\$39.01	\$42.78	\$47.75	\$46.56	\$58.23	\$69.80	\$68.34
Total barrels per month	21,812,241	20,747,934	23,020,348	20,160,047	22,186,732	17,785,719	252,970,029
Royalty & Federal barrels	2,848,947	2,848,947	2,848,947	2,848,947	2,848,947	2,848,947	34,187,360
Taxable barrels per month	18,963,294	17,898,987	20,171,402	17,311,100	19,337,785	14,936,772	218,782,669
Wellhead value	\$32.51	\$36.28	\$41.25	\$40.06	\$51.73	\$63.30	\$61.84
Gross value of taxable bbls	\$616,496,702	\$649,375,248	\$832,070,320	\$693,482,668	\$1,000,343,635	\$945,497,689	\$13,178,367,102
Deductible Opex	\$170,833,333	\$170,833,333	\$170,833,333	\$170,833,333	\$170,833,333	\$170,833,333	\$2,050,000,000
Deductible Capex	\$145,833,333	\$145,833,333	\$145,833,333	\$145,833,333	\$145,833,333	\$145,833,333	\$1,750,000,000
Taxable value	\$299,830,035	\$332,708,581	\$515,403,653	\$376,816,001	\$683,676,969	\$628,831,022	\$9,378,367,102
Base rate	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Base tax	\$74,957,509	\$83,177,145	\$128,850,913	\$94,204,000	\$170,919,242	\$157,207,756	\$2,344,591,775
Taxable value per barrel	\$15.81	\$18.59	\$25.55	\$21.77	\$35.35	\$42.10	\$44.27
Progressive tax rate	-	-	-	-	2.1%	4.8%	7.1%
Progressive tax	\$0	\$0	\$0	\$0	\$14,642,885	\$30,434,227	\$1,200,955,332
Tax before credits	\$74,957,509	\$83,177,145	\$128,850,913	\$94,204,000	\$185,562,128	\$187,641,982	\$3,545,547,108
Credits applied	\$29,150,000	\$29,150,000	\$29,150,000	\$29,150,000	\$29,150,000	\$29,150,000	\$349,800,000
Tax after credits	\$45,807,509	\$54,027,145	\$99,700,913	\$65,054,000	\$156,412,128	\$158,491,982	\$3,195,747,108
Effective tax rate on net	15%	16%	19%	17%	23%	25%	34%
						Less adjustments	\$83,792,561
						TOTAL TAX	\$3,111,954,547

Source: Department of Revenue from production tax monthly information forms, annual returns, and company forecasts



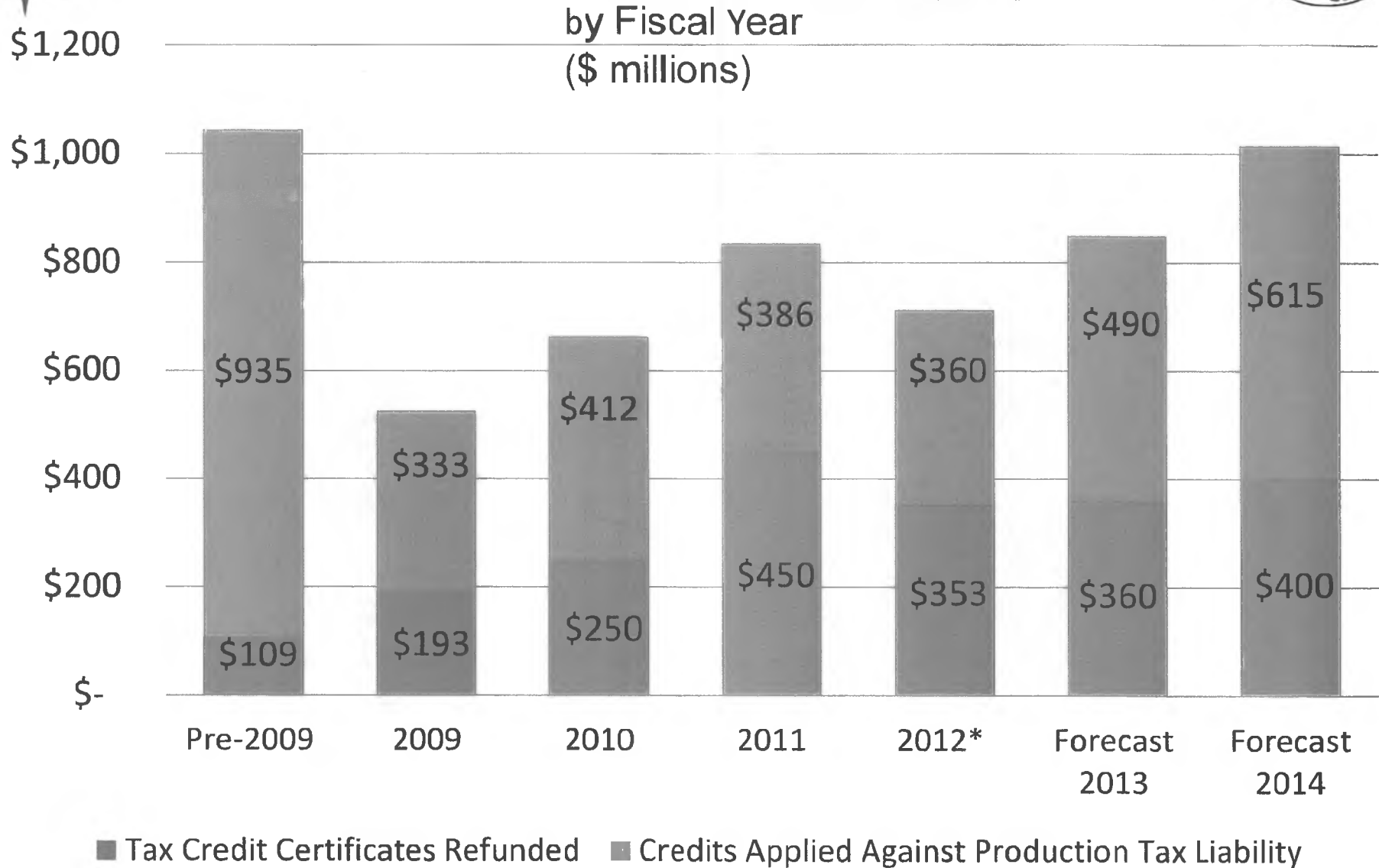
Summary



- Progressivity is not simple:
 - It reduces the cash margin per barrel in ways that leaves Alaska uncompetitive.
 - It is highly sensitive to price, production, and spending—making it difficult to predict for the State of Alaska and taxpayers.
 - It incentivizes spending—but not necessarily investments that lead to production.
 - It mutes the incentive to save costs or utilize technology.
 - It creates the decoupling dilemma.



Production Tax Credits Used and Forecast



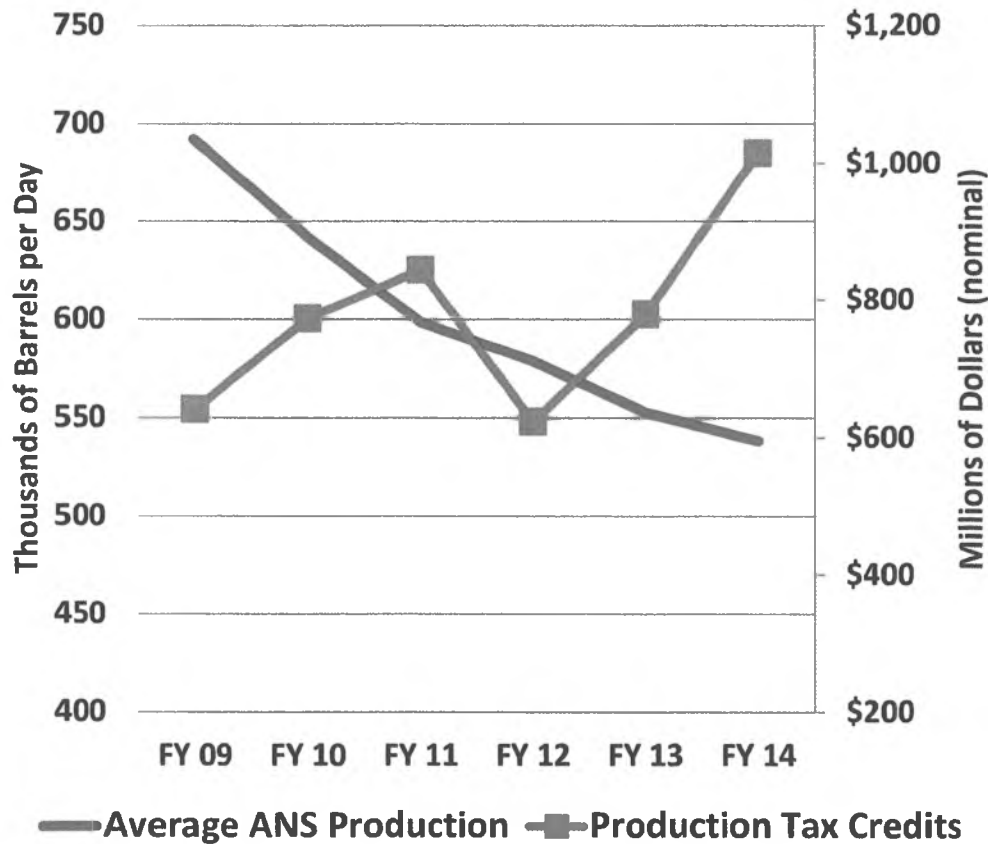
*Estimated pending final true-ups
Source: Alaska Department of Revenue



Production Tax Credits



Average ANS Production and Tax Production Tax Credits



- Production tax credits have increased while production continues to decline.
- The North Slope needs significant additional investment for new production.
- Additional investment will increase the credit liability to the state and reduce revenues.

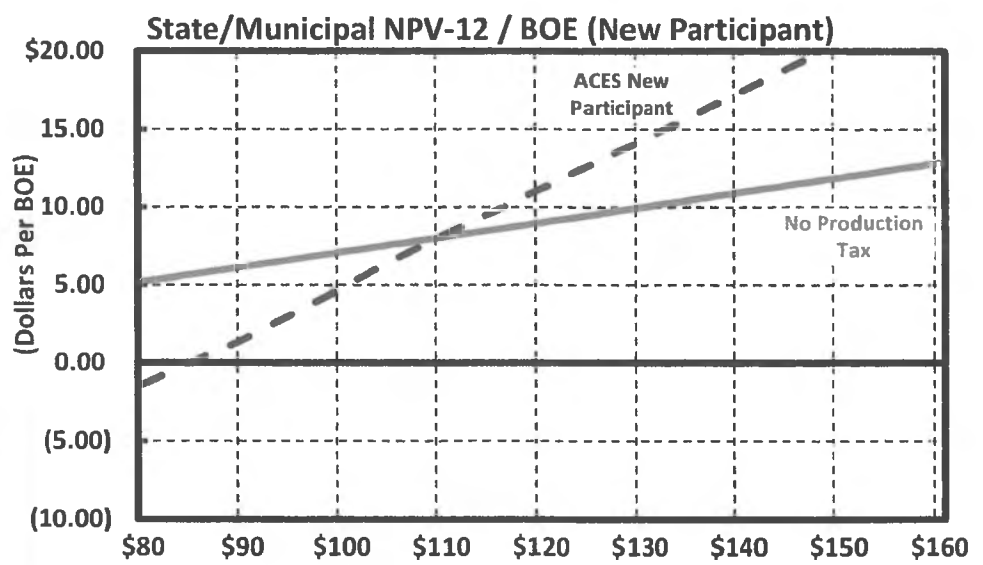
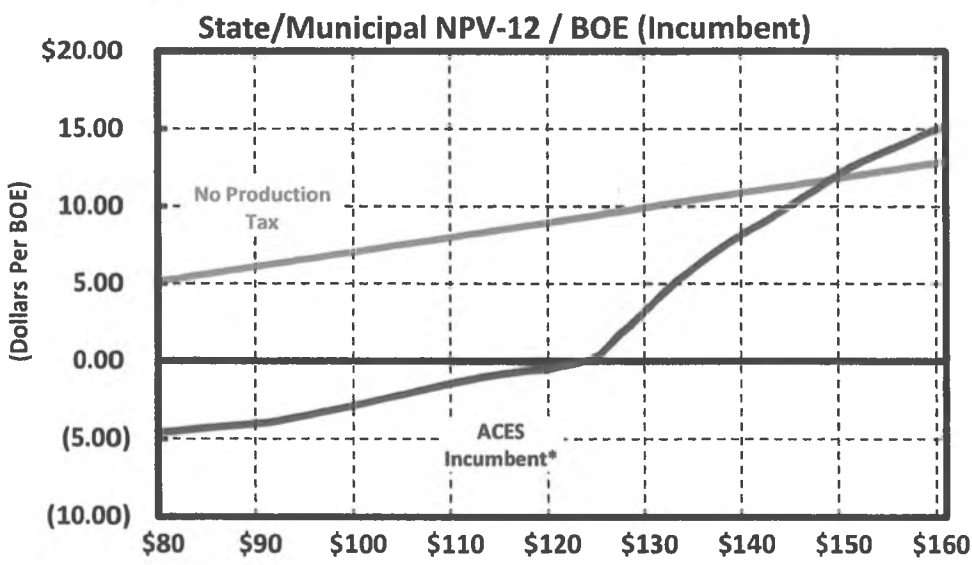
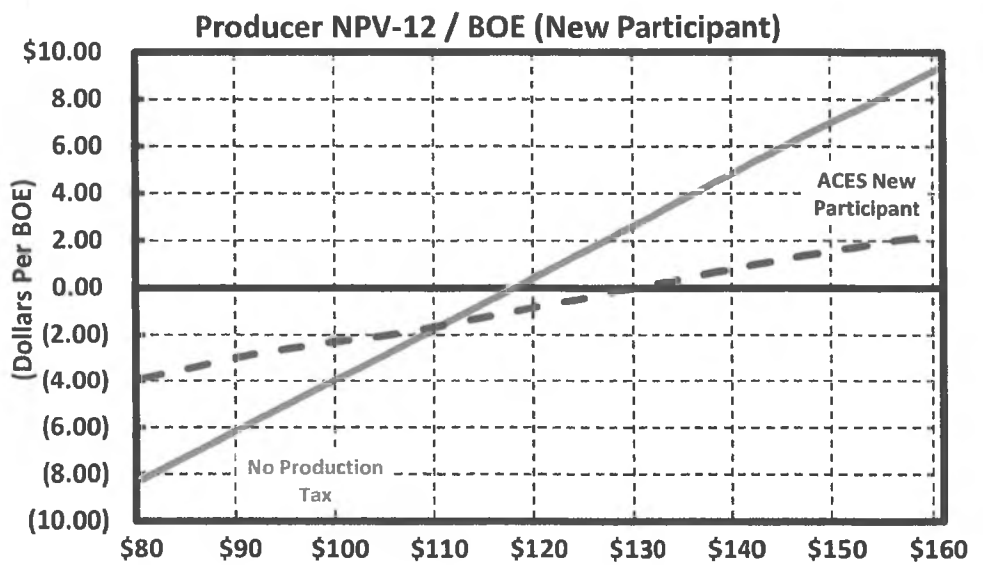
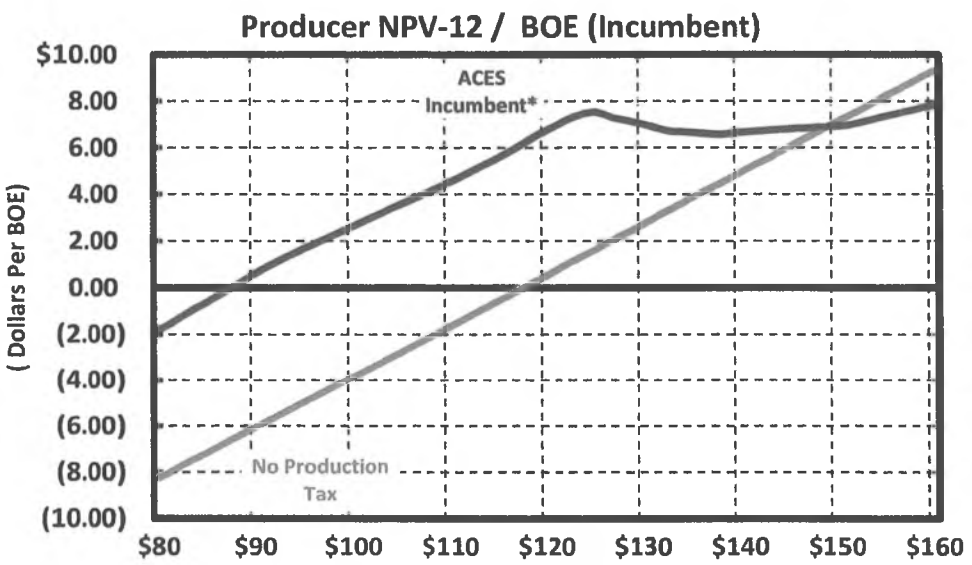


Production Tax Revenue Sensitivity



- Rising prices + Declining production can equal lower revenue, considering...
- Alaska's current production tax revenues depend on:
 - Price
 - Production
 - Company Spending
- Tax credits depend on spending.
- Creates potential scenario where low prices coupled with high spending create significant revenue shortfalls for the state.
- Regardless of price, increased investment will lead to near term revenue shortfalls for the state.

The Economics of High Cost Light Oil Development



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



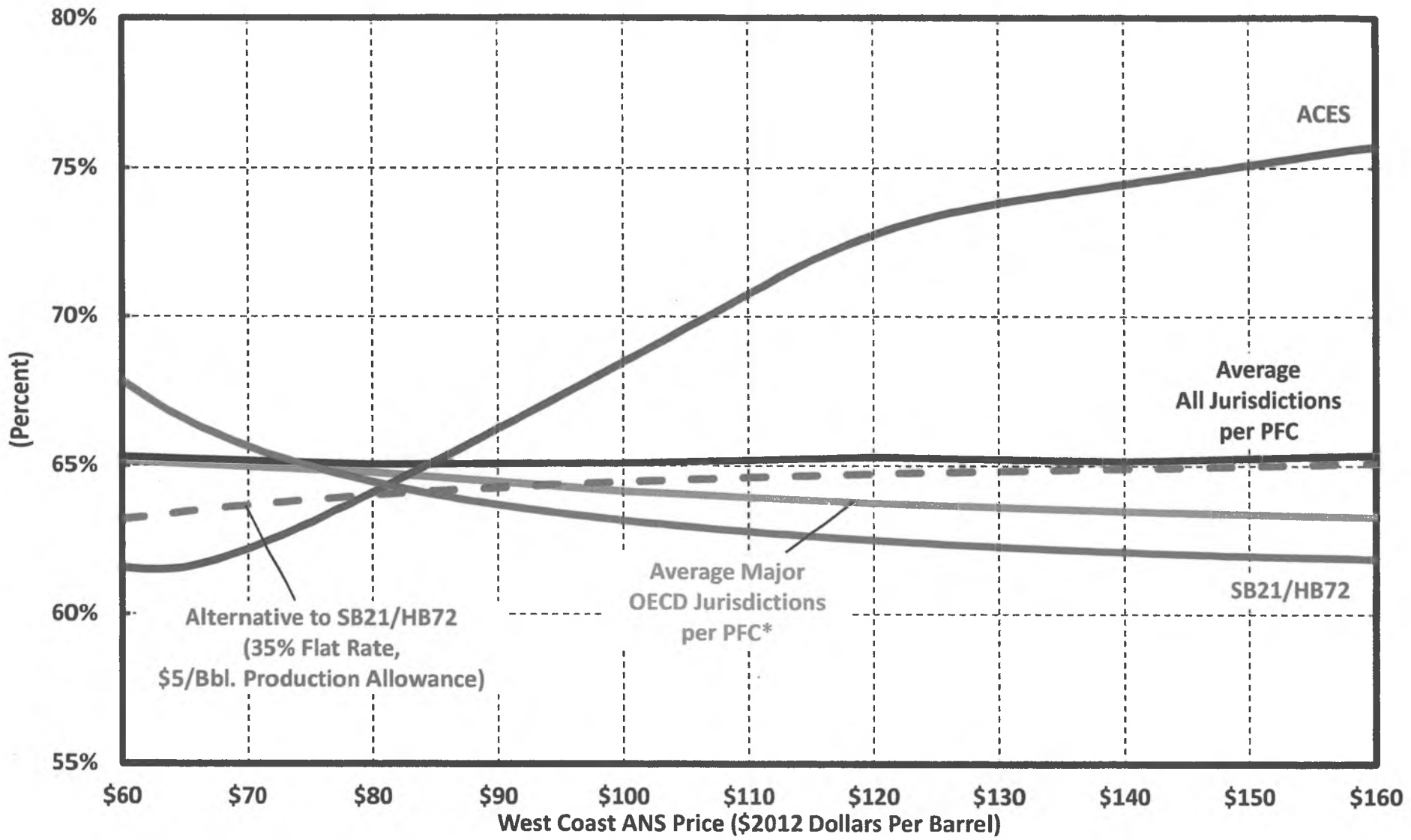
Senate Bill 21 and CS SB 21 (RES)

Primary Provisions



Provision	Current Tax System	SB 21	CS SB 21 Resources
Base Tax Rate	25%	25%	35%
Progressivity	Yes	No	No
Qualified Capital Credits	Yes, 20% of qualified capital spending.	No	No
Loss Carry Forward Credits	Yes, 25% of annual loss (transferred or state purchases)	Yes, 25% of annual loss (carried to production)	Yes, 35% of annual loss (carried to production)
Gross Revenue Exclusion	No	20% of GVPP, Units formed after Jan. 1, 2003 or new participating areas.	30% of GVPP, Units formed after Jan. 1, 2003, new participating areas, or expansion of existing participating areas.
Per Barrel Credit	No	No	\$5 per taxable barrel (applicable against tax liability only)

Average Government Take ACES v. SB21/HB72 and ^{CS}Alternative to SB21/HB72 for All Existing Producers (FY2015-FY2019) and Other Jurisdictions



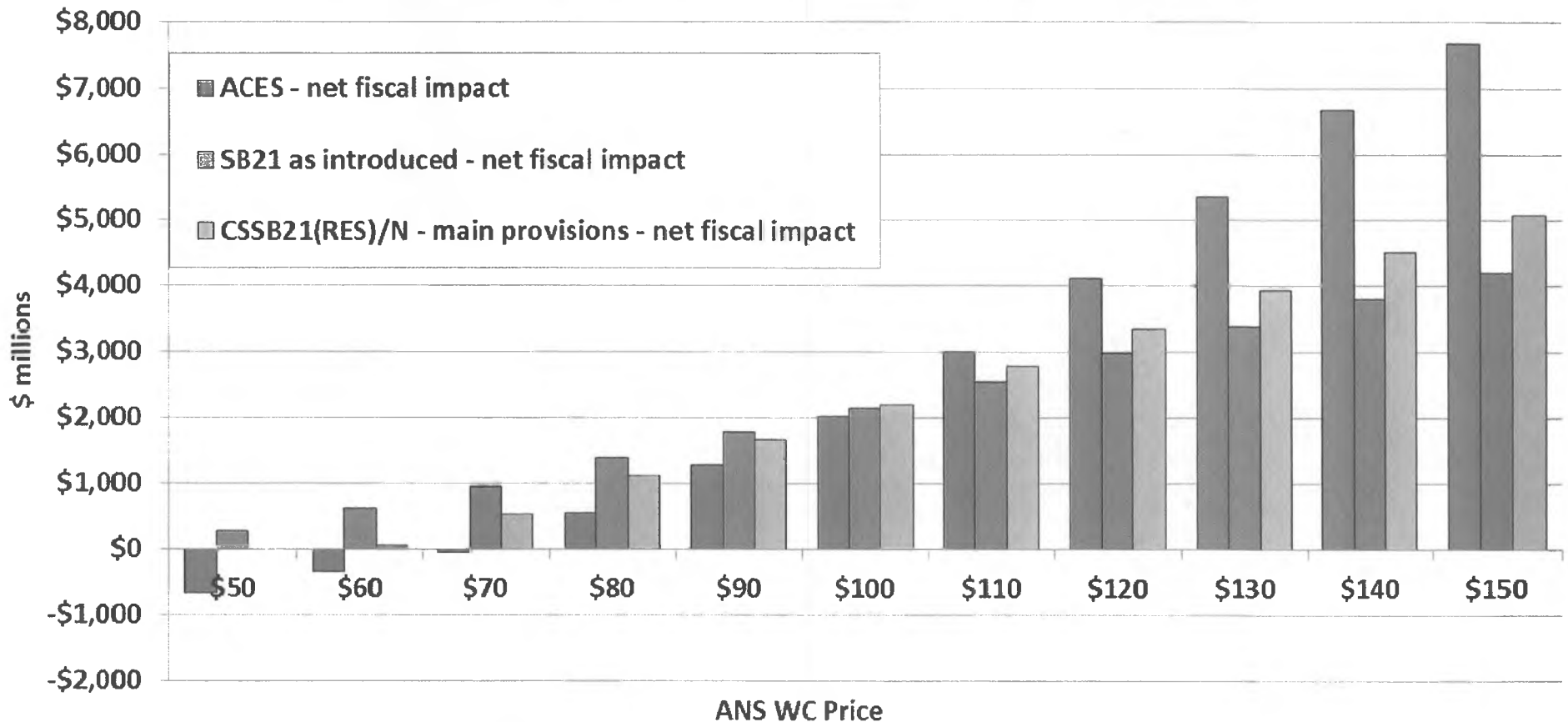
* Australia, Canada (Alberta Conventional), Norway, United Kingdom and United States.



Production Tax Revenue, less refunded and carried-forward credits



**FY15 ACES, SB21 and CSSB21(RES) -
Production Tax Revenue with certain adjustments**



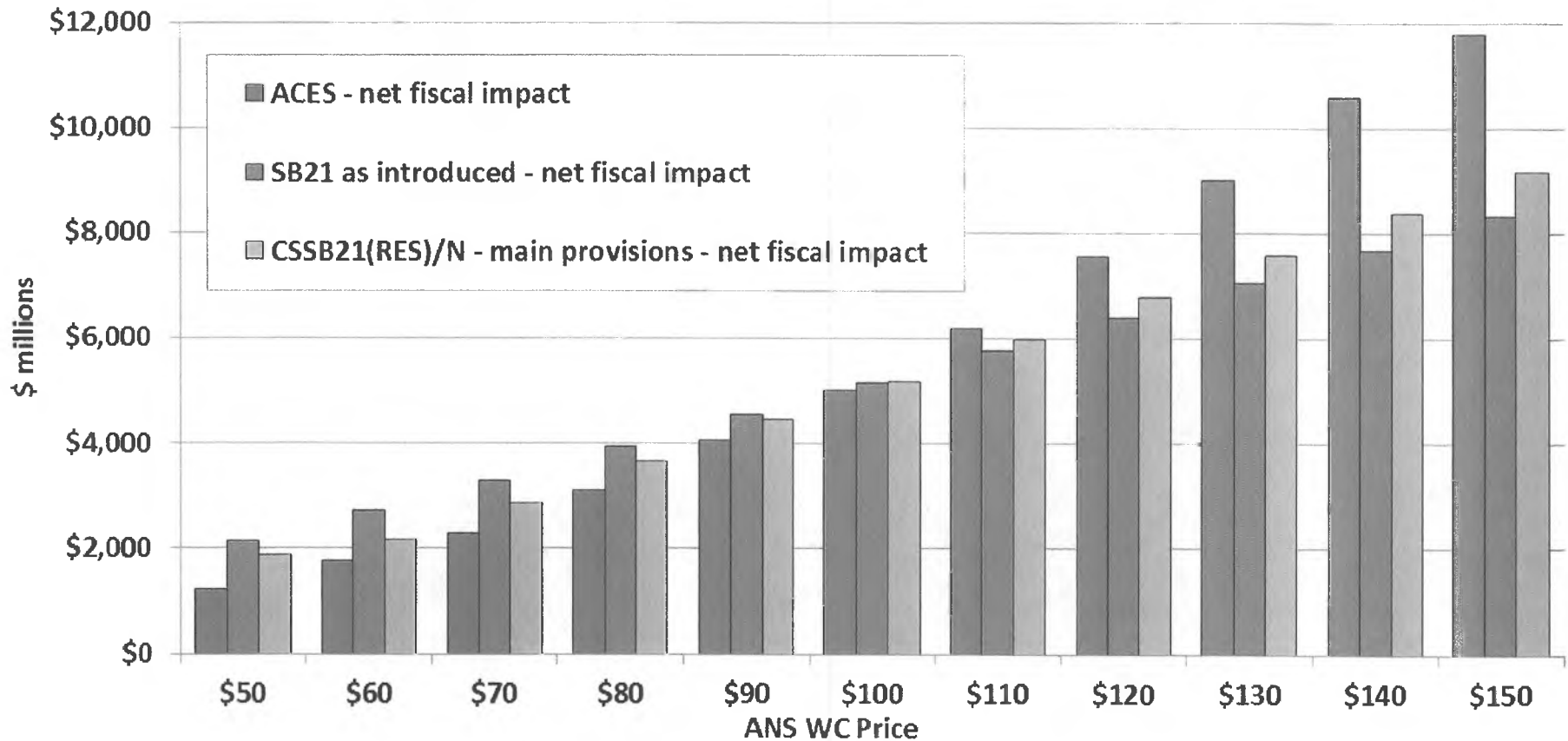
Source: Fall 2012 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. For \$50, also includes expected liability for carried forward credits in excess tax liability for major producers. CSSB21(RES)/N "Main Provisions" does not include impact of new service industry CIT credit, or expansion of exploration credit.



General Fund Unrestricted Revenue, less refunded and carried-forward credits



**FY15 ACES, SB21 and CSSB21(RES) -
GF Unrestricted Revenue with certain adjustments**



Source: Fall 2012 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. For \$50, also includes expected liability for carried forward credits in excess tax liability for major producers. CSSB21(RES)/N "Main Provisions" does not include impact of new service industry CIT credit, or expansion of exploration credit.



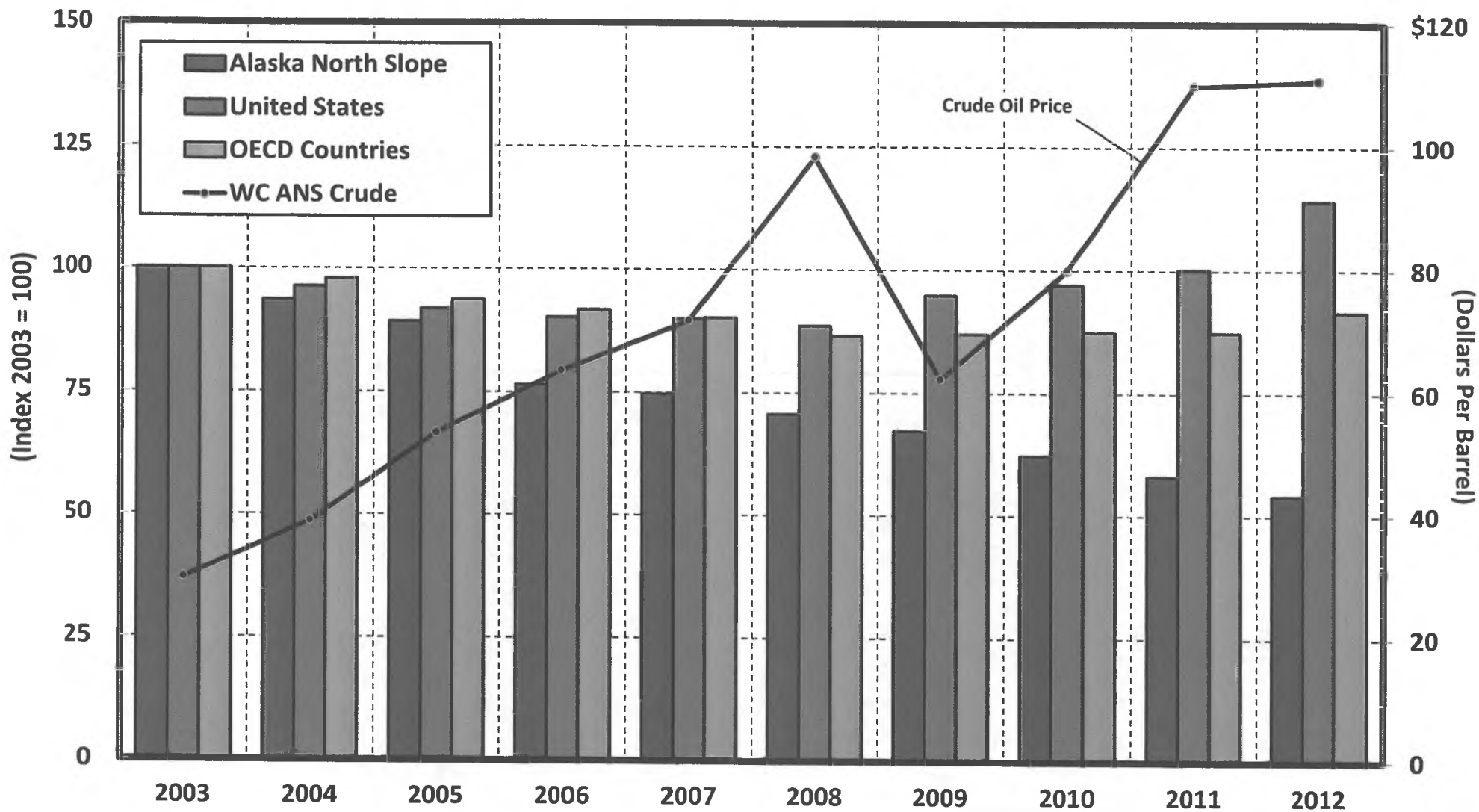
Supplemental Slides

The following slides were presented
by EconOne to the Senate Resources
Committee on February 13, 2013

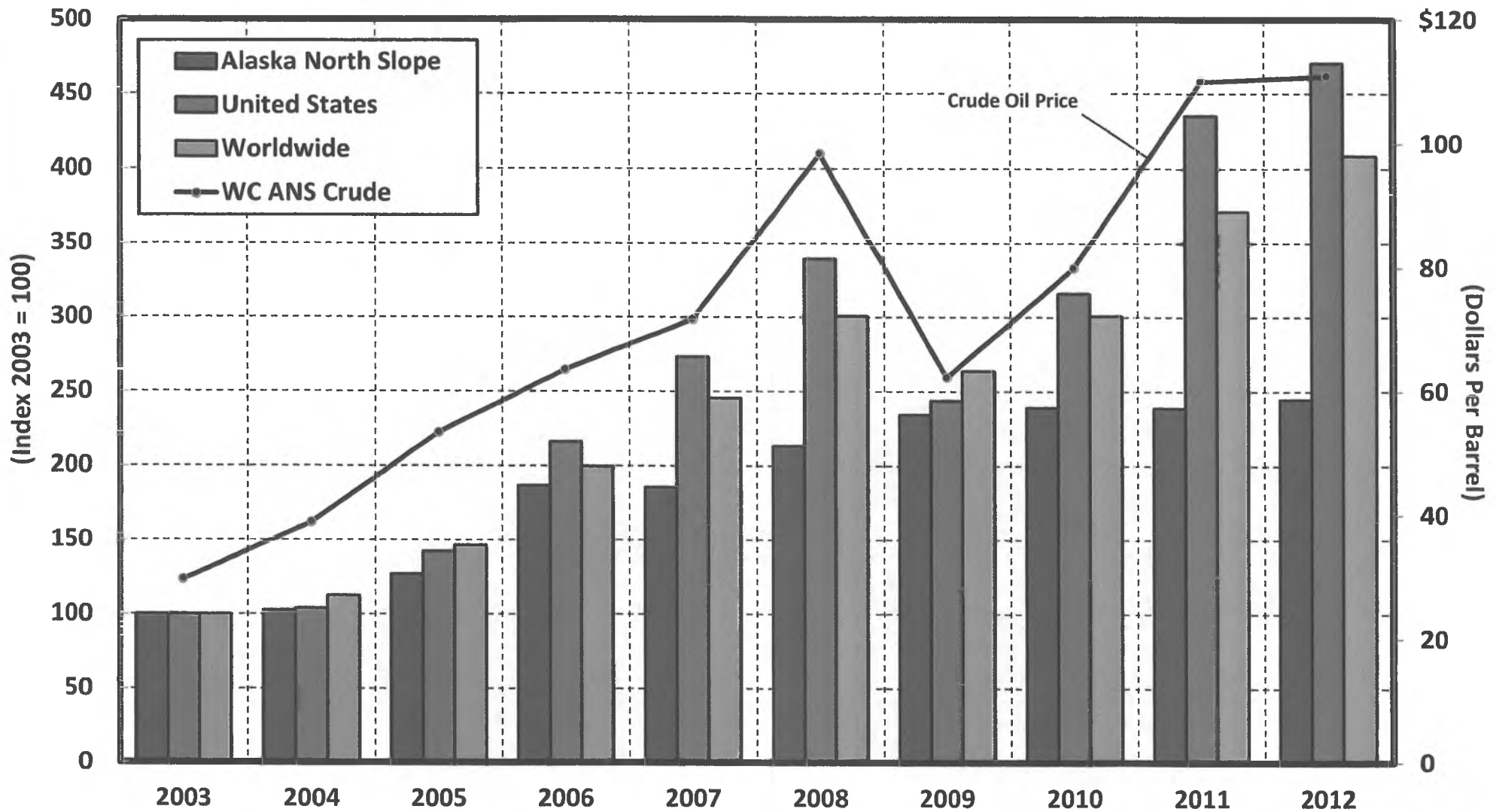
Crude Oil Production

Alaska North Slope vs. United States and OECD Countries

2003 - 2012



Estimated Capital Spending for Exploration and Development Alaska North Slope vs. United States and Worldwide Spending* 2003 - 2012



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

Calculation of ACES Tax: Varying Prices

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price (\$/Bbl)		\$80.00	\$100.00	\$120.00
Transportation Costs (\$/Bbl)	-	10.00	10.00	10.00
Wellhead Value (\$/Bbl)	=	\$70.00	\$90.00	\$110.00
Operating Costs (\$/Bbl)	-	\$15.00	\$15.00	\$15.00
Capital Expenditures (\$/Bbl)	-	15.00	15.00	15.00
Taxable Value (\$/Bbl)	=	\$40.00	\$60.00	\$80.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	4.0%	12.0%	20.0%
Total Tax Rate (%)	=	29.0%	37.0%	45.0%
Total Wellhead Value (\$)		\$3,500,000,000	\$4,500,000,000	\$5,500,000,000
Operating Expenditures (\$)	-	750,000,000	750,000,000	750,000,000
Capital Expenditures (\$)	-	750,000,000	750,000,000	750,000,000
Production Tax Value (\$)	=	\$2,000,000,000	\$3,000,000,000	\$4,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) (\$)		\$580,000,000	\$1,110,000,000	\$1,800,000,000
Capital Credits (20% x Capital Expenditures) (\$)	-	150,000,000	150,000,000	150,000,000
Production Tax After Credits (\$)	=	\$430,000,000	\$960,000,000	\$1,650,000,000
Effective Tax Rate After Credits (%)		21.5%	32.0%	41.3%

Calculation of ACES Tax: Varying Costs

\$100 West Coast ANS Price

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price (\$/Bbl)		\$100.00	\$100.00	\$100.00
Transportation Costs (\$/Bbl)	-	10.00	10.00	10.00
Wellhead Value (\$/Bbl)	=	\$90.00	\$90.00	\$90.00
Operating Costs (\$/Bbl)	-	\$10.00	\$20.00	\$30.00
Capital Expenditures (\$/Bbl)	-	10.00	15.00	20.00
Taxable Value (\$/Bbl)	=	\$70.00	\$55.00	\$40.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	16.0%	10.0%	4.0%
Total Tax Rate (%)	=	41.0%	35.0%	29.0%
Total Wellhead Value (\$)		\$4,500,000,000	\$4,500,000,000	\$4,500,000,000
Operating Expenditures (\$)	-	500,000,000	1,000,000,000	1,500,000,000
Capital Expenditures (\$)	-	500,000,000	750,000,000	1,000,000,000
Production Tax Value (\$)	=	\$3,500,000,000	\$2,750,000,000	\$2,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) (\$)		\$1,435,000,000	\$962,500,000	\$580,000,000
Capital Credits (20% x Capital Expenditures) (\$)	-	100,000,000	150,000,000	200,000,000
Production Tax After Credits (\$)	=	\$1,335,000,000	\$812,500,000	\$380,000,000
Effective Tax Rate After Credits (%)		38.1%	29.5%	19.0%

Calculation of ACES Tax: Varying Costs

\$80 West Coast ANS Price



Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price (\$/Bbl)		\$80.00	\$80.00	\$80.00
Transportation Costs (\$/Bbl)	-	10.00	10.00	10.00
Wellhead Value (\$/Bbl)	=	\$70.00	\$70.00	\$70.00
Operating Costs (\$/Bbl)	-	\$10.00	\$20.00	\$30.00
Capital Expenditures (\$/Bbl)	-	10.00	15.00	20.00
Taxable Value (\$/Bbl)	=	\$50.00	\$35.00	\$20.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	8.0%	2.0%	0.0%
Total Tax Rate (%)	=	33.0%	27.0%	25.0%
Total Wellhead Value (\$)		\$3,500,000,000	\$3,500,000,000	\$3,500,000,000
Operating Expenditures (\$)	-	500,000,000	1,000,000,000	1,500,000,000
Capital Expenditures (\$)	-	500,000,000	750,000,000	1,000,000,000
Production Tax Value (\$)	=	\$2,500,000,000	\$1,750,000,000	\$1,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) (\$)		\$825,000,000	\$472,500,000	\$250,000,000
Capital Credits (20% x Capital Expenditures) (\$)	-	100,000,000	150,000,000	200,000,000
Production Tax After Credits (\$)	=	\$725,000,000	\$322,500,000	\$50,000,000
Effective Tax Rate After Credits (%)		29.0%	18.4%	5.0%

Calculation of ACES Tax: Additional Capital Spending

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
Initial Expenditure (\$)		\$1,500,000,000	\$1,500,000,000	\$1,500,000,000
Additional Expenditure (\$)	+	250,000,000	250,000,000	250,000,000
Total Lease Expenditure (\$)		\$1,750,000,000	\$1,750,000,000	\$1,750,000,000
WC ANS Price (\$/Bbl)		\$80.00	\$100.00	\$120.00
Tax Value Prior To Additional Expenditure (\$/Bbl)		\$40.00	\$60.00	\$80.00
Additional Capital Spending Per-Barrel of Existing Production (\$/Bbl)	-	5.00	5.00	5.00
Tax Value After Additional Expenditure (\$/Bbl)	=	\$35.00	\$55.00	\$75.00
Taxes Before Additional Expenditure				
Tax Rate (%)		29.0%	37.0%	45.0%
Production Tax Before Credits (\$)		\$580,000,000	\$1,110,000,000	\$1,800,000,000
Capital Credits (20% x Capital Expenditures) (\$)	-	300,000,000	300,000,000	300,000,000
Production Tax After Credits (\$)	=	\$280,000,000	\$810,000,000	\$1,500,000,000
Taxes After Additional Expenditure				
Tax Rate (%)		27.0%	35.0%	43.0%
Production Tax Before Credits (\$)		\$472,500,000	\$962,500,000	\$1,612,500,000
Capital Credits (20% x Capital Expenditures) (\$)	-	350,000,000	350,000,000	350,000,000
Production Tax After Credits (\$)	=	\$122,500,000	\$612,500,000	\$1,262,500,000
Reduction in Taxes From Additional Expenditure				
Before Credits		\$107,500,000	\$147,500,000	\$187,500,000
Additional Credits	+	50,000,000	50,000,000	50,000,000
Total Reduction in Taxes After Credits	=	\$157,500,000	\$197,500,000	\$237,500,000
Reduction in Tax as % of Expenditure		63%	79%	95%
Due to Change in Taxes (Buy Down Effect)		43%	59%	75%
Due to Additional Credits		20%	20%	20%

3

Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal SB21 / SRES CS SB21

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

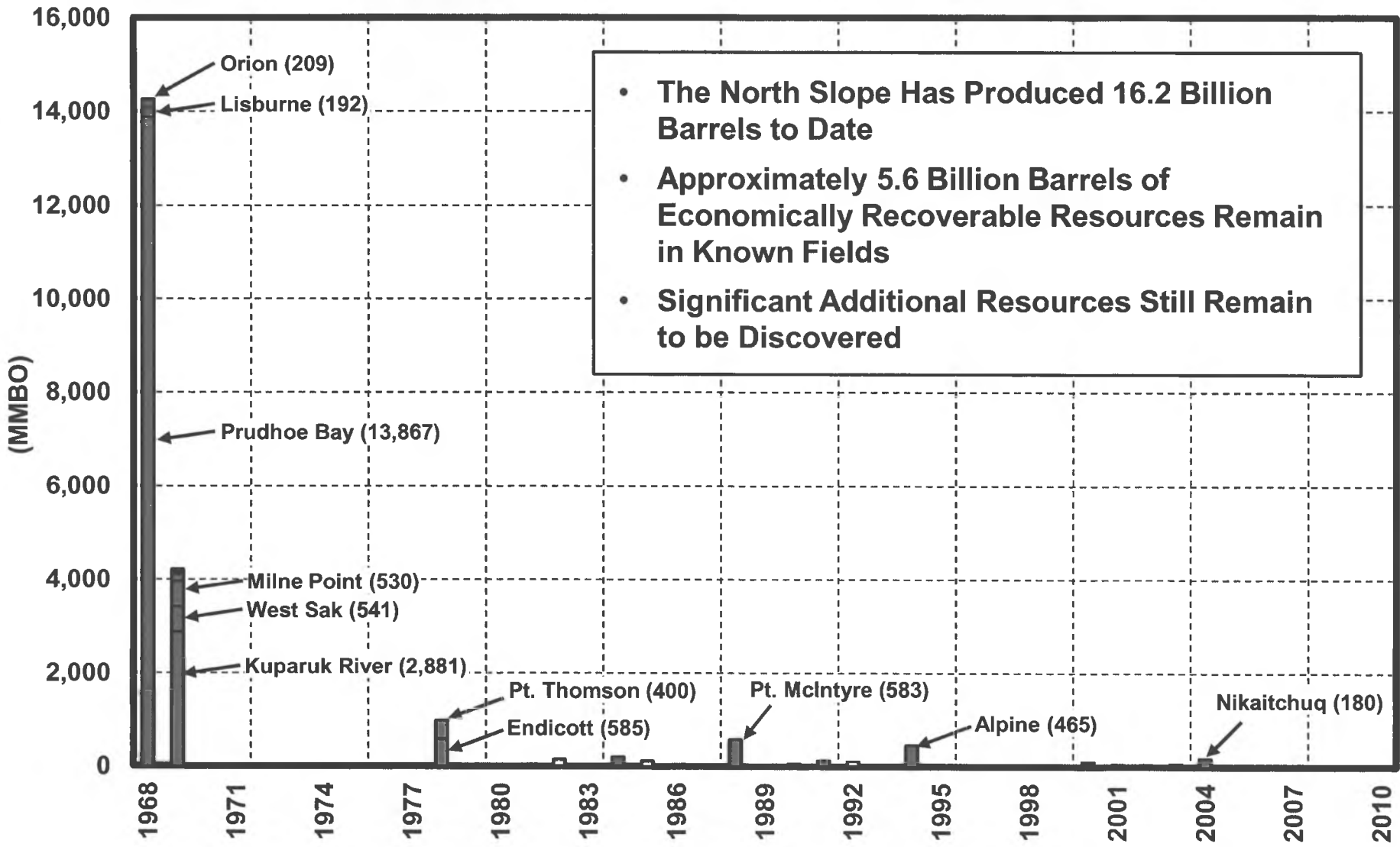
March 1, 2013

Econ One: Who We Are

- **Economic Research and Consulting Firm**
 - **We Provide Economic Analysis In Energy and Other Industries**
- **We Have Advised the State of Alaska on Petroleum Related Matters For Over Two Decades**
- **We Have Worked With the Cowper, Hickel, Knowles, Murkowski, Palin, and Parnell Administrations**
- **We Assisted the Legislature Between 2005 and 2008 on Tax and Gas Development Issues**
- **Our Energy-Related Work Outside Alaska**
 - **State Governments: Texas, Louisiana, New Mexico, Oklahoma, California**
 - **Federal Government Agencies: Department of Interior, Federal Trade Commission**
 - **Energy Companies: Producers, Refiners, Mid-Stream Services, Pipelines, Chemicals**

Background

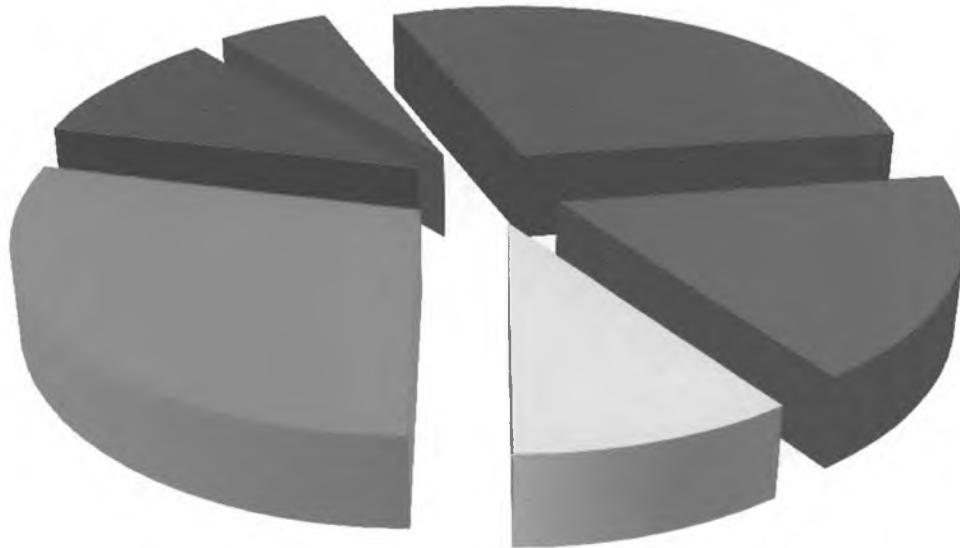
Alaska North Slope Discovered Resources by Discovery Year (1969 – 2010)



Source: DNR: The Historical Resource and Recovery Growth in Developed Fields, Arctic Slope of Alaska, 2004; DOE/NETL-2009/1385; AOGCC.

Alaska North Slope Production and Resources

- **Many North Slope Fields are Now at Mature Stages. However, Less Than Half of its Potential Economic Oil Resources Have Been Produced to Date**
- **In Total, the North Slope Contains Approximately 40 Billion Barrels of Additional Estimated Economic Recoverable Resources at Today's Prices**



- **Historical Production**
(16.2 BBO)
- **Conventional Resources - Discovered**
(5.6 BBO est.)
- **Conventional Resources - Undiscovered State Onshore**
(3.0 BBO est.)
- **Conventional Resources - Undiscovered Federal**
(16.2 BBO est.)
- **ANWR**
(9.9 BBO est.)
- **Unconventional Resources**
(5.5 BBO est.)

Estimated Undiscovered Conventional Oil Resources on Alaska North Slope

	Technically Recoverable Resources			Economically Recoverable @ \$90/bbl	Expected Typical Field Size
	P95	Mean	P5		
	(1)	(2)	(3)	(4)	(5)
	(Million Barrels)				
Central North Slope	2,800	3,400	3,900	3,000	32 - 64
Beaufort Sea	400	8,200	23,200	5,800	-
Chukchi Sea	2,300	15,400	40,100	9,900	-
NPRA	400	900	1,700	500	32 - 64
ANWR	5,900	10,400	15,200	9,900	64 - 128
Total		38,300		29,100	

Source:
 USGS Reports 2011-1103 and 2009-1112;
 BOEM, Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf.

Estimated Undeveloped Unconventional Oil Resources on Alaska North Slope

Shale

~ 1 Billion Bbls

(Mean Estimated Technically Recoverable Barrels)

(USGS, 2012)

Viscous and Heavy Oil

**(Includes All Schrader/West Sak and Ugnu Reservoirs in the Kuparuk River,
Prudhoe Bay, Milne Point and Nikaitchuq Units, Not Just PAs or Areas
Under Development)**

Total In-Place Resource

24 - 27 Billion Bbls

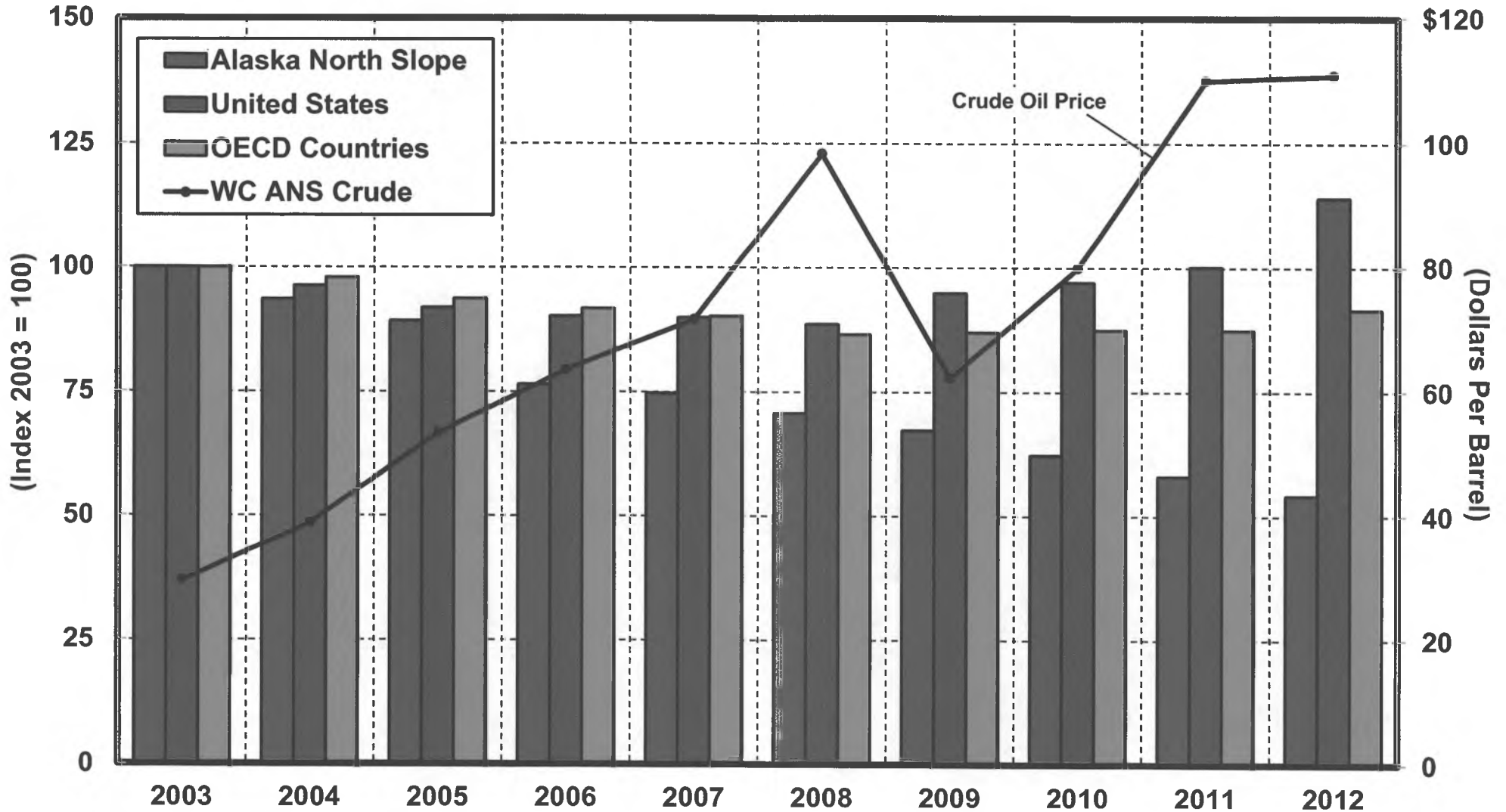
(Hartz, et al., 2007; AOGCC)

Economically Recoverable

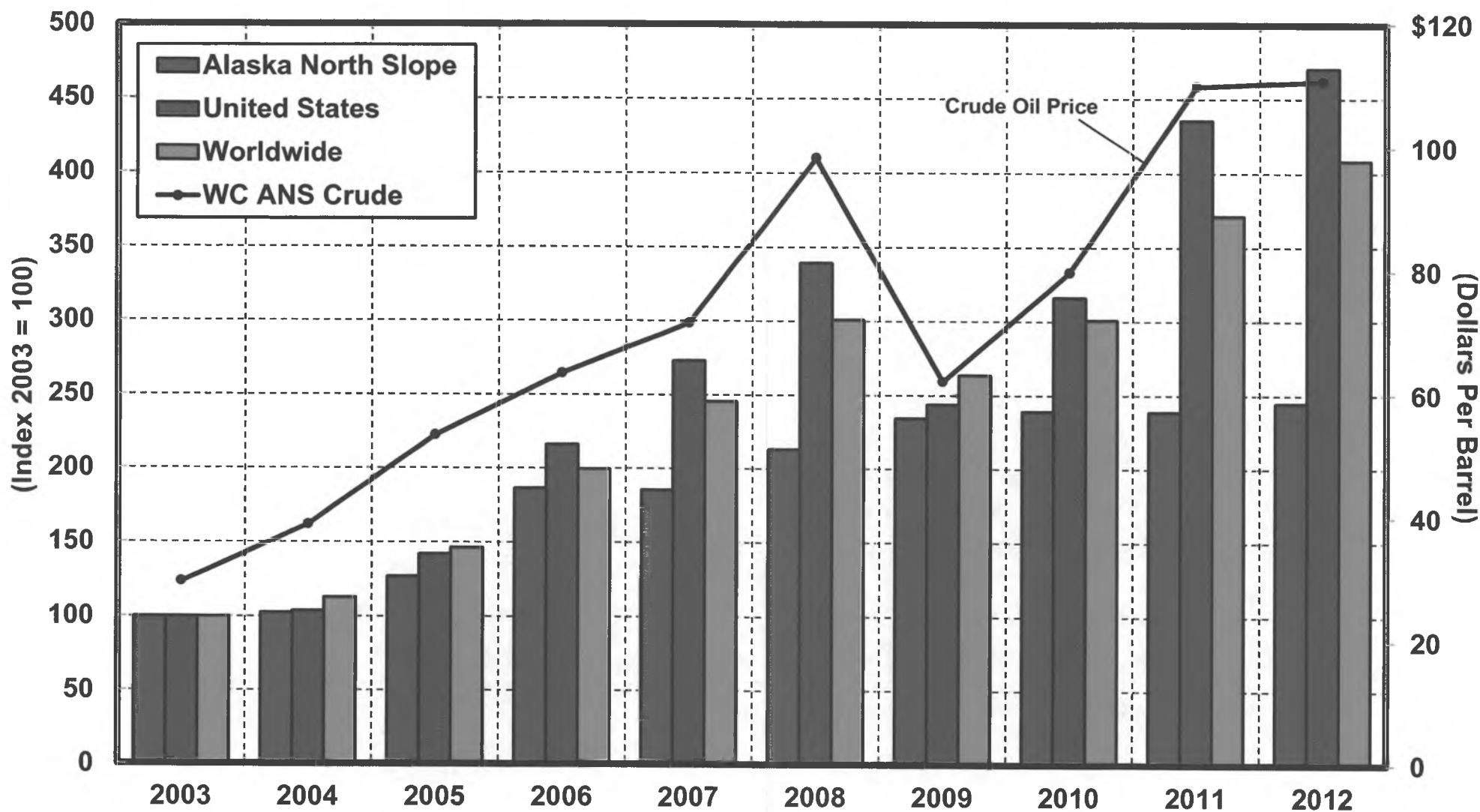
3.6 - 5.6 Billion Bbls

(Assuming 15% Average Recovery)

Crude Oil Production Alaska North Slope vs. United States and OECD Countries 2003 - 2012



Estimated Capital Spending for Exploration and Development Alaska North Slope vs. United States and Worldwide Spending* 2003 - 2012



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

Fundamentals of Tax Calculation, Potential Development, and State Exposure Under ACES

How ACES Works

- **Tax is Calculated on “Net Value” of Taxable Production**
 - Taxable Production is Total Production Less Royalties
 - Net Value is Gross Wellhead Value Less Cost of Production
 - Costs of Production are Capital Expenses, Operating Expenses and Property Tax Payments
- **Base Tax Rate of 25%**
- **Progressive Tax Rate of 0.4% Per \$1/Barrel (4% Per \$10/Barrel) Increase Over \$30/Barrel Net Value and 0.1% Per \$1/Barrel (1% Per \$10/Barrel) Over \$92.50, Capped at 50% Total**
- **Example: Taxable Value = \$100/Barrel “Production Tax Value”**
 - Base Rate = 25%
 - Progressive Rate = $(\$92.50 - \$30) \times 0.4\% + (\$100 - \$92.50) \times 0.1\% = 25.75\%$
 - Total Rate = $25\% + 25.75\% = 50.75\%$
- **Credit of 20% for Capital Expenditures (Taken Over 2 Years)**
- **Small Producer Credit of \$12 Million Per Year (Phased Out for Production over 50 MBD)**
- **State Purchases Credits and Net Operating Losses (NOLs) From Companies Without Tax Obligation**
 - Equals 45% of Capital Expenditures and 25% of Operating Expenditures

Calculation of ACES Taxes: Varying Prices

Annual Taxable Production (Bbls)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
West Coast ANS Price (\$/Bbl)	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00
Transportation Costs (\$/Bbl)	- 10.00	- 10.00	- 10.00	- 10.00	- 10.00
Wellhead Value (\$/Bbl)	= \$50.00	= \$70.00	= \$90.00	= \$110.00	= \$130.00
Operating Costs (\$/Bbl)	- \$15.00	- \$15.00	- \$15.00	- \$15.00	- \$15.00
Capital Expenditures (\$/Bbl)	- 15.00	- 15.00	- 15.00	- 15.00	- 15.00
Taxable Value (\$/Bbl)	= \$20.00	= \$40.00	= \$60.00	= \$80.00	= \$100.00
ACES Base Tax Rate (%)	25.0%	25.0%	25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+ 0.0%	+ 4.0%	+ 12.0%	+ 20.0%	+ 25.8%
Total Tax Rate (%)	= 25.0%	= 29.0%	= 37.0%	= 45.0%	= 50.8%
Total Wellhead Value (\$)	\$2,500,000,000	\$3,500,000,000	\$4,500,000,000	\$5,500,000,000	\$6,500,000,000
Operating Expenditures (\$)	- 750,000,000	- 750,000,000	- 750,000,000	- 750,000,000	- 750,000,000
Capital Expenditures (\$)	- 750,000,000	- 750,000,000	- 750,000,000	- 750,000,000	- 750,000,000
Production Tax Value (\$)	= \$1,000,000,000	= \$2,000,000,000	= \$3,000,000,000	= \$4,000,000,000	= \$5,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) (\$)	\$250,000,000	\$580,000,000	\$1,110,000,000	\$1,800,000,000	\$2,537,500,000
Capital Credits (20% x Capital Expenditures) (\$)	- 150,000,000	- 150,000,000	- 150,000,000	- 150,000,000	- 150,000,000
Production Tax After Credits (\$)	= \$100,000,000	= \$430,000,000	= \$960,000,000	= \$1,650,000,000	= \$2,387,500,000
Effective Production Tax Rate After Credits (%)	10.0%	21.5%	32.0%	41.3%	47.8%

Calculation of ACES Tax: Varying Costs

\$100 West Coast ANS Price

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price (\$/Bbl)		\$100.00	\$100.00	\$100.00
Transportation Costs (\$/Bbl)	-	10.00	10.00	10.00
Wellhead Value (\$/Bbl)	=	\$90.00	\$90.00	\$90.00
Operating Costs (\$/Bbl)	-	\$10.00	\$20.00	\$30.00
Capital Expenditures (\$/Bbl)	-	10.00	15.00	20.00
Taxable Value (\$/Bbl)	=	\$70.00	\$55.00	\$40.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	16.0%	10.0%	4.0%
Total Tax Rate (%)	=	41.0%	35.0%	29.0%
Total Wellhead Value (\$)		\$4,500,000,000	\$4,500,000,000	\$4,500,000,000
Operating Expenditures (\$)	-	500,000,000	1,000,000,000	1,500,000,000
Capital Expenditures (\$)	-	500,000,000	750,000,000	1,000,000,000
Production Tax Value (\$)	=	\$3,500,000,000	\$2,750,000,000	\$2,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) (\$)		\$1,435,000,000	\$962,500,000	\$580,000,000
Capital Credits (20% x Capital Expenditures) (\$)	-	100,000,000	150,000,000	200,000,000
Production Tax After Credits (\$)	=	\$1,335,000,000	\$812,500,000	\$380,000,000
Effective Tax Rate After Credits (%)		38.1%	29.5%	19.0%

Calculation of ACES Tax: Varying Costs

\$80 West Coast ANS Price

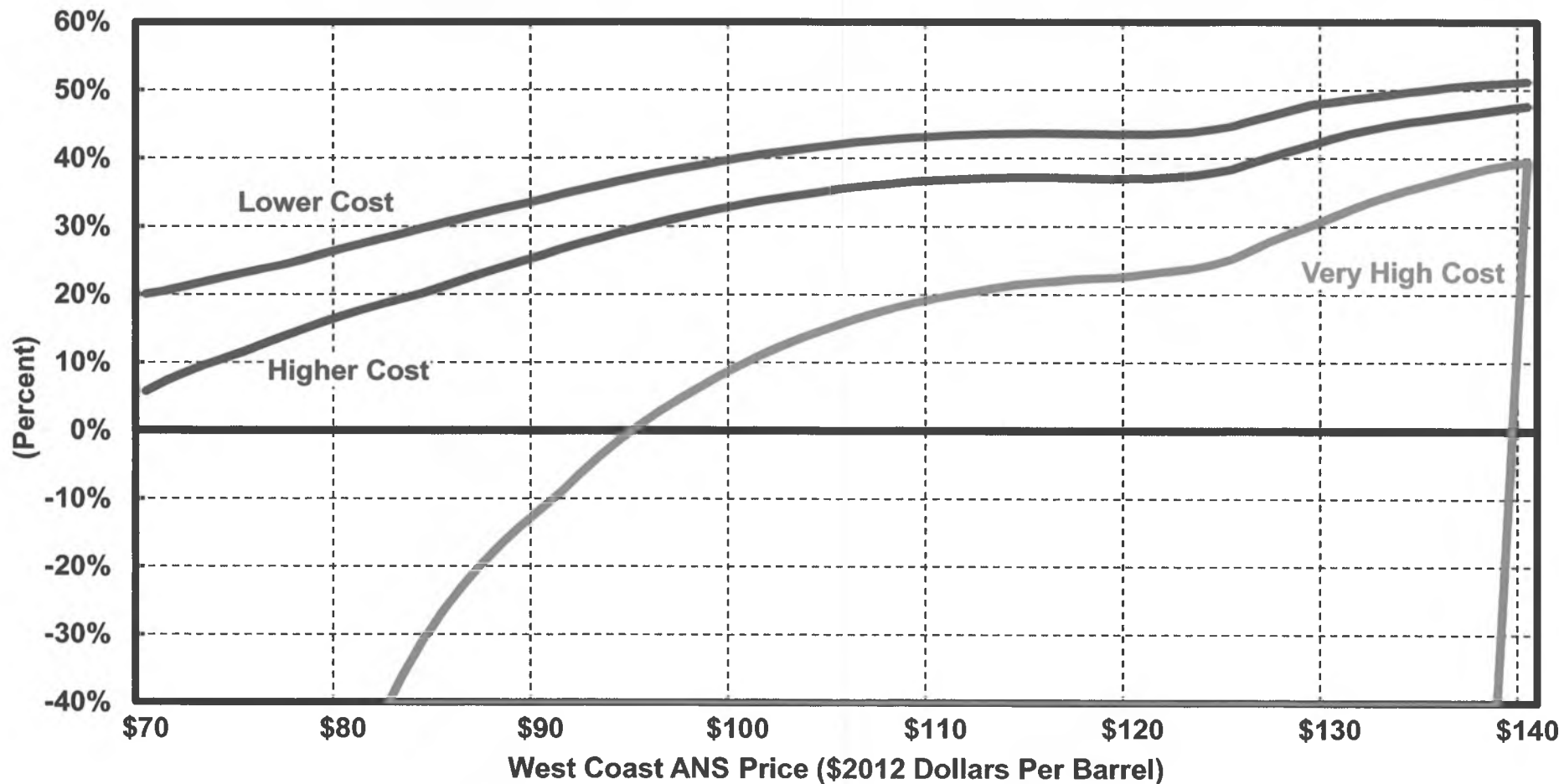
Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price (\$/Bbl)		\$80.00	\$80.00	\$80.00
Transportation Costs (\$/Bbl)	-	10.00	10.00	10.00
Wellhead Value (\$/Bbl)	=	\$70.00	\$70.00	\$70.00
Operating Costs (\$/Bbl)	-	\$10.00	\$20.00	\$30.00
Capital Expenditures (\$/Bbl)	-	10.00	15.00	20.00
Taxable Value (\$/Bbl)	=	\$50.00	\$35.00	\$20.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	8.0%	2.0%	0.0%
Total Tax Rate (%)	=	33.0%	27.0%	25.0%
Total Wellhead Value (\$)		\$3,500,000,000	\$3,500,000,000	\$3,500,000,000
Operating Expenditures (\$)	-	500,000,000	1,000,000,000	1,500,000,000
Capital Expenditures (\$)	-	500,000,000	750,000,000	1,000,000,000
Production Tax Value (\$)	=	\$2,500,000,000	\$1,750,000,000	\$1,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) (\$)		\$825,000,000	\$472,500,000	\$250,000,000
Capital Credits (20% x Capital Expenditures) (\$)	-	100,000,000	150,000,000	200,000,000
Production Tax After Credits (\$)	=	\$725,000,000	\$322,500,000	\$50,000,000
Effective Tax Rate After Credits (%)		29.0%	18.4%	5.0%

Calculation of ACES Tax: Additional Capital Spending

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Initial Operational Expenditure (\$)		\$750,000,000	\$750,000,000	\$750,000,000	\$750,000,000	\$750,000,000
Initial Capital Expenditure (\$)	+	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000
Additional Capital Expenditure (\$)	+	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000
Total Lease Expenditure (\$)	=	\$1,750,000,000	\$1,750,000,000	\$1,750,000,000	\$1,750,000,000	\$1,750,000,000
WC ANS Price (\$/Bbl)		\$60.00	\$80.00	\$100.00	\$120.00	\$140.00
Tax Value Prior To Additional Expenditure (\$/Bbl)		\$20.00	\$40.00	\$60.00	\$80.00	\$100.00
Additional Capital Spending Per-Barrel of Existing Production (\$/Bbl)	-	5.00	5.00	5.00	5.00	5.00
Tax Value After Additional Expenditure (\$/Bbl)	=	\$15.00	\$35.00	\$55.00	\$75.00	\$95.00
Taxes Before Additional Expenditure						
Tax Rate (%)		25.0%	29.0%	37.0%	45.0%	50.8%
Production Tax Before Credits (\$)		\$250,000,000	\$580,000,000	\$1,110,000,000	\$1,800,000,000	\$2,537,500,000
Capital Credits (20% x Capital Expenditures) (\$)	-	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000
Production Tax After Credits (\$)	=	\$100,000,000	\$430,000,000	\$960,000,000	\$1,650,000,000	\$2,387,500,000
Taxes After Additional Expenditure						
Tax Rate (%)		25.0%	27.0%	35.0%	43.0%	50.3%
Production Tax Before Credits (\$)		\$187,500,000	\$472,500,000	\$962,500,000	\$1,612,500,000	\$2,386,875,000
Capital Credits (20% x Capital Expenditures) (\$)	-	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000
Production Tax After Credits (\$)	=	\$0	\$272,500,000	\$762,500,000	\$1,412,500,000	\$2,186,875,000
Reduction in Taxes From Additional Expenditure						
Before Credits (\$)		\$62,500,000	\$107,500,000	\$147,500,000	\$187,500,000	\$150,625,000
Additional Credits (\$)	+	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Total Reduction in Taxes After Credits (\$)	=	\$112,500,000	\$157,500,000	\$197,500,000	\$237,500,000	\$200,625,000
Reduction in Tax as % of Expenditure		45%	63%	79%	95%	80%
Due to Change in Taxes (Buy Down Effect)		25%	43%	59%	75%	60%
Due to Additional Credits		20%	20%	20%	20%	20%

Effective Tax Rates For New Development Under ACES

Additional Tax as % of Production Tax Value: Incumbent Producer

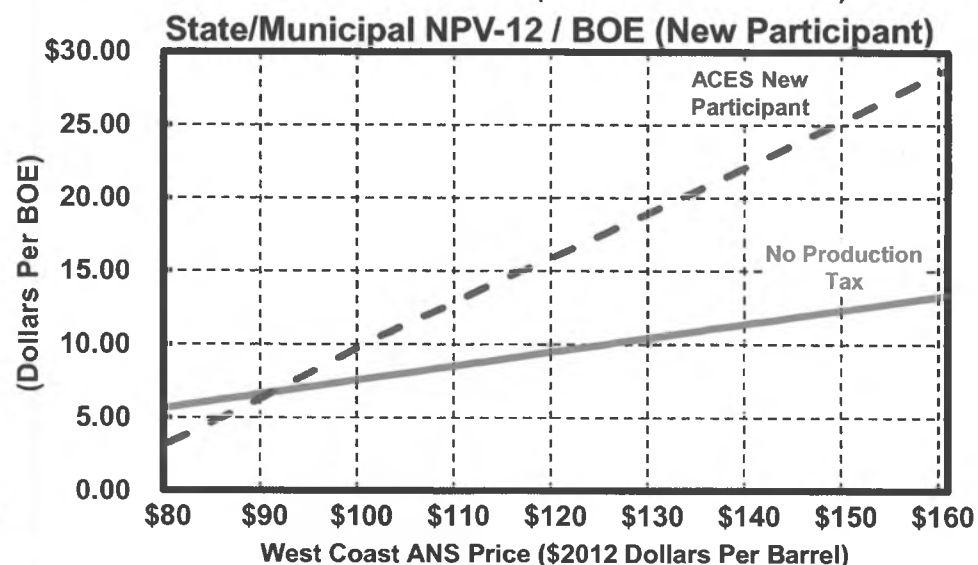
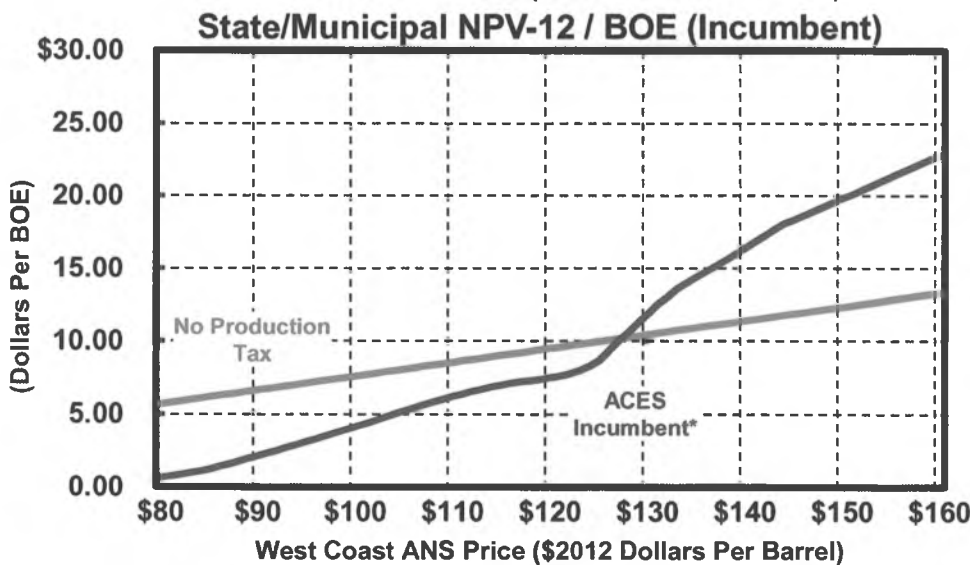
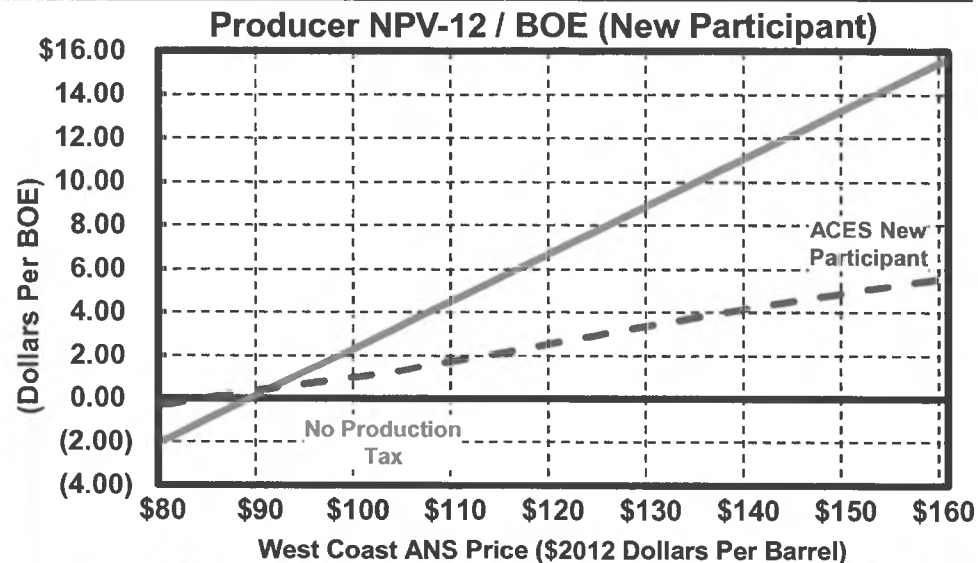
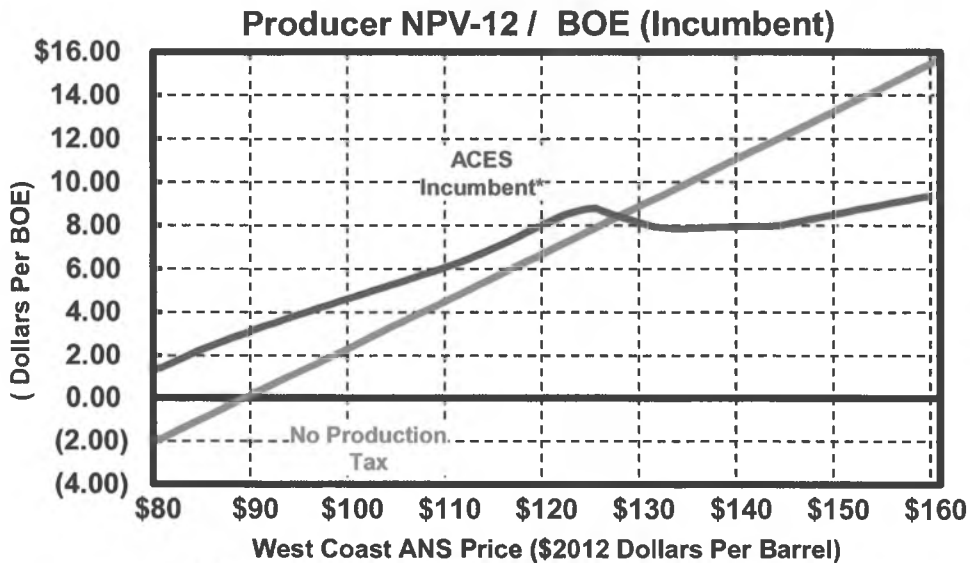


Lower Cost: \$16 Per Barrel Development Capex; \$14 Per Barrel Opex; 16.67% Royalty Rate; 50 MMBO New Development by Existing Owner With Initial Ongoing Production of Approximately 100 MBD and Costs Consistent with Prudhoe Bay/Kuparuk River Units

Higher Cost: \$25 Per Barrel Development Capex; \$14 Per Barrel Opex; 16.67% Royalty Rate; 50 MMBO New Development by Existing Owner With Initial Ongoing Production of Approximately 100 MBD and Costs Consistent with Prudhoe Bay/Kuparuk River Units

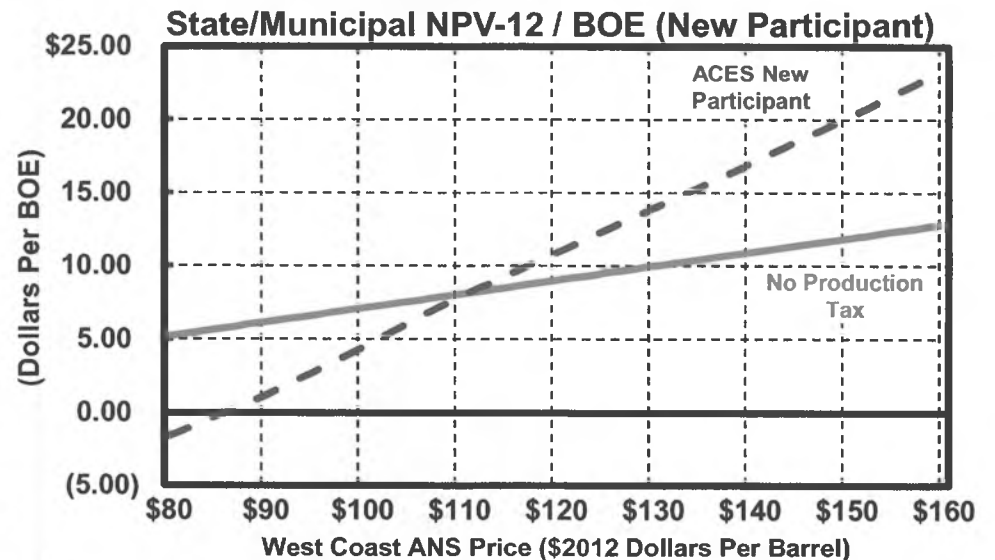
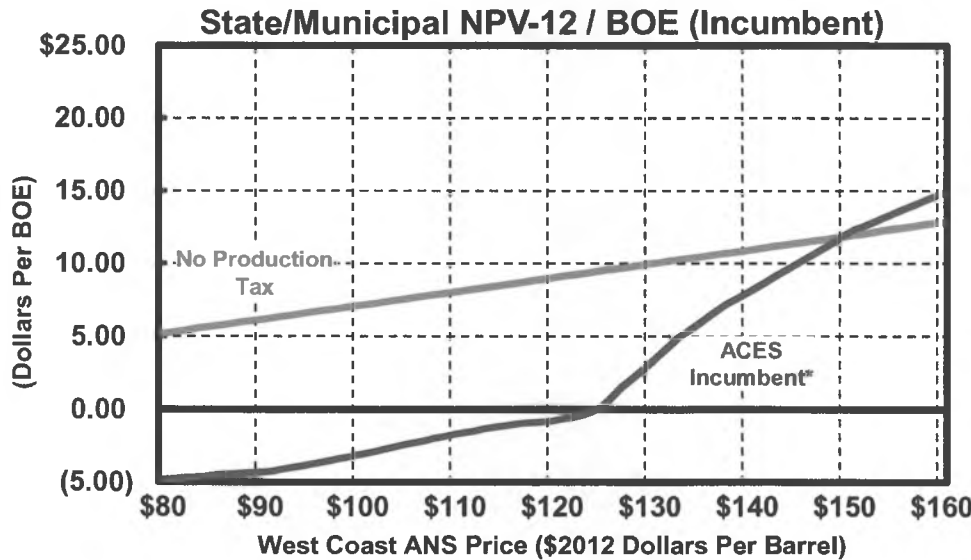
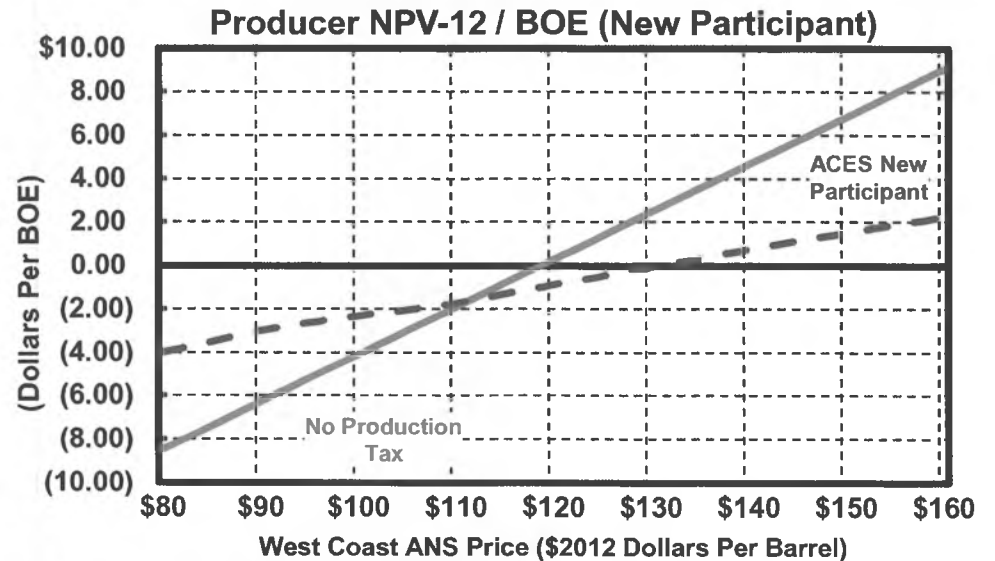
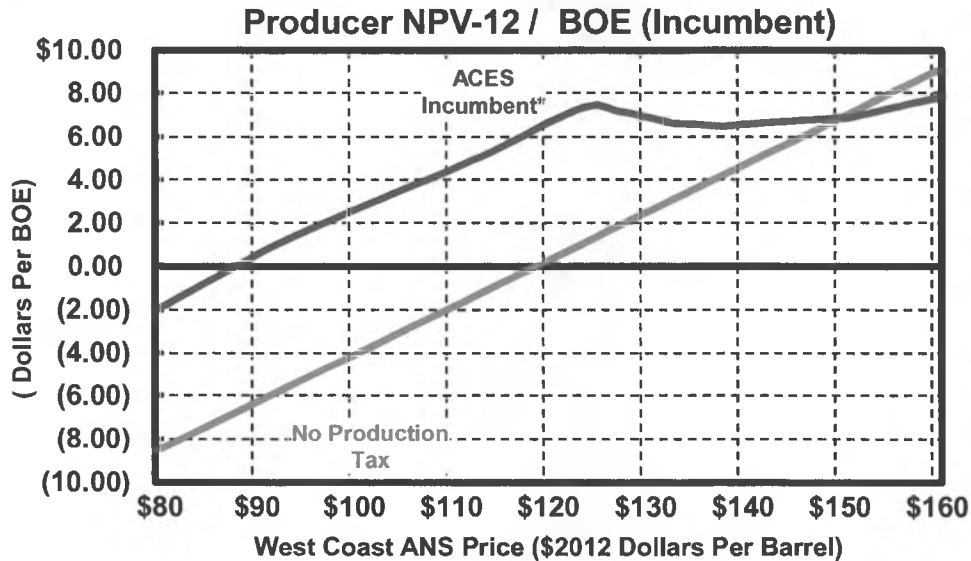
Very High Cost: \$34 Per Barrel Development Capex; \$21 Per Barrel Opex; 16.67% Royalty Rate; 50 MMBO New Development by Existing Owner With Initial Ongoing Production of Approximately 100 MBD and Costs Consistent with Prudhoe Bay/Kuparuk River Units

The Economics of Higher Cost Oil Development



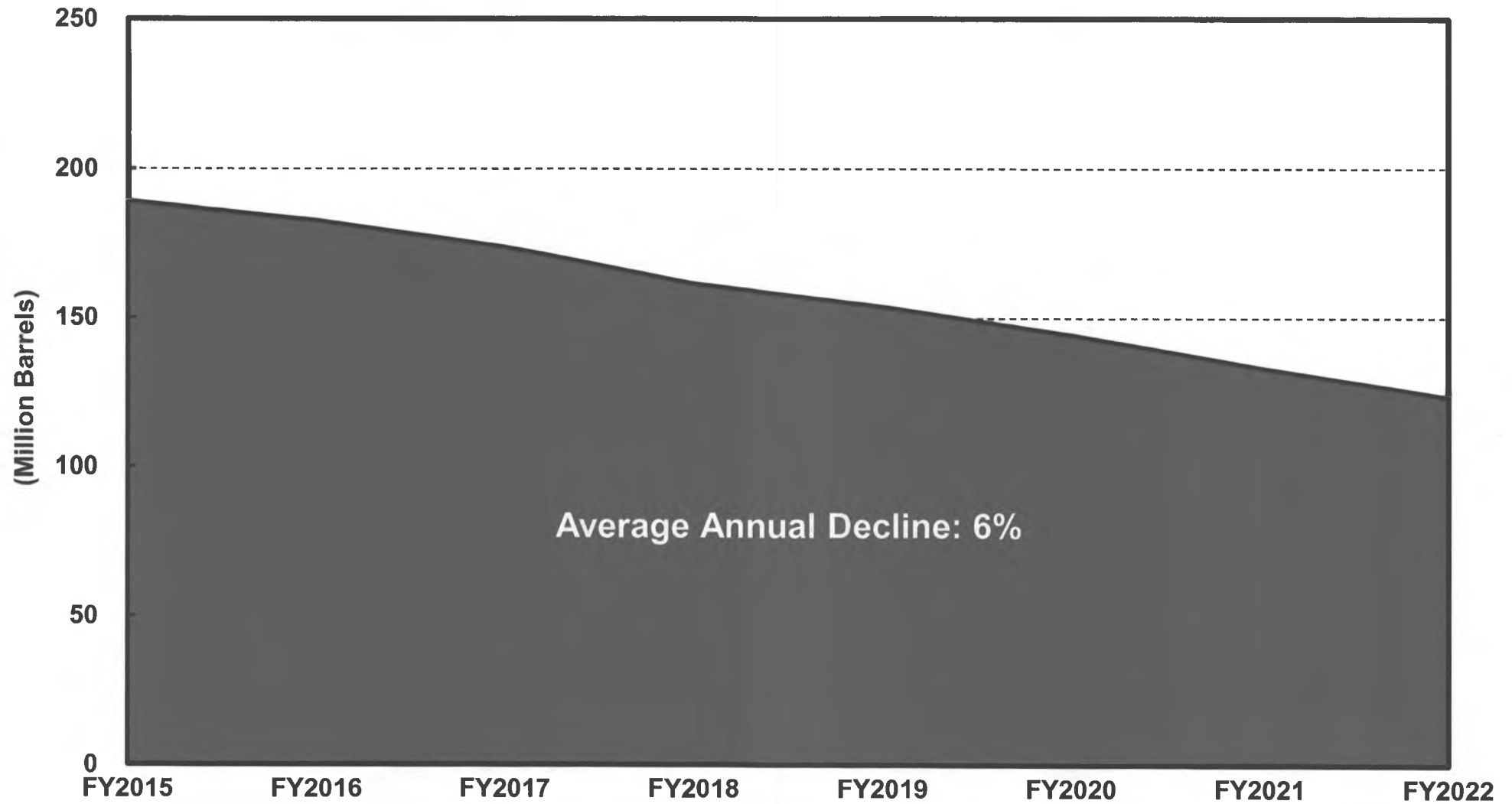
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.
Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex

The Economics of Very High Cost Oil Development

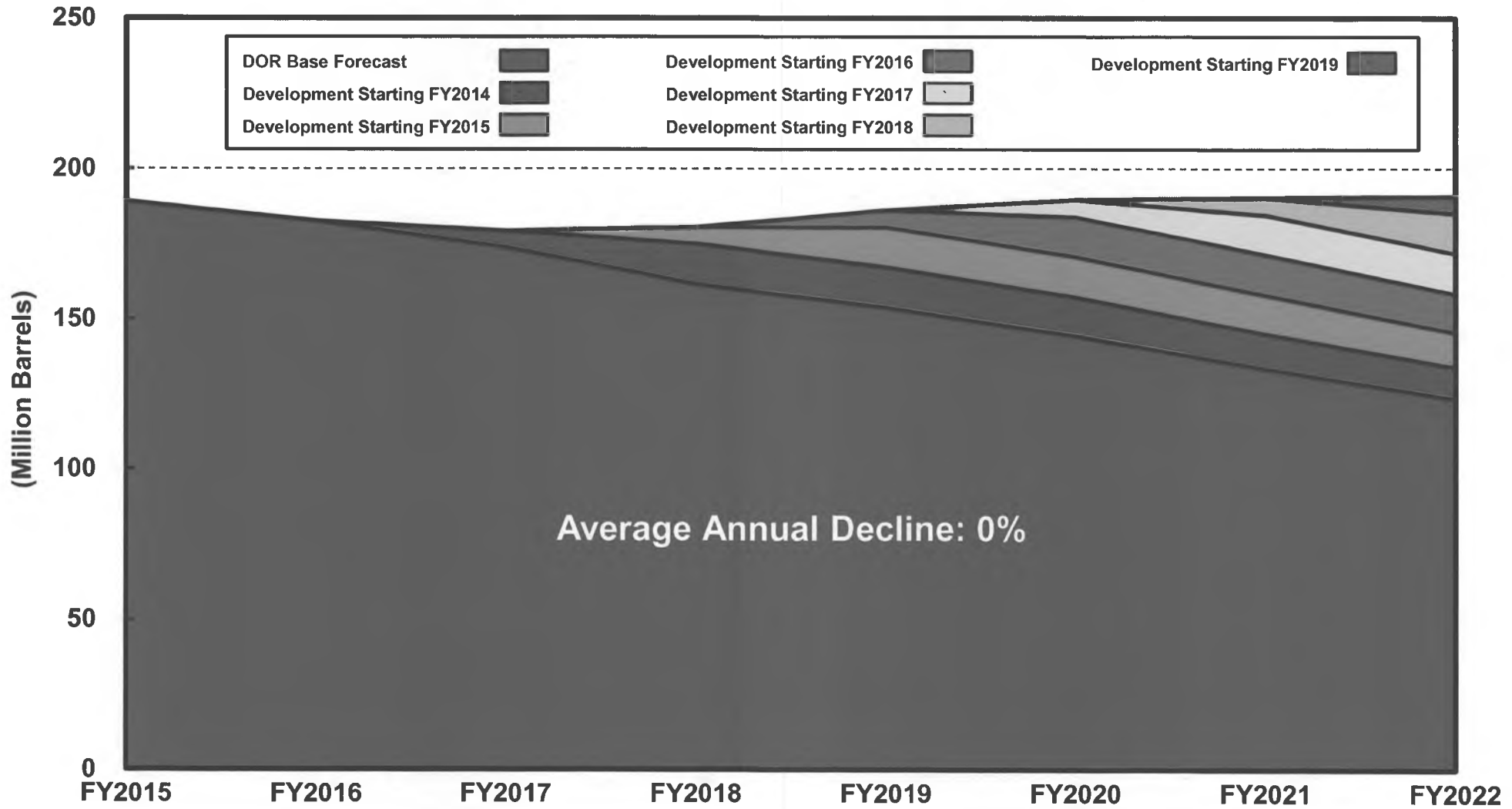


* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.
Very High Cost: \$34 Per Barrel Development Capex and \$21 Per Barrel Opex

DOR Forecast Levels of Production FY2015 - FY2022

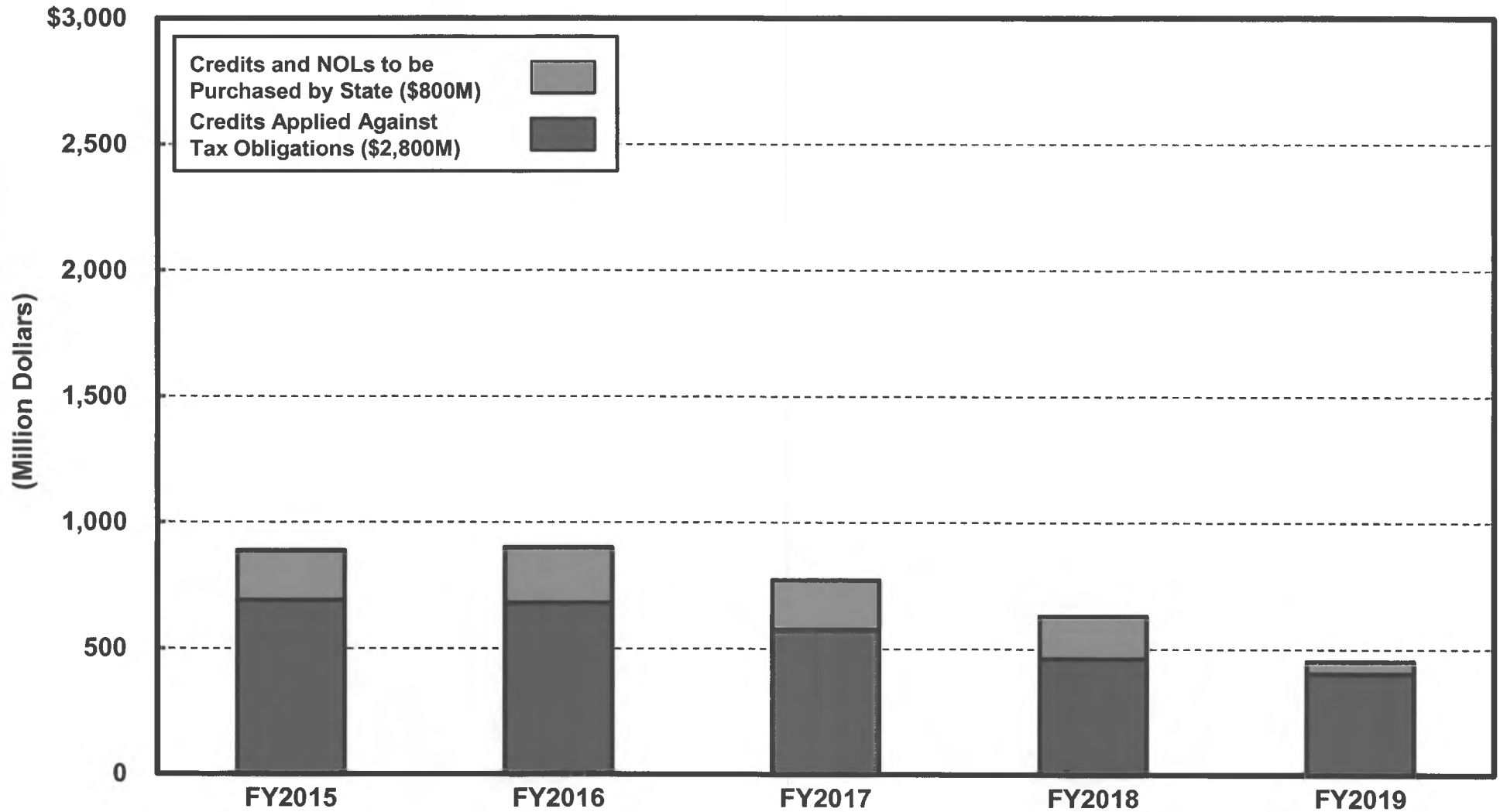


Production With Development of 150 MMB of Reserves Annually FY2015 - FY2022

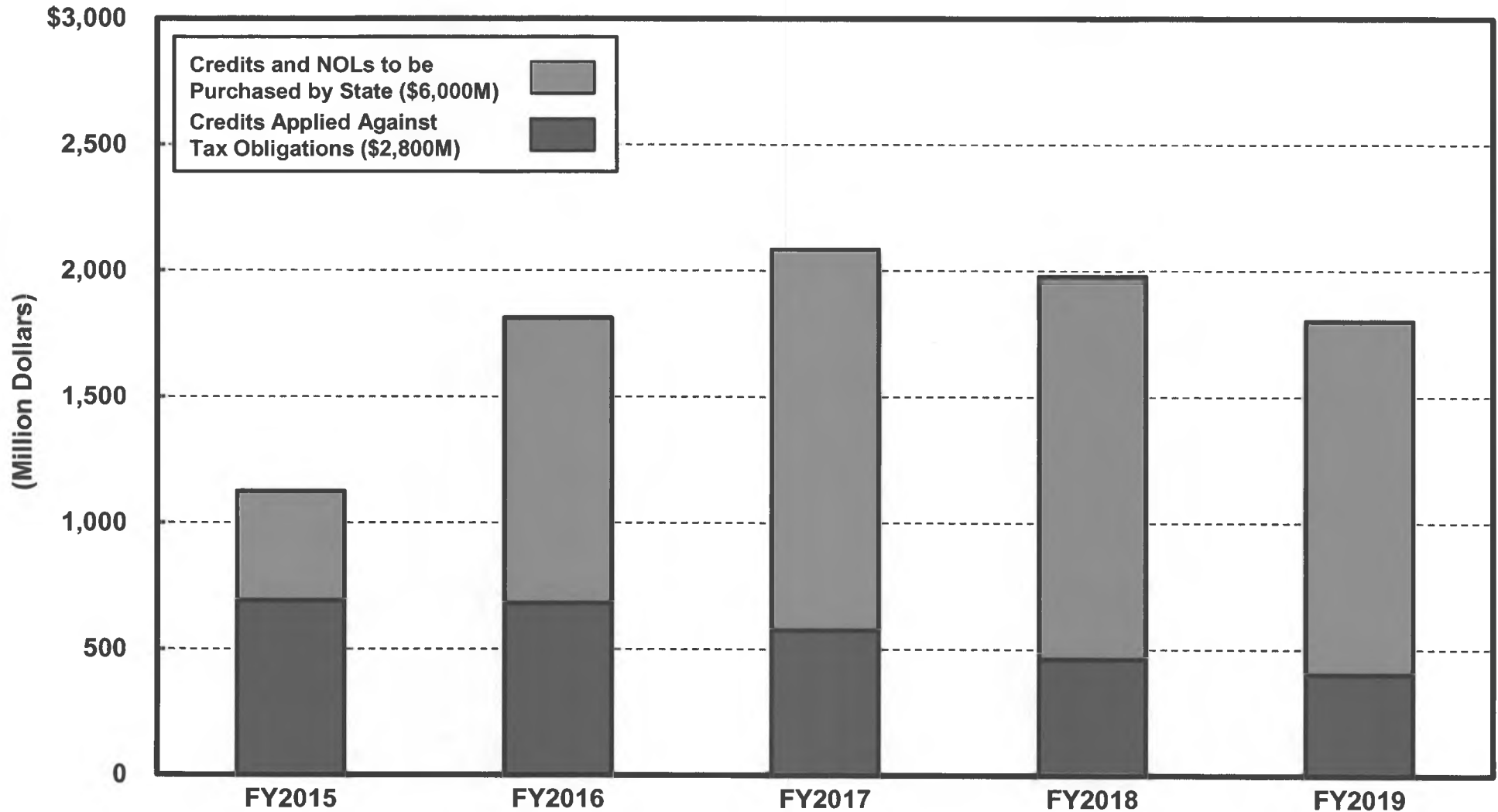


Note: Assumes 150 MMB of new production begins development each year starting in FY2014.

Forecast Levels of Capital Credits and NOLs FY2015 - FY2019

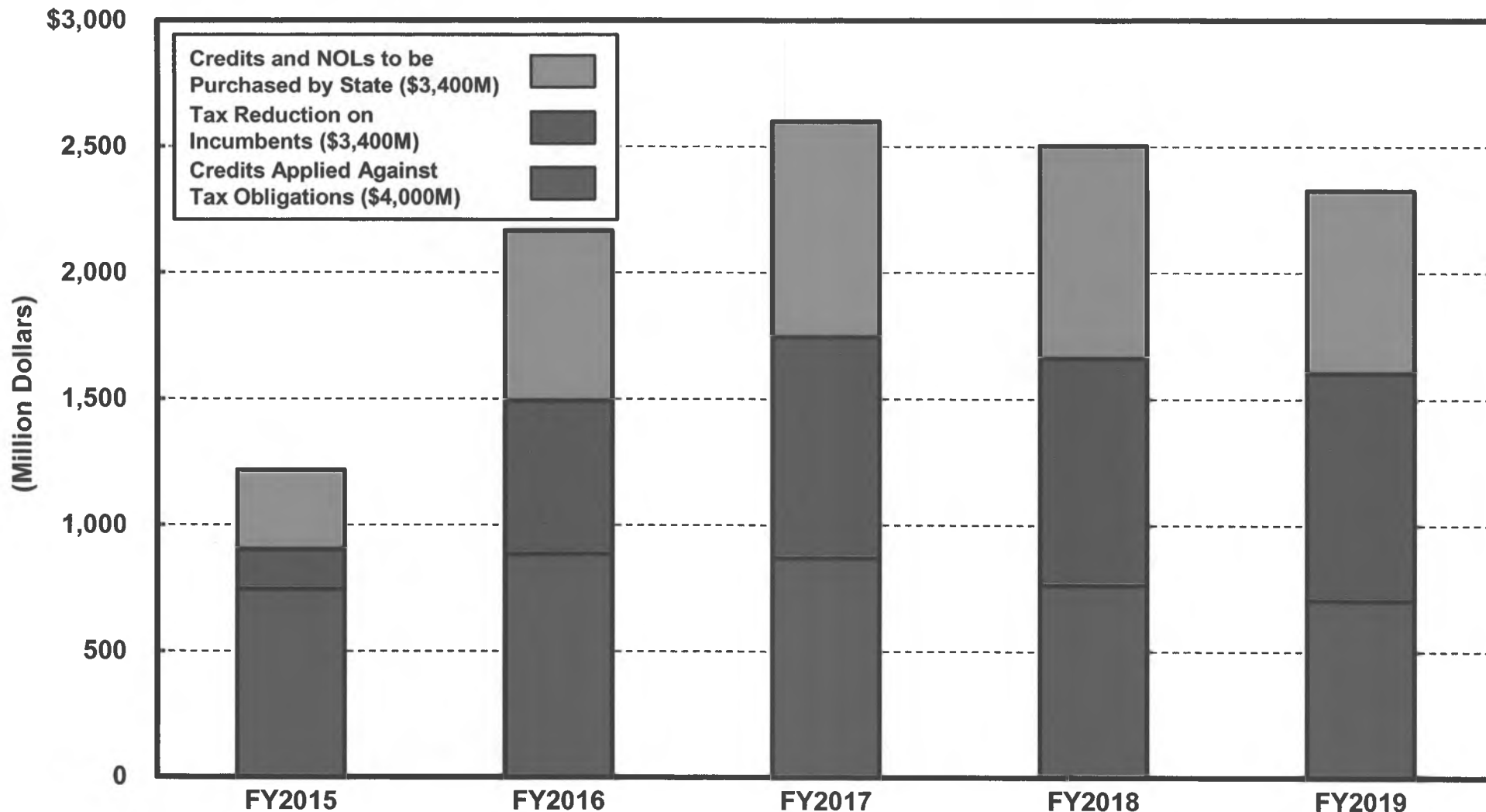


Capital Credits and NOLs Assuming Development of Additional 150 MMB of Oil Per Year Over Forecast By New Participant



Note: Assumes 150 MMB of new production begins development each year by new participants starting in FY2014.
Total exploration and development costs assumed to be \$20/bbl.

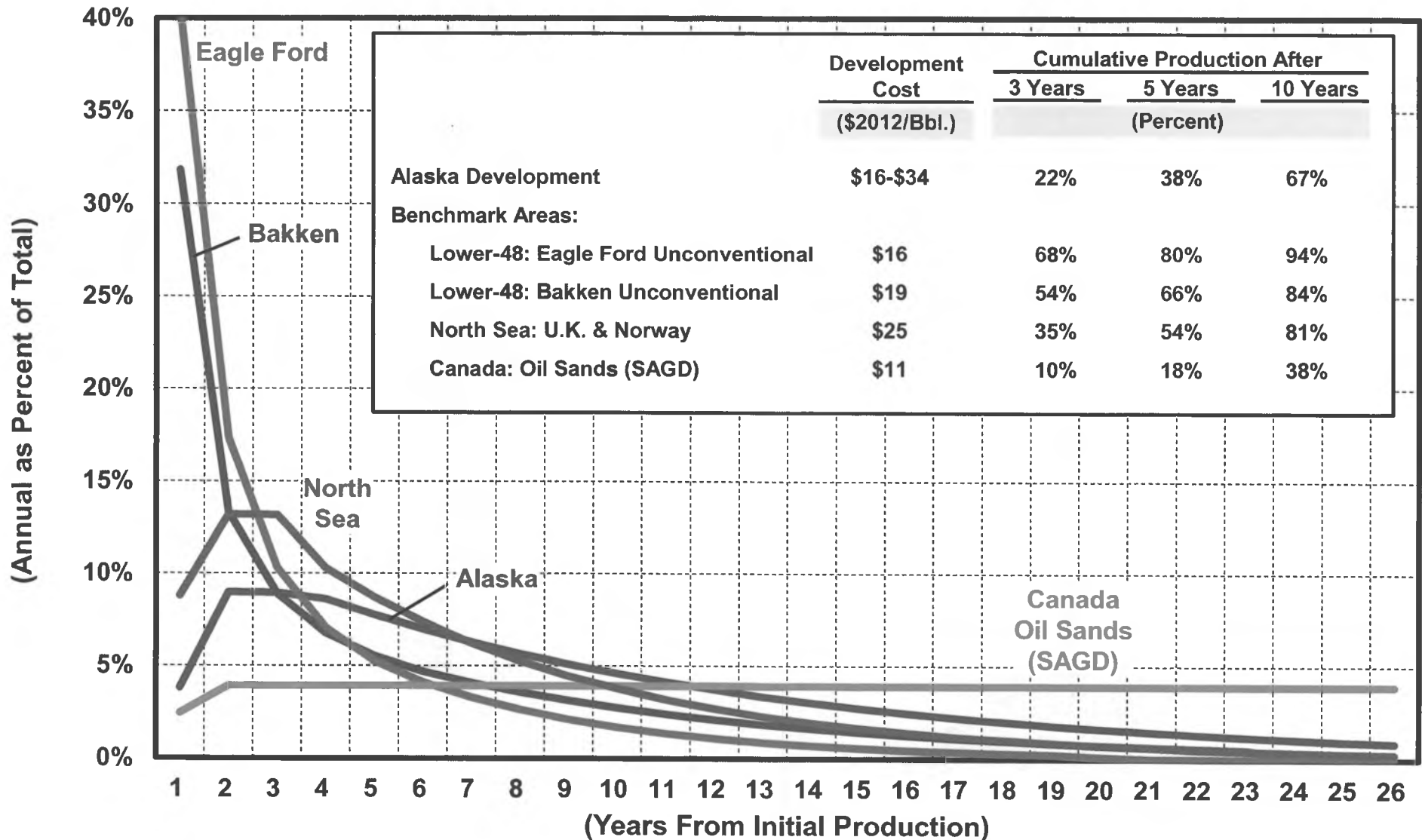
Capital Credits and NOLs Assuming Development of Additional 150 MMB of Oil Per Year Over Forecast 50% by New Participant and 50% by Incumbent



Note: Assumes 150 MMB of new production begins development each year by (50% new participants, 50% incumbents) starting in FY2014.
 Total exploration and development costs assumed to be \$20/bbl.
 For the incumbent, 20% credit and 60% of capital is shielded in the form of reduced taxes on existing production.

Analysis of Potential Investments In Alaska Under ACES Versus Other Areas

Summary of Production Profiles Examined For Alaska and Benchmark Developments



Summary of Investment Measures (New Participant)

Real \$2012 West Coast ANS Price	50 MMBO Alaska			Unconventional Lower-48		Canada Oil Sands	Norway	United Kingdom	
	Lower	Higher	Very High	Eagle Ford	Bakken	SAGD		Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
	Cost	Cost	Cost	(4)	(5)	(6)		(8)	(9)
	(1)	(2)	(3)				(7)		
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	\$2.55	(\$0.35)	(\$4.00)	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$3.85	\$0.97	(\$2.33)	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$5.48	\$2.58	(\$0.91)	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	1.19	0.98	0.86	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.29	1.05	0.92	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.41	1.12	0.97	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	19.7%	11.3%	5.3%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	23.4%	14.0%	8.2%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	27.6%	17.1%	10.6%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$25.84	\$28.03	\$28.73	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$28.84	\$31.03	\$32.48	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$33.13	\$35.32	\$36.02	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	70.8%	71.6%	72.4%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	75.8%	76.9%	77.2%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	77.2%	78.1%	79.5%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	\$6.67	\$3.24	(\$1.66)	-	-	-	-	-	-
\$100	\$13.32	\$9.86	\$4.42	-	-	-	-	-	-
\$120	\$19.46	\$16.02	\$10.88	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex; Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex; Very High Cost: \$34 Per Barrel Development Capex and \$21 Per Barrel Opex

Summary of Investment Measures (Incumbent Participant)

Real \$2012 West Coast ANS Price	50 MMBO Alaska			Unconventional Lower-48		Canada Oil Sands SAGD	Norway	United Kingdom	
	Lower Cost (1)	Higher Cost (2)	Very High Cost (3)	Eagle Ford (4)	Bakken (5)	(6)	(7)	Pre-1993 w/ Brownfield Allowance* (8)	Post-1993 w/ Brownfield Allowance* (9)
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	\$3.71	\$1.34	(\$1.93)	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$6.14	\$4.68	\$2.58	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$8.82	\$8.10	\$6.66	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	1.28	1.06	0.93	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.46	1.23	1.09	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.67	1.39	1.24	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	26.2%	15.4%	8.1%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	41.1%	27.2%	18.5%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	65.3%	46.0%	33.8%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$24.26	\$26.45	\$26.79	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$27.22	\$29.41	\$30.52	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$31.18	\$33.37	\$33.98	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	68.9%	67.8%	63.8%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	73.0%	71.2%	66.7%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	73.8%	71.6%	68.1%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	\$4.88	\$0.64	(\$4.84)	-	-	-	-	-	-
\$100	\$9.79	\$4.15	(\$3.14)	-	-	-	-	-	-
\$120	\$14.31	\$7.53	(\$0.76)	-	-	-	-	-	-

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

* Brownfield Allowance applied to 100 MMBOE development.

Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex; Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex; Very High Cost: \$34 Per Barrel Development Capex and \$21 Per Barrel Opex

The Administration's Proposed Changes SB21 / SRES CS SB21

Key Aspects of Administration's Proposal (SB21)

- **Establishes 25% Flat Net Tax Rate; No Progressivity**
- **Eliminates Capital Credit and State Purchase of Losses**
- **Establishes 20% Gross Revenue Exclusion (GRE) to Incent Production of New Oil**
- **Losses May be Carried Forward and Applied Against Tax Obligation When Production Occurs**
- **Extends New Entrant Credits Through 2022**
- **No Change Outside of North Slope**

Key Aspects of Administration's Proposal (cont'd)

- **Provides Balance Between State and Producers**
 - **Reduction of Tax Rates at High Prices, Balanced with Elimination of Credits**
 - **State Continues to Receive Largest Percentage of Oil Production Revenues at Any Price**
- **Simplifies Tax System and Provides Clarity for Planning**
 - **Eliminates Question of Marginal Tax Rate / Take for Investment Planning**
 - **Eliminates Incentives for "Gold Plating" Caused by High Marginal Rates**
- **Maintains Alignment Between State and Producer Incentives**
 - **Net Tax Allows for Deduction of Costs Against Tax**
- **Provides Incentive for Development of New Resources Without Taxing State Treasury**
 - **GRE Provides Lower Effective Tax Rate for New Development**
 - **New Developers can Recover Costs of Development Once Production Begins**
 - **Does Not Require State to Fund Development Costs Through Potentially Expensive Credit Purchases**
- **Extremely Positive Message to Potential Investors**
 - **Will Encourage Broader Participation in Development of Alaska's North Slope**
 - **Economics of New Participants Closer to Incumbents'**

Key Changes to SB21 From Senate Resources CS

- **Base Tax Rate Increased from 25% to 35%**
- **\$5/Bbl Production Allowance (Credit)**
- **GRE Raised to 30%**
- **Allows Producers to Apply for GRE in Legacy Units for Targeted Development of New Oil**
- **Relaxes Current Restriction on Exploration Credits**

Key Attributes of Senate Resources CS SB21

- **Results in Slightly Progressive Government Take Overall Without Problems Associated with “Progressivity”**
- **Reduces Effective Tax Rate and Government Take at Low Prices, While Increasing Tax Rates and Government Take at Higher Prices**
- **Effect of Fixed \$/Bbl Allowance is to Provide Support at Low Prices Where Needed, Diminishing as Prices Rise**
- **Provides System in Competitive Range for Taxpayers/Investors**
- **Provides Simple, Straightforward and Understandable Tax Framework**
- **Allows DOR/DNR to Address Individual Circumstances as Needed**
- **Allows for Significant Investment on North Slope Without Taxing State Treasury**

Illustration of Tax Calculation Under Senate Resources CS for SB21

Taxable Barrels (Bbls)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
West Coast Price (\$/Bbl)	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Transportation (\$/Bbl)	- 10.00	10.00	10.00	10.00	10.00	10.00
Gross Value (\$/Bbl)	= \$50.00	\$70.00	\$90.00	\$110.00	\$130.00	\$150.00
Lease Expenditures (\$/Bbl)	- 30.00	30.00	30.00	30.00	30.00	30.00
Per-Barrel Taxable Value (\$/Bbl)	= \$20.00	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00
Total Production Tax Value (\$)	\$1,000,000,000	\$2,000,000,000	\$3,000,000,000	\$4,000,000,000	\$5,000,000,000	\$6,000,000,000
Production Tax Before Allowance @ 35%	\$350,000,000	\$700,000,000	\$1,050,000,000	\$1,400,000,000	\$1,750,000,000	\$2,100,000,000
Production Allowance @ \$5/Bbl	- 250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000
Production Tax After Allowance	= \$100,000,000	\$450,000,000	\$800,000,000	\$1,150,000,000	\$1,500,000,000	\$1,850,000,000
Nominal Tax Rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Reduction in Tax Rate From Allowance	25.0%	12.5%	8.3%	6.3%	5.0%	4.2%
Effective Tax Rate After Allowance	10.0%	22.5%	26.7%	28.8%	30.0%	30.8%
Allowance as % of Gross Value	10.0%	7.1%	5.6%	4.5%	3.8%	3.3%

State Outlays Prior to Production Associated With Development of 50 MMBO by Non-Taxpayer Under ACES and SRES CS SB21



	<u>Lower Cost Field</u>	<u>Higher Cost Field</u>
Costs (\$M)		
Exploration	\$125	\$125
Development	+ 800	+ 1,250
Total	= \$925	= \$1,375
State Funding Prior to Production (\$M)		
ACES:		
QCE 20%	\$185	\$275
Purchased Losses 25%	+ 231	+ 344
Total	= \$416	= \$619
% of Costs	45%	45%
SRES CS SB21		
Exploration Credit 30%	\$38	\$38
% of Costs	4%	3%
Savings Under SRES CS SB21 (\$M)	\$379	\$581
% of Costs	41%	42%

Note: Assumes \$2.50/bbl exploration costs and \$16/bbl and \$25/bbl development costs for lower and higher cost field, respectively.

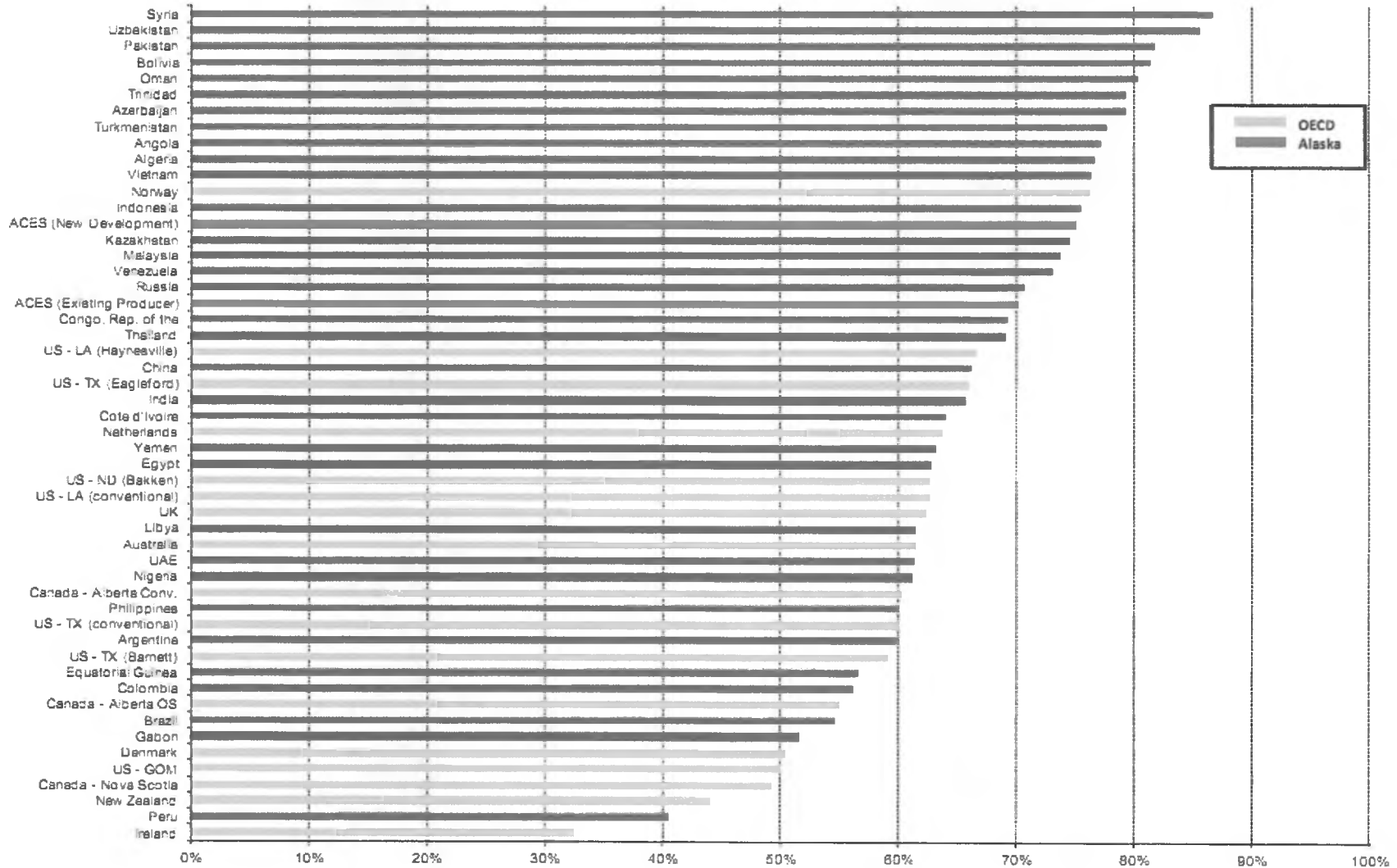
Expected Annual State Outlays Necessary to Replace Current Production by Non-Taxpayer Under ACES and SRES CS SB21



	<u>Lower Cost Field</u>	<u>Higher Cost Field</u>
Annual North Slope Production (MMBO)	150	150
Number of 50 MMBO Developments Required to Replace Annual Production	3	3
Exploration Costs (\$M)	\$375	\$375
Development Costs (\$M)	+ 2,400	+ 3,750
Total (\$M)	= \$2,775	= \$4,125
State Outlays Under ACES (\$M)	\$1,249	\$1,856
State Outlays Under SRES CS SB21 (\$M)	- 113	- 113
Savings Under SRES CS SB21 (\$M)	= \$1,136	= \$1,744

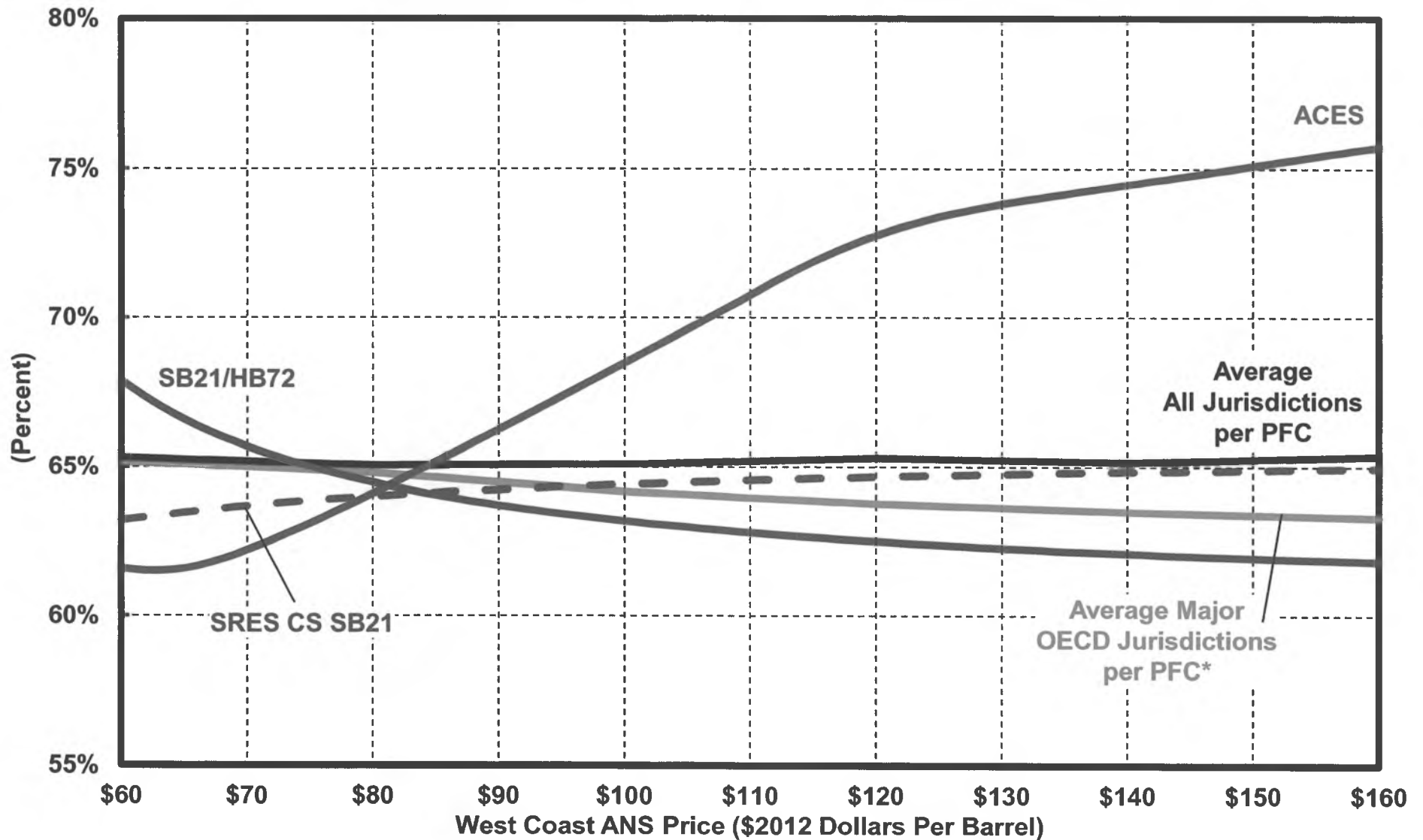
Average Government Take at \$100 Per Barrel Other Jurisdictions

Average Government Take of Global Fiscal Regimes at \$100/bbl



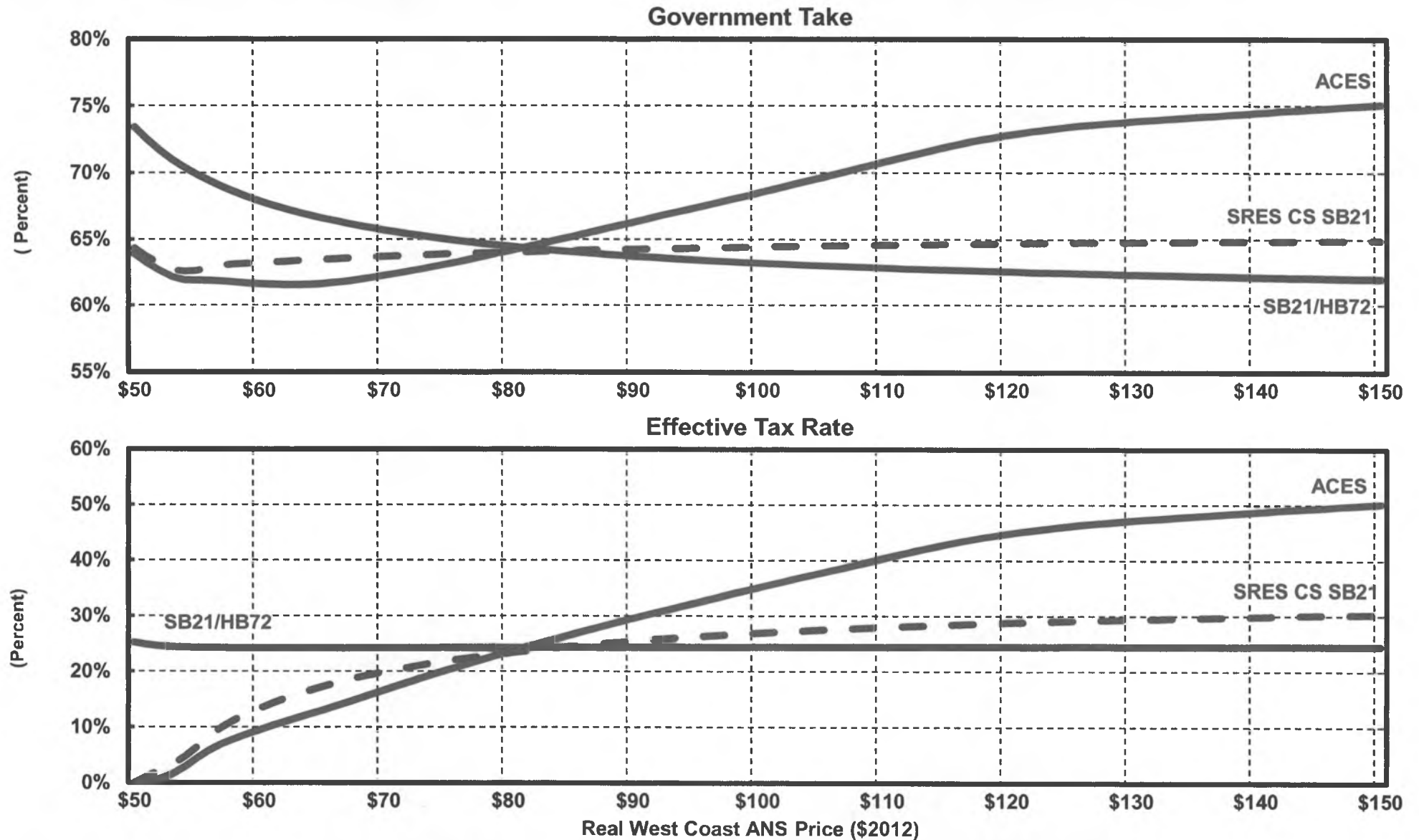
Source: PFC Energy.

Average Government Take ACES v. SB21/HB72 and SRES CS SB21 for All Existing Producers (FY2015-FY2019) and Other Jurisdictions



* Australia, Canada (Alberta Conventional), Norway, United Kingdom and United States.

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



Summary of Investment Measures for New Participant Lower Cost Alaska Oil Development ACES and SRES CS SB21 v. Benchmark Areas



Real \$2012 West Coast ANS Price	Lower Cost Alaska			Unconventional Lower-48		Canada Oil Sands	Norway	United Kingdom	
	ACES	SRES CS SB21		Eagle Ford	Bakken	SAGD		w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
		Without GRE	With GRE						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	\$2.55	\$2.25	\$2.81	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$3.85	\$5.23	\$6.95	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$5.48	\$8.15	\$10.37	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	1.19	1.17	1.21	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.29	1.39	1.52	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.41	1.61	1.78	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	19.7%	16.7%	17.5%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	23.4%	22.7%	24.9%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	27.6%	28.0%	31.0%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$25.84	\$36.94	\$36.94	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$28.84	\$42.79	\$48.99	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$33.13	\$49.19	\$57.96	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	70.8%	64.9%	59.4%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	75.8%	65.9%	58.0%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	77.2%	66.3%	59.3%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	\$6.67	\$7.13	\$6.27	-	-	-	-	-	-
\$100	\$13.32	\$11.19	\$8.55	-	-	-	-	-	-
\$120	\$19.46	\$15.34	\$11.93	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex

Summary of Investment Measures for Incumbent Lower Cost Alaska Oil Development ACES and SRES CS SB21 v. Benchmark Areas



Real \$2012 West Coast ANS Price	Lower Cost Alaska			Unconventional Lower-48		Canada	Norway	United Kingdom	
	ACES	SRES CS SB21		Eagle Ford	Bakken	Oil Sands SAGD		Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
		Without GRE	With GRE						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	\$3.71	\$2.54	\$4.00	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$6.14	\$5.38	\$7.27	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$8.82	\$8.23	\$10.55	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	1.28	1.19	1.30	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.46	1.41	1.55	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.67	1.62	1.80	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	26.2%	18.9%	22.3%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	41.1%	25.6%	29.5%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	65.3%	31.8%	36.1%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$24.26	\$27.76	\$32.07	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$27.22	\$35.59	\$41.17	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$31.18	\$43.42	\$50.27	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	68.9%	67.8%	59.3%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	73.0%	67.6%	60.2%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	73.8%	67.5%	60.6%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	\$4.88	\$6.69	\$4.44	-	-	-	-	-	-
\$100	\$9.79	\$10.95	\$8.05	-	-	-	-	-	-
\$120	\$14.31	\$15.22	\$11.66	-	-	-	-	-	-

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

* Brownfield Allowance applied to 100 MMBOE development.

Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex

Summary of Investment Measures for New Participant Higher Cost Alaska Oil Development ACES and SRES CS SB21 v. Benchmark Areas



Real \$2012 West Coast ANS Price	Higher Cost Alaska			Unconventional Lower-48		Canada	Norway	United Kingdom	
	ACES	SRES CS SB21		Eagle Ford	Bakken	Oil Sands SAGD		w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
		Without GRE	With GRE						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	(\$0.35)	(\$2.32)	(\$2.11)	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$0.97	\$1.52	\$2.12	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$2.58	\$4.45	\$6.36	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	0.98	0.89	0.90	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.05	1.07	1.10	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.12	1.21	1.31	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	11.3%	8.8%	9.1%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	14.0%	14.0%	14.7%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	17.1%	17.9%	19.8%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$28.03	\$39.10	\$39.10	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$31.03	\$51.15	\$51.15	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$35.32	\$57.98	\$63.19	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	71.6%	67.4%	63.6%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	76.9%	64.9%	60.0%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	78.1%	66.2%	58.3%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	\$3.24	\$6.27	\$5.96	-	-	-	-	-	-
\$100	\$9.86	\$9.01	\$8.08	-	-	-	-	-	-
\$120	\$16.02	\$13.14	\$10.21	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex

Summary of Investment Measures for Incumbent Higher Cost Alaska Oil Development ACES and SRES CS SB21 v. Benchmark Areas



Real \$2012 West Coast ANS Price	Higher Cost Alaska			Unconventional Lower-48		Canada	Norway	United Kingdom	
	ACES	SRES CS SB21		Eagle Ford	Bakken	Oil Sands SAGD		w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
		Without GRE	With GRE						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	\$1.34	(\$0.80)	\$0.66	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$4.68	\$2.05	\$3.94	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$8.10	\$4.89	\$7.21	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	1.06	0.96	1.03	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.23	1.10	1.19	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.39	1.24	1.35	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	15.4%	10.5%	13.2%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	27.2%	15.6%	18.6%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	46.0%	20.2%	23.5%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$26.45	\$29.92	\$34.23	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$29.41	\$37.75	\$43.33	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$33.37	\$45.58	\$52.42	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	67.8%	69.4%	59.1%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	71.2%	68.5%	60.1%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	71.6%	68.1%	60.6%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	\$0.64	\$3.93	\$1.69	-	-	-	-	-	-
\$100	\$4.15	\$8.20	\$5.29	-	-	-	-	-	-
\$120	\$7.53	\$12.46	\$8.90	-	-	-	-	-	-

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

* Brownfield Allowance applied to 100 MMBOE development.

Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex

Summary of Investment Measures for New Participant Very High Cost Alaska Oil Development ACES and SRES CS SB21 v. Benchmark Areas



Real 2012 West Coast ANS Price	Very High Cost Alaska			Unconventional Lower-48		Canada Oil Sands SAGD	Norway	United Kingdom	
	ACES	SRES CS SB21		Eagle Ford	Bakken			Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
		Without GRE	With GRE						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	(\$4.00)	(\$8.72)	(\$8.53)	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	(\$2.33)	(\$4.54)	(\$4.28)	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	(\$0.91)	(\$0.37)	(\$0.04)	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	0.86	0.69	0.70	1.25	1.04	0.88	1.01	1.22	1.21
\$100	0.92	0.84	0.85	1.47	1.28	1.06	1.14	1.33	1.38
\$120	0.97	0.99	1.00	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	5.3%	2.1%	2.6%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	8.2%	7.2%	7.6%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	10.6%	11.6%	12.0%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$28.73	\$37.26	\$37.26	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$32.48	\$49.31	\$49.31	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$36.02	\$61.36	\$61.36	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	72.4%	84.4%	78.7%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	77.2%	69.8%	65.7%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	79.5%	65.1%	61.7%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	(\$1.66)	\$5.60	\$5.31	-	-	-	-	-	-
\$100	\$4.42	\$7.83	\$7.42	-	-	-	-	-	-
\$120	\$10.88	\$10.05	\$9.55	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Very High Cost: \$34 Per Barrel Development Capex and \$21 Per Barrel Opex

Summary of Investment Measures for Incumbent Very High Cost Alaska Oil Development ACES and SRES CS SB21 v. Benchmark Areas



Real \$2012 West Coast ANS Price	Very High Cost Alaska			Unconventional Lower-48		Canada Oil Sands	Norway	United Kingdom	
	ACES	SRES CS SB21		Eagle Ford	Bakken	SAGD		Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
		Without GRE	With GRE	(4)	(5)	(6)		(8)	(9)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)									
\$80	(\$1.93)	(\$5.17)	(\$3.71)	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$2.58	(\$2.32)	(\$0.43)	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$6.66	\$0.52	\$2.84	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12									
\$80	0.93	0.82	0.87	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.09	0.92	0.98	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.24	1.02	1.10	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)									
\$80	8.1%	4.1%	6.6%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	18.5%	8.7%	11.4%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	33.8%	12.7%	15.6%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
\$80	\$26.79	\$29.48	\$33.79	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$30.52	\$37.31	\$42.89	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$33.98	\$45.14	\$51.98	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)									
\$80	63.8%	76.0%	58.1%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	66.7%	71.5%	60.0%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	68.1%	70.0%	60.7%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)									
\$80	(\$4.84)	\$0.14	(\$2.10)	-	-	-	-	-	-
\$100	(\$3.14)	\$4.41	\$1.50	-	-	-	-	-	-
\$120	(\$0.76)	\$8.67	\$5.11	-	-	-	-	-	-

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

* Brownfield Allowance applied to 100 MMBOE development.

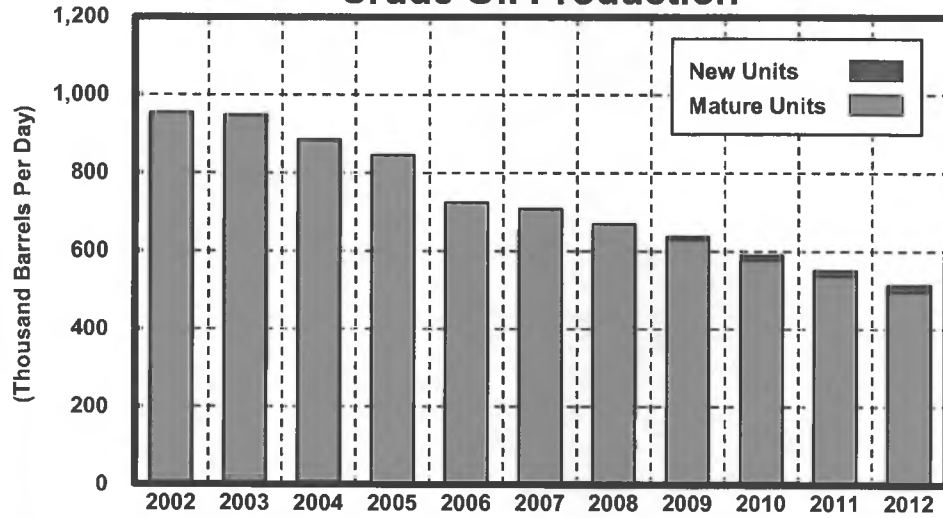
Very High Cost: \$34 Per Barrel Development Capex and \$21 Per Barrel Opex

Appendix

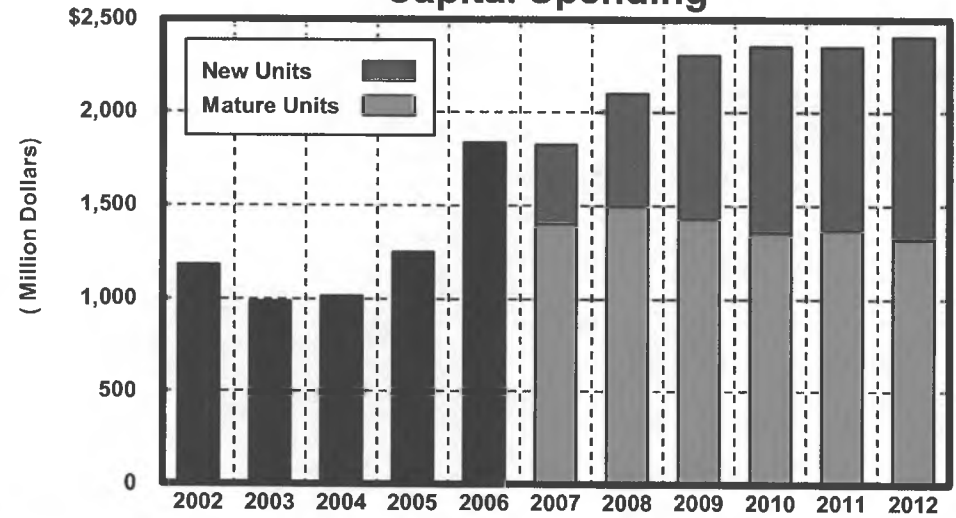
Country/Area Profile

Alaska North Slope

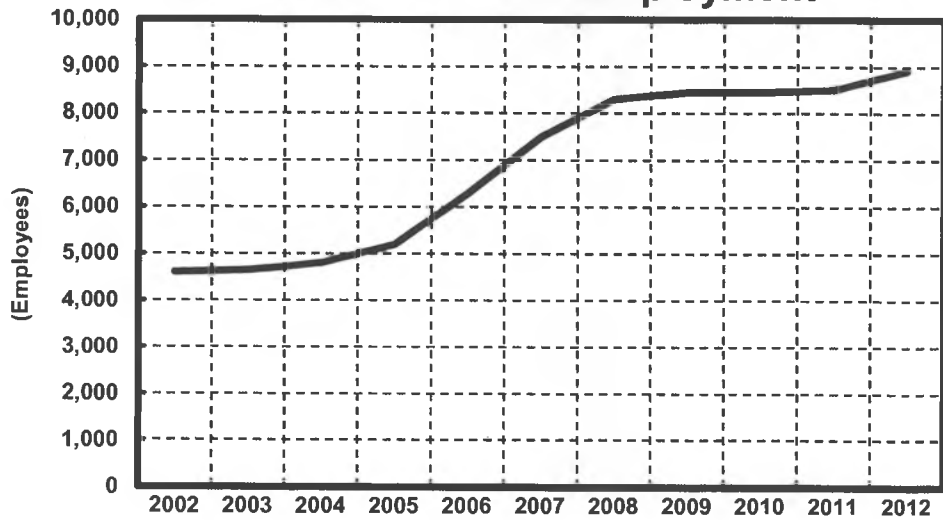
Crude Oil Production



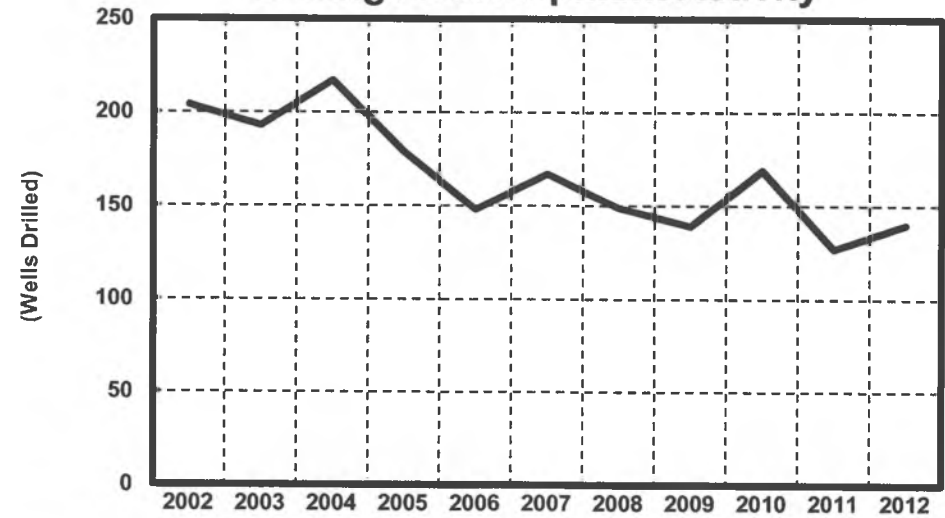
Capital Spending



Petroleum Sector Employment



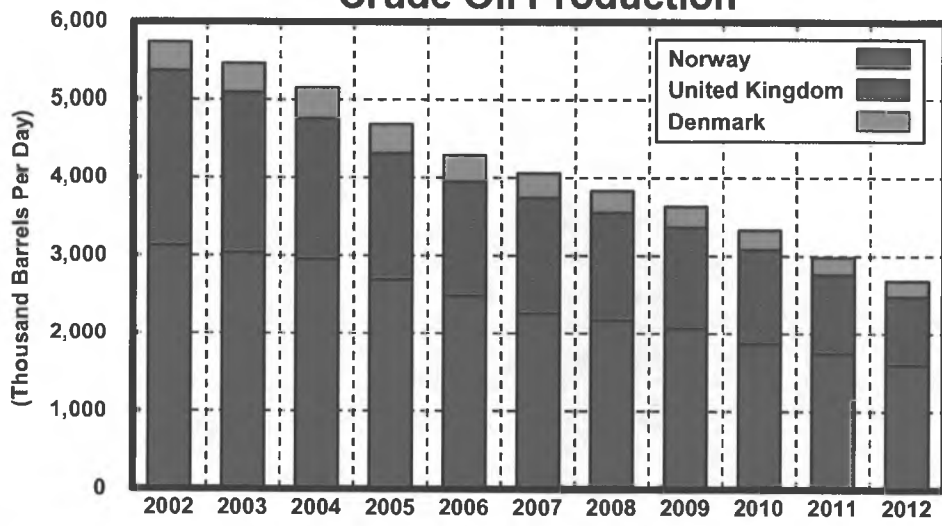
Drilling / Development Activity



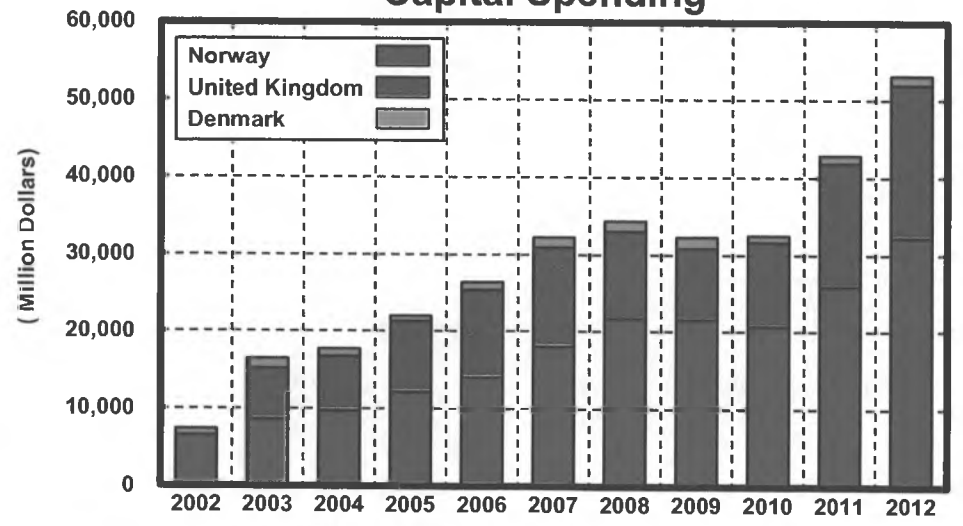
Country/Area Profile

Northwest Europe (North Sea)

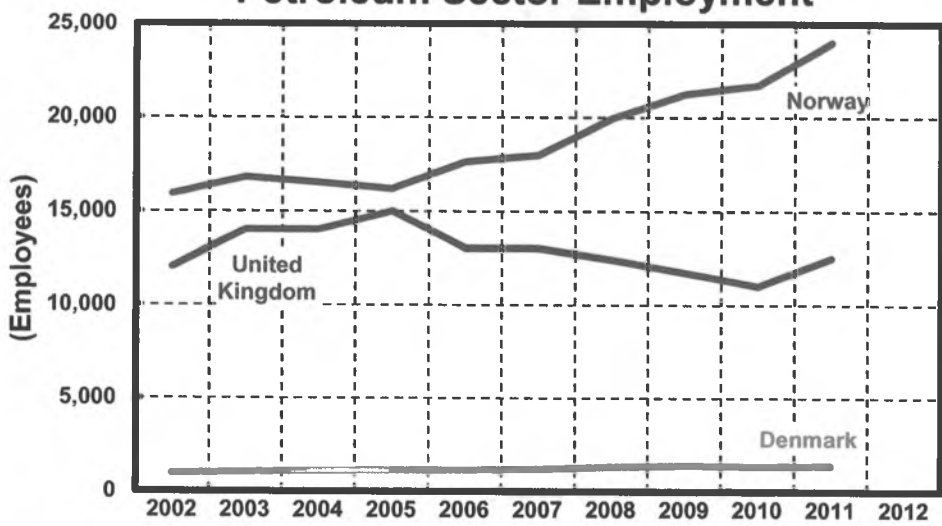
Crude Oil Production



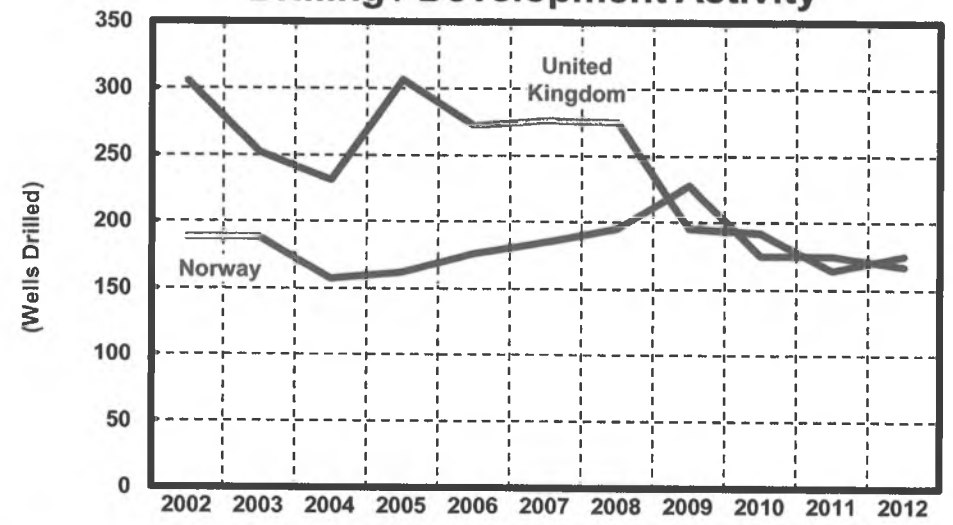
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity

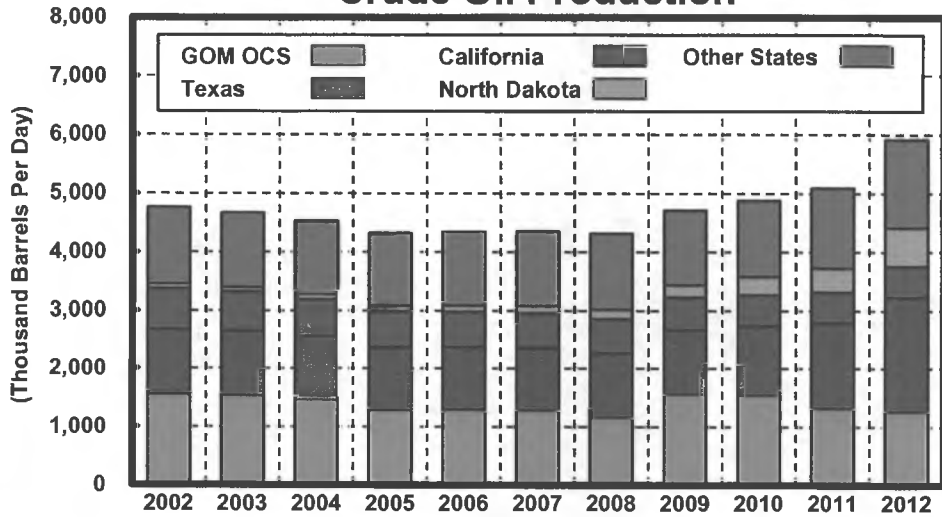


Note: 2012 figures are preliminary.

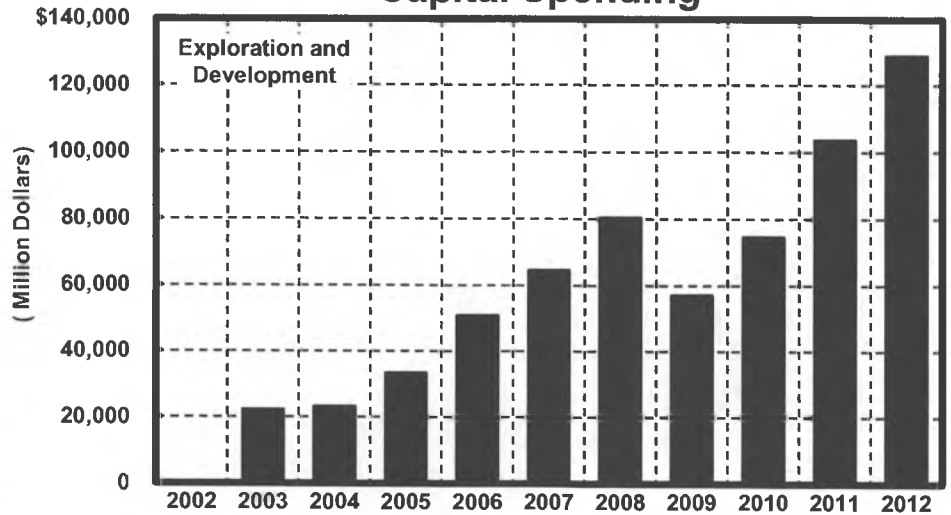
Country/Area Profile

United States Excluding Alaska North Slope

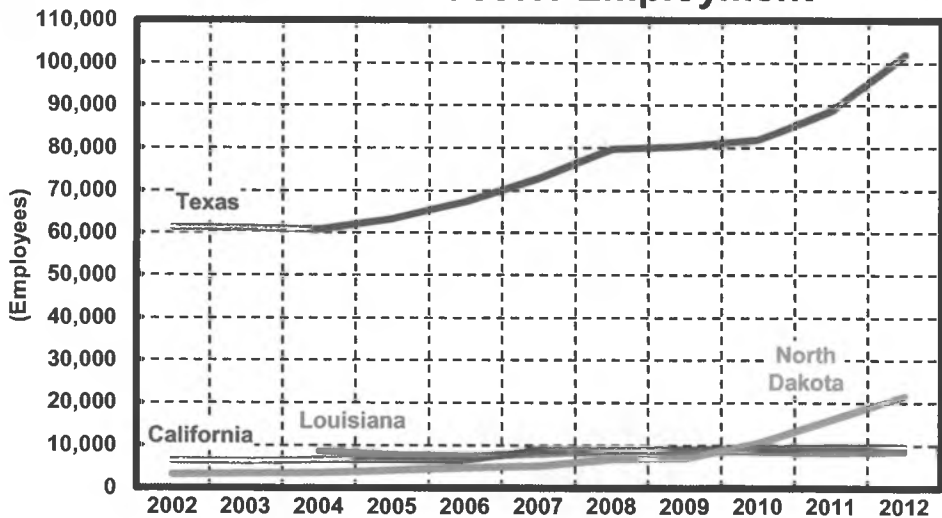
Crude Oil Production



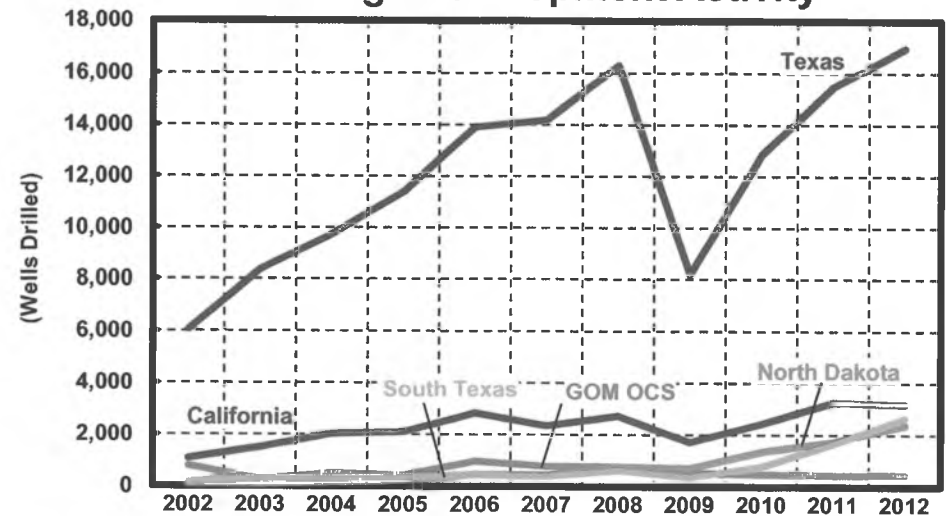
Capital Spending



Petroleum Sector Employment



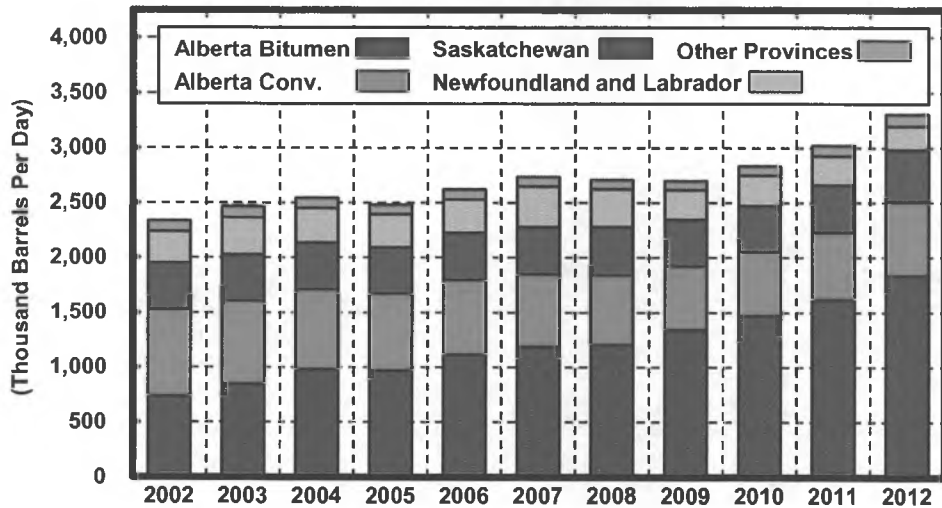
Drilling / Development Activity



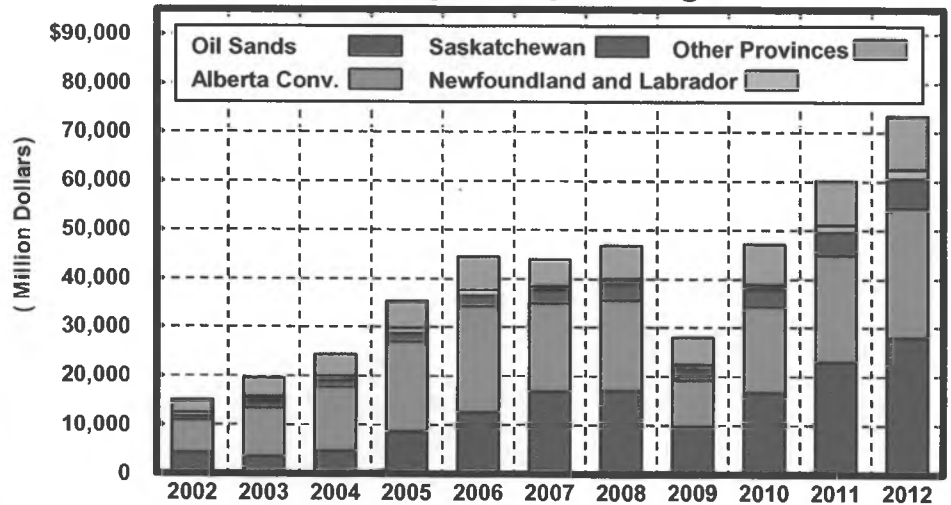
Note: 2012 figures are preliminary.

Country/Area Profile Canada

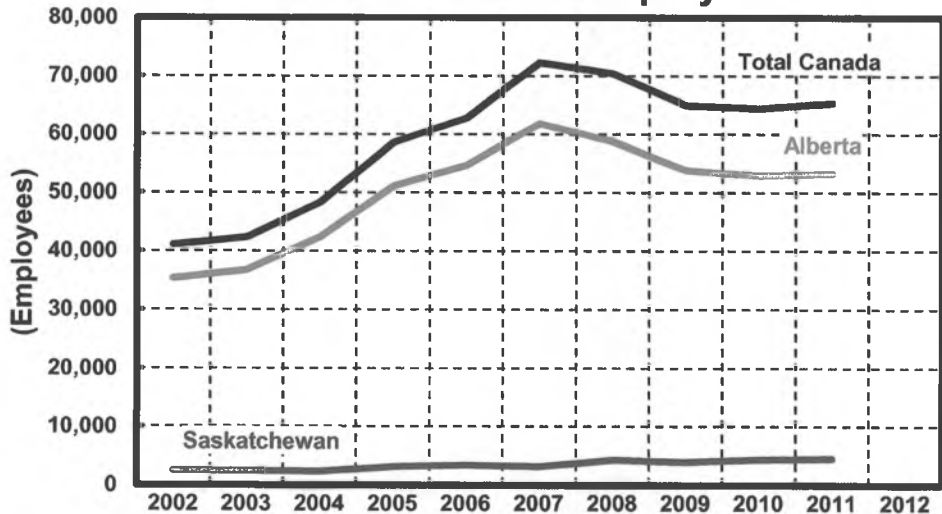
Crude Oil Production



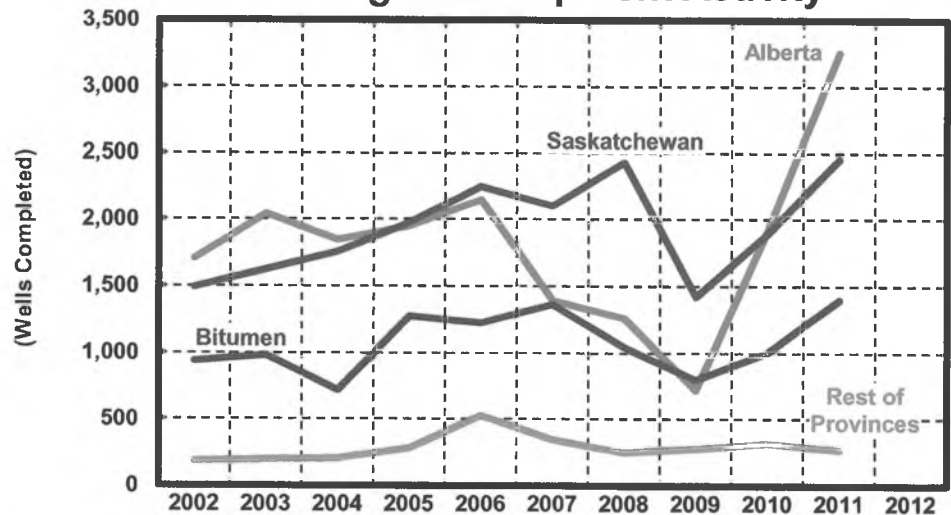
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity

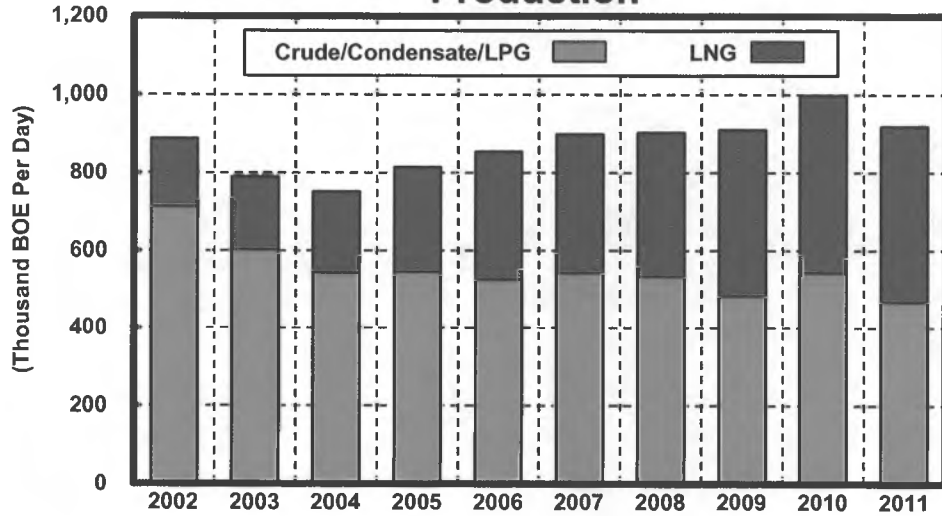


Note: 2012 figures are preliminary.

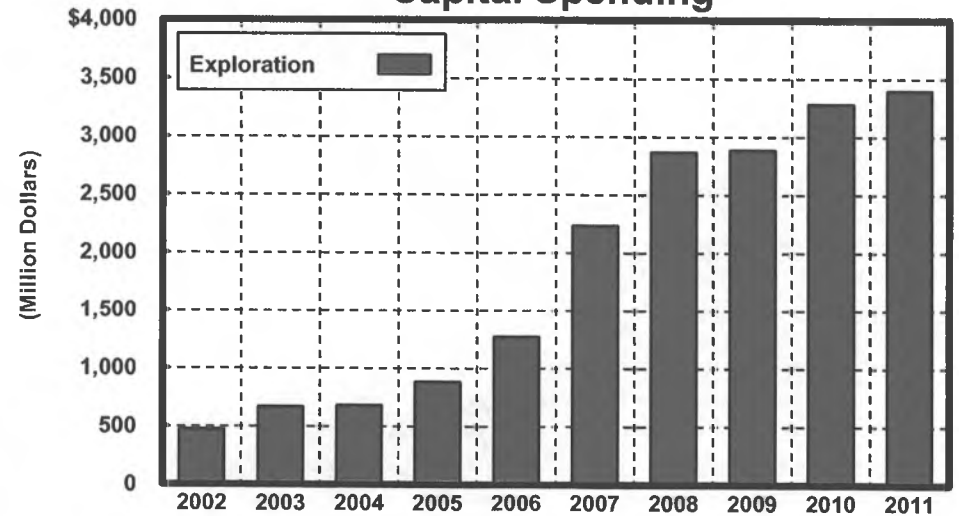
Country/Area Profile

Australia

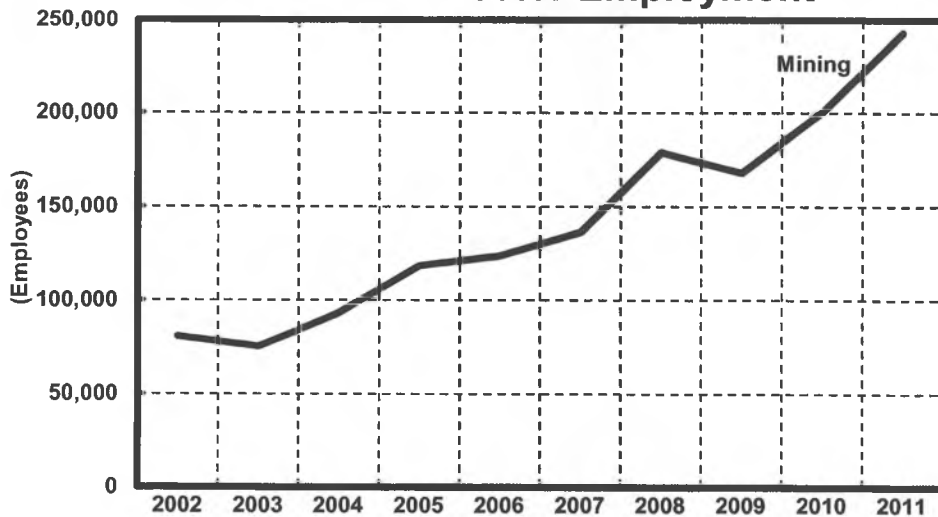
Production



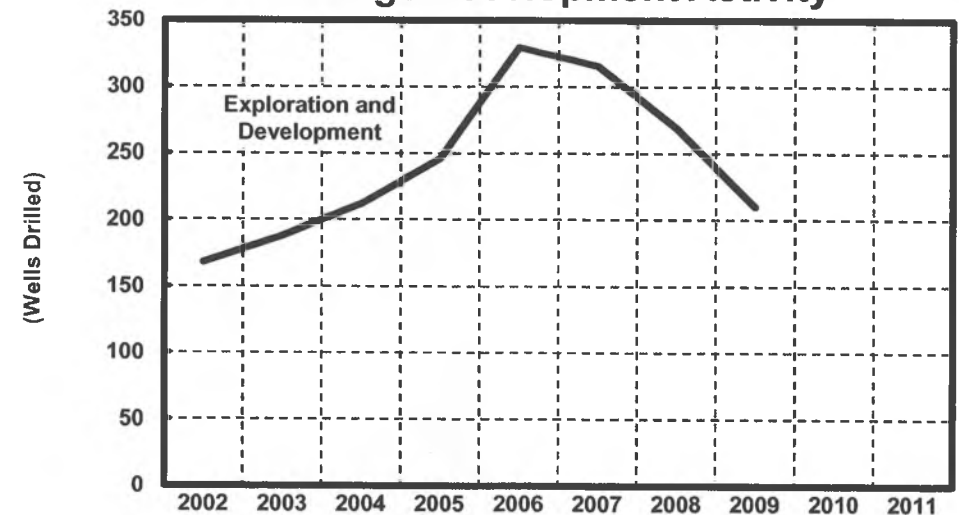
Capital Spending



Petroleum Sector Employment

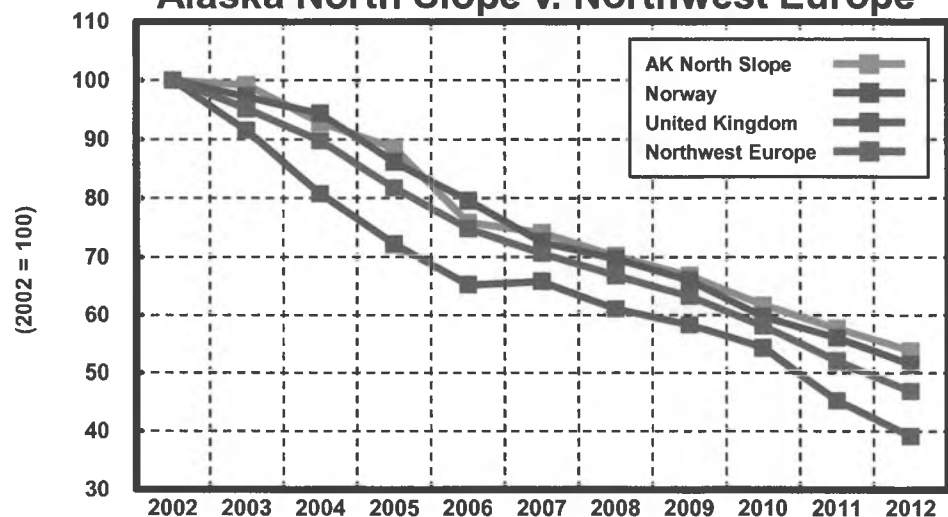


Drilling / Development Activity

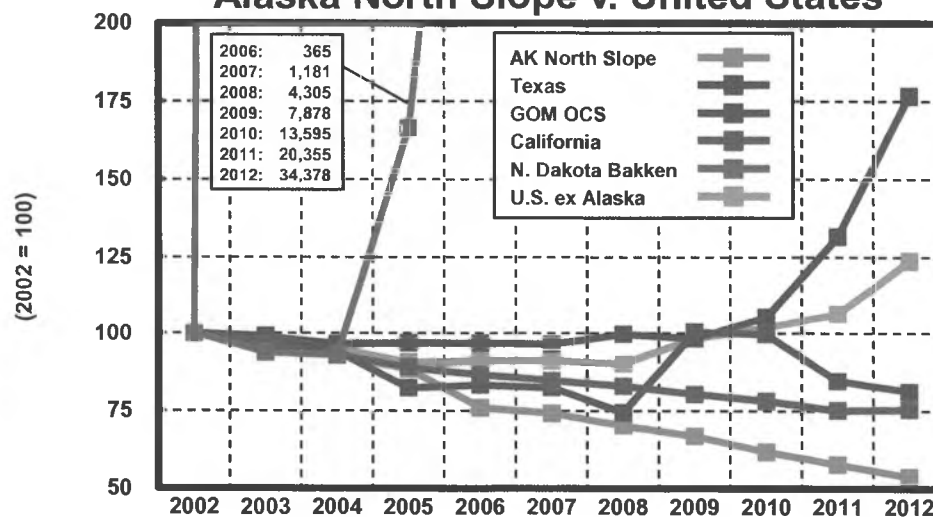


Crude Oil Production Comparisons to Alaska

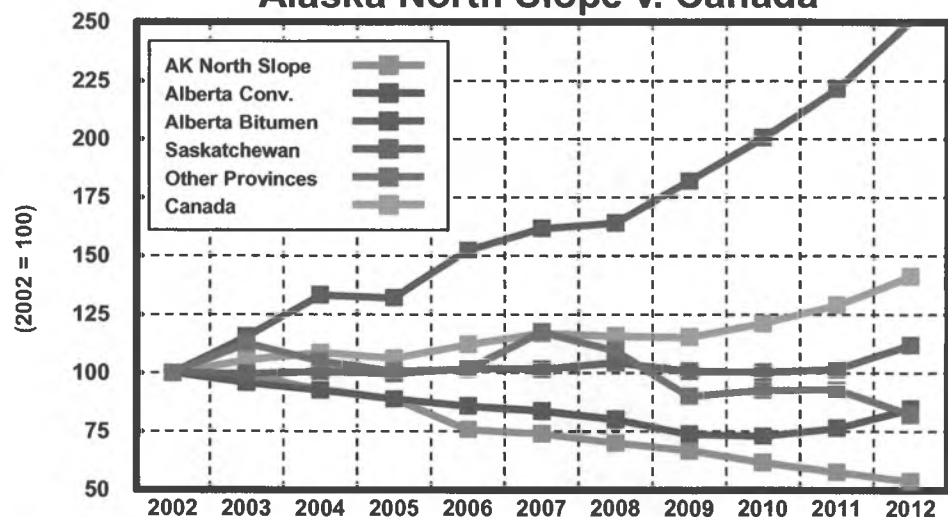
Alaska North Slope v. Northwest Europe



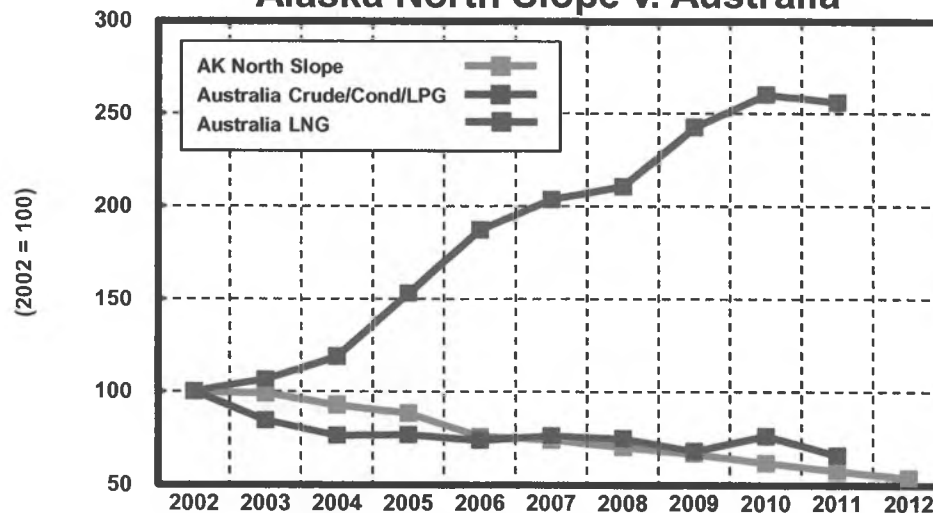
Alaska North Slope v. United States



Alaska North Slope v. Canada

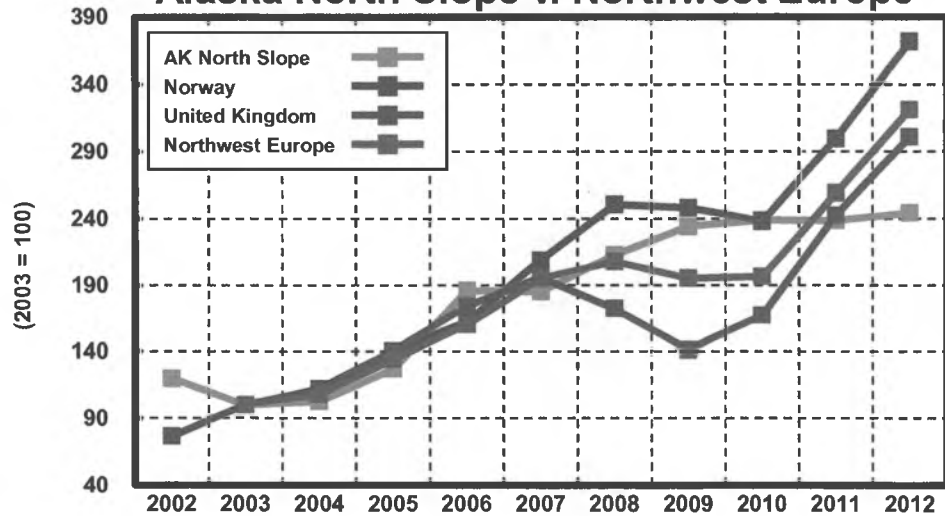


Alaska North Slope v. Australia

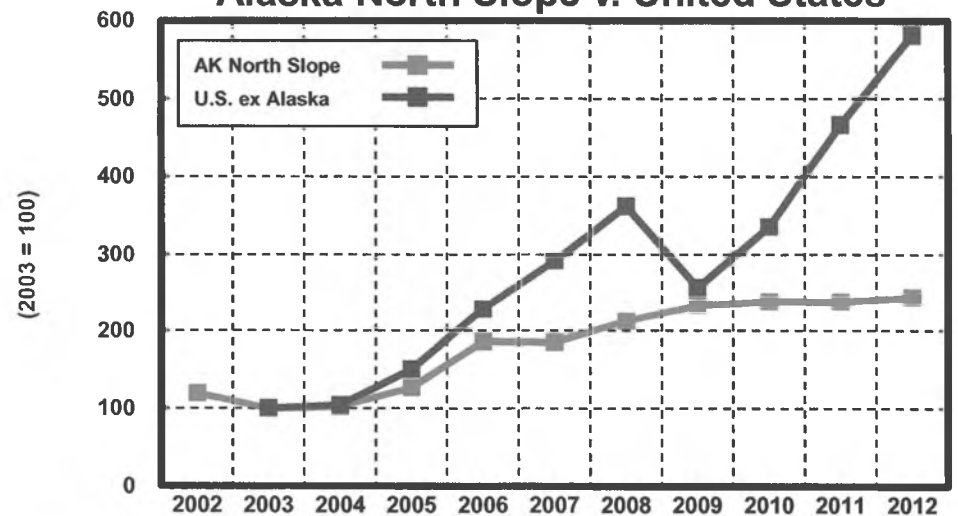


Capital Spending Comparisons to Alaska

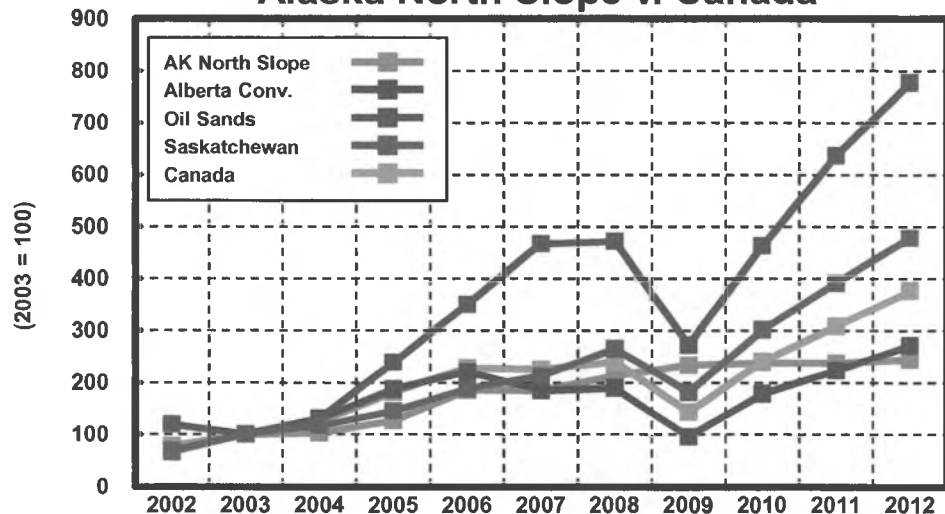
Alaska North Slope v. Northwest Europe



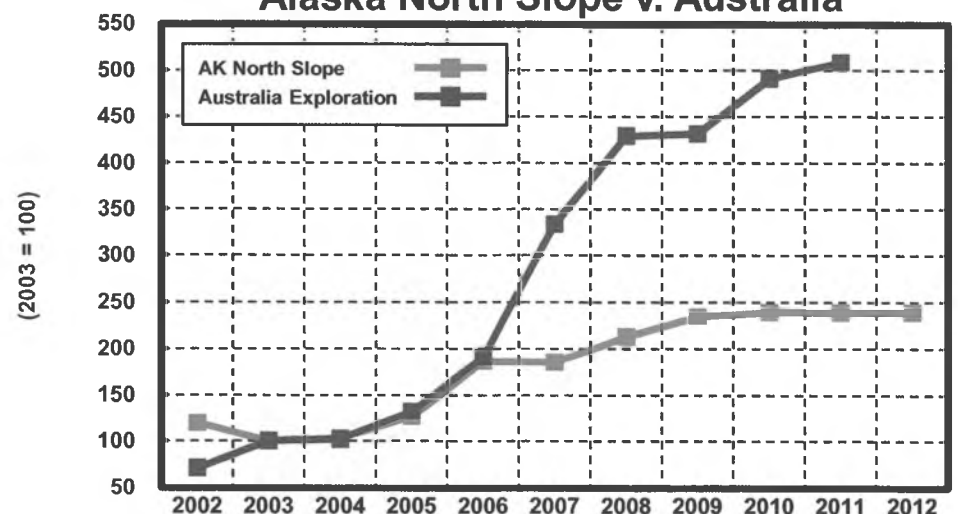
Alaska North Slope v. United States



Alaska North Slope v. Canada

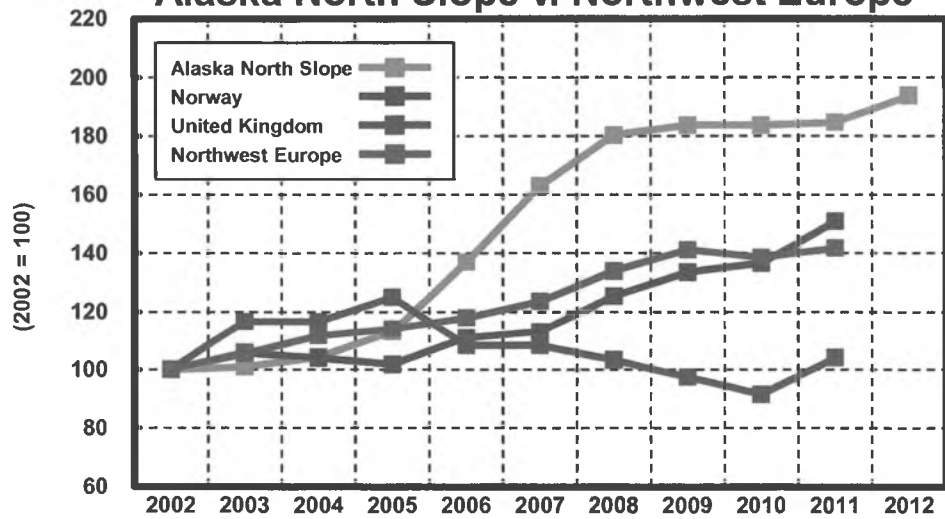


Alaska North Slope v. Australia

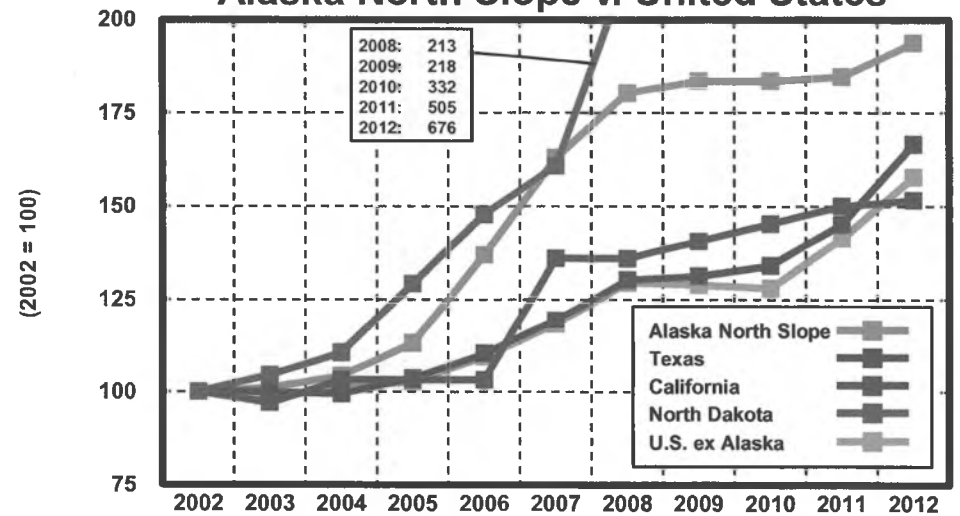


Employment Comparisons to Alaska

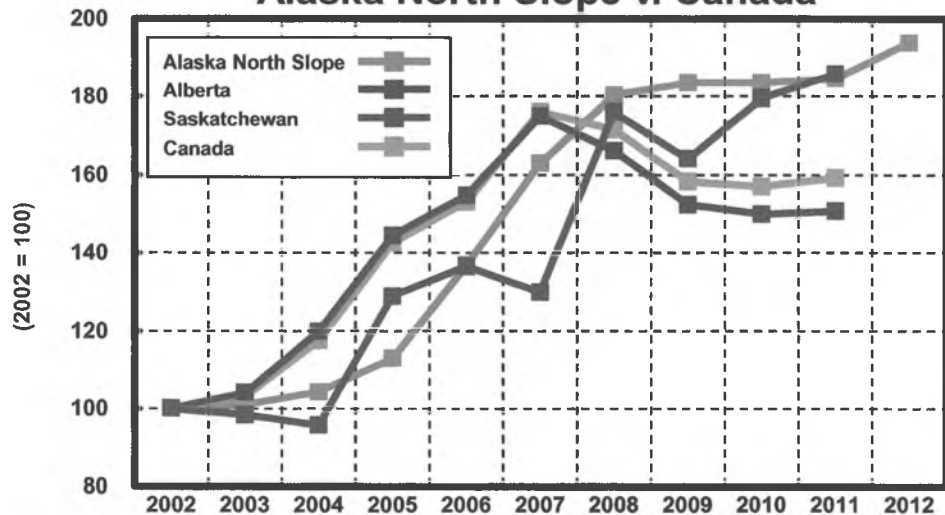
Alaska North Slope v. Northwest Europe



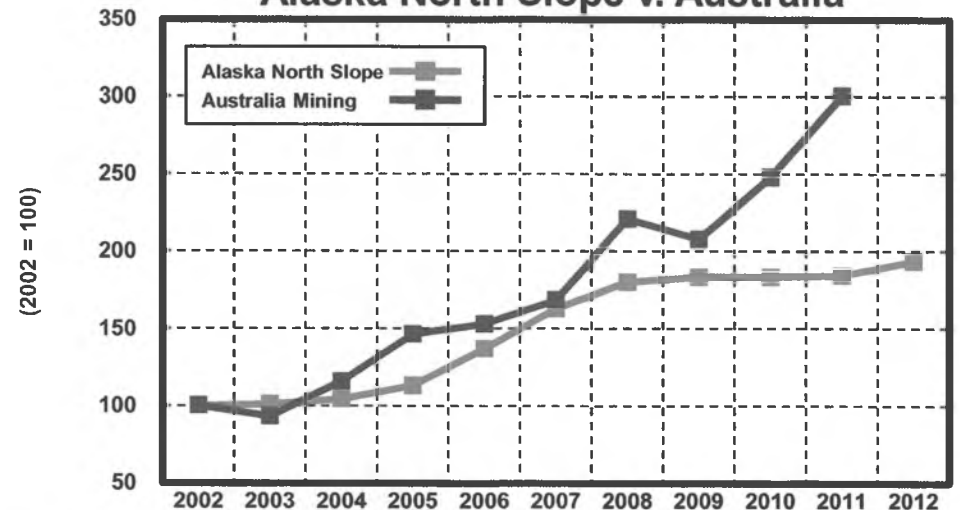
Alaska North Slope v. United States



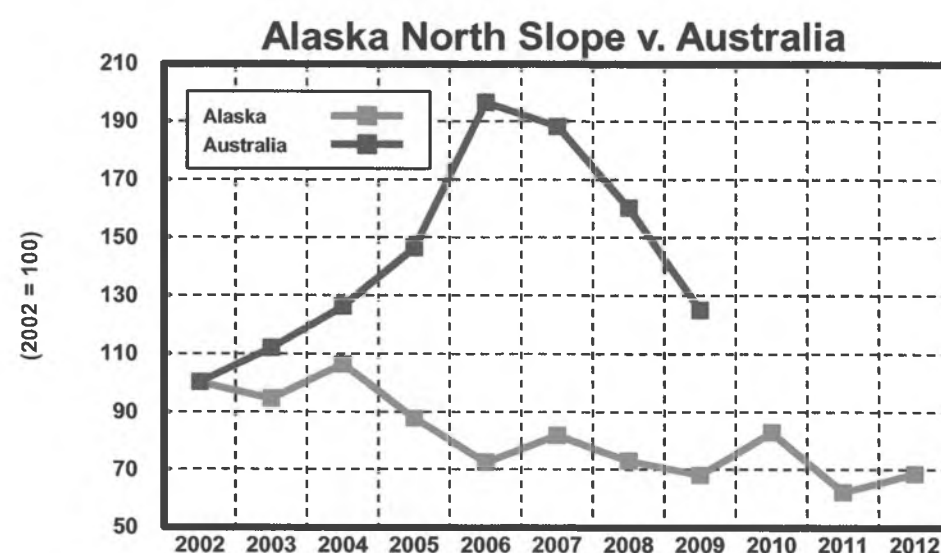
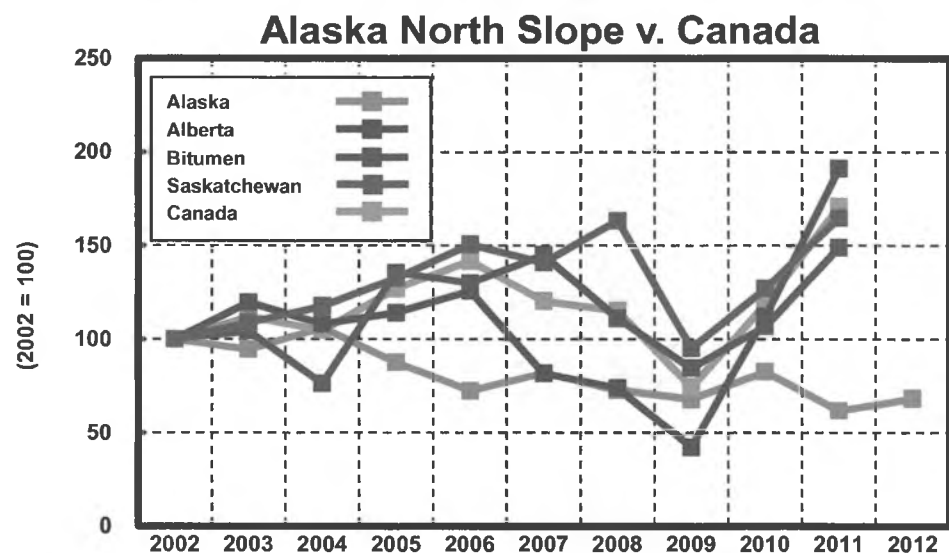
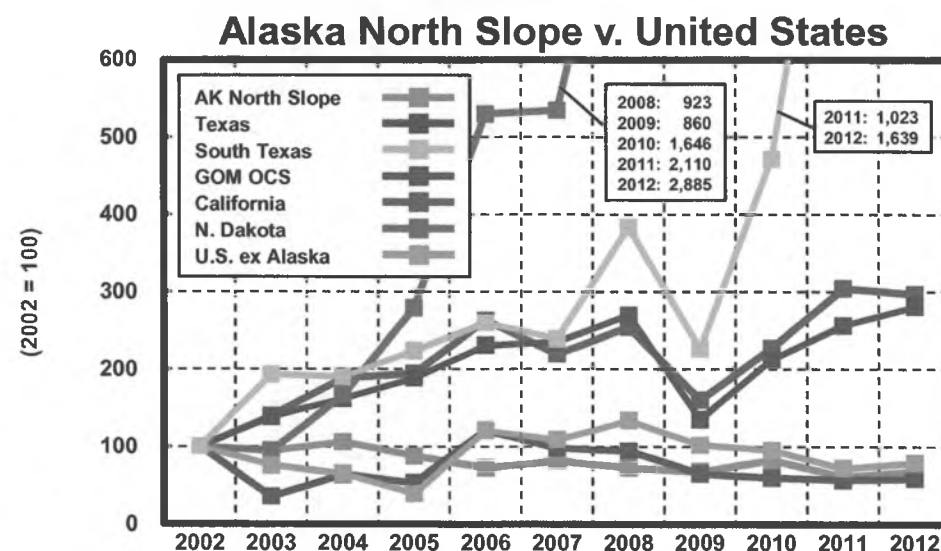
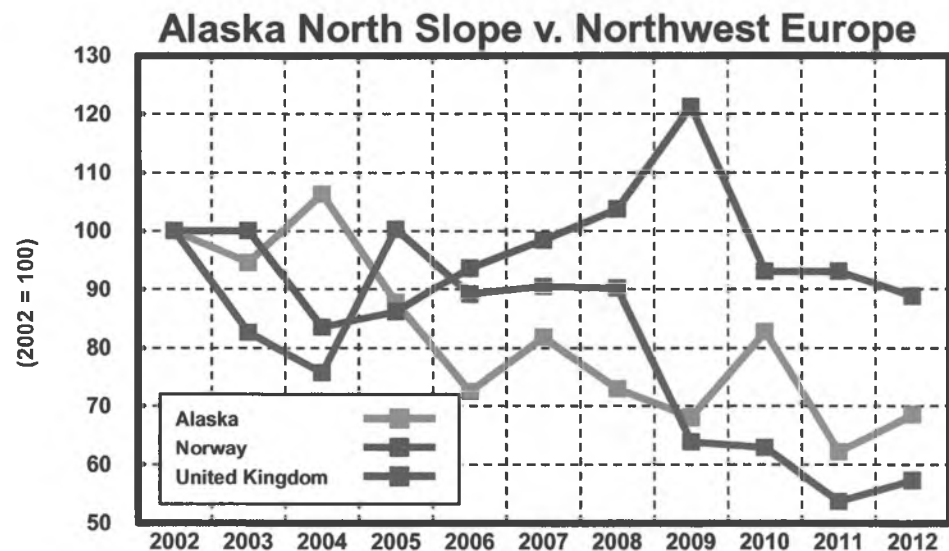
Alaska North Slope v. Canada



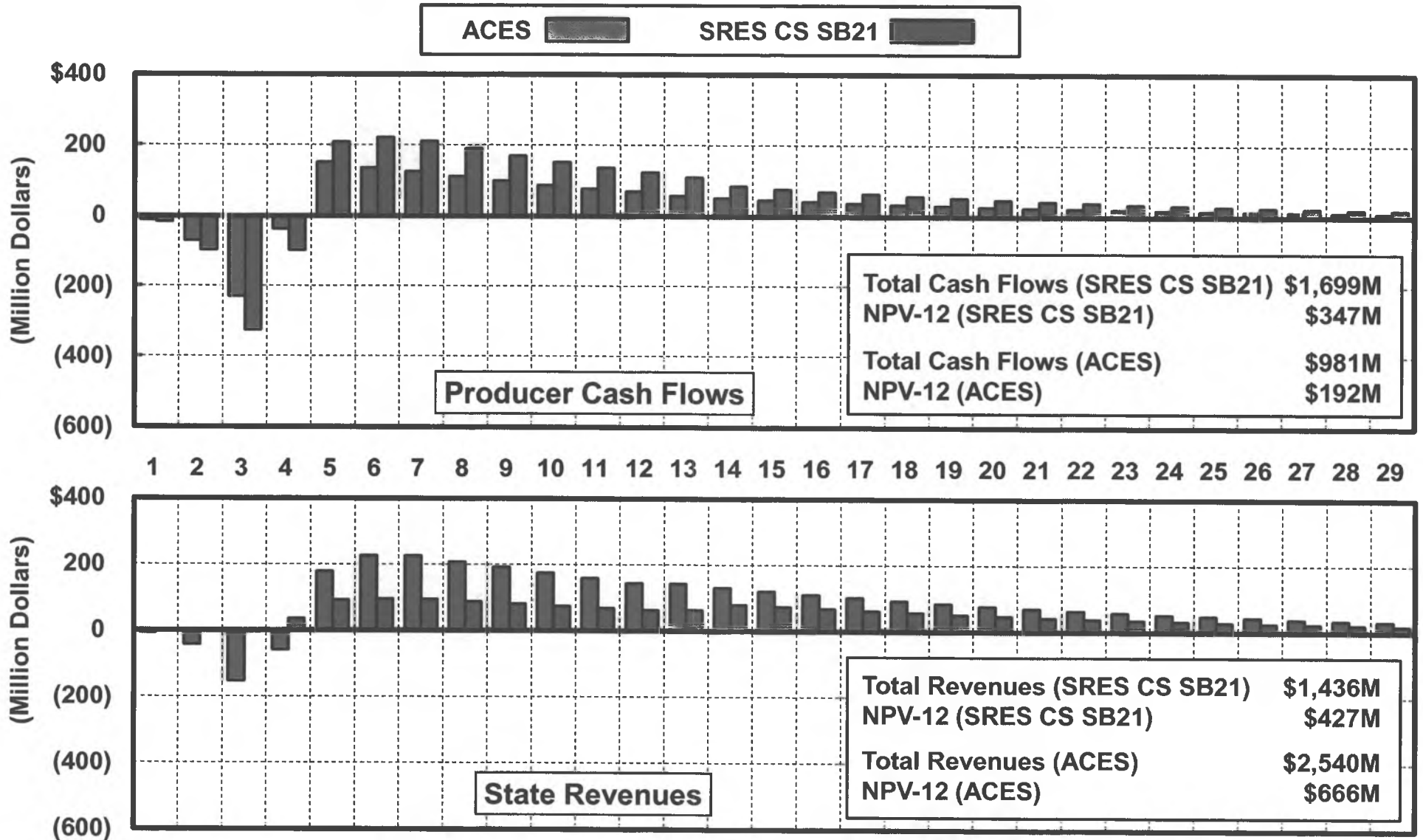
Alaska North Slope v. Australia



Drilling / Development Activity Comparisons to Alaska

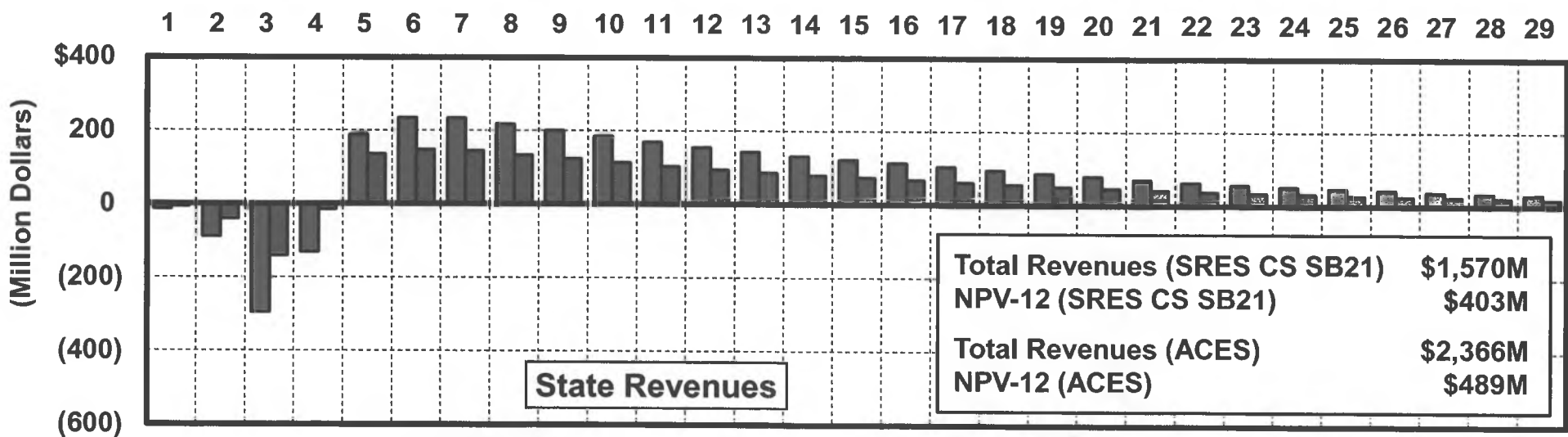
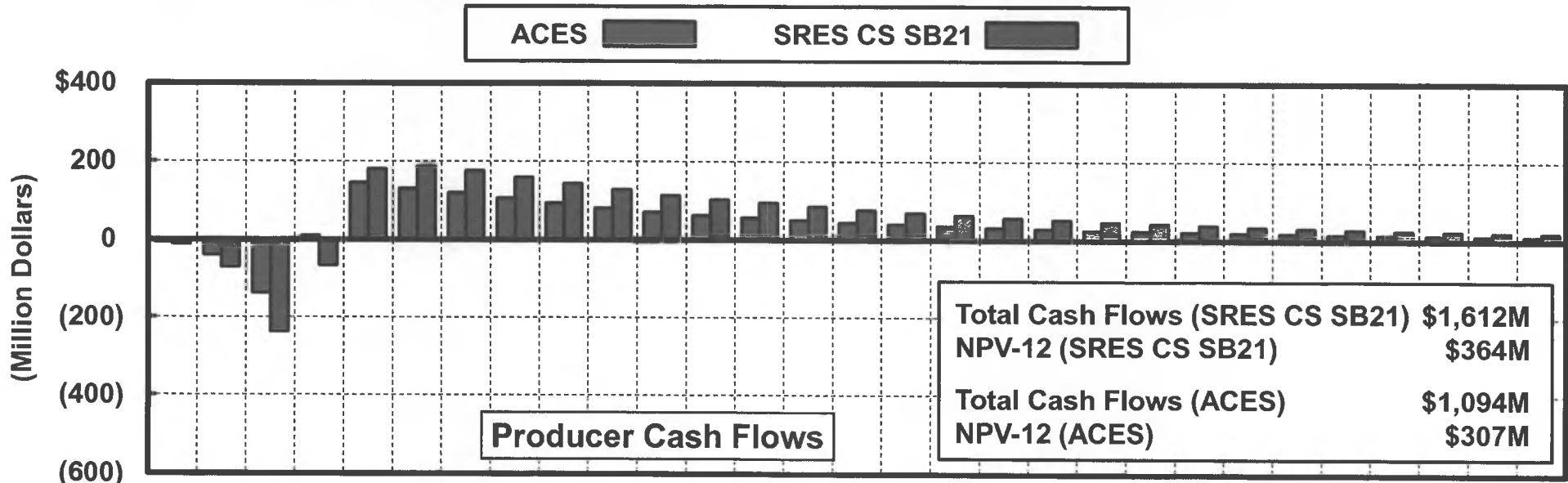


Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) Lower Cost Oil Alaska Development New Participant in Alaska



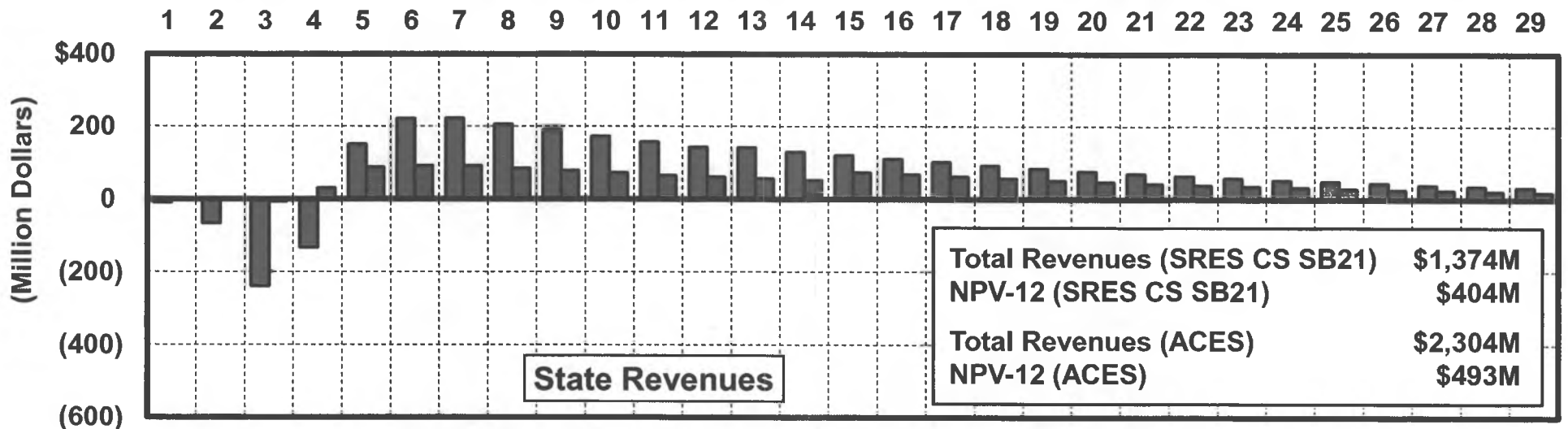
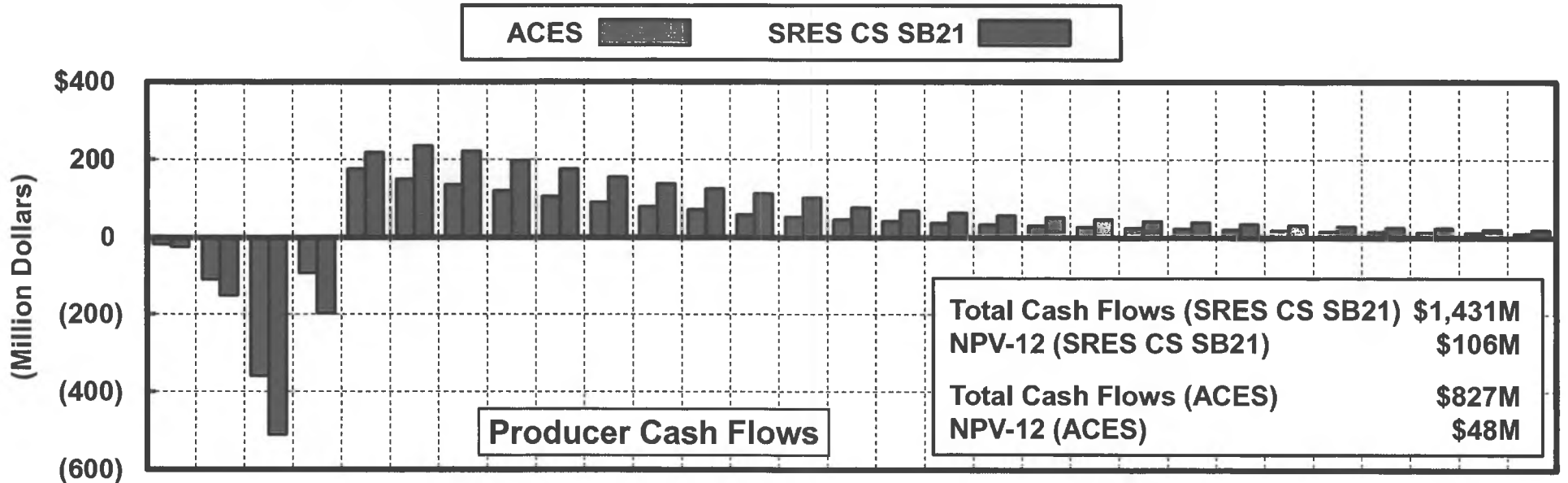
Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) Lower Cost Oil Alaska Development Incumbent Participant in Alaska



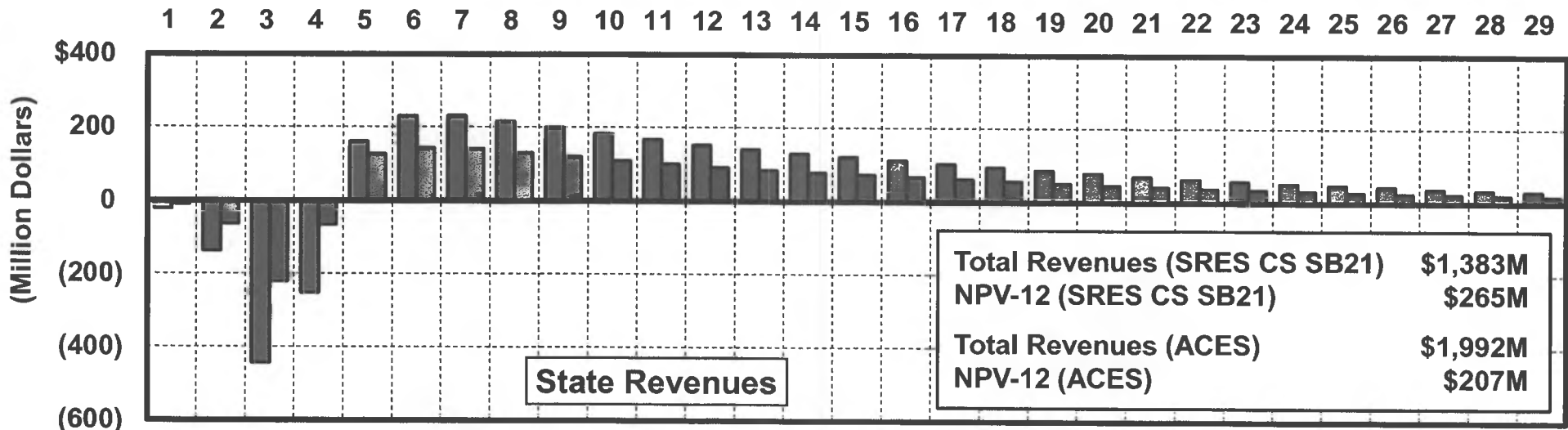
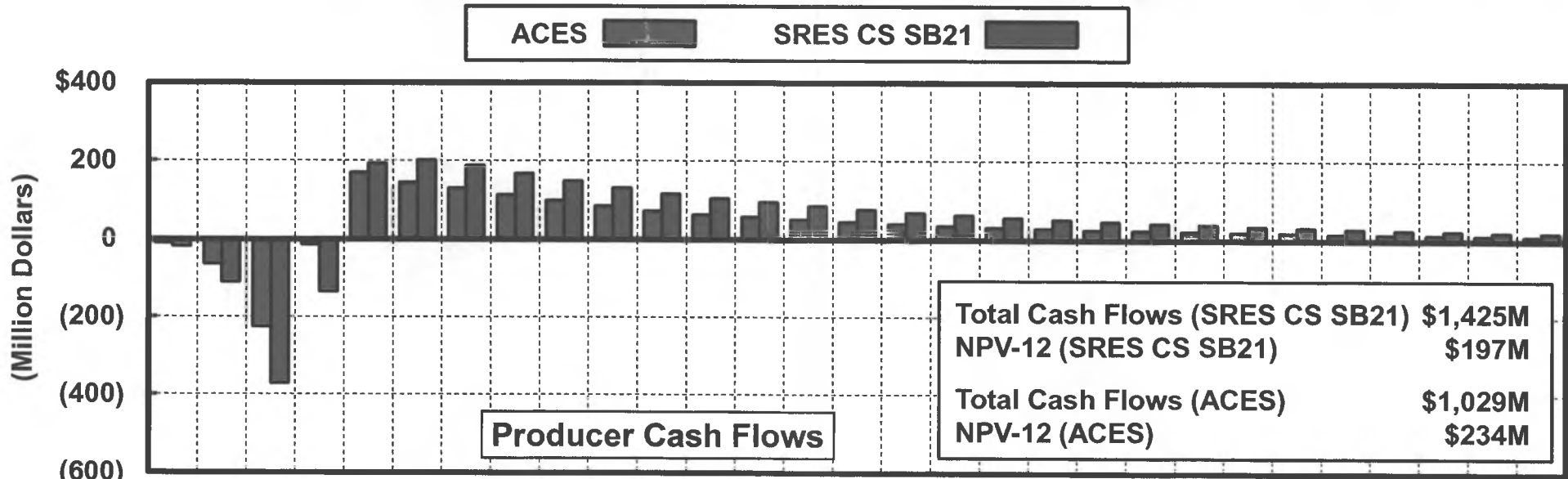
Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex

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



Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) Higher Cost Oil Alaska Development Incumbent Participant in Alaska



Higher Cost: \$25 Per Barrel Development Capex and \$14 Per Barrel Opex

4

Review of CS SB 21 (Res) Presentation to Senate Finance

Roger Marks
March 4, 2013

Roger Marks - Background

- **Since 2008**: Private consulting practice in Anchorage specializing in petroleum economics and taxation
 - Clients include: State of Alaska Legislature, federal government, local municipalities, University of Alaska, independent oil and gas explorer/producers, pipeline companies
- **1983-2008**: Senior petroleum economist with State of Alaska Department of Revenue Tax Division
 - Fiscal development
 - Statutory and regulatory design
 - Petroleum economic and commercial valuation of exploration, development, production, transportation, refining, marketing, taxation
 - Analysis of international competitiveness
 - Oil and gas valuation
 - North Slope gas commercialization
 - Economic valuation
 - International competitiveness
 - Pipeline financing
 - Taxation
 - Tariff design
- **1977-1983**: Petroleum economist with United States Geological Survey
 - Resource evaluation of unleased acreage on Alaska federal Outer Continental Shelf
 - Design of bidding systems
- **Publications on Alaska petroleum taxation**: Journal of Petroleum Technology, OPEC Review, Journal of Energy Finance and Development, Oil & Gas Financial Journal, Journal of Economic Issues, Journal of Legal Issues and Cases in Business

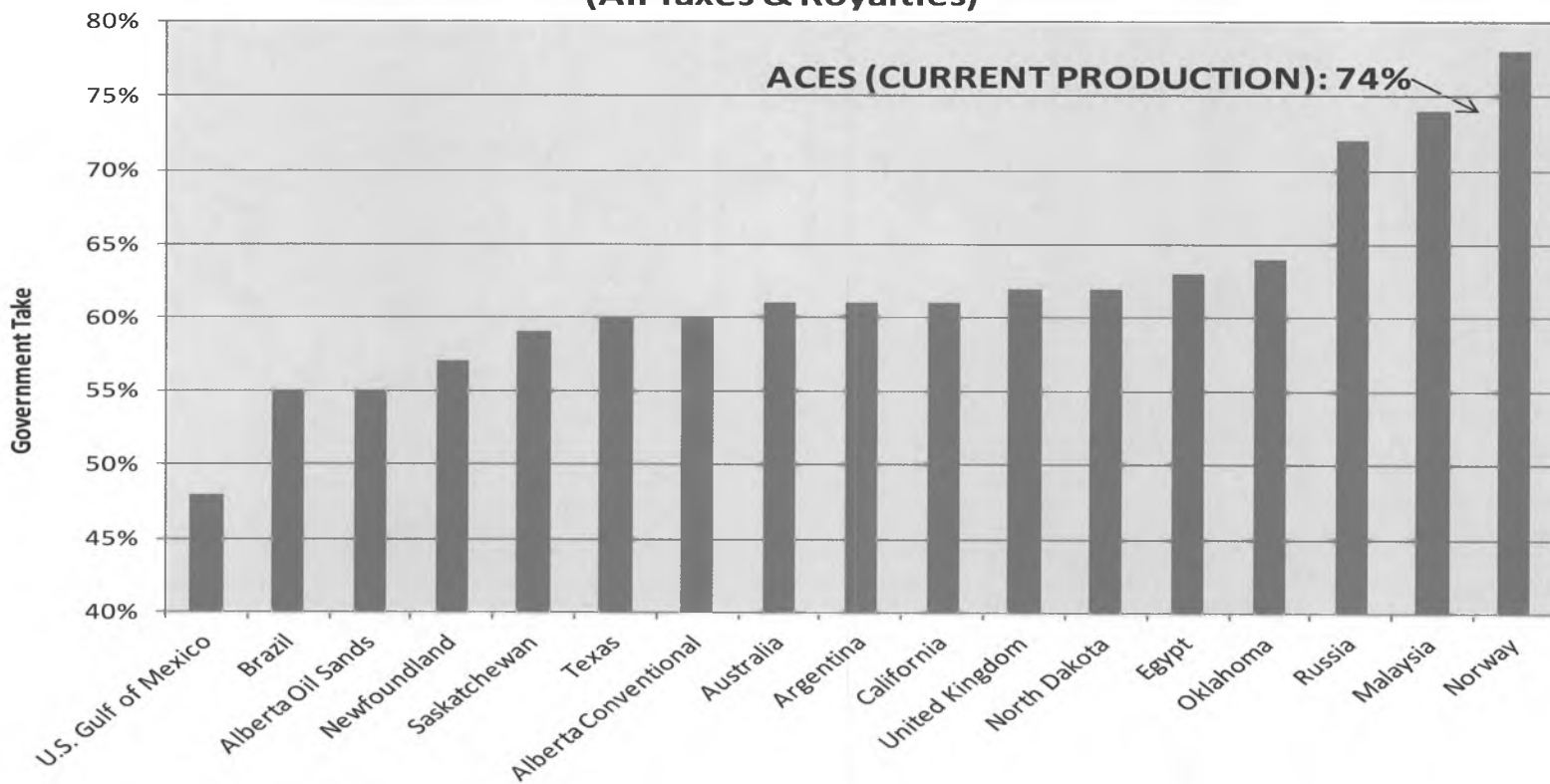
Approach for Evaluation

- The interest in evaluating the production tax stems from concern over the perception of slow investment and declining production levels on the North Slope
- The international investment climate is characterized by plenty of opportunities, fluid capital, but finite capital
- Investors allocate productive resources to their most highly valued uses
- Taxes are a significant part of the cost structure and under ACES they are relatively high
- Tax rates under ACES have made Alaska uncompetitive
- The goal is to make Alaska competitive

Defining Fair Share: Determining a Competitive Tax Structure

- Determine who the competition is
- Determine where Alaska should be in within that competition
- Design a system to achieve that target

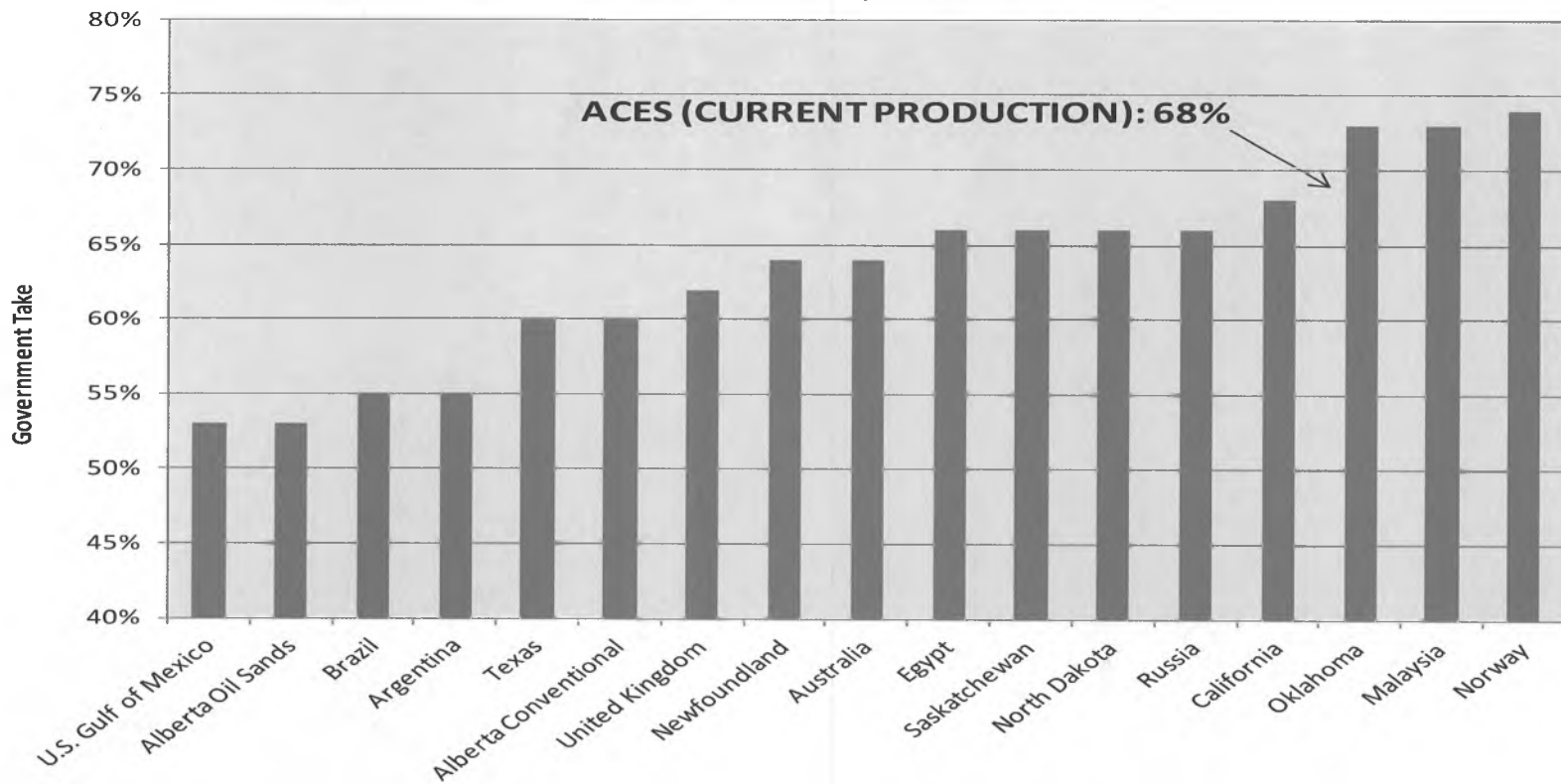
Alaska Peer Group*
Government Take at \$110/bbl Market Price
(Total Taxes as a Percentage of Net Value)
(All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
 Tax & royalty regimes
 Arctic regimes
 Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between
 2-6 billion bbls proved reserves)

Source: PFC Energy except Newfoundland, Saskatchewan, California, Oklahoma

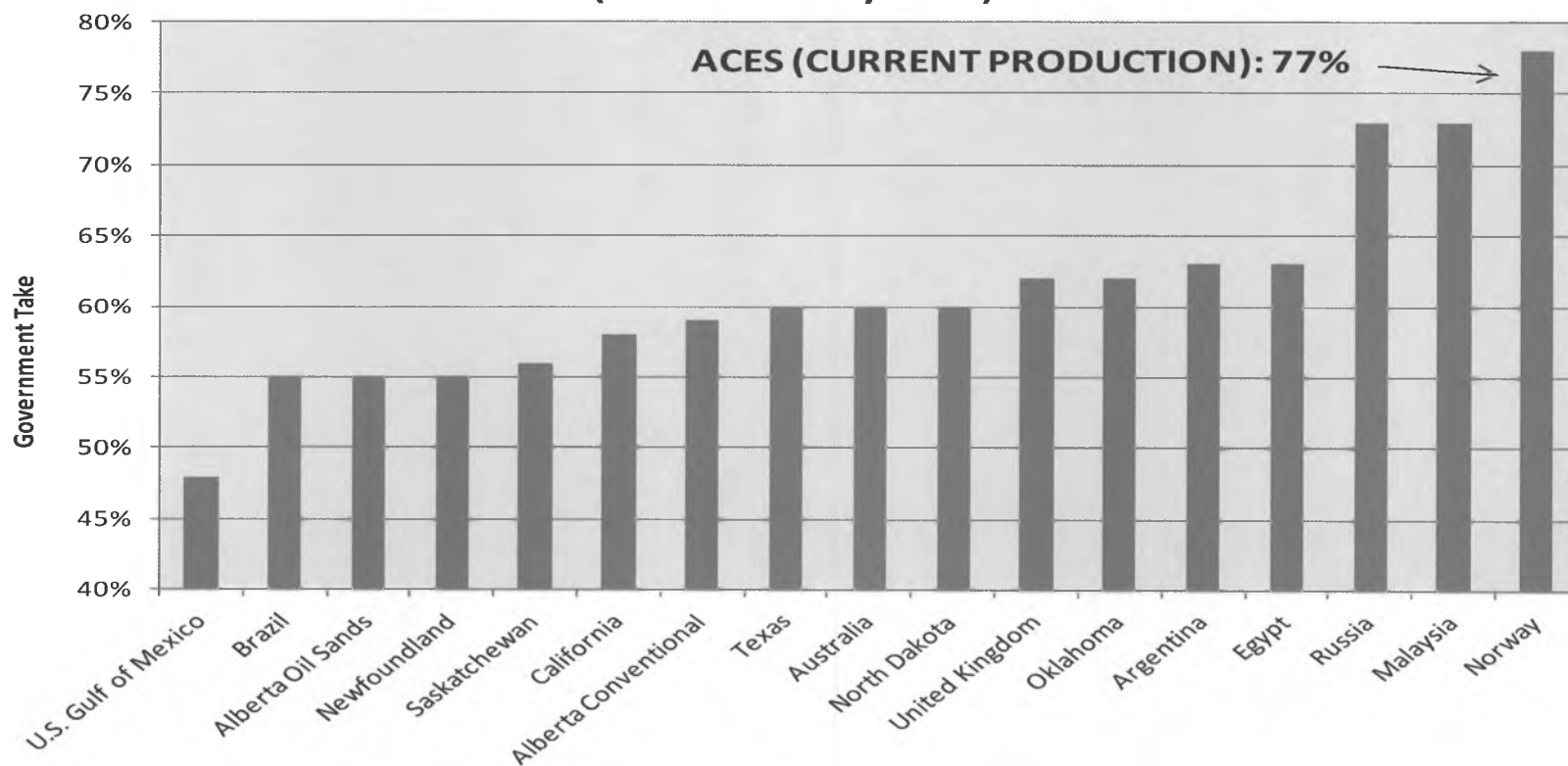
Alaska Peer Group*
Government Take at \$70/bbl Market Price
 (Total Taxes as a Percentage of Net Value)
 (All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
 Tax & royalty regimes
 Arctic regimes
 Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between 2-6 billion bbls proved reserves)

Source: PFC Energy except Newfoundland, Saskatchewan, California, Oklahoma

Alaska Peer Group*
Government Take at \$160/bbl Market Price
(Total Taxes as a Percentage of Net Value)
(All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
 Tax & royalty regimes
 Arctic regimes
 Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between 2-6 billion bbls proved reserves)

Source: PFC Energy except Newfoundland, Saskatchewan, California, Oklahoma

Proposed Target Government Take to be Competitive

- 65% take at \$70/bbl
- Level down to 62% take at current prices (\$110/bbl) and beyond
- A fairly neutral system

Each Percentage Point of Take is Worth a Lot of Money
At \$110/bbl Each Percentage Point in Government Take
Means \$142 Million Annually to Government/Producers

• Market Price	\$110/bbl	
– Costs	<u>\$29</u>	
• Net value		\$81/bbl
• Taxable percentage		.875
• Million bbls/yr (@550,000/day)		201
• One-percent		<u>.01</u>
• TOTAL		\$142 mm

Regressive Elements in Fiscal System

- Make for challenging economics at low prices, particularly for high cost fields
- Makes for challenge in designing production tax to offset effects
- Royalty
- Property Tax
- Minimum Tax

Cost Spectrum

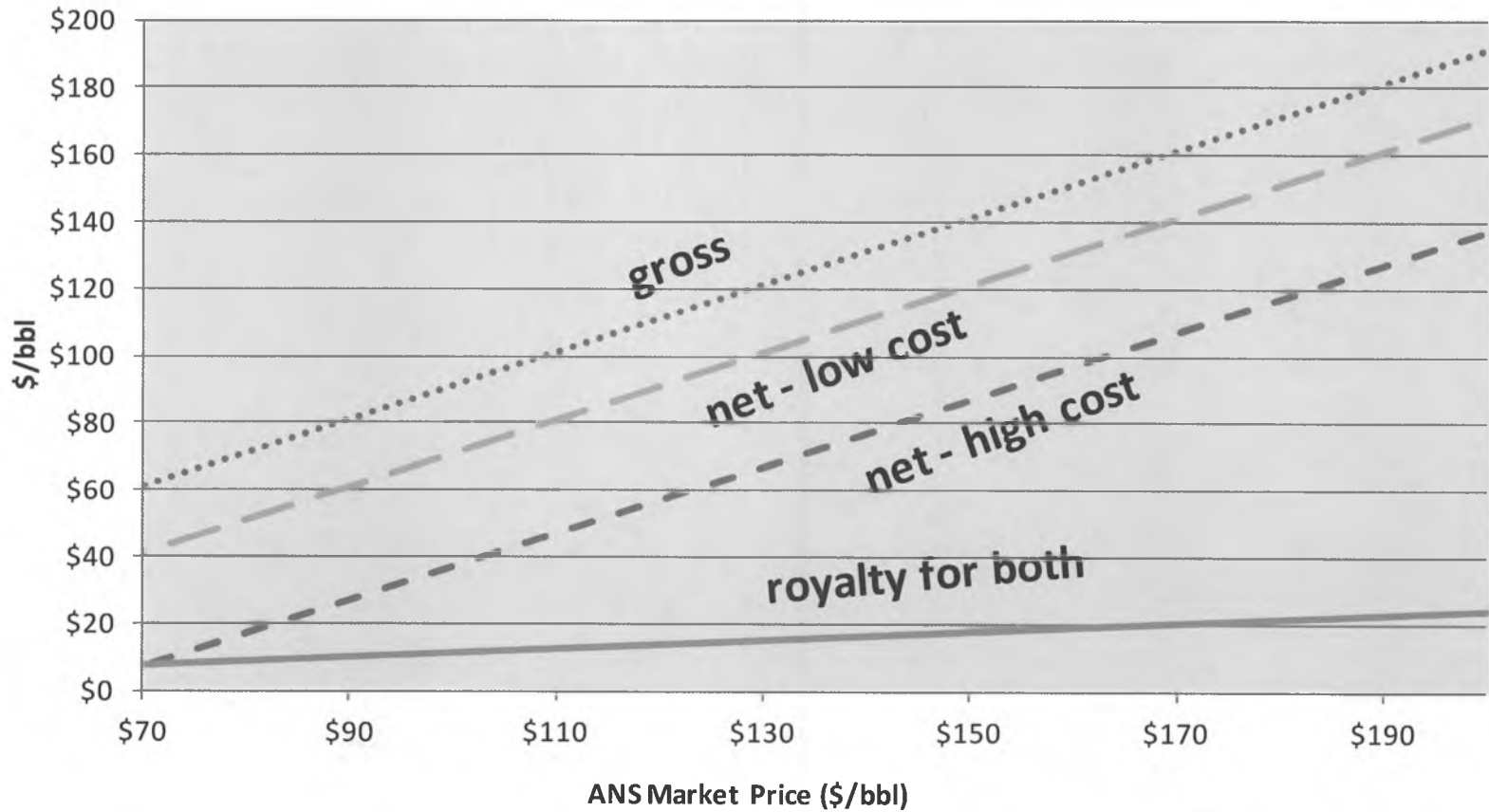
- Low cost fields (existing production)
 - \$7/bbl capital; \$13/bbl operating (\$20/bbl total)
- Medium cost fields (new production from existing fields)
 - \$20/bbl capital; \$17/bbl operating (\$37/bbl total)
- High cost fields (new fields and some heavy and viscous oil)
 - \$33/bbl capital; \$21/bbl operating (\$54/bbl total)

Example of Royalty Regressivity

ANS Market Price (\$/bbl)	\$70.00
Less: Transportation Costs (\$/bbl)	\$9.00
Gross Value (\$/bbl)	\$61.00
Less: Upstream Capital and Operating Costs (\$/bbl)	\$50.00
Net Value (\$/bbl)	\$11.00
Royalty (1/8 of Gross Value) (\$/bbl)	\$7.63

Royalty chews up 70% of profit before property, production and income taxes

Comparison of Gross, Net & Royalty Low & High Cost Fields



..... gross - - - net - high cost fields - - - net - low cost fields ——— royalty ——— royalty

CS SB 21 (Res) Features

- 35% rate applied to net (production tax) value (ptv)
- 30% gross revenue exclusion (GRE) used in computing net
- \$5/bbl credit
- If ptv is negative, the loss can be carried forward to when ptv is positive as a credit at 35% of the loss

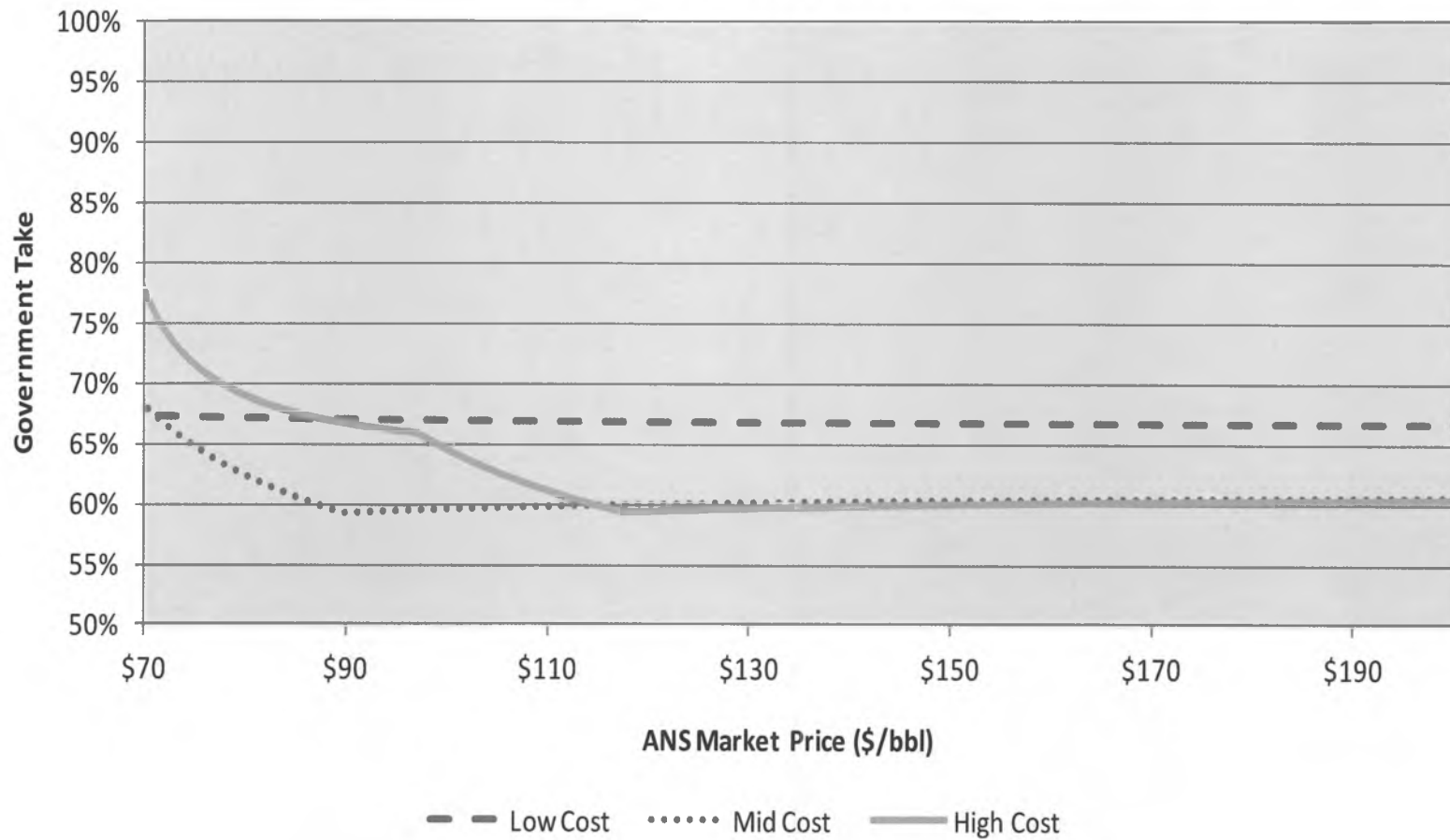
How Features Operate

- 1) GRE (CS increased from 20% to 30% for new fields)
 - Brings down tax rate more for high cost fields and more at lower prices
- 2) Per barrel credit (Introduced in CS)
 - Focuses on bringing tax rate down high cost fields at low prices
- 3) Rate (Increased from 25% to 35% in CS)
 - Moves entire curve for all fields up or down

Overview of How Features Interact

- Tax is higher of net and 4% of gross calculation
- There is a floor of zero on each
- The GRE is used to calculate the net; it is not used to calculate the gross minimum
- The loss carry-forward credit is applicable regardless of whether net or the gross minimum is invoked
- The \$5/bbl credit is applicable for both the net and gross minimum calculation. It can only take the tax down to zero. Any unused amounts are lost.

Government Take CS SB 21 (Res)



General Comments

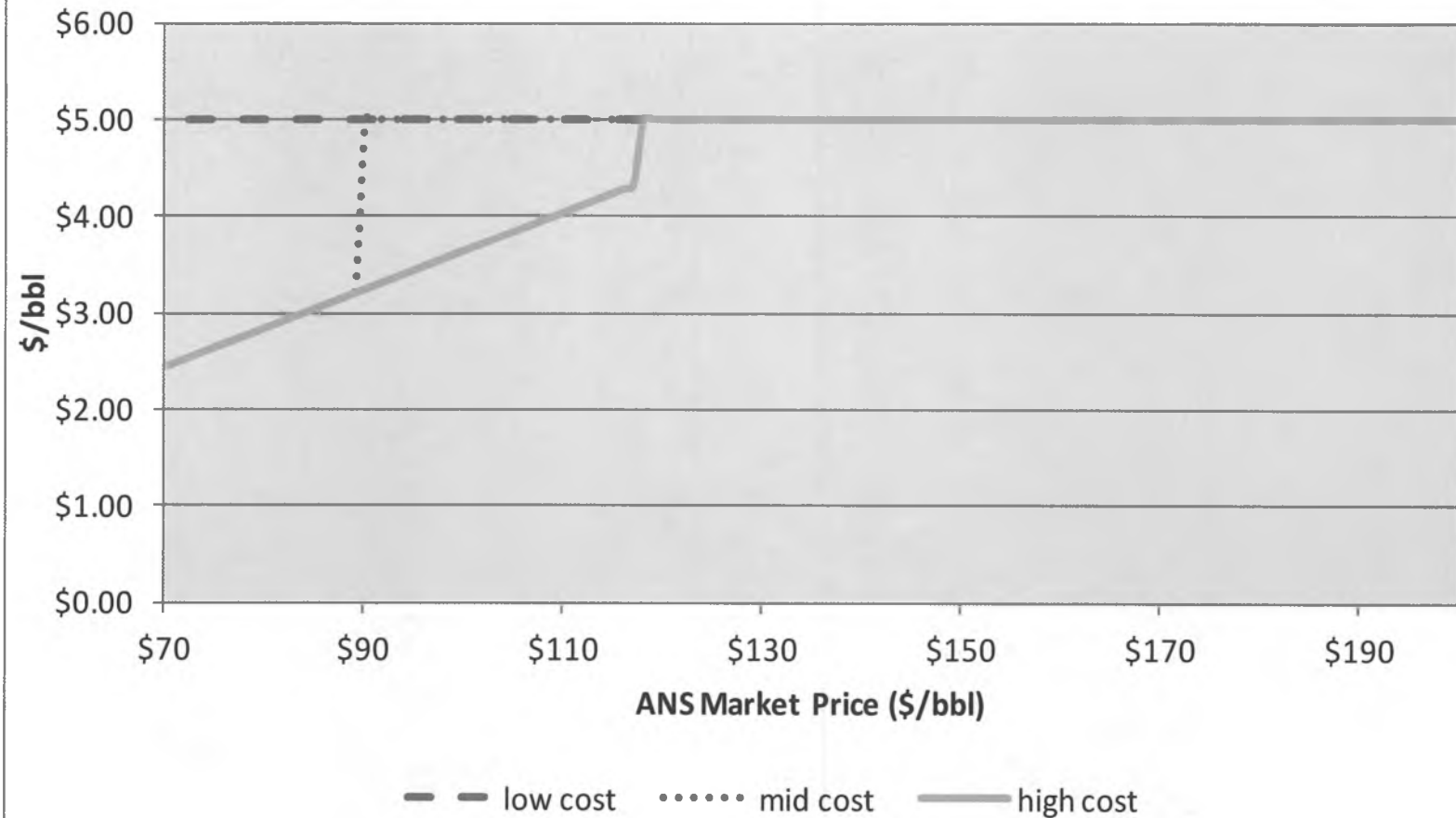
Differences in Take Depending on Costs and Fields

- Given a target take at a given price, the system should come as close as possible to hitting the target over a spectrum of costs
- Treating Different Fields Differently (No GRE for Existing Participating Areas)
 - Both existing and new production benefit from existing and new investment.
 - Existing fields may contain costly isolated targets in existing participating areas.
 - The system is efficient when the highest valued resources get produced. The tax system should not distort this; it should not favor investing in certain cost fields over others.
 - Differential treatment could cause unwanted shifts in investment.

Specific Comments on Features

- Gross Revenue Exclusion and \$5/bbl Credit
 - Same for all cost structures – unconnected to actual production costs
 - Has different effects at low prices depending on cost structure
 - *Unaffected* by investment
 - \$5/bbl credit: Lose some of it at low prices if at \$0 tax floor
- 20% Capital Credit (Revoked in Original Bill and CS)
 - Explicitly related to actual costs
 - Automatic adjustment to different cost structures: low credit if low costs; high credit if high costs
 - *Affected* by investment
 - Do not lose it at low prices
 - Boost to net present value and rate of return

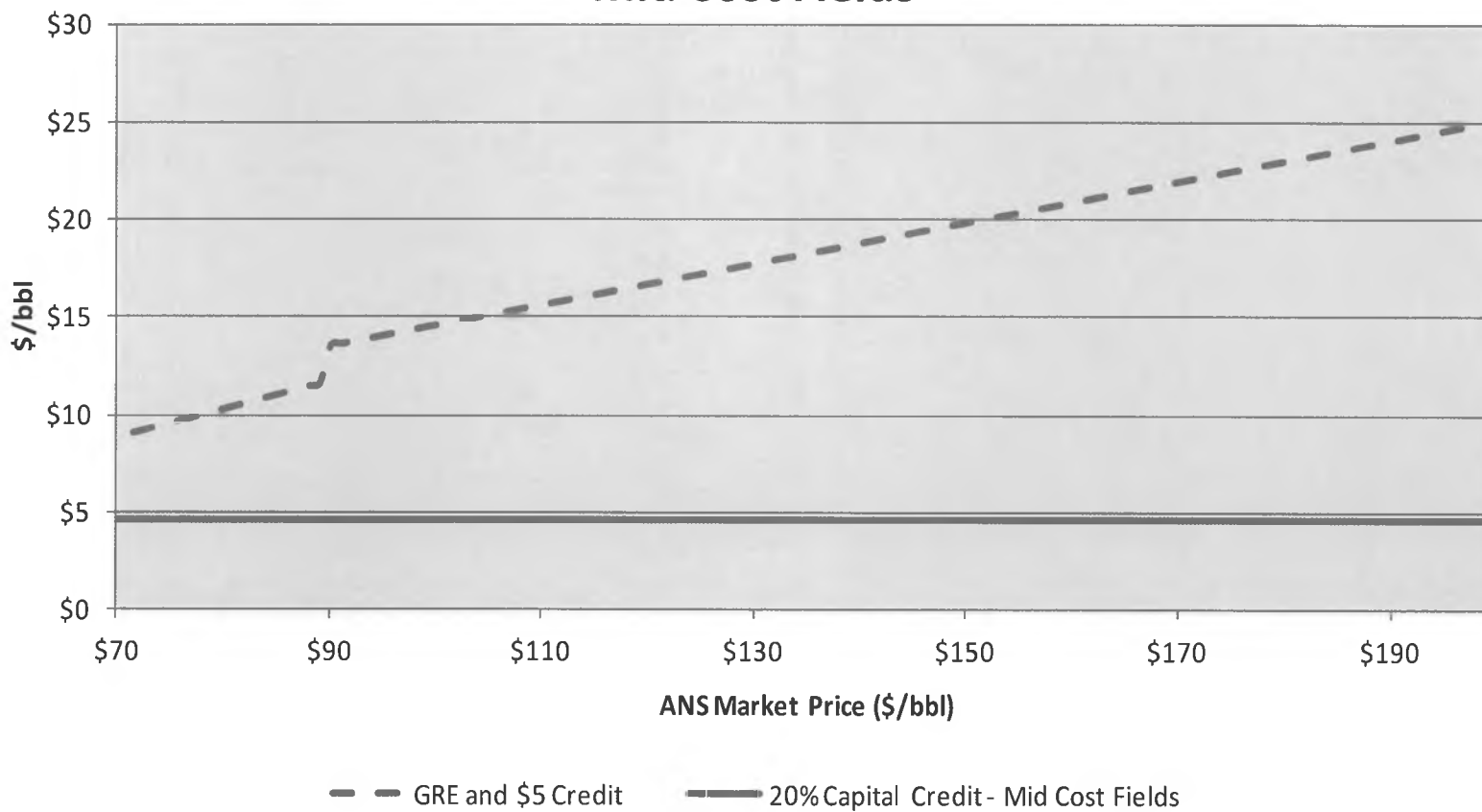
How Much of \$5 Credit Used



Cash Flow Comparison

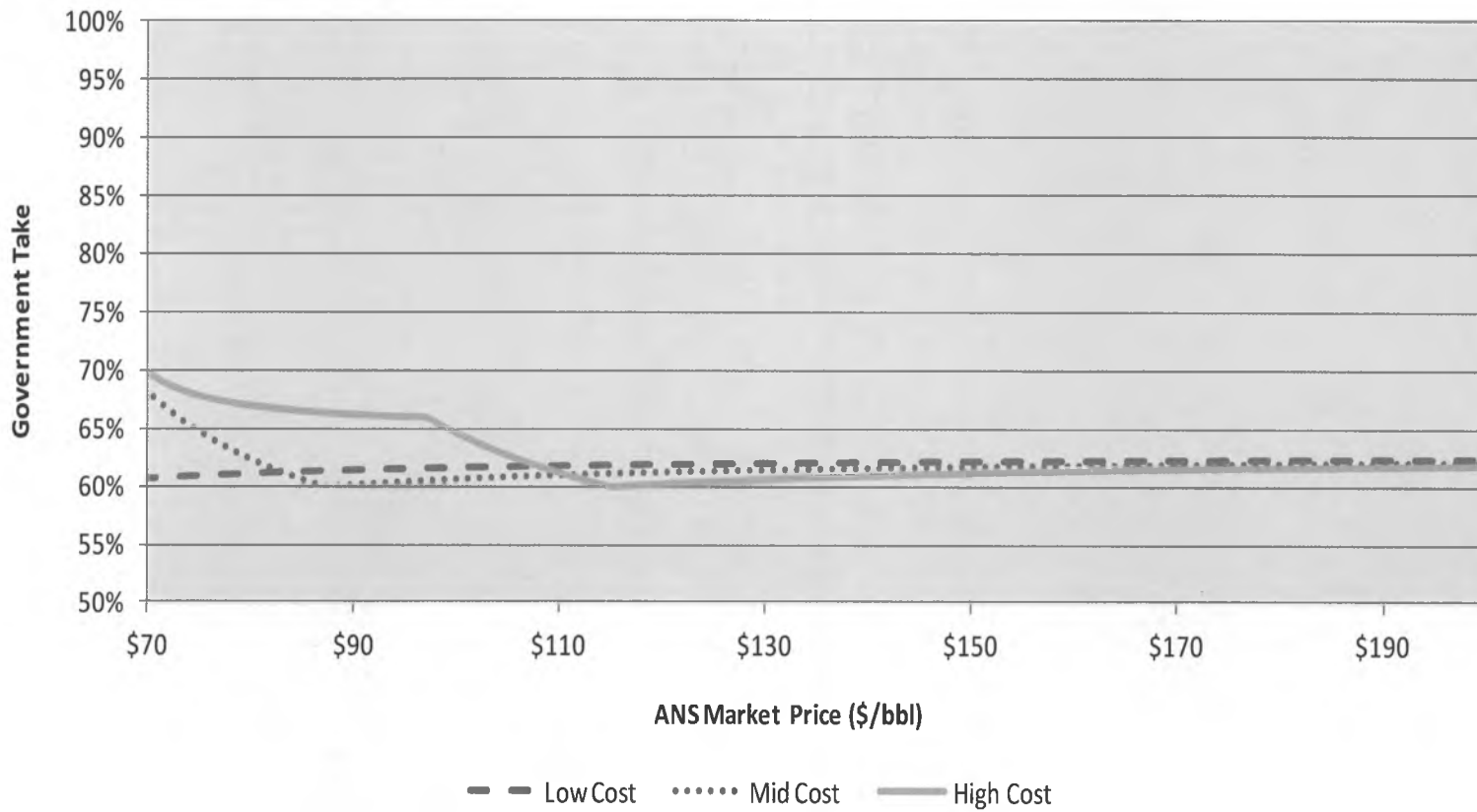
Value of 30% GRE & \$5 Credit vs. 20% Capital Credit

Mid Cost Fields

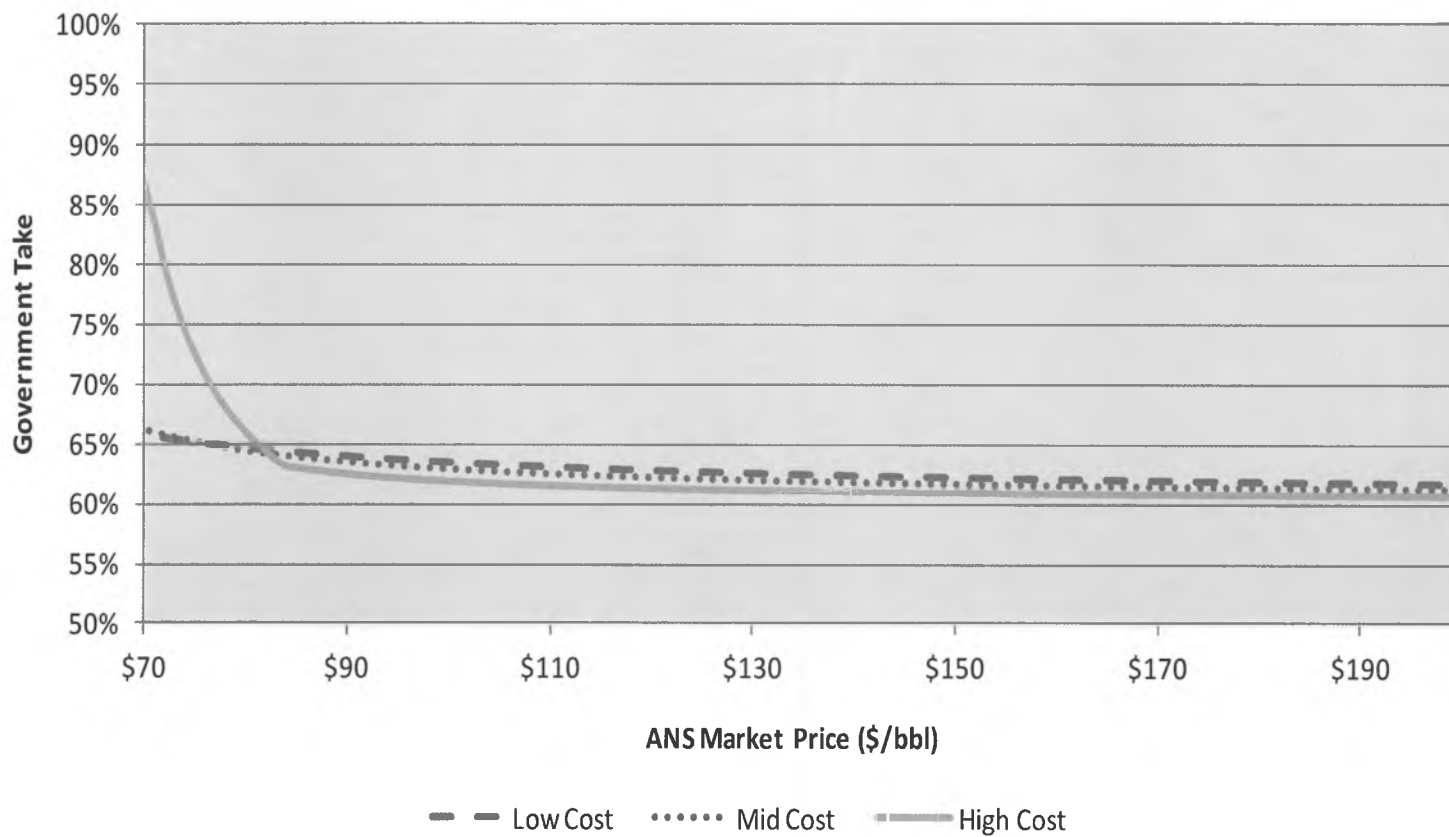


Government Take

40% Rate / 30% GRE All Fields / \$5/bbl Credit

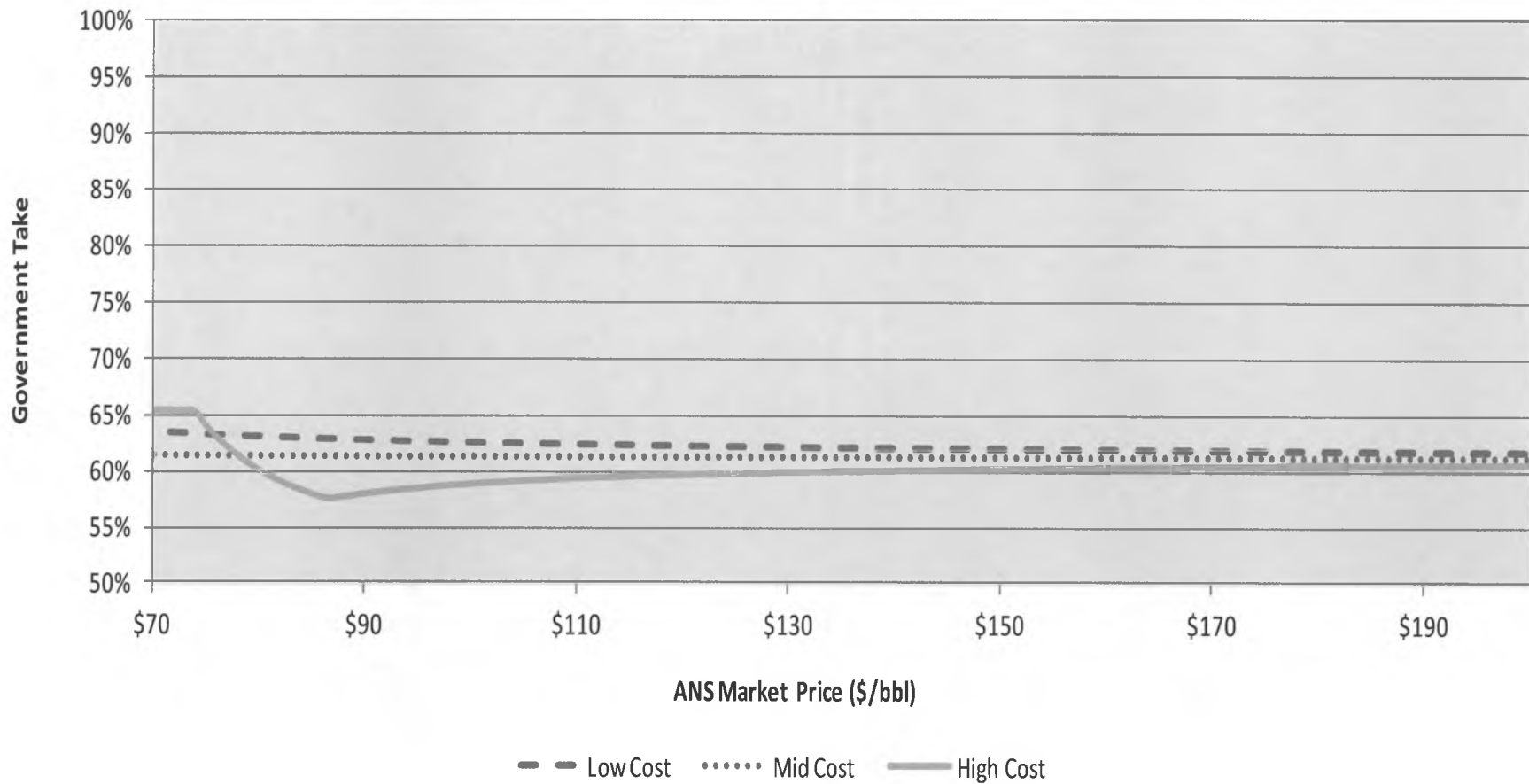


Government Take 23% Rate / 20% Capital Credit



Government Take

26% Rate / 20% Capital Credit / 5% GRE All Fields / \$2/bbl Credit



Progressivity?

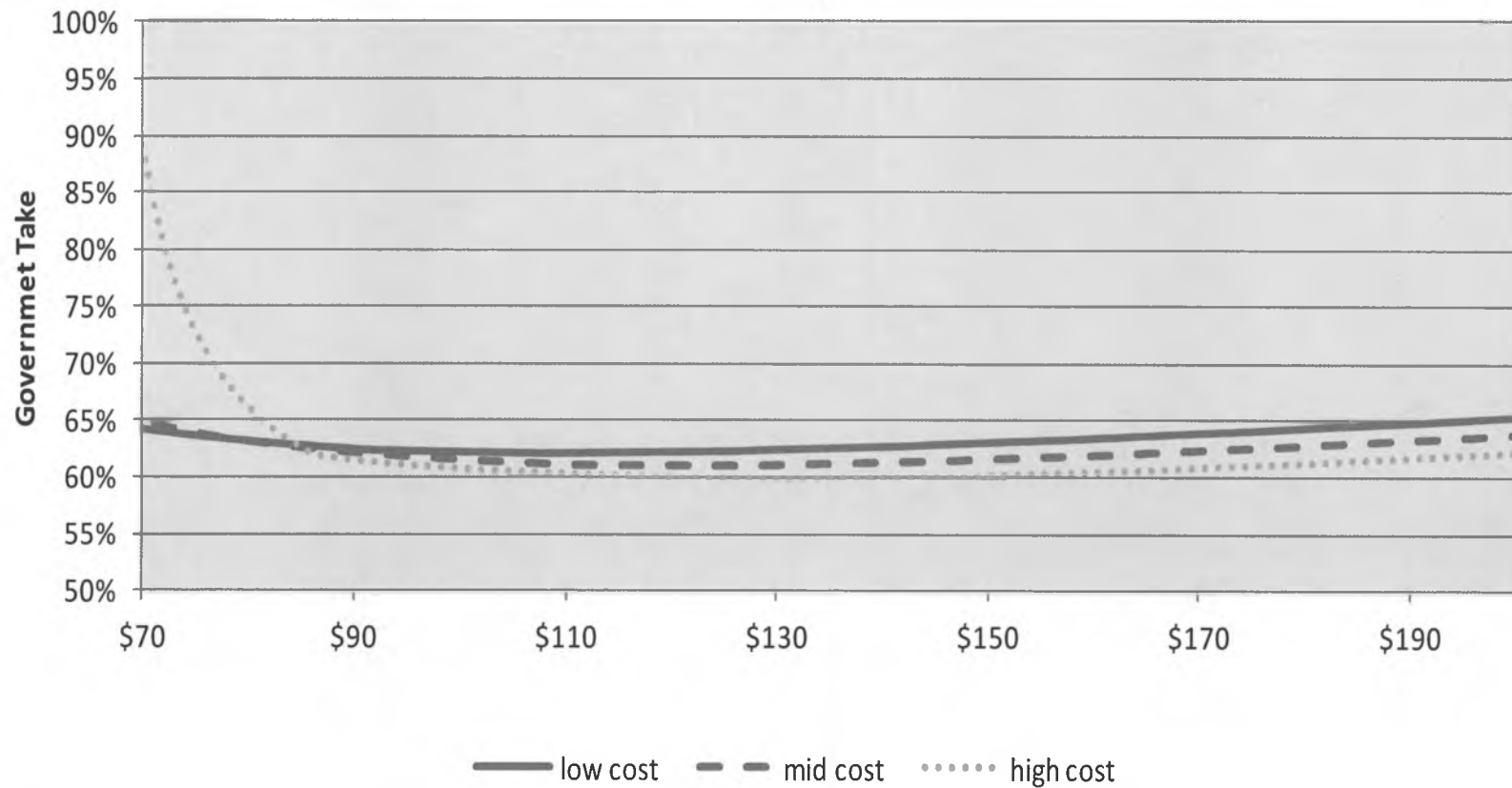
- Can use a progressive structure to flatten out the curve at both ends and make a neutral system, which aligns interests
- Or can make a progressive system
 - Pros (if not excessive)
 - Protects producers interests at low costs
 - Protects state's interests at high costs
 - May be necessary for fiscal stability
 - Cons
 - Only works if balanced at low and high prices
 - With inherent regressive elements may be difficult to achieve, or can only achieve modestly
 - Many jurisdictions in the peer group do not have progressivity

Example: Government Take under Bracketed Progressivity

Base Rate of 20% up to \$60 Net

Brackets up to 50% at \$160 Net

Includes 20% Capital Credit



Other Issues: Section 10

- Defers loss carry-forward credits until positive income
- Would eliminate loss carry-forward credit for unsuccessful explorer with no other nexus in state
- May discourage new entrants

Other Issues: Section 25

- Eliminates loss carry-forward credits for exploration expenses
- Explorers with offsetting income can still realize benefit of deduction; those without offsetting income will not
- Disparate treatment
- Also, suppose a producer has \$100 in gross value. Suppose exploration expenses are \$90. And suppose non-exploration expenses are \$80. If they deduct the exploration expenses first, they will have \$10. Then they can deduct the \$80 non-exploration expense from the \$10. This will give them \$70 in losses they can use for the loss carry-forward credit.

But, if they deduct the \$80 non-exploration first, they will have \$20. Under the amendment they would only be able to deduct \$20 of the exploration expense.

So there needs to be something about the order in which costs are deducted.

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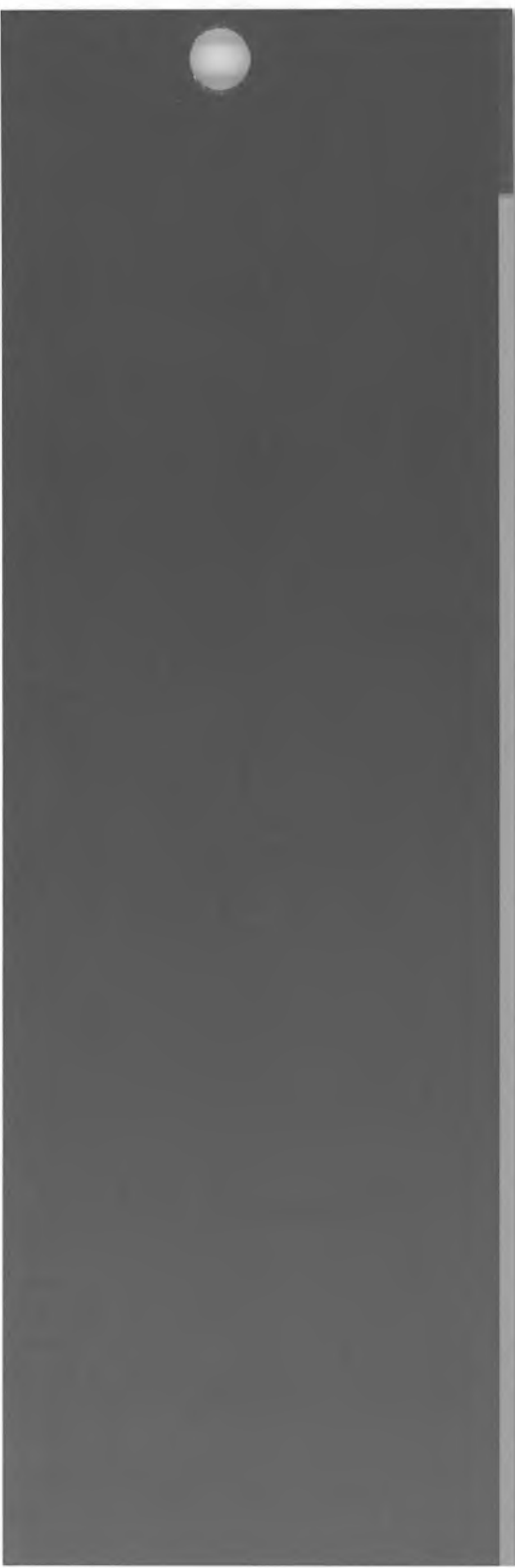


Senate Finance Committee

Alaska Fiscal System Discussion Slides

March 4 2013

Janak Mayer
Manager, Upstream
PFC Energy



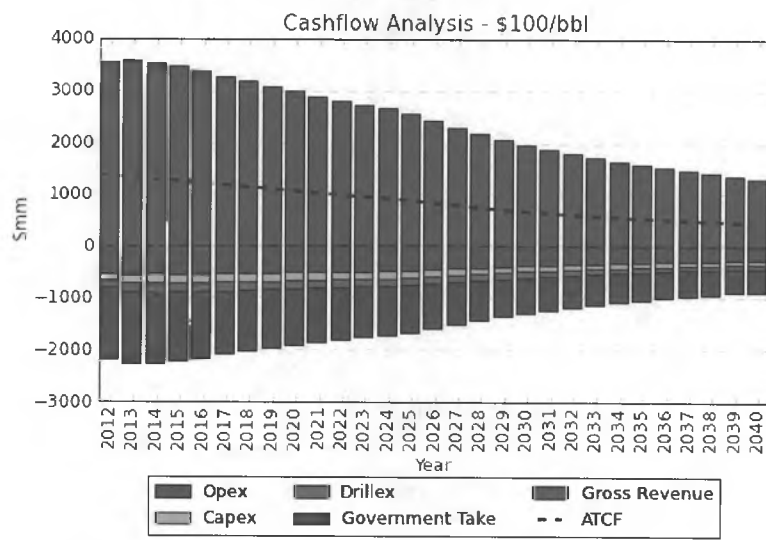
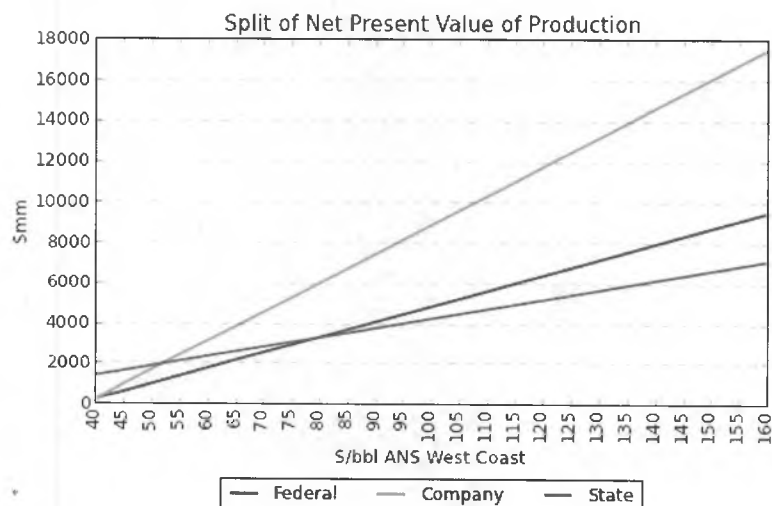
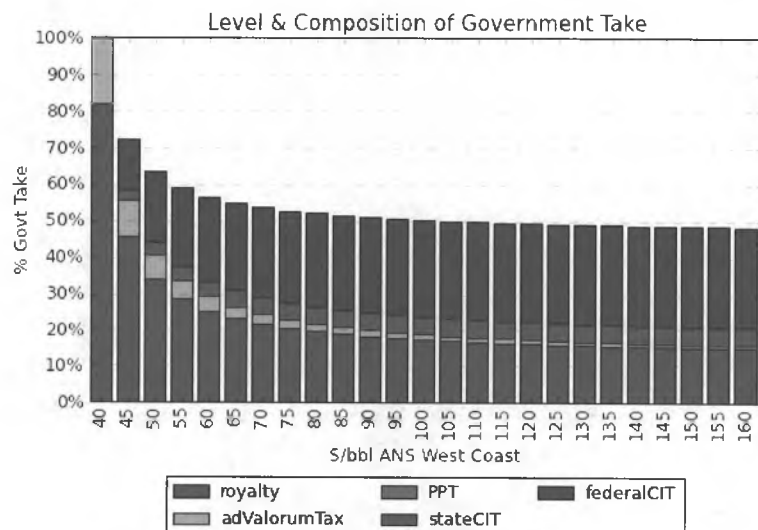
**Regressive and Progressive
Regimes**

Regressive and Progressive Regimes

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

Royalty Only Base Production

Royalty Only, 12.5%, Base Production



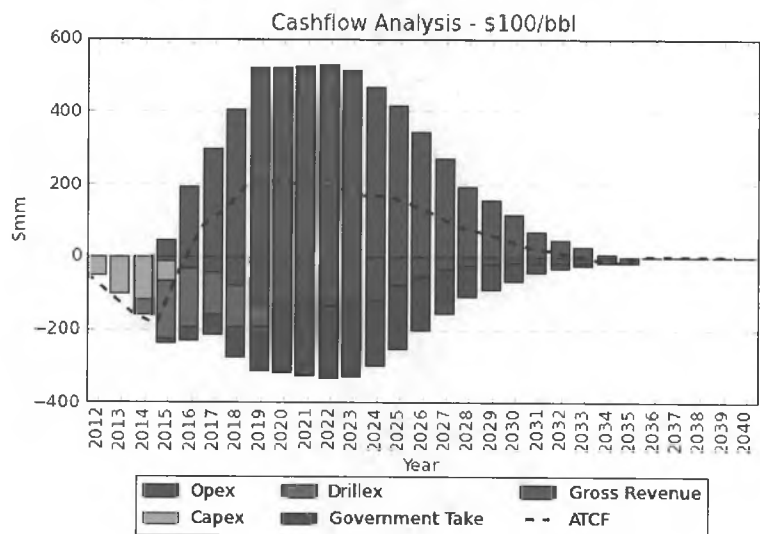
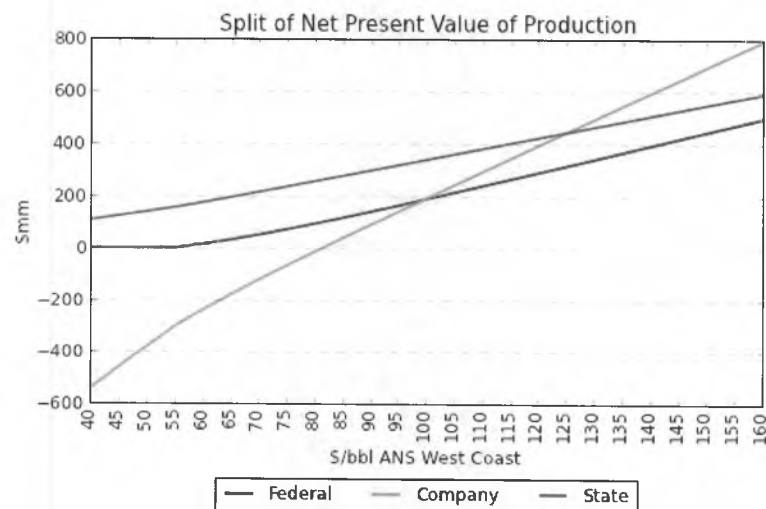
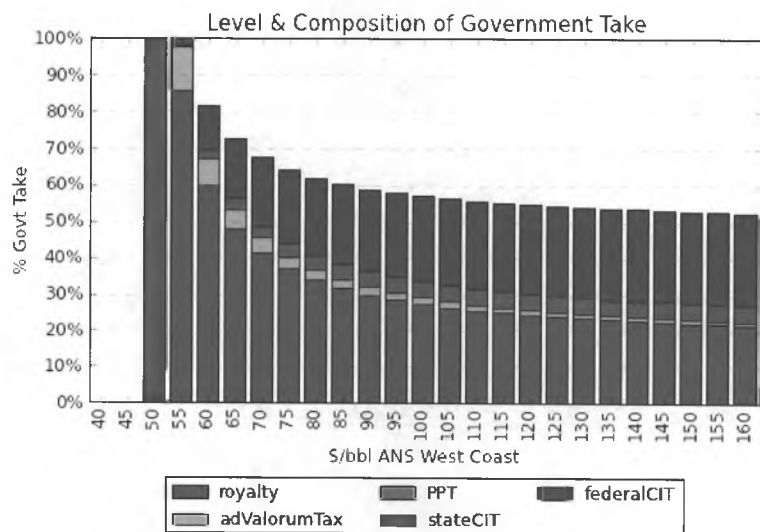
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	52.09%	5.81		26.27
\$100/bbl	50.37%	8.61		39.1
\$120/bbl	49.46%	11.4		51.93
\$140/bbl	48.90%	14.2		64.76

Even with just a 12.5% royalty on base production, a fixed royalty is regressive at low prices; at \$40/bbl the royalty and property tax consume all divisible income

Royalty Only \$18/bbl New Development, Standalone

16.7% Royalty, \$18/bbl New Development



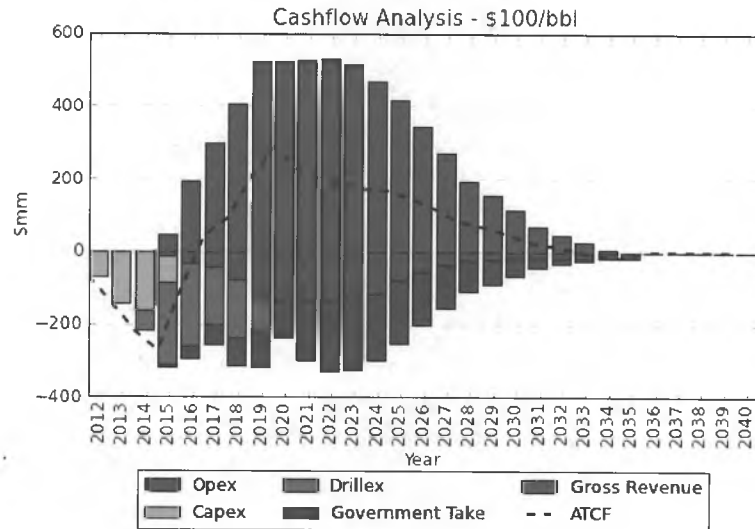
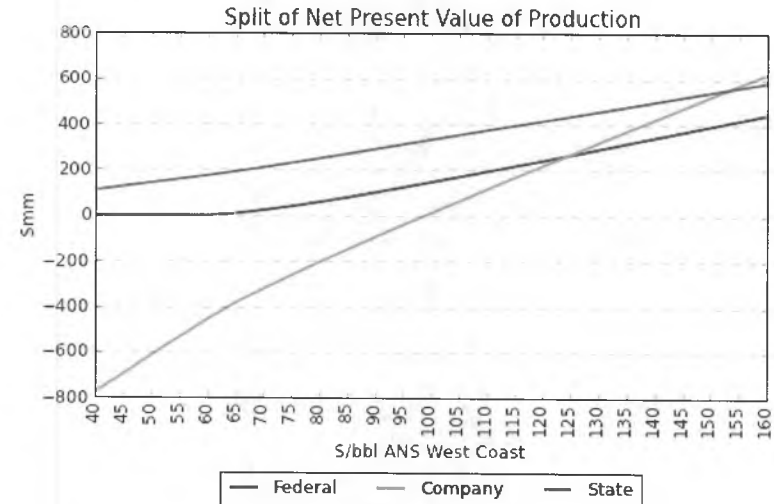
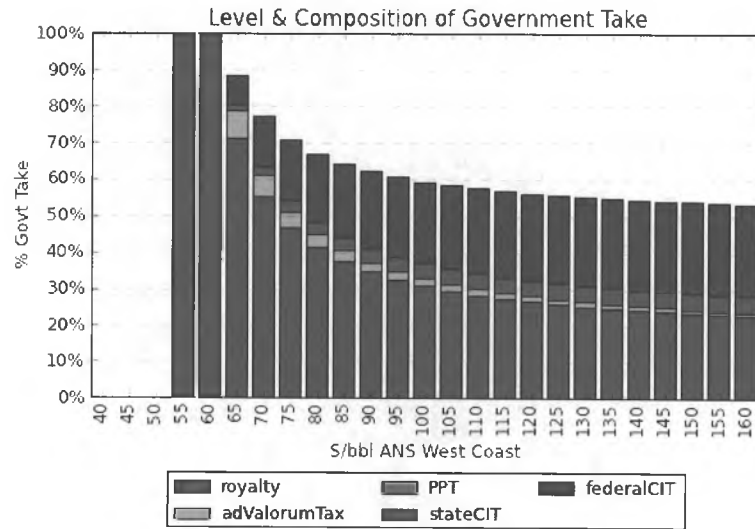
Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	61.95%	-0.26	11.52%	27.34
\$100/bbl	57.10%	3.88	18.56%	39.0
\$120/bbl	54.90%	7.91	24.44%	50.65
\$140/bbl	53.64%	11.91	29.55%	62.39

With the 16.7% royalty that generally applies to newer leases, an \$18/bbl new development faces more than 70% government take at \$65/bbl

Royalty Only \$25/bbl New Development, Standalone

16.7% Royalty, \$25/bbl New Development



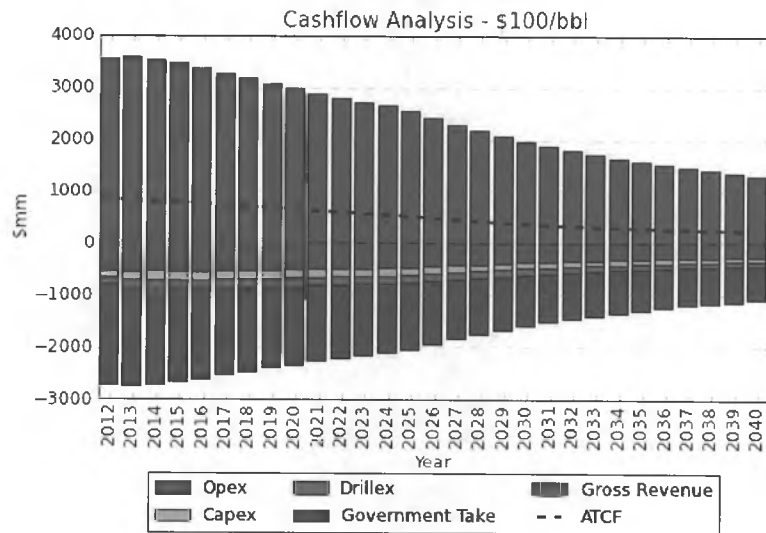
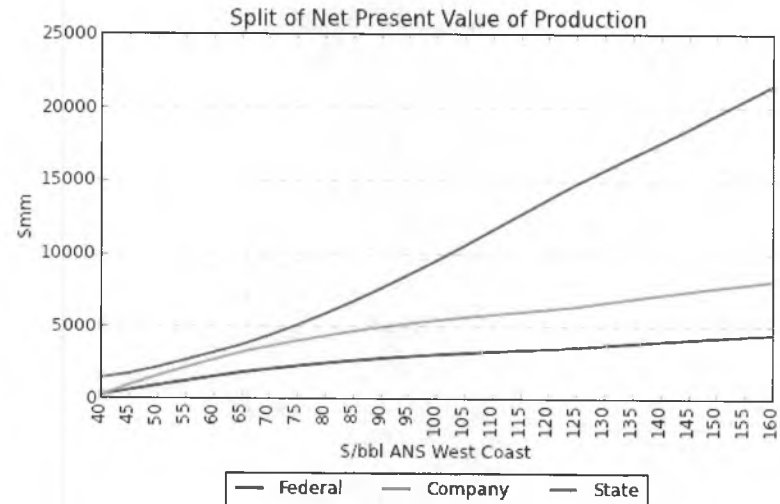
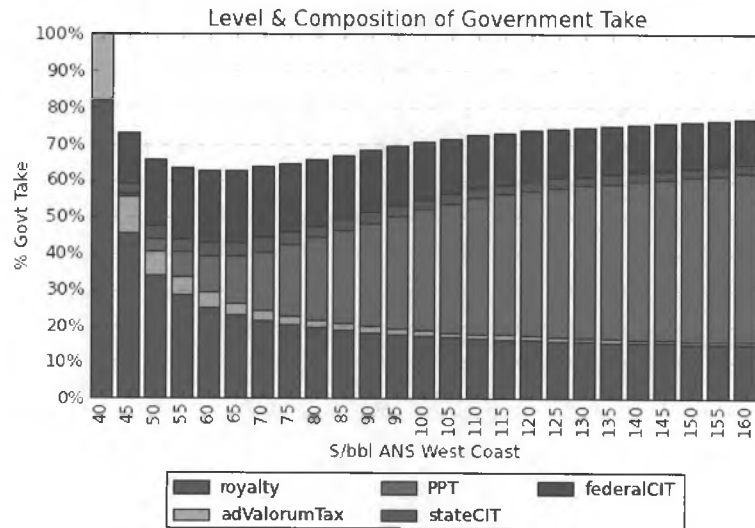
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	66.93%	-4.08	6.32%	27.03
\$100/bbl	59.37%	0.25	12.33%	40.1
\$120/bbl	56.30%	4.4	17.41%	51.76
\$140/bbl	54.64%	8.45	21.83%	63.42

A high-cost, \$25/bbl development may face more than 70% government take at \$85/bbl

ACES – Base Production

ACES, 12.5% Royalty, Base Production



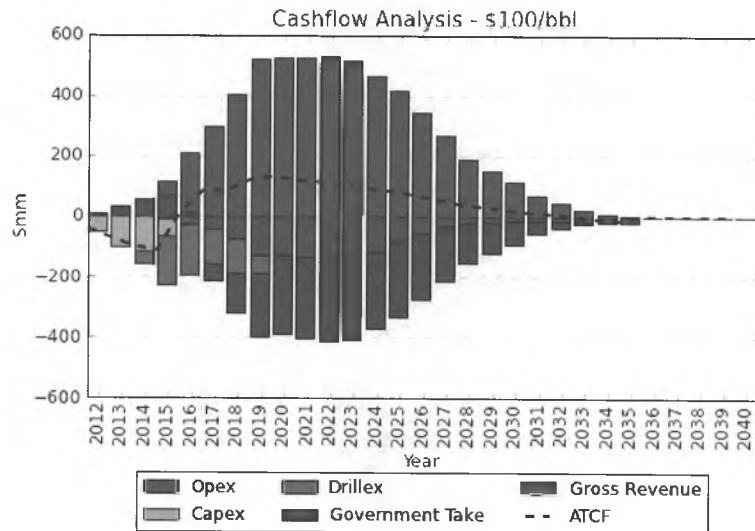
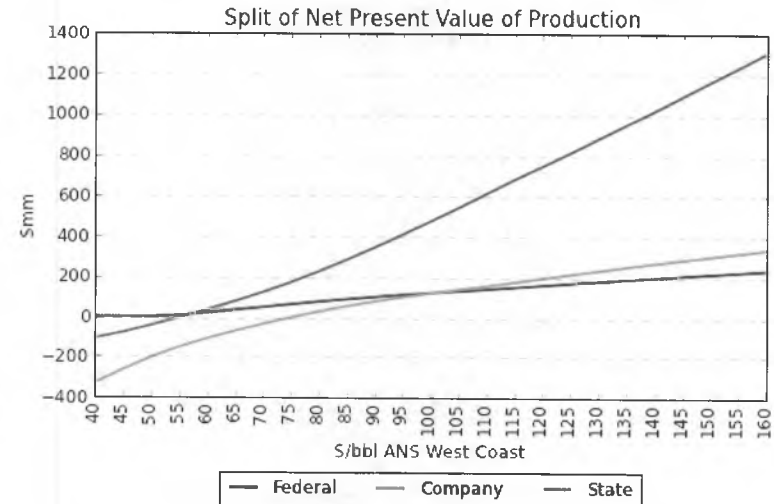
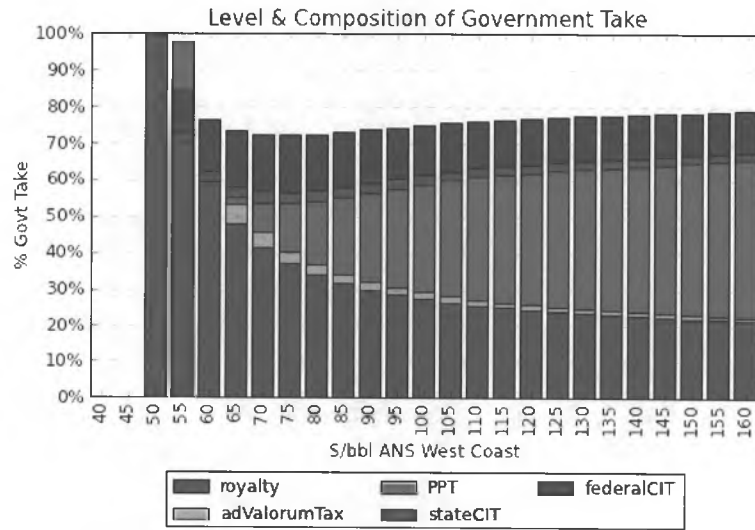
Economic Summary

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

ACES layers onto the regressive fixed royalty a highly progressive profit-based production tax. The gross-based minimum tax also increases the regressive nature at the low end. The result is very high levels of government take at both very low and high prices

ACES - \$18/bbl New Development, Standalone

ACES, 16.7% Royalty, \$18/bbl New Development



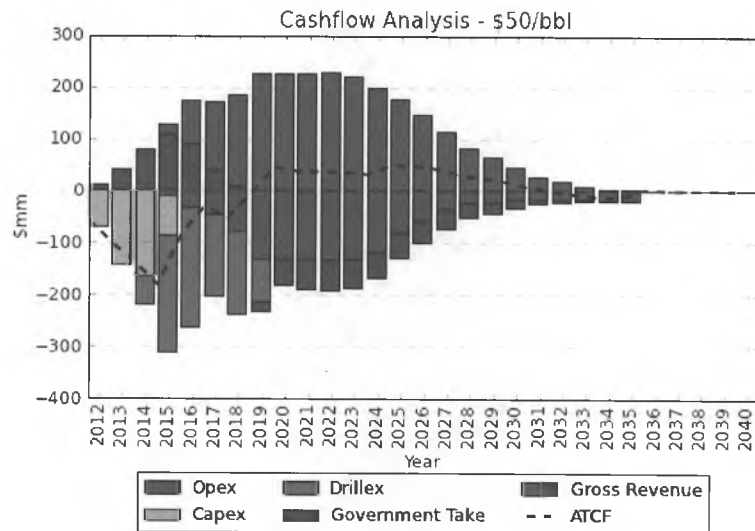
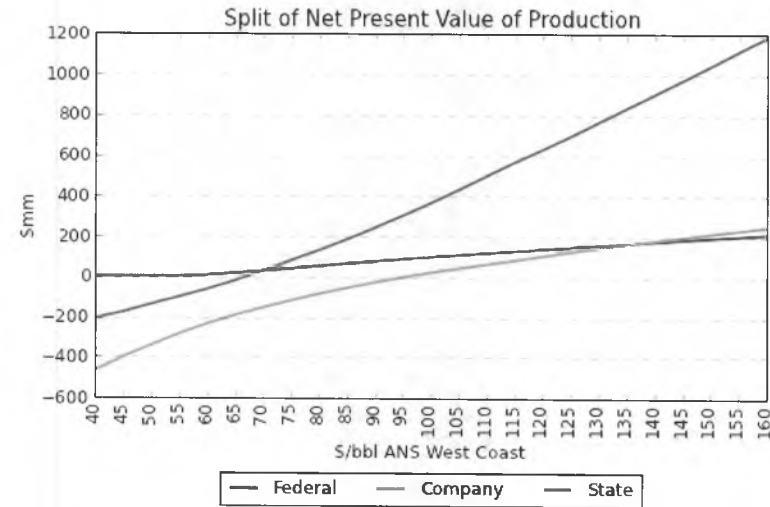
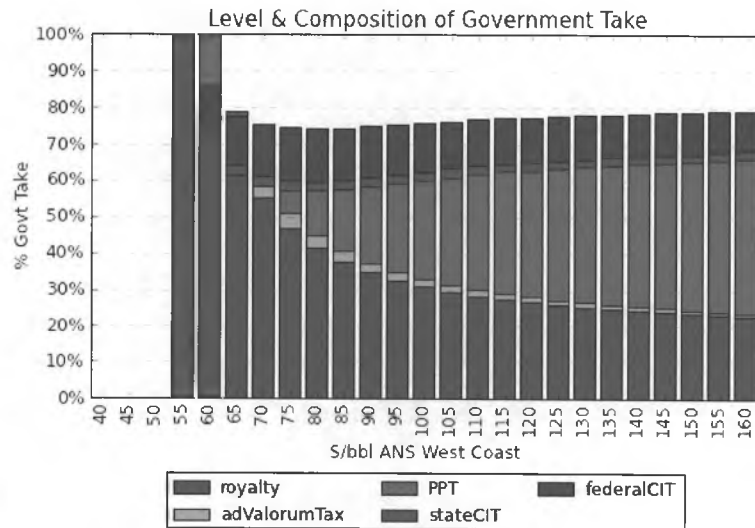
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	72.49%	0.63	13.88%	19.94
\$100/bbl	75.08%	2.48	19.07%	25.18
\$120/bbl	77.01%	3.98	22.94%	28.63
\$140/bbl	78.10%	5.46	26.44%	32.33

Standalone new developments face particularly high government take – although this is partly offset by the significant downside risk the state takes through reimbursable credits

ACES - \$25/bbl New Development, Standalone

ACES, 16.7% Royalty, \$25/bbl New Development



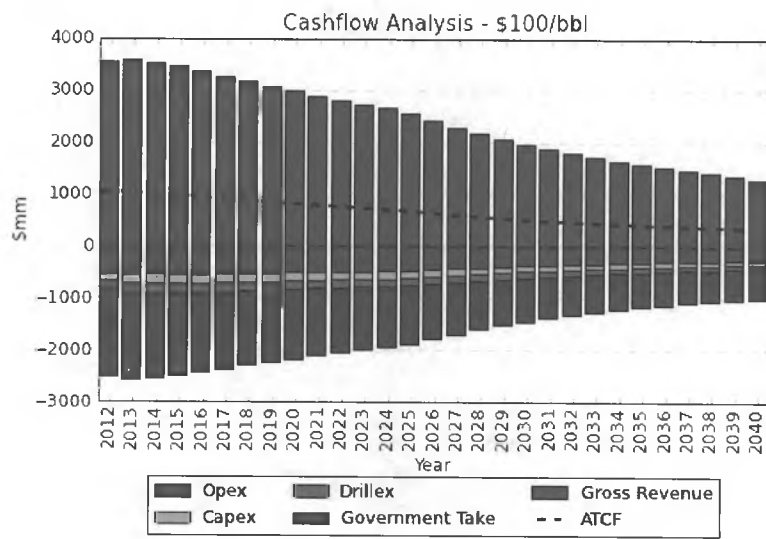
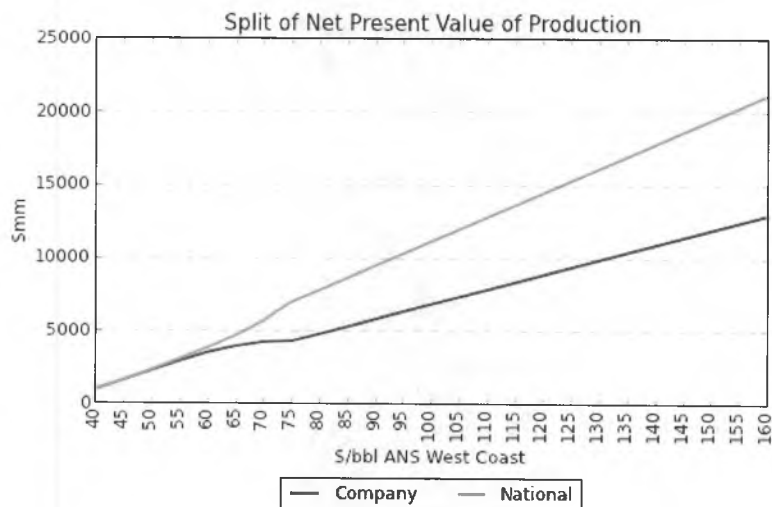
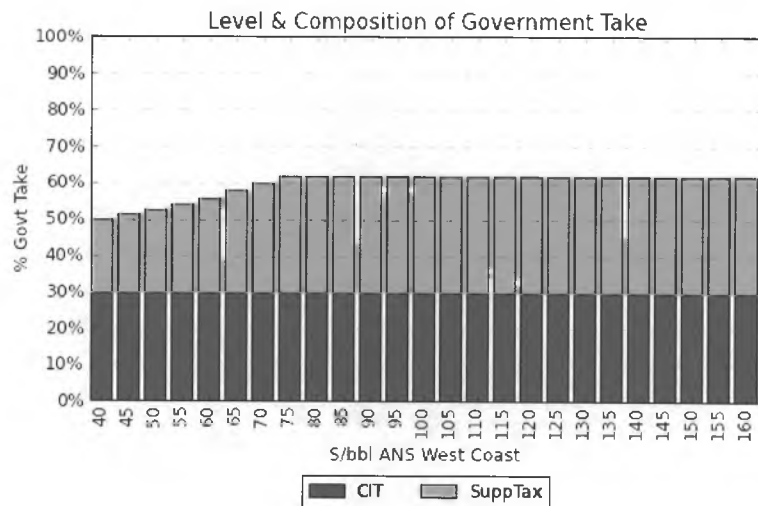
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	74.31%	-1.62	8.31%	20.76
\$100/bbl	75.84%	0.5	13.11%	26.72
\$120/bbl	77.49%	2.11	16.56%	30.66
\$140/bbl	78.49%	3.64	19.58%	34.49

The downside exposure to the state from reimbursable credits to small producers is potentially significant for high-cost projects in low price environments

Alaska Base Production under UK North Sea regime

UK North Sea, Base Production



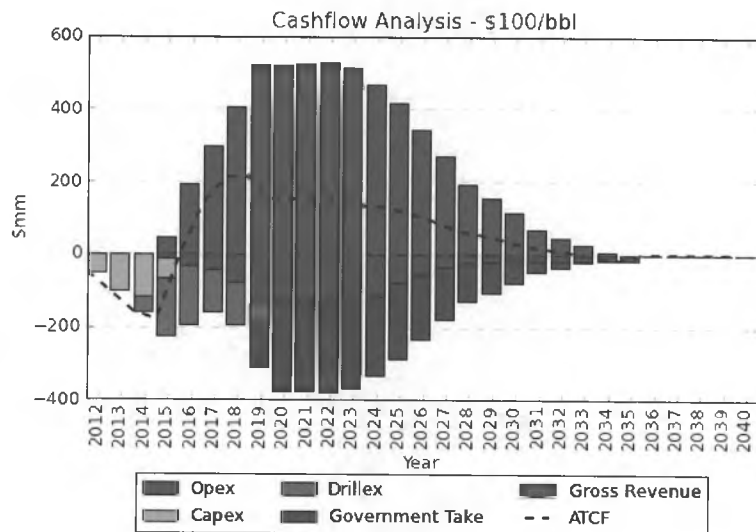
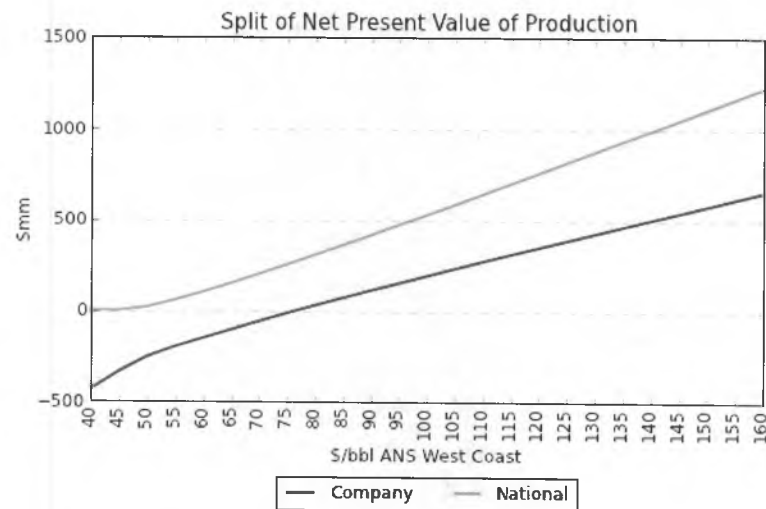
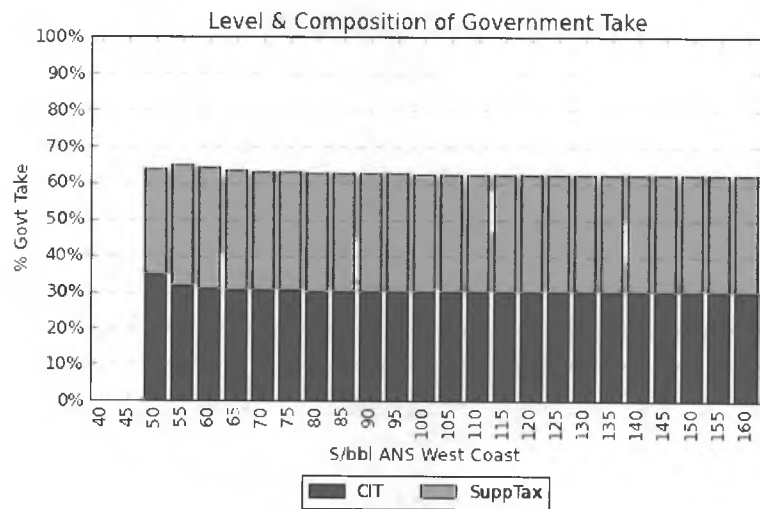
Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	62.00%	4.63		20.79
\$100/bbl	62.00%	6.62		29.9
\$120/bbl	62.00%	8.6		39.02
\$140/bbl	62.00%	10.59		48.14

By comparison, pure profit-tax based regimes like the UK North Sea can be completely neutral over an indefinite range of prices, with or without some progressivity at low prices

Alaska \$18/bbl Development under UK North Sea regime

UK North Sea, \$18/bbl New Development



Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	62.79%	0.62	13.29%	30.66
\$100/bbl	62.46%	3.89	19.64%	38.58
\$120/bbl	62.31%	7.04	25.09%	46.5
\$140/bbl	62.23%	10.11	29.82%	54.42

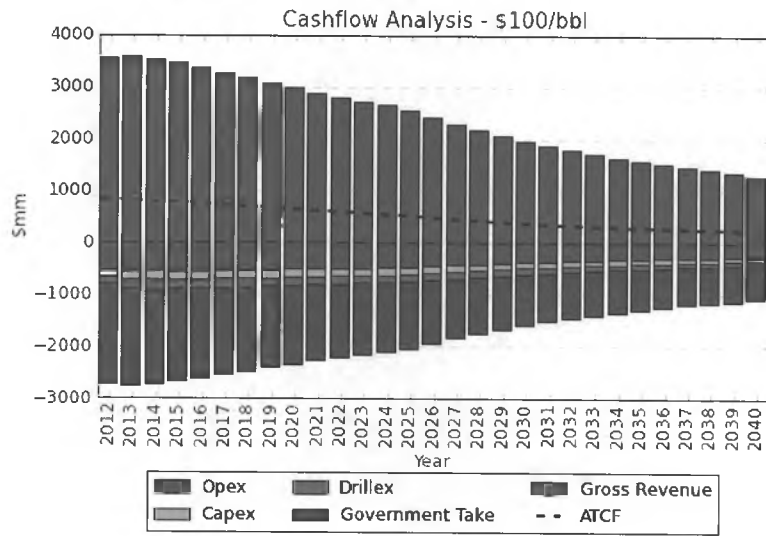
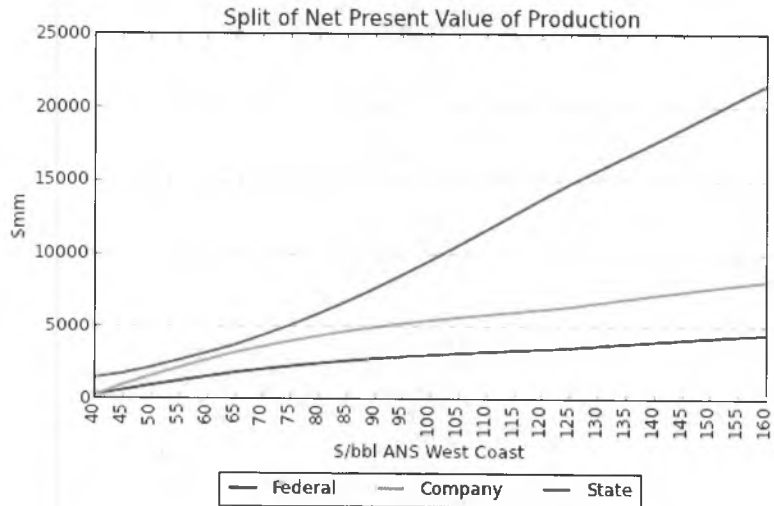
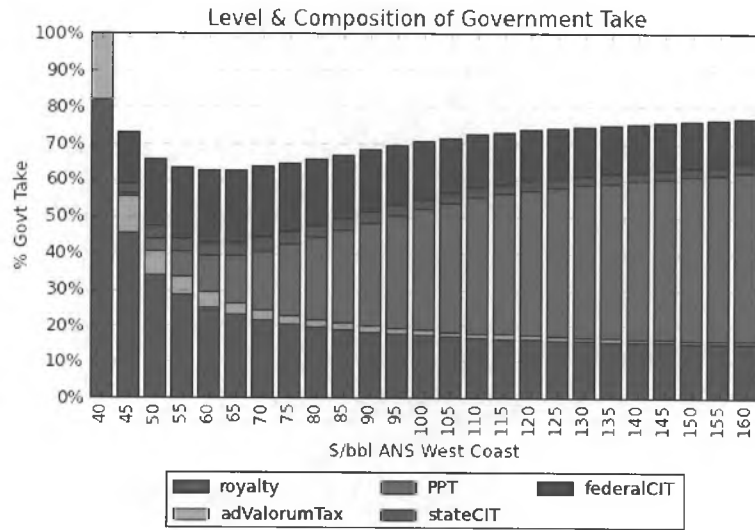
By comparison, pure profit-tax based regimes like the UK North Sea can be completely neutral over an indefinite range of prices, with or without some progressivity at low prices

Regime Comparisons:

**Seeking regime neutrality around the mid-60%
government take level**

ACES – Base Production

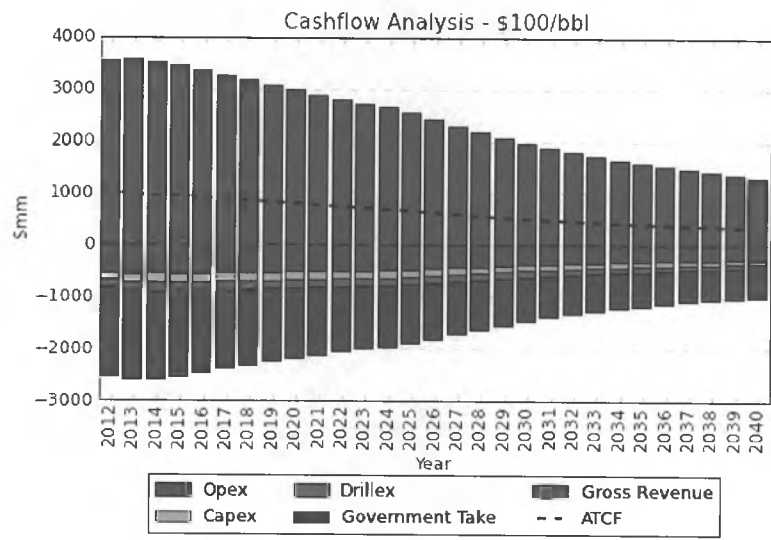
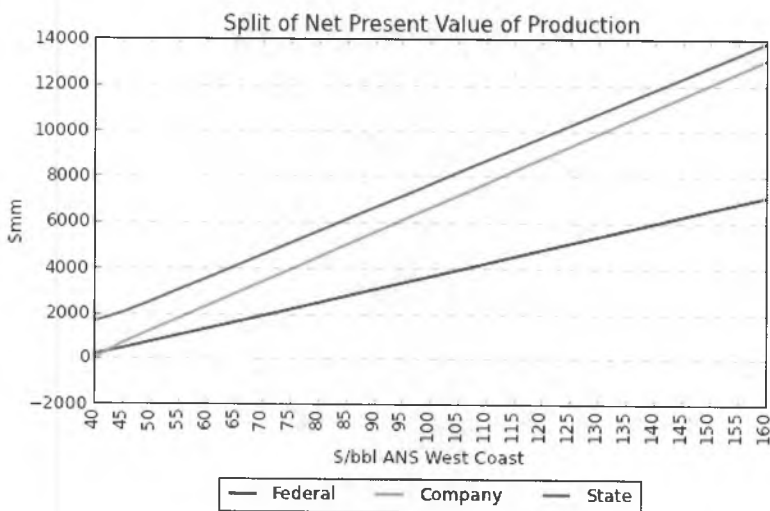
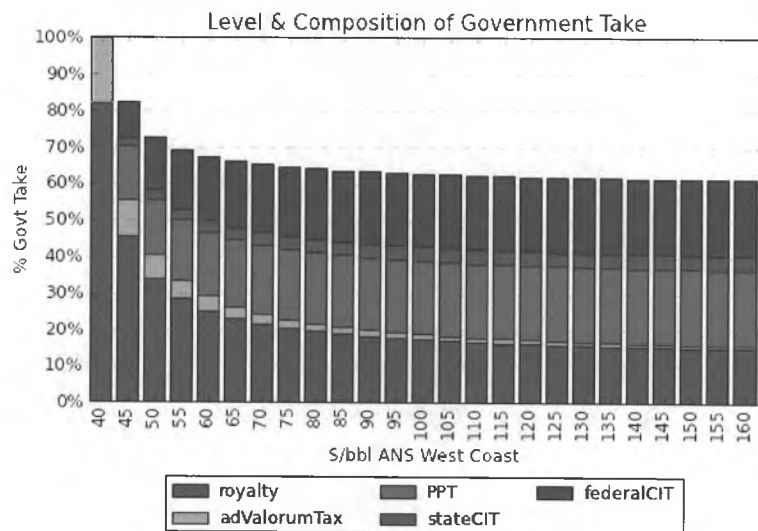
ACES, 12.5% Royalty, Base Production



Economic Summary

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

SB 21, 12.5% Royalty, Base Production



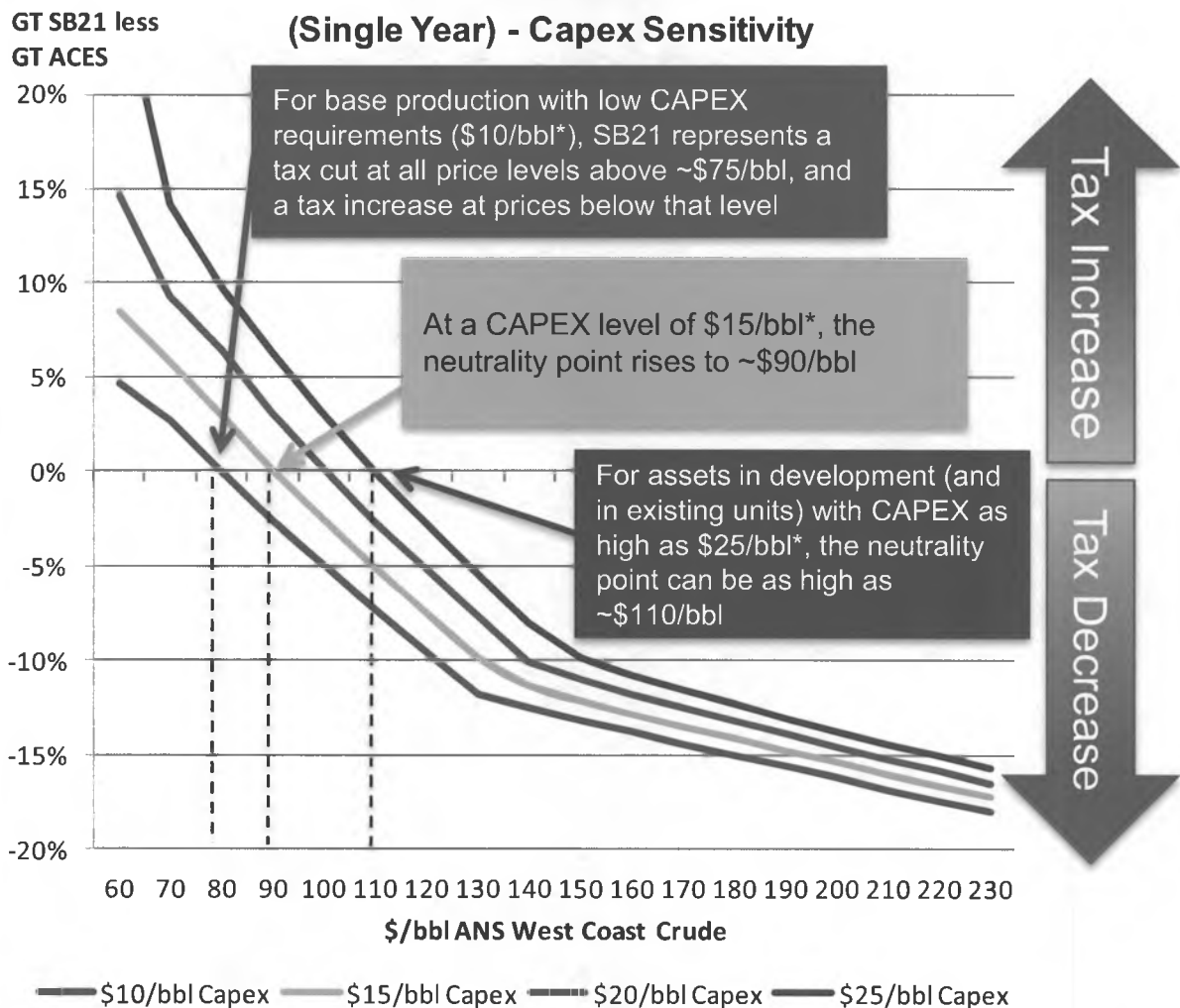
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.04%	4.35		19.72
\$100/bbl	62.76%	6.44		29.34
\$120/bbl	62.08%	8.54		38.96
\$140/bbl	61.67%	10.63		48.58

Government Take under SB21 and ACES

Capex Sensitivity

Government Take under SB21 less Government Take under ACES (Single Year) - Capex Sensitivity



* All CAPEX figures are in gross bbl terms (\$15 per gross bbl is roughly equivalent to DOR 2014 average North Slope forecast of \$19.6 per bbl net of royalty, when adjusted for gross/net and for capital expenditures by non-taxable entities)

- As noted in PFC Energy testimony on 1/31/13, at low oil prices, Relative Government Take under SB 21 is higher than under ACES, due to the impact of low or no progressivity, combined with the elimination of the 20% capital credit under SB 21

- The **oil price level** at which this occurs is highly **sensitive to annual levels of capital spending**, since CAPEX both reduces the oil price level at which progressivity kicks in under ACES, and determines the size of the available capital credit under ACES

- Looking at a **single year of production** also slightly raises this neutrality point, since over many years, inflation reduces the real price level at which progressivity starts under ACES

- For mature, producing assets with a low ongoing CAPEX requirement (\$10/bbl), SB21 represents a **reduction in government take at prices above ~\$75**, however for capital intensive new developments in existing units, that neutrality point can be as high as **\$110/bbl**

- It is thus important to understand that one impact of the removal of the 20% capital credit under SB 21 is that for companies with high development costs relative to overall production, it **can represent a tax increase at current prices**

Regimes for comparison: CS SB 21

- CS SB 21:
 - 35% Profit-based Production Tax, \$5/bbl allowance, 30% GRE for certain new production
 - Production-based allowance curves the tax-rate down at lower prices, creating a progressive element that achieves relative overall neutrality
 - Overall relative neutrality removes potential for 'gold-plating incentives'
 - Progressive element being determined on gross basis removes issue of oil vs gas 'decoupling'
 - Gross Revenue Exclusion reduces the overall level of government take for incentivized projects
 - Elimination of capital credit and carryforward of NOL credit reduces downside risk to state, but carries a cost in terms of project economics

\$5 production allowance is like reverse progressivity

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

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

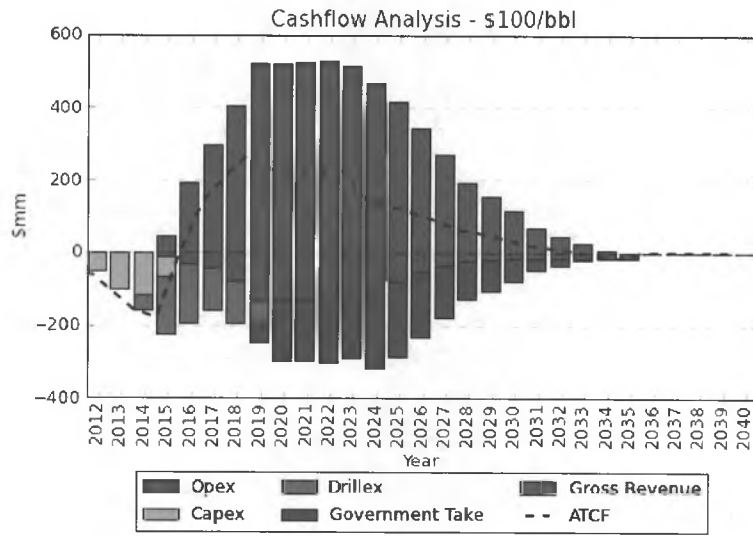
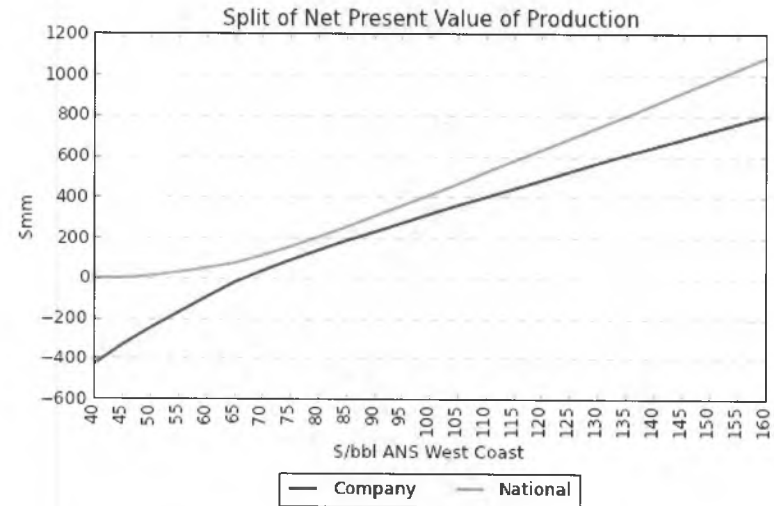
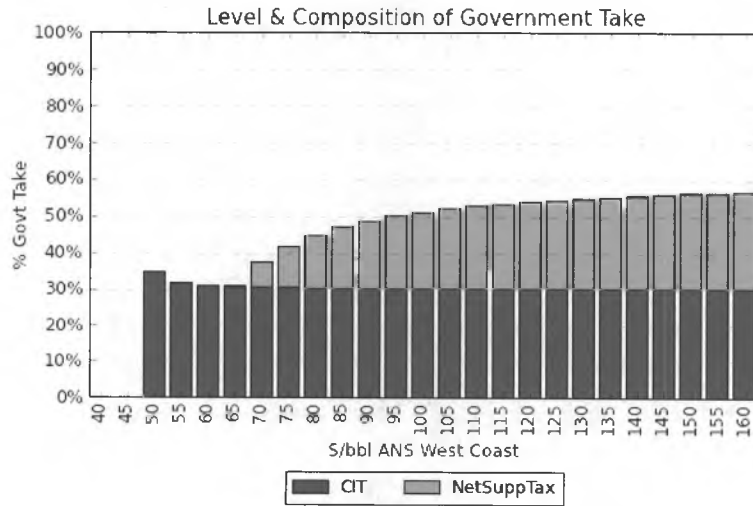
Taxable Production	50,000,000	50,000,000	50,000,000	50,000,000
ANS West Coast	60	80	120	140
Transportation	10	10	10	10
Gross Value at Point of Production	2,500,000,000	3,500,000,000	5,500,000,000	6,500,000,000
Lease Expenditures	1,500,000,000	1,500,000,000	1,500,000,000	1,500,000,000
GVPP/bbl	50	70	110	130
Lease Expenditures / bbl	30	30	30	30
GRE 30%	750,000,000	1,050,000,000	1,650,000,000	1,950,000,000
PTV	250,000,000	950,000,000	2,350,000,000	3,050,000,000
PTV/bbl	20	40	80	100
Production Tax without Allowance	87,500,000	332,500,000	822,500,000	1,067,500,000
Production Allowance	250,000,000	250,000,000	250,000,000	250,000,000
Production Tax	-	82,500,000	572,500,000	817,500,000
Nominal Tax Rate	35%	35%	35%	35%
Rate after Allowance	0.0%	8.7%	24.4%	26.8%
Progressive Tax Rate Deduction	35.0%	26.3%	10.6%	8.2%

Both share similarities with UK Brownfield Allowance

- The UK's fiscal regime is a relatively simple one, with two core components – a Corporate Income Tax (CIT) of 30%, and a Supplemental Resource Tax (SRT) of 32%, levied on the CIT tax base
- The UK Brownfield Allowance is an income exclusion, used in calculating the SRT. Up to a total £250mm of income can be excluded, with up to 20% of the exclusion amount allowed in a given year. For projects subject to the additional Petroleum Tax (pre-1993 projects), the exclusion is up to £500mm of income
- Because it is a fixed exclusion, it has a greater impact at lower oil prices
- Projects are individually assessed for qualification, and for the total amount of relief available. Qualifying projects are incremental projects increasing production from mature fields.
- A 100mmb incremental development, with costs of \$25/bbl, could see its government take reduced by to anywhere from 3 to 11 percentage points, depending on the oil price level

Alaska \$18/bbl Development under UK North Sea regime

UK North Sea, \$18/bbl New Development, with Brownfield Allowance



Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	44.85%	2.75	17.04%	38.16
\$100/bbl	51.26%	6.34	23.38%	49.73
\$120/bbl	54.16%	9.64	28.68%	59.14
\$140/bbl	55.83%	12.92	33.60%	69.08

Regimes for comparison: Bracketed Progressivity (Net)

- Bracketed Progressivity (Net):
 - 25% Profit-based Production Tax
 - Bracketed progressivity with the following thresholds and rates:
 - \$30 PTV – 5%
 - \$42.5 PTV – 10%
 - \$55 PTV – 15%
 - 20% capital credit maintained, but carried forward to production for producers with no liability
 - Overall relative neutrality removes potential for ‘gold-plating incentives’
 - Progressive element being determined on net basis does not entirely remove issue of oil vs gas ‘decoupling’, but low degree of progressivity minimizes impact
 - Gross Revenue Exclusion not included in modeling, but could be applied to incentivize new projects
 - Carryforward (without escalation) of credits reduces some downside risk to state, while retaining a cost-progressive element. Escalation could also be included to compensate for time value of money foregone

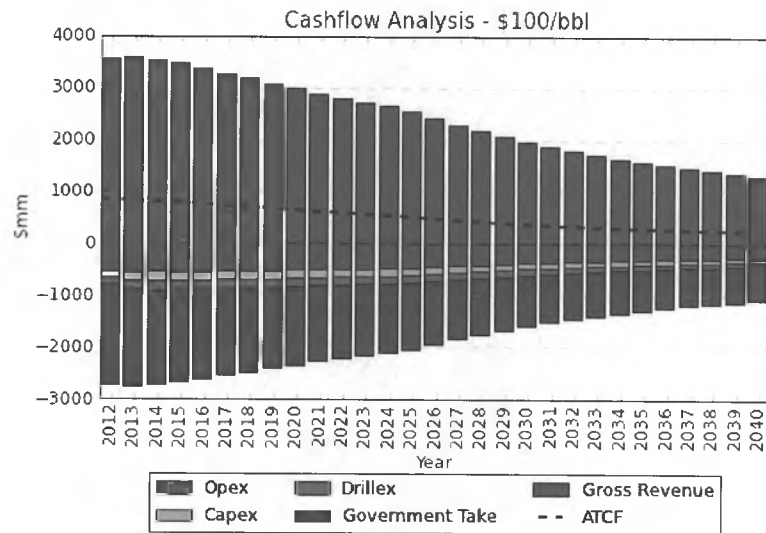
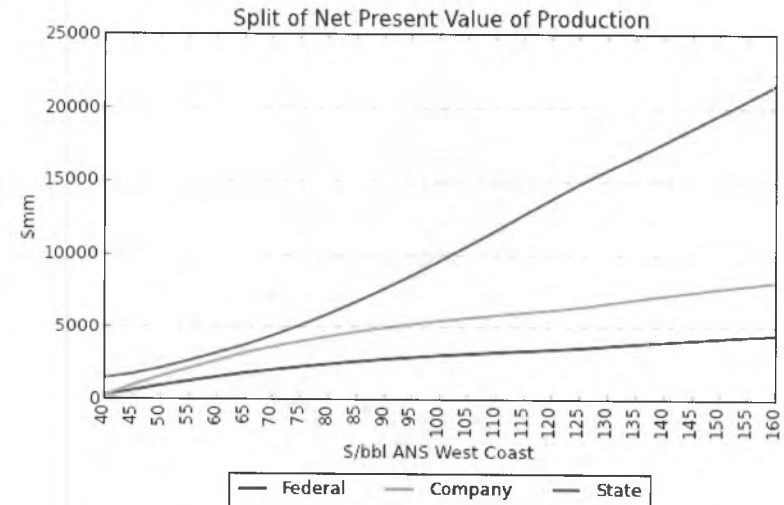
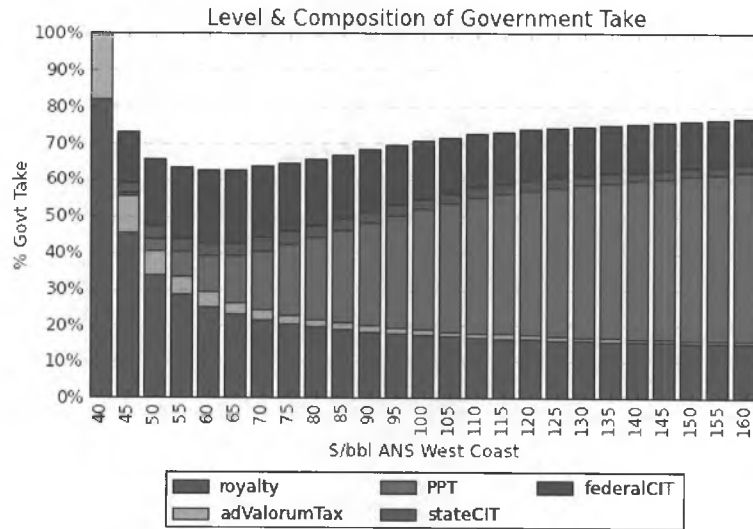
Regimes for comparison: Bracketed Progressivity (Gross)

- Bracketed Progressivity (Net):
 - 20% Profit-based Production Tax – lower rate needed to when progressivity on gross to prevent a tax increase at lower price levels for higher cost producers
 - Bracketed progressivity with the following thresholds and rates:
 - \$70 ANS West Coast Crude – 5%
 - \$90 ANS West Coast Crude– 10%
 - \$110 ANS West Coast Crude– 15%
 - \$130 ANS West Coast Crude– 20%
 - 20% capital credit maintained, but carried forward to production for producers with no liability
 - Overall relative neutrality removes potential for ‘gold-plating incentives’
 - Progressive element being determined on net basis does not entirely remove issue of oil vs gas ‘decoupling’, but low degree of progressivity minimizes impact
 - Gross Revenue Exclusion not included in modeling, but could be applied to incentivize new projects
 - Carryforward (without escalation) of credits reduces some downside risk to state, while retaining a cost-progressive element. Escalation could also be included to compensate for time value of money foregone

- **Base Production**

ACES – Base Production

ACES, 12.5% Royalty, Base Production

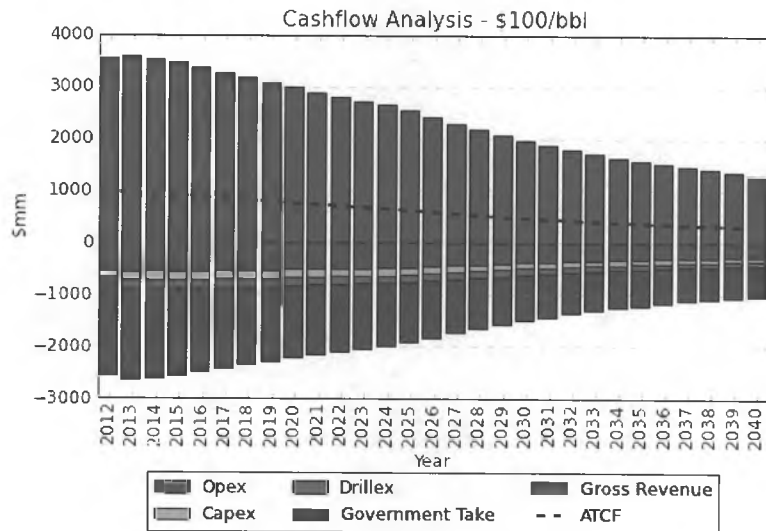
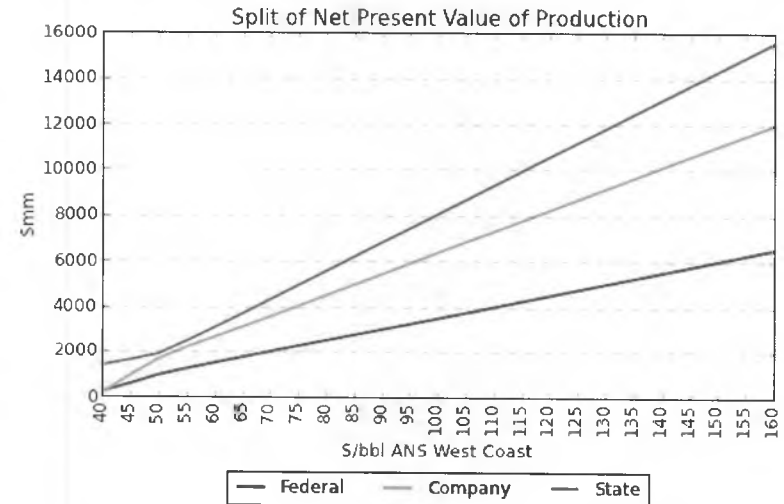
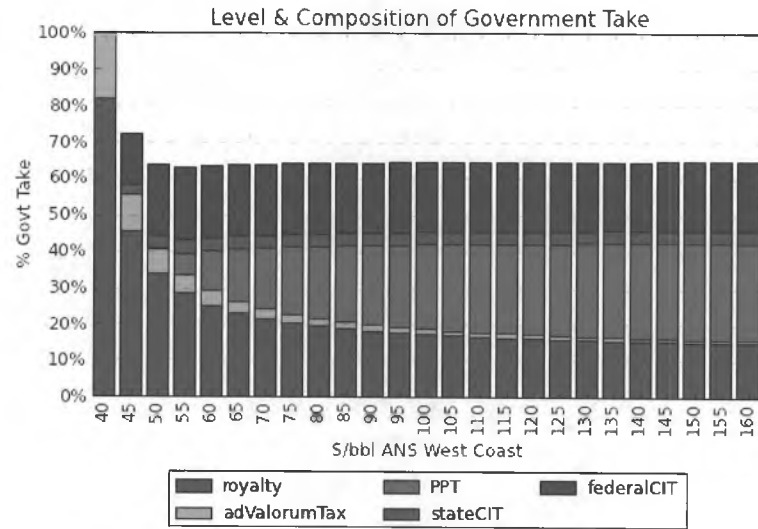


Economic Summary

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

CS B21 Base Production

CS SB 21, 12.5% Royalty, Base Production

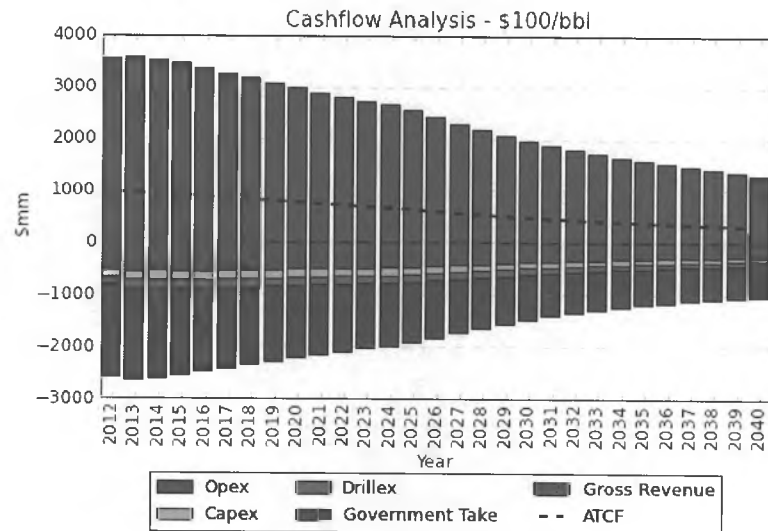
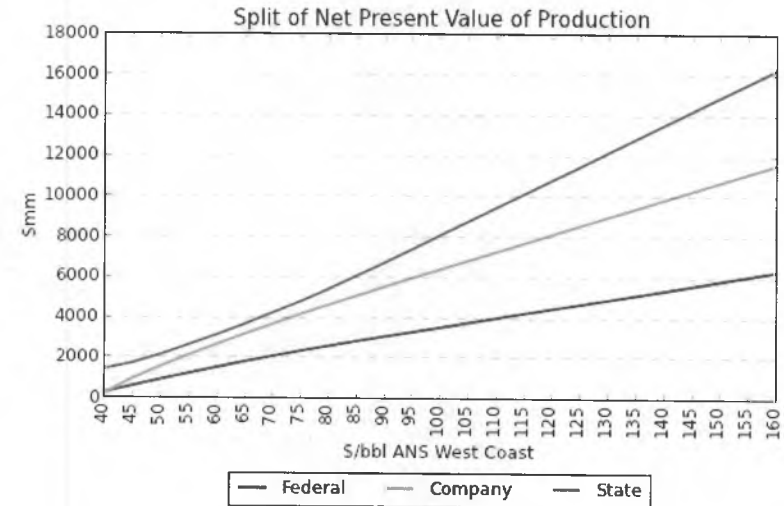
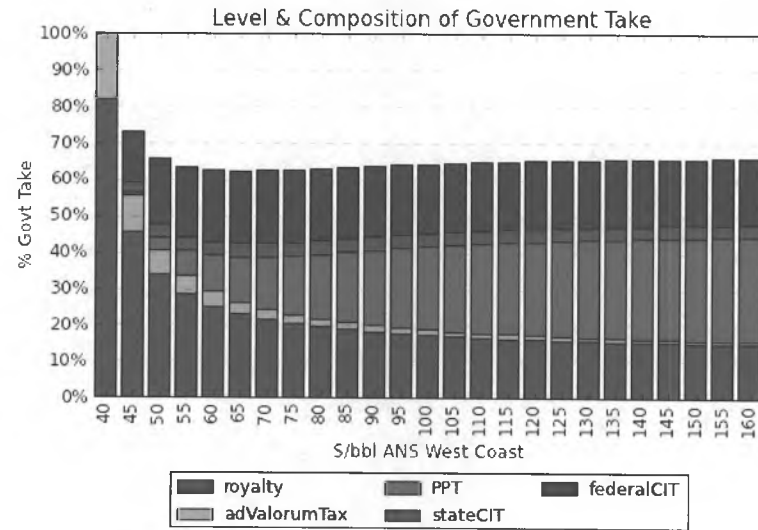


Economic Summary

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

Bracketed Progressivity (Net) Base Production

Bracketed Progressivity (Net), 12.5% Royalty, Base Production

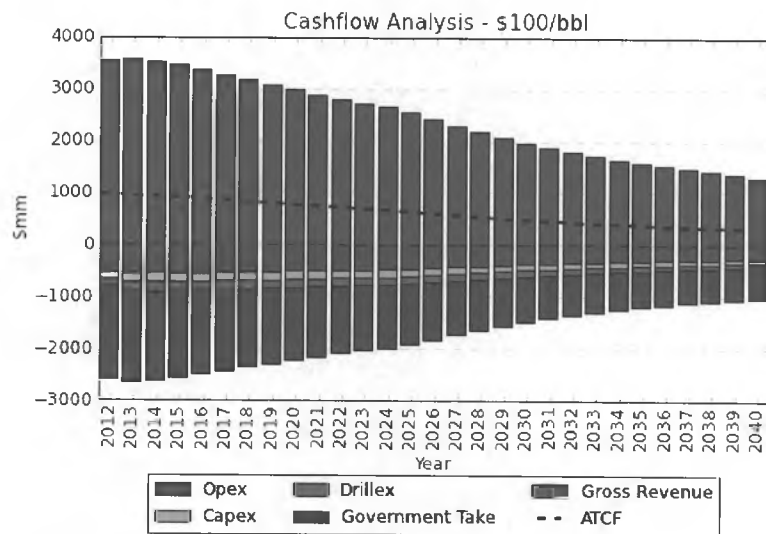
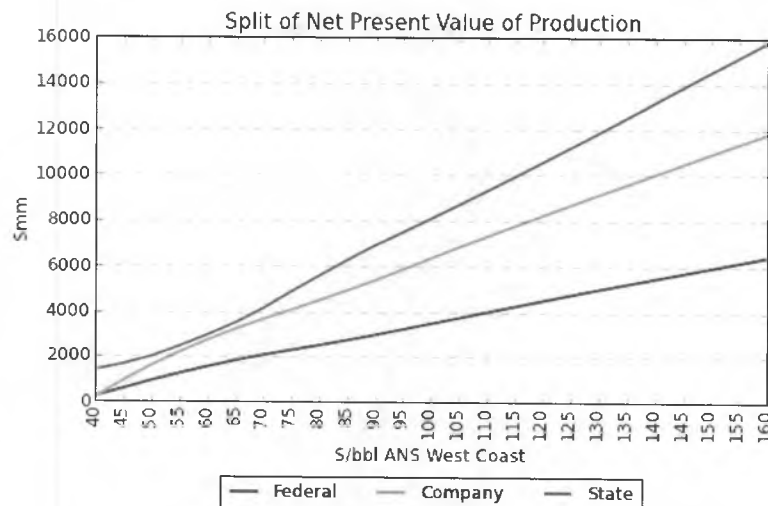
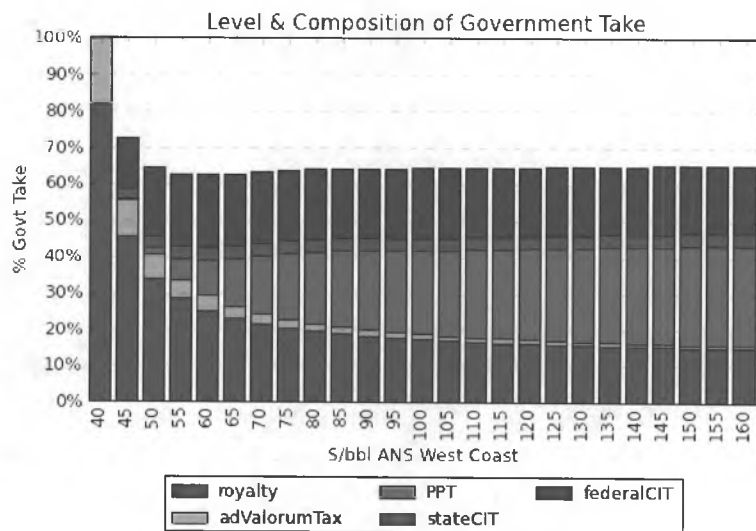


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	63.02%	4.47		20.38
\$100/bbl	64.39%	6.19		28.23
\$120/bbl	65.22%	7.87		35.93
\$140/bbl	65.74%	9.54		43.63

Bracketed Progressivity (Gross) Base Production

Bracketed Progressivity (Gross), 12.5% Royalty, Base Production



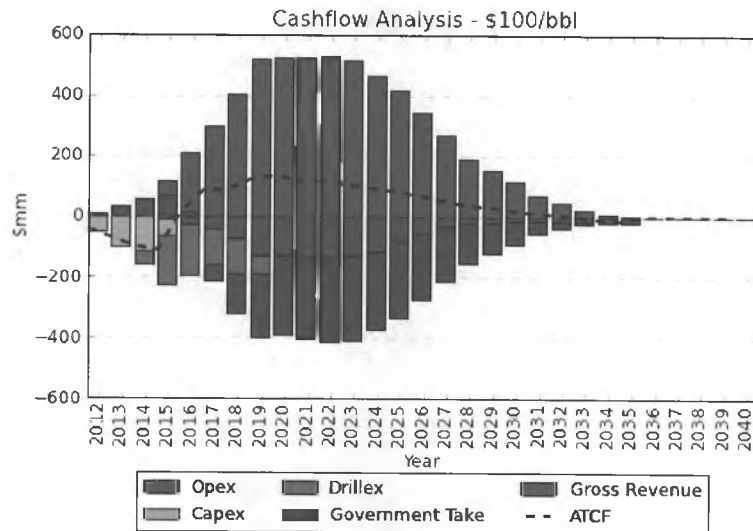
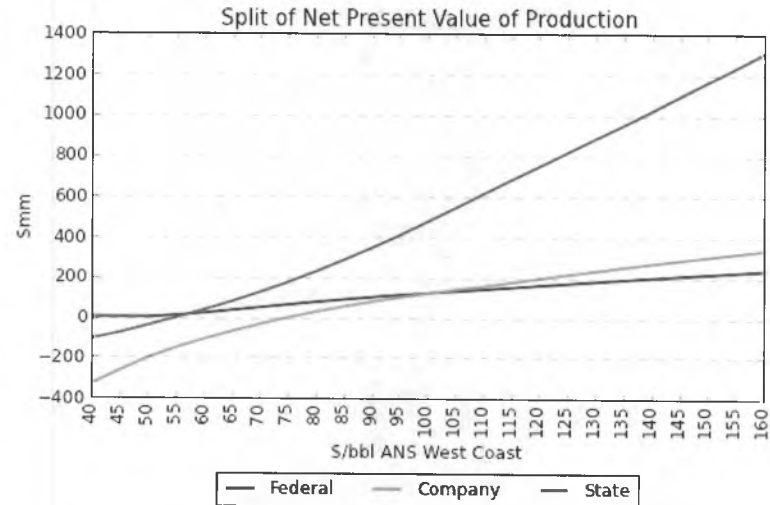
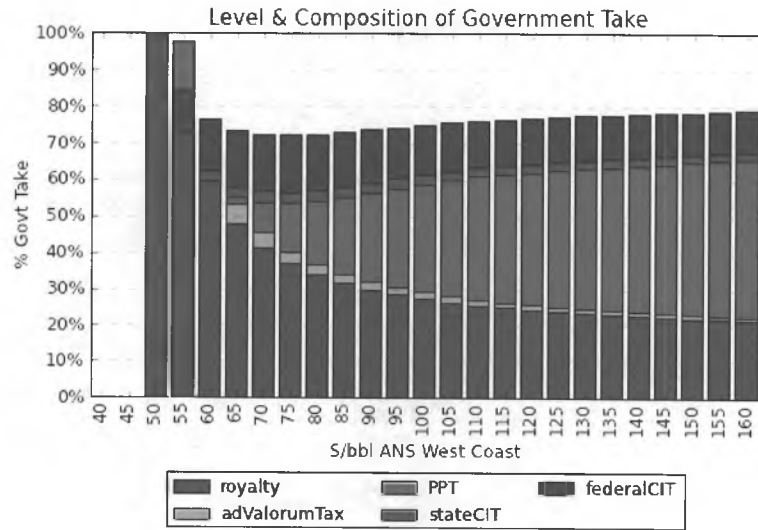
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.13%	4.36		19.49
\$100/bbl	64.44%	6.17		28.25
\$120/bbl	64.75%	8.0		36.5
\$140/bbl	65.14%	9.75		44.47

- **\$18/bbl New Development**

ACES - \$18/bbl New Development, Standalone

ACES, 16.7% Royalty, \$18/bbl New Development

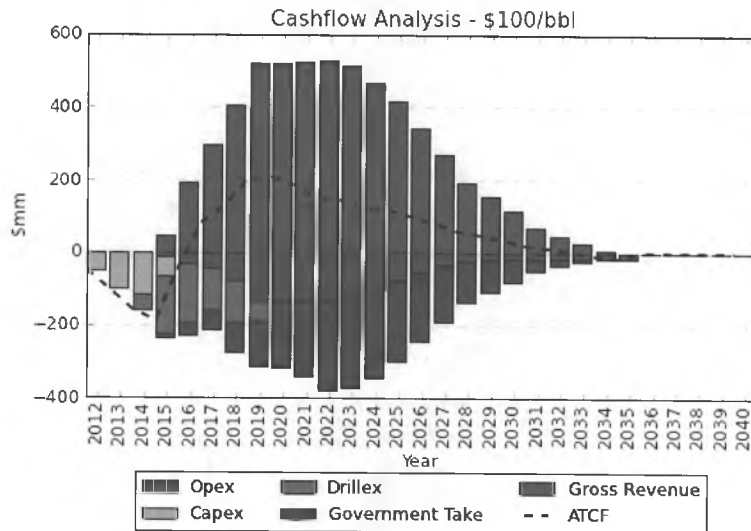
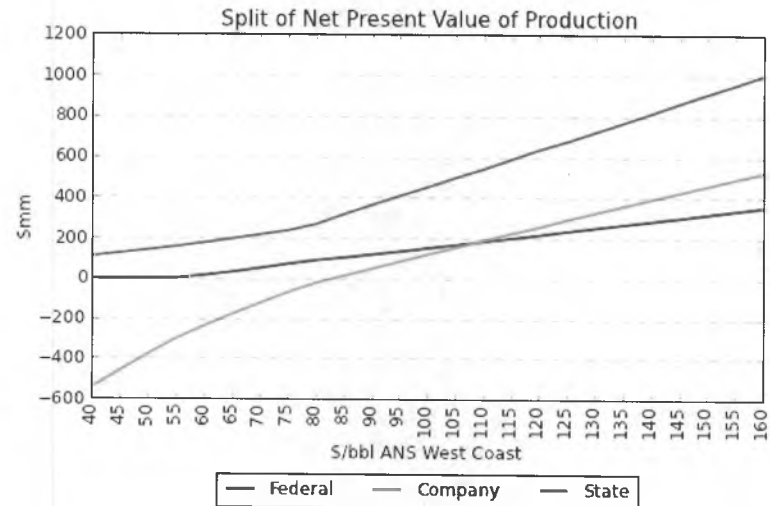
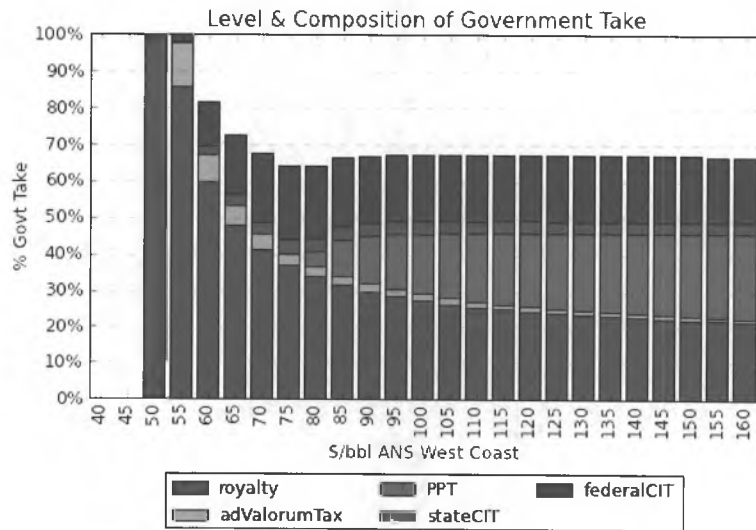


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	72.49%	0.63	13.88%	19.94
\$100/bbl	75.08%	2.48	19.07%	25.18
\$120/bbl	77.01%	3.98	22.94%	28.63
\$140/bbl	78.10%	5.46	26.44%	32.33

\$18/bbl New Development, Standalone, no GRE

CS SB 21, 16.7% Royalty, \$18/bbl New Development

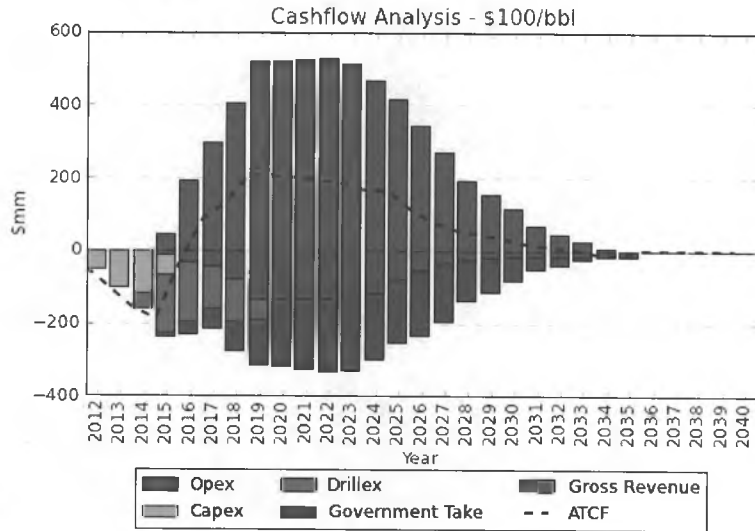
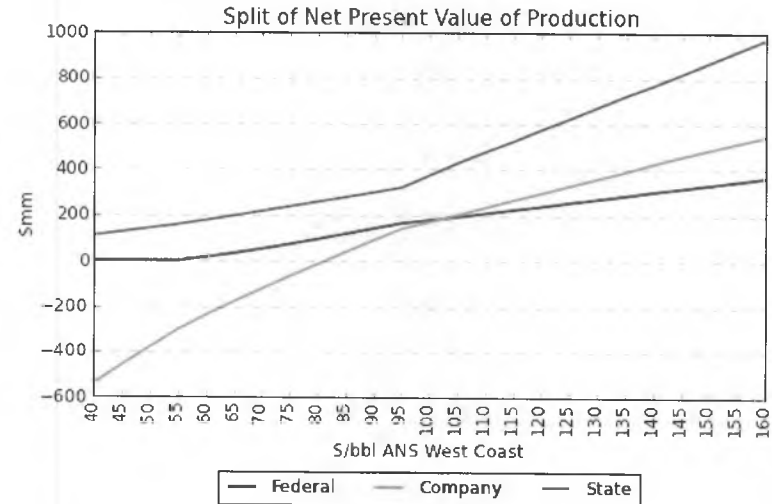
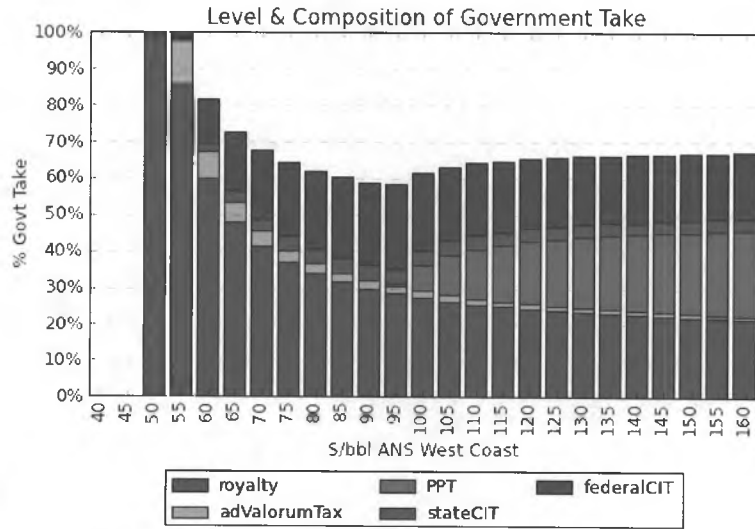


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.41%	-0.4	11.25%	27.34
\$100/bbl	67.20%	2.44	16.61%	36.68
\$120/bbl	67.36%	5.16	21.37%	43.19
\$140/bbl	67.18%	7.88	25.67%	50.4

Bracketed Progressivity (No) \$18/bbl New Development, Standalone

Bracketed Progressivity (Net), 16.7% Royalty, \$18/bbl New Development

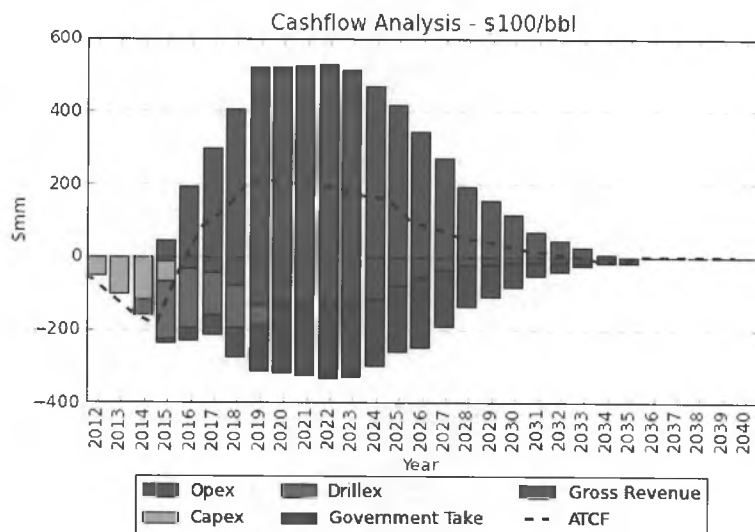
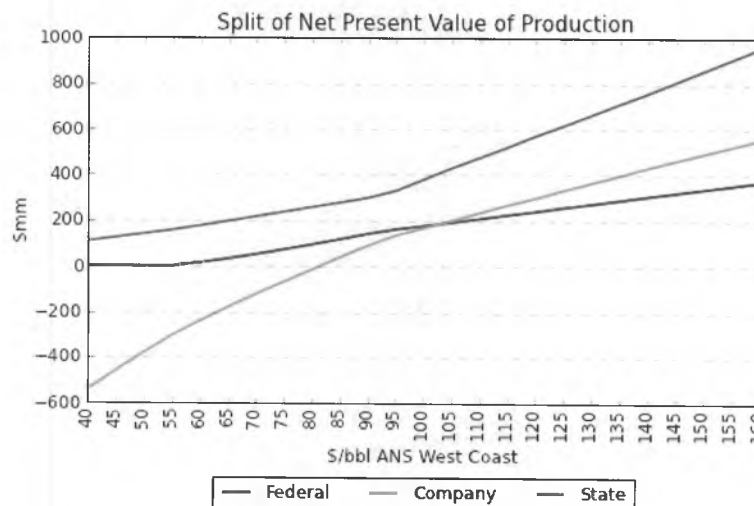
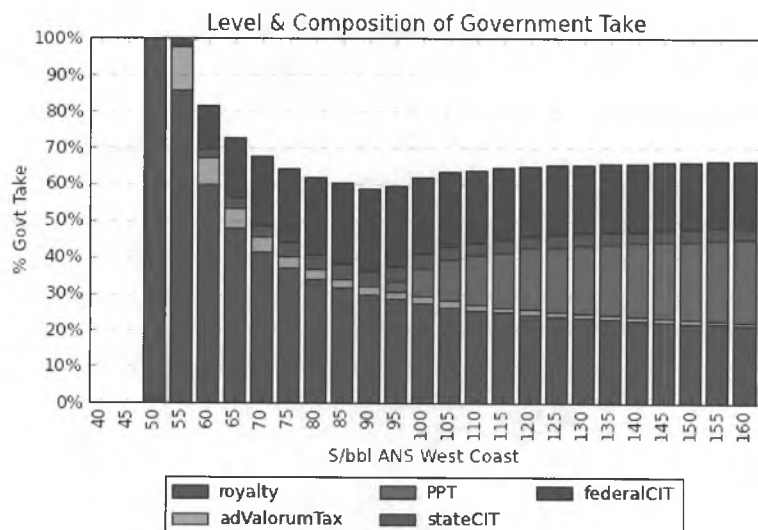


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	61.95%	-0.26	11.52%	27.34
\$100/bbl	61.47%	3.43	18.09%	39.0
\$120/bbl	65.34%	5.94	22.63%	48.76
\$140/bbl	66.41%	8.52	26.84%	54.68

Bracketed Progressivity (Gross) \$18/bbl New Development, Standalone

Bracketed Progressivity (Gross), 16.7% Royalty, \$18/bbl New Development

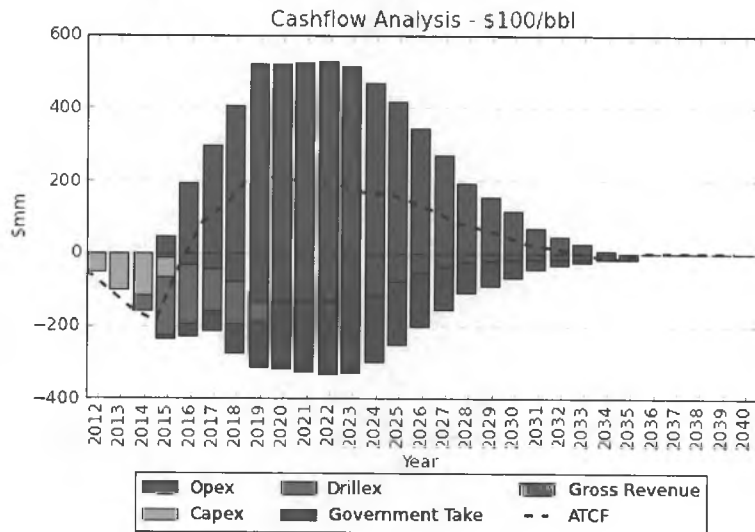
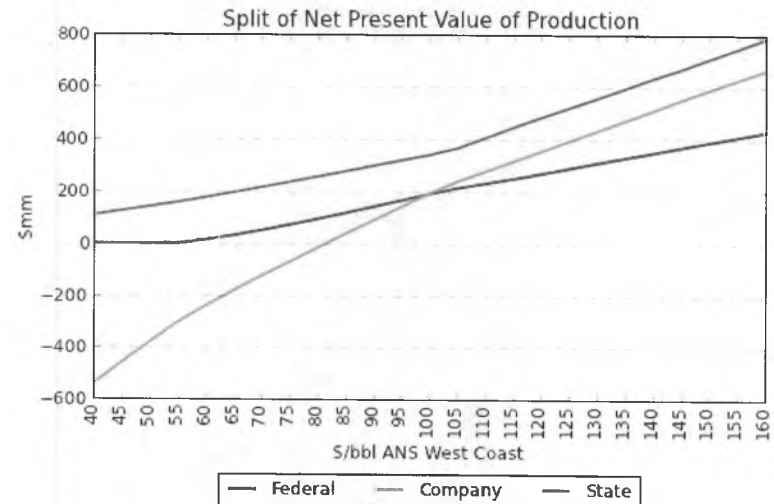
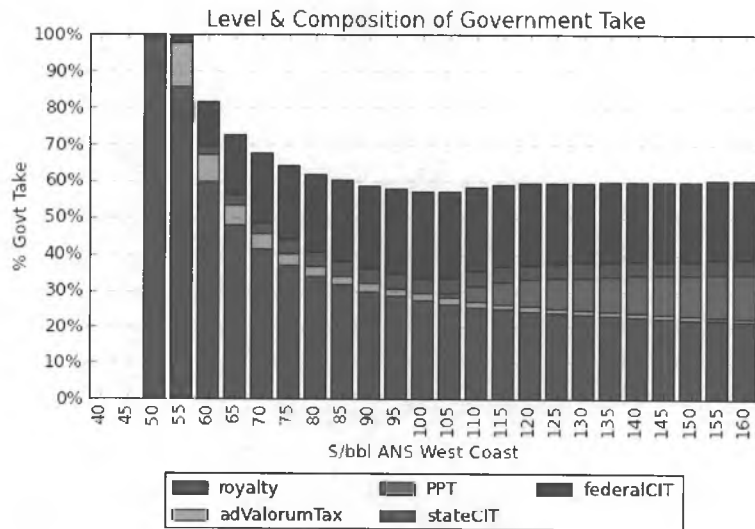


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	61.95%	-0.26	11.52%	27.34
\$100/bbl	61.97%	3.37	18.01%	39.0
\$120/bbl	65.03%	6.0	22.68%	48.72
\$140/bbl	65.94%	8.64	26.95%	54.97

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

CS SB 21, 16.7% Royalty, \$18/bbl New Development with GRE

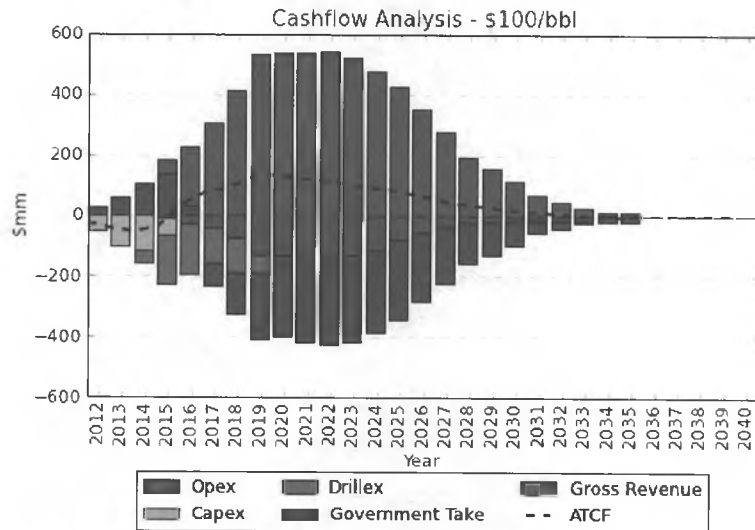
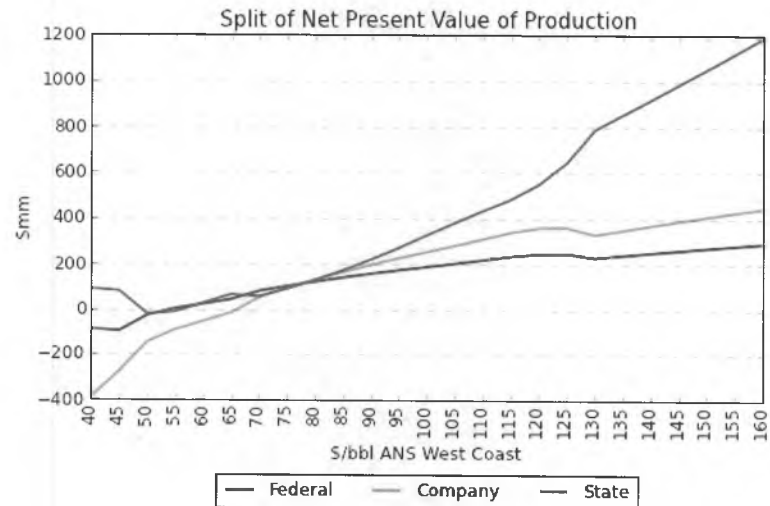
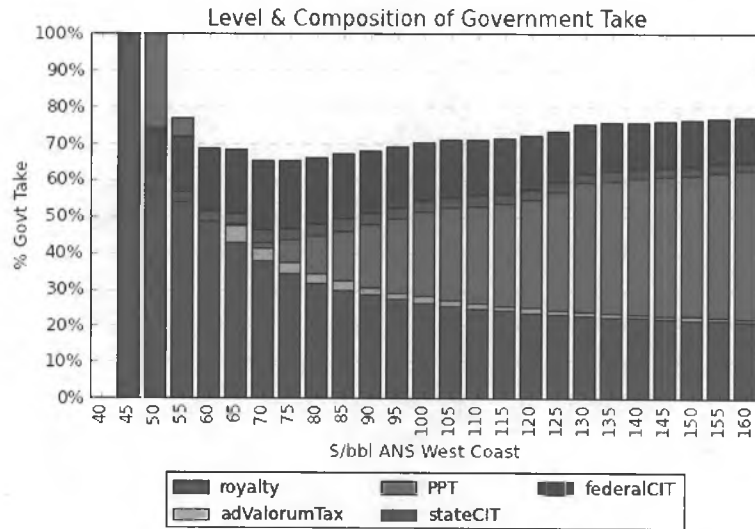


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	61.95%	-0.26	11.52%	27.34
\$100/bbl	57.10%	3.88	18.56%	39.0
\$120/bbl	59.45%	7.12	23.80%	50.65
\$140/bbl	60.03%	10.25	28.35%	59.02

\$18/bbl New Development, Incremental

ACES, 16.7% Royalty, \$18/bbl New Development, Incremental to Incumbent

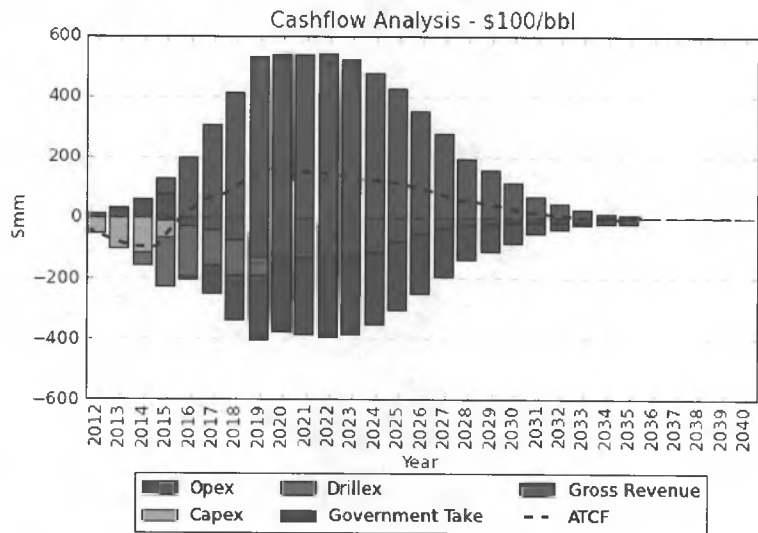
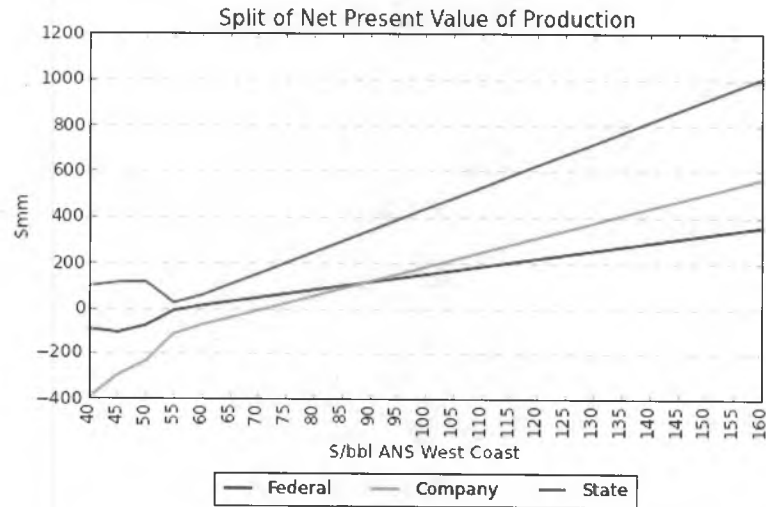
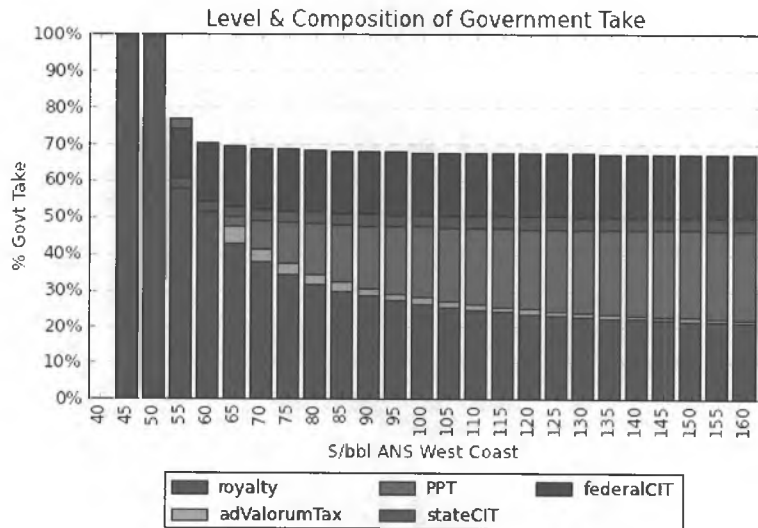


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	66.28%	2.62	21.78%	19.9
\$100/bbl	70.46%	5.08	33.40%	25.29
\$120/bbl	72.43%	7.19	46.62%	28.55
\$140/bbl	75.95%	7.42	38.65%	32.8

\$18/bbl New Development, Incremental

CS SB 21, 16.7% Royalty, \$18/bbl New Development, Incremental to Incumbent

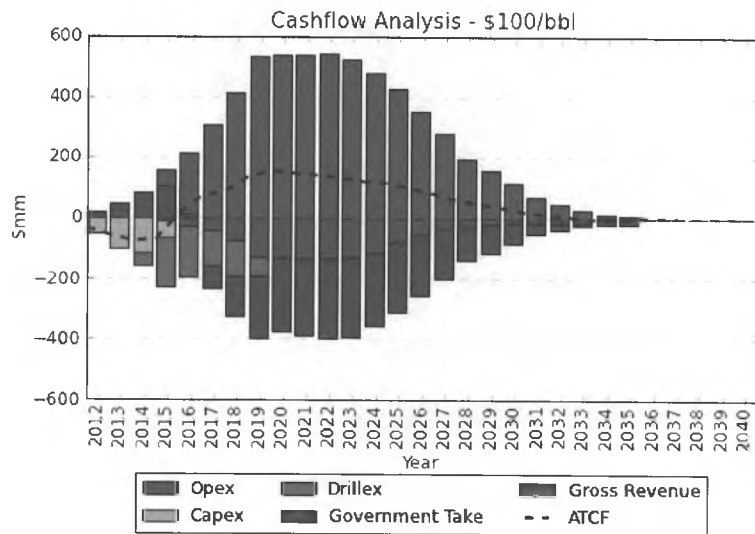
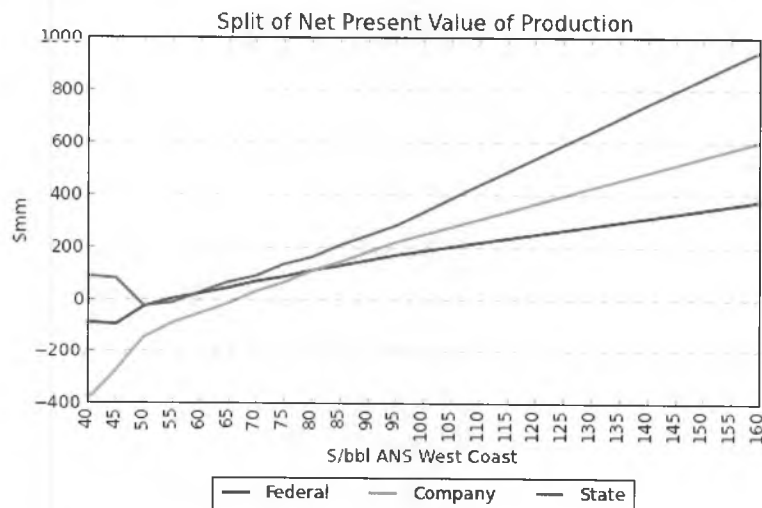
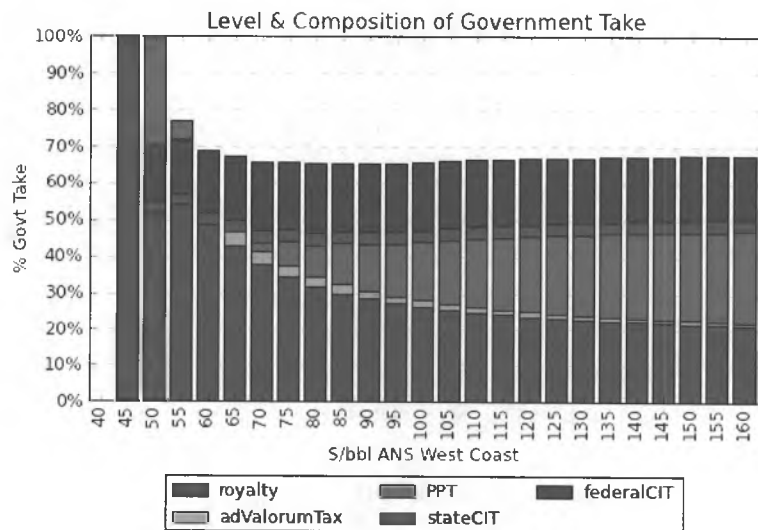


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	68.44%	1.11	15.08%	19.6
\$100/bbl	67.89%	3.66	21.20%	27.61
\$120/bbl	67.63%	6.22	26.41%	35.63
\$140/bbl	67.48%	8.77	31.01%	43.64

Bracketed Progressivity (Net) \$18/bbl New Development, Incremental

Bracketed Progressivity (Net), 16.7% Royalty, \$18/bbl New Development, Incremental to Incumbent

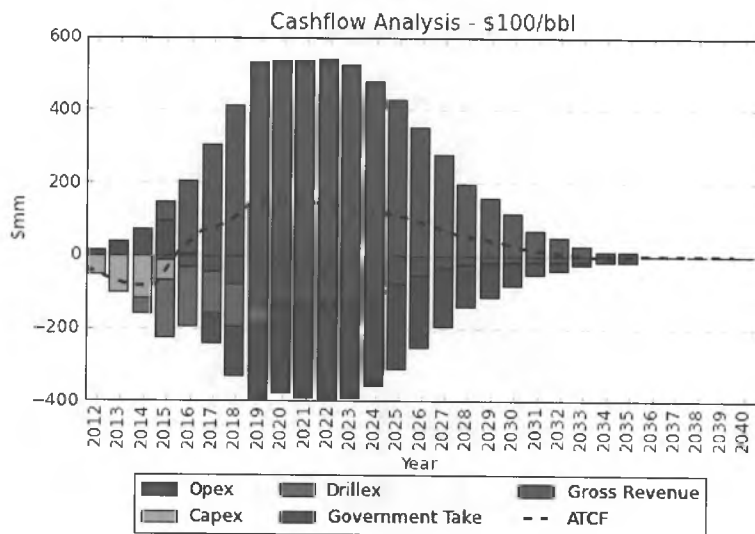
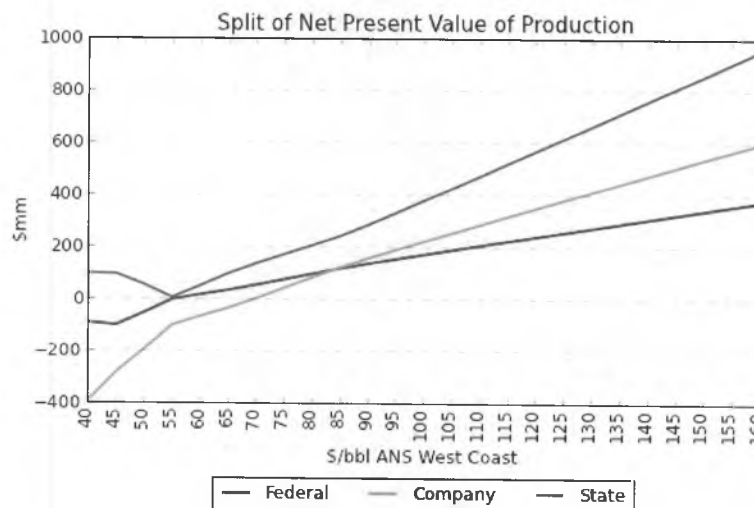
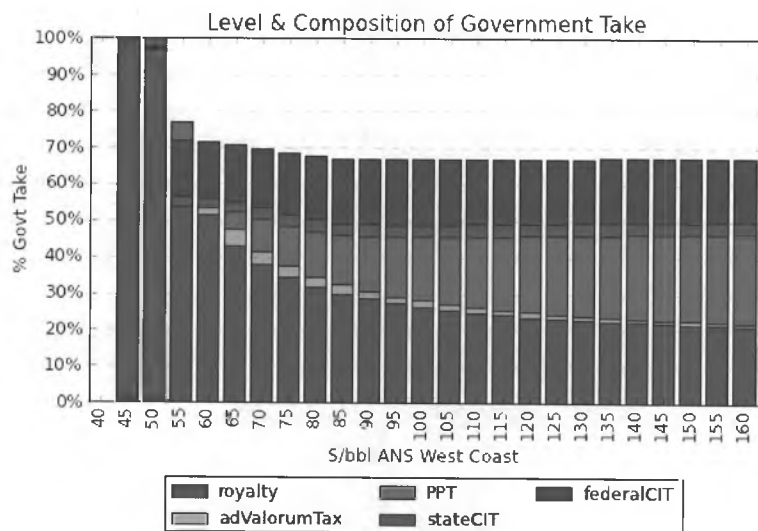


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	65.23%	2.19	18.94%	20.59
\$100/bbl	65.82%	4.97	26.93%	28.33
\$120/bbl	66.78%	7.33	32.24%	35.73
\$140/bbl	67.34%	9.69	36.93%	43.13

Bracketed Progressivity (Gross) \$18/bbl New Development, Incremental

Bracketed Progressivity (Gross), 16.7% Royalty, \$18/bbl New Development, Incremental to Incumbent



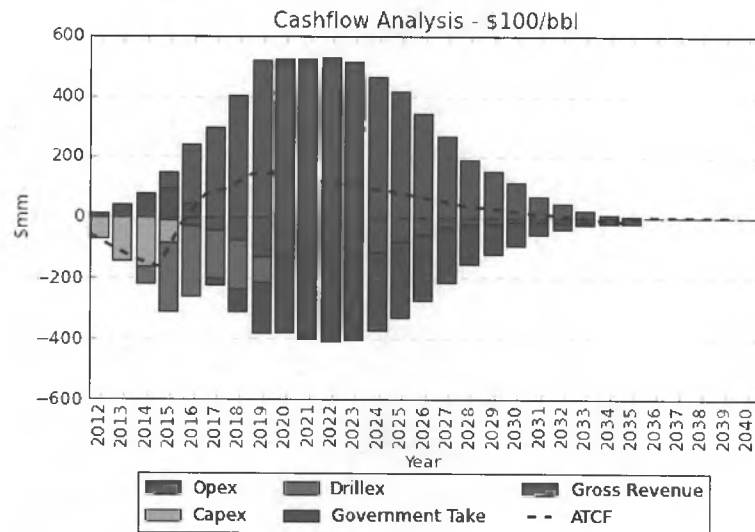
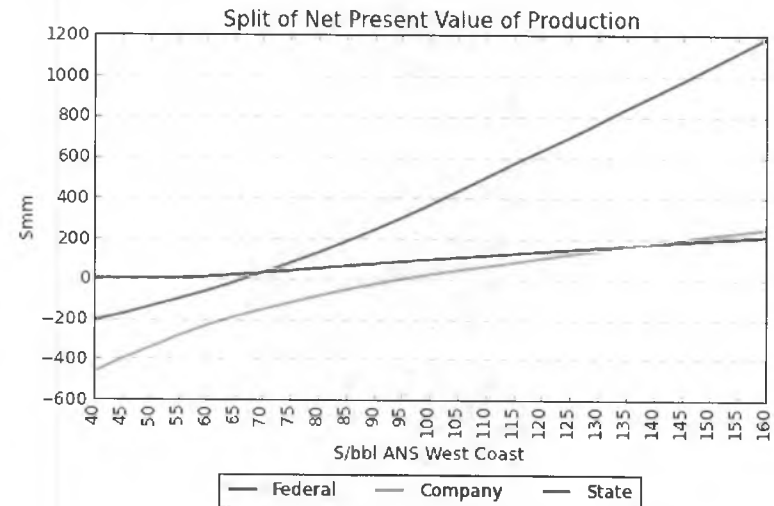
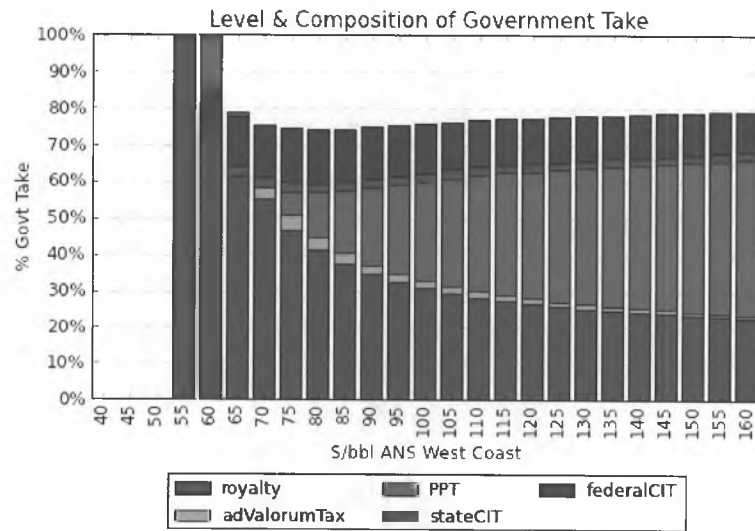
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	67.63%	1.64	17.00%	19.59
\$100/bbl	66.80%	4.42	24.30%	28.0
\$120/bbl	66.99%	6.97	29.90%	35.94
\$140/bbl	67.21%	9.48	34.88%	43.64

- **\$25/bbl New Development**

ACES - \$25/bbl New Development, Standalone

ACES, 16.7% Royalty, \$25/bbl New Development

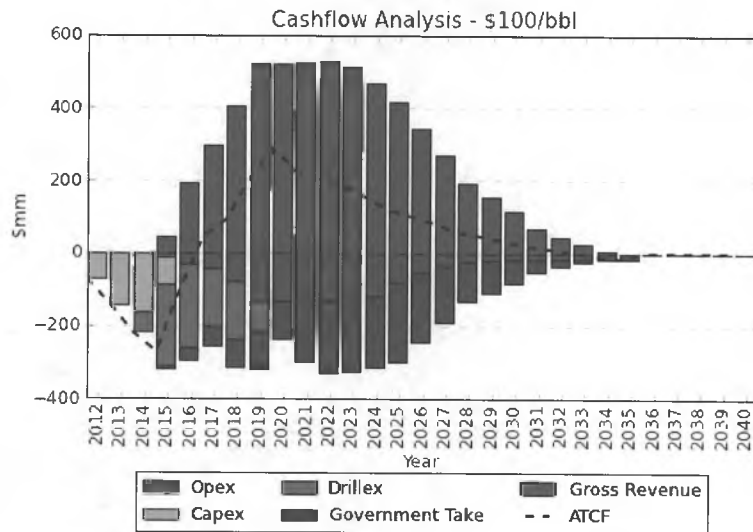
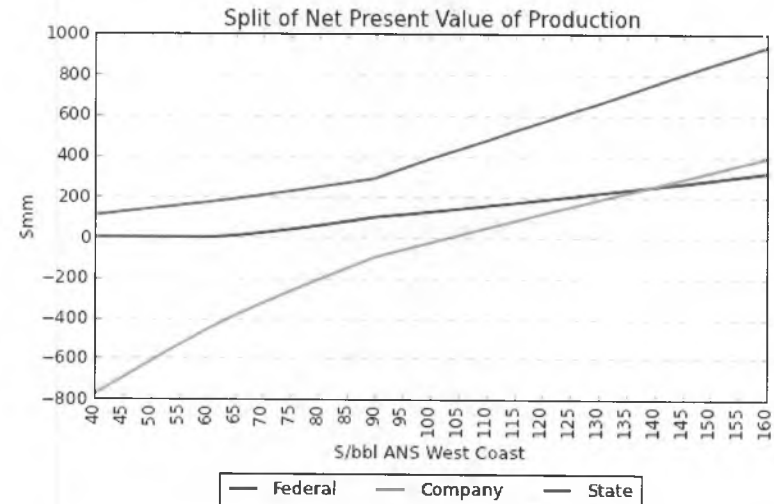
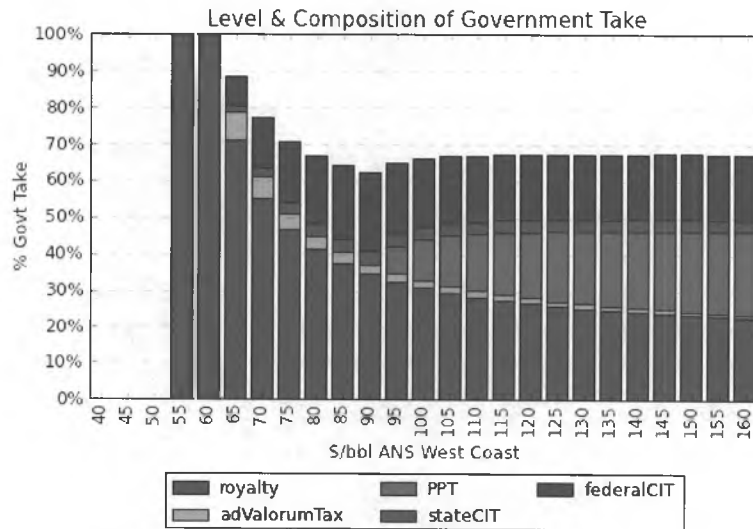


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	74.31%	-1.62	8.31%	20.76
\$100/bbl	75.84%	0.5	13.11%	26.72
\$120/bbl	77.49%	2.11	16.56%	30.66
\$140/bbl	78.49%	3.64	19.58%	34.49

\$25/bbl New Development, Standalone, No GRE

CS SB 21, 16.7% Royalty, \$25/bbl New Development, No GRE

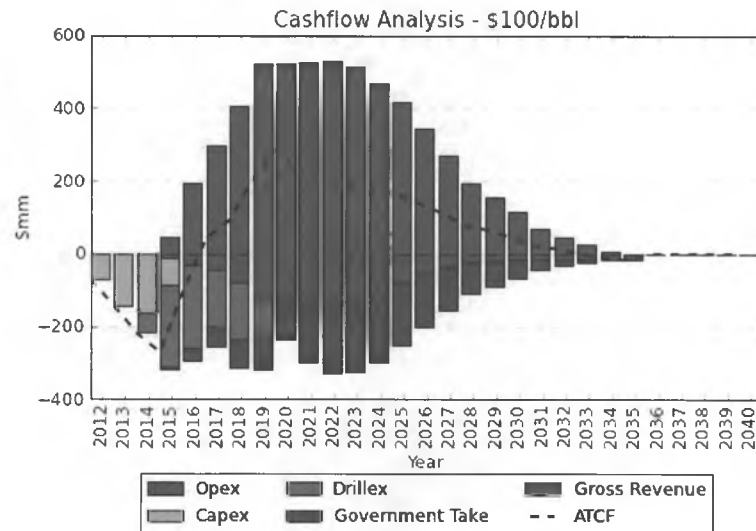
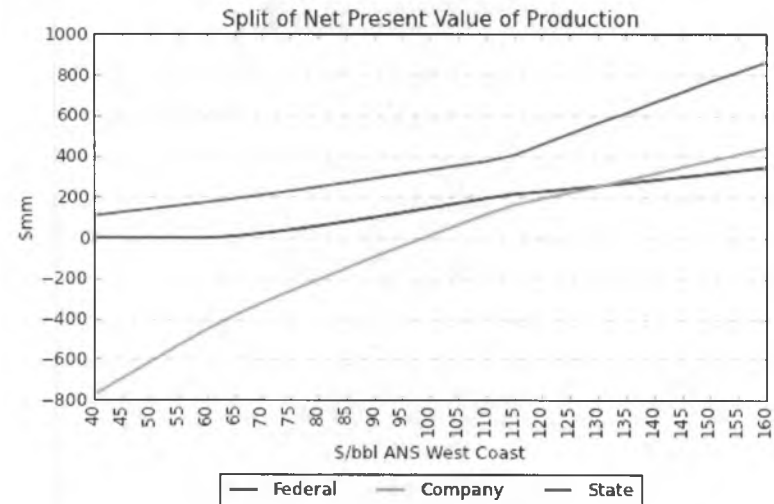
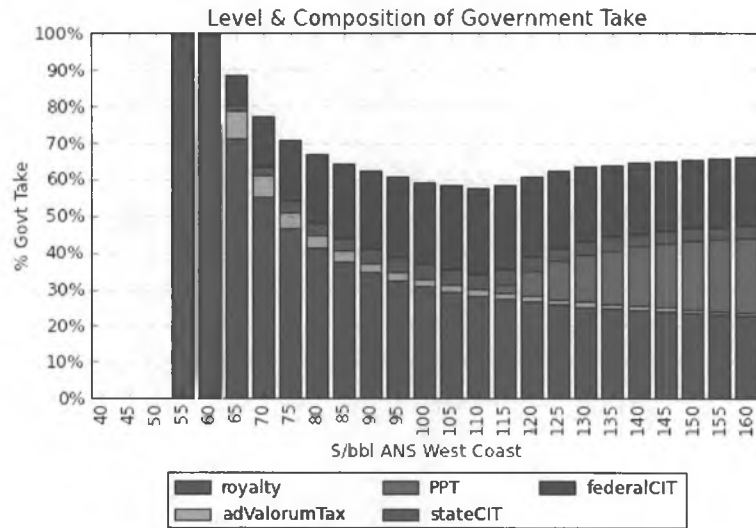


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	66.93%	-4.08	6.32%	27.03
\$100/bbl	66.29%	-0.46	11.35%	40.1
\$120/bbl	67.34%	2.4	15.31%	48.48
\$140/bbl	67.50%	5.12	18.87%	54.85

Bracketed Progressivity (Net) \$25/bbl New Development, Standalone

Bracketed Progressivity (Net), 16.7% Royalty, \$25/bbl New Development

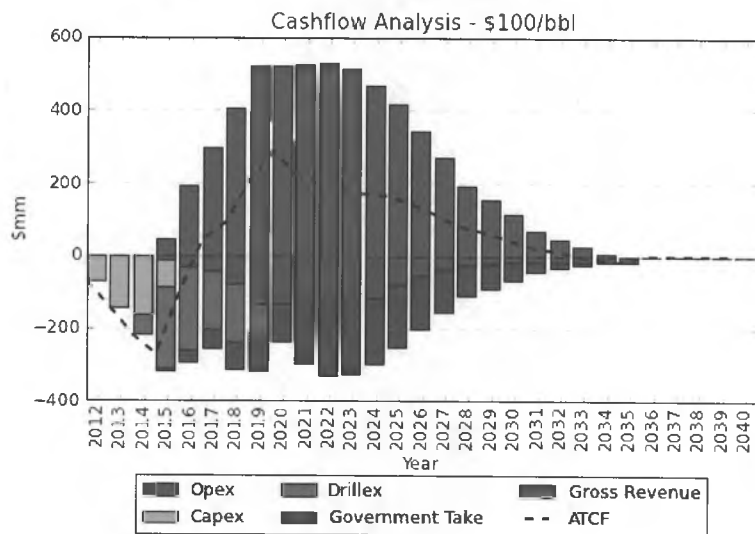
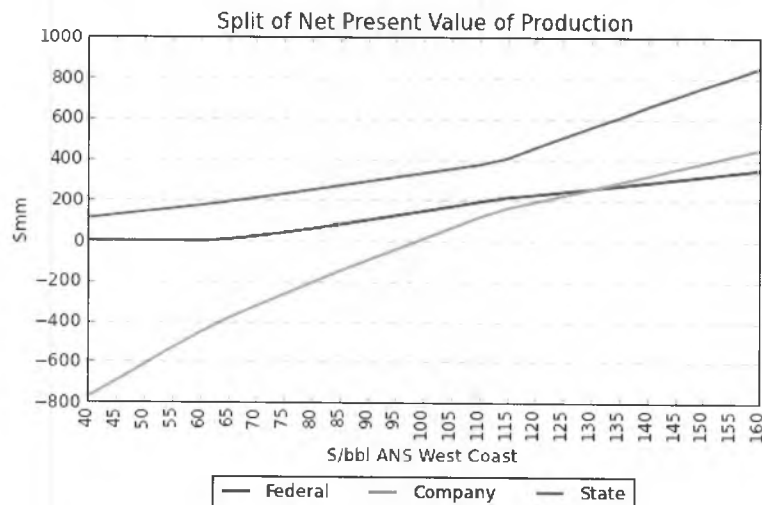
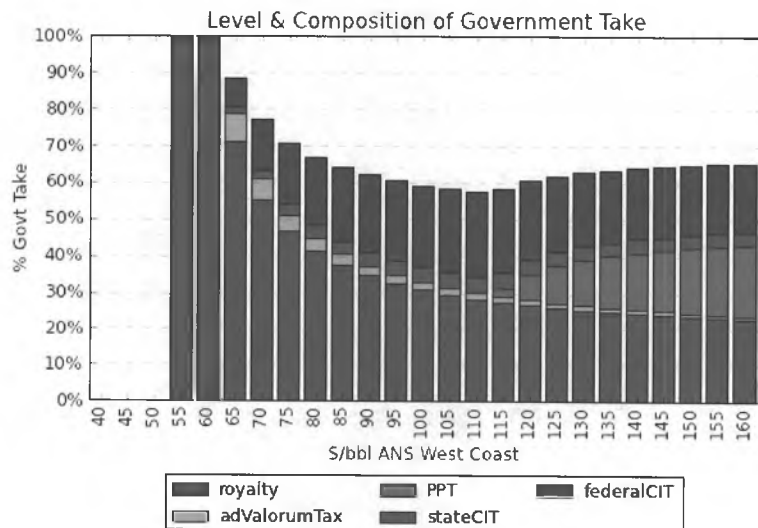


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	66.93%	-4.08	6.32%	27.03
\$100/bbl	59.37%	0.25	12.33%	40.1
\$120/bbl	60.71%	3.84	16.94%	51.76
\$140/bbl	64.68%	6.3	20.24%	63.42

Bracketed Progressivity (Gross) \$25/bbl New Development, Standalone

Bracketed Progressivity (Gross), 16.7% Royalty, \$25/bbl New Development

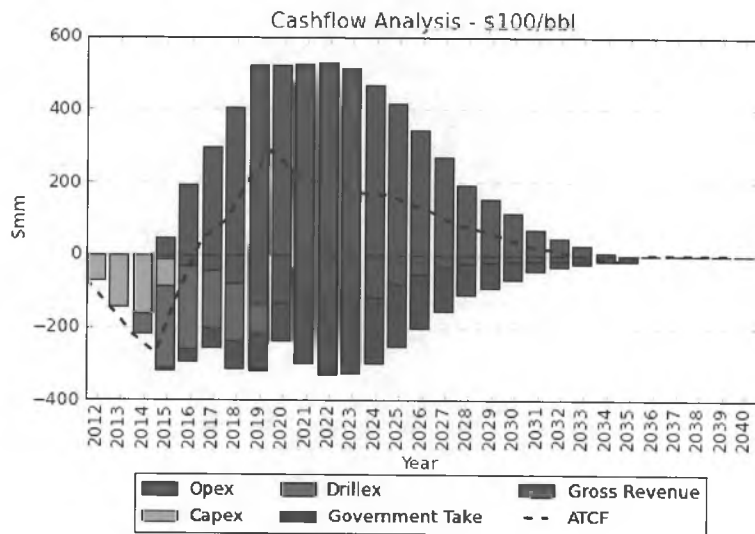
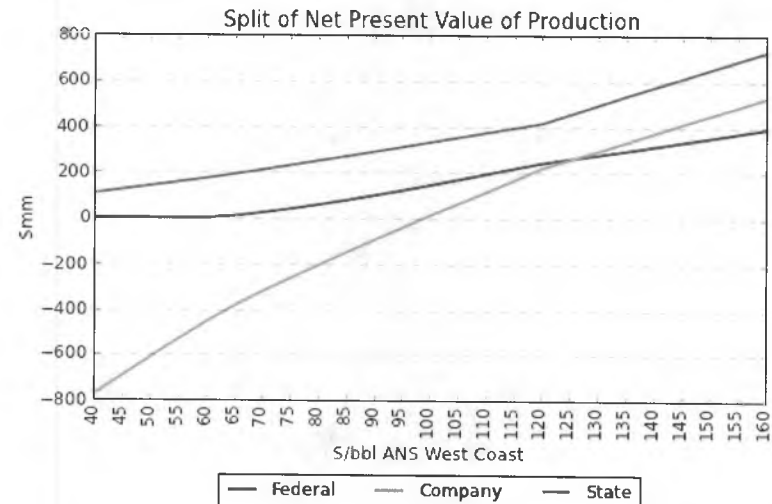
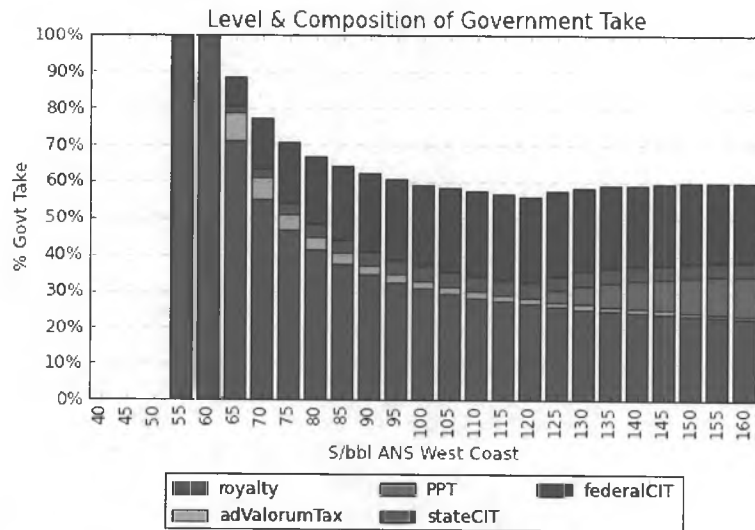


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	66.93%	-4.08	6.32%	27.03
\$100/bbl	59.37%	0.25	12.33%	40.1
\$120/bbl	60.58%	3.86	16.96%	51.76
\$140/bbl	64.26%	6.39	20.32%	63.42

\$25/bbl New Development, Standalone, with GRE

CS SB 21, 16.7% Royalty, \$25/bbl New Development, with GRE

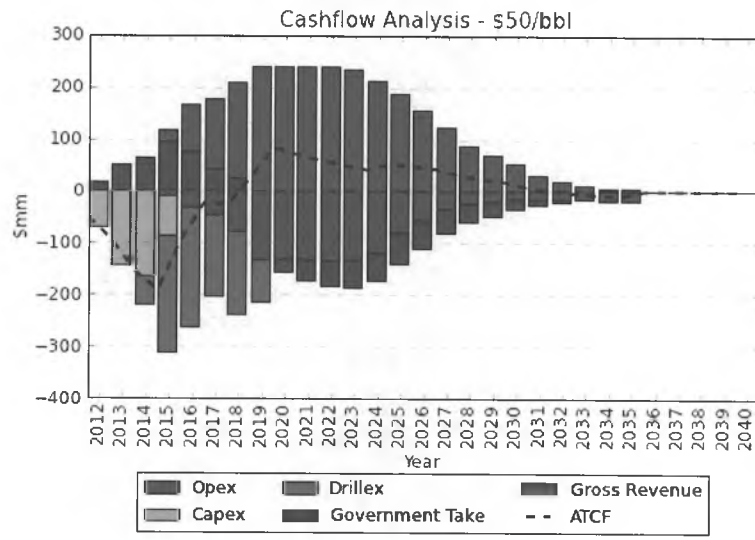
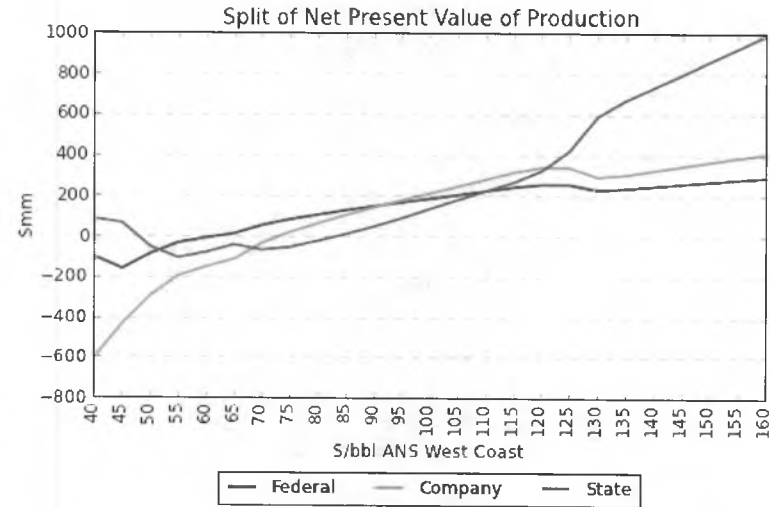
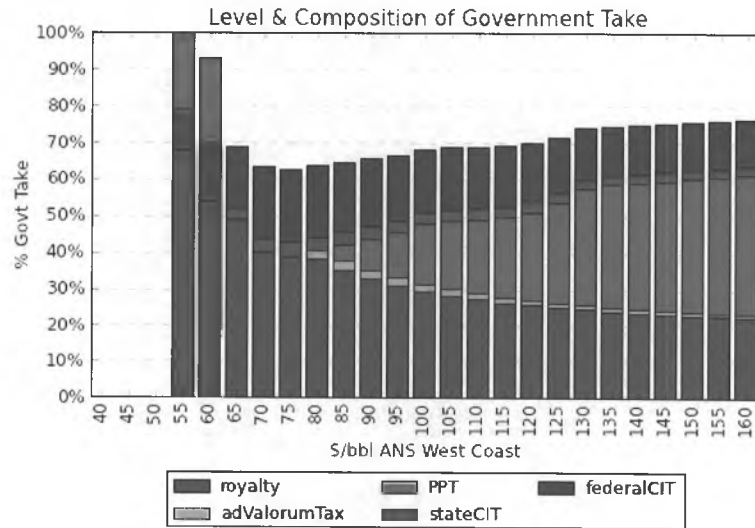


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	66.93%	-4.08	6.32%	27.03
\$100/bbl	59.37%	0.25	12.33%	40.1
\$120/bbl	56.30%	4.4	17.41%	51.76
\$140/bbl	59.37%	7.48	21.18%	63.42

ACES - \$25/bbl New Development, Incremental

ACES, 16.7% Royalty, \$25/bbl New Development, Incremental to Incumbent

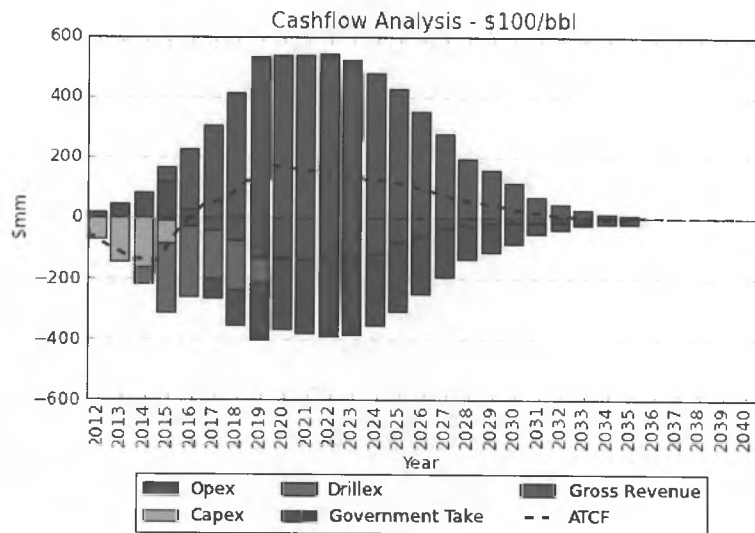
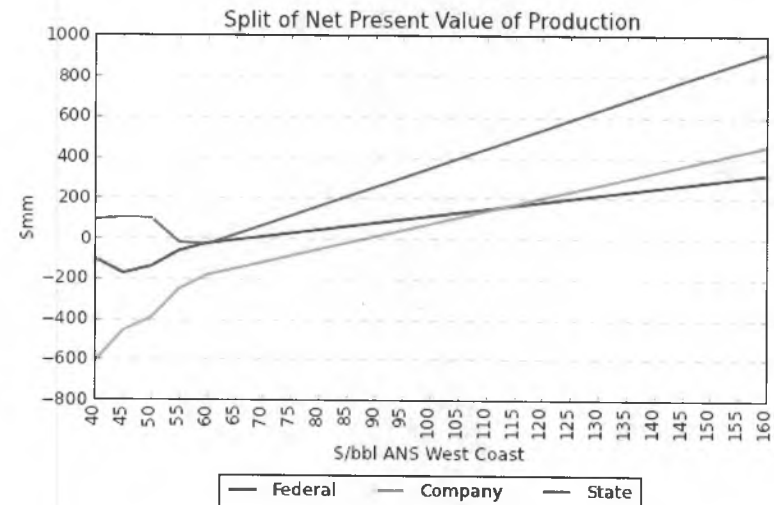
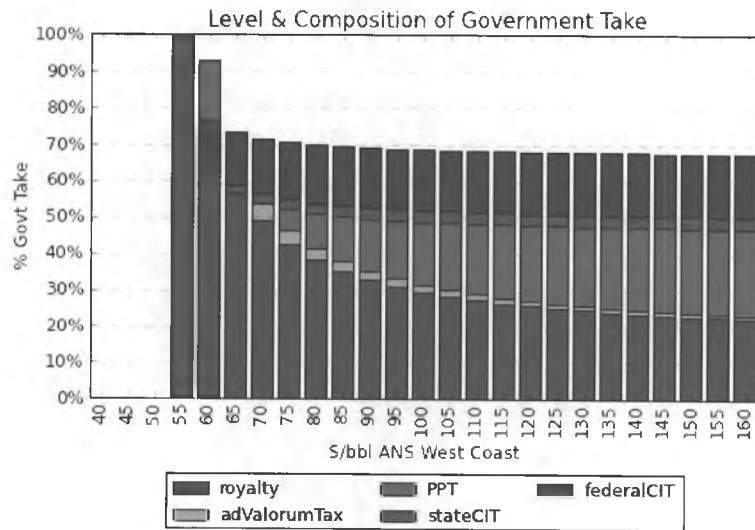


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	63.66%	1.29	15.81%	20.56
\$100/bbl	68.12%	4.24	26.30%	26.43
\$120/bbl	70.12%	6.82	38.62%	30.02
\$140/bbl	75.08%	6.54	31.02%	33.84

\$25/bbl New Development, Incremental

CS SB 21, 16.7% Royalty, \$25/bbl New Development, Incremental to Incumbent

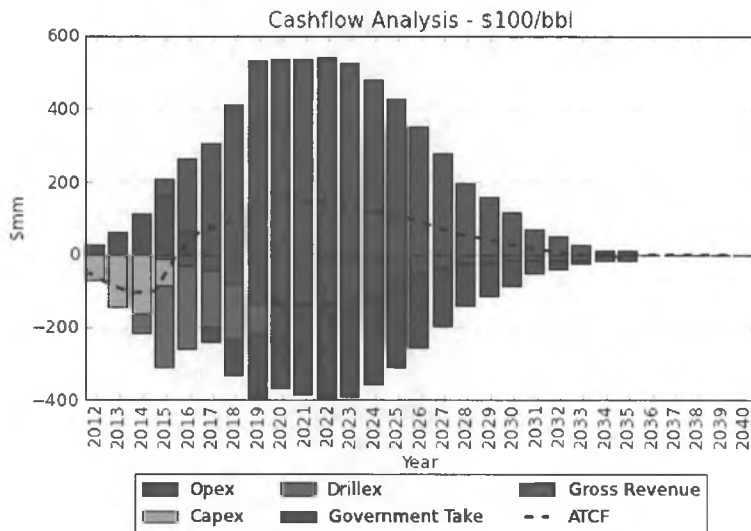
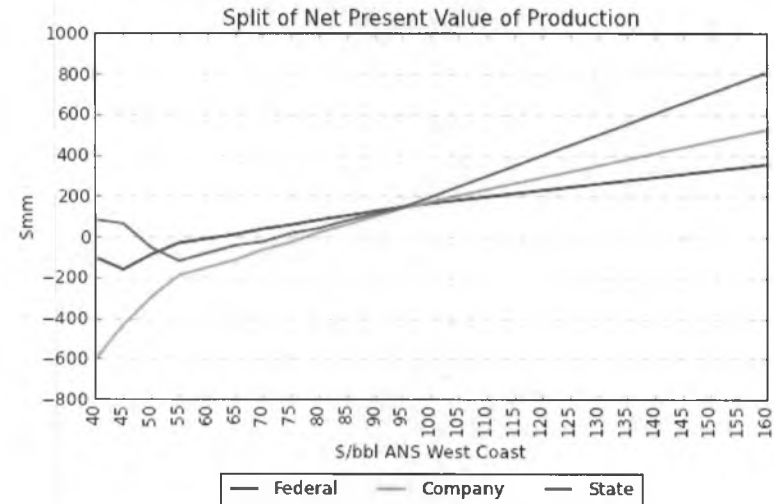
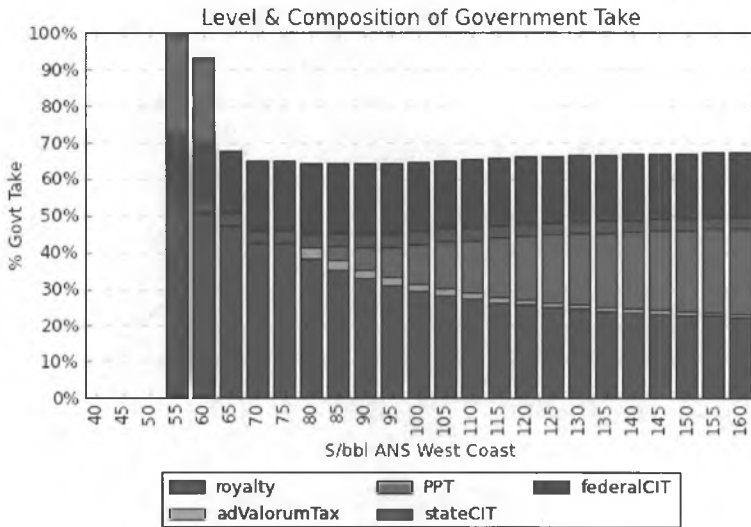


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	70.08%	-1.08	9.62%	19.22
\$100/bbl	68.80%	1.47	14.94%	27.23
\$120/bbl	68.25%	4.03	19.46%	35.25
\$140/bbl	67.95%	6.58	23.45%	43.26

Bracketed Progressivity (Net) \$25/bbl New Development, Incremental

Bracketed Progressivity (Net), 16.7% Royalty, \$25/bbl New Development, Incremental to Incumbent

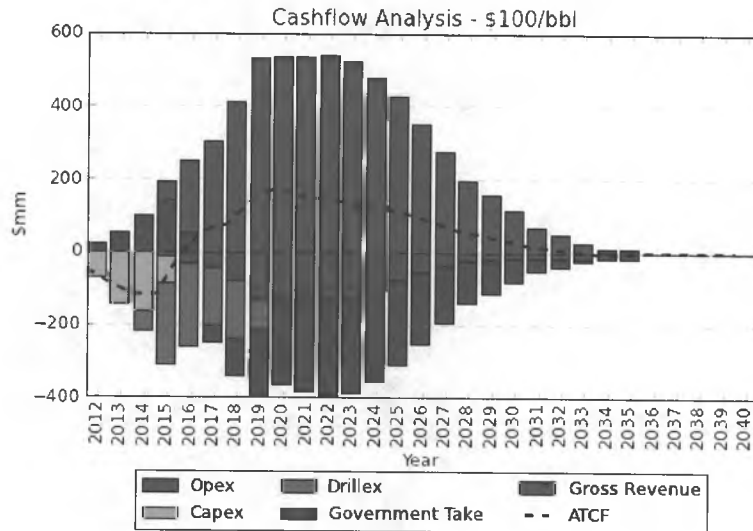
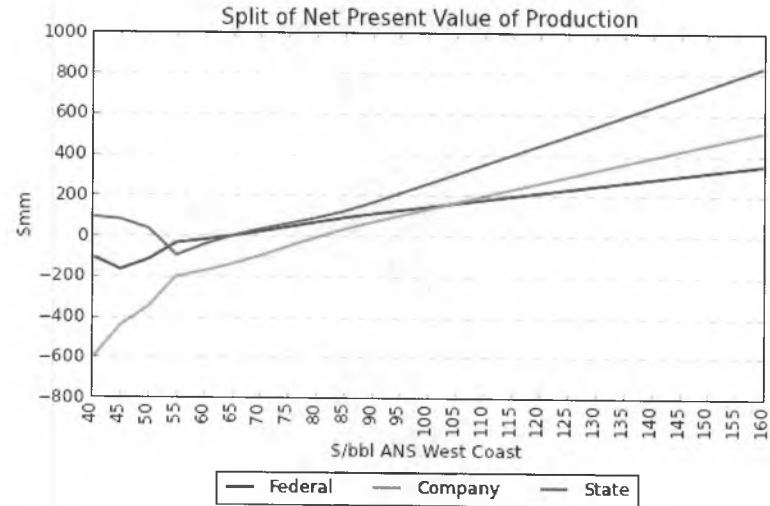
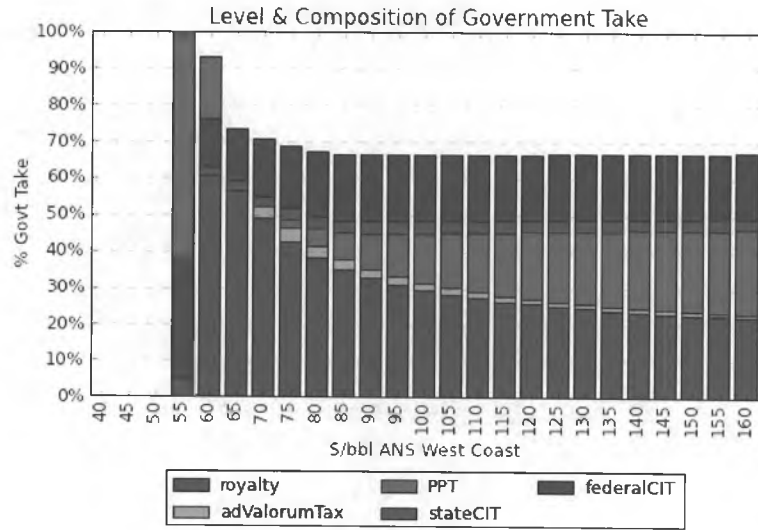


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	64.17%	0.44	13.11%	20.88
\$100/bbl	64.66%	3.47	20.34%	28.76
\$120/bbl	66.03%	5.83	24.95%	36.16
\$140/bbl	66.79%	8.19	29.03%	43.56

Bracketed Progressivity (Gross) \$25/bbl New Development, Incremental

Bracketed Progressivity (Gross), 16.7% Royalty, \$25/bbl New Development, Incremental to Incumbent



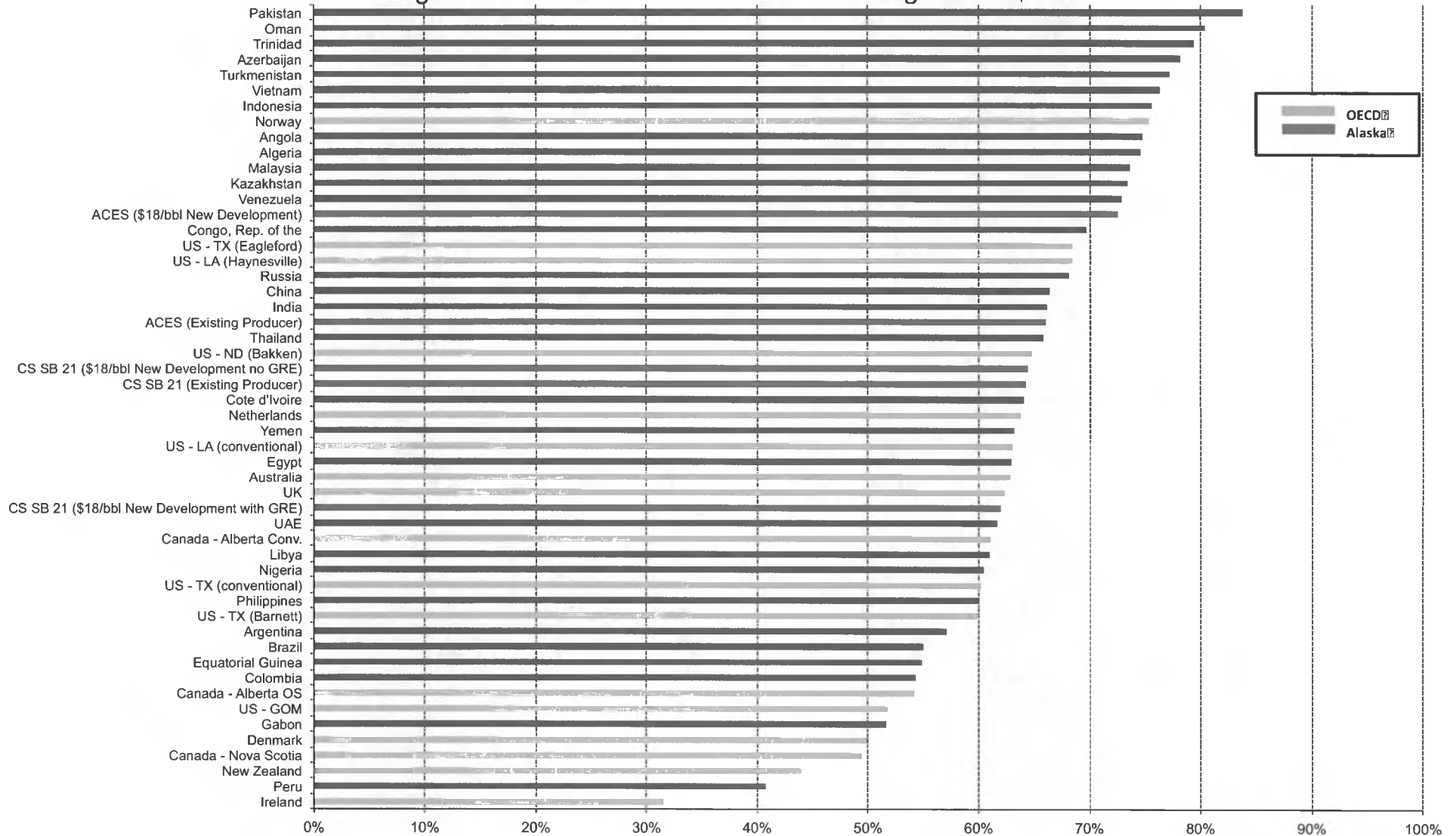
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	67.33%	-0.17	11.59%	19.78
\$100/bbl	66.41%	2.66	17.91%	28.19
\$120/bbl	66.70%	5.22	22.77%	36.15
\$140/bbl	66.95%	7.77	27.12%	43.89

CS SB 21 Competitiveness

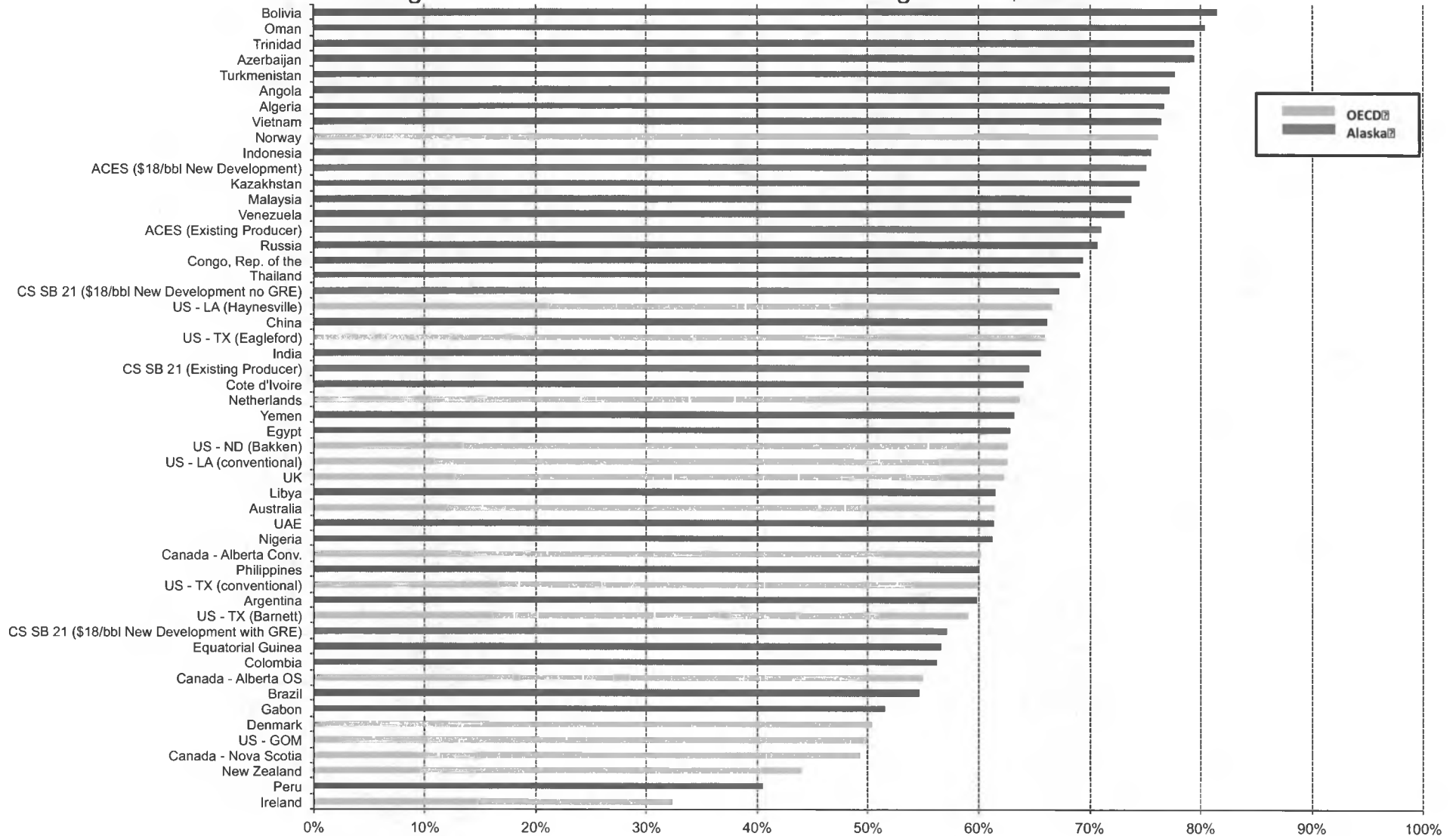
Regime Competitiveness - \$80/bbl

Average Government Take of Global Fiscal Regimes at \$80/bbl



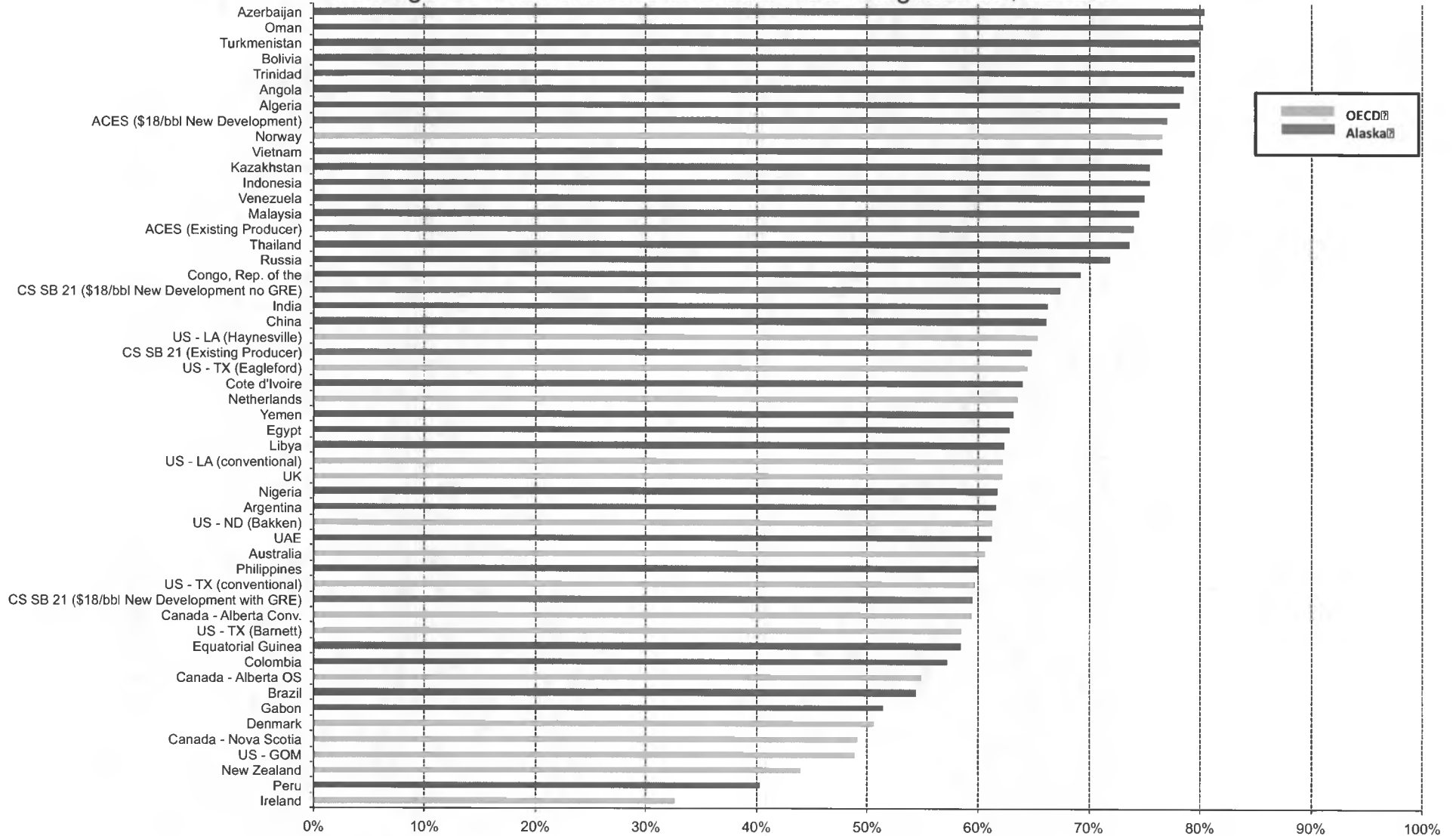
Regime Competitiveness - \$100/bbl

Average Government Take of Global Fiscal Regimes at \$100/bbl



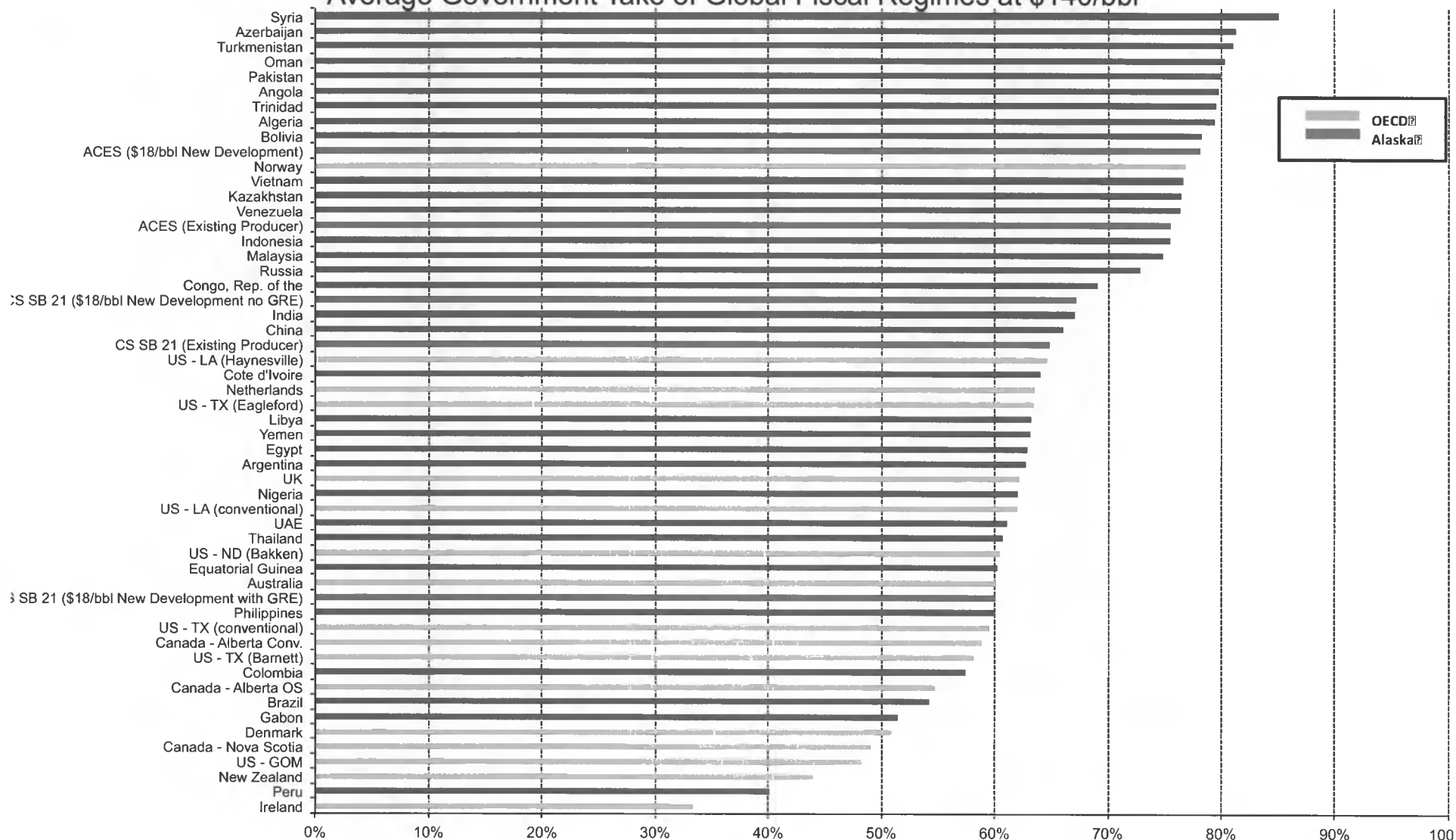
Regime Competitiveness - \$120/bbl

Average Government Take of Global Fiscal Regimes at \$120/bbl



Regime Competitiveness - \$140/bbl

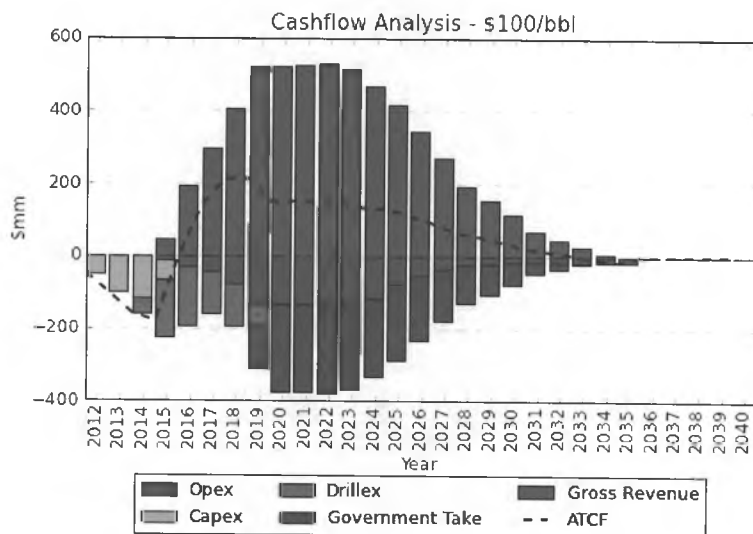
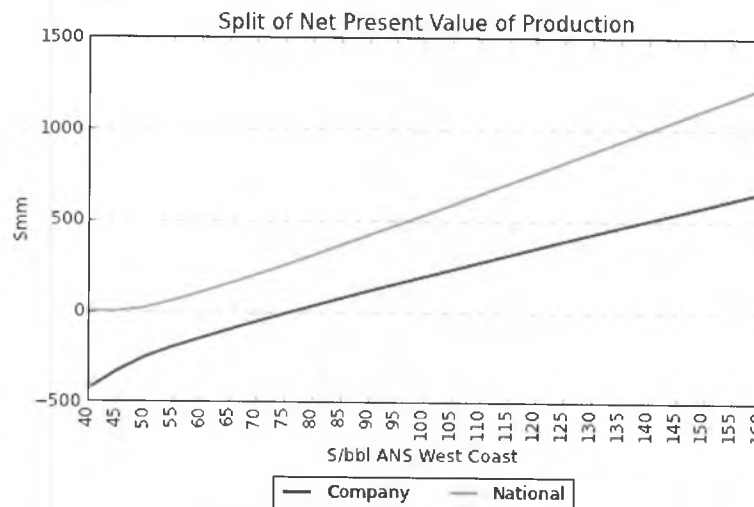
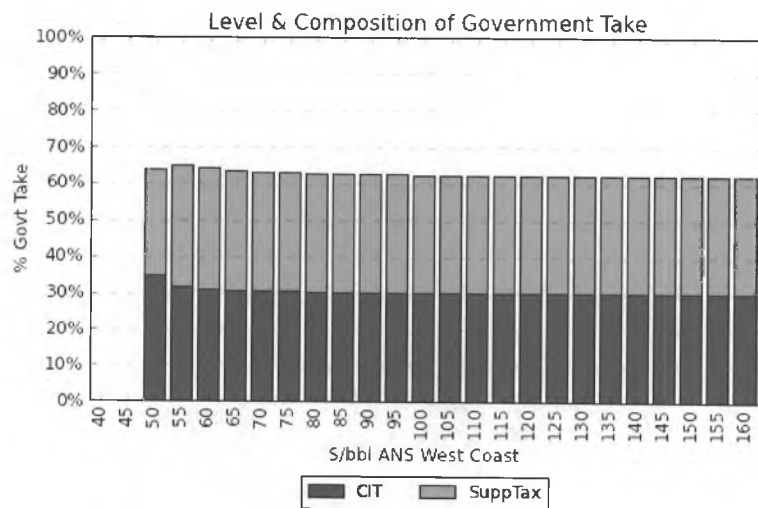
Average Government Take of Global Fiscal Regimes at \$140/bbl



Targeting Neutrality Directly

Alaska \$18/bbl Developer under UK North Sea regime

UK North Sea, \$18/bbl New Development

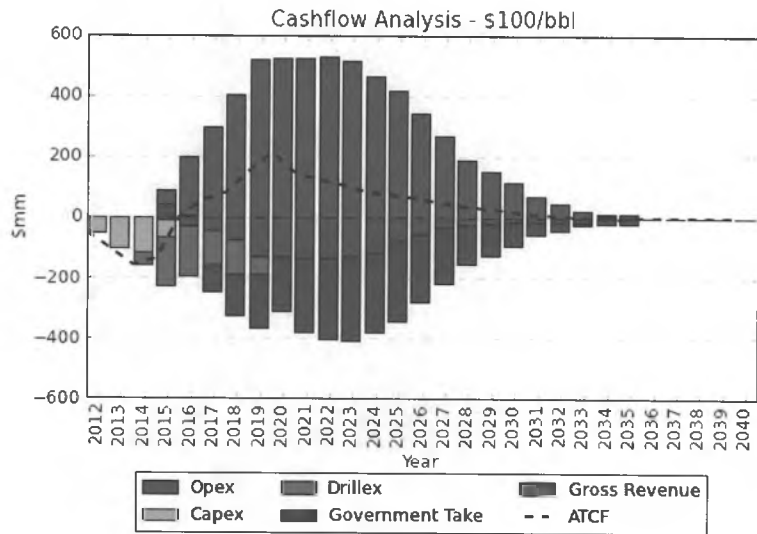
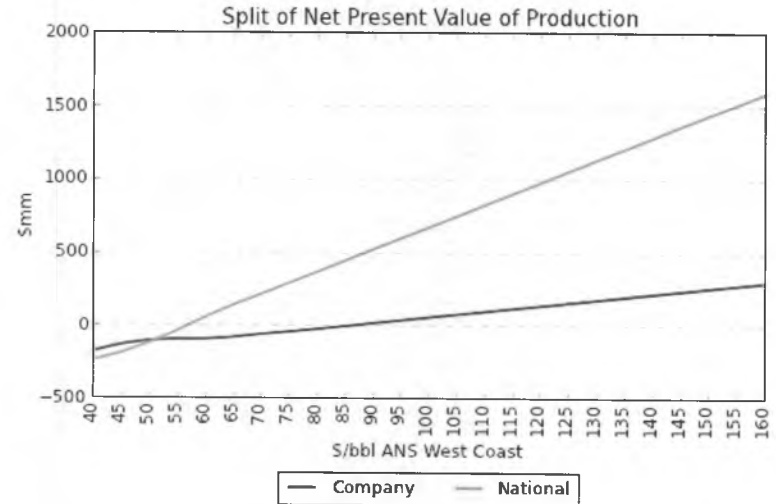
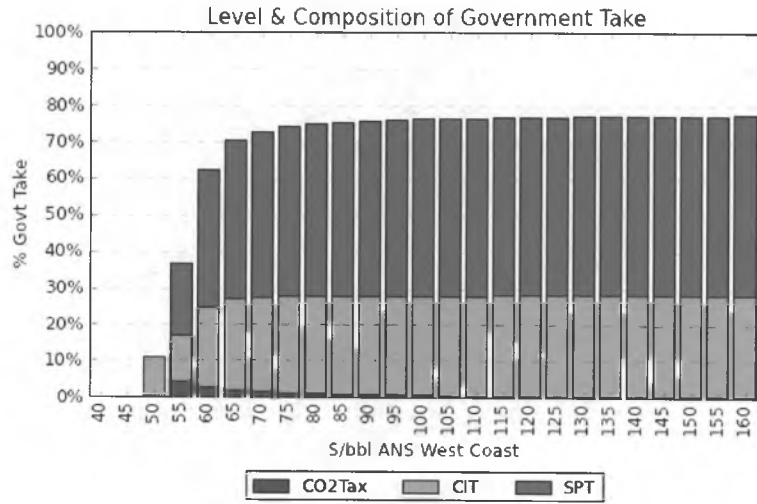


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	62.79%	0.62	13.29%	30.66
\$100/bbl	62.46%	3.89	19.64%	38.58
\$120/bbl	62.31%	7.04	25.09%	46.5
\$140/bbl	62.23%	10.11	29.82%	54.42

Alaska \$18/bbl Development under Norway regime

Norway, \$18/bbl New Development



Economic Summary

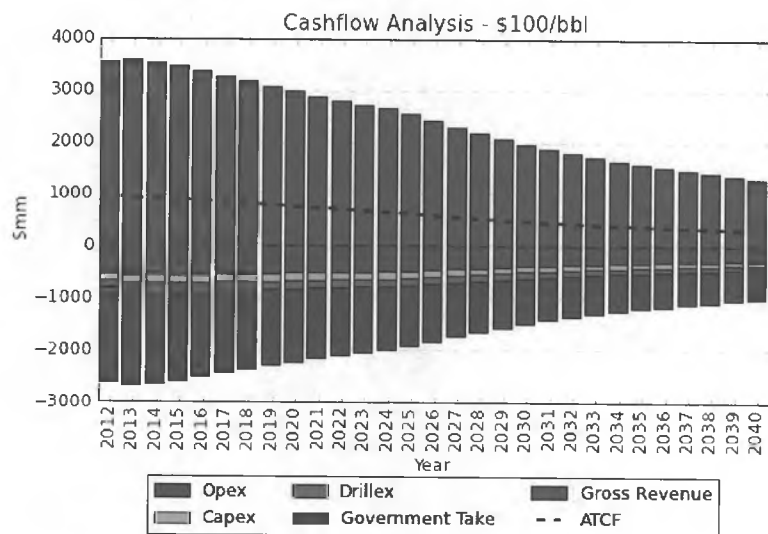
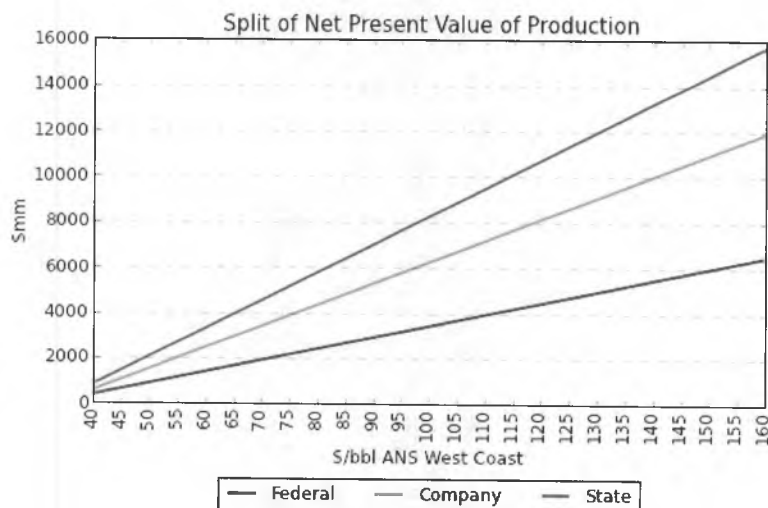
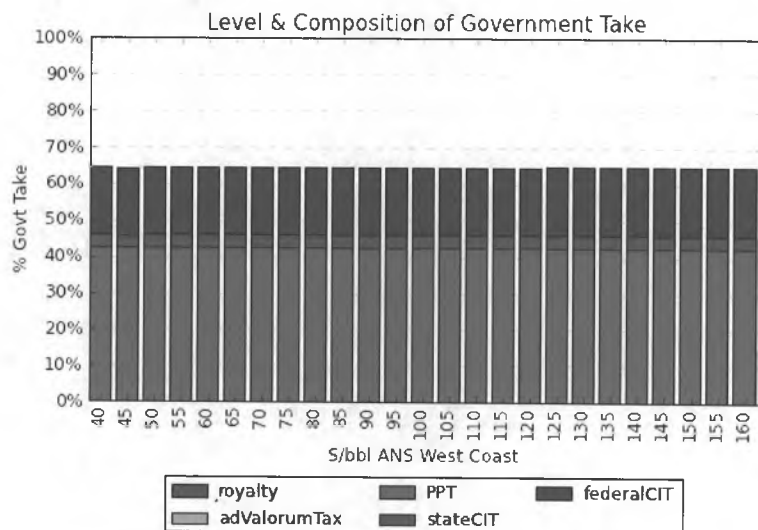
	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	75.12%	-0.53	10.71%	25.65
\$100/bbl	76.44%	1.13	14.53%	29.36
\$120/bbl	77.04%	2.74	17.69%	34.6
\$140/bbl	77.38%	4.34	20.47%	39.93

Targeting Neutrality Directly

- All of the preceding regimes seek to compensate indirectly for the regressive nature of the fixed royalty and ad valorem tax by inserting a roughly equal and opposite progressive element
- Inevitably, the match must be imperfect
- At low prices, government take is still very high – and for high cost developments, the fixed royalty can create a high level of price downside risk, particularly in conjunction with the gross minimum tax
- The only way to create a completely neutral regime is to counteract the regressive elements directly – either by eliminating or perfectly opposing them
 - Since royalties are contractual, and ad valorem taxes shared with local government, if this were desired, putting in place a perfect offset might be easier than elimination
 - All that would be required to achieve this would be a fully reimbursable tax credit equal to the amount of royalty and ad valorem tax paid
 - A completely neutral regime could increase downside price risk to the state, but would also lead to an even sharing of risk and reward
 - Many major OECD oil producing states with profit-based taxes have chosen to eliminate regressive elements altogether - ie Australia, UK, Norway – because of the distorting impact such elements have on investment
- The following slides model a **42.5% Profit-Based Production Tax rate**, combined with a fully reimbursable tax credit equal to the amount of royalty and ad valorem tax paid (or the eventual elimination or one or both of those elements)

Profit Tax Only (Royalty and Ad Valorem Reimbursed) Base Production

Profit Tax Only, Base Production

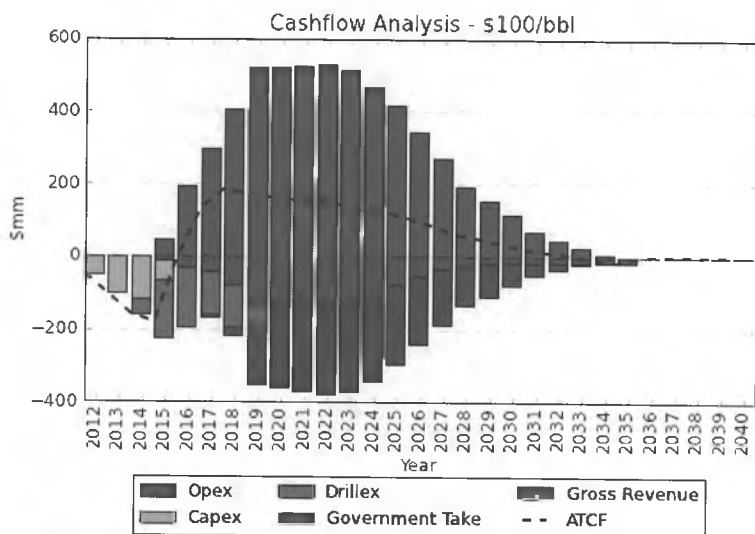
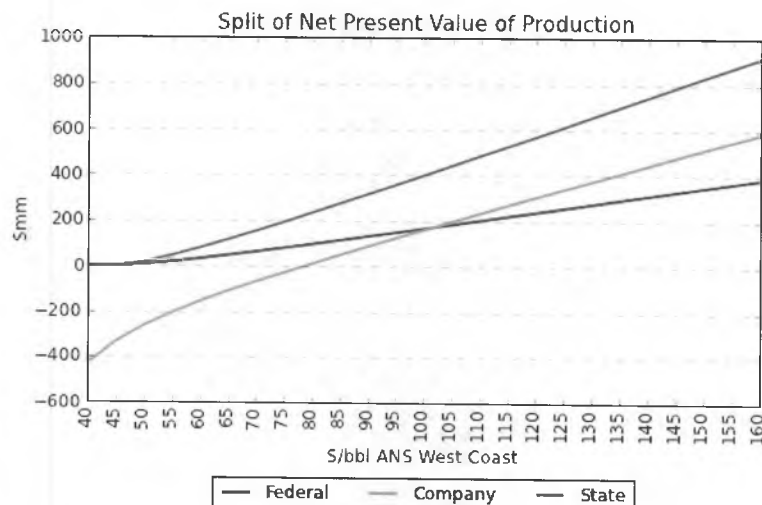
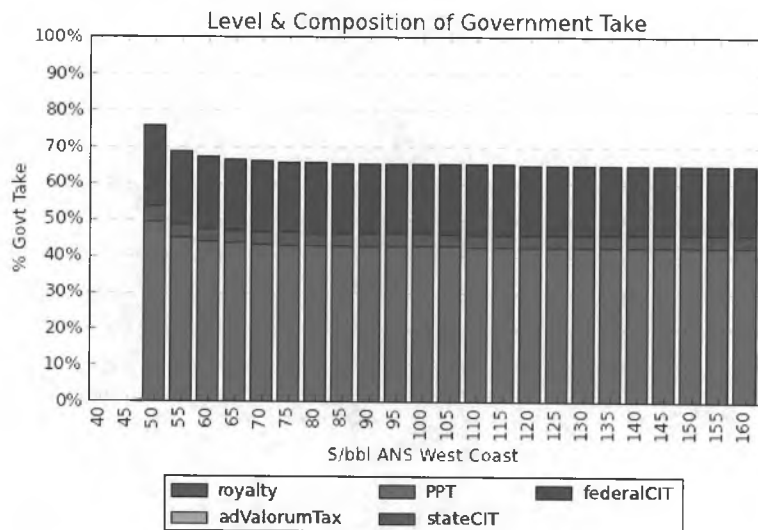


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.76%	4.23		19.27
\$100/bbl	64.80%	6.06		27.7
\$120/bbl	64.81%	7.9		36.13
\$140/bbl	64.82%	9.74		44.57

Profit Tax Only (Royalty and Ad Valorem Reimbursed) \$18/bbl New Development, Standalone

Profit Tax Only, \$18/bbl New Development



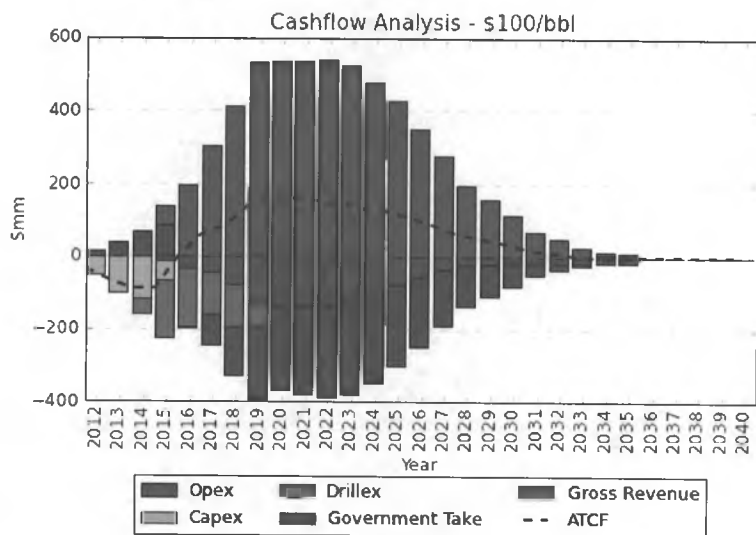
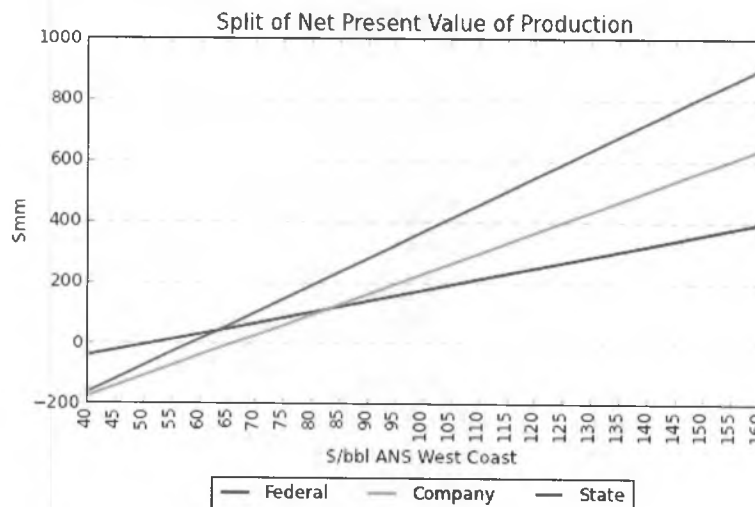
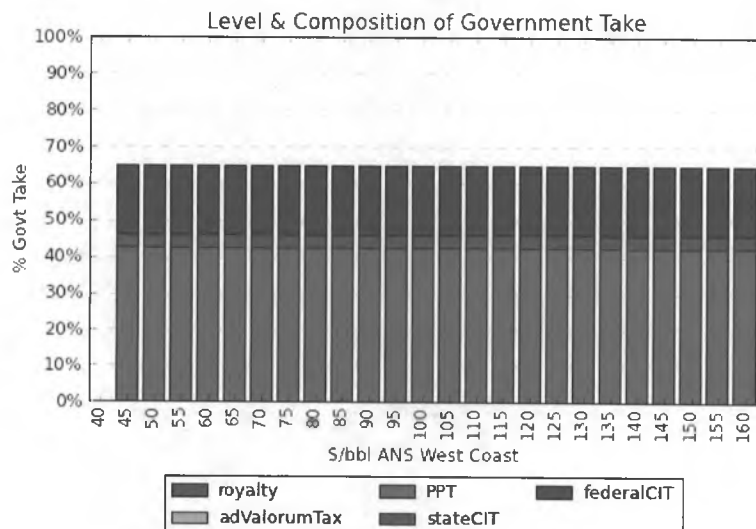
Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	65.70%	0.23	12.48%	29.25
\$100/bbl	65.35%	3.21	18.39%	36.41
\$120/bbl	65.20%	6.09	23.42%	43.67
\$140/bbl	65.11%	8.9	27.77%	50.96

Profit Tax Only (Royalty and Ad Valorem Reimbursed)

\$18/bbl New Development, Incremental

Profit Tax Only, \$18/bbl New Development, Incremental to Incumbent



Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.87%	1.85	17.38%	20.75
\$100/bbl	64.87%	4.57	23.92%	29.25
\$120/bbl	64.87%	7.28	29.46%	37.76
\$140/bbl	64.87%	9.99	34.34%	46.27

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PFC Energy Locations and Contact Information

NORTH AMERICA

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

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

EUROPE

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

RUSSIA

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

ASIA

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

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

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

www.pfcenergy.com | info@pfcenergy.com