

HB 72

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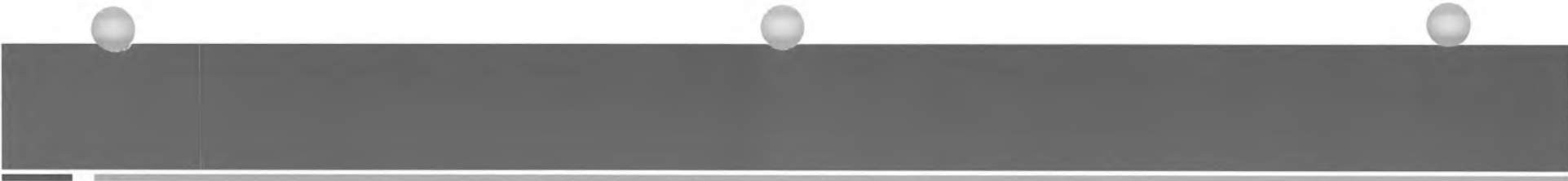
<TARGET><BILL>HB 72</BILL><SUBJECT>HB 72 (FILE
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House Resources Committee

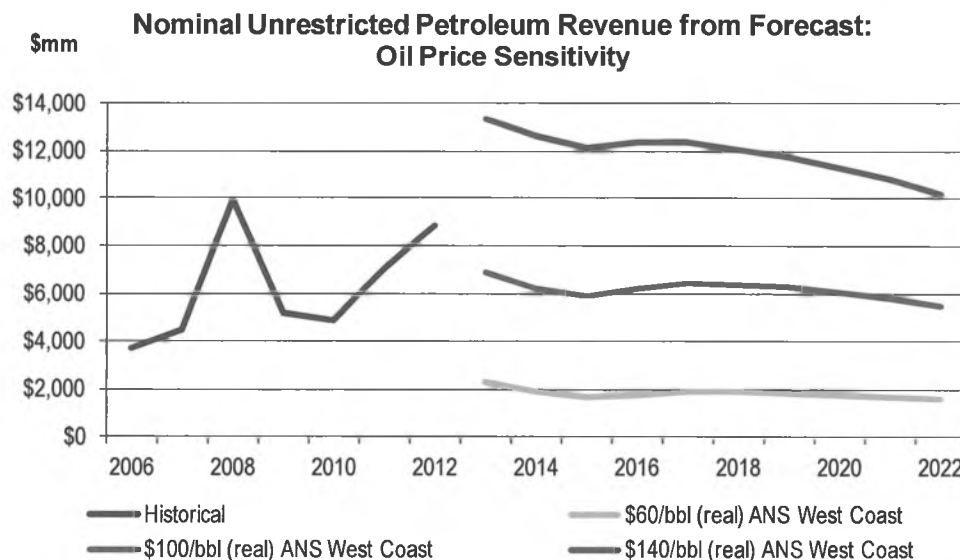
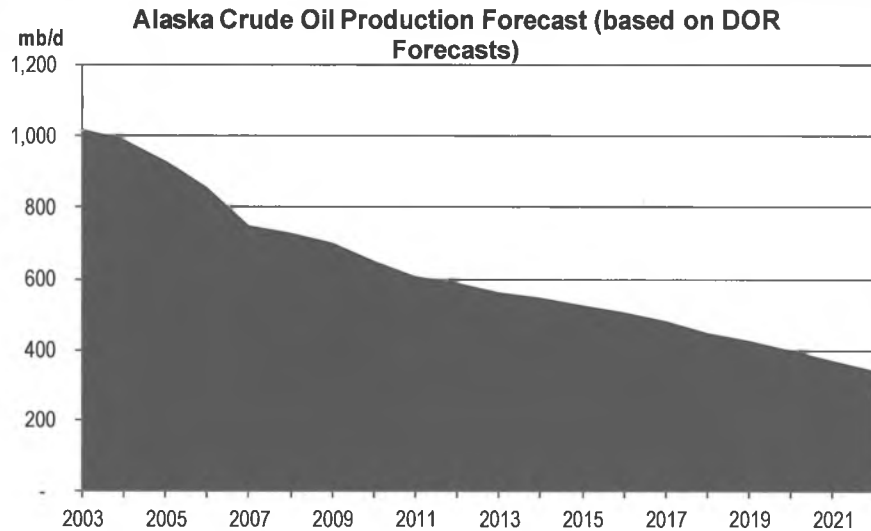
Alaska Fiscal System Discussion Slides

February 15 2013
Janak Mayer
Manager, Upstream
PFC Energy



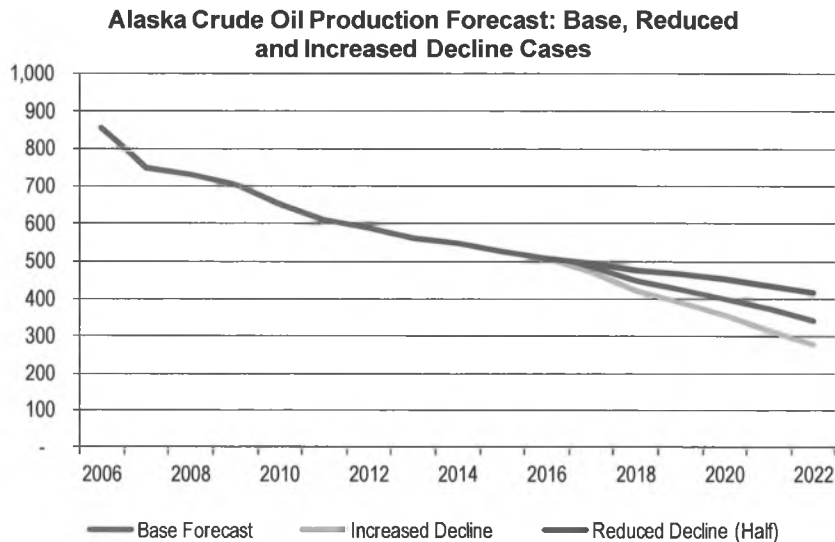
Alaska's Future Petroleum Revenues: Sensitivities to Oil Price, Production Decline, and Fiscal Terms

Oil Price is the Major Determinant of Alaska's Future Petroleum Revenue

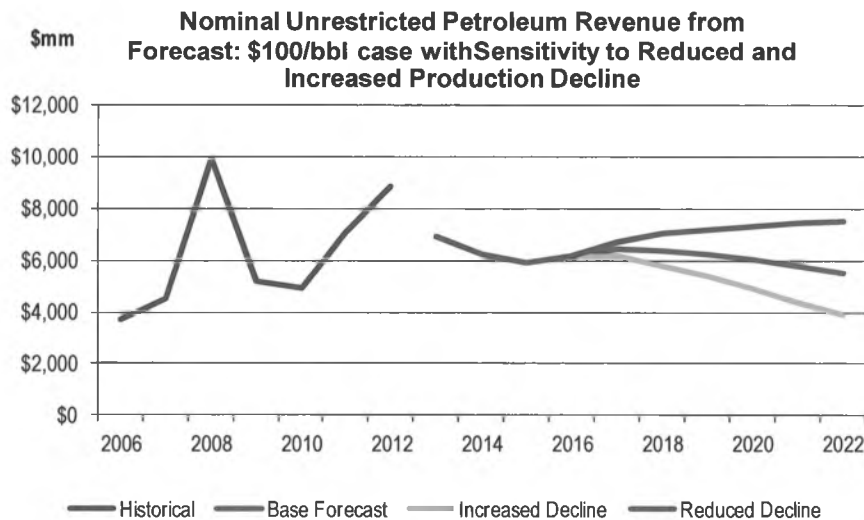


- The major factor determining Alaska's future petroleum revenue is not oil & gas fiscal terms, or even, in the short run, production levels, but rather something entirely outside Alaska's control: the crude oil price
 - Restricting a sensitivity analysis only to the a range of oil prices observed in the last 5 years, and **holding future production constant** (based on DOR forecasts) the potential variation in possible future petroleum revenue is substantial:
 - In a \$140/bbl environment, revenue in 2022 under ACES would approach \$10bn
 - In a \$60/bbl environment, revenue in 2022 under ACES would be as low as \$1.8bn
- In reality, the potential for variation is even greater than this, since production also responds to price:
- In a sustained high price environment, more projects would be economic, and long-run production would improve
 - In a sustained low price environment, fewer projects would be economic and sustaining capital would be lower, resulting in a more rapid decline in long run production

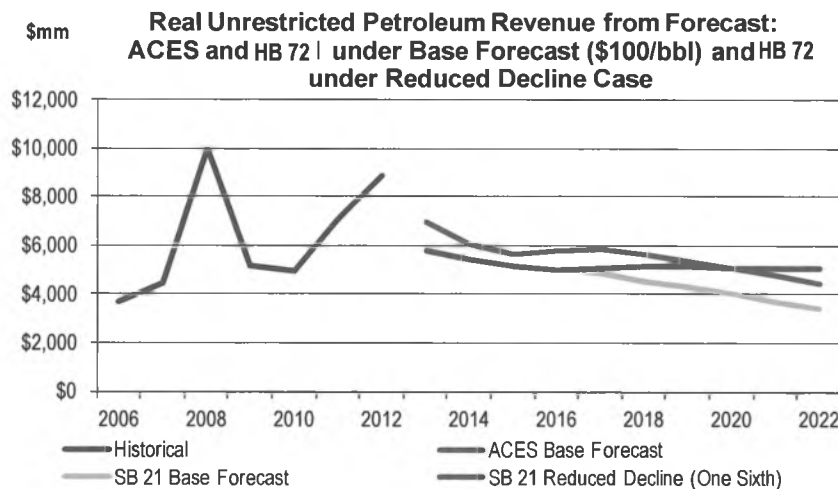
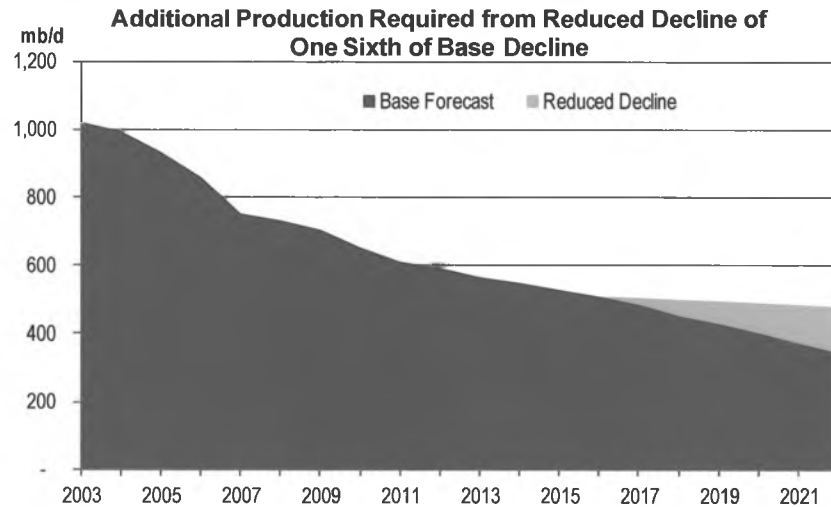
Decline Rate is the Other Major Determinant



- The Base Forecast anticipates an average annual production decline between 2017 and 2022 of ~6% (including the contribution from new producing areas brought on-stream), yielding production of ~344 mb/d in 2022
- Increasing the average decline rate by half to 9% in every year from the base case would see production declining to ~280 mb/d in 2032
- Reducing the average decline rate by half to 3% in every year from the base case would see production of ~419 mb/d in 2032
- In the low decline scenario, more robust production combined with the impact of inflation mean that nominal revenues would continue to grow beyond 2017, reaching ~\$7.8 bn at a nominal crude price of \$100/bbl
- In the high decline scenario, 2022 nominal revenues would fall well below the \$4 bn level anticipated in the Base Forecast case, reaching less than ~\$4 bn even with nominal crude prices at \$100/bbl




Fiscal Terms Changes and Investment Impacts



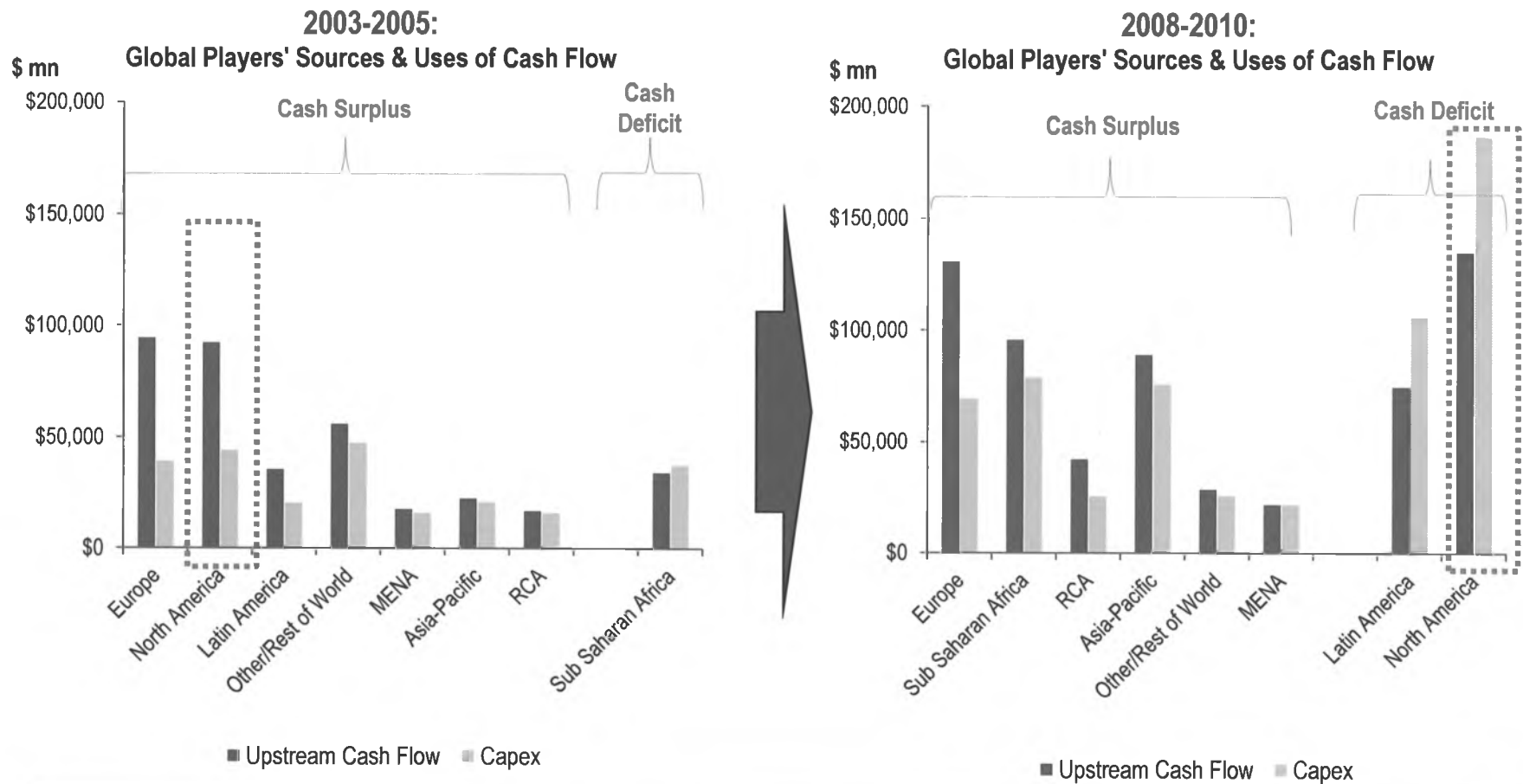
Year	2017	2018	2019	2020	2021	2022
Additional Production (mboe/day)	20	48	66	88	111	133

- Even significant changes to fiscal terms, by contrast, have a far smaller impact on future revenues than either oil price or future production declines
 - Under the Base Forecast decline case, at \$100/bbl crude oil, SB 21/HB72 results in a parallel shift of the revenue curve, reducing the state’s petroleum revenue by a little over \$1 bn each year
- If an improvement in fiscal terms can stimulate sufficient new investment to stem declines, it has the long run potential to increase revenue, despite the near-term cost of the change
 - To maintain revenues to the state at a steady level in real terms, a reduction in government take such as that under SB 21 would need to spur sufficient investment to **reduce the North Slope base decline from 6% as currently forecast to 1%**



Context: Investment Competition & Global Oil Price Environment

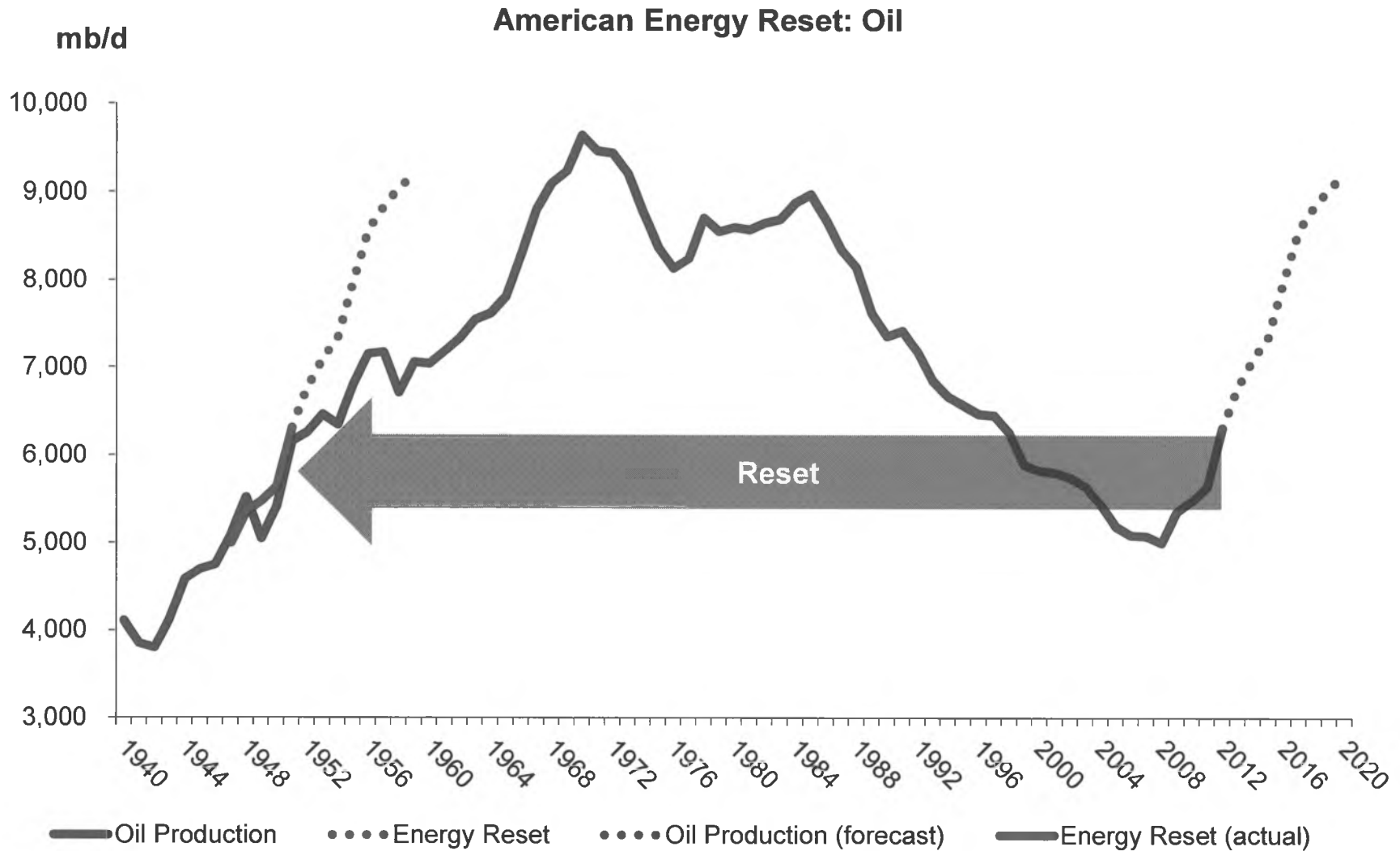
Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars



It is now an exception not to be targeting unconventional in North America as a major growth platform.

American Energy Reset

United States Production – Back at Post-War Period



Anatomy of the Physical Market for Crude Oil



Final Product Consumption

- Fuel needed for economic activity
- Main ingredient in hot dogs



Refining Demand for Crude

- Inputs needed to provide fuel demanded by consumers



Non-OPEC Crude

- As price takers, will produce at capacity given positive project economics



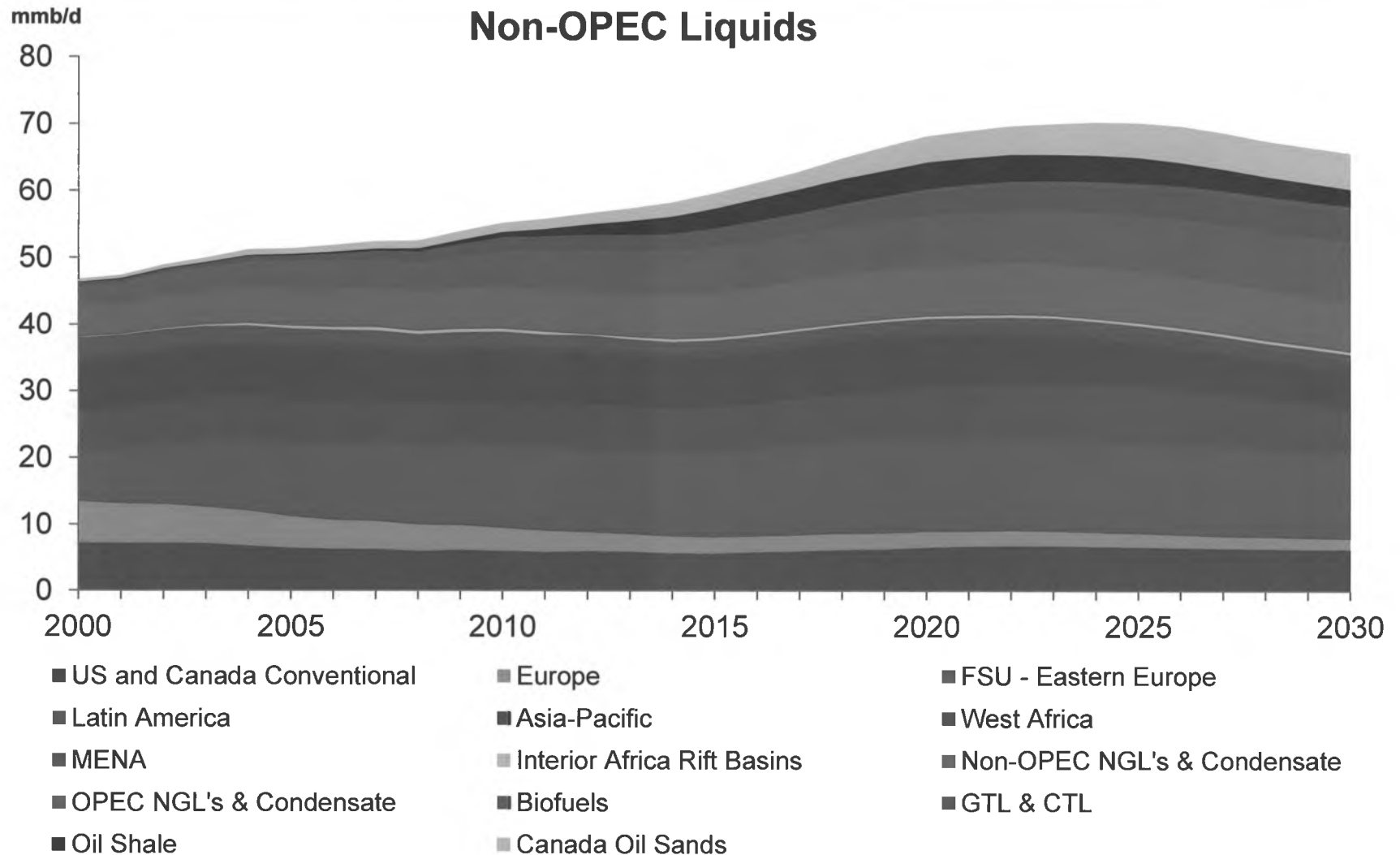
OPEC Crude

- Plays a balancing role, adjusting output as needed in line with overall objectives

Four broad segments to balance the market

Non-OPEC Liquids Will Show Substantial Growth

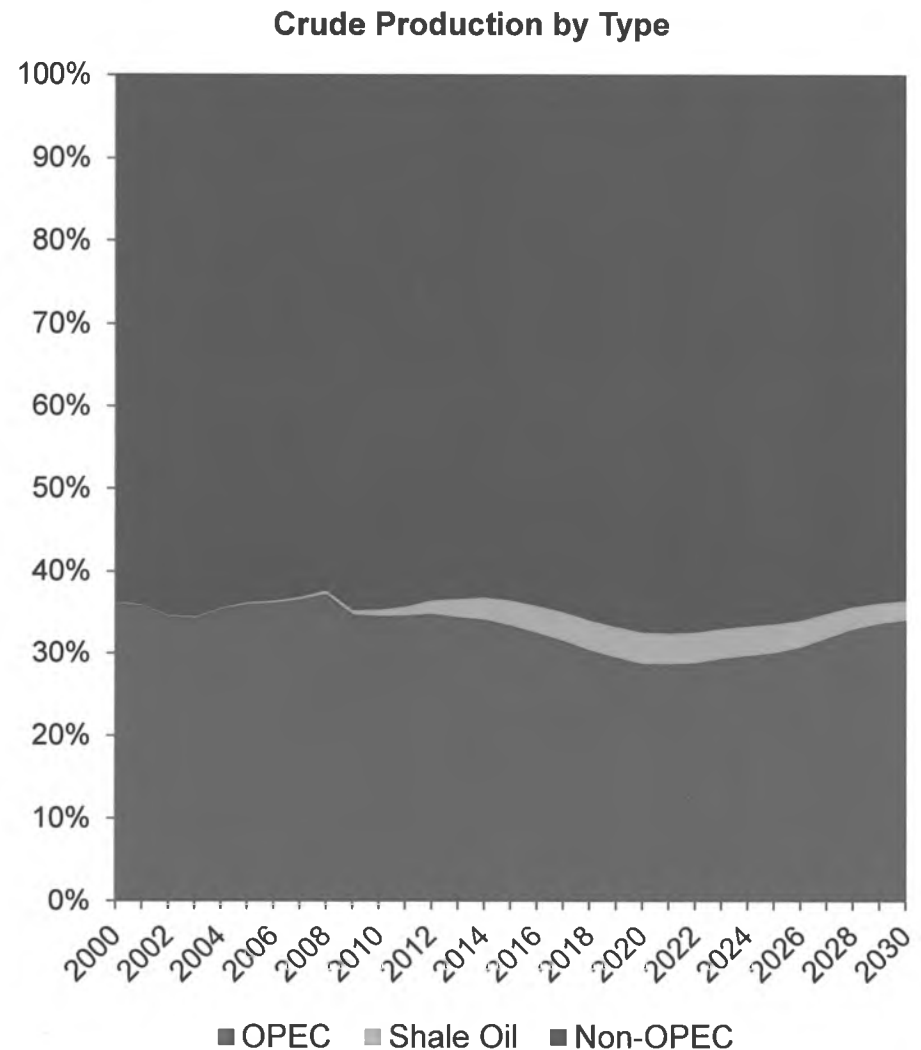
In the past production not affected by price swings



Shale Oil Major Factor in Reducing OPEC's Share

Potentially upsetting to long-time oil market balancer

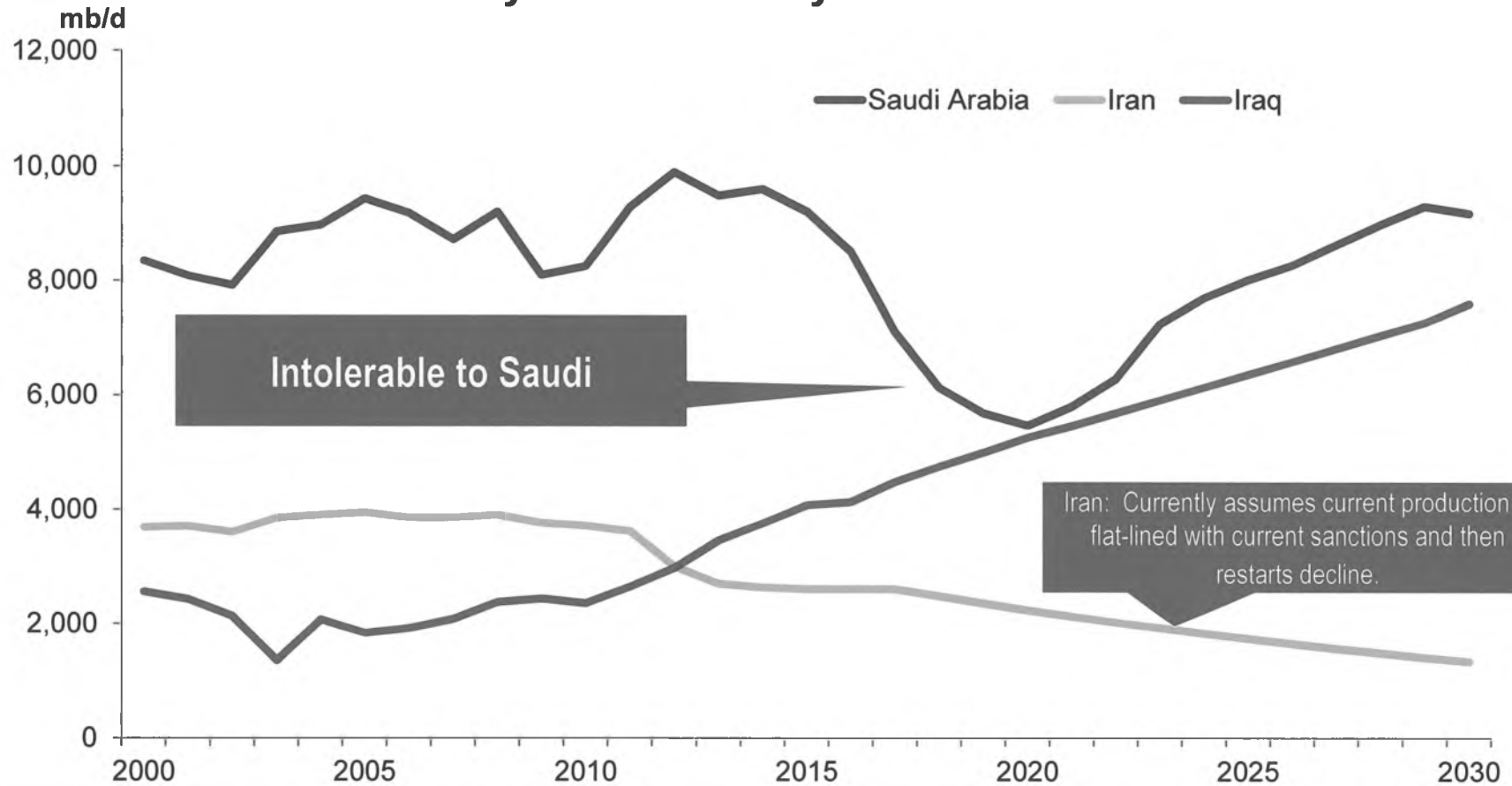
- Shale oil now forecast to reach ~4 mmb/d of production by end of the decade (largest recent Saudi swing was 2.2 mmb/d – post recession through Libya response)
- Shale oil production joins ranks of potential short-term global oil balancers. Traditionally made up of:
 - OPEC (Primarily Saudi Arabia)
 - IEA/SPR stocks
 - Demand destruction (potential is diminishing with rise of non-OECD demand growth given subsidies)
- OPEC has yet to begin grasping both the scale and potential impact that shale oil will have on its traditional role.
 - Is only now beginning to address Iraqi production



Initial Output Implications for Major OPEC Producers

Iran and Iraq complicate market management

Key OPEC Country Production

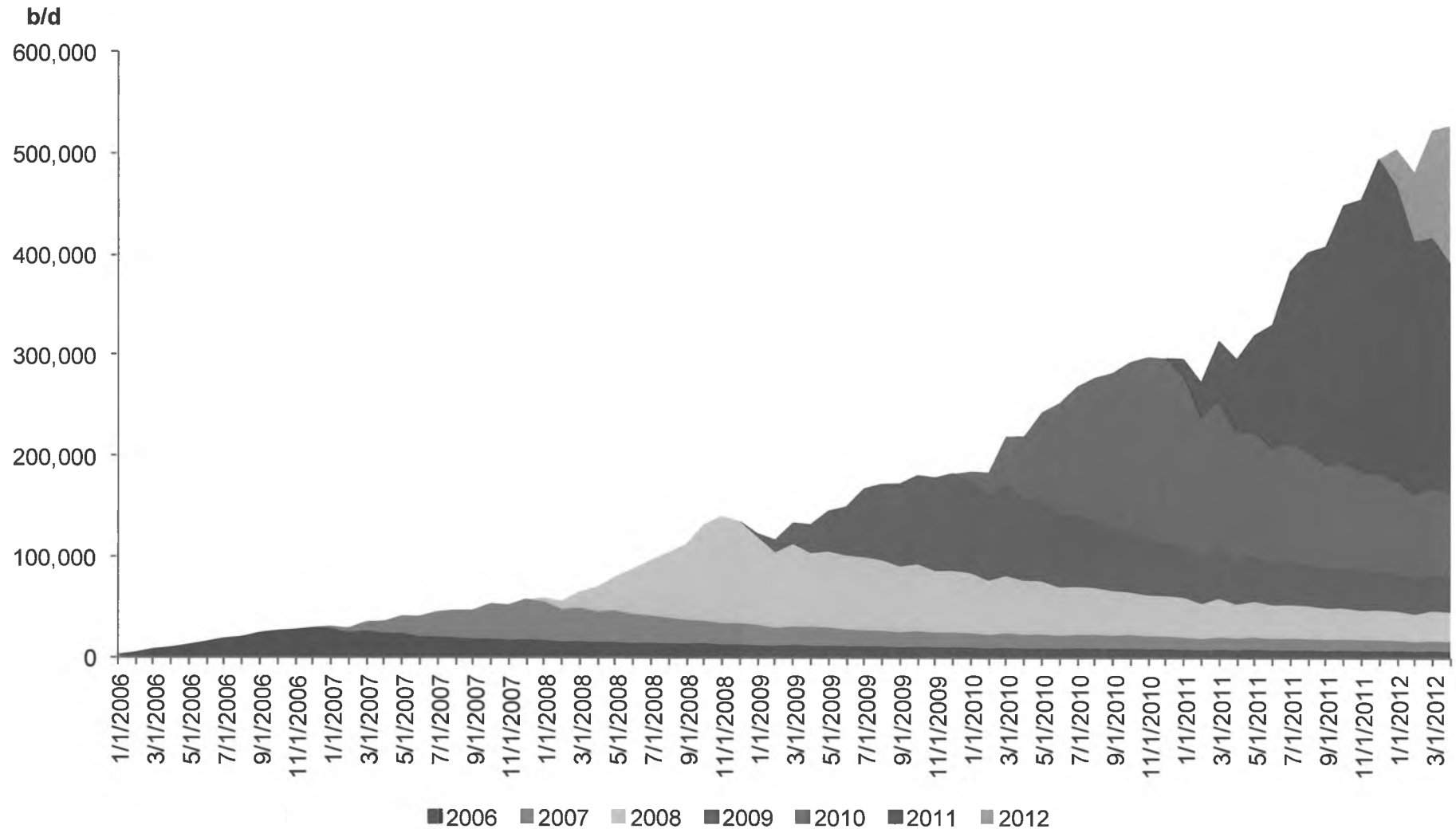


A diplomatic solution that brings Iran back into the oil markets makes OPEC management worse via increased volumes

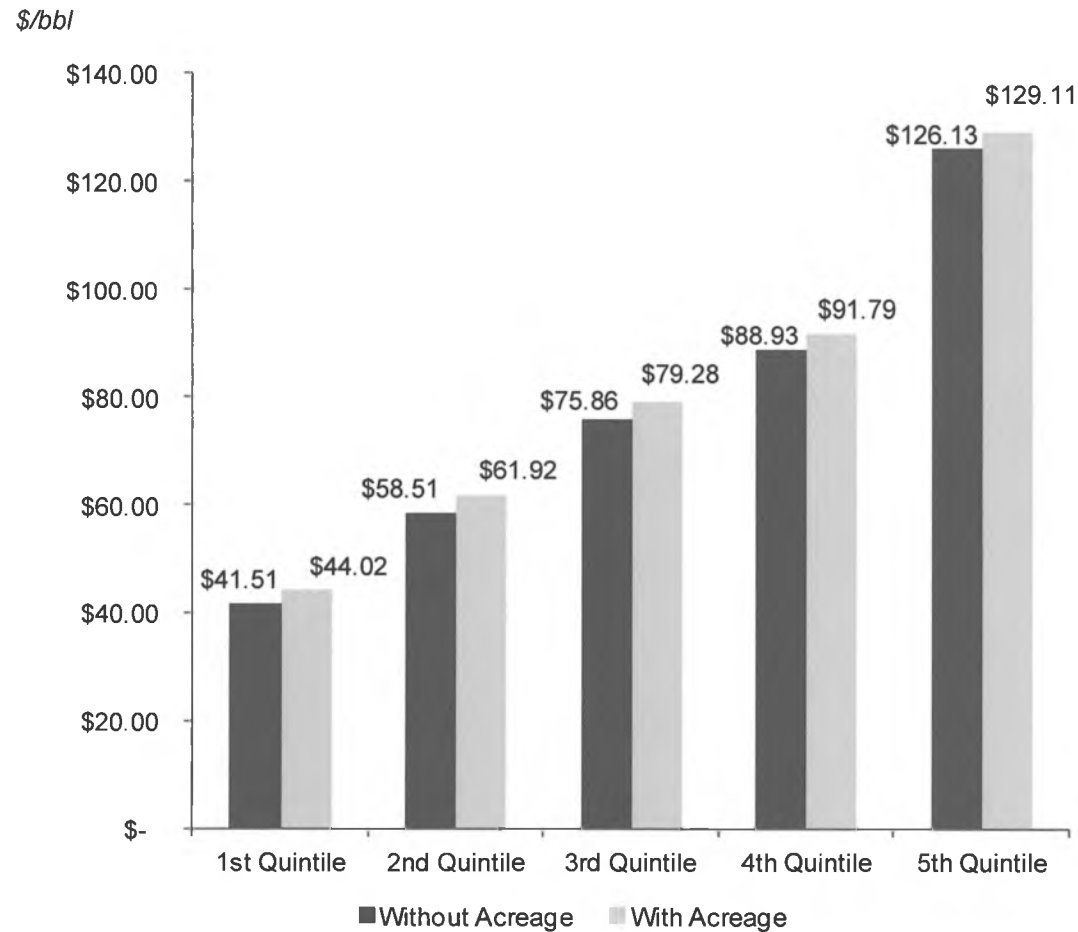
Character of US Growth Changing

Potential for sudden stop to growth or even declines on price softness

- Each year more production must be brought on just to maintain the prior year's levels.



Bakken Quintile Breakeven PV 10



Assumptions for Breakeven are:

Drilling Cost: \$8MM

Acreage Costs by Class:

- Class 1 \$20,000/acre
- Class 2 \$13,333/acre
- Class 3 \$8,889/acre
- Class 4 \$5,926/acre
- Class 5 \$3,951/acre

Risked : 95%

Basis : \$(10.00)/bbl

Severance taxes:

- Gas: 7.5%
- Oil: 4.6%

Fed taxes: 35%

Operating Costs:

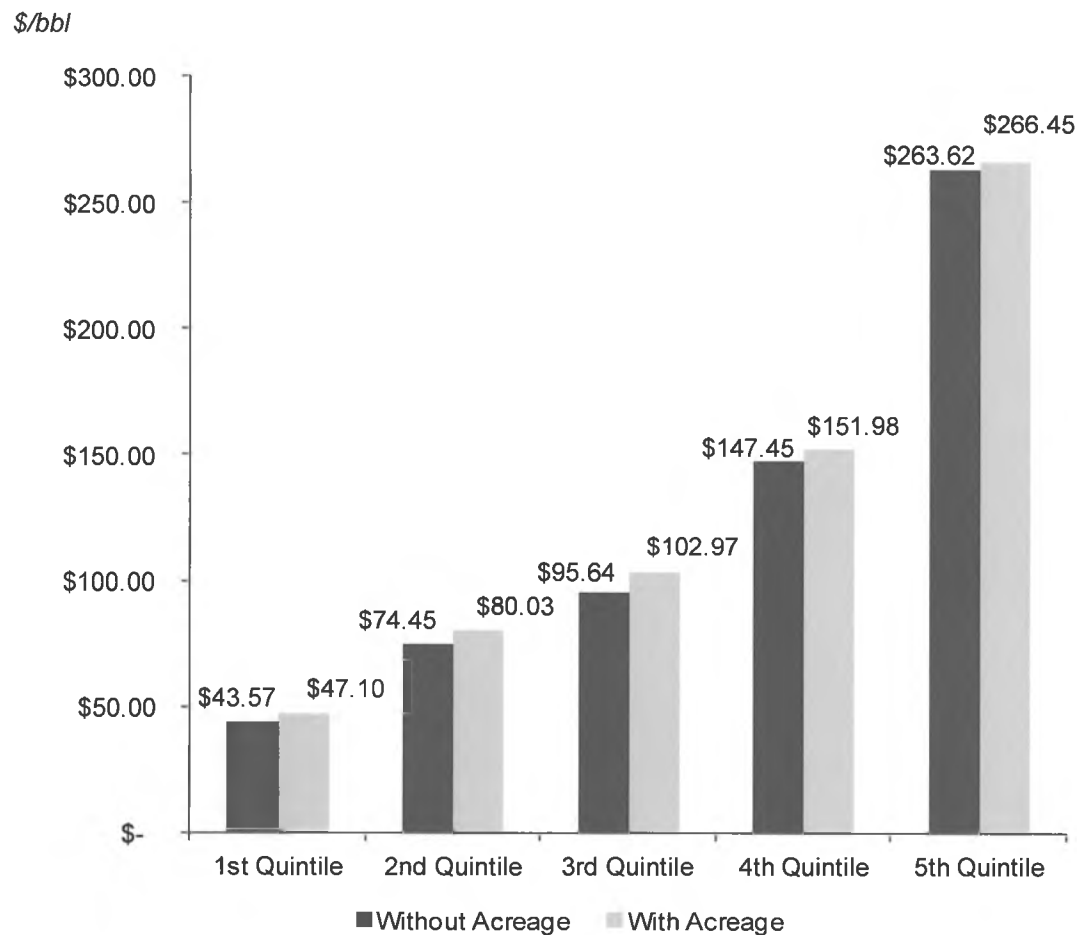
- Fixed: \$1,000/well/month
- Variable: \$7.00/ boe

Gen/Admin costs: \$1.50 / boe

Royalty Rates:

- Q 1: 18.8%
- Q 2: 14.1%
- Q 3: 10.6%
- Q 4: 7.9%
- Q 5: 5.9%

Eagleford Quintile Breakeven PV 10



Assumptions for Breakeven are:

Drilling Cost: \$7.5 MM

Acreage Costs by Class:

Class 1 \$20,000/acre

Class 2 \$15,000/acre

Class 3 \$10,000/acre

Class 4 \$5,000/acre

Class 5 \$2,000/acre

Risked : 95%

Basis : \$(4.00)/bbl

Severance taxes:

Gas: 7.5%

Oil: 4.6%

Fed taxes: 35%

Operating Costs:

Fixed: \$1,000/well/month

Variable: \$3.00/ boe

Gen/Admin costs: \$1.50 / boe

Royalty Rates:

Q 1: 25%

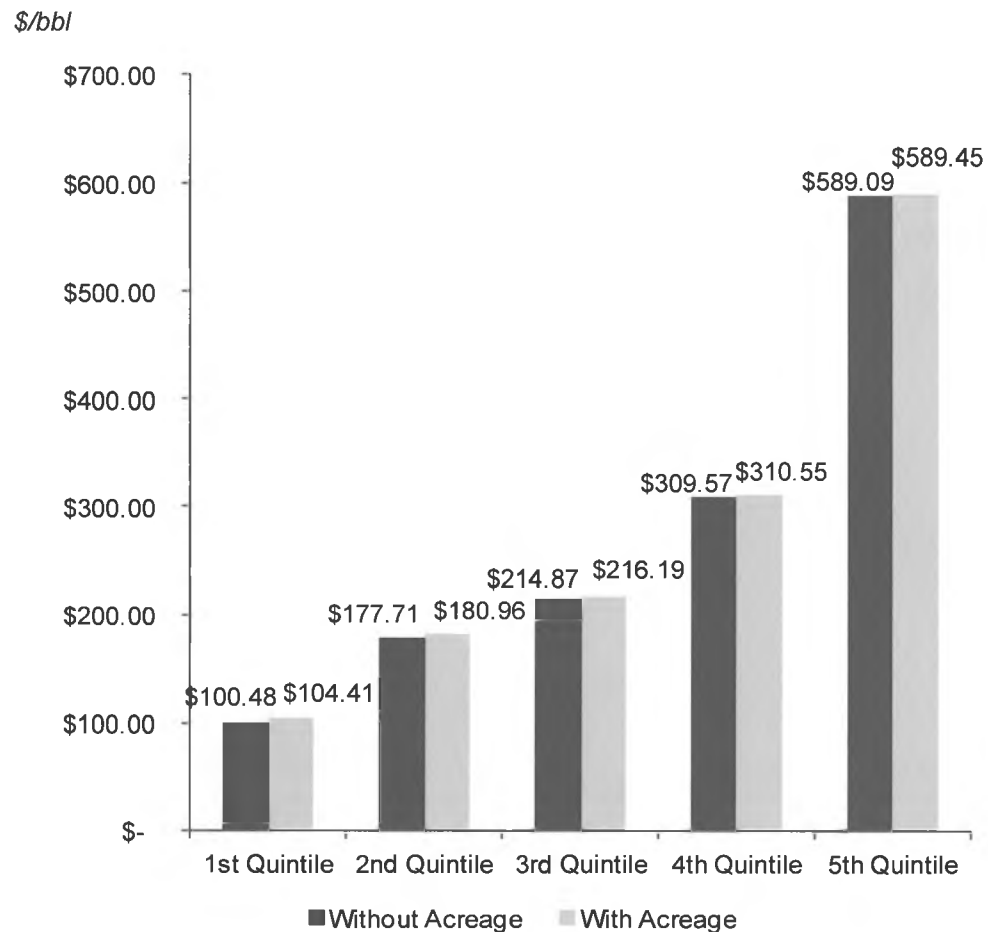
Q 2: 20%

Q 3: 18%

Q 4: 14%

Q 5: 12.5%

Granite Wash Quintile Breakeven PV 10



Assumptions for Breakeven are:

Drilling Cost: \$7.5 MM

Acreage Costs by Class:

- Class 1 \$6,000/acre
- Class 2 \$3,000/acre
- Class 3 \$1,000/acre
- Class 4 \$500/acre
- Class 5 \$100/acre

Risked : 95%

Basis : \$(4.00)/bbl

Severance taxes:

- Gas: 7.3%
- Oil: 7.3%

Fed taxes: 35%

Operating Costs:

- Fixed: \$1,000/well/month
- Variable: \$3.00/ boe

Gen/Admin costs: \$1.50 / boe

Royalty Rates:

- Q 1: 1/6
- Q 2: 1/6
- Q 3: 1/6
- Q 4: 1/8
- Q 5: 1/8

Risks to Price Forecast

Upside Price Risk

Strong global economic growth

- Increases demand strongly, tightening supply/demand balance

Instability removes barrels from market

- Repeat of Libya-type event
- Confrontation with Iran

Downside Price Risk

American Energy Reset

- US production boom is now delivering most of the worlds incremental demand growth, leaving little room for additional growth from other countries

Economic slowdown

- Eurozone, US or China slowdown causing demand slowdown. Loosens supply/demand balance

OPEC mismanagement

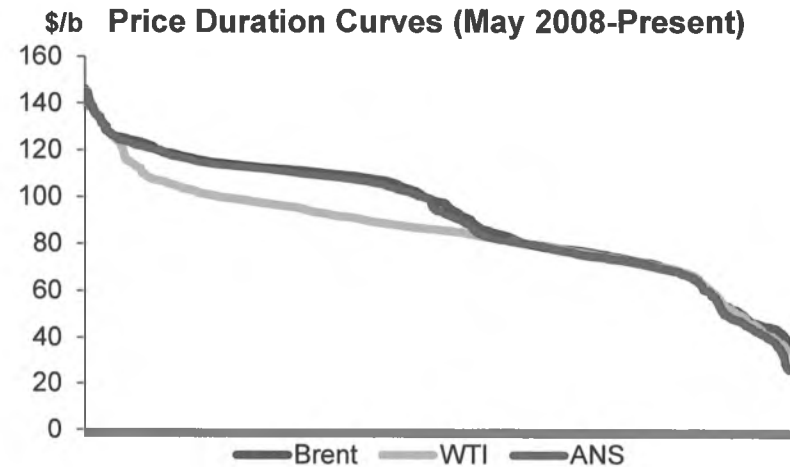
- OPEC will need to cut barrels in the future but may have difficulty organizing this among its members

US WTI disconnect expands geographic scope

- Discounts to WTI and other inland markers may begin to affect US west coast markets as Bakken and Eagle Ford crudes increase into those areas.

What is the Potential Floor for ANS West Coast Crude?

- Since 2008, the average for the 100 lowest priced days ranged from \$38-44/b for the three key markers.
- **In the short-term, the potential floor price for ANS is in the mid-\$30/b range.**
 - Would require substantial global oversupply, likely through a combination of OPEC mismanagement and booming US production
 - This low price is not sustainable for long as it will begin to cut US production within 60-90 days.
- **In the medium- to long-term, the floor price is near the cost of the marginal barrel:**
 - If US constrained, potential for \$55-60/b
 - If global (and assuming US production does not again surprise to the upside), the price floor is higher at \$70-75/b





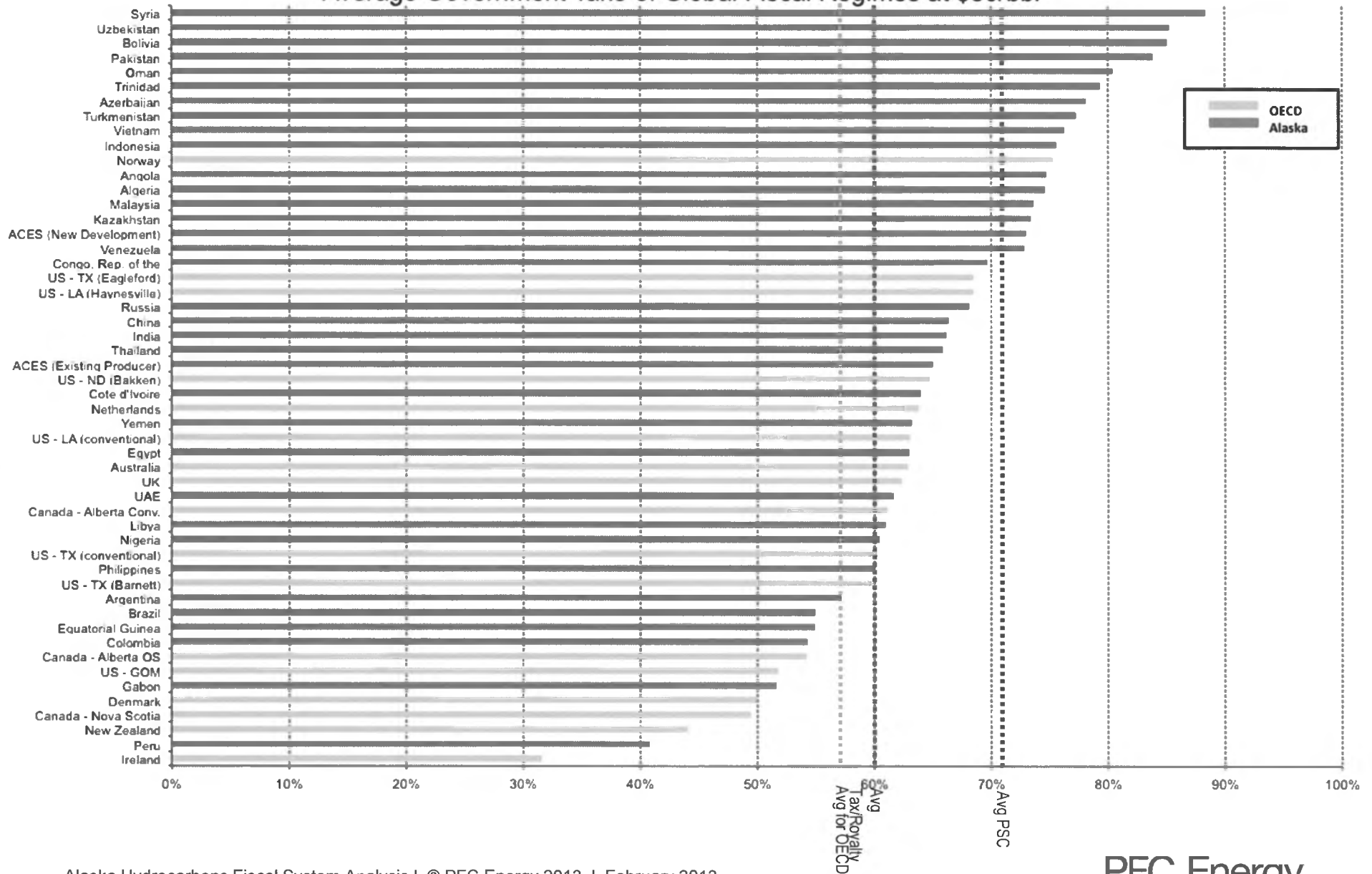
Alaska's Fiscal System: Problems and Approaches

ACES: 5 key problems

- **High levels of Government Take reduce competitiveness for capital, especially at high prices**
- High marginal tax rates reduce incentives for spending control
- Complexity makes meaningful economic analysis and comparison difficult
- Significant state exposure in low price environments, and for high-cost developments
- Impact of large-scale gas sales on tax rates

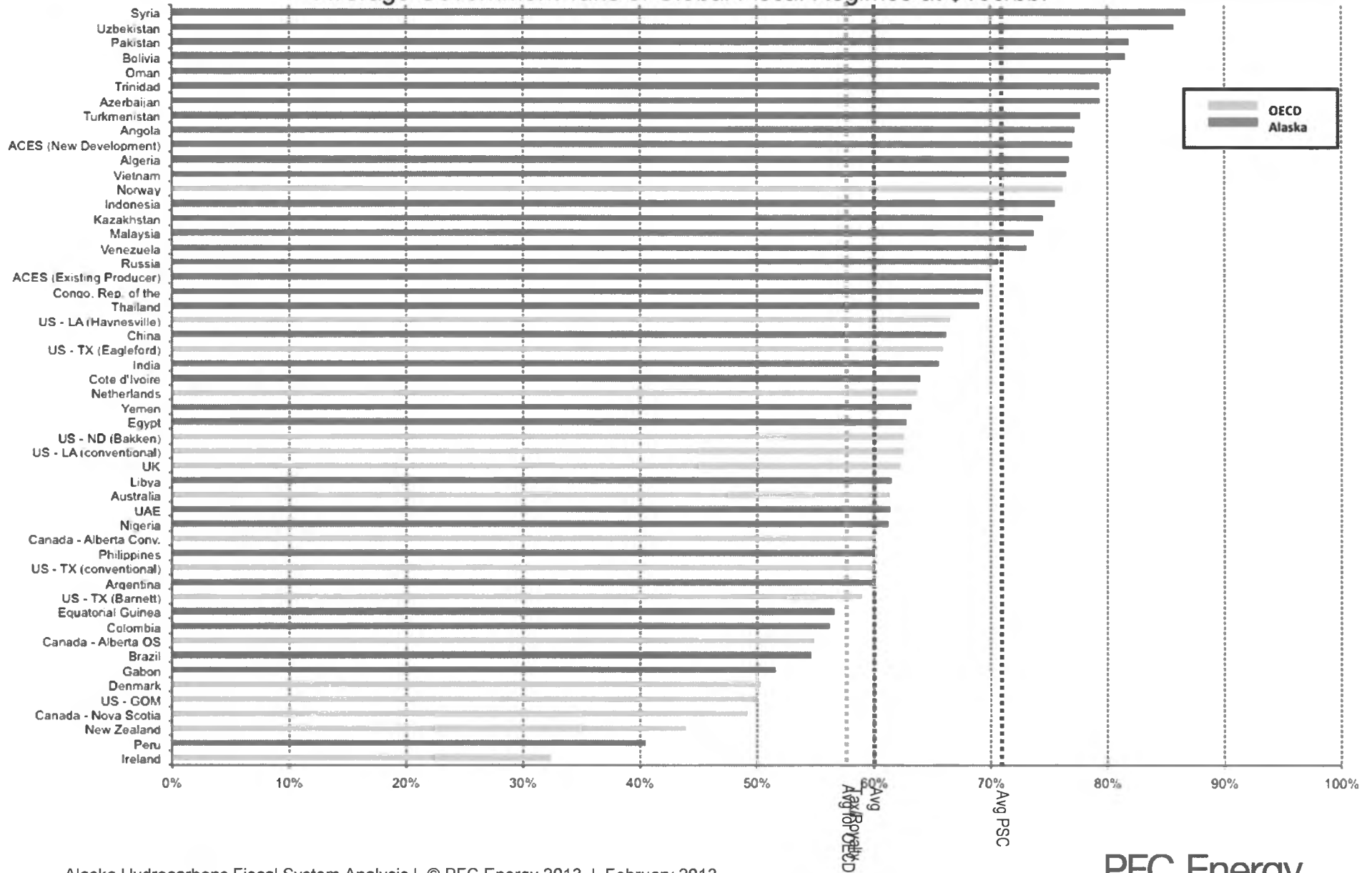
Regime Competitiveness: Average Government Take at \$80/bbl

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



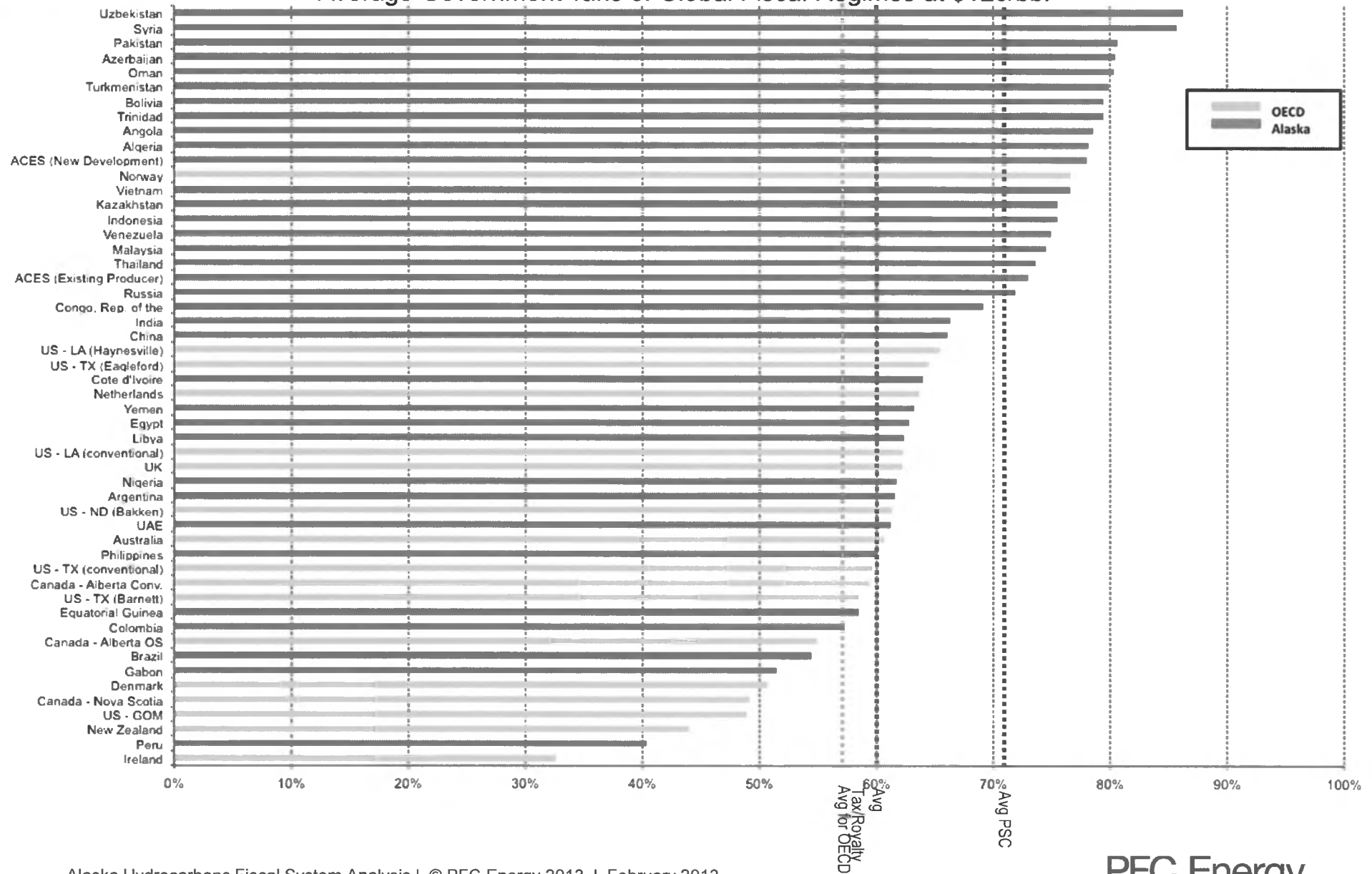
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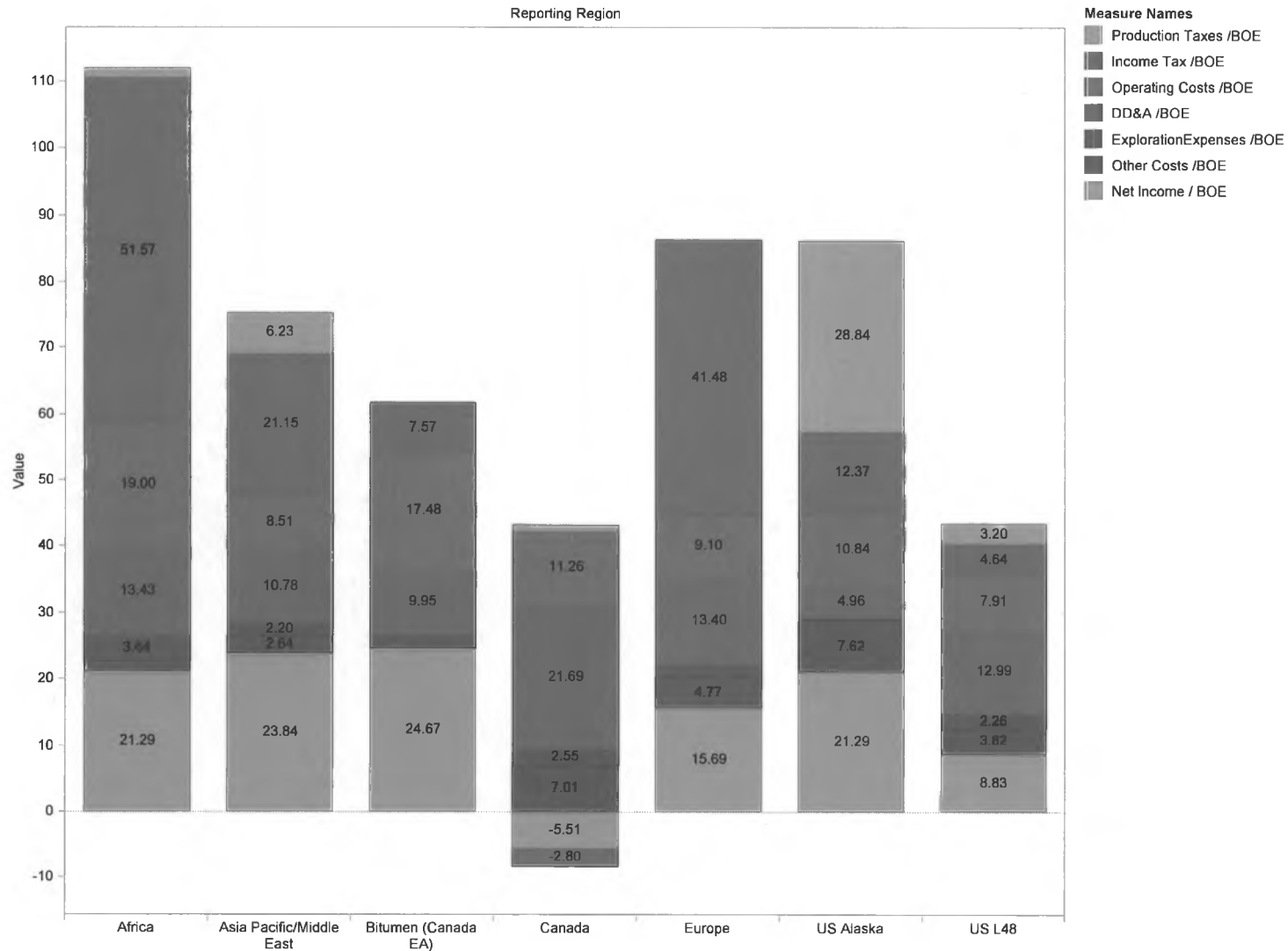
Regime Competitiveness: Average Government Take at \$120/bbl

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



Difference Between New Investment vs Base Production is Critical

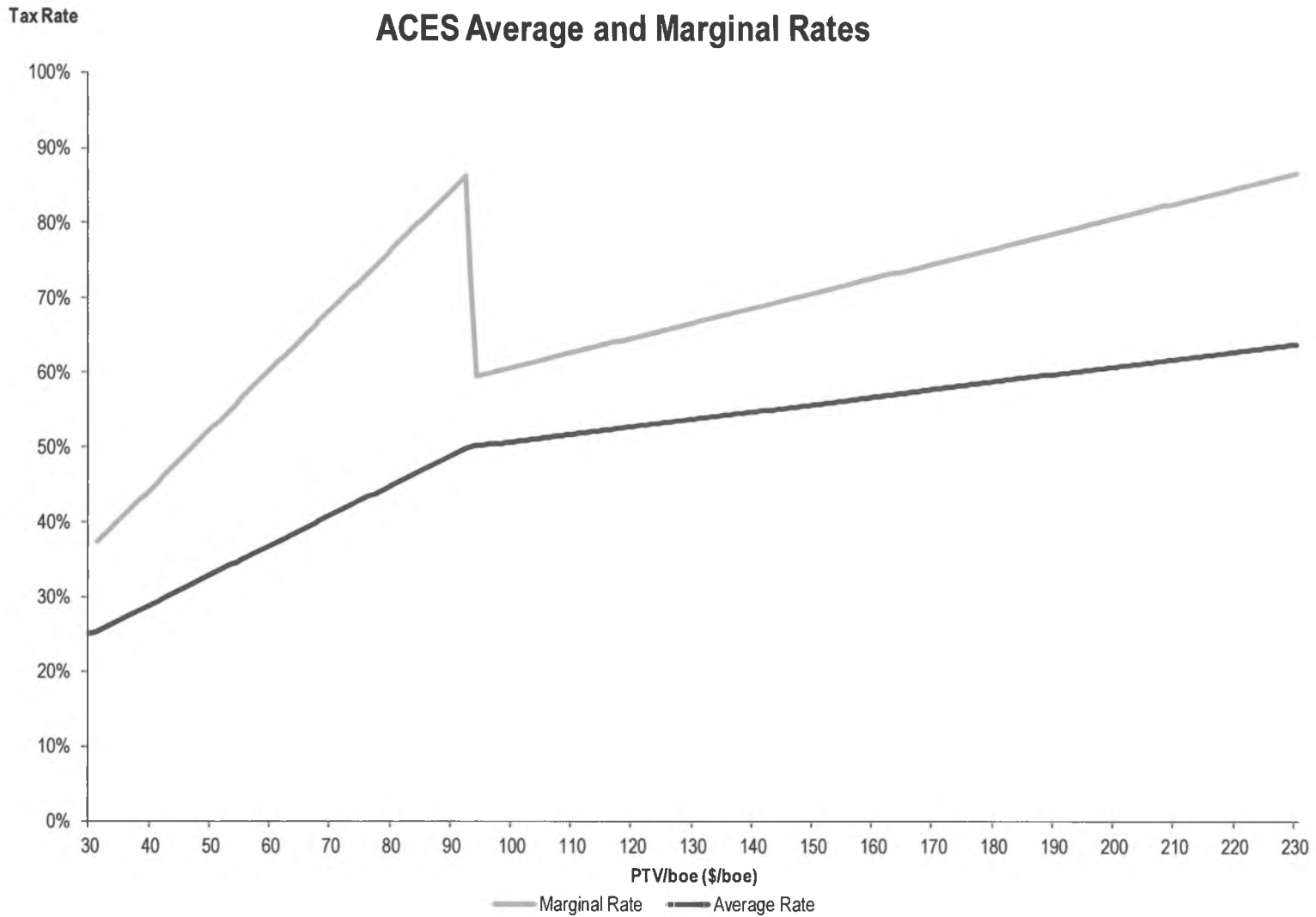
ConocoPhillips: 2011 Revenue and Income / bbl



ACES: 5 key problems

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ACES: Average and Marginal Production Tax Rates



Impact of Spending Under High Marginal Rates



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%

Econ One Research

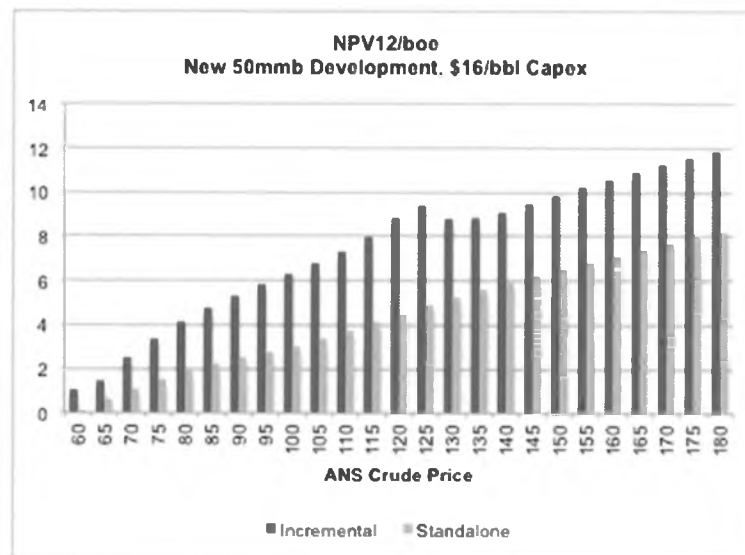
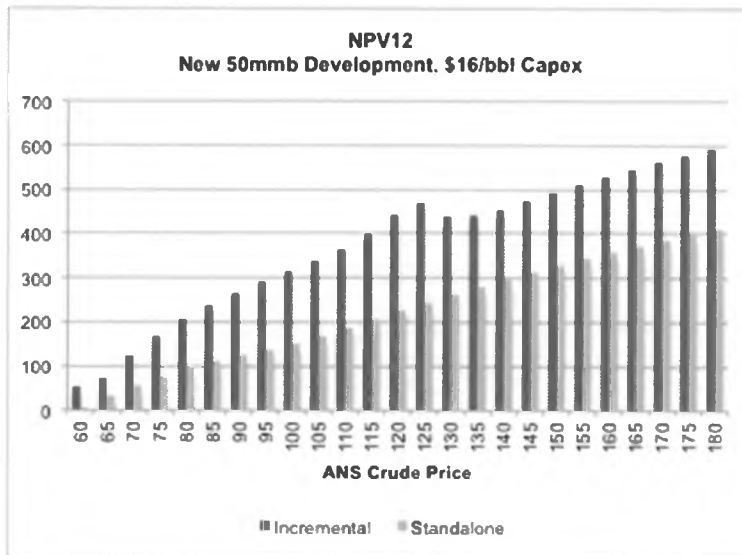
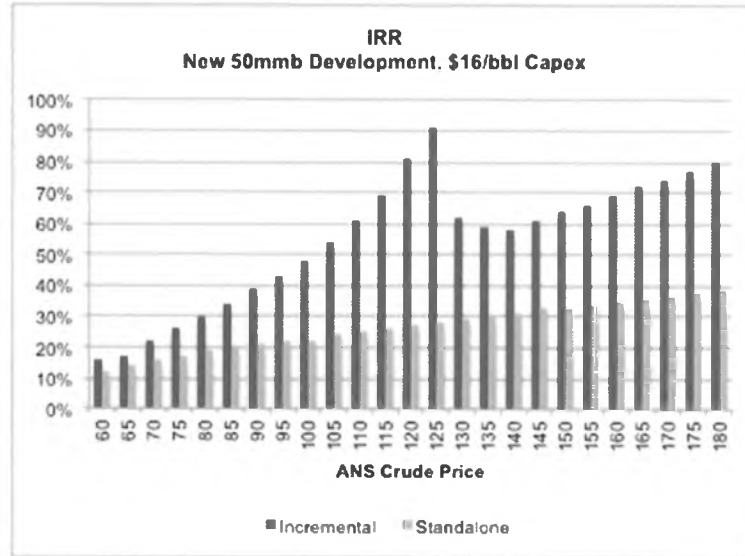
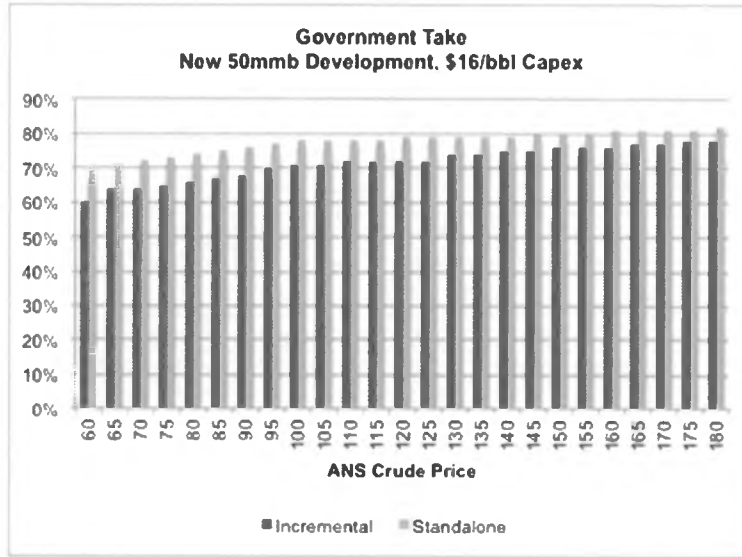
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Source: Econ One Presentation, February 13 2013

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ACES: Standalone vs Incremental

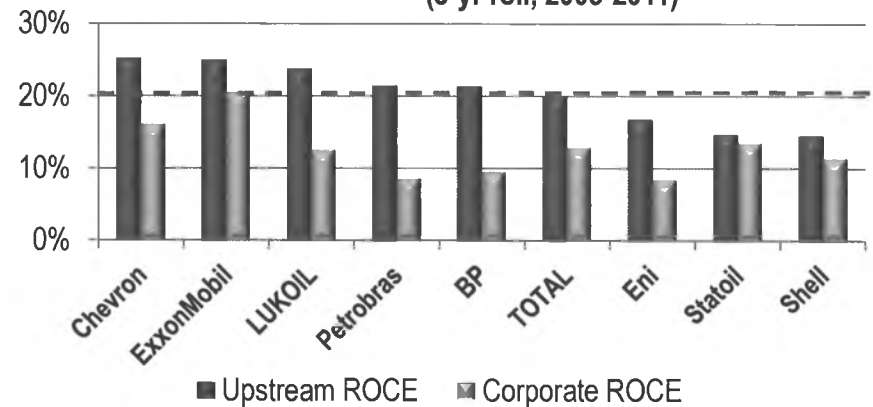


Portfolio Efficiency: Return on Capital Employed (ROCE)

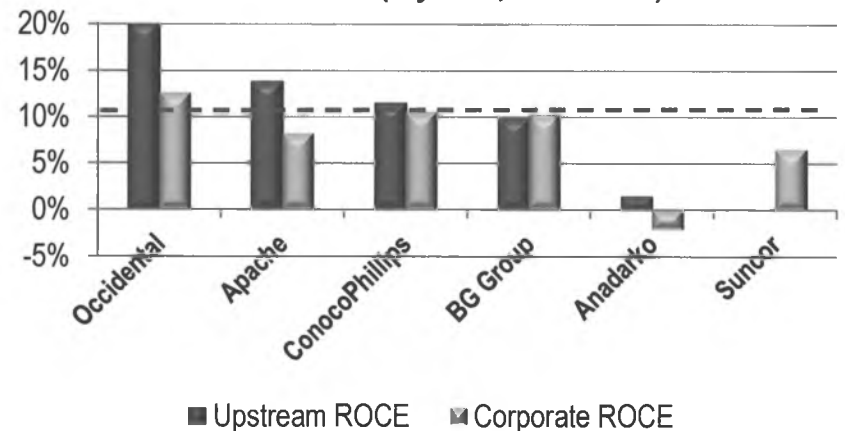
Return on Capital Employed:

- ROCE = [(Net profit before interest and taxes) / (Gross Capital employed)] x 100
- Where:
 - Gross capital employed = Fixed assets + Investments + Current assets *OR*
 - Gross capital employed = Share Capital + General & Capital Reserves + Long term loans
 - (+) Correlation with production, commodity prices
 - (-) Correlation with upstream spending
- Indicates how well management has used the investment made by owners and creditors into the business.
- The higher the return on capital employed, the more efficient the firm is in using its funds. Over time, ROCE reveals whether the profitability of the company is improving or eroding

Upstream & Corporate ROCE, Global Players
(3-yr roll, 2009-2011)



Tier I Indies Upstream & Corporate ROCE
(3-yr roll, 2009-2011)



Global Players Average Upstream ROCE: 20.4%

Tier I Independents Average Upstream ROCE: 11.4%

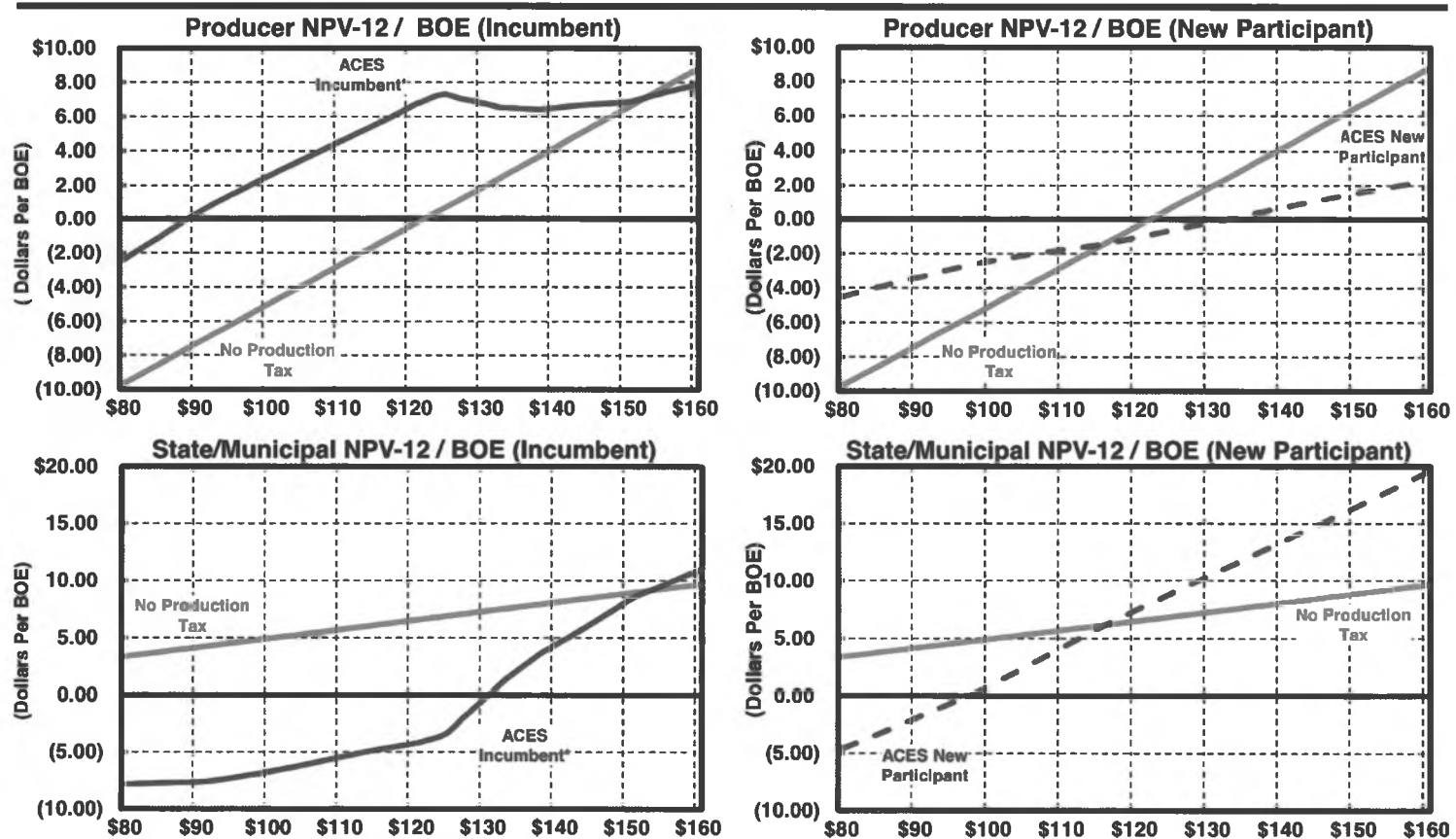
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High state exposure for high-cost developments



The Economics of High Cost Heavy Oil Development



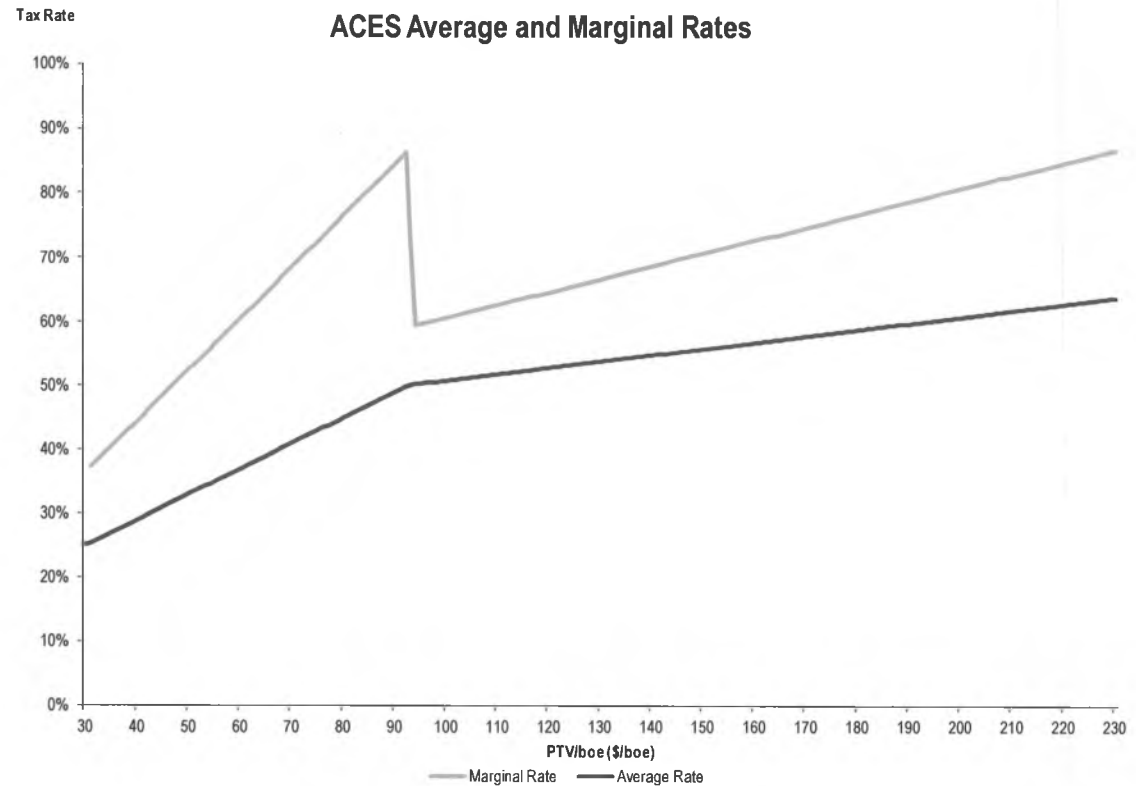
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

ACES: 5 key problems

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- Complexity makes meaningful economic analysis and comparison difficult
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- **Impact of large-scale gas sales on tax rates**

Impact of Large-Scale Gas Sales on Tax Rates

- Under ACES, production tax value is assessed on a combined BTU-equivalent basis for both oil and gas production
 - So long as no major gas export project is under development, this has no impact
 - In the event of the development of a major gas export project, however, when gas prices are significantly lower than oil prices, this could lead to significant reductions in Government Take



ACES: 5 key problems – *available solutions*

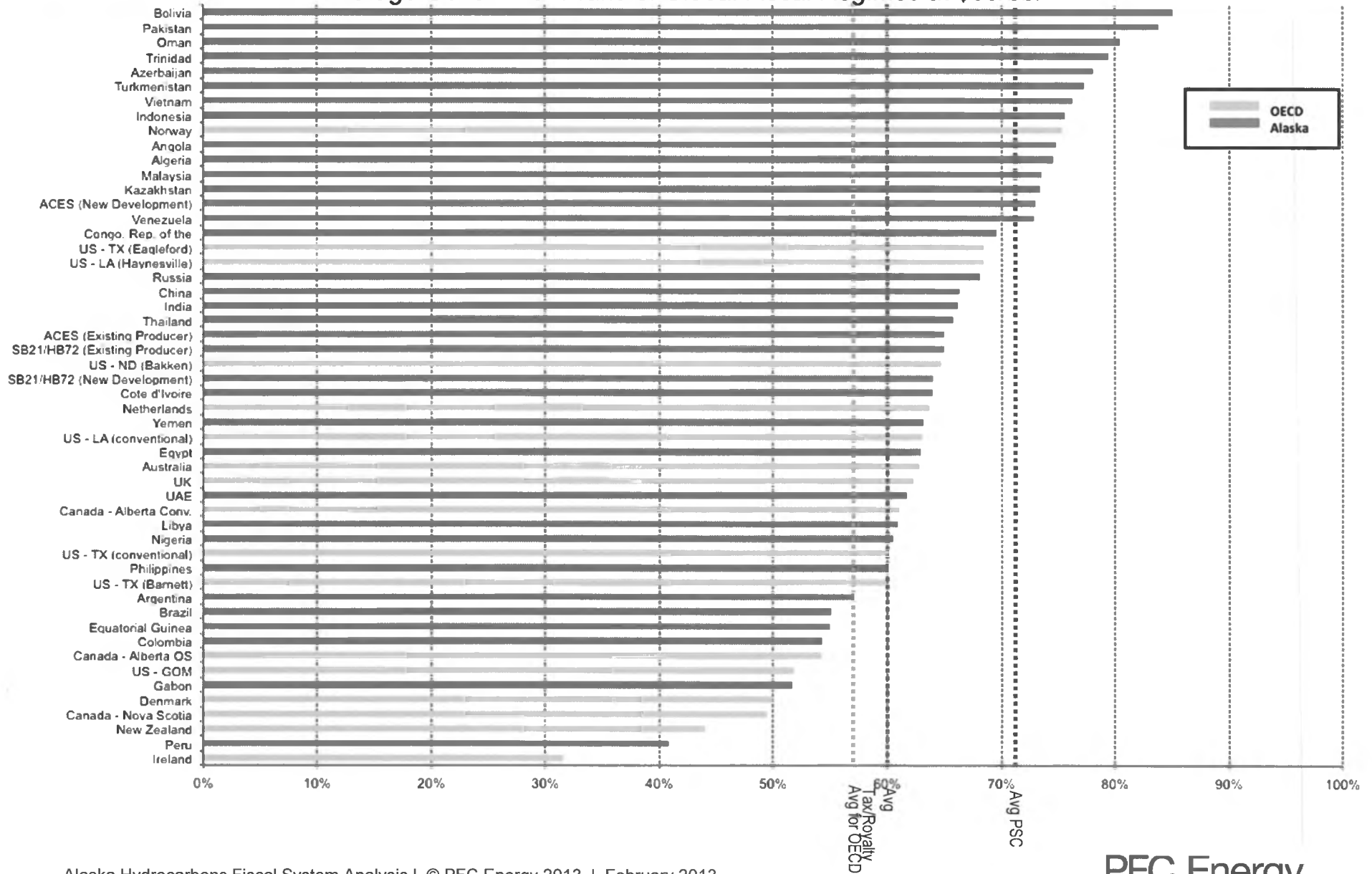
- High levels of Government Take reduce competitiveness for capital, especially at high prices
 - *Reduce, bracket or eliminate progressivity*
 - *Reduce base rate*
- High marginal tax rates reduce incentives for spending control
 - *Reduce, bracket or eliminate progressivity*
 - *Reduce, restrict or eliminate credits*
- Complexity makes meaningful economic analysis and comparison difficult
 - *Simplify overall system design, especially interaction of progressivity with credits*
 - *Improve economics for new development*
- Significant state exposure in low price environments, and for high-cost developments
 - *Reduce or eliminate some or all credits*
 - *Eliminate ability to claim credits from state treasury*
 - *Carry credits forward to production*
- Impact of large-scale gas sales on tax rates
 - *Eliminate progressivity, levy progressivity on gross basis, or use progressive Gross Revenue Exclusion*

ACES: 5 key problems – *SB21/HB72 Solutions*

- High levels of Government Take reduce competitiveness for capital, especially at high prices
 - *Reduce, bracket or eliminate progressivity*
 - *Reduce base rate*
- High marginal tax rates reduce incentives for spending control
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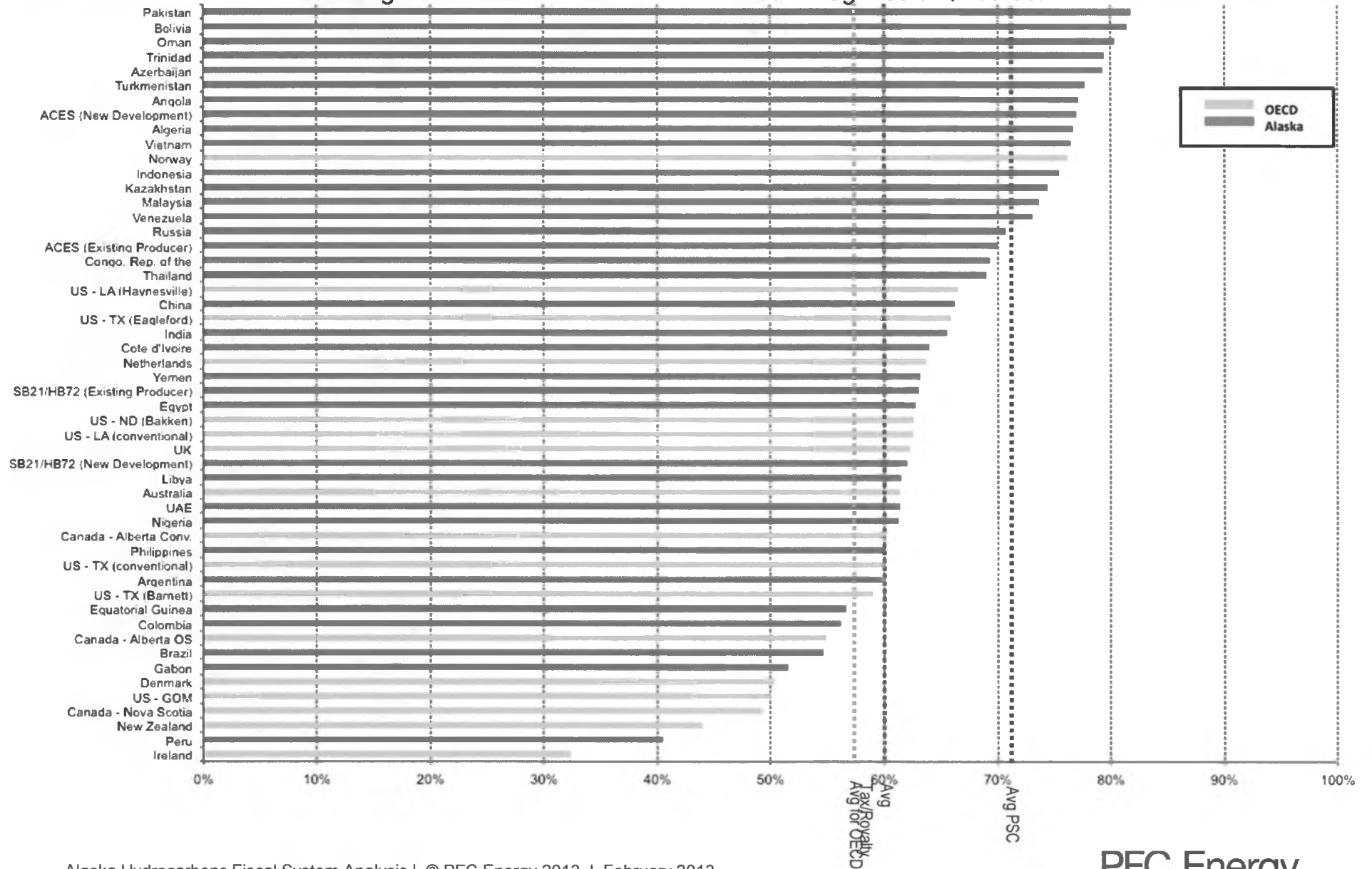
Regime Competitiveness: Average Government Take at \$80/bbl

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



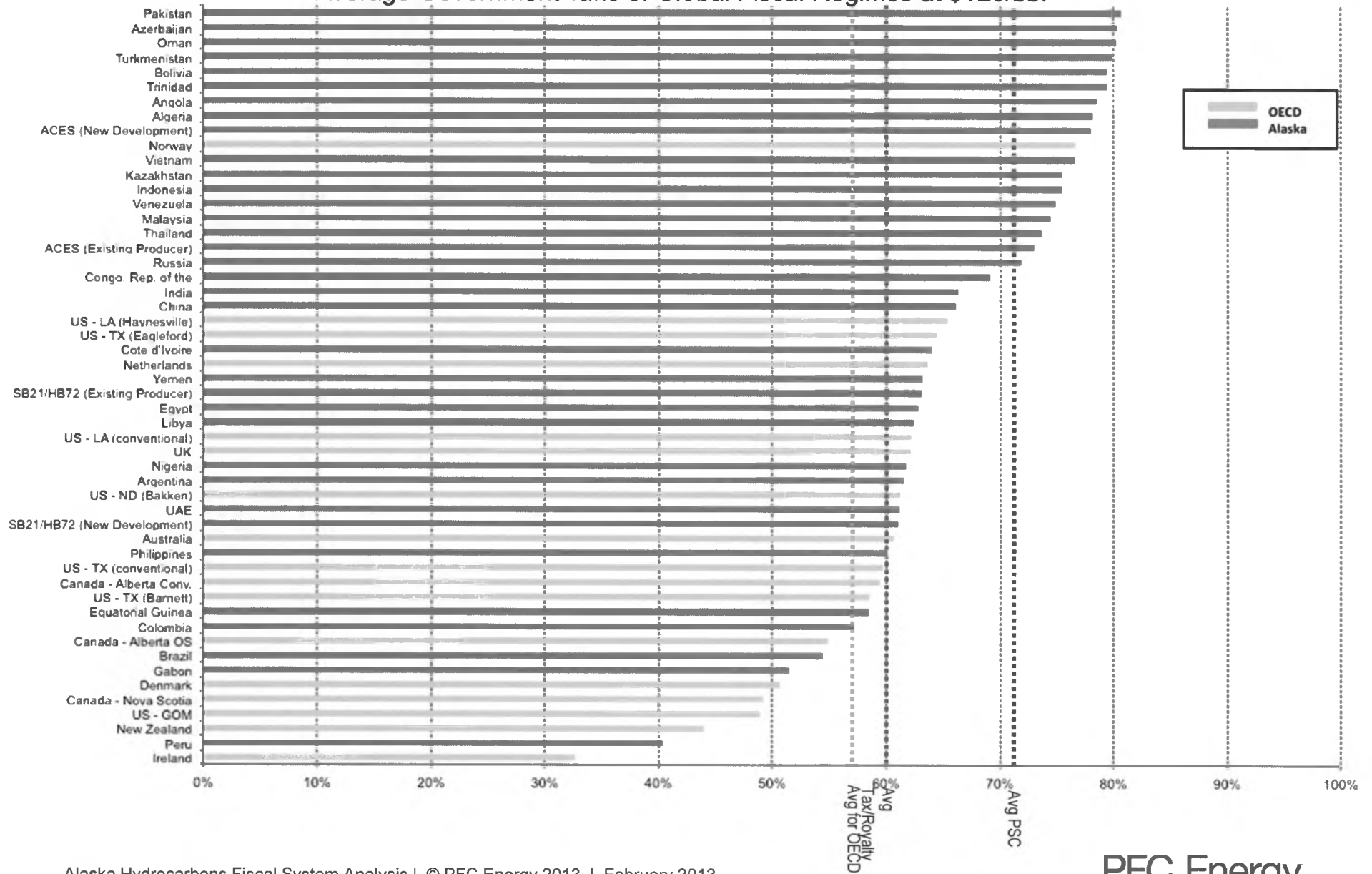
Regime Competitiveness: Average Government Take at \$100/bbl

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

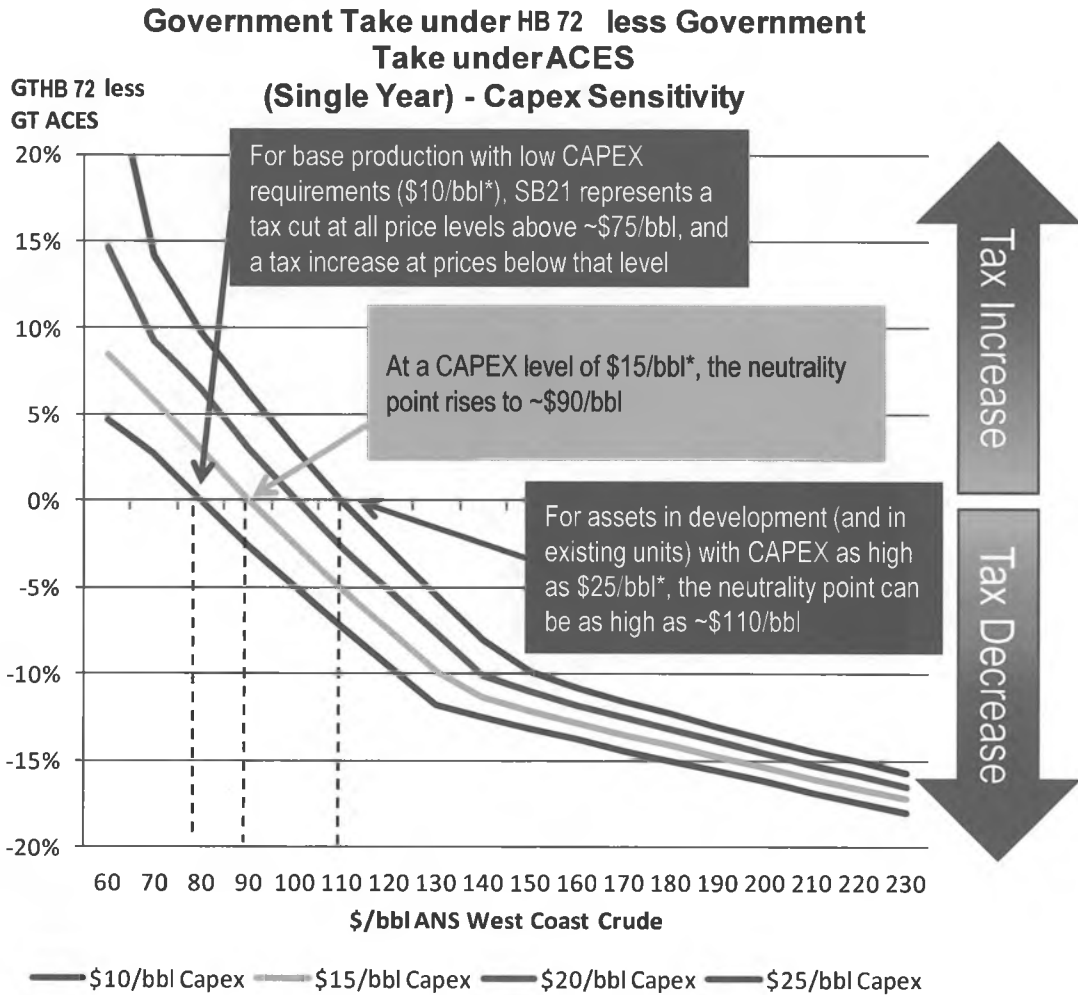


Regime Competitiveness: Average Government Take at \$120/bbl

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



Government Take under SB21/HB72 and ACES – Capex Sensitivity



- 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**

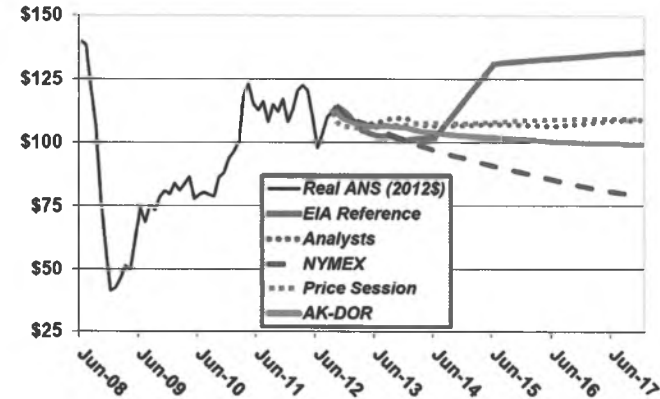
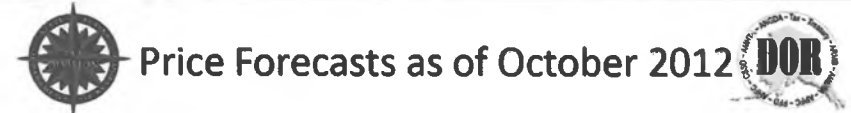
* All CAPEX figures are in gross bbl terms (\$15 per gross bbl is roughly equivalent to DOR 2014 average North Slope forecast of \$19.6 per bbl net of royalty, when adjusted for gross/net and for capital expenditures by non-taxable entities)



Additional Responses to Questions from the Chair

Assessment of DOR Price Forecast Methodology

- Price uncertainty has risen with the increase in non-OPEC supply (largely North America).
- The volatility seen from 2008-2012 is not a one off event.
- A relatively flat price, as shown at right, can still be a “good forecast” if actual prices show equivalent value errors on either side.



Note: All estimates are for ANS prices, some were converted by Department of Revenue from WTI to ANS.
Sources: DOR, Bloomberg, NYMEX, Energy Information Agency

Alaska Department of Revenue

11

- A “good forecast” forecast must still be understood to hold a great deal of uncertainty with each data point (month) forecasted and the range of error grows the further into the future the forecast extends.
- Successfully managing forecast uncertainty requires:
 - Understanding the magnitude of the potential error
 - Recognizing and/or setting the forecast skewed toward the high or low side
 - Implementing price risk mitigation strategies (options, budgeting, contractual language, non-correlated diversification)

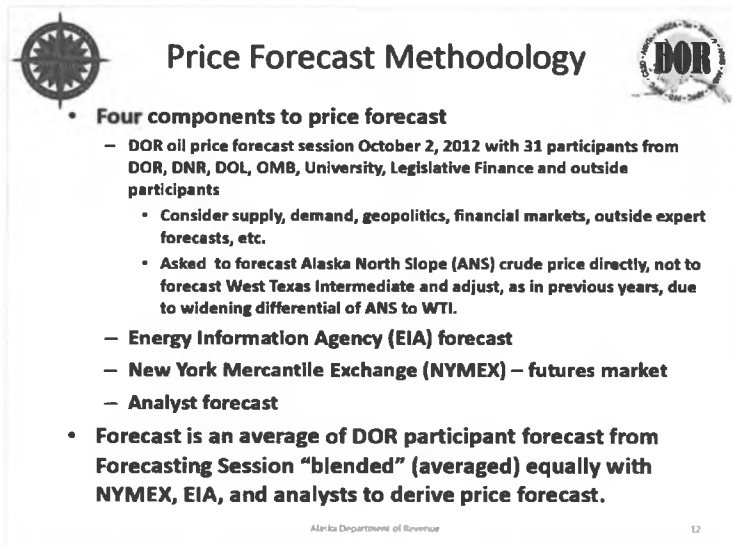
Assessment of DOR Price Forecast Methodology



Positive Aspects of Methodology

- Using blended forecast can often provide a more “technically” accurate forecast
- Recognizing that WTI is no longer a good global marker – just one indicator of a radically changing oil market
- Examining supply, geopolitics, financial markets when considering the forecast

Risks of Methodology

- Futures market should not be used as a forecast
- Using multiple time-horizon EIA forecasts can cause a jump in forecast price not intended
- Holding large group forecasting meeting can result in herd behavior and “talking your book”, skewing forecast results.
- Relatively flat price forecast (without proper understanding of upside/downside risks) can result in poor allocation of resources as price diverges from forecast.

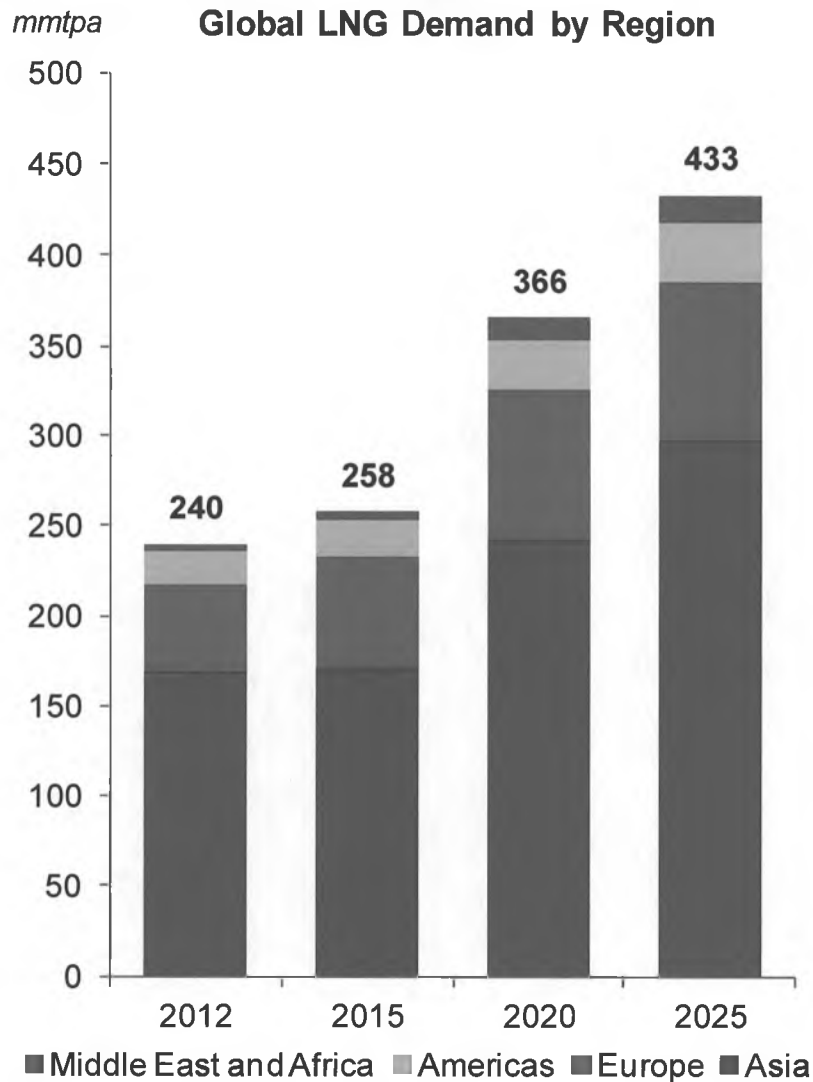


 **Price Forecast Methodology** 

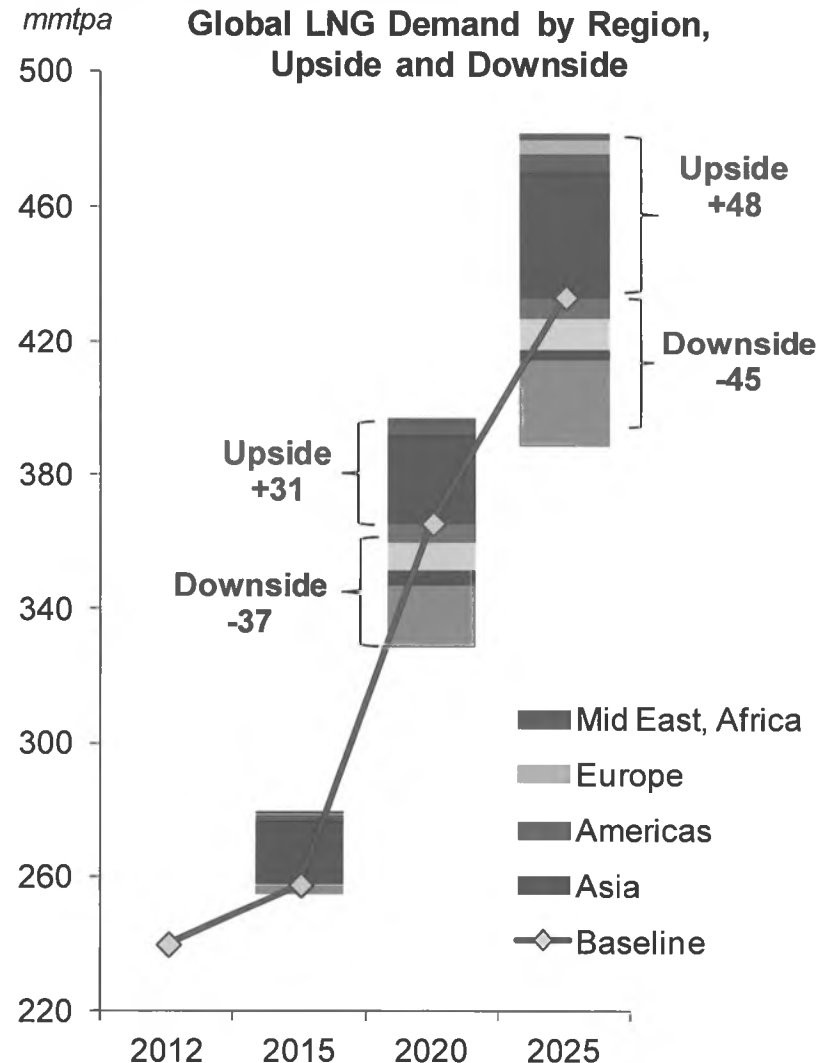
- **Four components to price forecast**
 - DOR oil price forecast session October 2, 2012 with 31 participants from DOR, DNR, DOL, OMB, University, Legislative Finance and outside participants
 - Consider supply, demand, geopolitics, financial markets, outside expert forecasts, etc.
 - Asked to forecast Alaska North Slope (ANS) crude price directly, not to forecast West Texas Intermediate and adjust, as in previous years, due to widening differential of ANS to WTI.
 - Energy Information Agency (EIA) forecast
 - New York Mercantile Exchange (NYMEX) – futures market
 - Analyst forecast
- **Forecast is an average of DOR participant forecast from Forecasting Session “blended” (averaged) equally with NYMEX, EIA, and analysts to derive price forecast.**

Alaska Department of Revenue 12

Global LNG Demand Driven by Asia



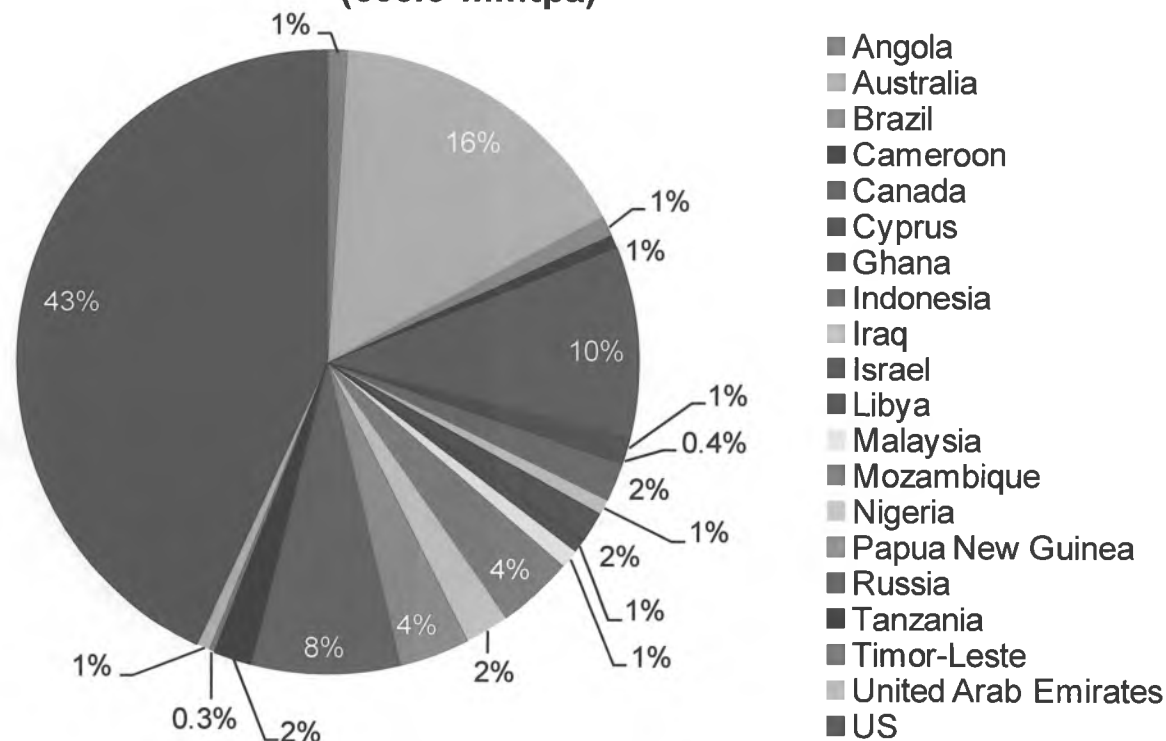
Source: PFC Energy Global LNG Service



Source: PFC Energy Global LNG Service

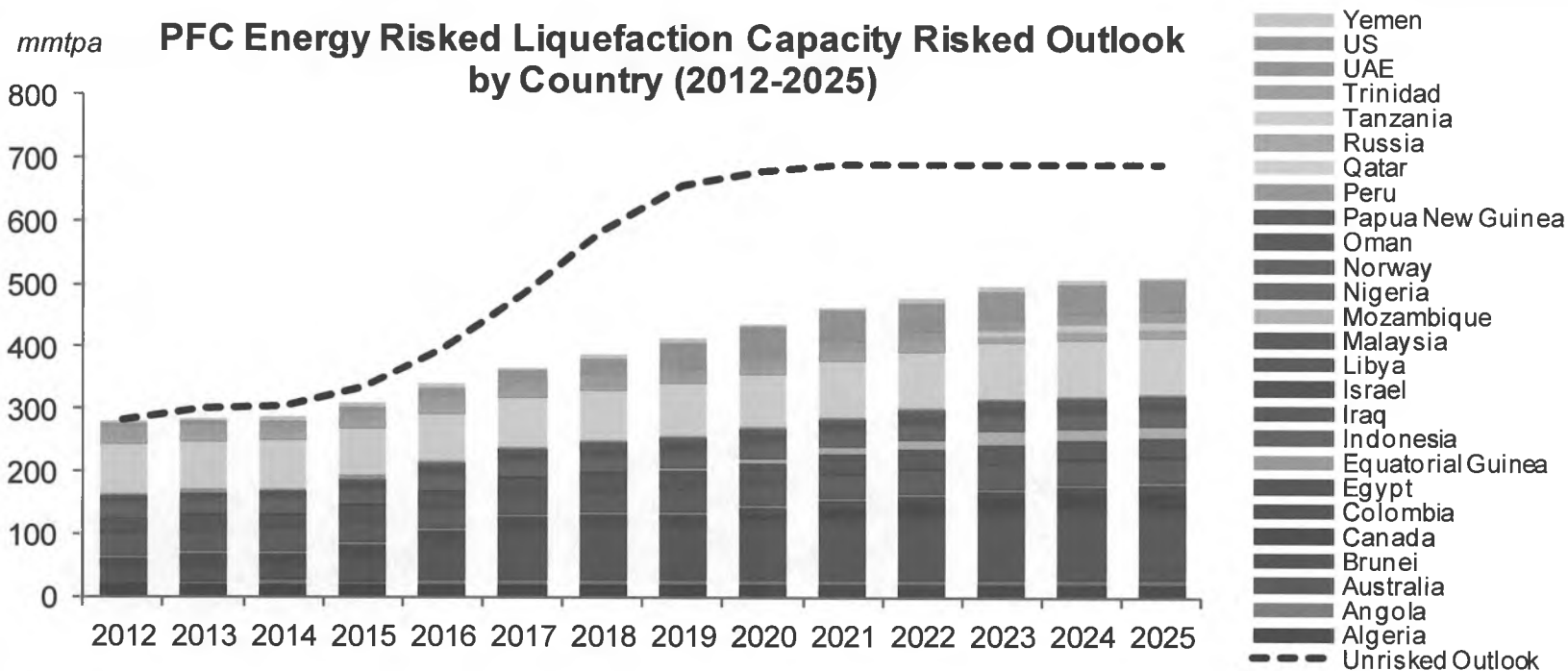
Proposed LNG Capacity by Country

Proposed Liquefaction Capacity by Country*
(503.5 mmtpa)



- As of February 2012, 503.5 mmtpa of new liquefaction projects had been proposed. Over three-fourths of this capacity is located in four countries: the United States (217.4 mmtpa or 43%), Australia (81.4 mmtpa or 16%), Canada (50.2 mmtpa or 10%), and Russia (38.6 mmtpa or 8%). each of these countries face the Pacific Basin, making them logical suppliers to Asian markets.

PFC Energy Risked LNG Supply Outlook by Country



- Global liquefaction capacity stood at 281.6 mmtpa in 2012. A great number of new projects have been proposed or are in various stages of development. If all of these projects moved forward according to their announced timetables, global LNG capacity would reach 678 mmtpa by 2020 and 689 mmtpa in 2025.
- PFC Energy believes that a number of these projects face considerable development risks – ranging from geopolitical risk to lack of secured feedstock – that will delay project development timelines. We estimate that global liquefaction capacity will reach 438 mmtpa in 2020 (a full 240 mmtpa below announced capacity levels) and 513 mmtpa in 2025.

Risk Factors: Asia-Pacific (Australia)

Country	Main Risks
Australia (General)	<ul style="list-style-type: none"> ▪ Cost inflation for materials and labor is causing higher EPC costs and delays ▪ The particular combination of multiple LNG projects simultaneously under construction and strong demand from other extractive industries has created significant labor market tightness ▪ The government's current carbon tax legislation will impact project economics to an extent, though not enough to block project development
Eastern Australia (CBM)	<ul style="list-style-type: none"> ▪ Environmental regulations over water extraction could delay projects ▪ Companies still need to prove up reserves to justify plans for brownfield expansions ▪ Unclear how the production / ramp-up process will impact feedstock reliability ▪ CBM contains virtually no liquids, thus the project will not see upside from liquids revenues
Western Australia	<ul style="list-style-type: none"> ▪ The fact that multiple IOCs are involved in multiple projects in the region offers the potential for partner drag issues; IOC projects in Western Australia will compete for company resources against each other and also with projects in other parts of the world
Brunei	<ul style="list-style-type: none"> ▪ Brunei recently renewed its original long-term contracts with Japanese utilities, but for lower volumes and over a 10-year duration only ▪ The largest constraint to future LNG production is a gas supply risk. In the medium-term, upstream co-venturers will need to prove-up new reserves and develop new gas projects to increase volumes and contract periods ▪ If available proved reserves are insufficient to support liquefaction capacity, under-utilization of existing capacity will ensue
Indonesia	<ul style="list-style-type: none"> ▪ The government's preference to satisfy growing domestic gas needs has threatened the longevity of existing projects and the viability of new ones
Malaysia	<ul style="list-style-type: none"> ▪ Malaysia's new projects are often farther removed from existing infrastructure ▪ Sustaining and growing volumes will depend on exploration success
Papua New Guinea	<ul style="list-style-type: none"> ▪ Limited established infrastructure and difficult physical conditions challenge project developers ▪ Social unrest/ landowner issues / disagreements over revenue-sharing pose key political risks

Risk Factors: Europe and MENA

Europe

Country	Main Risks
Overview	<ul style="list-style-type: none"> No new liquefaction capacity additions have been planned.

MENA

Country	Main Risks
General	<ul style="list-style-type: none"> The region faces a range of issues that continue to impact new project development, including rising domestic demand, poor regulatory or energy policy clarity, economic and political instability, sanctions (in the case of Iran), and more difficult reserves. These factors have already constrained gas exports from the region over the past years, markedly from Egypt, Algeria, Libya and Yemen. PFC Energy expects this trend to continue, limiting prospects for liquefaction capacity growth in the MENA region. To 2025, PFC Energy projects that only three countries are likely to add liquefaction capacity: Israel, Qatar and UAE.
Israel	<ul style="list-style-type: none"> Ability to develop exports will hinge on overcoming challenges such as financing, offtake, and a political hesitation towards exports.
Qatar	<ul style="list-style-type: none"> Moratorium on new gas production from the North Field to 2015 has blocked project development. Debottlenecking of mega trains could offer growth, but this prospect remains highly uncertain
United Arab Emirates	<ul style="list-style-type: none"> Proposal to add another train to the country's existing liquefaction facility will likely be hindered by rising domestic demand, leading to fewer exports.

Risk Factors: North America

Country	Main Risks
United States (General)	<ul style="list-style-type: none"> ▪ New exports licenses are on hold as the Department of Energy (DOE) reviews its export approval process. ▪ A partial consensus – that LNG exports should be allowed, but limited – seems to be emerging from both the Obama Administration and the US Congress. The major issue delaying further approvals is the scale of exports to allow and from which projects they should come
United States (West Coast)	<ul style="list-style-type: none"> ▪ Alaska. Multiple IOCs have agreed with the State of Alaska on the development of gas resources located in the North Slope starting in 2015-16, but a decision on how the gas will be commercialized has yet to be made. Exporting LNG, one of the options being considered, would require a substantial pipeline investment to a greenfield LNG plant. With regard to Kenai LNG, it remains uncertain whether the plant will be able to renew its license beyond 2013. ▪ Oregon. The proposed LNG facility in Oregon has faced significant local opposition for years due to the potential environmental impact of LNG, a fact that could delay the project significantly.
Canada	<ul style="list-style-type: none"> ▪ Permitting and constructing a pipeline from the wellhead to the port will take time, although it is unlikely to be a project blocker ▪ British Columbia's current carbon tax legislation will impact project economics

Risk Factors: Sub-Saharan Africa and South America

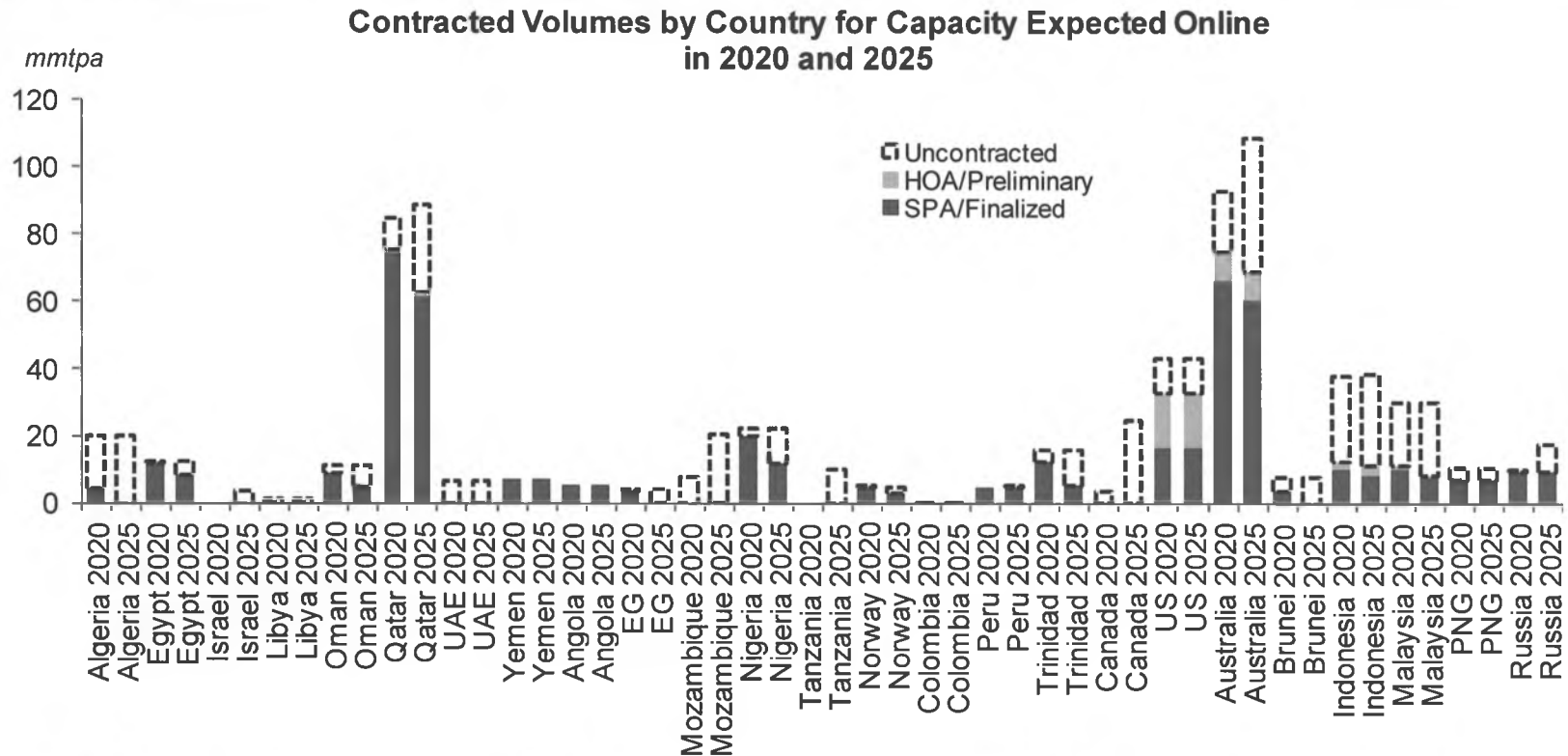
Sub-Saharan Africa

Country	Main Risks
Mozambique	<ul style="list-style-type: none">▪ Large infrastructure development will put a stress on infrastructure and government institutions▪ Need for bigger players and gas field unitization could delay LNG projects
Nigeria	<ul style="list-style-type: none">▪ Significant resource potential but the majority of gas reserves are stranded, flared, or expected to feed the domestic market▪ Large amount of proposed liquefaction projects but little progress to date and none of the project partners have taken a final investment decision
Tanzania	<ul style="list-style-type: none">▪ Large infrastructure development will put a stress on infrastructure and government institution▪ Gas policy revisions – and the associated uncertainty over contract terms – could delay project development. Local protests over resource allocation and the government’s insistence on a single project development could further setback project timelines

South America

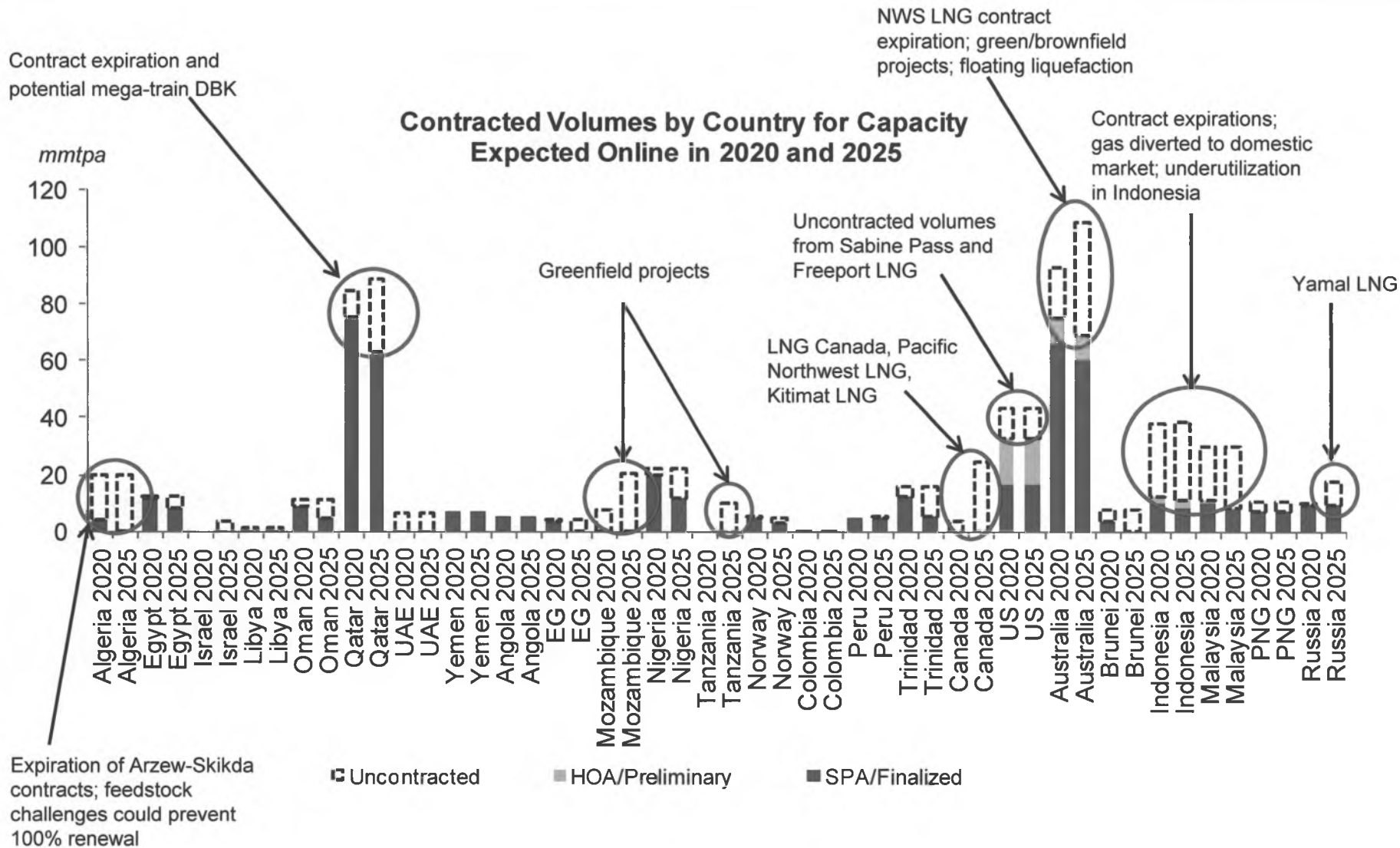
Country	Main Risks
Trinidad	<ul style="list-style-type: none">▪ Unlikely to add liquefaction capacity due to uncertainty over gas reserves
Peru	<ul style="list-style-type: none">▪ The government is anxious to meet domestic demand and current plant may not be utilized fully▪ The government has announced that it intends to reallocate reserves currently feeding the Peru LNG project to the domestic market
Colombia	<ul style="list-style-type: none">▪ Only one small (0.5 mmtpa) project under construction; no further capacity additions planned

Share of Contracted Capacity by Country



- 31% of liquefaction capacity projected online in 2020 (134 mmtpa) is uncontracted; this share rises to 52% (267 mmtpa) in 2025, providing opportunities for new LNG volumes to enter the market.
- A number of existing contracts will expire between 2018 and 2025, notably for projects in Australia, Indonesia, Malaysia and Algeria. PFC expects that many will not be renewed at current volumes.
- Remaining uncontracted volumes reflect projects that are still in the early phases of development (e.g. Mozambique, Tanzania, the US, Canada and Australia). The potential debottlenecking of Qatar's mega-trains would add further uncontracted volumes to the market.

Share of Contracted Capacity by Country



Competitive Landscape for LNG Sales to Asia

- **Rising Demand in Asia.** PFC Energy projects that LNG demand in Asia* will grow from 168 mmtpa in 2012 to 240 mmtpa by 2020 and 300 mmtpa by 2025.
- **Shortfall in Contracted Capacity.**
 - PFC Energy has identified enough projects to meet growing Asian demand through 2025. However, finalized and preliminary contracts fall short in meeting this demand.
 - Even if all preliminary contracts are finalized, PFC Energy expects the Asian market will need an extra 58 mmtpa of LNG by 2020 for which there are no contracts in place; by 2025, that gap grows to 140 mmtpa and continues to rise thereafter.
- **New Contracts Required.** Buyers will need to both extend existing contracts and sign long-terms contracts with new projects which have uncontracted capacity.
- **Key Competitors.**
 - A slew of new liquefaction projects have been proposed – notably in North America, Australia and East Africa – that would be logical LNG suppliers to the Asian market. The eventual debottlenecking of the Qatari mega trains could also provide incremental volumes to Asia.
 - Still, PFC Energy believes that many of these projects will not move forward according to their announced timelines due to a variety of development challenges, ranging from cost escalation (Australia) to lack of institutional capacity (East Africa).
 - This provides room for the development of new projects and an outlet for new LNG volumes in the Asian market.

** Refers to the following markets: Japan, Korea, Taiwan, China, India, Thailand, Indonesia, Malaysia, Vietnam, Bangladesh, and the Philippines.*

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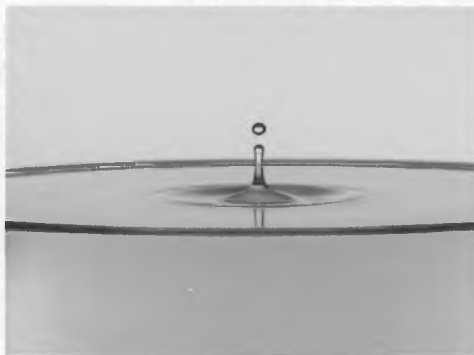
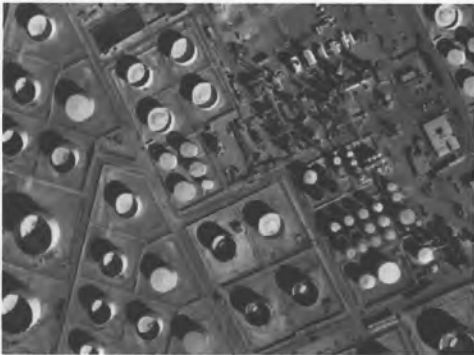
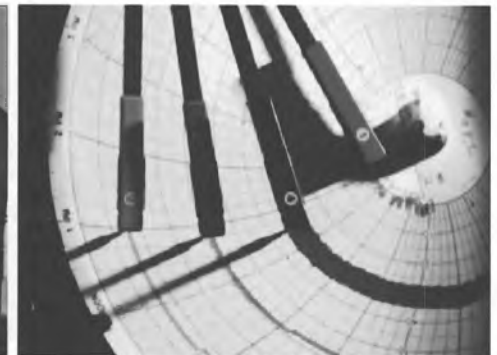
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable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

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PFC Energy

House Resources Committee

Testimony re: SB 21/HB72

Feb. 18, 2013

J. Patrick Foley

Land and External Affairs Manager

Incoming President, Pioneer Natural Resources, Alaska



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Pioneer Natural Resources, Alaska

Forward Looking Statements

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

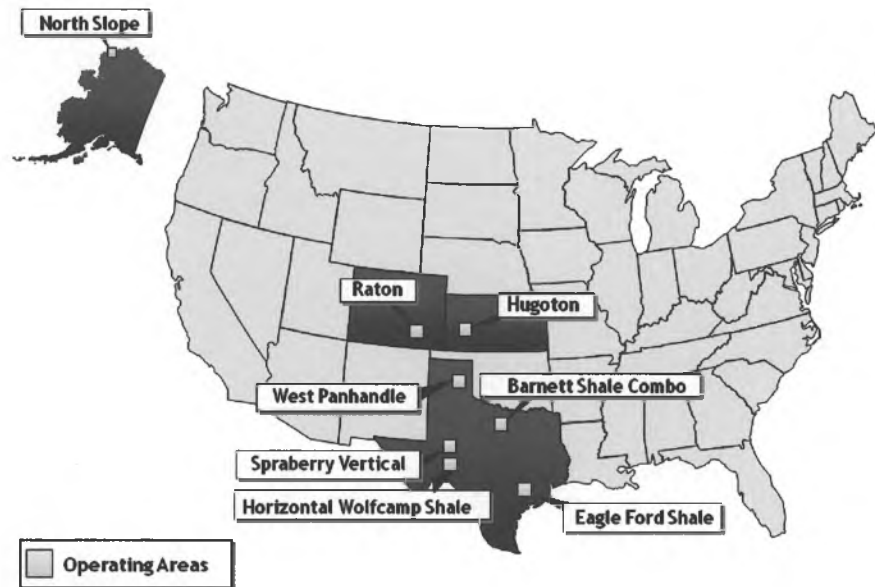
Presentation Overview

- Pioneer overview
- Importance of a healthy industry
- Competition for capital
- SB 21/HB 72
- Incentives for Alaskan investments
- Closing thoughts



Corporate overview:

- \$19 Billion enterprise value
- ~3,500 employees
- \$3 Billion capital budget
- \$2 Billion cash flow from operations
- Leading performer in peer group



Alaska Operations Overview:

- 1st independent operator on North Slope
- 70+ full-time Alaska employees
- \$14+ million in annual wages (employees)
- 150 - 300 Alaska contract workers
- ~\$180 million 2013 capital budget
- ~ 6,000 BOPD gross production
- ~ 40% production growth anticipated for 2014

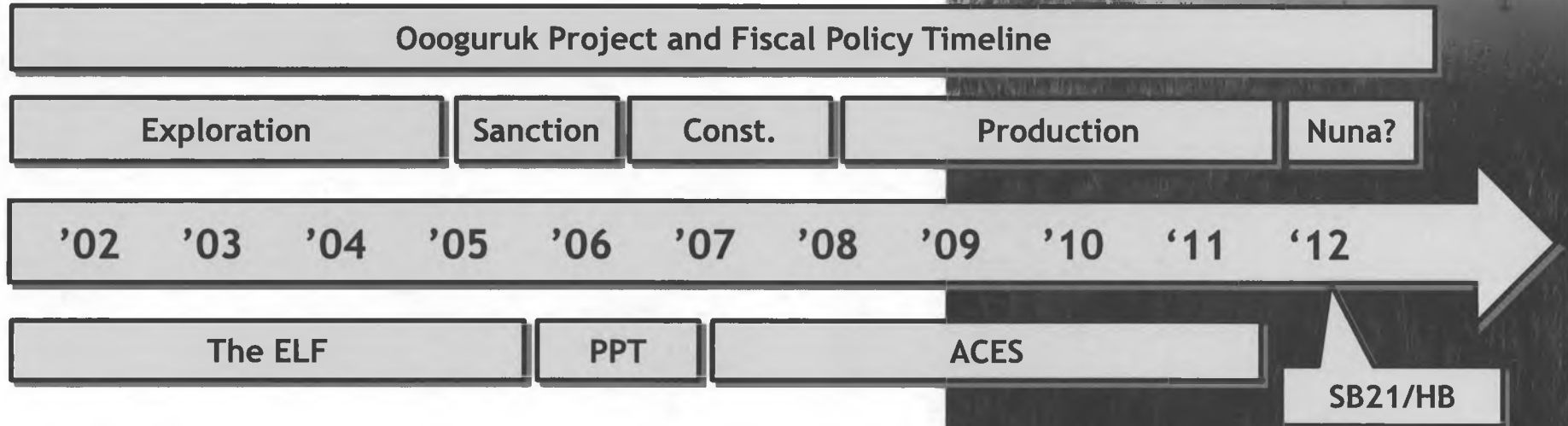
Pioneer Alaska Profile: Oooguruk

Exploration:

- 11 exploration wells '02 - '05
- 1 commercial project

Oooguruk Quick Facts:

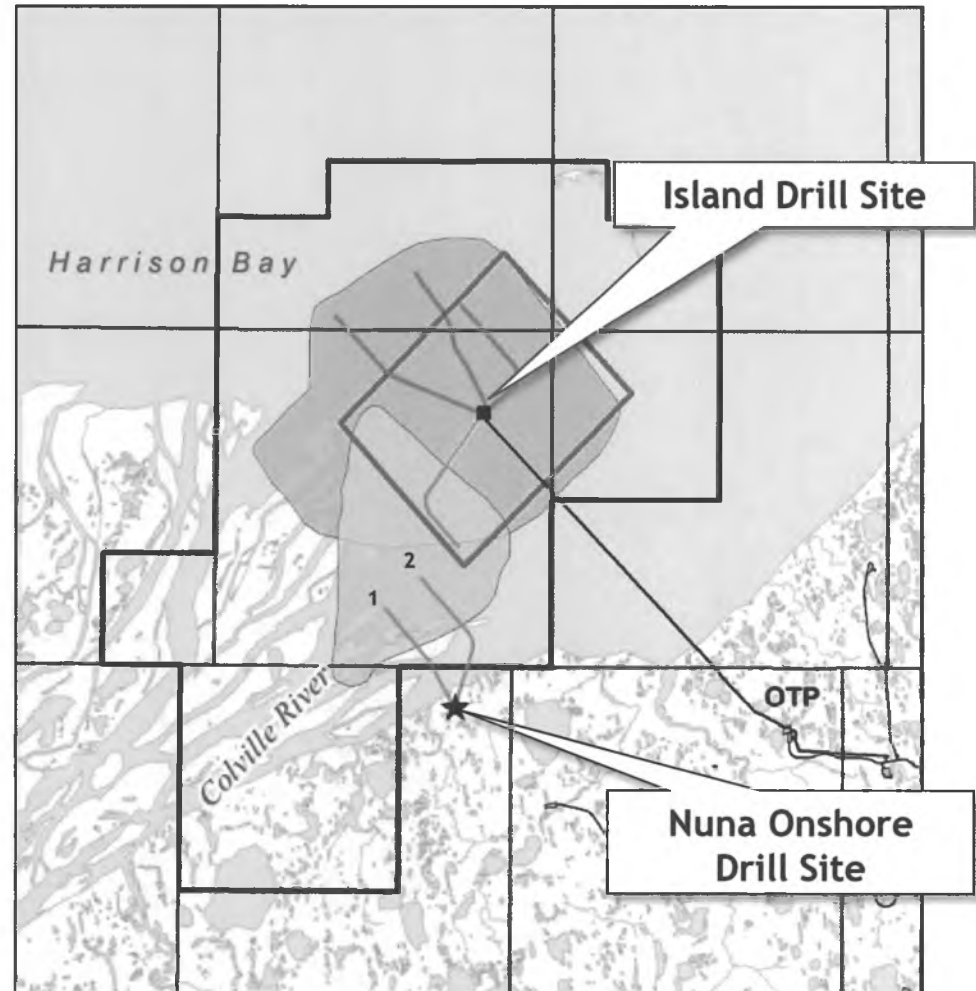
- 70% Pioneer (operator) : 30% Eni
- ~\$1 billion capital invested
- 12+ million barrels produced
- ~\$270 million in credits received
(~7 % of total credits issued by the state)



What's Next?

Nuna Project:

- Nuna-1 well drilled in 2012
- ~50 MMBO of resource potential
- Nuna-2 drilling underway
- Phase I development overview
 - Q3 2013 sanction decision
 - ~\$1 Billion capital required
 - 2015 first oil
 - 14 MBOPD peak production
 - Jobs and economic impact
- Potential for 2nd drill site
- **Must compete for limited capital against low-risk, fast-cycle projects in Lower 48**



Alaska Relative to Lower 48 Resource Plays:

Resource

	Alaska	Lower 48
Resource Report Card		
Resource Potential	✓	✓
Resource Competition	✓	
Geologic Risk		✓
Oil Bias	✓	✓
Regulatory Process Ease		✓
Land Acquisition	✓	✓

Profitability

	Alaska	Lower 48
Profitability Report Card		
Cycle Times / Payback		✓
Execution Risk		✓
Operational Flexibility		✓
Operating Margins		✓

Pioneer Competitive Resource Opportunities

WOLFCAMP / SPRABERRY

\$1,650 MM Drilling Program
627 MMBOE Proven

Vertical Program

20 Wells ('13)

+1.5 BBOE Net Potential

Wolfcamp / Spraberry

30-40 Wells ('13)

+3.0 BBOE Net Potential

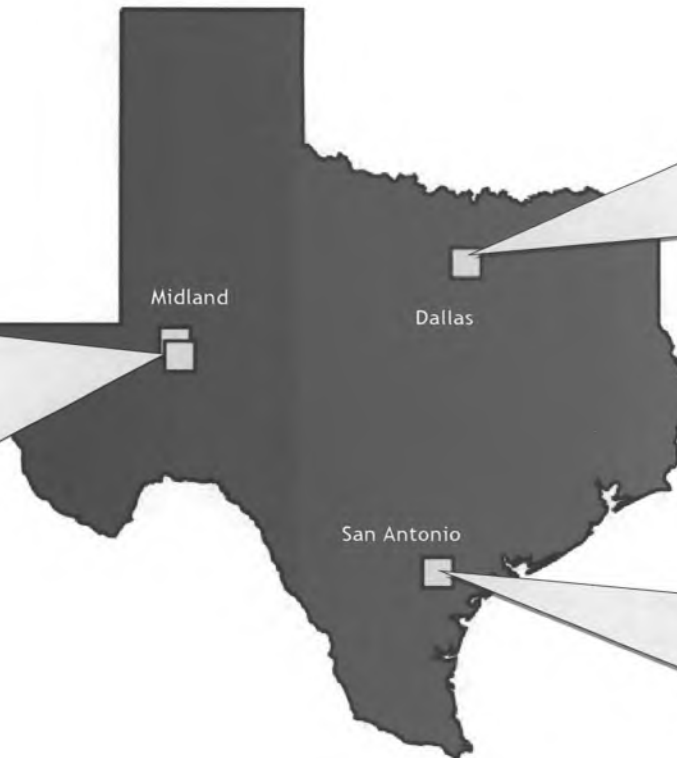
Wolfcamp Joint Interest Area Drilling Program(2)

120 wells ('14)

+1.6B BBOE Net Potential

2013 Production (Growth):
75-80 MBOEPD (+14 - 21%)

> 40 rigs running
> 2000 drilling locations



Barnett Shale Combo
\$185 MM Drilling Program
33 MMBOE Proved
+300 MMBOE Net Potential

2013 Production (Growth):
9-12 MBOEPD (+22 - 41%)

Eagle Ford Shale
\$575 MM Drilling Program
116 MMBOE Proved
86 Wells ('13)
+340 MMBOE Net Potential

2013 Production (Growth):
38-42 MBOEPD (+36% - 50%)

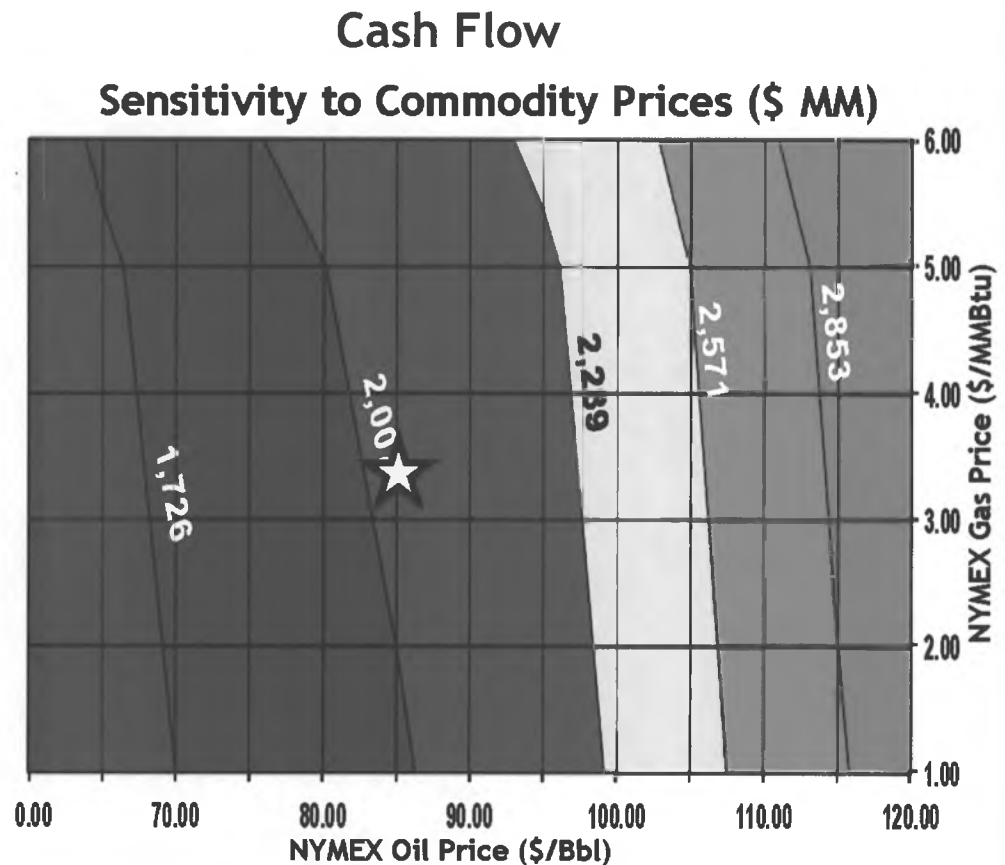
2013E Capital Spending and Cash Flow¹

- Capital Program of \$3.0 B includes:

- Drilling capital: 2.75 B total
 - \$190 MM Alaska
(7% of pioneer drilling capital)

- Capital program funded from:

- \$2.0 B operating cash flow
- \$0.6 B joint interest cash flow (2)
- \$0.4 B capital markets



★ 2013 capital program based on \$85/Bbl oil and \$3.25/MMBtu gas

1) Capital spending excludes acquisitions, asset retirement obligations, capitalized interest and G&G G&A
 2) Pioneer incurs 100% of capital costs from January 1st through estimated closing date of June 1st; Pioneer will be reimbursed by Sinochem for 40% of this amount as an adjustment at closing (not credited to cost incurred); Sinochem pays 40% of capital costs and carries Pioneer for 75% of Pioneer's 60% of capital costs post closing

Governor's Guiding Principles

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

■ Positives:

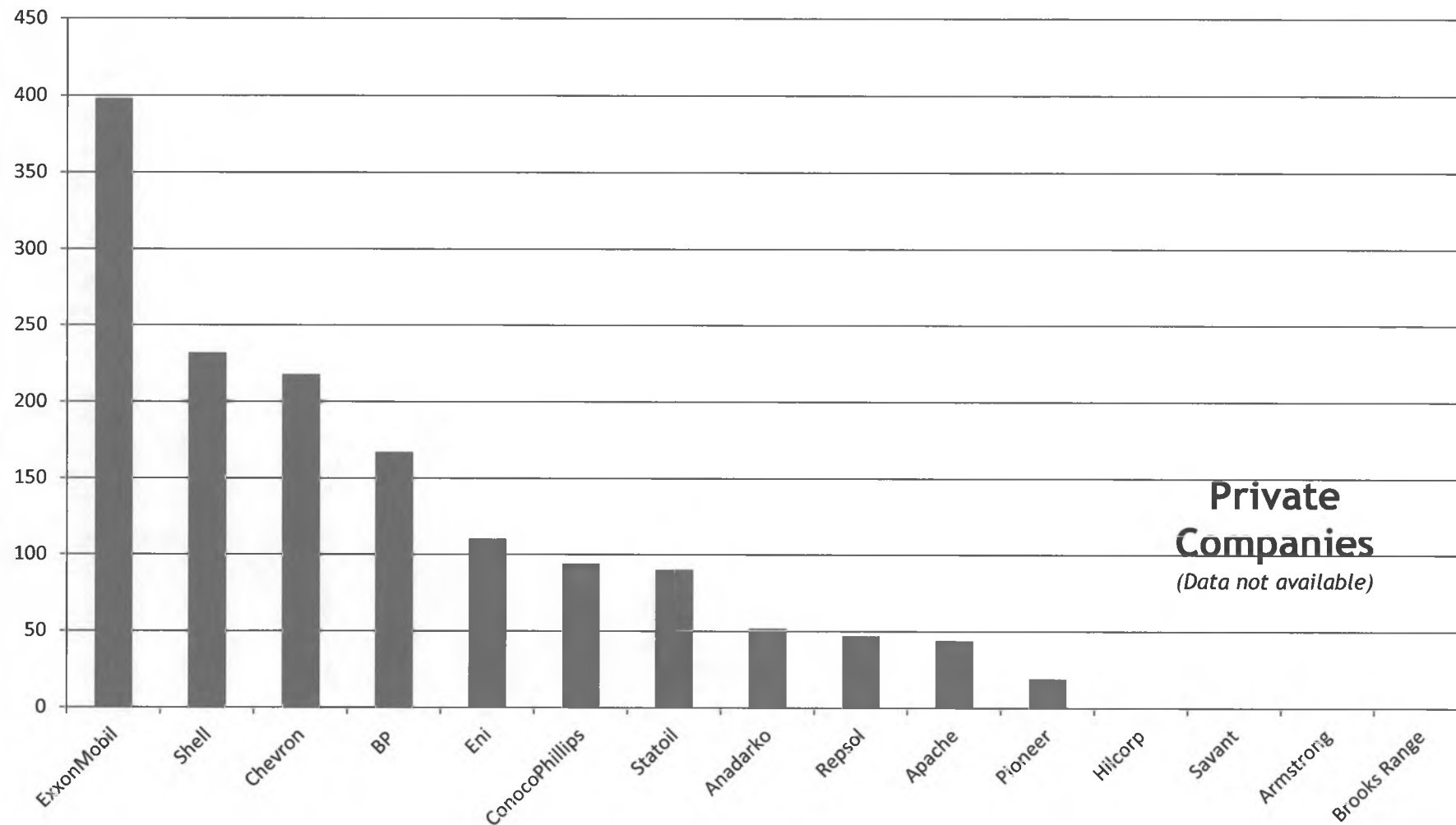
- Elimination of progressivity
- Small producer credit extension
- Gross revenue exclusion (GRE)
- Escalating loss carry forward credit

■ Negatives:

- Disadvantages smaller new projects
- Loss of capital credits
- Complicated carried-forward loss calculation
- No GRE for legacy fields
- Advantage to legacy producers may motivate consolidation of assets

Relative Rankings

Enterprise Value (Bn\$)



**Private
Companies**
(Data not available)

What is an Independent Oil and Gas Company?

▪ Independents ¹

- A non-integrated company
- Primarily in the exploration and production side of the industry (limited downstream)
- Come in large, medium and small varieties
- ~18,000 companies in U.S.
- Accounted for 2.1 million U.S. jobs in 2010
- First to drill in the offshore
- Often first to adopt and develop new technologies
- Independents account for 65% of total natural gas production and 45% of total oil production in the United States
- Independents drill close to 94% of America's oil and natural gas wells

▪ Financial Market Drivers

- Independents are rewarded for **production growth and debt management**

¹ Source: The Economic Contribution of the Onshore Independent Oil and Natural Gas Producers to the US Economy, IHS Global insight(USA), Inc, April 2011

“While their [smaller Independents] production may not seem significant, their economic impact is. Some companies would have had to move their work to North Dakota if it wasn't for them.”

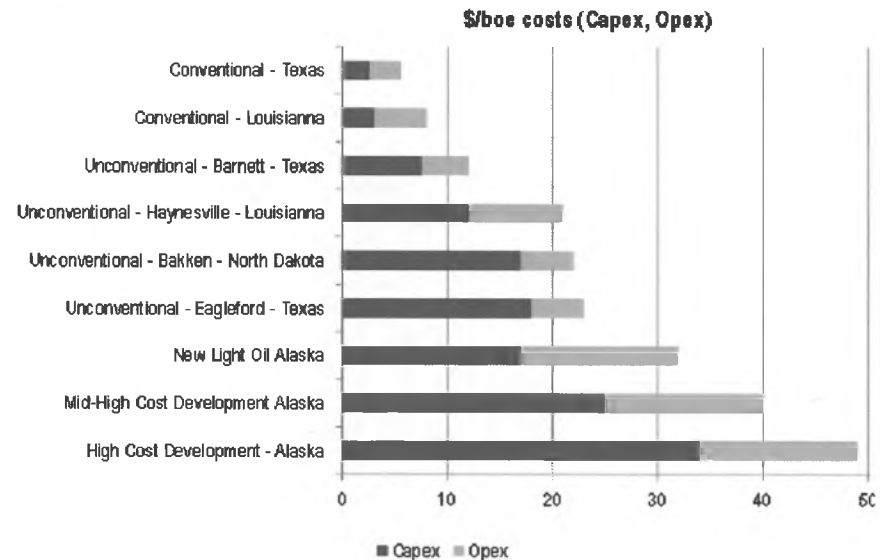
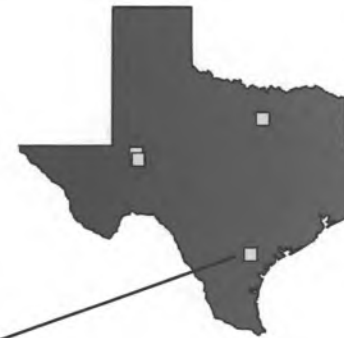
-Doug Smith, president, Little Red Services,
Testimony before TAPS Throughput
Committee Jan 13, 2013

“Independents compete on growth”

-Tony Reinsch, PFC Energy
TAPS Throughput Decline Committee
1/31/13

Eagle Ford Operators and Companies

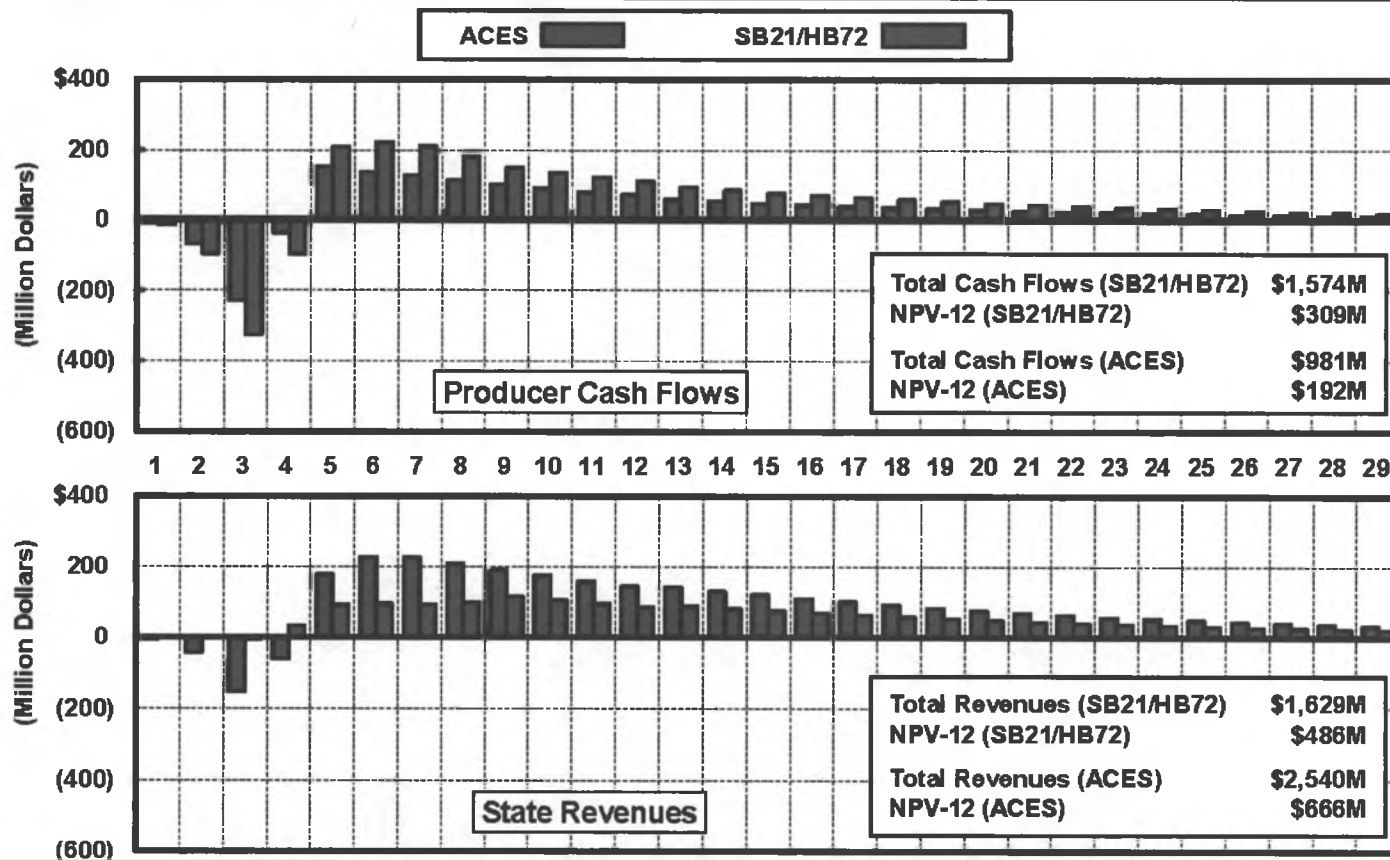
■Abraxas Petroleum ■Alta Mesa Holdings ■Anadarko ■Apache Corp. ■Aruba Petroleum ■Aurora resources ■Austin Exploration (Aus-Tex Expl.) ■BHP Billiton ■BP ■Cabot Oil & Gas ■Carrizo Oil & Gas ■Chaparral Energy ■Chesapeake Energy ■Cinco Resources ■Clayton Williams Energy ■Comstock Resources ■ConocoPhillips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



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

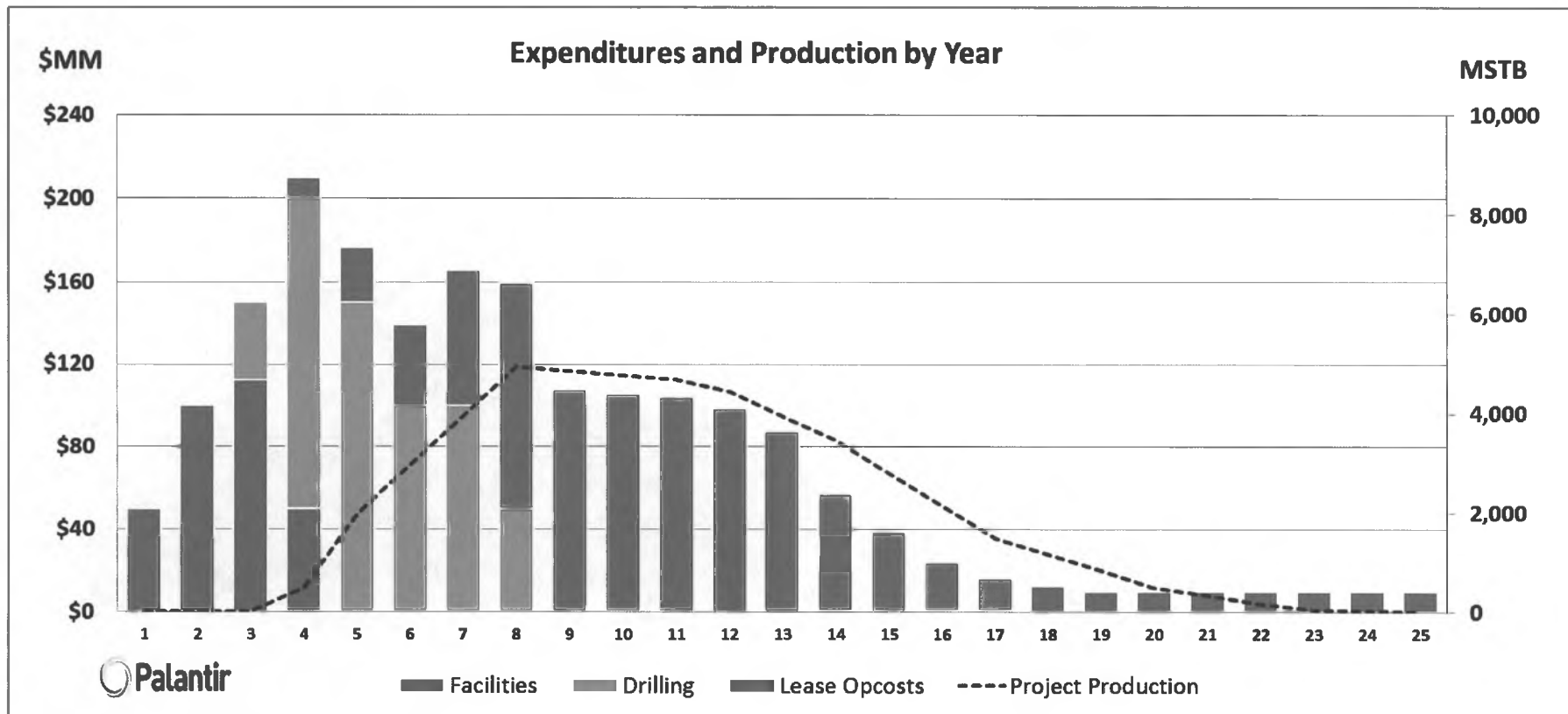
SB21/HB72: Econ One Initial Project Evaluation

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS Light Conventional Oil Alaska Development New Participant in Alaska



+\$115MM

Typical New Project Spend Profile



Typical Project (after discovery):

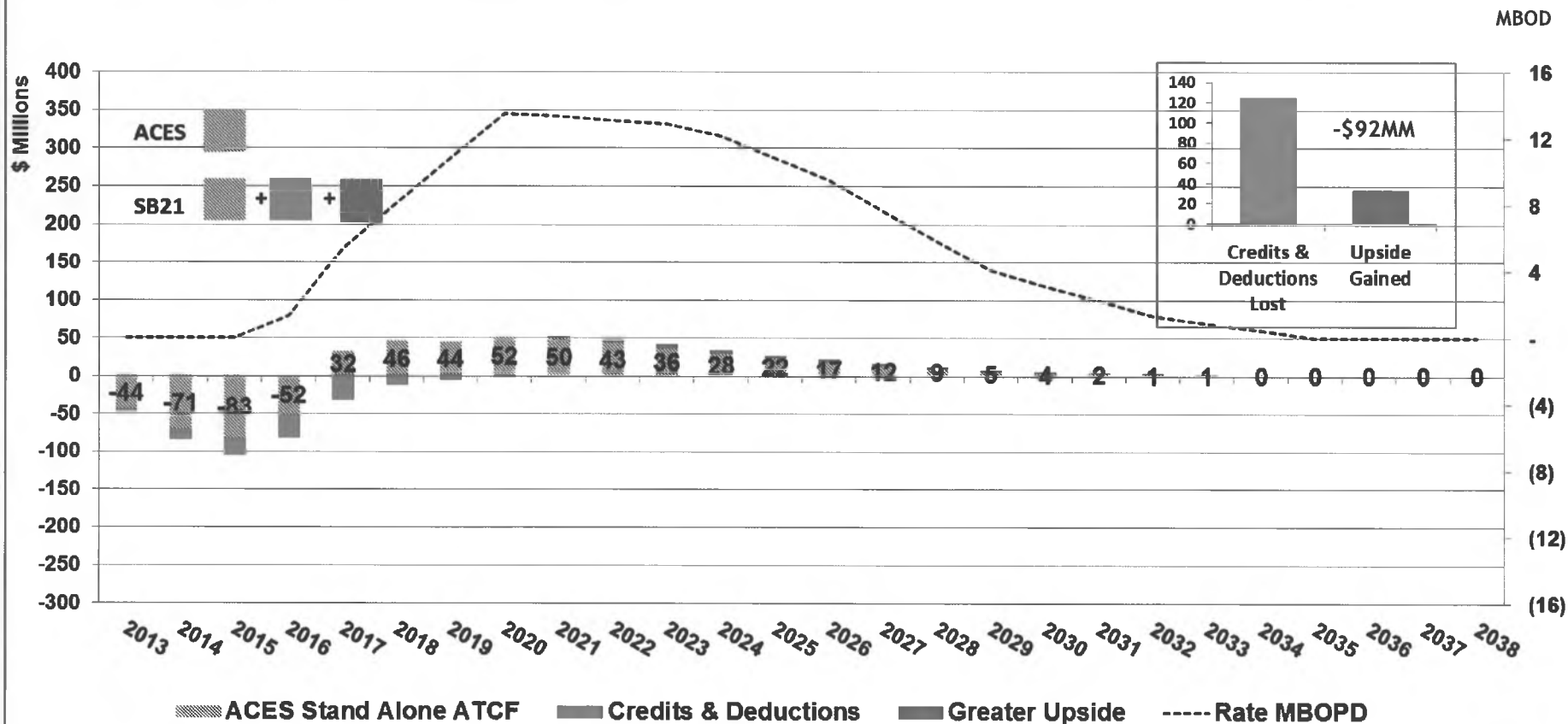
- 1st year: front end engineering work
- 2nd year: 100% of capital spent on facilities
- 3rd year: 75% capital is for facility work
- Drilling begins late in 3rd year, no production until 4th year
- 4th year: production begins
- Peak production rate occurs during 5th year after start of production

New Entrant - Stand Alone Project



DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under SB21 a standalone producer has to source more upfront capital in exchange for greater upside later



Field assumptions:

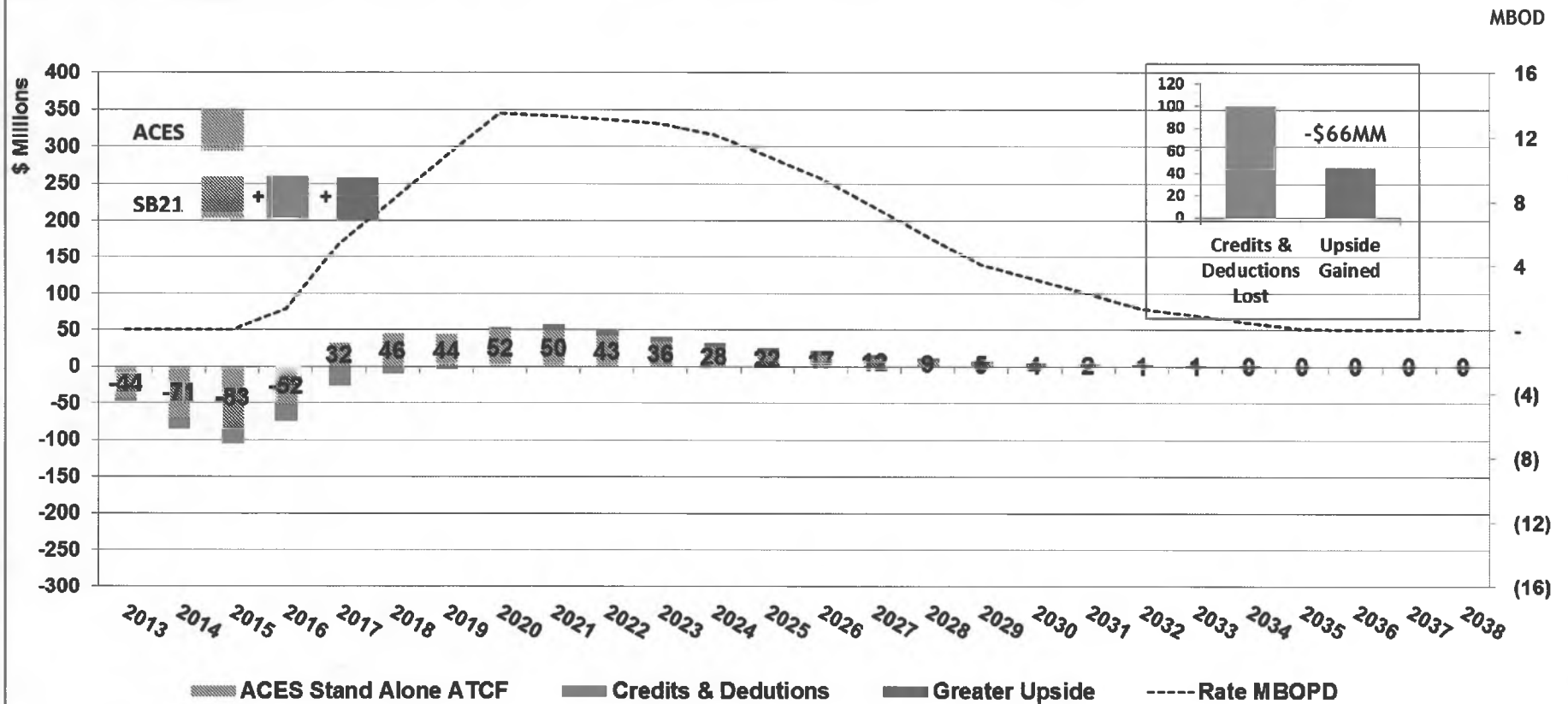
- 50 MMBO field
- \$1 billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast
- NPV-12
- Gross revenue exclusion
- Small producer credit

Current Small Producer



DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under SB21 a midsize producer has to source more upfront capital in exchange for greater upside later



Field assumptions:

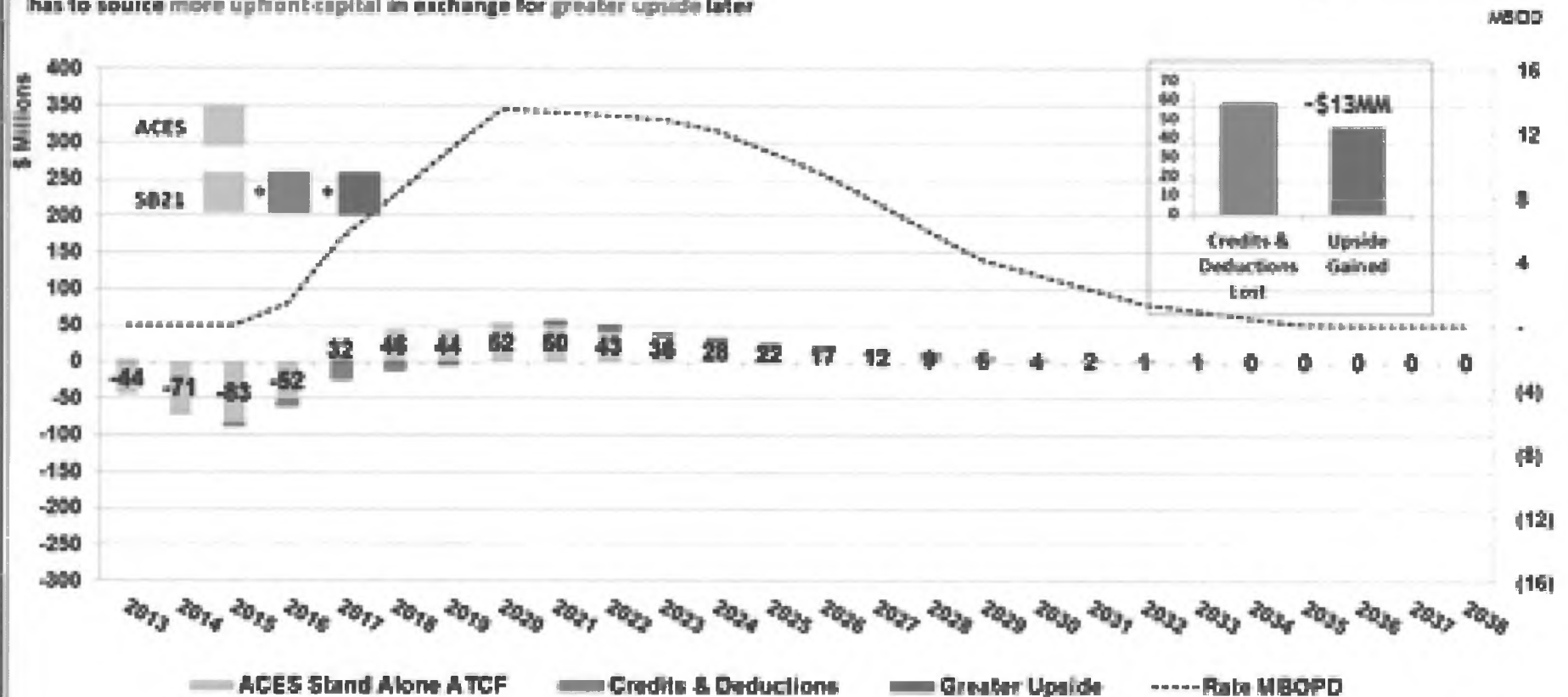
- 50 MMBO field
- \$1 billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast
- NPV-12
- Gross revenue exclusion
- Small producer credit

Current Large Producer with GRE



DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

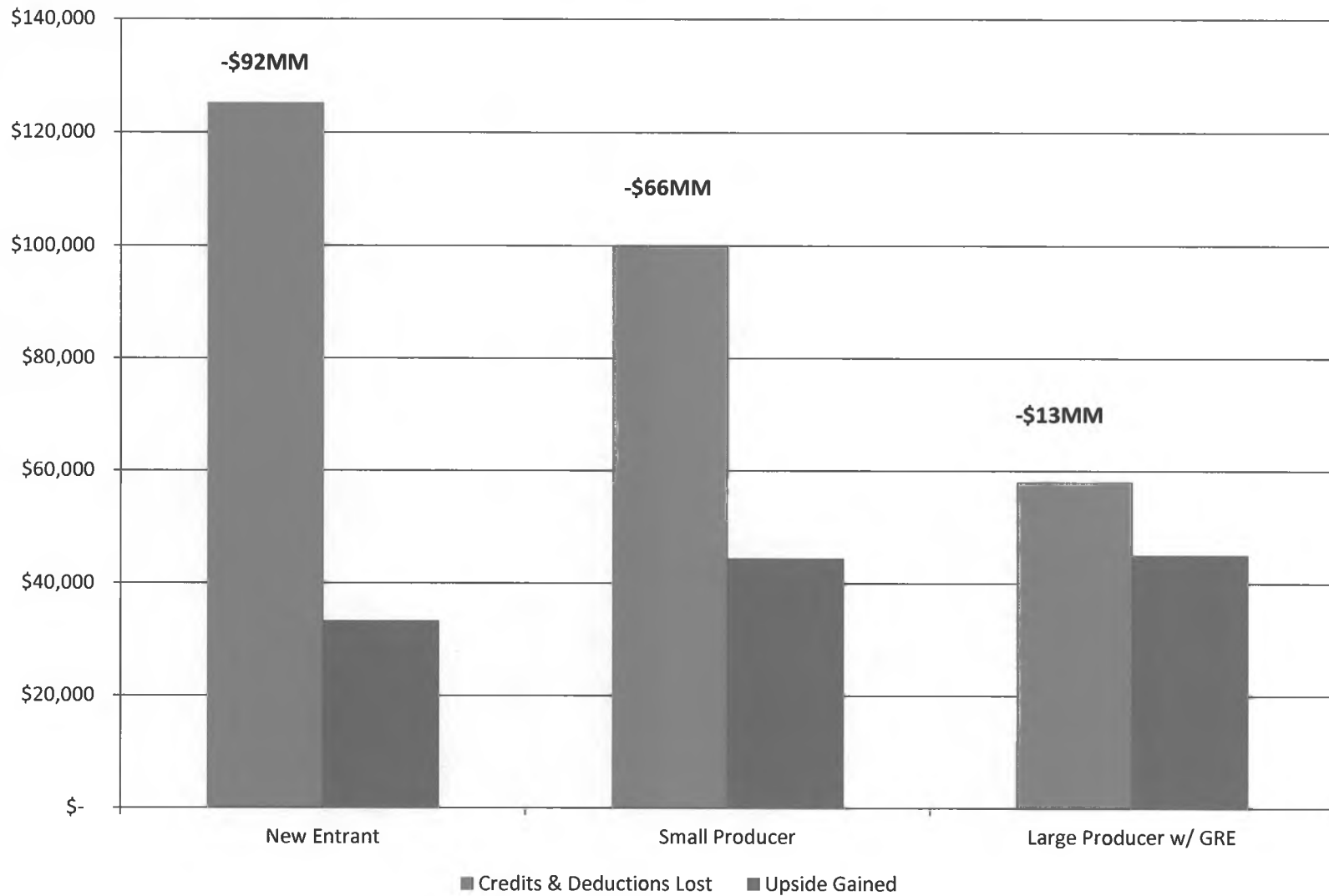
Under S821 a large producer with gross value exemption has to source more upfront capital in exchange for greater upside later



Field assumptions:

- 30 MWBO field
- \$1 billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast
- NPV-12
- Gross revenue exclusion
- Small producer credit

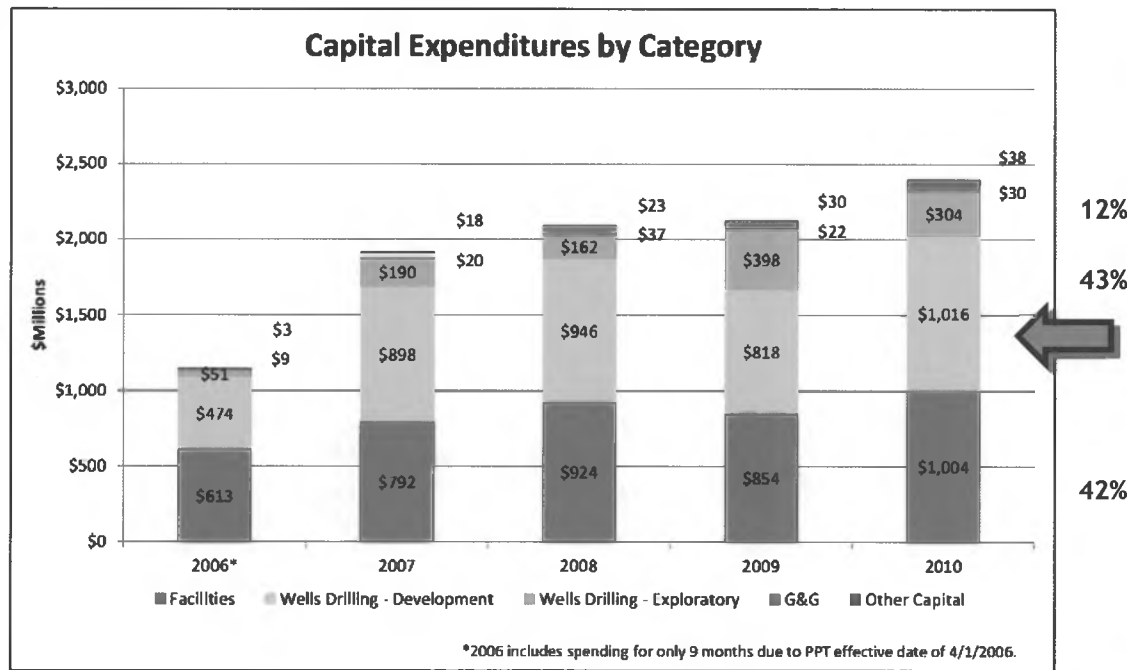
New Field: ACES vs. SB21/HB 72 Summary



Industry Spending on North Slope



Historical CAPEX by Category (CY)



Alaska Department of Revenue: 5 year look back

- Goal: to answer capital expenditure questions relating to credits
- Oil industry capital expenditures by category
- Categorized capital expenditure data represents 90% of costs related to credit applications

Source: Dept. of Revenue presentation to the Senate Resources Committee, Feb. 13, 2012

■ Benefits to State

- Credits encourage activity
 - Jobs, direct and indirect (9X multiplier)
 - More wells
 - More oil
 - More royalties, taxes and throughput

■ Benefits to Developer

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

Purpose of Tax Credit Provisions:

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

- Senate Finance Committee 5/13/2003

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

SB 21 Closing Thoughts:

■ Pros

- Eliminates progressivity
 - Shares upside potential
 - Improves competitiveness
- GRE reduces tax reductions for new oil
- Extends small producer credit

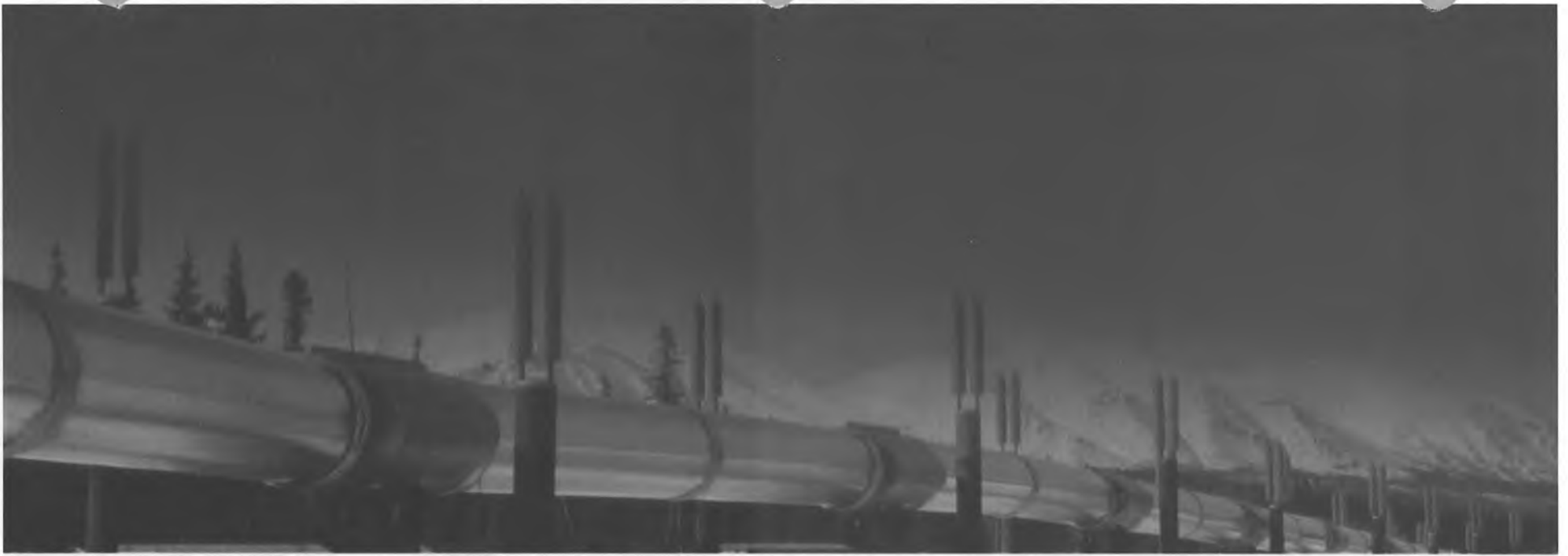
■ Cons

- Elimination of credits increases investor risk
 - Requires more upfront capital
- Does not simplify tax calculations
 - Complex carried-forward loss calculations
- Does not strongly motivate additional investment
- Does not create balance/equities among investors

■ SB 21 / HB 72 Suggestions

- Targeted incentives for well related costs
- Targeted incentives for new facilities (time limited)
- Redeemable / transferable credits for new projects
- Expand use of the gross revenue exclusion (legacy fields)
- Simplify carry-forward loss calculation





AOGA

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

House Resources Committee – HB 72

February 18, 2013
Kara Moriarty, Executive Director

AOGA Member Companies

PIONEER
NATURAL RESOURCES ALASKA



Apache



Hilcorp Alaska, LLC



ExxonMobil.



TESORO



petroleum

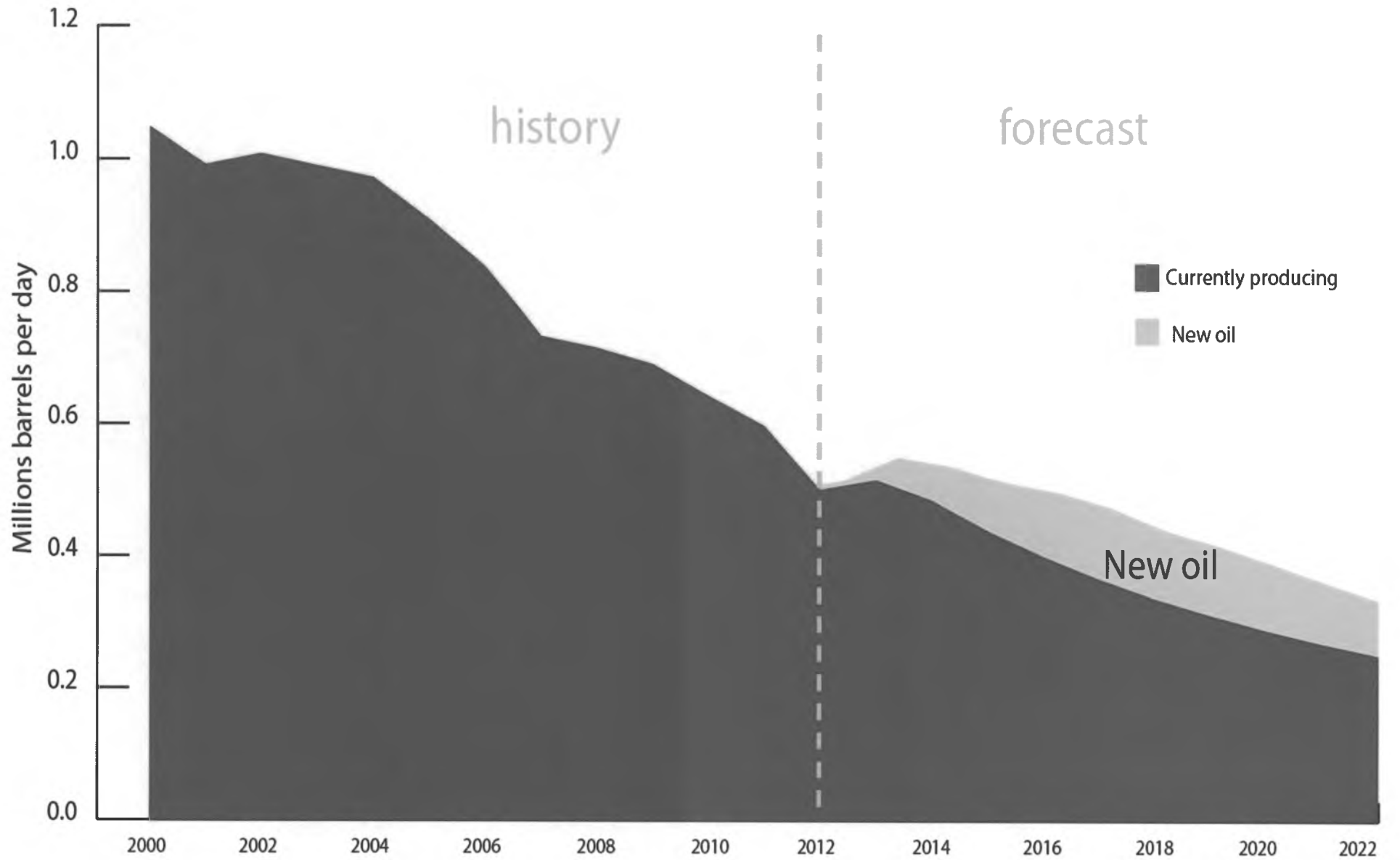


bp



Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



Source: Department of Revenue - Dec. 2012

Governor Lays out Principles for Oil Tax Reform

Anchorage Daily News, Jan. 6, 2013:

Reform must:

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

Governor Lays out Principles for Oil Tax Reform

Anchorage Daily News, Jan. 6, 2013:

Reform must:

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

HB 72 Component: Progressivity

- *AOGA supports the elimination of progressivity*
 - 1) Progressivity attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness.
 - 2) Progressivity bring extraordinary complexity to the tax.

HB 72 Component: Tax Credits

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

1) *AOGA does not support repeal of Qualified Capital Expenditure Credits (QCE)*

- a) Elimination of QCE would undo significant part of competitive environment
- b) Repeal likely creates “winners & losers”

HB 72 Component: Tax Credits

2) AOGA supports extension of Small-producer tax credit

- Attracts new players to Alaska
- From testimony...has made a material difference for some companies

3) AOGA Recommendation: Extend exploration credits as well

- Support for the same reason as small-producer credit
- Exploration credits bring about exploration in a timely fashion

HB 72 Component: Tax Credits

4) AOGA opposes the current proposal to bar almost completely the transferability of “Loss Carry Forward” credit

- 10 year shelf life is unrealistically short

- *AOGA Recommendation:*

Increase the shelf life to 15 years

HB 72 Component: Gross Revenue Exclusion (GRE)

AOGA supports concept, but concerned it will not apply to majority of current production

- Misses 80-90 percent of potential production
- Fields likely to lose out from GRE: Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, Alpine, PBU Satellite fields (Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion, and Polaris) and Kuparuk satellites (Meltwater, NEWS, Tabasco, Tarn and West Sak)

AOGA Recommendation:

More needs to be done for these fields

Estimated Undiscovered Conventional Oil Resources on Alaska North Slope

	Technically Recoverable Resources			Economically Recoverable	Expected Typical
	P95	Mean	P5	@ \$90/bbl	Field Size
	(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
<u>ANWR</u>	<u>5,900</u>	<u>10,400</u>	<u>15,200</u>	<u>9,900</u>	<u>64 - 128</u>
<u>Total</u>		<u>38,300</u>		<u>29,100</u>	

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.

Components Not Addressed in HB 72

1) Minimum Tax

- AOGA Recommendation: Minimum Tax should be repealed.

2) Statute of Limitations & Statutory Interest

At 3 years: \$0.38

$$\begin{aligned} \$1.00 &\times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 3 \text{ years})} - 1] \\ &= \$1.00 \times [1.38478 - 1] = \$0.38. \end{aligned}$$

At 6 years: \$0.92

$$\begin{aligned} \$1.00 &\times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 6 \text{ years})} - 1] \\ &= \$1.00 \times [1.91763 - 1] = \$0.92. \end{aligned}$$

Components Not Addressed in HB 72

2) Statute of Limitations & Statutory Interest

- It is the combination of a 6-year statute of limitation plus the minimum 11% interest rate that is harmful.

- 6-year statute of limitations also creates uncertainty and complicated audit assessments due to inconsistent terms in regulation and inability to predict DOR's calculations

- *AOGA Recommendation: Either shorten the period for DOR determinations from 6 years back to 3 years, or eliminate the 11% minimum interest rate, or both*

Components Not Addressed in HB 72

3) Joint-interest Billings:

- Instead of one audit of the expenses by a joint venture (found in a joint-interest billing) for any given period, DOR audits each participant separately for its respective share of the same pool of expenses

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

AOGA Supports Components of HB 72

Cornerstone for significant and crucial tax reform

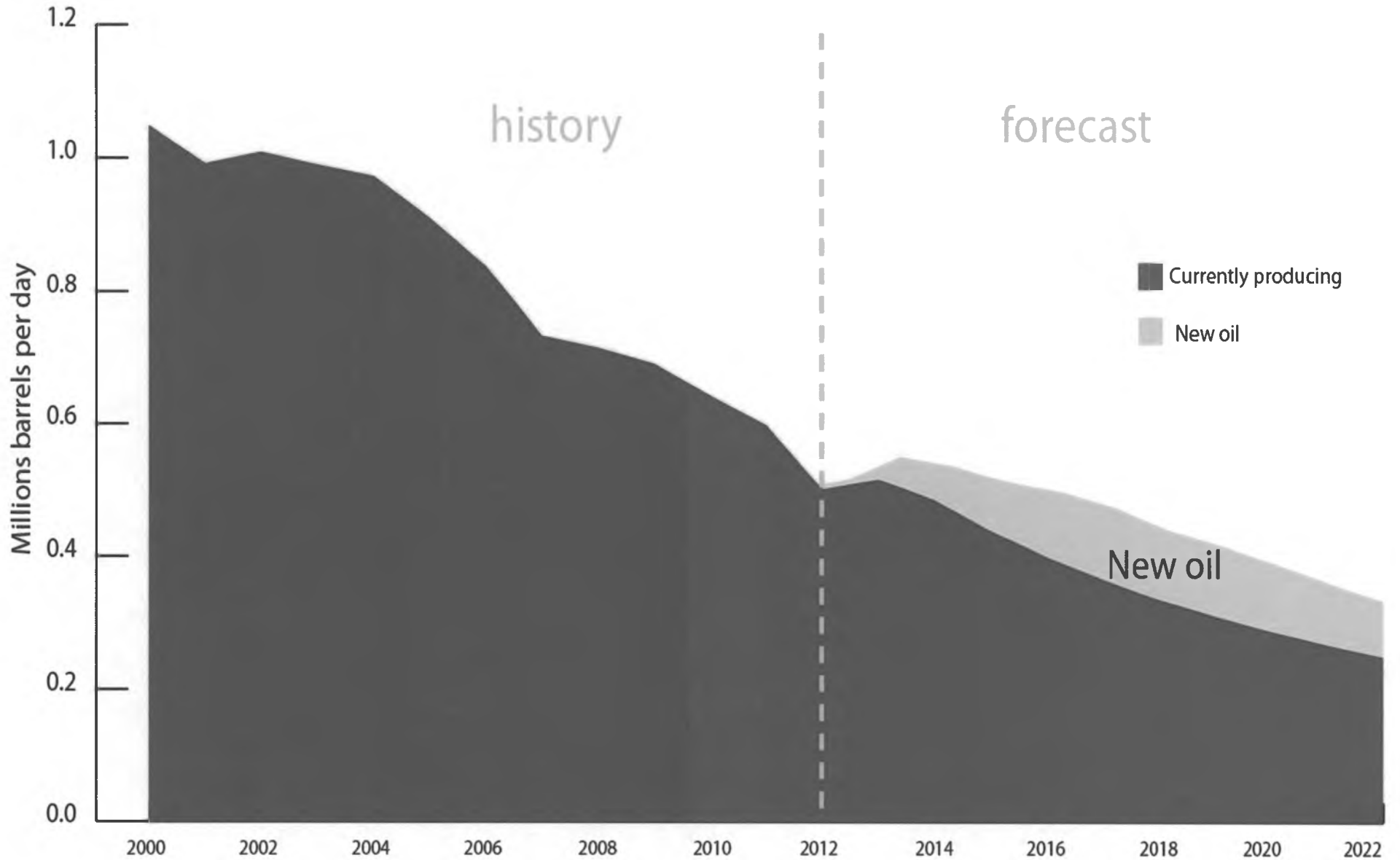
- Support the elimination of progressivity
- Support the concept of gross revenue exclusions
- Support the extension of the small producer tax credit

AOGA Concerns with HB 72

- Serious concerns with how the bill addresses tax credits (QCE elimination, no extension of exploration credit, and changing the loss carry forward credit)
- Gross Revenue Exclusions should be expanded to fit the majority of projects in legacy fields
- Identified other ways to improve policy (repeal minimum tax, change statute of limitations/interest rate, and allow DOR to use joint-interest billings)

Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



Source: Department of Revenue - Dec. 2012

Alaska Oil and Gas Association

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

ALASKA OIL AND GAS ASSOCIATION TESTIMONY ON HOUSE BILL 72 TO THE HOUSE RESOURCES COMMITTEE

February 18, 2013

Good Afternoon. For the record, my name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding House Bill 72 have been reviewed by all members and were approved unanimously.

The greatest, and most urgent challenge facing Alaska today is the decline of oil production from the North Slope. And the greatest, most urgent issue facing this Legislature is how you will address this problem.

For someone who is happy and content to see Alaska continue along the path it is headed on, the answer to this question is — do nothing; leave the present tax system alone.

But most Alaskans would disagree that this is the future they want. They hope for a robust industry on the North Slope beyond their own lifetimes. They want their children and grandchildren to have the benefits from the oil industry that this generation of Alaskans, and the one before, have enjoyed. They want the good jobs that the industry offers to continue, and they want industry to continue to support the education and skills training that are needed to qualify for many of those jobs. They want their friends and neighbors who work for the industry to stay here. They want all the volunteer community services to continue that industry employees perform, and that companies themselves do directly. They want the activity and growth in the Alaskan economy that industry stimulates to continue. And, of course, they like the fact that industry pays for a great majority of the costs of government and hope that this, too, will continue.

The role of AOGA, and of individual companies doing business here, is not to tell Alaska how much it ought to collect from oil and gas, nor should that be our role. Rather, we should tell you about

how Alaska's tax regime is affecting our businesses, about the parts of the present tax laws that are not working as intended, and about ways to improve the tax structure to get more of the intended results. With that knowledge, you can then make sound, informed decisions about how much tax to collect, how to collect that amount, and when to collect it.

For several years there has been a red herring in the public discussion about oil taxes. This is the notion that any change in tax structure that reduces tax revenues below the projections in the Revenue Sources Book is a "giveaway." This reflects an assumption that those forecasted oil and gas taxes are somehow a "given" — something like money already in the bank, and all the State Treasury needs to do is wait for it to be deposited into the State's account. The fact, however, is that industry has to spend roughly \$2 billion dollars each year just to slow the production decline from what it would naturally be, in order even to approach the level of production published in the Revenue Sources Book. And just like any other investment industry makes here, these production-sustaining investments have to beat the competition elsewhere for those investment dollars: they are both not a "given."

Worse, the "tax giveaway" argument assumes the production in the Revenue Sources Book is all that will be produced. These critics factor in nothing for any additional production and revenue resulting from a tax reduction. Instead it looks only at the downside and ignore the upside. The upside, though, is real. If a tax reduction makes investments here more competitive, companies will want to make more investments here for that upside. And they will do so even though they, like the State, lack the gift of prophecy and cannot know beforehand exactly what the upside will turn out to be for any particular investment.

As you consider solutions to the momentous challenge that production decline creates, it will be wise and useful to identify the principles you want the tax system to embody, and the specific goals you want it to achieve. AOGA believes Governor Parnell's four "core principles" offer an excellent cornerstone for this:

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

We believe a fifth such principle will be prudent as well, because the challenge facing Alaska is not that there are too many companies pursuing opportunities they see here, but that there are too few. Alaska should therefore avoid tax changes that artificially create "winners" and "losers."

With respect to House Bill 72, there are four major features in it that we wish to address, and the Bill omits several others that we would like to draw your attention to.

The major features in the Bill are the elimination of progressivity, changes to the present system of tax credits, a "gross revenue exclusion" for certain new production, and the timing for these changes to occur. Here are our thoughts on them.

1. Repeal of Progressivity. AOGA endorses the elimination of progressivity. First, progressivity directly attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness. It costs \$9.42 on average to ship a barrel of oil from the North Slope to the West Coast, according to the Fall 2012 Revenue Sources Book, Appendix D-1b. This means Alaska starts off with a disadvantage of \$9.42 a barrel against Outside competition, so other parts of an Alaskan investment must be pretty strong in order to overcome this disadvantage. Otherwise they won't be made.

If oil prices turn out to be higher than what they were projected to be in the investment analysis, nearly 100% of each extra dollar in price flows directly into the Gross Value at the Point of Production (GVPP) and then, after royalties and taxes, flows straight into the investor's bottom line. This, in turn, improves the economic performance of an Alaskan investment relative to an equally competitive one Outside, because the Alaskan baseline was \$9.42-a-barrel lower and an additional dollar in price is a larger percentage of that baseline than for the percentage for the Outside investment. This can be particularly significant for potential investors who are bullish on oil prices.

Currently, progressivity in conjunction with a 25% base tax will take half of each dollar from higher prices when the West Coast price is \$132.38 (using the Fall 2012 Source Book numbers) — a price that has already been seen, although somewhat higher than today's. So, even for investors who are bullish on oil prices, progressivity destroys half of the one strategic advantage that Alaska's economic remoteness provides. And the more bullish they are, the more this advantage is undone because they will see higher rates for progressivity at those prices in their investment analysis.

Second, progressivity brings extraordinary complexity to the tax, not only in calculating what the tax is, but also in analyzing what the amount of the progressivity is for any particular item that affects a taxpayers Production Tax Value (PTV). This complexity exists because the tax rate for progressivity depends on the taxpayer's PTV per barrel, and then the resulting rate is applied to the very same PTV that set the rate. This circularity in the tax calculation leads to bizarre effects. For instance, simply the fact that oil prices fluctuate during a year instead of remaining perfectly flat increases the tax even though the average of the fluctuating prices is the same as the flat price — and the greater the fluctuation, the greater the tax from progressivity becomes. There is no objective economic or financial reason for the tax to go up; instead, this occurs entirely because the progressivity calculation is circular.

2. Tax Credits

In general, tax credits, whether they be for drilling a well, building a facility to gather new oil or the pipe to build a flowline, represent a direct reduction in the amount that a potential investor puts at

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

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

Even while the elimination of progressivity would improve the competitiveness of Alaskan investments from the present ACES tax, the elimination of the QCE Credit would claw back a big chunk of that money and undo a significant part of that competitive improvement. This is because the benefit of the QCE Credit depends only on how much is invested here, while the benefit from ending progressivity depends on the price of oil relative to a producer’s lease expenditures. For every producer, there is a price below which the lost QCE Credit would start to outweigh the benefit from the end of progressivity, and exactly where that crossover comes would depend on factors that are specific to each individual producer, such as how much oil it produces, where it sells the oil, its costs to deliver it there, and its lease expenditures.

AOGA fears the repeal of the QCE Credit is likely to create “winners” and “losers” artificially among producers, and we see no sound tax policy justification for doing so.

B. Small-Producer and Exploration Credits. AOGA endorses the proposal in HB 72 to extend the small-producer tax credit under AS 43.55.024 from the present sunset dates at the start or middle of 2016 to 2022 and encourages the same extension the exploration tax credits under AS 43.55.025. The State had sound policy reasons for creating these tax credits, and those reasons are just as valid today as they were then.

The purpose of the small-producer tax credit was to attract new players to Alaska who might otherwise have been deterred from coming here by its remoteness, northern climate, and the resulting challenges of higher-than-average costs and expenses. The success of the credit in doing this is a fact that cannot be denied. AOGA sees this success in its own membership, and in other companies that have come here and are active. The importance of having a healthy contingent of smaller producers comes from the facts, first, that they often have a different perspective about the opportunities around them, and second, that no company or group of companies can have a monopoly on good ideas and innovation. For both reasons, the continuing and increasing presence of these smaller producers strengthens and improves the Alaskan petroleum industry. We know from testimony that the small-producer tax credit has made a material difference in individual companies’ decisions to do business and invest in Alaska.

The purpose and justification for the exploration tax credits under AS 43.55.025 are equally plain and clear. Huge geographical swaths of this state remain unexplored for oil and gas, or have been explored in little more than a rudimentary way. If exploration is to occur in a timely fashion so any resulting production can be transported through existing infrastructure, the exploration tax credits are a direct way of bringing that exploration about and these type of credits should be extended as well. Just as with the QCE credits for capital investments, there is no exploration tax credit without real money

having first been spent on exploration work that qualifies for these tax credits.

C. Limiting the transferability of "carried-forward annual loss" tax credits. We have some reservation about the proposal in HB 72 to bar almost completely the transferability of the current "carried-forward annual loss" tax credits under AS 43.55.023(b). These credits arise every year for any active explorer until it finds something and finally has production that has a tax to apply the credit against. At present explorers can only realize immediate benefit from these credits by selling them to other taxpayers or cashing them in at the state Oil and Gas Tax Credit Fund established in AS 43.55.028.

Such sales and cash-ins would stop for North Slope explorers under the Bill, who instead would be able to hold the credit for up to 10 years for possible use against tax on their own production, assuming they find something to produce. During this 10-year shelf-life the unused credits would increase at an annual rate of 15 percent, compounded annually. The same would apply for a North Slope producer with a year resulting in a "carried-forward annual loss."

The Bill's only exception to this ban would be for a transfer made in conjunction with a sale or other transfer of an "operating right, operating interest, or working interest" in a lease or property—the person acquiring that interest could also acquire a proportionate share of the lease-or-property's annual-loss credits arising before that transaction.

To prevent taxpayers from deliberately hoarding these credits instead of using them in order to get the 15% annual increase, the Bill would deny the 15% increase for each year when they could use their credits but don't. We believe this would be an effective deterrent against abuse that might otherwise occur.

In general, if sales and transfers of these annual-loss tax credits are to be limited at all, then the limitations proposed in HB 72 would be a reasonable way to do it. Our major concern of the proposal is that the 10-year shelf-life for using a credit is unrealistically short. If all the stars, planets and constellations are in just the right alignment, it might be possible for an explorer to go from exploration and discovery to production in just 10 years. But that is not the norm — particularly on the North Slope, where the limitation on transferability would apply. We think 15 years would be more in line with actual experience.

The geographical limitations on where the tax credits must arise in order still to be freely sold or transferred may have unintended consequences, but because of confidentiality considerations, they are not appropriate matters to be discussed within a trade association like AOGA. We must therefore leave this for individual companies to address if there is a problem.

Of course, without the 15% annual increase in the unused credits, AOGA would oppose the ban on transferability because it would destroy the incentives which the credit is supposed to provide to explorers.

3. Gross Revenue Exclusion. This is the most innovative feature in HB 72, and our major substantive concern is that it is too narrowly focused.

The Gross Revenue Exclusion (GRE) would, in calculating the taxable Production Tax Value, exclude 20% of the Gross Value at the Point of Production of what we'll call "non-legacy" production. Bill Section 24 calls it production "from a lease or property that does not contain land that was within a unit on January 1, 2003[,] or if it does have land that was in a unit before 2003, "the oil or gas is produced from a participating area established after ... 2011 [that] does not contain a reservoir that had previously been in a participating area established before ... 2012."

What this means is, the fields that are likely to lose out on getting any GRE under HB 72 are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, and Alpine; as well as the Prudhoe Bay satellite fields Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion and Polaris and the Kuparuk satellites Meltwater, NEWS, Tabasco, Tarn and West Sak.

Econ One Research, Inc. made a presentation to this committee just last Wednesday entitled *Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal, HB 72*. In Slide 6 of that presentation Econ One showed oil and gas resources described as "Economically Recoverable @ \$90/bbl" totaling 29.1 billion barrels of oil and barrel-equivalents of gas. Of this total, the slide shows that 10.4 billion are in ANWR and the National Petroleum Reserve-Alaska, another 9.9 billion in the Chukchi Sea Outer Continental Shelf, 5.8 billion in the Beaufort Sea OCS, and 3 billion in the central North Slope where all the producing fields are that I just named.

To us, the slide shows that more than half — 54% — of this 29.1 billion-barrel resource lies in the federal OCS, outside Alaska's sea-ward boundary and beyond its jurisdiction to tax. Current federal law does not provide for any OCS revenue-sharing with Alaska, and even though Alaska's Congressional Delegation is trying to change that, for now the only direct revenues that the State stands to see from OCS production are property taxes on the in-state portion of a pipeline linking the OCS fields to TAPS, and an increase in North Slope "wellhead" values resulting from the greater TAPS throughput.

Another 34% of the resource is in ANWR — which, again, we hope the Delegation will be able to open up, although even Ted Stevens was unable to achieve it despite four decades of dedicated effort. Another 1.7% is in NPRA, which — if the Interior Department gets its way — will have its best prospective acreage turned into a bird sanctuary despite being a "Petroleum Reserve".

So, of the 29.1 billion barrels of potential reserves identified by Econ One, only the 3 billion in the central North Slope has any potential to contribute significantly to Alaska's economic well-being in

the near and mid-term future. In other words, of the 29.1 billion barrel resources, only a tenth of it is within the State's power to do anything about. And of this 3 billion barrels, 2.5 billion or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production. The Governor's second "core principle" for tax legislation is that "it must encourage new production." But, in order to get results from such encouragement, the tax legislation must reflect the opportunities that Alaska has for getting results. Maybe the present Gross Revenue Exclusion in HB 72 can get results, in some small way. But in terms of what it attempts to "encourage," it leaves out at least 80 – 90 percent of the 3 billion-barrel opportunity in the central North Slope that Econ One has identified as "Economically Recoverable @ \$90/bbl[.]"

AOGA is continuing to search for ways to adapt the Gross Revenue Exclusion to include legacy fields in a way that might be acceptable to the Administration and the Legislature. It may turn out, however, that a different approach may be necessary to "encourage new production" from legacy fields.

For now, though, all we can say is, not enough is being done in HB 72 to improve the economic competitiveness of legacy fields, and for the coming decade or so these legacy fields will be the "trunk" that supports all the rest of the North Slope "tree." Until there is significant production from the Arctic OCS, the tree cannot survive very long without the trunk production to keep per-barrel transportation costs down and necessary infrastructure in place. It would be a mistake to let that trunk wither.

4. Issues that HB 72 does not address. There are several significant problems in the present ACES tax that are not addressed in HB 72.

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

The minimum tax only complicates potential new investors' analyses of what their tax would be if they invest here instead of someplace else, and consequently it has, if anything, driven investments away. AS 43.55.011(f) should be repealed.

B. Statute of limitations & statutory interest. Here we have two concerns that are interrelated, but not in an immediately obvious way.

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

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

Taxpayers are required under AS 43.55.020(a)(1)-(3) to make monthly estimated tax payments for each calendar month’s taxable production during a year, but the final tax amount for the entire year is reported on March 31 of the following year under AS 43.55.030(a). And AS 43.55.020(a)(4) requires any additional tax to be paid at that time. The statutory interest under AS 43.05.225(1) starts to accrue on any underpayment from that March 31st true-up date.

In practical terms, what these various statutes all mean is this.

For each dollar of underpaid tax that the Department of Revenue may claim after an audit, statutory interest on that dollar at the end of three years would be —

$$\begin{aligned} \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 3 \text{ years})} - 1] &= \$1.00 \times [1.38478 - 1] \\ &= \$0.38. \end{aligned}$$

After six years the statutory interest on the dollar would be —

$$\begin{aligned} \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 6 \text{ years})} - 1] &= \$1.00 \times [1.91763 - 1] \\ &= \$0.92. \end{aligned}$$

Thus, for each dollar of uncertainty there is in what the taxpayer reports on its March 31st true-up for a given year, there is about 38 cents of additional uncertainty due to statutory interest under a three-year statute of limitations, but 92 cents under a six-year statute.

It is the combination of a six-year statute of limitations plus a minimum statutory interest rate of 11% APR that is so harmful for a taxpayer and any would-be investor. Each dollar of uncertainty in the amount of tax will nearly be doubled by statutory interest after six years.

When we speak about uncertainty and audit assessments six years after the filing of tax returns, many people will think the oil companies could calculate their correct tax liability under the ACES tax if they wanted to. Frankly, so did I before I got this job. So let us take a few moments to illustrate why this is not the case.

As amended by ACES, AS 43.55.150 (captioned “Determination of gross value at the point of production”) says the Gross Value at the Point of Production (GVPP) “is calculated using the actual costs of transportation” from the field to market unless the “shipper ... is affiliated with the transportation carrier[.]” or the “contract for the transportation ... is not a[t] arm’s length[.]” or the “method or terms of

[the] transportation ... are not reasonable in view of existing alternative transportation options.” “If the department finds that” any of these situations exists, then the GVPP “is calculated using the actual costs ... or the reasonable costs of [the] transportation ..., whichever is lower.”

The immediate questions about the statute are — How does the Department of Revenue get the information to make such a finding? What is the procedure for making them; is there a hearing, an investigation or what? How does a taxpayer ascertain what the Department has found?

15 AAC 55.193 is the regulation with an important part of the Department’s answers to these questions. Before getting to those answers, we note that subsection (a) seems to disregard the statutory distinction between “actual” and “reasonable” costs, by declaring that “Costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas”¹ — which could get to the same result as the statutory terms, but not necessarily.

Subsection (e) of the regulation starts answering our questions. It says “a tariff rate ... adjudicated as just and reasonable by the Regulatory Commission of Alaska ... establishes the reasonable costs of the pipeline transportation[.]” So, suppose there has been full-blown tariff dispute before the Regulatory Commission of Alaska, and the RCA has “adjudicated [a tariff] as just and reasonable[.]” And suppose also that a producer ships its oil through its pipeline-company affiliate and pays that RCA-approved tariff. Is this “reasonable” cost under (e) of the regulation the same as the “ordinary and necessary” cost for it for purposes of subsection (a)? Apparently so, but the inconsistent terms in the two subsections prevent this from being completely clear. Moreover, if the transportation occurs “later than five years after the end of the test period on which the tariff rate is based[.]” then even subsection (e) says the tariff ceases to “establish [the] reasonable costs” for the transportation. But it doesn’t say what the right tariff is after those five years are up, or even how to find out or calculate what it is. It is utterly silent.

The very next sentence in subsection (e) after the one speaking about that five-year period starts, “If a complaint challenging [a] tariff rate has been filed with [the RCA] and accepted for investigation” — this is not a situation involving an already “adjudicated” tariff, but one that deals with a new tariff that has been filed for RCA’s approval, which is then challenged. Here, too, the tariff on file is not allowed as the transportation cost under (e) of the regulation. Instead, the cost that is allowed is “103 percent of the costs of transportation calculated by the department using the methodology under 15

¹ Emphasis added.

AAC 55.197, for the period [while the complaint is being heard and adjudicated by the RCA.]* Note that it is the Department of Revenue, not the taxpayer that makes the calculation under 15 AAC 55.197. It is impossible for the taxpayer to know beforehand what the Department's calculation will turn out to be.

Now it is true that 15 AAC 197(m) says a taxpayer may each year "request in writing the department's determination of the applicable after-tax rate of return under (f) of this section [and t]he department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 90 days after the department receives the producer's request." But the "after-tax rate of return" that the Department promises to provide is only one of the parameters in the cost-based tariff calculation under 15 AAC 55.197. The taxpayer is left on its own to find the correct numbers for the other parameters. More importantly, subsection (m) applies only to "a producer [that] expects to produce oil or gas the actual costs of transportation of which are required by 15 AAC 55.193(b)(6)[.]" Section -193(b)(6) applies only to "transportation of oil or gas by a nonregulated pipeline facility ... that is owned or effectively owned ... by the producer of th[e] oil or gas[.]" In the situation I'm describing, it is a regulated pipeline, not an unregulated one, so this promise in 197(m) does not apply.

We find nothing else in the calculation-methodology regulation, 15 AAC 55.197, nor in 15 AAC 55.193(e), the transportation-cost regulation, that commits the Department to make the cost-based tariff calculation called for in 193(e) and inform the producer of that result before the producer has to report and pay estimated tax each month, or before it makes its annual true-up on March 31st of the following year. The only deadline for informing the producer of the Department's calculated tariff is the six years under the statute of limitations.

And the same or very similar unknowable answers — including tariff calculations by the Department under 15 AAC 55.197 — arise under 15 AAC 55.193(f) regarding tariffs for new transportation facilities that are just being placed in service, and under -193(g)–(h) regarding tariffs set under a settlement agreement to which the State of Alaska is a party.

And just to prevent any misunderstanding, although I have been testifying about proceedings and adjudications by the RCA, these regulations also apply to proceedings and adjudications by some "other regulatory agency" — which would include FERC.

There is a built-in uncertainty created by these regulations, and others that is beyond a taxpayer's allowed authority to answer and beyond its ability to know before the Department gives the answer. And to see a "Technicolor®" version where essential elements of the tax calculation are being

reserved for the Department to “determine” in its discretion with no specific deadline, one should look at all the crucial “determinations” in 15 AAC 55.173 (“Prevailing value for gas”) that are reserved for the Department to make regarding the valuation of natural gas that would be transported to markets outside Alaska.

We are not asking for a statutory fix to the regulations. But we are asking that, if the Department chooses to defer making calculations and similar determinations that are necessary in order even to be able to calculate the correct amount of tax at all, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making those “determinations” from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.

C. Joint-interest billings. Our concern about joint-interest billings is also primarily a problem caused by the approach the Department has chosen to take with its tax regulations. Instead of starting with the joint-interest billings that participants in a unit or other joint operation receive from the operator, the regulations reflect an assumption that each non-operating participant has information, in addition to the operator’s billings to them, that allows them to determine which expenditures are deductible as allowed “lease expenditures” under AS 43.55.165 and which are not. This assumption is wholly unrealistic. And even if there were some merit to it, the regulations opt to audit each participant separately regarding that participant’s interpretation of which expenditures are deductible and which are not, instead of auditing the system of accounts used by the operator and telling all participants which cost items in that accounting system are deductible and which are not. In other words, instead of one audit of the expenses by a joint venture for any given period, the Department audits each participant separately for its respective share of the same pool of expenses.

Again, we are not asking for legislation to put the Department’s regulations on a different track. But there are some in the Department who believe that the repeal by the 2007 ACES legislation of AS 43.55.165(c) and (d) — which specifically authorized the Department to rely on joint-interest billings — means the Department cannot legally rely on them now. While we disagree with this position (which is also at odds with what the Department testified to during the enactment of the 2007 ACES legislation), we do think it would be appropriate to restore language specifically authorizing the Department to rely on joint-interest billings if it chooses to do so.

Conclusion. We support the proposed elimination of progressivity, but we have concerns with what the Bill proposes for tax credits — most importantly with the proposed repeal of tax credits for qualified capital expenditures. The trade-off between repealing progressivity and losing the QCE credit is not a net benefit for industry at low oil prices, although it would be with prices that are high relative to costs.

The concept of the Gross Revenue Exclusion has considerable potential, but its narrow focus in

HB 72 misses 80 – 90 percent of the opportunity in the central North Slope described by Econ One. We will continue to work with you and the Administration to find a fair and reasonable way to expand its scope, or to find an alternative that will address the central North Slope appropriately.

The reasons that led the State to create the small-producer tax credit under AS 43.55.024 and the exploration tax credits under AS 43.55.025 remain valid today. We are pleased that HB 72 will extend the sunset date for the small-producer tax credit and encourage the same extension be applied to the exploration tax credits.

Overall, the Bill as introduced represents a cornerstone for significant and crucial tax reform that move toward Governor Parnell's four "core principles" — fairness for Alaskans, encouraging new production, simplicity with balance, and durability for the long term.

I have not mentioned, until now, the North Slope decline curve that's on the slide I've showed at the beginning, and now here at the end of this testimony. I don't need to mention it. It's the elephant in the room. As I said at the beginning, the greatest, and most urgent challenge facing Alaska today is the decline of oil production from the North Slope. We believe it is up to you, the legislative leaders of our time, and the Governor, to shape a competitive oil fiscal policy that is supported by strong principles and will lead Alaska towards a prosperous future for the long-term. You have a difficult task ahead and AOGA stands ready to assist you throughout this process.

Brooks Range Petroleum Corporation

Presentation for:

House Resources Committee

HB 72

Bart Armfield, Chief Operating Officer

February 18, 2013

HB 72 Support / Considerations

AS 43.55.023(a)

- ✓ Allows for certificate payment in single year
- Eliminates 023 credits after 12/31/13 (consider extension or .023 (l) redefinition of .025 to include exploration projects)

AS 43.55.023 (l) (suggest adoption for North Slope)

- ✓ Allows 40% capital credit for all intangible well work (consider adoption)

AS 43.55.011 (e)

- ✓ Eliminates progressivity maintains 25% base tax

AS 43.55.023(b)

- After 12/31/13, CFL credits no longer redeemed for cash must apply to tax burden
- ✓ 15 % interest on unused credits

AS 43.55.024(c)

- ✓ Extends Small Producer Credits to 2022

AS 43.55.160

- ✓ Gross Revenue Exclusion
- “Does not contain land that was in a unit on January 1, 2003” (consider adjustment)

✓ Support

● Consider Adjustment

Reasons for Entering Alaska

- L48 oil price, reduced cash flows, lack of quality prospect inventory
 - In 2000, oil price had dipped to very low levels
 - Lower 48 average wells struggled to generate breakeven cash flow
 - Prospect reserve base was not very attractive
 - Deals were few and those that were being shopped didn't impact CF for risk
- Drivers to Increase Cash Flow
 - Big reserves with high production rates increases cash flow
 - Acceptable cost of doing business
 - Tax policy was not an impact consideration - ELF
 - Expected eventual cycle change in focus with some majors lessening activity and independents entering as occurred in;

Mid-continent, Rocky Mountains, Gulf of Mexico, North Sea

What does Alaska have to offer ??

	ALASKA	LOWER 48
World class reserve base	X →	
Accessible infrastructure		X
Cost environment		X
Relative Oil Price	X ←	
Meaningful SOA credit structure	X	
Impacts of tax policy	?	?
Perception of tax consequences		X
Confidence in a 5 to 10 year business plan		X

Why more players are not in Alaska

3 Key Elements

- Aggressive desire to be in Alaska
- Knowledge base to understand
- Financial capacity to fully execute

What is the Reality

- Most are content with core areas
- High oil price provides superior cash flows
- Established relationships with knowledgeable investors and traditional capital sources
- Insufficient cause to compel a change in their operational focus
- Many would prefer to control own destiny
- Question internal geologic expertise for Alaska
- Deficiencies of staff operational competence
- Lack of fiscal comprehension
- Unable to model minimum 5 year business plan that is consistent
- Current capital commitments on other projects
- Alaska requires **VERY** patient capital
- Perception that majors control and inability or reluctance to compete

"Alaska is an educational process"

Credits have helped keep us in the game

QCE - .023 (a)

Qualified Capital Expenditures

20% QCE tax credit for capital expenditures

50% of credit year 1 other 50% in year 2

Credits do not expire and can be held, sold to third parties or sold back to the state.

CFL - .023 (b)

Carry Forward Loss Credits

25% credit based on calendar year losses

50% of credit in year 1 other 50% in year 2

Credits do not expire and can be sold to third parties or sold back to the state.

SPC - .024 (d)

Small Producer Credit

Small producers (less than 50,000 BOPD)
Entitled to a \$12MM per year production tax credit.

Credit is in effect for 10 years after start of production

(need to start production by 2016 to qualify).

EIC - .025

Exploration Incentive Credits

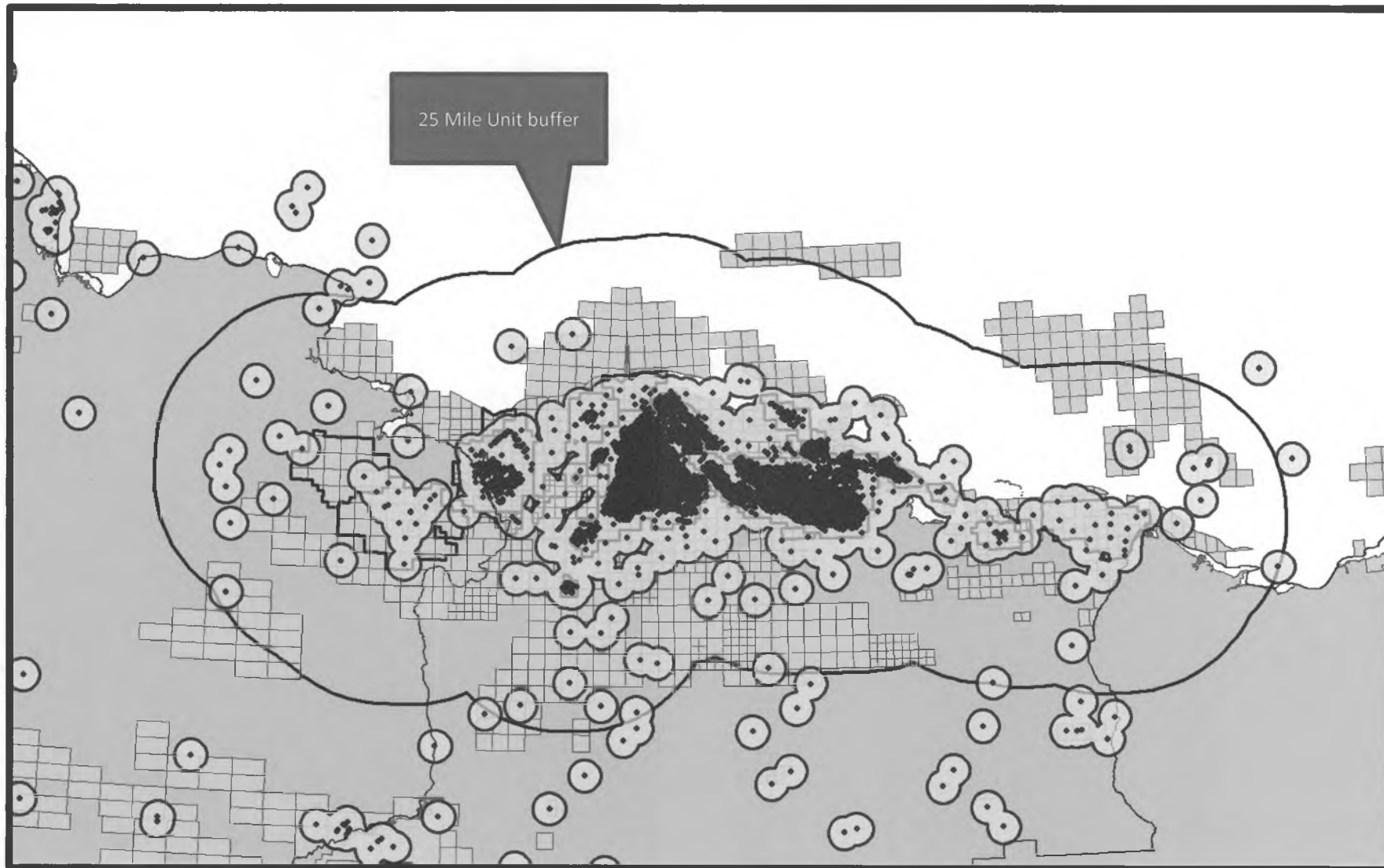
40% credit depending on well location and the prospect traits.

Can take EIC credit or the QCE credits, but not both.

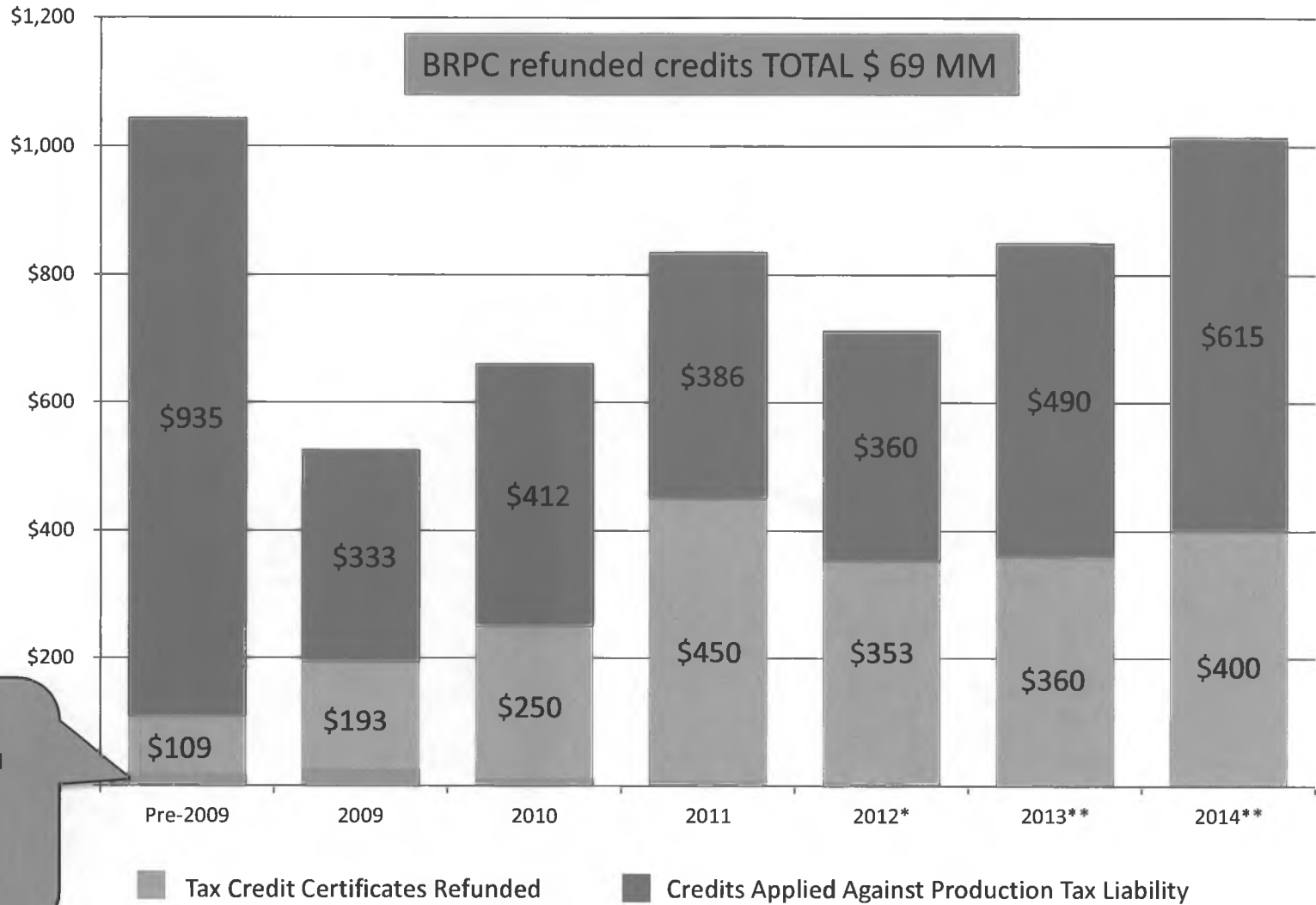
Work needs to be complete by July 1, 2016 to qualify.

BRPC has never received this for exploration wells

AS 43.55.025 Limitations - 25 Mile Unit Buffer With 3 Mile Well Buffer



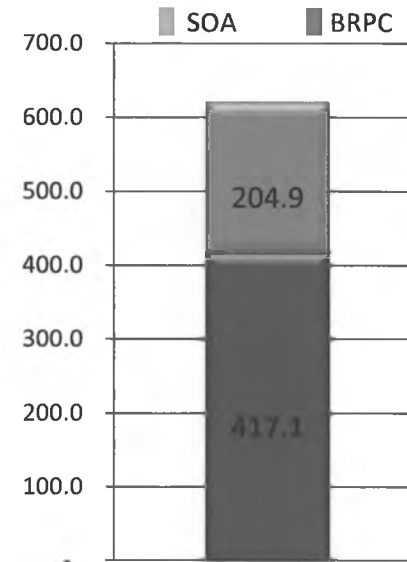
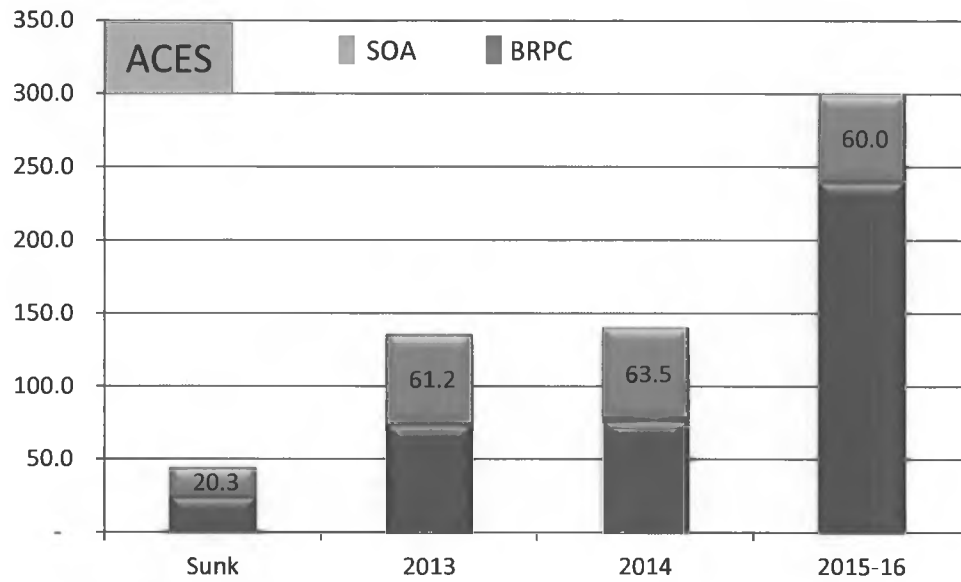
Tax Credits History & Forecast



* Estimated pending final true-ups

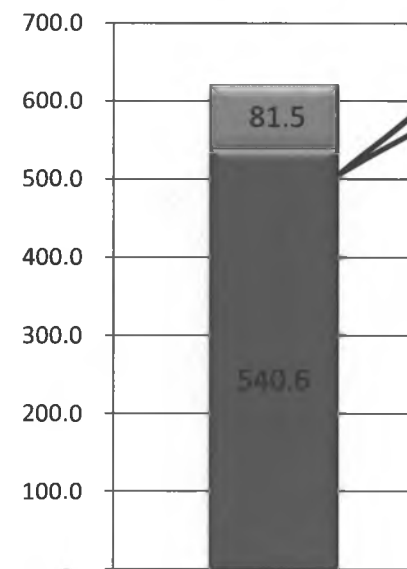
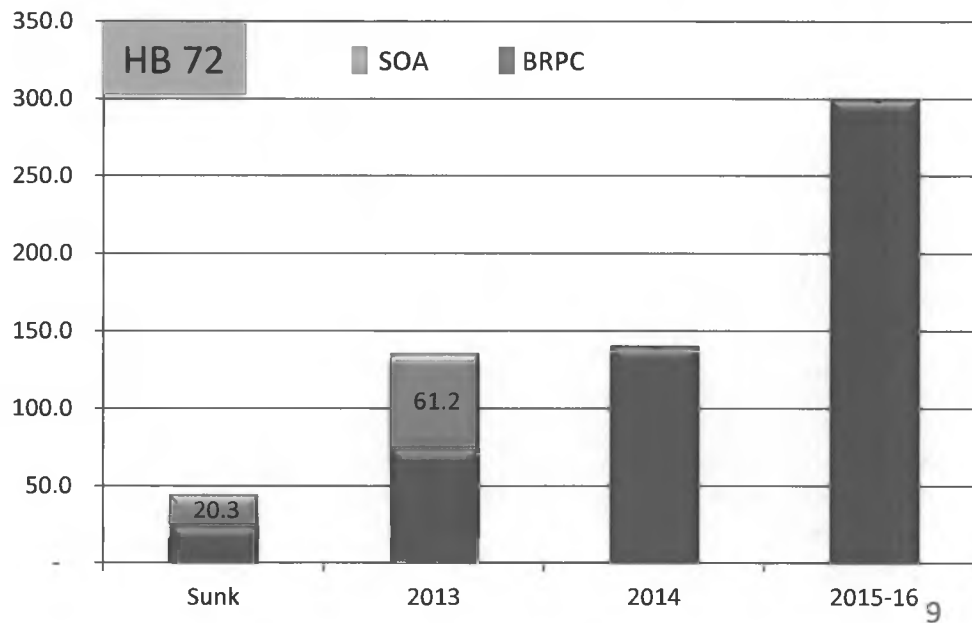
** Fall 2012 Revenue Source Forecast

Impacts to Mustang Development Funding



Under ACES, Mustang SOA revenues \$ 1.2 B Life of Field

Requires \$ 123.4 MM additional funding not planned in sanction process

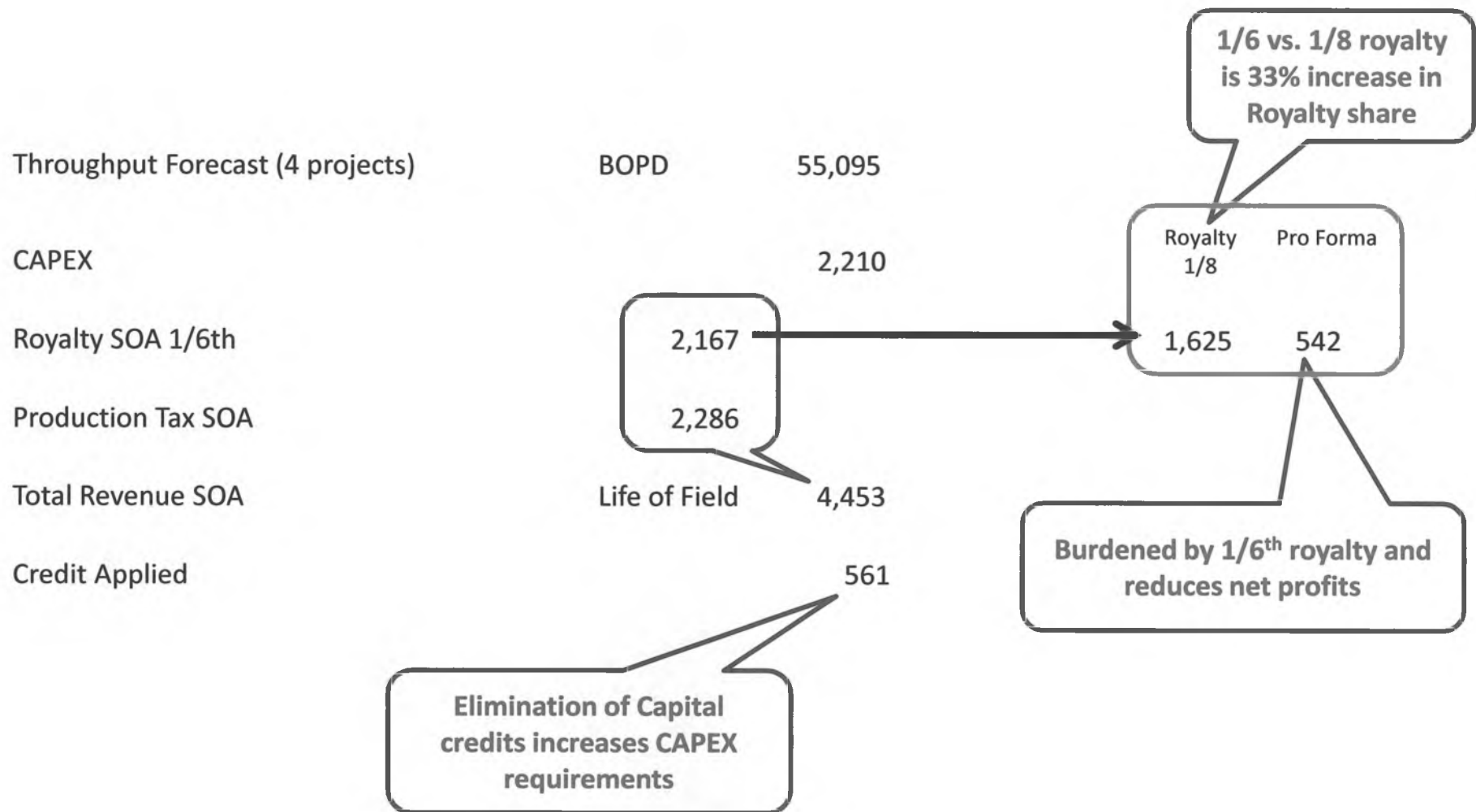


Forecast by Development Project

	Peak Throughput	SOA Rev. (B)
Mustang Development	14,806	1.2
Appaloosa Development	12,722	1.0
Tofkat Development	8,667	0.7
Beechey Point Development	12,000	0.9
Badami Expansion	6,900	0.6
<hr/>		
	55,095	4.4
Annual Average SOA Revenues		0.293
10 new entrants replicated		10
Annual Average SOA Revenues		2.933

Includes \$ 561 MM
in credit support

Combined Development Projects and Throughput Forecast



One Size Does NOT Fit ALL

- Legacy Tier.....
- Mid-size Production and Development Tier.....
- Exploration and Discovery Tier.....
- New Entrants Tier.....

HB 72 Support / Considerations

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✓ Support

● Consider Adjustment

Comments on SB 21/HB 72

Before the Senate and House Resources
Committees

February 18, 2013

Bradford G. Keithley
Partner & Co-Head, Oil & Gas Practice
Perkins Coie, LLP
Anchorage & Washington, D.C.

Background

- Testifying on my own behalf
 - Not representing a client or being paid
 - Bearing my own expenses
- My background
 - Corporate executive (1984 – 1990)
 - Attorney
 - Thirty five years total (full time oil)
 - Been a partner in regional, national and global law firms
 - During my career, have advised major oil companies, mid-majors, small independents, industrial consumers
 - Write often on Alaska oil & gas issues (among others, column for *Alaska Business Monthly*)

Five things ...

- Competitive rates
- Durability
- Neutrality
- Simplicity/Predictability
- Alignment
- Goal: Grow the pie

February 18, 2013

2/15/13 Five things to look for in oil tax reform ... | Thoughts on Alaska Oil & Gas

Thoughts on Alaska Oil & Gas
Biac Keithley's Blog

Five things to look for in oil tax reform ...
Posted on November 23, 2012 | 1 Comment |



Politico, a mostly online newspaper that covers national political affairs – and with which I often open my mornings – routinely attempts to provide readers with a guide to significant upcoming events with a list – usually five – of what they consider the most important things to look for as the event unfolds.

As Alaska begins to consider changing its approach to oil taxes in the upcoming session, I have developed a list of five characteristics that I will look for in evaluating various proposals. I share them for whatever value that may have to others.

1. Competitive Rates. As a number of other commentators have observed, one of the most important characteristics of ACES that needs to be addressed in order to restore investment is the level of tax – the “tax rate.” As former Division of Revenue economist Roger Marks summarizes in a [recent piece](#) in the *Oil & Gas Finance Journal*, Alaska’s current tax rate under ACES is “fourth highest out of 24 [comparable] regimes.” A “comparable regime” means a place “with a comparable risk/reward balance [to Alaska], in terms of features such as reserves, costs, and geological risk.”

“For 17 of those regimes Alaska’s effective tax rate ranged from 12 to 37 percentage points higher. At a \$118/bbl market price, and a \$91/bbl net value, each percentage point difference is worth 91 cents/bbl after-tax.”

Marks concludes, “because of taxes, ... producers can demonstrably make considerably more money nearly anywhere else in the other comparable jurisdictions than in Alaska.”

Achieving tax rates *competitive with comparable jurisdictions* is critical if Alaska is to reestablish significant investment. But rates aren’t the only characteristic that is important. Read on ...

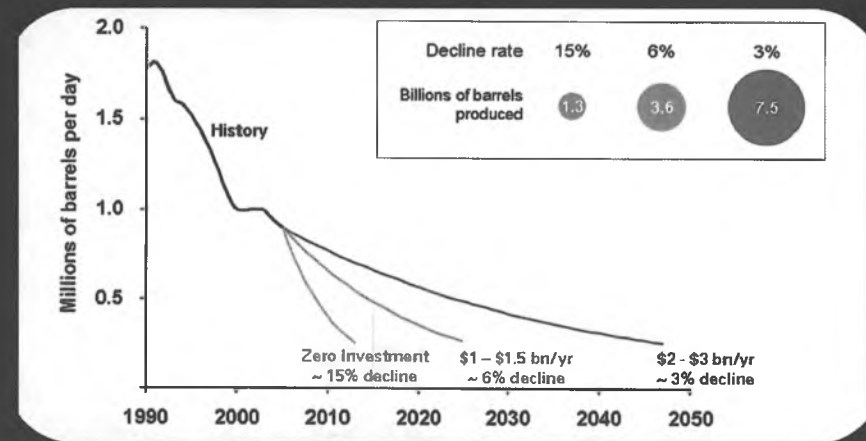
2. Durability. While Alaska previously had made occasional adjustments to its tax policy prior to 2007, none came close to the sea change created by ACES. Compared with ACES, the previous changes mostly could be described as tweaks. By some estimates, ACES increased oil taxes by over 400%.

kgkethley.com/2012/11/23/five-things-to-look-for-in-oil-tax-reform/

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Goal: Grow the pie

- Art. VIII, Sec. 2
*"[t]he legislature shall provide for the ... development... of all natural resources belonging to the State... for the **maximum benefit of its people.**"*
- Not just current, but *all* generations
- From my perspective, an important question is what policy achieves the best return overall, not what produces the largest short term revenue stream



Sample calculation (before NPV):*

$$7.5 \text{ Bbbl} \times \$29 = \$217.5 \text{ Billion}$$

$$3.6 \text{ Bbbl} \times \$34 = \$122.4 \text{ Billion}$$

**Tax levels based on DOR/DNR SRES 2.15.2013 Presentation (p.5-6), includes royalty and production tax.*

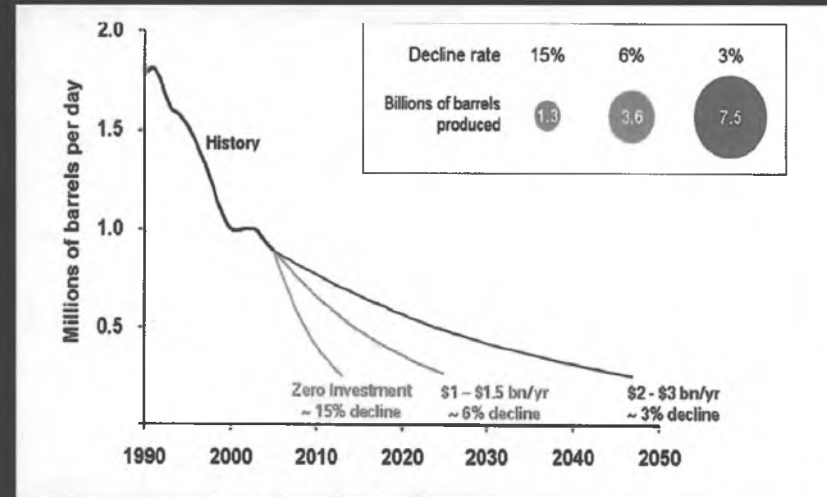
Competitive Rates

- What are competitive rates
 - Those necessary to attract *sustained, long term* capital
 - Sufficient to move the decline curve to the right

- DNR Commissioner Sullivan

"We need \$4 billion [a year] minimum, and we're not even close to that now ..."

February 18, 2013



2/18/13 Alaska Journal of Commerce | DNR commissioner: Oil investments must ramp up

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DNR commissioner: Oil investments must ramp up

BY TIM BRADNER, ALASKA JOURNAL OF COMMERCE

The petroleum industry has to ratchet up Alaska investments in new exploration and development to at least \$4 billion a year if the decline in oil production is to be reversed, state Commissioner of Natural Resources Dan Sullivan says.

"We need \$4 billion minimum, and we're not even close to that now," Sullivan told the Resource Development Council in Anchorage Sept. 15. RDC is a natural resource development advocacy group. The number could be higher, too.

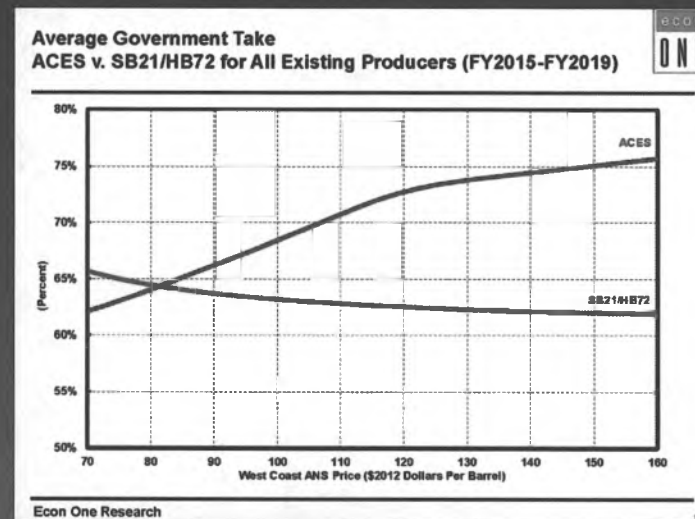
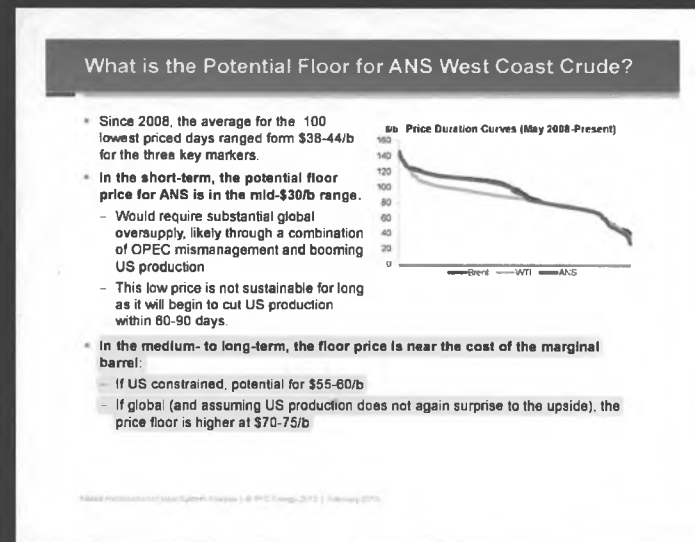
The industry is now spending about \$2.5 billion a year in capital investment, according to the state Department of Revenue, but most of that is related to facility upgrades in existing fields and not in new drilling or developments that add new production.

Sullivan said he has read reports that 2012 is a record year for new industry capital investment.

Competitive Rates

- In order to attract sustained, long term capital, *Alaska must be competitive across the full, anticipated, long term price range, not just a portion*
- The problem with ACES is that it is uncompetitive at the higher ends of the range
- As currently constructed, SB 21/HB 72 may simply reverse the problem

February 18, 2013



Durability

- What is durability
 - Investors are able to rely on fiscal terms over full investment cycle
 - Substantial, decline rate changing investments contemplate 15 – 25 year payout
- SB 21/HB 72
 - No durability mechanisms included
 - Not established by contract
 - No economic stabilization clause
 - Somewhat internally unstable
 - 20% GRE (ELF experience)

Durability

Canadian approach: Long-term durability depends on producer involvement

"[BC Premier Christy] Clark said Wednesday she will not be able to discuss any of the proposals that are being considered for the new tax regime until after negotiations are complete.

"We have to make sure that, first of all, we are getting maximum benefit for the people of our province, and at the same time that we aren't imperiling their business case," she said.

"Because if we want to be competitive, we need to do that through the course of negotiations with (industry), so that's what we're working on right now."

February 18, 2013

2/15/13

Oil and gas producers balk at LNG tax

Oil and gas producers balk at LNG tax

Association is cool to premier's plan to rake in revenues from gas exporters

BY PETER O'NEIL, VANCOUVER SUN FEBRUARY 14, 2013



An artist's rendering of the planned Kilmel Apache Canada LNG facility, one of several proposed for northwestern B.C.

OTTAWA — Canada's oil and gas industry disagrees with B.C. Premier Christy Clark's plan to rake in extra revenues from future liquefied natural gas plants.

A spokesman for the Canadian Association of Petroleum Producers said Wednesday the industry doesn't share the Clark government's view that B.C.'s LNG sector, once it's up and running, will have a significant competitive advantage compared to its assumed top competitor, Australia.

Clark's government revealed this week it plans to collect a new tax from LNG exporters to help ensure the province can cash in on the expected boom.

"That resource belongs to British Columbians, and I am determined to make sure that the people of this province share in the benefits of that resource," Clark said Wednesday, when talking about the need for a new tax on LNG.

The new tax is expected to play an essential role in building Clark's promised Prosperity Fund, which her government announced in Tuesday's throne speech.

www.vancouversun.com/story_print.html?id=7251720&pos=1

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Durability

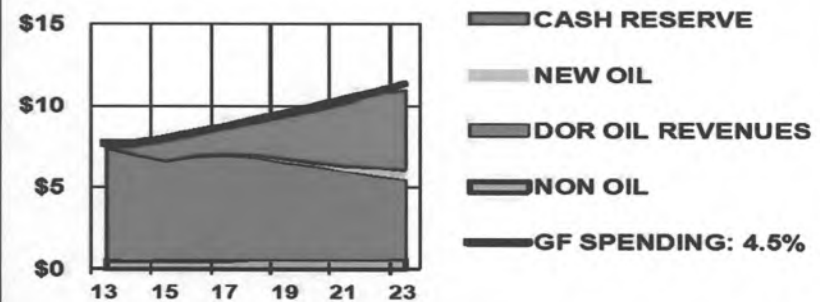
Durability also depends on overall fiscal policy ...

"In its 10-year fiscal plan, the state Office of Management and Budget (OMB) projects that spending the cash reserves might fill this gap until 2023 But what happens after 2023?"

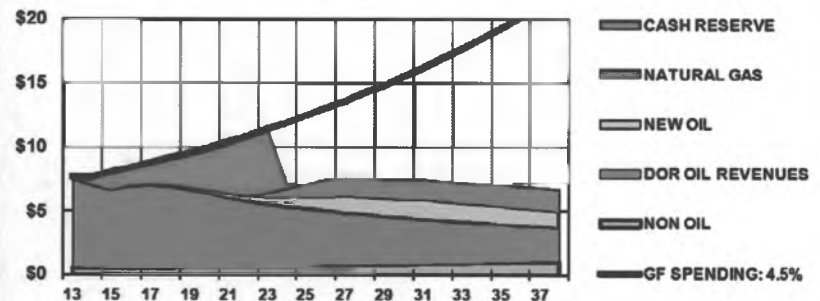
"Reasonable assumptions about potential new revenue sources suggest we do not have enough cash in reserves to avoid a severe fiscal crunch soon after 2023, and with that fiscal crisis will come an economic crash. "

- SB21/HB 72 assumption of durability appears to be based on hope, not much more

ALASKA 10-YEAR FISCAL PLAN



LOOKING BEYOND THE 10-YEAR HORIZON



Neutrality

- What is neutrality
 - Letting market decide what investments are best
 - Government bias impairs benefitting from changing technology and market dynamics
- Oil market is dynamic
 - New technology provides new access
 - New understanding of old information
 - Opportunities that might seem the best today are overtaken by new technology and understanding
- Providing incentives to some areas burdens others

Neutrality

- Alaska has significant potential in realizing improved recovery rates from existing fields
 - BP: *"When production started at the Prudhoe Bay field the recovery rate of the 25 billion barrels of oil in place was expected to reach 40 percent. Today, using new technologies that estimate has increased to more than 60 percent."*
 - Each 1% improvement in Prudhoe recovery rate equals an additional 250 MMbbls
- Consistent with focus elsewhere
 - Current emphasis in Norway

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) (Million Barrels)	(4)	(5)
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

Econ One Research

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SB 21/HB 72

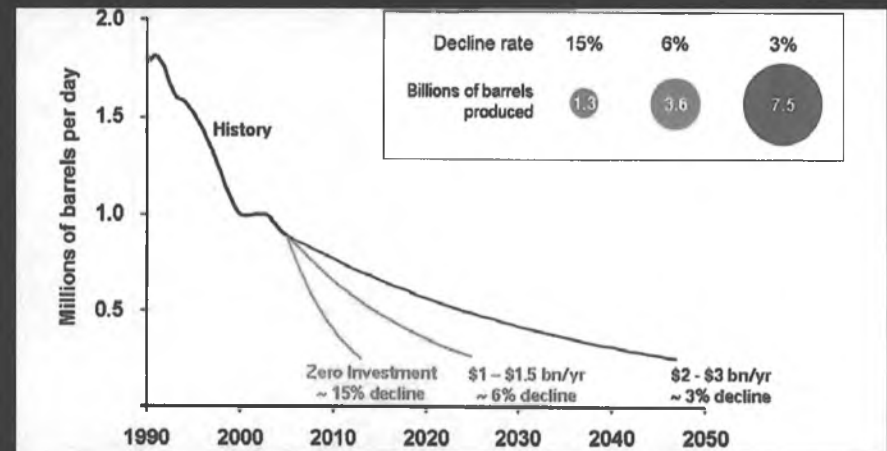
- Better than ACES, but still attempts to direct investments
- Favors investment in new fields (bill does significantly expand what is considered new)
- But burdens investments that are designed to increase ultimate recovery in old fields

Simplicity/Predictability

- What is simplicity
 - Easy to administer; not subject to significant interpretation/dispute
 - Easy to calculate and compare to other investment alternatives across a range of prices
- SB 21/HB 72
 - Structure much more simple than ACES
 - Meets global expectations for simplicity
 - GRE is a simple way to deal with preferred investments (if that is a valid goal)

Alignment

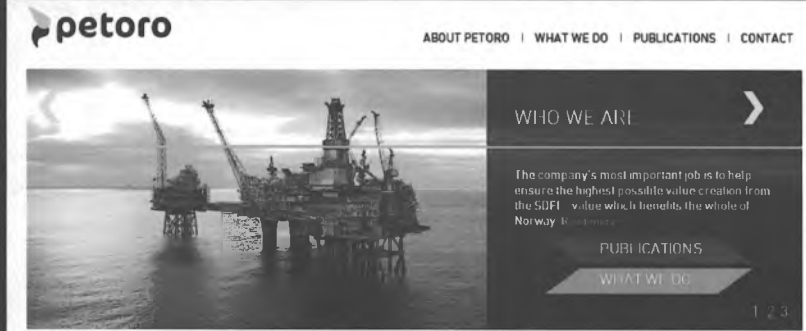
- What is alignment
 - Aligned with investors in growing the pie (moving the decline curve to the right)
- Alaska's approach
 - Relies on indirect policy tools
 - Carrot (fiscal tools)/stick (regulatory action)
 - Relies on consultants for understanding of industry
 - Analogous to driving a car from the back seat
 - Not "in the game," seeing shifts in market dynamics and identifying new opportunities



- SB 21/HB 72
 - Continues the same approach
 - Continues to look at the industry from the outside and use indirect policy tools

Alignment

- Current approach worked in a Prudhoe-dominated world
 - Uncertain it works as well in a dynamic environment dependent on continual investment
- There may be other ways, but the best I have seen in the world is Norway's co-investment approach
 - Results in an intense and collaborative focus on developing state resources
 - Developed when Norway realized "royalty" model was not resulting in optimum investment



The screenshot shows the Petoro website header with the logo and navigation links: ABOUT PETORO | WHAT WE DO | PUBLICATIONS | CONTACT. Below the header is a large image of an offshore oil rig. To the right of the image is a navigation menu with 'WHO WE ARE' and a right arrow, 'PUBLICATIONS', and 'WHAT WE DO'. Below the image is a section titled 'PETORO | A DRIVING FORCE ON THE NORWEGIAN CONTINENTAL SHELF' with a sub-header 'Vi søker geofysiker' and a button 'KLIKK HER >>'. Below that is a text block starting with 'The Norwegian government has large holdings in oil and gas licences on Norway's continental shelf (NCS) through the State's Direct Financial Interest (SDFI). These are managed by Petoro AS. The company's most important job is to help ensure the highest possible value creation from the SDFI - value which benefits the whole of Norway.' To the right of this text is another button '93 % av de ansatte i'.

"The company's main objective is to maximize the economic value of the state's oil and gas portfolio on the basis of sound business principles. ...

... The company's ability to create value is closely related to its ability to collaborate with and influence operators and other partners."

Summary of Conclusions

*Better than ACES ... but material concerns remain,
more likely to result in short term than long term investments*

- **Competitive rates**
 - SB21/HB72 not competitive at full range of anticipated prices
 - “Mostly competitive” isn’t good enough when evaluating long term investments
- **Durability**
 - No mechanism included to ensure durability
 - State’s financial position creates significant concerns around long term durability
- **Neutrality**
 - Significantly reduced tilt, but some bias nevertheless remains against important investment opportunities
- **Simplicity/Predictability**
 - Substantially improved
- **Alignment**
 - Same approach as past policy, but with an uncertain effect in an increasingly dynamic and competitive world

Recommendations

- Adopt SB 21/HB 72 with amendments:
 - Make competitive across all anticipated price ranges, not just the higher end (avoid a tax increase at the lower end)
 - Provide GRE or similar incentives for investments designed to increase ultimate recovery in existing fields (enable them to compete on level playing field)
- As important, identify fiscal policy concerns in forwarding the bill to Senate and House Finance Committees
 - Changing tax policy without fiscal policy likely will encourage only short term investments
 - There are long term fixes: ISER “sustainable budget” model
- Hold hearings on co-investment model
 - Norway also made the shift from “royalty” to “co-investment” model
 - Compare against other ways of developing “forward looking radar” for Alaska
 - Evaluate potential contribution toward Commissioner Sullivan’s \$4 billion goal

Thoughts on Alaska Oil & Gas

Brad Keithley's Blog

Five things to look for in oil tax reform ...

Posted on [November 23, 2012](#) | [1 Comment](#) |



Politico, a mostly online newspaper that covers national political affairs — and with which I often open my mornings — routinely attempts to provide readers with a guide to significant upcoming events with a list — usually five — of what they consider the most important things to look for as the event unfolds.

As Alaska begins to consider changing its approach to oil taxes in the upcoming session, I have developed a list of five characteristics that I will look for in evaluating various proposals. I share them for whatever value that may have to others.

1. *Competitive Rates.* As a number of other commentators have observed, one of the most important characteristics of ACES that needs to be addressed in order to restore investment is the level of tax — the “tax rate.” As former Division of Revenue economist Roger Marks summarizes in a [recent piece](#) in the *Oil & Gas Finance Journal*, Alaska’s current tax rate under ACES is “fourth highest out of 24 [comparable] regimes.” A “comparable regime” means a place “with a comparable risk/reward balance [to Alaska], in terms of features such as reserves, costs, and geological risk.”

“For 17 of those regimes Alaska’s effective tax rate ranged from 12 to 37 percentage points higher. At a \$118/bbl market price, and a \$91/bbl net value, each percentage point difference is worth 91 cents/bbl after-tax.”

Marks concludes, “because of taxes, ... producers can demonstrably make considerably more money nearly anywhere else in the other comparable jurisdictions than in Alaska.”

Achieving tax rates *competitive with comparable jurisdictions* is critical if Alaska is to reestablish significant investment. But rates aren’t the only characteristic that is important. Read on ...

2. *Durability.* While Alaska previously had made occasional adjustments to its tax policy prior to 2007, none came close to the sea change created by ACES. Compared with ACES, the previous changes mostly could be described as tweaks. By some estimates, ACES increased oil taxes by over 400%.

Because the revised tax applied equally to both old and new investments, ACES had the effect of dramatically altering the economics of investments made not only subsequent to its passage, but also those that were made prior to 2007. At least from the perspective of investors, the 2007 passage of the tax had the effect of retroactively confiscating a significant portion of the return which they had anticipated earning from prior investment decisions.

Going forward, investors will evaluate any proposed change in Alaska's tax structure not only from the perspective of what the change is, but also whether the change is likely to be durable. Now that Alaska has demonstrated an inclination to apply tax changes retroactively to prior investments, investors will be highly concerned about being caught again in a situation where they make long term investment decisions and the state thereafter once again increases the tax structure after a few more years.

Investors will be much less likely to invest if that potential remains.

While some legislators (including Republicans) have suggested that the legislature is not able to provide certainty about its tax policy, that is not the case. The state clearly has the power to enter into long term, binding contracts with investors, such as it does with unions and has with investors through oil & gas leases.

Some suggest that the power to tax is unique and one legislature cannot contract away a subsequent legislature's ability to exercise that power. Even if that is true, however, there are other ways of stabilizing total state take, such as by providing that any future increases in taxes can be taken as a credit against royalty. Such "economic stabilization" clauses are common throughout the world.

The extent to which the legislation provides for durability is important. Investors will be *much* less likely to commit to substantial, long term projects — the very type of projects that result in significant additions to the supply base — without some assurance that the revised system is durable.

3. Neutrality. As I have written elsewhere, one of the worst characteristics of ACES is its vastly differing treatment of various sources of supply. Production from existing units is taxed at a significantly higher rate than is otherwise needed in order to fund direct state subsidies (what some refer to euphemistically as "credits") of up to 60% of total costs for activities undertaken outside of the units.

The result is that activity inside existing units is artificially suppressed while activity outside of existing units is artificially subsidized, appearing to make those activities economic, when they likely are not. **No** activity is left to respond to pure market signals.

This approach makes no sense in Alaska's current situation. As I have previously explained, by far the largest new production potential lies inside of Alaska's existing units, and the sources of supply inside the existing units likely can be brought on line faster than those that are located farther from existing infrastructure. As a result, if anything Alaska should favor higher tax credits for the development of new fields located inside of existing units than outside. Currently, however, ACES produces the opposite result.

At their core, credits are a way of substituting government's judgment for business in picking economic winners and losers. Through tax policy, the government favors investment in some activities — the winners — and discourages investment in others — the losers — by raising their costs. ACES backs the wrong horses.

Rather than attempt to outguess the market, the government should adopt a neutral stance between fields and let the market decide which are the most economic to produce.

4. *Simplicity/Predictability.* One of the most consistent complaints from current and potential investors about ACES is its complexity. While companies can employ people and computing power to deal with complex equations, generally speaking simple tax structures attract more investment than complex structures.

There largely are two reasons for that. The first is that investors generally are concerned that complex tax structures have a greater potential for producing surprises than simple ones — and their experience is that, when they arise, surprises generally produce bad things.

The second reason is that complex tax structures usually are the result of a lot of fine tuning, and that once legislators and regulators start down the road of “managing” investments through the use of the tax code, they can't resist the temptation to continue fiddling with the knobs as the tax structure fails to produce the results that they intended. As a result, complex tax structures tend to be changed more often than simple ones, making them much less predictable.

ACES, literally, is one of, if not the most complex oil tax structures in the world. (With the exception of the 1970 -80's era federal windfall profits tax, ACES is by far the most complex structure with which I have dealt.) It also is one of the least predictable. Even five years after its passage, very few, if any, audits have been completed and the implementing regulations, which at times are extremely vague, have yet to be interpreted. As a consequence, even now, five years after passage, investors are not certain how ACES ultimately will be applied to investments.

Investors understandably favor simplicity and predictability. To help improve the investment climate in Alaska, the coming changes to the Alaska tax structure should make a **significant** move in that direction.

5. *Alignment.* As I explain in a [recent piece](#) in the *Alaska Business Monthly*, Alaska's current oil policy is significantly out of alignment with the state's own objectives. Certainly part of that relates to the tax code. As explained above, ACES attempts significantly to tilt private investment in Alaska away from the state's largest and best defined new prospects to smaller, uncertain and unknown opportunities. By overcharging potential production from its best prospects in order to subsidize exploration of others, Alaska's policies impair the achievement of its own objectives.

But the misalignment between policies and objectives goes much further. The state's recent actions regarding the Pt. Thomson leases provide another good example.

After protracted legal proceedings, this year the Pt. Thomson owners agreed to pursue the development of the field.

Like its approach to tax credits, however, the state's efforts at directing these investment decisions have created unintended consequences. As operator, Exxon already has spent in excess of \$1 billion on the Pt. Thomson project and estimates that, before completion, it will spend billions more. At the same time, investment in the development of the oil available in other existing North Slope units has declined.

In the absence of developing a major gas market, the maximum production anticipated from Point Thomson is 10,000 barrels of liquids per day, which is significantly smaller than other potential opportunities available in the existing units and a minor offset to the anticipated net loss of 50,000 barrels per day of production projected by the state between 2011 and 2015.

As a consequence, the effect of the state's efforts at Pt. Thomson essentially has been to focus investment on one project on the North Slope, likely at the expense of others offering significantly greater potential.

The reason that the state pursues such counter productive efforts is that the state currently does not have either the ability — or, seemingly, even a compelling economic interest — in determining which projects make the most economic sense. Instead, the state's decisions are driven largely by political reasoning. In essence, the state acts as a back seat driver, attempting to steer industry investment indirectly and towards non-economic objectives.

Recently, a co-author and I proposed a means of better achieving alignment between the state's actions and objectives that has proven highly successful in other parts of the world and, I firmly believe, would have the same result in Alaska. While the proposal met some criticism, I anticipate that support will grow as others come to realize that a revised tax policy alone will be insufficient to attract the levels of investment — estimated by DNR Commissioner Dan Sullivan to be a minimum of \$4 billion/year — required to realize Alaska's full oil potential.

Any tax reform proposal should progress toward alignment.

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ONE RESPONSE TO FIVE THINGS TO LOOK FOR IN OIL TAX REFORM ...

Pingback: ["Five things to look for in oil tax reform": The radio interview | Thoughts on Alaska Oil & Gas](#)

House Resources Committee

HB72

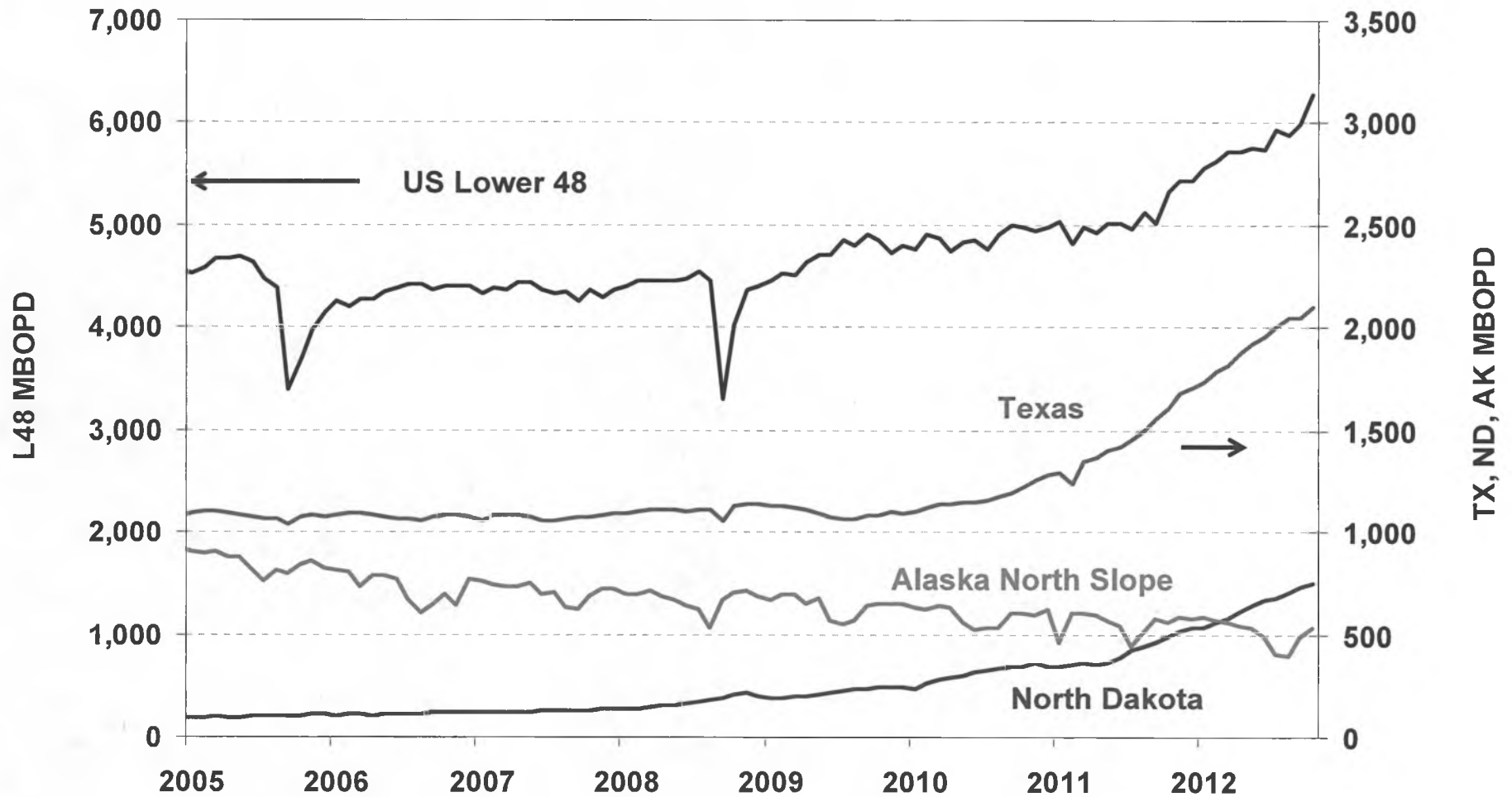
Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

February 20, 2013

Topics

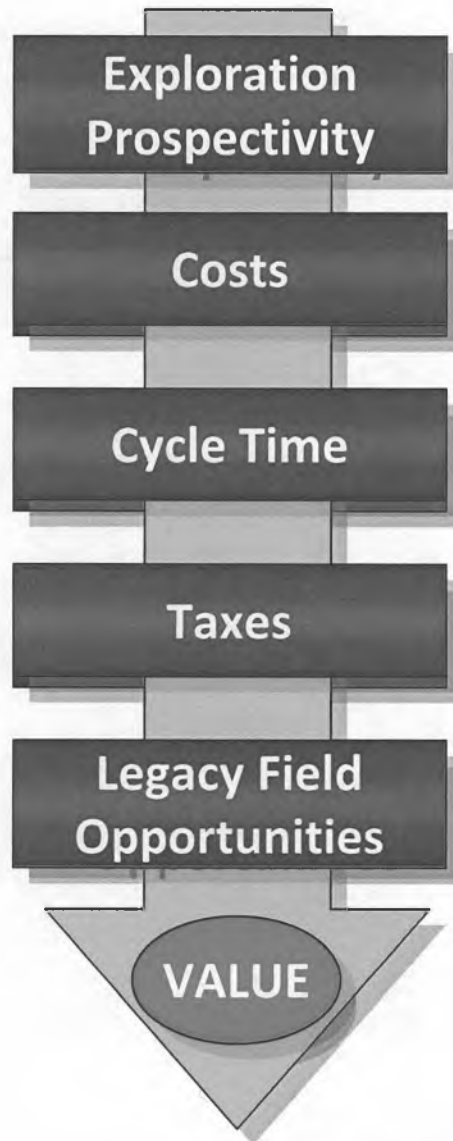
- Alaska's Production Challenge
- Investment Considerations and Alaska's Cost Environment
- ACES and HB72
- Observations

Alaska Decline Continues While Lower 48 Production Continues to Increase



Alaska – A Challenging Investment Climate

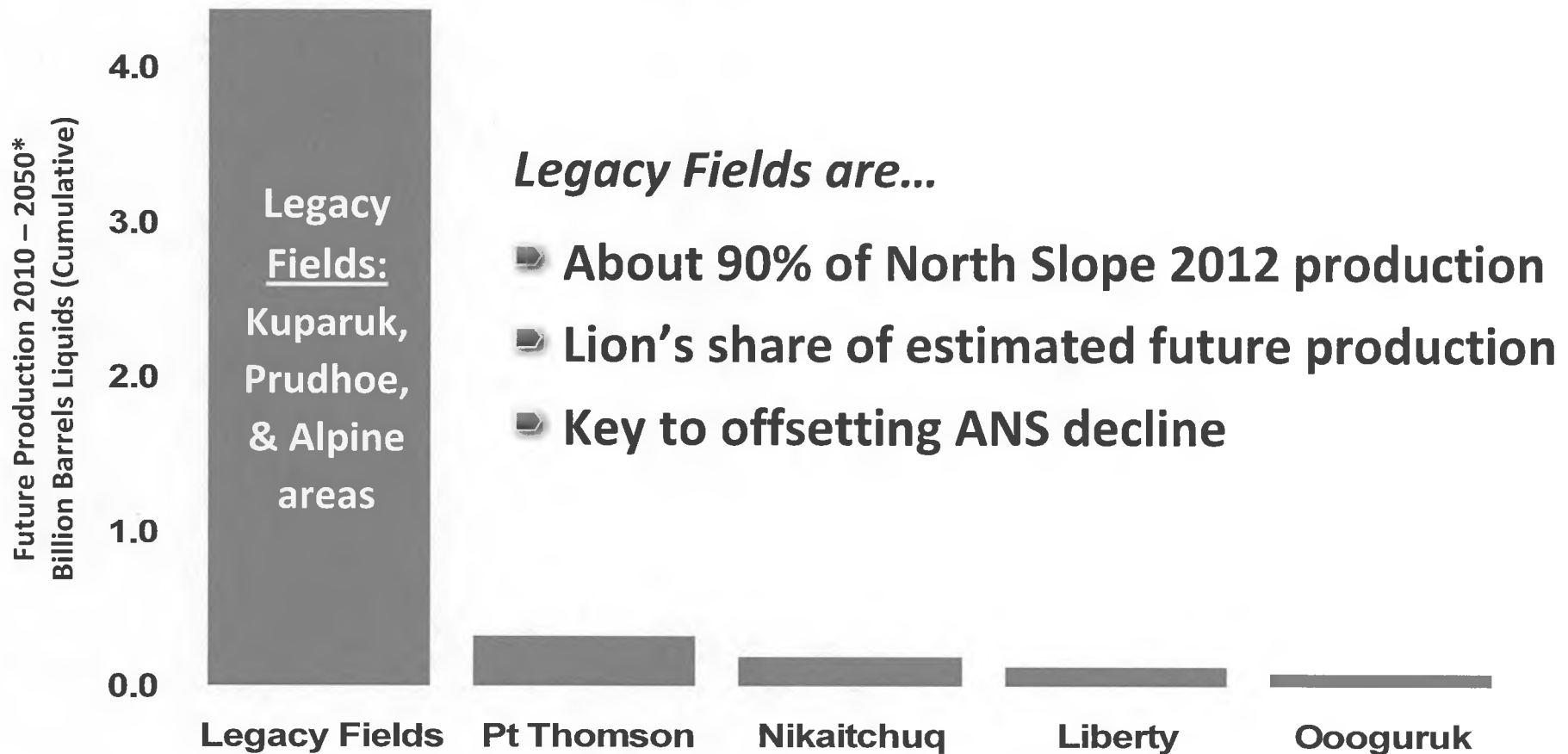
Investment Criteria: How Alaska Ranks



- Expected field size/maturity
- Crude quality
- Exploration, development & production cost
- Transportation costs to market
- Time to production
- Permitting/regulatory environment
- Tax rates given challenged location
- Tax rates compared to other states & countries
- Billions of barrels left to be developed
- Significant production volumes

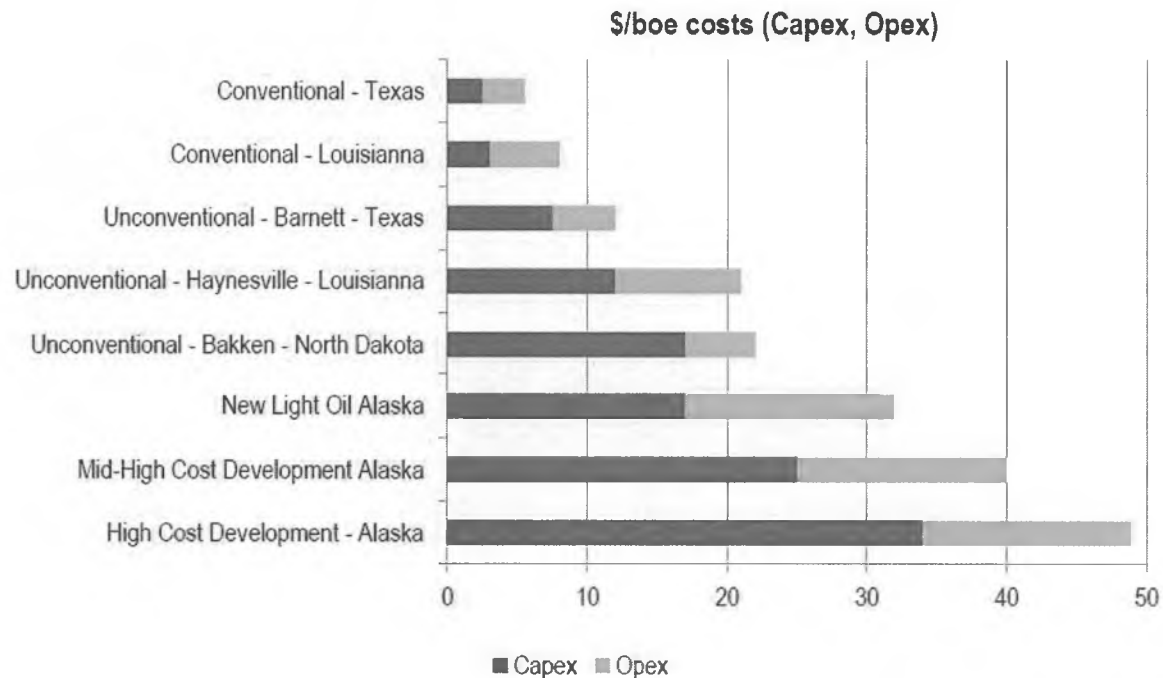


Alaska Legacy Fields Still Provide Significant Opportunity



*Source: DOR 2009 production forecast 2010 – 2050 volumes

Alaska's Days of "Easy Oil" Are Gone: High Costs and High Government Take Present Challenges



Costs are significantly higher in Alaska than the Lower 48 – even compared to unconventional. Meanwhile, Alaska's Government Take has risen significantly over recent years, meaning new project economics can be very challenging

“Easy Oil” In the Legacy Fields Is Gone

- Challenged oil remains
 - Complex, high cost wells
 - Smaller reserve targets
 - Fault blocks, flank oil
 - Satellites, viscous oil
 - Most new wells produce oil AND water
 - Facilities handling ~ three times as much water as oil
- **A billion dollars does not go as far as it used to...**
 - 2000 Alpine development ~80,000 BOPD
 - 2012 CD-5 Drillsite ~18,000 BOPD



Initial Alpine Development



CD-5 Type Development

ACES Observations

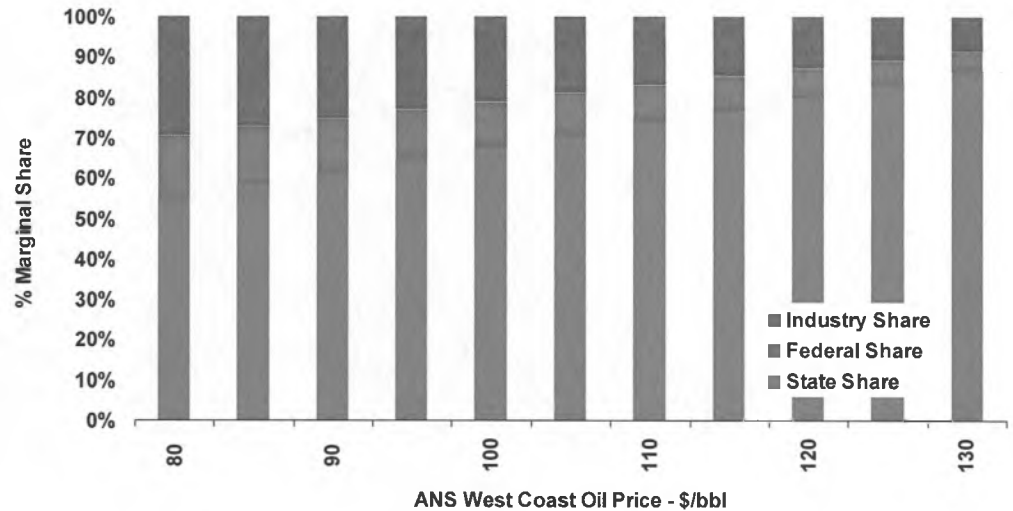
Positive Elements

- Tax credits help offset Alaska's high cost environment
- Tax credits provided for both new and legacy fields

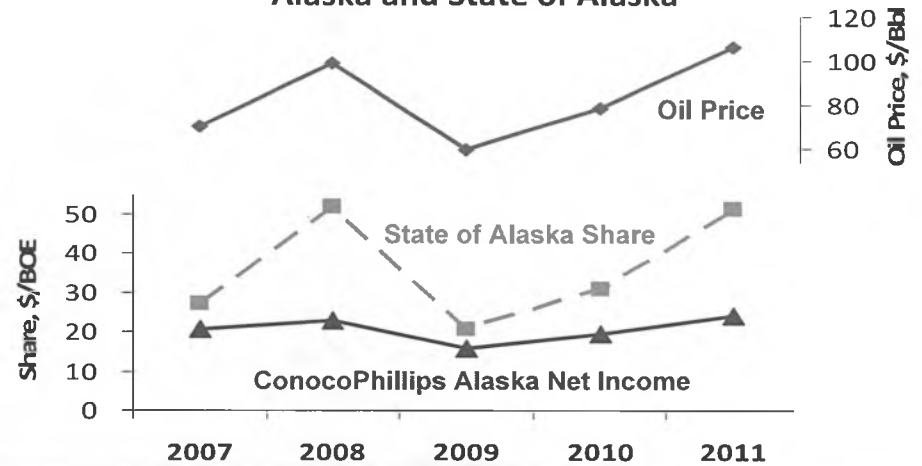
Negative Elements

- High average tax rates
- High marginal tax rates
- Gross minimum tax
 - Tax still paid if revenues don't cover costs

Government and Industry Marginal Share in Alaska

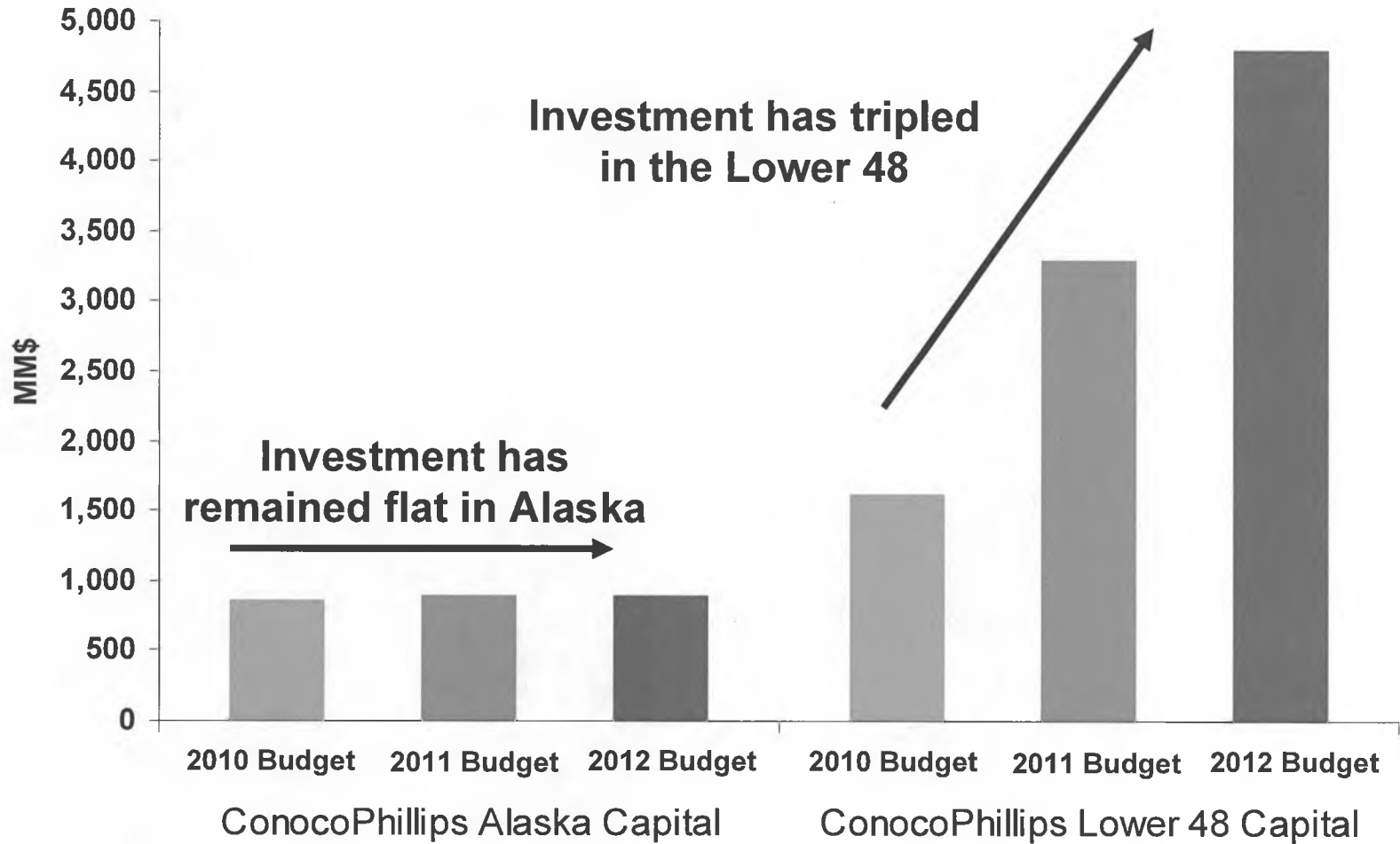


Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska



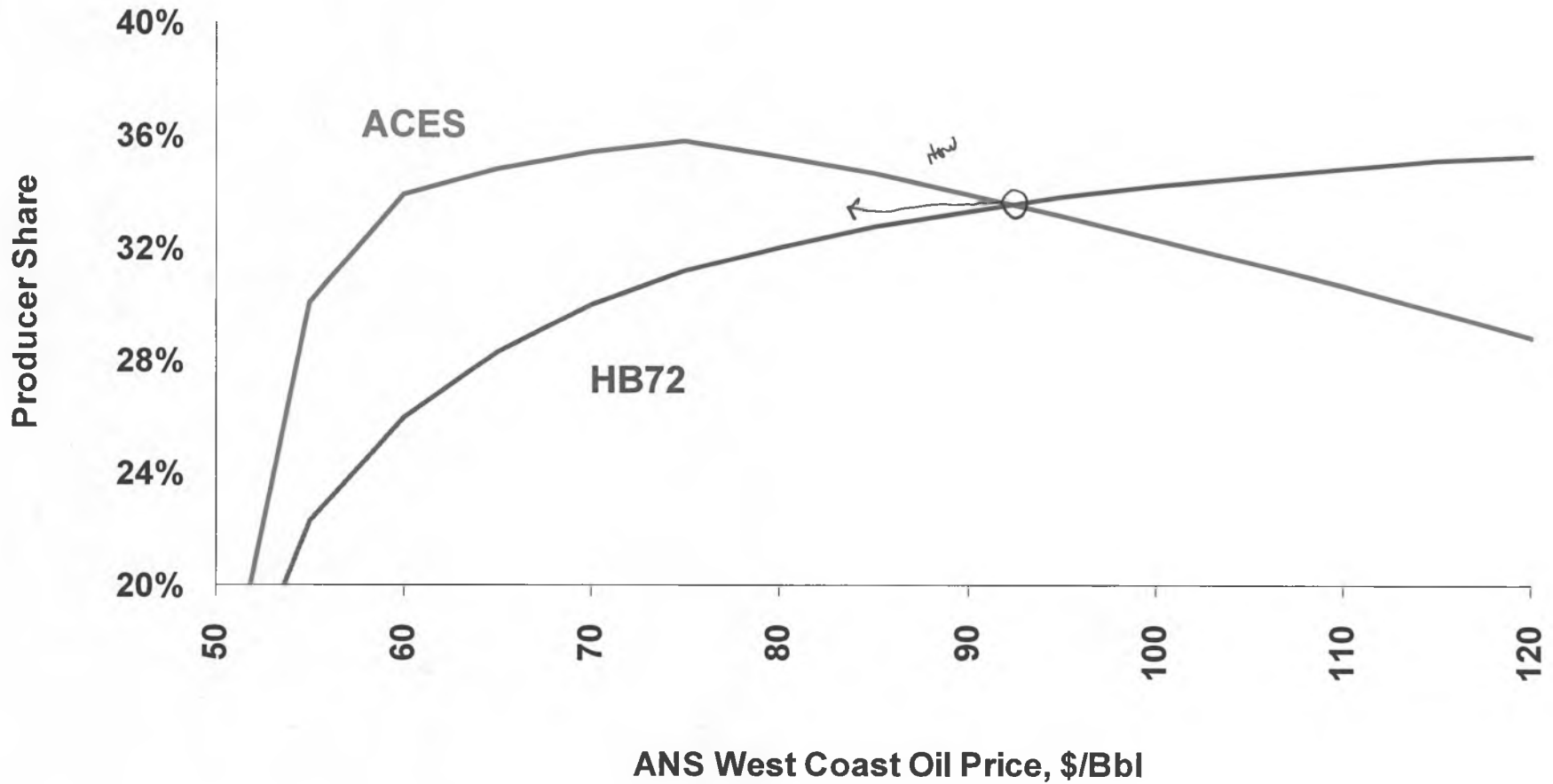
Upper right plot based on Fall 2012 Revenue Sources Book data for FY2014
 Lower right plot based on ConocoPhillips 2007 – 2011 10-K reports; State share is royalties (estimated), production tax, ad valorem tax and state income tax; oil prices are ConocoPhillips average realized prices on the West Coast

ConocoPhillips Capital Allocation



Investment flows where investor has upside

Producer Share under HB72



Recap of ConocoPhillips Perspective

■ ACES

- Progressivity takes the upside and discourages investment
- Tax credit investment incentives positive, but do not offset the negative effects of ACES progressivity

■ HB72 Positive Elements

- Positive step to improve Alaska's business climate
- Solves the high marginal tax problem
- Makes Alaska more competitive at \$100+ prices

■ HB72 Areas for Improvement

- Bill does not contain sufficient investment incentives for legacy fields to offset Alaska's high cost environment
- Does not encourage investment relative to ACES in a downward trending oil price environment

Are prices downward trending recently?

TESTIMONY ON HB 72
by
THOMAS K. WILLIAMS
SENIOR ROYALTY AND TAX COUNSEL
BP EXPLORATION (ALASKA) INC.
to the
HOUSE RESOURCES COMMITTEE
20 FEBRUARY 2013

Mister Chair, Members of the Committee:

Good Afternoon. For the record, my name is Thomas K. Williams and I am Senior Royalty and Tax Counsel for BP Exploration (Alaska) Inc. Thank you for inviting us here to testify on House Bill 72, which has been introduced by Governor Parnell and proposes to amend the so-called "ACES" production tax on oil and gas produced in Alaska.

There are three primary changes that HB 72 would make to ACES: one, repeal progressivity, which we think is good; two, change the system of tax credits that now exists, which threatens to harm some producers even if it may help others; and three, create a new "gross revenue exclusion" for new production that we view as innovative but largely misdirected. My testimony today will review these changes in the context of the tax issues that my employer faces under the present tax, which the Governor and apparently the entire Legislature, with the introduction of Senate Bill 50, agree needs to be reformed.

First, progressivity. As you know, progressivity is a sliding-rate tax that runs quickly up to a 25% rate and then rises more slowly above 25 percent. It is in addition to the basic 25% tax that is also levied on the "production tax value" of a producer's taxable production. Repealing progressivity is a good idea for a number of reasons, which AOGA has identified in its testimony on Monday and which other taxpayers will probably present to you as well. Many of those objections are for effects from progressivity that were intentional as part of the way progressivity was designed. What I'd like to do today is to describe two significant, unintended effects of progressivity that seem largely unknown and even less understood. I have eight slides to present that will show you exactly what these unintended consequences are.

To begin, let me quickly review how the tax is calculated for the example I will use.

		Bbl	\$/bbl
USWC Price	\$1,000,000	10,000	\$100.00
Transportation	<u>\$150,000</u>	10,000	<u>\$15.00</u>
GVPP	\$850,000	10,000	\$85.00
Field Expense	<u>\$300,000</u>	10,000	<u>\$30.00</u>
PTV	\$550,000	10,000	\$55.00
25% Base Tax	\$137,500		
Prog'y Rate	10.000%		
Prog'y Tax	<u>\$55,000</u>		
Total Tax	\$192,500		

Slide 1. How ACES works

If you look at this first slide, you will see the tax calculation for a hypothetical producer with 10,000 barrels of oil who sells it on the West Coast for \$100 a barrel and receives a million dollars. It cost \$150,000 – or \$15 a barrel – to transport that oil from the field in Alaska to the West Coast, which leaves \$850,000 as the gross value at the point of production or “GVPP.” The producer had \$300,000 of allowable lease expenditures, or field expense, to produce the oil, which leaves a taxable production tax value, or “PTV,” of \$550,000 or \$55 a barrel. The base tax is 25% of the PTV, or \$137,500.

The progressivity rate equals four tenths of a percentage point times the difference between \$30 and the producer’s PTV per barrel. Here the difference between \$30 and \$55 is \$25, and \$25 times four tenths of a point per dollar equals 10 percent. Ten percent of \$550,000 is \$55,000 of progressivity tax. That plus the base tax of \$137,500 equals a total tax of \$192,500. So far there is nothing here that is new to you.

So now let me begin to show you something you probably have not seen before. This scenario is not about what the producer has actually produced, but about an evaluation of what could happen from the development of a new reservoir or field if the investment is made. And let’s suppose that this producer sees three different ways that she could potentially improve this investment. One is that she knows of a buyer willing to pay a premium of a dollar a barrel for the oil delivered on the West Coast, the second is a way to save \$20,000 in transportation costs, and the third is a way to cut the costs for field operations by \$30,000. If she can do all three, what is the change in the tax?

	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640 All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	
GVPP	\$850,000		\$880,000	10,000	\$85.00	\$88.00	
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	
PTV	\$550,000		\$610,000	10,000	\$55.00	\$61.00	
25% Base Tax	\$137,500		\$152,500				
Prog'y Rate	10.000%		12.400%				
Prog'y Tax	<u>\$55,000</u>		<u>\$75,640</u>				
Total Tax	\$192,500		\$228,140				
Change in tax			\$35,640				

Slide 2. Example – The three changes together

In this slide we see the three changes. The extra dollar a barrel in the price increases the sales revenue from the oil to \$1,010,000. The transportation savings reduces that cost from \$150,000 to \$130,000. Between the increased price and the transportation savings, the GVPP of the oil back in the field is \$880,000 instead of \$850,000. And the reduction in upstream lease expenditures raises the taxable PTV by another \$30,000, for a total increase in PTV of \$60,000 from \$550,000 to \$610,000.

The 25% base tax is now \$152,500 instead of \$137,500. And with PTV per barrel now \$61, the progressivity rate is \$61 minus \$30, or \$31, times four tenths of a percentage point per dollar, or 12.4 percent. Twelve-point-four percent of \$610,000 is \$75,640, and the total tax is \$228,140 instead of \$192,500. This is an increase of \$35,640.

I have highlighted this change in yellow and recorded it in the upper right corner of the slide in order to keep it on screen so we can remember what it was, because in this scenario the producer next asks what the tax change is separately for each of these improvements to the investment. This next slide shows the change resulting only from the extra dollar in the West Coast price.

	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640 All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>	
GVPP	\$850,000		\$860,000	10,000	\$85.00	\$86.00	\$5,740 Price
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>	
PTV	\$550,000		\$560,000	10,000	\$55.00	\$56.00	
25% Base Tax	\$137,500		\$140,000				
Prog'y Rate	10.000%		10.400%				
Prog'y Tax	<u>\$55,000</u>		<u>\$58,240</u>				
Total Tax	\$192,500		\$198,240				
Change in tax	-		\$5,740				

Slide 3 Example – Price change only

The higher price increases the sales proceeds by \$10,000 to \$1,010,000. And as you go down the “As Revised” column you see this \$10,000 flowing down into the \$860,000 GVPP and then into the taxable PTV, raising it to \$560,000. The 25% base tax on \$560,000 is \$140,000. The progressivity rate is \$56 minus \$30, or \$26, times four tenths of a percentage point per dollar, which is 10.4 percent. Ten-point-four percent of \$560,000 is \$58,240 and the total tax is \$198,240, an increase of \$5,740 from the base case. Again, I have recorded this at the right side of the table so we can remember what it is without having to flip back and forth between slides.

The next slide shows the change in tax from the \$20,000 savings in transportation costs.

	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640 All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00	\$5,740 Price
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>	\$11,560 Transpo.
PTV	\$550,000		\$570,000	10,000	\$55.00	\$57.00	
25% Base Tax	\$137,500		\$142,500				
Prog'y Rate	10.000%		10.800%				
Prog'y Tax	<u>\$55,000</u>		<u>\$61,560</u>				
Total Tax	\$192,500		\$204,060				
Change in tax	-		\$11,560				

Slide 4. Example – Transportation cost savings

The \$20,000 again flows straight down into the taxable PTV, increasing it from \$550,000 to \$570,000. The progressivity rate is now \$57 dollars minus \$30, or \$27, times four tenths of a percentage point per dollar or 10.8 percent. That plus the 25% base rate on \$570,000 of PTV yields a total tax of \$204,060, an increase of \$11,560 from the base case. This, too, I have

recorded on the right side of the table.

Finally, this next slide shows the effect of saving \$30,000 in field expense. The PTV increases by \$30,000 to \$580,000, the progressivity rate is 11.2 percent. The base tax and progressivity add up to \$209,960 — an increase of \$17,460 from the base case.

	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640	All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>		
GVPP	\$850,000		\$850,000	10,000	\$85.00	\$85.00	\$5,740	Price
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560	Transpo.
PTV	\$550,000		\$580,000	10,000	\$55.00	\$58.00	<u>\$17,460</u>	Lease Exp.
25% Base Tax	\$137,500		\$145,000				\$34,760	
Prog'y Rate	10.000%		11.200%					
Prog'y Tax	<u>\$55,000</u>		<u>\$64,960</u>					
Total Tax	\$192,500		\$209,960					
Change in tax	-		\$17,460					

Slide 5. Whole is greater than the sum of its parts

And here at last, this slide shows what it is that you probably have not seen before. The sum for the three changes separately is \$34,760, which is in bold font to make it easier to spot. This is less than the \$35,640 change in tax when all three are factored in at once (also in bold font). In other words, with progressivity, the whole is greater than the sum of its parts.

And that's not all. The amount of tax that is calculated for each individual part changes, depending on what order you look at them. Here's a slide that looks at the \$20,000 savings in transportation cost and the \$30,000 reduction in field expense together.

	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$11,560	Transpo. Only
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	\$17,460	Field Exp. Only
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00		
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560	Transpo. 1st
PTV	\$550,000		\$600,000	10,000	\$55.00	\$60.00	<u>\$17,940</u>	Field Exp.2nd
25% Base Tax	\$137,500		\$150,000				\$29,500	
Prog'y Rate	10.000%		12.000%					
Prog'y Tax	<u>\$55,000</u>		<u>\$72,000</u>				\$12,040	Transpo. 2nd
Total Tax	\$192,500		\$222,000				<u>\$17,460</u>	Field Exp.1st
Change in tax	-		\$29,500				\$29,500	

Slide 6. ACES's continuously changing tax effect

The two cost reductions together increase PTV by \$50,000, to \$600,000. The base tax on that is \$150,000. Progressivity for \$60 of PTV per barrel is \$60 minus \$30, or \$30, times four tenths of a percentage point per dollar, or 12 percent, times \$600,000, which is \$72,000. The total tax change from the two is \$29,500. From the previous cases where we considered each cost reduction separately, the tax increase with transportation only was \$11,560 and for field

expense only was \$17,640, and these appear in the upper right of the slide.

If we look at transportation first, it is equivalent to looking at it standing alone, and we have already calculated what that is — \$11,560. So \$11,560 of the combined \$29,500 tax increase is from the change in transportation cost, and the rest — \$17,940 — is for the change in field expense. But this means the field expense is almost \$500 greater than what it is when it's standing alone. And if you reverse the order, then the field-expense tax increase is the same as when it stands alone, but now the tax increase for the transportation savings is different — \$12,040 instead of the \$11,560 when it stands alone or is taken first.

What we have done here on this sixth slide is to look at the pair of cost savings for downstream transportation and upstream lease expenditures, and we've looked at that pair first, ahead of the change in market price. If we go back to the previous slide, we see that if we take transportation first and subtract its \$5,740 from the total \$35,640 tax effect for all three, then that leaves a different number — \$29,900 — for this pair of changes instead of the \$29,500 we have here on slide six when we calculate that pair back first.

There is nothing special about this particular pair of changes that creates this difference. There would be a similar difference if we pair price with transportation or price with lease expenditures. With either one, we'd get one set of tax effects for this pair if we calculate them first, and a different set of tax effects if we calculate the effect of the unpaired change first. And, as here, within each pair, there is a different cost for each change in that pairing depending on whether its effect is calculated first or the other's effect is first.

These examples involve a triplet of categories of change that could be made to improve the economics of the project: an increase in price, a reduction in transportation costs to market, and greater efficiency in field operations. But I have simplified these examples by using lease expenditures generically as a single cost category. In the real world a would-be investor would look at capital expenditures separately from operating costs because the timing for when the two kinds of cost are incurred is different and — especially important in the context of analyzing tax effects — the capex generates a 20% Qualified Capital Expenditure tax credit in addition to changing the PTV and the progressivity rate. So there are really four categories of change to look at: changes in sales price, changes in transportation costs, changes in operating expense, and changes in capital expenditures.

For each one of these four categories, its respective tax effect can be calculated separately from the other three, either ahead of them or after them. And each such triplet of changes has the same analysis and the same variations in tax effect for individual changes that we have seen in the entire analysis that we have just gone through in this and the four earlier slides — namely, the tax effect for the entire triplet being greater than the sum of the effects for the individual categories in it; the different amount for the unpaired category in each triplet relative to the pair of other categories, depending on whether the effect of the pair is calculated first or second; and within each such pair, the different amount depending on which category in that pair is calculated first. Each of these numerous variations and combinations will divide the \$35,640 total tax effect up into a different set of amounts calculated for the four categories. Yet even with all those sets of calculated amounts for the categories, none of those sets will add up to the tax effect for all the changes taken together as a whole.

And all this complexity doesn't begin to reflect the likelihood that there may well be several different changes that could be made within one or more of these four basic cost categories.

These bizarre effects are not mere abstract curiosities. If you are an investor and you have a variety of ways to try to improve the performance of an investment, these effects from progressivity mean there is no single correct answer about how much each one changes the tax and improves the investment. The more ways you have to improve the investment, the more the change in tax for each one depends on where you put it in the sequence of calculating the changes for all of the opportunities. This is because each opportunity in that sequence not only increases the PTV, but it also increases the progressivity rate applicable to the base case PTV plus all the PTV that has been added by the prior opportunities in the sequence.

Interestingly, the Department of Revenue has exactly the same problem when it audits a taxpayer and makes multiple changes to figures reported on the tax return and increases the amount of tax. The auditor can quantify the whole tax increase from all the changes, but he or she cannot make a definitively correct determination of the amount of any one of those changes. A taxpayer might have an interesting time in an appeal having an auditor admit, issue by issue, that there is no correct amount for each one.

There is a second unintended consequence of progressivity that is also important. I call it a tax on price volatility because it increases the tax when prices change during a tax year even though the total PTV is exactly the same as if the prices had stayed constant at the average price for the year.

	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)
Jan	\$61.25	2.00	\$122.50	12.50%	\$15.31
Feb	61.25	2.00	122.50	12.50%	15.31
Mar	61.25	2.00	122.50	12.50%	15.31
Apr	61.25	2.00	122.50	12.50%	15.31
May	61.25	2.00	122.50	12.50%	15.31
Jun	61.25	2.00	122.50	12.50%	15.31
Jul	61.25	2.00	122.50	12.50%	15.31
Aug	61.25	2.00	122.50	12.50%	15.31
Sep	61.25	2.00	122.50	12.50%	15.31
Oct	61.25	2.00	122.50	12.50%	15.31
Nov	61.25	2.00	122.50	12.50%	15.31
<u>Dec</u>	<u>61.25</u>	<u>2.00</u>	<u>122.50</u>	<u>12.50%</u>	<u>15.31</u>
Full Year	\$61.25	24.00	\$1,470.00		\$183.75

Slide 7. Flat price scenario

On this slide we see such a "flat price" scenario. To fit conveniently within the space available in a slide, the table omits columns for West Coast prices, transportation costs and field expenses, and starts instead with the PTV that is calculated from them. Here the PTV is \$61.25 per barrel, and with 2 million barrels of production a month, the amount of the taxable PTV is \$122.5 million a month.

Progressivity starts when the PTV per barrel exceeds \$30, and it reaches 25% at a PTV

per barrel of \$92.50. I have chosen \$61.25 as the PTV per barrel in this base case because it is half way between \$30 and \$92.50. The progressivity rate at this price is \$61.25 minus \$30, or \$31.25, times four tenths of a percentage point per dollar, or 12.5 percent. This also is half way between the zero rate at \$30 and the 25% rate at \$92.50. As you can see, each month the PTV is \$122.5 million, the progressivity rate is always 12.5%, and the progressivity tax is exactly the same for each month as \$15.31 million. Total progressivity for the year is \$183.75 million.

	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)
Jan	\$61.25	2.00	\$122.5	12.50%	\$15.31	\$30.00	2.00	60.0	0.00%	-
Feb	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Mar	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Apr	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	\$46.25
May	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jun	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jul	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Aug	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Sep	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Oct	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Nov	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Dec	<u>61.25</u>	<u>2.00</u>	<u>\$122.5</u>	<u>12.50%</u>	<u>15.31</u>	<u>30.00</u>	<u>2.00</u>	<u>60.0</u>	<u>0.00%</u>	-
Full Year	\$61.25	24.00	\$1,470.0		\$183.75	\$61.25	24.00	1,470.0		\$277.50

Slide 8. Progressivity increases taxes with fluctuating price even when the economics don't change

In this next slide the left half is exactly the same as the previous one with the flat-price scenario. The right half of the table shows what happens when there are six months in the year when the PTV per barrel is \$30 and six when it is \$92.50. In this case the first three months and the last three have the \$30 PTV per barrel, and the middle six from April through September have the \$92.50. This price profile resembles what actually happened with West Coast prices for North Slope oil during 2008, when they peaked at the all-time record of \$144.59 a barrel on July 3rd.

For the six months when the PTV per barrel is \$30, the progressivity tax rate is zero because \$30 of PTV per barrel minus the \$30 threshold for progressivity is zero. So, as you can see, there is no progressivity tax for the first three months of the year and the last three. In the middle six, the PTV per barrel is \$92.50. That is \$62.50 higher than the \$30 threshold, so the progressivity rate is four tenths of a percentage point times 62.50, or 25.00 percent. At \$92.50 a barrel, the progressivity tax on two million barrels a month is \$46.25 million, so the total progressivity tax for the six non-zero months is \$277.5 million.

The progressivity tax under the changing-price scenario is 51% higher than the \$183.75 million of progressivity for the flat-rate scenario.

This tax increase is entirely the result of the fact that prices changed during the year instead of being flat. You can see this for yourselves. The total PTV for the year in the right-hand column is 1,470 millions of dollars, or \$1.47 billion — exactly the same as in the flat-price

scenario on the left. Total production for the year is exactly the same — 24 million barrels. Dividing \$1.47 billion of PTV by 24 million barrels equals \$61.25 per barrel, exactly the same. But progressivity is 51% higher.

And if you look at the monthly calculations in the changing-price scenario, you can see that the monthly progressivity tax will be exactly the same for each of the \$30 months no matter what order you put those months in. The same is true for the \$92.50 months. So this phenomenon is different from what I showed you earlier about the whole being greater than the sum of its parts, because here there are no changes in the actual progressivity calculation for a \$30 month or a \$92.50 one.

The bottom line here is this. The year under the changing-price scenario is just as profitable as the flat-price one, and for the same amount of production. The tax base to which progressivity applies is exactly the same for the year. Yet the tax is 51% higher when prices change during the year.

Now, I have chosen these PTV-per-barrel figures so they would show the greatest amount of tax increase resulting from prices that are not flat all year long. I did this because, if I showed you an example with a smaller effect, someone would surely ask me what the maximum effect could be. My example gives you that answer at the same time it explains the phenomenon.

Those of you who were here in the Legislature in 2009 may recall the surprise of the Department of Revenue when the actual ACES tax collected during its first full year of operation — the 2008 calendar year — came in about half a billion dollars higher than the Department had forecasted. This tells you why: 2008 was a very volatile year for prices. While that volatility did not generate the maximum 51% increase that my example illustrates, it did produce a very substantial increase in progressivity tax — on the order of half a billion dollars — from the mere fact that prices fluctuated during 2008, instead of being flat at the volume-weighted average price for the year.

So, to summarize: Progressivity has two major unintended consequences. First, when you are analyzing combinations of steps to take to improve an investment opportunity, the whole is greater than the sum of its parts. Second, if you do not take into account the effect from price volatility during each year in an investment's life, the progressivity could turn out to be 50% higher than what you have estimated. Both of these unintended effects promise to increase the risks and reduce the competitiveness of an Alaskan investment relative to a comparable one elsewhere.

These negatives of progressivity complement what AOGA told you during its testimony last Monday. Without repeating that testimony here, I will only list AOGA's main points. One, progressivity sacrifices the one advantage Alaska has from its economic remoteness — namely, the greater improvement in financial performance for investments here if prices turn out better than projected — because progressivity taxes away more and more of that improvement the better it turns out to be. And two, progressivity makes the tax extraordinarily complex and inconsistent to compute, and to analyze.

For these reasons BP fully endorses the proposed repeal of progressivity that House Bill

72 proposes.

Let me now turn to the second main feature in this Bill — the changes it proposes to the present system of tax credits, and in particular to the sunset of the credit for “qualified capital expenditures” or “QCE” at the end of this calendar year.

The first, and probably most important observation I can offer about tax credits in general is they would not be so significant for the economics of oil and gas production here if the production tax were not so high.

Second, the QCE tax credit depends solely on how much a company invests for oil and gas exploration, development and production in Alaska. Period. If you want to address the North Slope decline curve, there have to be investments here leading to more production — not just by finding and developing new fields and new reservoirs, but also by getting more recovery out of fields already in production. The QCE tax credit is a direct incentive for making these investments. And it costs the State nothing unless there are investments: if investment is zero, then 20% of zero is zero. The QCE tax credit arises only when it succeeds, and costs nothing if it doesn't.

The QCE tax credit is not affected by oil prices, the costs of transporting oil and gas to market, nor the operating costs of the field. Consequently its value to a business like BP's is the same for a given amount of QCE expenditure, regardless of the price and the transportation and field operating cost scenarios that the business estimates in its investment decisions. And it is the same regardless of how prices and those other costs actually turn out. Progressivity, on the other hand, is dependent on prices and costs in a twofold way: once in determining the amount of PTV that is subject to tax, and again in calculating the tax rate that progressivity will apply to that PTV.

Thus, the point where the cost of losing the QCE credit year begins to outweigh the benefit from repealing progressivity depends both on the price of oil and, for each individual producer, on that producer's own unique portion of the lease expenditures for the North Slope. For BP's own business and expenditures, this crossover comes at a higher price level — in the mid to upper 90s — than that which Econ One and others are presenting for North Slope producers as a whole. So the improvement to our investment economics from the repeal of progressivity stands to be substantially undone by the sunset of the QCE tax credit. Since I am a tax man who is here to testify about this tax, I would ask, please, for your patience for just a few minutes if you have questions regarding this point, so I can quickly finish up and Mr. Bilbao can testify.

The third major feature in HB 72 is its proposed “gross revenue exclusion” or “GRE” which is something new. It would exclude from the taxable PTV (production tax value) a percentage of the gross value at the point of production for additional or new volumes of oil or gas being produced. This concept could have significant potential, and indeed it may prove very valuable for explorers and others who can bring new fields and reservoirs into production.

Unfortunately, the proposed GRE aims away from the significant opportunities for new production that BP has identified for its business. HB 72 would allow a GRE only for produc-

tion “from a lease or property that does not contain land that was within a unit on January 1, 2003[,]” or if it does have land that was in a unit before 2003, “the oil or gas is produced from a participating area established after ... 2011 [that] does not contain a reservoir that had previously been in a participating area established before ... 2012.”

BP’s business centers primarily around units that were established before 2003 — the Prudhoe Bay Unit, Kuparuk River Unit, Duck Island Unit and Milne Point Unit. These units are fully explored, and the likelihood is small that any significant new participating area will be established in them that “does not contain a reservoir that had previously been in a participating area established before ... 2012.” So these units are unlikely to receive any GRE, as the Bill reads now.

The present focus of the proposed GRE is misdirected. Econ One a week ago told you that an estimated 29.1 billion barrels of oil and barrel-equivalents of gas on the North Slope and offshore in the OCS is “Economically Recoverable @ \$90/bbl”. But, as AOGA pointed out in its testimony on Monday, only 10% of that resource is in an area that Alaska has any direct economic stake in and control over — the central North Slope. Of the 3 billion barrels there that Econ One identified, AOGA’s testimony (in which we and the other members of AOGA all concurred) estimated that “2.5 billion barrels or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production” that have little or no chance of getting any GRE under the Bill.

If you’re going to hunt for eggs, you have to look where the hens nest. The same is true for oil. If you are going to provide an incentive to increase production rates and ultimate recovery, offer it where the oil is.

There are several problems with the present ACES law that HB 72 does not address, and I will quickly brief you about them.

The first is the disallowance under AS 43.55.165(e)(19) of “costs incurred for repair, replacement, or deferred maintenance” of production facilities “in response to a failure, problem, or event that results in the unscheduled interruption ... or reduction in the rate of ... production ... or in response to ... an unpermitted release of a hazardous substance or [natural] gas[.]” This was enacted in 2007 in response to the partial shutdown of Prudhoe Bay in 2006 after two corrosion-caused leaks were discovered. BP is not seeking change to the substance of the disallowance itself, but we think the statutory language should be improved to establish clarity about its applicability.

There are minor hiccups in production operations almost every day in fields around the world, and Alaska’s fields are no exception. The present statute sets no standard of materiality for an “unscheduled interruption .. or reduction” in production. If production at a facility is “interrupted” for five minutes because of a temporary hiccup in operations, does that cause a disallowed expense? If production is “reduced” by five barrels a day for a field producing over 400,000 barrels daily, does that cause a disallowed expense? If production is interrupted for a material period of time, but ultimately it turns out to cost only \$10 to respond to it, is it worthwhile to identify and quantify this \$10 so it can be disallowed? There is no answer to these and similar questions in the statute, and the Department of Revenue has not adopted regulations that

answer them.

We are not asking you to try to write the answers to these questions in the statute, although you certainly could if you want to do all that work. But we suggest, instead, that you expressly give the Department of Revenue not only the authority, but the duty, to adopt regulations that set reasonable thresholds for materiality about how long an "interruption" has to last, about how large a "reduction" in production has to be, about how much an unauthorized release has to be or in what circumstances must it occur, and about how much the cost "incurred ... in response to" such situations has to be, in order to trigger the disallowance.

As you know, I worked in the Department of Revenue some 30-odd years ago, and if I had to administer this statute in light of the circumstances and controversy that led to its enactment, I would be reluctant to adopt regulations on my own initiative to establish such thresholds unless I had some kind of go-ahead or permission from the Legislature. Perhaps the Department is waiting for such a sign from you.

The second unaddressed problem comes from the changes that ACES made to AS 43.55.150, the statute that determines the gross value at the point of production on the basis of destination prices or values minus the costs of transporting the oil or gas to those destinations from the point of production in the field. As amended, the actual cost that a producer pays to a regulated pipeline carrier to ship the producer's oil could be set aside if the producer and carrier are "affiliated." The Department has adopted regulations calling for "cost-based" tariff calculations in lieu of the actual regulated tariffs that are paid.

But under those regulations these calculations of the "cost-based" tariffs are made by the Department, not the taxpayer, and there is no deadline in the regulations or in AS 43.55.150 for the Department to make its calculations and share the results with the taxpayer. The only deadline is the six-year statute of limitations under AS 43.55.075(a). We concur with AOGA's testimony about the interplay between this six-year statute and interest at 11% APR, compounded quarterly, for any tax underpayment that, in this regulated-pipeline situation, might result from the Department's calculation of a lower tariff than the one allowed by the governmental regulatory agency having jurisdiction over that tariff. Six years at 11% almost doubles-up the amount of a tax increase from such a "cost-based" tariff.

Further, the tax laws of the State are not an appropriate place for Alaska to try to regulate pipeline tariffs. That is a function of the Police Power, and the Regulatory Commission of Alaska has been established as the executive agency to exercise that regulatory power. The Federal Energy Regulatory Commission has similarly been created by Congress to regulate pipeline tariffs for interstate shipments under the Congressional power created by the United States Constitution power to regulate interstate commerce. State tax authorities have no business trying to supplant either of these agencies.

Any further matters regarding HB 72 that we would bring to your attention have already been addressed by AOGA in its testimony to you on Monday.

Thank you for this opportunity to testify to you today.



BP Testimony to House Resources

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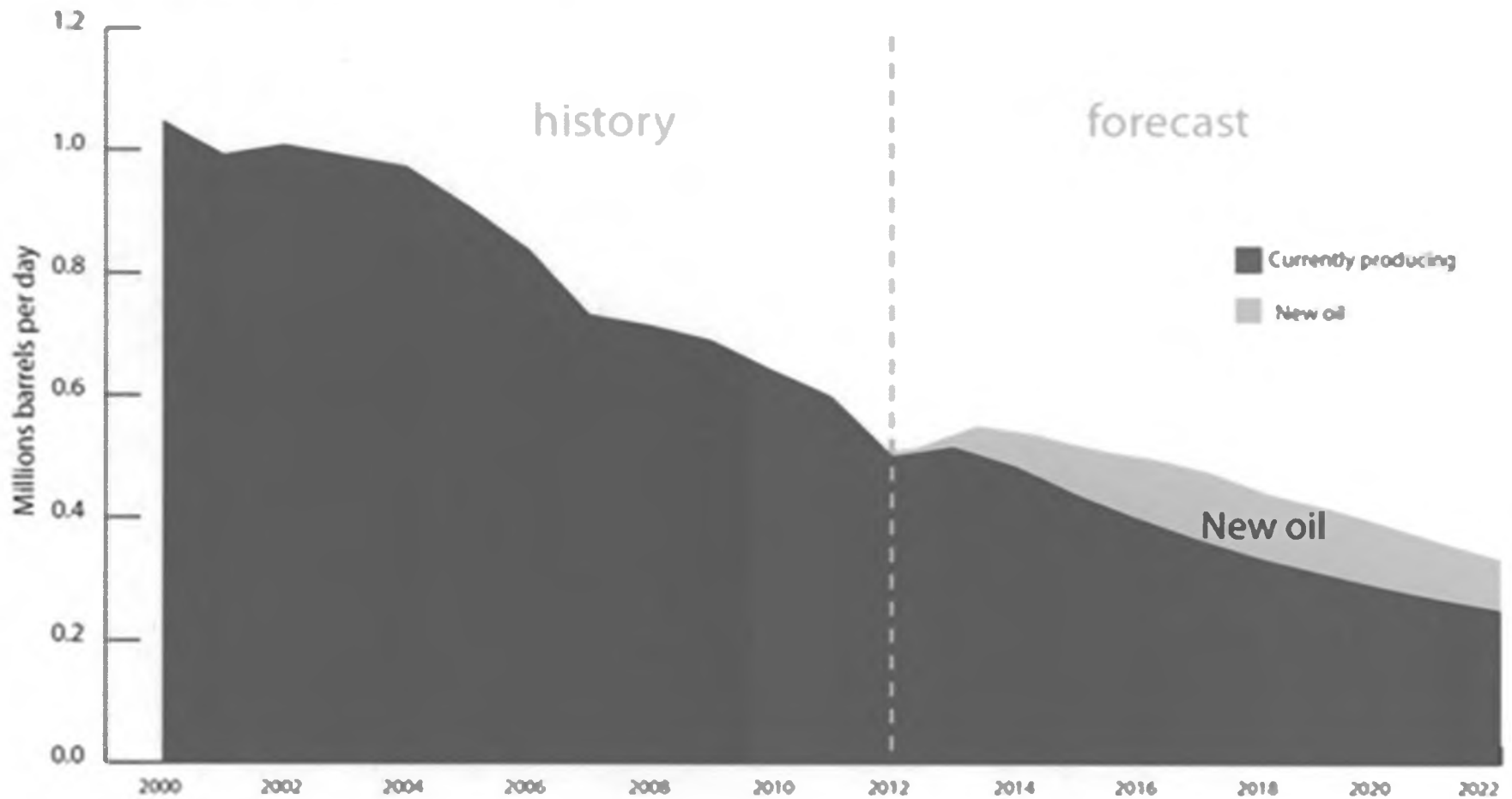
February 20, 2013

Production Decline is Real



Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



How ACES works



	Bbl	\$/bbl
USWC Price \$1,000,000	10,000	\$100.00
Transportation <u>\$150,000</u>	10,000	<u>\$15.00</u>
GVPP \$850,000	10,000	\$85.00
Field Expense <u>\$300,000</u>	10,000	<u>\$30.00</u>
PTV \$550,000	10,000	\$55.00
25% Base Tax \$137,500		
Prog'y Rate 10.000%		
Prog'y Tax <u>\$55,000</u>		
Total Tax \$192,500		

USWC – U.S. West Coast
GVPP – Gross Value at the Point of Production
PTV – Production Tax Value
Prog'y - Progressivity

Example – The three changes together



	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax	
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640	All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>		
GVPP	\$850,000		\$880,000	10,000	\$85.00	\$88.00		
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>		
PTV	\$550,000		\$610,000	10,000	\$55.00	\$61.00		
25% Base Tax	\$137,500		\$152,500					
Prog'y Rate	10.000%		12.400%					
Prog'y Tax	<u>\$55,000</u>		<u>\$75,640</u>					
Total Tax	\$192,500		\$228,140					
Change in tax	-		\$35,640					

USWC – U.S. West Coast
 GVPP – Gross Value at the Point of Production
 PTV – Production Tax Value
 Prog'y - Progressivity

Example – Price change only



	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax	
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640	All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>	\$5,740	Price
GVPP	\$850,000		\$860,000	10,000	\$85.00	\$86.00		
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>		
PTV	\$550,000		\$560,000	10,000	\$55.00	\$56.00		
25% Base Tax	\$137,500		\$140,000					
Prog'y Rate	10.000%		10.400%					
Prog'y Tax	<u>\$55,000</u>		<u>\$58,240</u>					
Total Tax	\$192,500		\$198,240					
Change in tax	-		\$5,740					

USWC – U.S. West Coast
 GVPP – Gross Value at the Point of Production
 PTV – Production Tax Value
 Prog'y - Progressivity

Example – Transportation cost savings



	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640	All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>		
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00	\$5,740	Price
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>	\$11,560	Transpo.
PTV	\$550,000		\$570,000	10,000	\$55.00	\$57.00		
25% Base Tax	\$137,500		\$142,500					
Prog'y Rate	10.000%		10.800%					
Prog'y Tax	<u>\$55,000</u>		<u>\$61,560</u>					
Total Tax	\$192,500		\$204,060					
Change in tax	-		\$11,560					

USWC – U.S. West Coast
 GVPP – Gross Value at the Point of Production
 PTV – Production Tax Value
 Prog'y - Progressivity

Whole is greater than the sum of its parts



	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640 All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>	
GVPP	\$850,000		\$850,000	10,000	\$85.00	\$85.00	\$5,740 Price
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560 Transpo.
PTV	\$550,000		\$580,000	10,000	\$55.00	\$58.00	<u>\$17,460</u> Lease Exp.
25% Base Tax	\$137,500		\$145,000				\$34,760
Prog'y Rate	10.000%		11.200%				
Prog'y Tax	<u>\$55,000</u>		<u>\$64,960</u>				
Total Tax	\$192,500		\$209,960				
Change in tax	-		\$17,460				

USWC – U.S. West Coast
 GVPP – Gross Value at the Point of Production
 PTV – Production Tax Value
 Prog'y - Progressivity

ACES's continuously changing tax effect



	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$11,560 Transpo. Only
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	\$17,460 Field Exp Only
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00	
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560 Transpo. 1st
PTV	\$550,000		\$600,000	10,000	\$55.00	\$60.00	<u>\$17,940</u> Field Exp. 2nd
25% Base Tax	\$137,500		\$150,000				\$29,500
Prog'y Rate	10.000%		12.000%				
Prog'y Tax	<u>\$55,000</u>		<u>\$72,000</u>				\$12,040 Transpo. 2nd
Total Tax	\$192,500		\$222,000				<u>\$17,460</u> Field Exp. 1st
Change in tax	-		\$29,500				\$29,500

USWC – U.S. West Coast
 GVPP – Gross Value at the Point of Production
 PTV – Production Tax Value
 Prog'y - Progressivity

Flat price scenario



	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)
Jan	\$61.25	2.00	\$122.5	12.50%	\$15.31
Feb	61.25	2.00	\$122.5	12.50%	15.31
Mar	61.25	2.00	\$122.5	12.50%	15.31
Apr	61.25	2.00	\$122.5	12.50%	15.31
May	61.25	2.00	\$122.5	12.50%	15.31
Jun	61.25	2.00	\$122.5	12.50%	15.31
Jul	61.25	2.00	\$122.5	12.50%	15.31
Aug	61.25	2.00	\$122.5	12.50%	15.31
Sep	61.25	2.00	\$122.5	12.50%	15.31
Oct	61.25	2.00	\$122.5	12.50%	15.31
Nov	61.25	2.00	\$122.5	12.50%	15.31
Dec	<u>61.25</u>	<u>2.00</u>	<u>\$122.5</u>	<u>12.50%</u>	<u>15.31</u>
Full Year	\$61.25	24.00	\$1,470.0		\$183.75

Progressivity increases taxes with fluctuating price even when the economics don't change



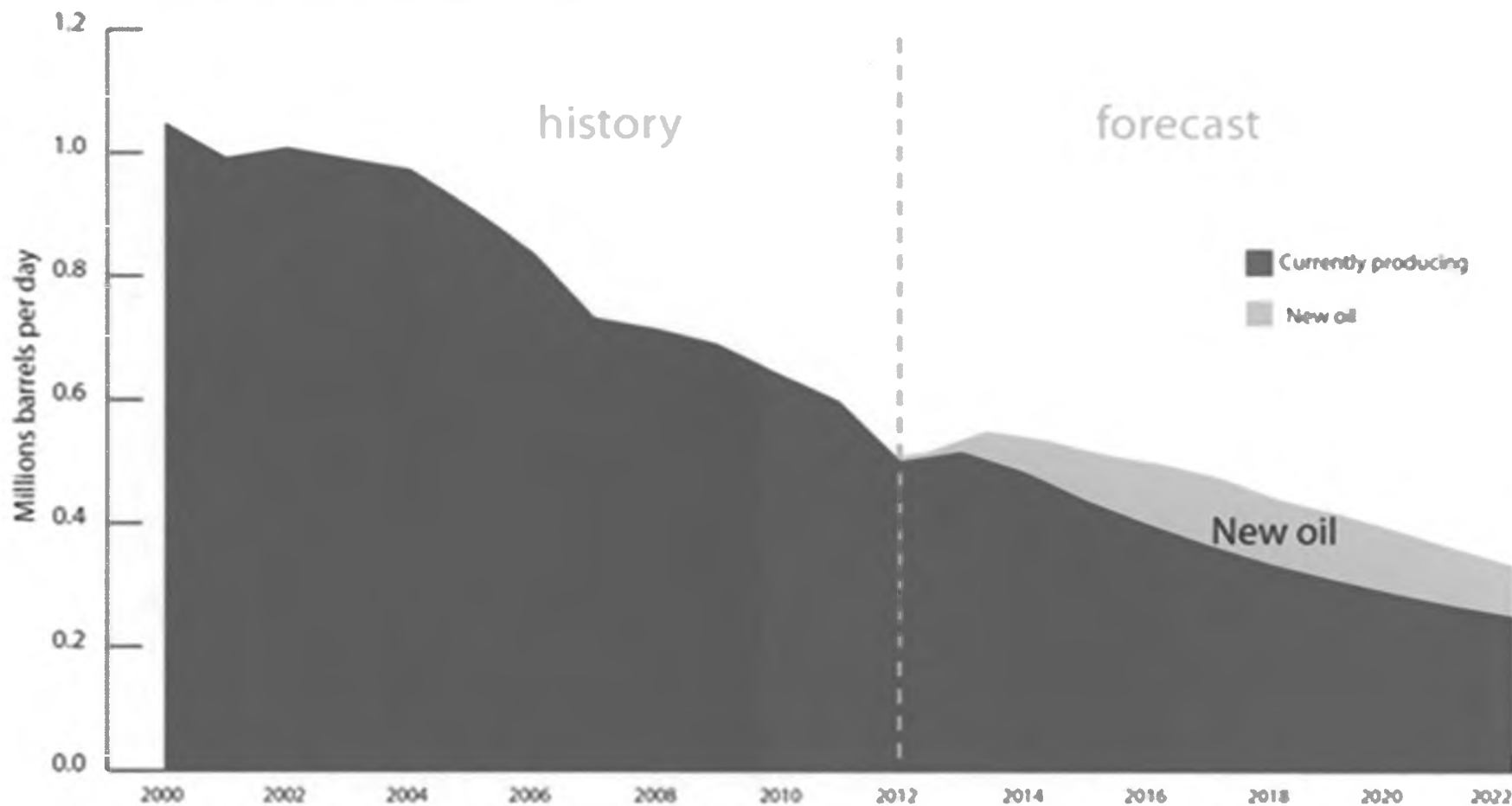
	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)
Jan	\$61.25	2.00	\$122.5	12.50%	\$15.31	\$30.00	2.00	60.0	0.00%	-
Feb	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Mar	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Apr	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	\$46.25
May	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jun	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jul	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Aug	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Sep	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Oct	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Nov	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Dec	<u>61.25</u>	<u>2.00</u>	<u>\$122.5</u>	<u>12.50%</u>	<u>15.31</u>	<u>30.00</u>	<u>2.00</u>	<u>60.0</u>	<u>0.00%</u>	<u>-</u>
Full Year	\$61.25	24.00	\$1,470.0		\$183.75	\$61.25	24.00	1,470.0		\$277.50

Production Decline is Real



Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



TESTIMONY OF EXXONMOBIL
ON ALASKA'S INVESTMENT CLIMATE
TO THE ALASKA HOUSE REOURCES COMMITTEE ON
FEBRUARY 20, 2013

Mister Chairman, members of the Committee:

For the record, my name is Dan Seckers. I am ExxonMobil's Tax Counsel, based in Anchorage. I want to thank the Committee for the opportunity to express ExxonMobil's views on Alaska's current investment climate and the impacts of Alaska's oil and gas production tax or ACES.

Let me begin by underscoring what many of you have likely heard ExxonMobil say throughout the years - that Alaska has been and continues to be an important component of ExxonMobil's world-wide investment portfolio. We have had a presence in Alaska for over 50 years and have been a key player in Alaska's oil industry development. We are the operator of Point Thomson, hold the largest working interest at Prudhoe Bay (36.4%) and are the largest lease holder of discovered Alaska gas resources. We are committed to Alaska and its future and expect to be involved here for many years to come.

Let me also state that ExxonMobil continues to support Governor Parnell's efforts toward substantive reform of ACES. We appreciate his willingness to champion this

difficult issue for the past two years and his committed effort again this legislative session. The need for Alaska to develop a competitive, stable fiscal regime that attracts the levels of investments that Alaska's North Slope requires is one of the most, if not the most, important issues facing the State. We believe the Governor's four core "principles", as emphasized in his State of the State speech that any reform of ACES:

- Be fair to Alaskans
- Encourage new oil production
- Simplify and restore balance to Alaska's fiscal system
- Make Alaska competitive for the long term

can form the foundation of a successful, long-term taxation policy for the State.

The Governor has not been alone in his efforts. Many members of the Legislature have worked hard the past two years to examine and understand the impact of ACES on Alaska's global competitiveness. That hard work has been having a positive effect as it appears legislators and most Alaskans now recognize that Alaska's production tax system is not well designed to tackle the production decline and attracting investments to develop new production.

Consistent with the testimony we have given over the past several years, ExxonMobil believes that the changes made to Alaska's oil and gas production tax since 2005 have had a negative impact on business activity in Alaska and Alaska's overall investment

climate. Fundamentally, the progressivity component of the ACES tax regime, on top of an already high base tax rate, creates a major disincentive to invest in the high-risk, high-cost opportunities available in Alaska. These two features must be addressed for any tax policy to be successful in meeting the State's desired production and long-term revenue goals.

Two aspects of the current tax policy, however, are pro-development. The deduction of operating and capital expenditures before applying the tax rates recognizes the high cost of doing business in Alaska. The further tax credit for capital expenditures rewards those who invest in future production and infrastructure. These are key components of the current ACES whose benefits should be reflected in any revised tax policy the State is considering.

As the Legislature's and State's own consultants have indicated over the previous two legislative sessions and during recent hearings in your Committee and other committees, Alaska has one of the highest and most punitive tax systems in the world. The high progressivity is directly impeding Alaska's global competitiveness. To significantly grow state revenues, secure jobs and stem the production decline, it is essential that Alaska's tax structure encourages long-term development of all of Alaska's resource potential.

As the Governor has stated, Alaska's fiscal regime must be competitive and durable for the long term. ExxonMobil values a predictable fiscal environment in which to make

long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view stability of the Alaskan fiscal environment, which in turn impacts how we evaluate the risk basis of future investment decisions. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the long lead time required to recoup that investment, stable fiscal terms are key to any investment decision.

To date, Alaska has produced more than 16 billion barrels of oil from the North Slope, and according to the Department of Natural Resources there are over 5 billion barrels of known resources remaining. These undeveloped resources represent a substantial opportunity, but their development is at risk under the current ACES tax system. Oil production today is less than one-third of the peak oil production of more than 2 million barrels per day in 1988, and annual production continues to decline.

You have heard about the continued and alarming decline of North Slope oil production from the Department of Revenue, State consultants and individuals that have testified earlier. But it is important to reemphasize that industry currently invests more than \$1 billion per year just to maintain current North Slope oil production decline at six to seven percent. The substantial majority of that annual investment is in the legacy fields – Prudhoe Bay and Kuparuk. Absent that continued investment, the annual production decline would likely be in the range of 12 to 15 percent annually. Without meaningful

tax reform that includes Alaska's legacy fields, Alaska can expect production declines to continue.

Production from the legacy fields not only provides the majority of the State's revenues, it sustains the current North Slope infrastructure and the operation of TAPS, which are critical to enabling new production. The infrastructure from these legacy fields has been leveraged historically for satellite developments, such as Pt. McIntyre, Orion, Borealis and other non-legacy fields to economically process and transport their oil from the North Slope to refinery destinations. If the large legacy fields did not exist, it is unlikely any of these other developments would have been economic.

Without healthy legacy fields, the prospects of any future new fields or developments become even more economically challenged and the probabilities of Alaska reaching its desired goal of long-term sustained production levels more difficult.

Encouraging increasing investment to keep these key fields healthy is therefore at least as important as encouraging investment in exploration and development of new fields. For any tax reform to contribute to the Governor's stated objectives for Alaska's long-term production, it must also be applicable to the legacy fields where the State's near and long term economic future rests.

Considerable attention has been placed on making Alaska more competitive relative to other regimes. While that focus is extremely important, it is only part of the overall

picture. Benchmarking government take against other producing areas is a useful tool for gauging basic competitiveness, but does not provide the full picture of investment health. As the Department of Revenue and various consultants have testified, spending on the North Slope has remained relatively flat since the enactment of ACES. But what needs to be clarified is that the majority of that spending has been for maintenance and upkeep to sustain existing operations, not for new development. Under ACES, the State has not attracted the new investment needed to increase production.

Complicating Alaska's production decline is its high exploration, development and production costs. Alaska is one of the most expensive places in the world to develop and produce oil and gas. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- Environmental challenges
- Remote location of the resource and distance to market
- Restriction of exploration opportunities

These are complications that Alaska faces that most other areas do not; but they do factor into the economic decisions being taken by investors and need to be considered when assessing what is Alaska's optimum production tax regime.

ExxonMobil is willing to accept the risks of long-term, capital intensive investments when a stable tax structure allows and encourages investment and ensures a corresponding opportunity for upside potential. Upside factors such as increased production and higher prices can compensate for risks taken by investors, because companies are certainly negatively impacted when lower than expected production or prices occur. The high marginal tax rates under the progressive structure of ACES take away the upside potential and reduce the attractiveness of those capital intensive investments, compared to other locations where the upside benefit can be retained.

Alaska faces significant challenges. As I mentioned, costs are high and production continues to decline. We all need to work together to achieve the right balance – as Governor Parnell stated - a balance that maximizes the benefit to Alaskans while encouraging industry to continue to invest in Alaska.

ExxonMobil recognizes the difficulty you face as policy makers in tackling the State's tax policy while protecting current revenue streams and addressing the revenue problems just over the horizon due to the production decline. We appreciate how hard and difficult that task is.

Today's production rates are the product of government policies, technical work, and investment decisions that in many cases were made decades ago. Increasing production rates in the decades to come will result from sound policies, decisions, and commitments that are made by this Legislature. As policy makers, you will need to

decide whether Alaska's current high production tax regime is the right course for Alaska or if another course is necessary to harness the remaining resource potential, given the high costs and steadily declining oil production rates we as Alaskans face.

It is important to recognize that any decision made by this Legislature impacts much more than tax revenue in the near term and in the future. Decisions made today will influence the life of production in existing fields and investments required to develop Alaska's remaining resource potential. This will in turn impact jobs for Alaskan workers, revenue for many Alaska businesses, infrastructure that benefits Alaskan communities, and set the stage for the future of Alaska for many generations to come.

As I indicated, ExxonMobil fully supports the Governor's and this Legislature's efforts to reform ACES and to make Alaska's investment climate globally competitive. To maximize its resource potential while receiving a fair share of the resource revenues, Alaska needs a long-term resource development policy that will encourage increasing investment. The reform of ACES needs to result in a competitive, stable and predictable fiscal environment that will encourage investment at all price levels and incentivize the development of remaining resources that are economically challenged, including both new fields and resource development opportunities in existing fields. ExxonMobil believes the key focus of the reform needs to create a balanced program using a combination of changes to progressivity, the base tax rate and capital expenditure tax credits to provide a competitive balance of government take across all price bands.

Let me conclude by reiterating that ExxonMobil is committed to Alaska and to pursuing competitive investment opportunities here in the future. Unfortunately, the resource and cost structure in Alaska is becoming increasingly challenging. It is ExxonMobil's firm belief that passage of meaningful changes to ACES this year will support additional investments in Alaska that will lead to greater development and production as well as economic opportunities for Alaskans.

ExxonMobil looks forward to working with the Administration, the Legislature, industry and the people of Alaska in the pursuit and development of Alaska's oil and gas resources.

Thank you again Mister Chairman for the opportunity to present these written comments to you and your Committee.



THE STATE
of **ALASKA**
GOVERNOR SEAN PARNELL

Department of Revenue

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Bryan Butcher, Commissioner

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February 21, 2013

The Honorable Eric Feige and the Honorable Dan Saddler
Alaska State Representatives
Co-Chairs, House Resources Committee
State Capitol Room 126 and 104
Juneau, AK 99801

Dear Co-Chairs Feige and Saddler:

The purpose of this letter is to provide you with a response to questions to the Department of Revenue and Econ One, during their presentations to the House Resources Committee on February 11 and 13, 2013. Please see questions in italics and our responses immediately below the questions.

- 1. Is governor committed to \$60 million / year community revenue sharing even if the state is in deficit?*

This question is best answered by the Governor's office or the Office of Management and Budget.

- 2. Provide information on the detail with which DOR tracks actual activity performed in relation to credits. Is it possible for companies to spend money and claim credits in advance of actual work or equipment? That is, qualified capital expenditure credits are allowed at the time the expenditure is made and not at the time work is done. Is DOR tracking the "frontloading issue?"*

Capital expenditures qualify for the Qualified Capital Expenditure (QCE) credit when the expenditure is made. However, our audit staff are not aware of any significant "frontloading of capital expenditures," i.e. paying money up front for capital expenditures before work is done. Conversely, general accepted accounting principles allow for the recognition of costs being incurred for work done prior to actual payment for the activity. In accrual basis accounting, a company recognizes the fact that a capital asset has been incurred by recording work in progress accruals and thus charging capital accounts prior to the actual money for the work being paid. There are occasions when companies will order and pay for long lead items such as drill pipe in the instance of an anticipated extensive drilling program, however, in those cases, the cost of the pipe prior to being used in the drilling of wells, is recorded in inventory accounts which at that point do not constitute capital expenditures. The costs are charged out to the various drilling projects, i.e. capital accounts, when the pipe is actually used in the wells, and the cost is transferred from inventory to the project. At that point, the cost would then qualify as capital expenditures eligible for the production tax credit. In the event that a company does pay in advance for work to be done at a future date,

generally accepted accounting principles would dictate that the upfront payment be recognized as a prepaid (a non-capital account) in the accounting records and amortized to either capital or expense when the actual work is done.

DOR's ability to track capital expenditures is limited to the performance of due diligence reviews or audits of supporting documentation submitted with production tax credit applications and review of capital expenditure documentation requested during assessment of tax filings. We have not experienced this frontloading issue, and would not allow this type of activity to be included as expenditures eligible for production tax credits.

3. *Provide information about "sustained production" and whether a company could stop producing, and restart to gain a Gross Revenue Exclusion (GRE) under HB72.*

A company could not stop producing from a currently producing participating area and then restart production to gain a GRE under HB 72, section 24. Section 24 of the bill does not contain any language regarding "sustained production" as necessary to qualify for the GRE. To qualify for the GRE, oil or gas production must qualify under either or both of the following provisions: (1) production from a lease or property that does not contain land that was within a unit on January 1, 2003; or (2) production from a participating area established after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before January 1, 2012. To qualify a participating area must be a new one, and not part of a reservoir previously in production. The 20 percent reduction for the gross value at the point of production only applies for the new unit production or from the new participating areas.

4. *Slide 5-6 of Econ One presentation: provide the portion of each category that would qualify for GRE.*

Slide 5 in Econ One's presentation from February 13, 2013 presents five categories of Alaska North Slope production and resources: "Historical Production," "Conventional Resources – Discovered," "Conventional Resources – Undiscovered," "ANWR," and "Unconventional Resources." The category "Historical Production" would not be eligible for the GRE. "Conventional Resources-Discovered" would include some oil that may be eligible for the GRE, and some that would not be eligible, depending on the location of the oil. "Conventional-Undiscovered," "ANWR," and "Unconventional Resources" would all be eligible for the GRE.

5. *Slide 8 of Econ One presentation: provide estimated effective tax rate by decade.*

As illustrated in slide 8 of Econ One's presentation to House Resources on February 13, 2013, Alaska's production tax underwent extensive change between the former production tax under the Economic Limit Factor (ELF) and the current production tax under ACES. Under the ELF system, the production tax was paid on the gross value at the point of production (GVPP) as modified by the ELF. As such, minimal information was collected on the expenditures made to find and produce oil.

The effective tax rate during the years in which ELF was in place was therefore, the production tax paid divided by the GVPP.

With the passage of PPT and then ACES, production tax was levied on the net value of oil after the expenditures to find and produce oil were deducted. The effective tax rate under PPT and ACES then, is the production tax paid divided by the net value of production, commonly referred to as the production tax value (PTV).

To give an apples-to-apples comparison, we prepared effective tax rates on the gross value at the point of production. Note that this is a different metric than the effective tax rates on net commonly shown when comparing ACES to other net profits-based alternatives.

Shown below are estimated effective tax rates on gross by decade from start of Alaska North Slope production in FY 1978 through FY 2012. Also provided for context are average daily oil production and average wellhead value. As evidenced in the data, the effective tax rate on gross increased significantly under ACES.

Average Effective Tax Rates on Gross,* by Fiscal Year Decade				
	FY 1978-87	FY 1988-97	FY 1998-2007	FY 2008-12
	ELF tax system	ELF tax system	ELF tax system**	ACES tax system
Average ANS daily production, in MMbbls	1.519	1.707	0.990	0.647
Average tax rate*	12%	14%	10%	26%
Average wellhead value in \$/barrel	\$14.19	\$12.06	\$28.35	\$84.24
Average production tax payment in \$M	\$957	\$907	\$837	\$4,701

*Average tax rate calculated by dividing production tax paid by estimated gross value at point of production, averaged over decade.

**ELF tax system was in place from FY 1998 through FY 2006; PPT was in place in FY 2007

6. *Slide 23 of Econ One presentation: Provide at \$60/bbl.*

Slides from Econ One with the requested information are attached.

7. *Add HB72 comparison on slides 20-23 of the Econ One presentation using \$60 / barrel oil on the low end and \$140 / barrel oil on the high end*

Slides from Econ One with the requested information are attached.

8. *Show the impact on revenue if 50% of oil produced received a GRE under HB72.*

Our Fall 2012 forecast does not anticipate 50% of oil being eligible for the GRE under HB72 in any of the years under our forecast. For purposes of this question, however, we have calculated what the

The Honorable Eric Feige and the Honorable Dan Saddler
February 21, 2013
Page 4

difference in revenue would be if 50% of oil received the GRE in FY 2022 – the last year of our forecast. It should be noted that this is a purely hypothetical exercise.

In FY 2022, we are forecasting total ANS production to be 338.5 thousand barrels per day. Without any changes in production, under HB72, the total production tax revenue would be approximately \$2 billion in FY 2022. If half of the 338.5 thousand barrels per day were subject to the GRE, the impact on production tax revenue would be a reduction of approximately \$300 million. As stated above, this is not a realistic scenario under HB72 and is calculated for illustration only.

I hope you find this information to be useful. Please do not hesitate to contact me if you have further questions.

Sincerely,



Bryan Butcher
Commissioner

Attachments: Revised slides 20-A, 20-B, and 23 from Econ One

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 Government Take Under ACES: Varying Prices

West Coast ANS Price (\$/Bbl)	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00
Royalty Volumes (Bbls)	7,142,857	7,142,857	7,142,857	7,142,857	7,142,857
Wellhead Value (\$/Bbl)	x \$50.00	\$70.00	\$90.00	\$110.00	\$130.00
Royalty Value (\$)	= \$357,142,857	\$500,000,000	\$642,857,143	\$785,714,286	\$928,571,429
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 (\$)	- 100,000,000	430,000,000	960,000,000	1,650,000,000	2,387,500,000
State Income Tax Base (\$)	= \$900,000,000	\$1,570,000,000	\$2,040,000,000	\$2,350,000,000	\$2,612,500,000
State Income Tax Rate (%)	x 6.5%	6.5%	6.5%	6.5%	6.5%
State Income Tax (\$)	= \$58,500,000	\$102,050,000	\$132,600,000	\$152,750,000	\$169,812,500
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 (\$)	- 100,000,000	430,000,000	960,000,000	1,650,000,000	2,387,500,000
State Income Tax (\$)	- 58,500,000	102,050,000	132,600,000	152,750,000	169,812,500
Federal Income Tax Base (\$)	= \$841,500,000	\$1,467,950,000	\$1,907,400,000	\$2,197,250,000	\$2,442,687,500
Federal Income Tax Rate (%)	x 35%	35%	35%	35%	35%
Federal Income Tax (\$)	= \$294,525,000	\$513,782,500	\$667,590,000	\$769,037,500	\$854,940,625
Property Tax (\$1.25 x Total Barrels)	\$71,428,571	\$71,428,571	\$71,428,571	\$71,428,571	\$71,428,571
Production Tax Value (\$)	\$1,000,000,000	\$2,000,000,000	\$3,000,000,000	\$4,000,000,000	\$5,000,000,000
Royalty Value (\$)	- 357,142,857	500,000,000	642,857,143	785,714,286	928,571,429
Property Tax (\$)	- 71,428,571	71,428,571	71,428,571	71,428,571	71,428,571
Divisible Income (\$)	= \$1,428,571,429	\$2,571,428,571	\$3,714,285,714	\$4,857,142,857	\$6,000,000,000
Royalty Value (\$)	\$357,142,857	\$500,000,000	\$642,857,143	\$785,714,286	\$928,571,429
Production Tax (\$)	+ 100,000,000	430,000,000	960,000,000	1,650,000,000	2,387,500,000
State Income Tax (\$)	+ 58,500,000	102,050,000	132,600,000	152,750,000	169,812,500
Federal Income Tax (\$)	+ 294,525,000	513,782,500	667,590,000	769,037,500	854,940,625
Property Tax (\$)	+ 71,428,571	71,428,571	71,428,571	71,428,571	71,428,571
Government Revenues (\$)	= \$881,596,429	\$1,617,261,071	\$2,474,475,714	\$3,428,930,357	\$4,412,253,125
Government Take (%)	61.7%	62.9%	66.6%	70.6%	73.5%

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 (\$/Bb -		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%

Linda Hay

From: Linda Hay
nt: Monday, February 25, 2013 9:58 AM
o: HRES Members & Staff
Cc: resourceslaanotice; resourceslaanotice
Subject: FW: HRES 2.22.13
Attachments: HRES HB 72 2.22.13 FollowUp Progressivity Impact on IRR.pdf

With attachment this time.

Linda Hay
House Resources Committee Aide
Representative Eric Feige
House Resources Co-Chair
State Capitol Room 126
907-465-3715 - Direct
907-321-1249 - Cell
[*linda.hay@akleg.gov*](mailto:linda.hay@akleg.gov)

From: Linda Hay
Sent: Monday, February 25, 2013 9:55 AM
To: HRES Members & Staff
Cc: resourceslaanotice; resourceliaisons
Subject: HRES 2.22.13

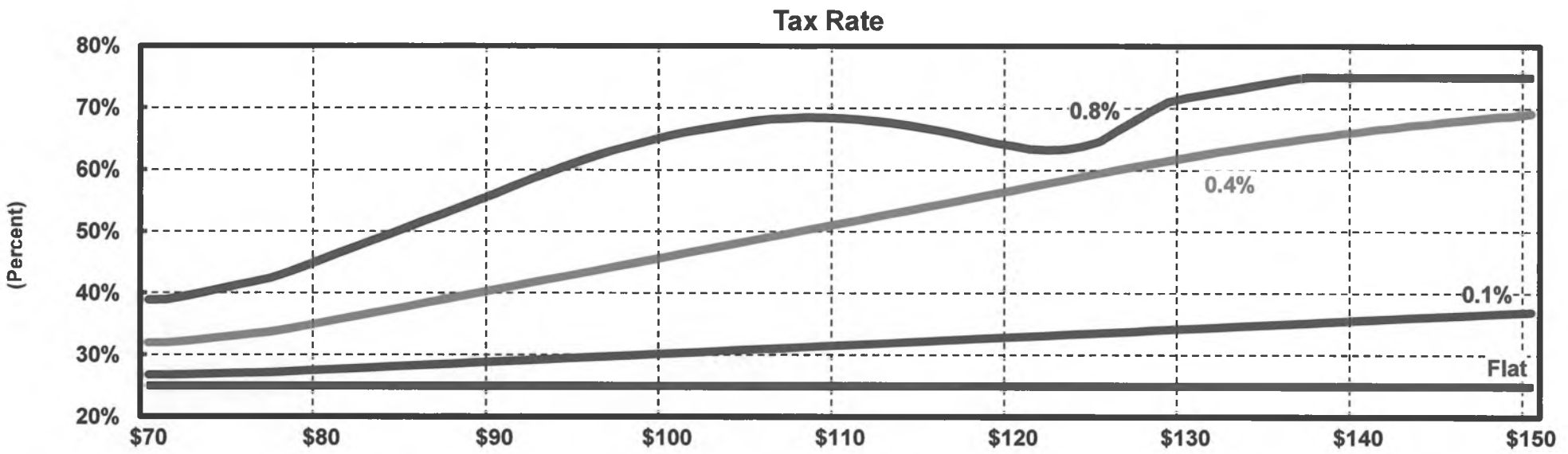
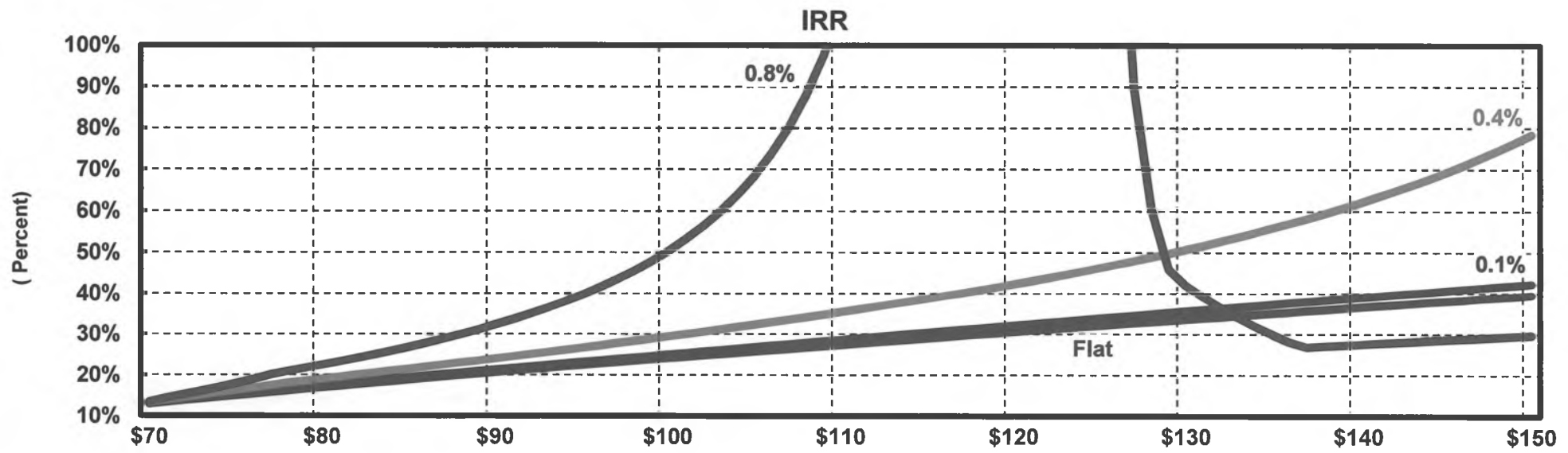
Good Morning - Attached is the follow up slide as promised by Barry Pulliam from EconOne. This is the slide that he showed on 2.22.13.

Regards
lh

Linda Hay
House Resources Committee Aide
Representative Eric Feige
House Resources Co-Chair
State Capitol Room 126
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907-321-1249 - Cell
[*linda.hay@akleg.gov*](mailto:linda.hay@akleg.gov)

Progressivity Impact on IRR and Tax Rate

25% Base Rate, \$30 Net Trigger, 75% Cap, No Credit





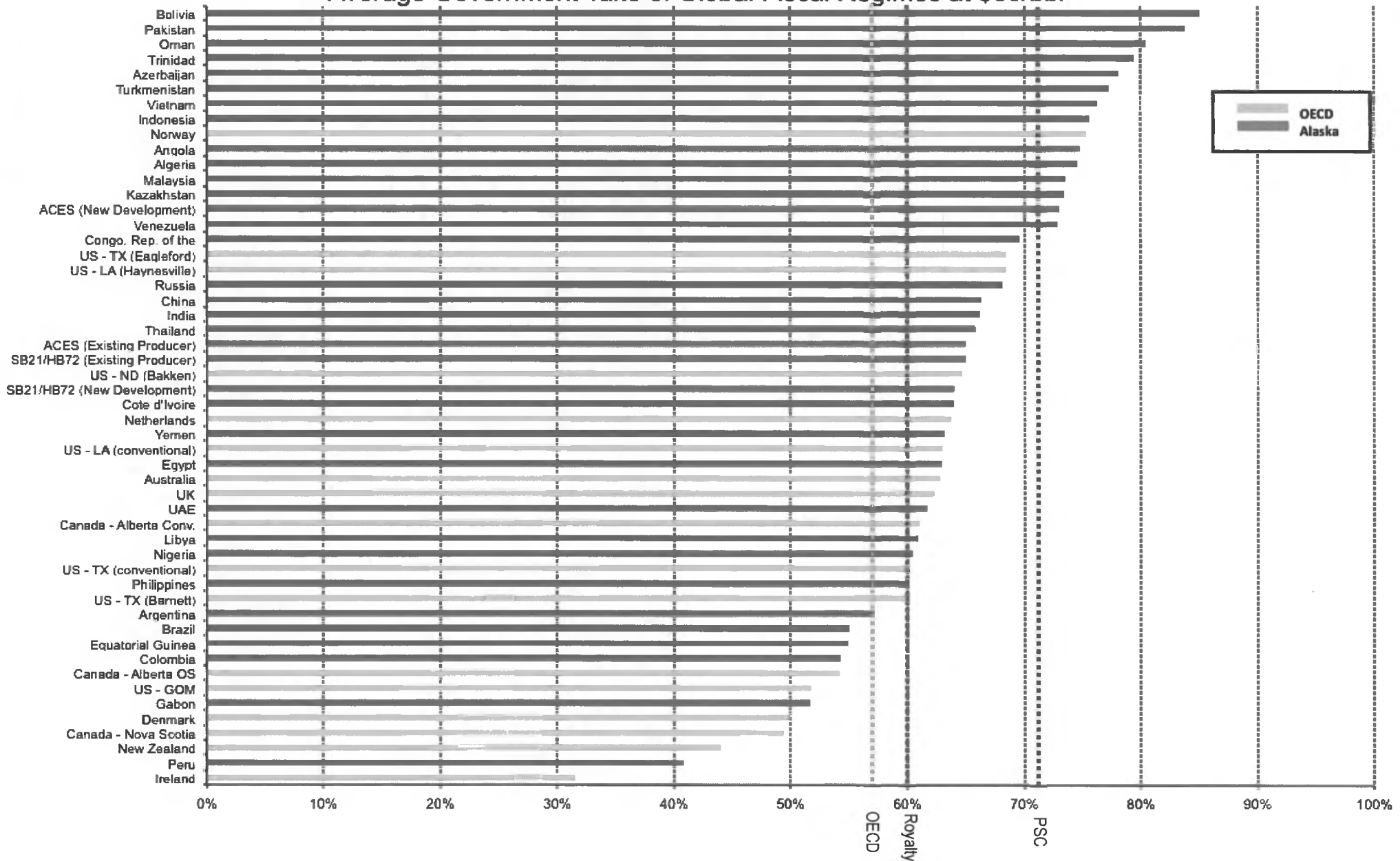
House Resources Committee

Alaska Fiscal System Discussion Slides

February 22 2013
Janak Mayer
Manager, Upstream
PFC Energy

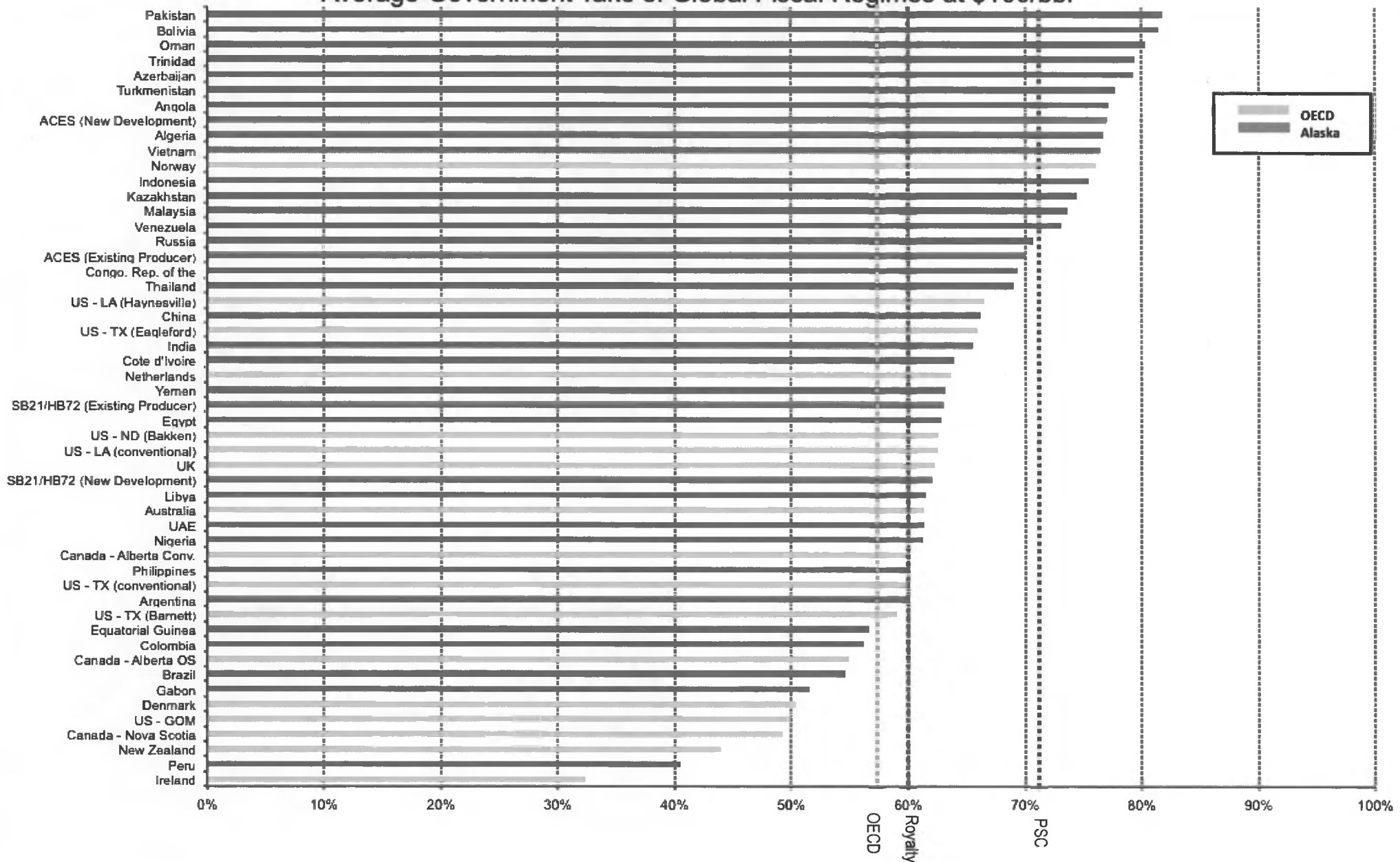
Regime Competitiveness: Average Government Take at \$80/bbl

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



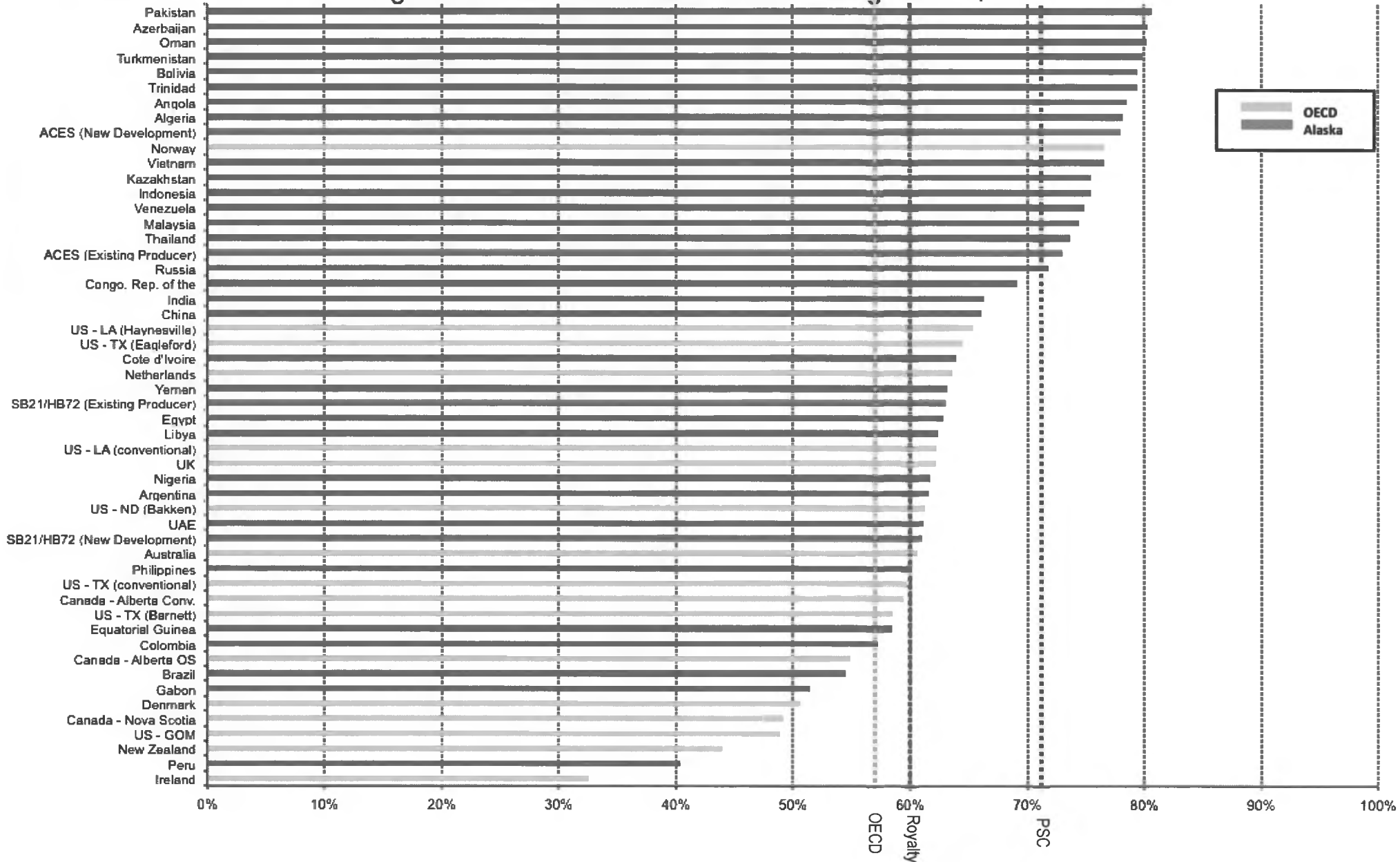
Regime Competitiveness: Average Government Take at \$100/bbl

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

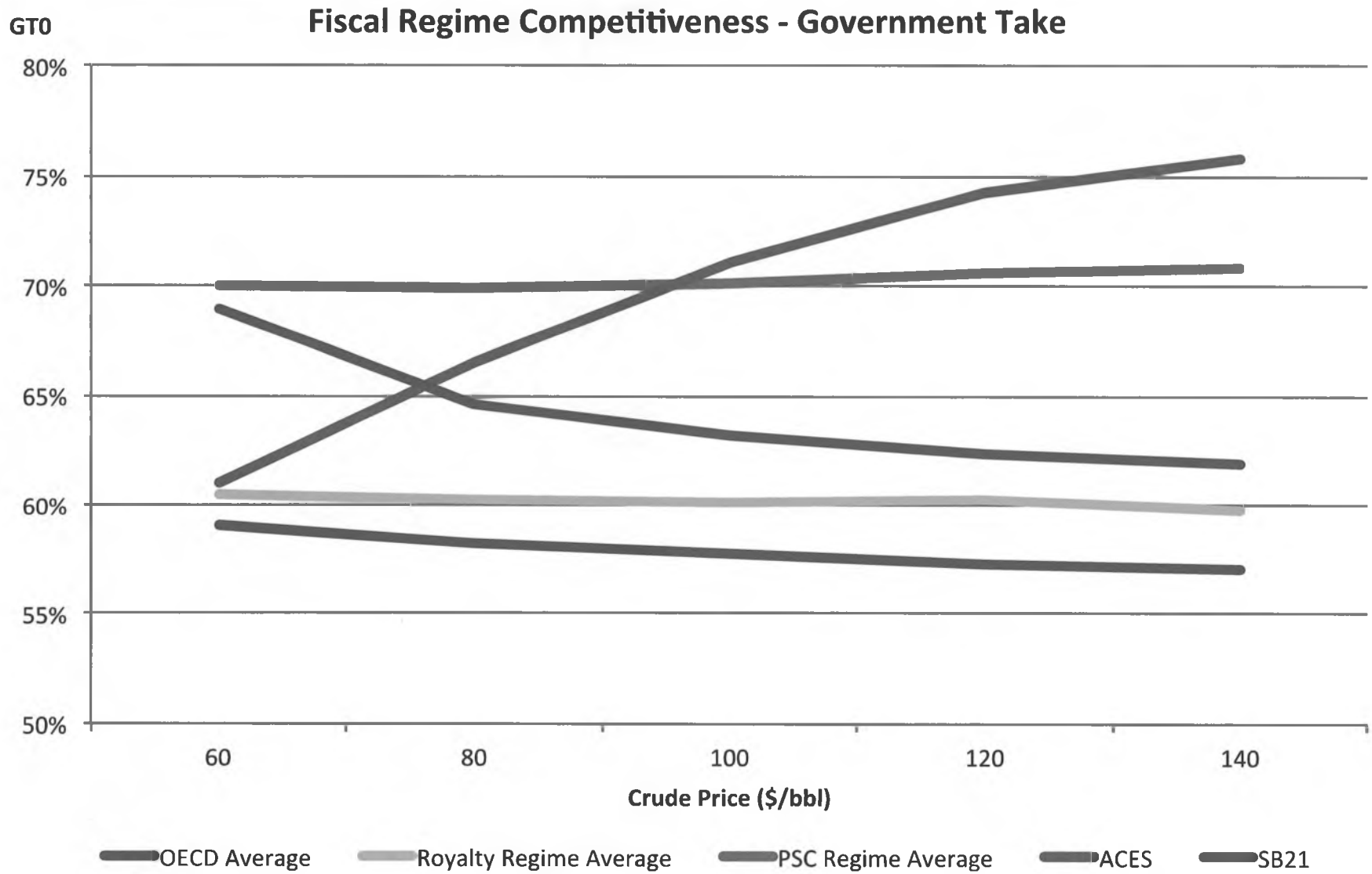


Regime Competitiveness: Average Government Take at \$120/bbl

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



Fiscal Regime Competitiveness (Base Production)



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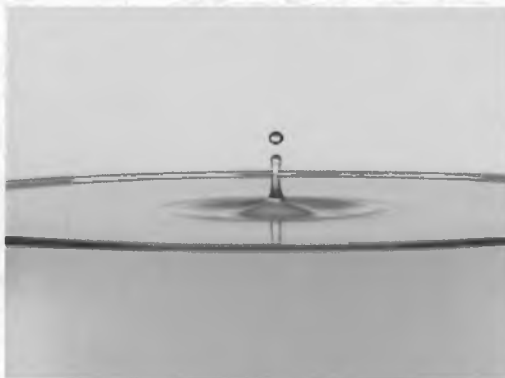
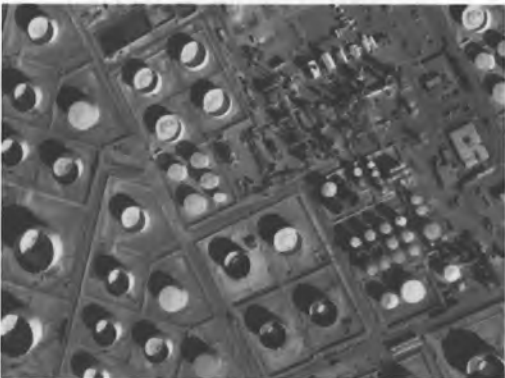
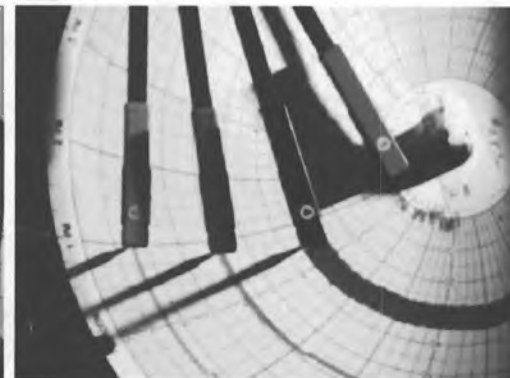
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable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

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A trusted advisor to energy companies and governments for over twenty five years



PFC Energy

70 & 148, LLC

• 1421 Blake Street • Denver, CO 80202 •
Phone 303-623-1821 • Fax 303-623-3019

February 20, 2013

Representative Eric Feige
Representative Dan Saddler
The Alaska State Legislature, House of Representatives
State Capital Room 126 & Room 104
Juneau, AK 99801

Re: House Bill 72

Dear Co-Chairs Feige and Saddler,

Thank you for the opportunity to testify to the House Resources Committee concerning House Bill 72. I would like to commend your committee on its diligence in assessing the key issues surrounding increasing activity and production on the North Slope of Alaska.

70 & 148, LLC (hereinafter referred to as "Armstrong") is a strong supporter of Governor Parnell's House Bill 72 and his efforts to increase production on the North Slope. Armstrong supports the Governor's proposal to offer a more equitable tax policy for the legacy fields as this will provide the quickest new barrels on the North Slope, however as we are not a working interest owner in any legacy field, we feel it is inappropriate for us to comment on this portion of the bill.

We do feel that the bill does need some modifications in order to place Alaska in a more competitive position relative to the rest of the U.S. and other producing provinces around the world. As such we would recommend the following modifications:

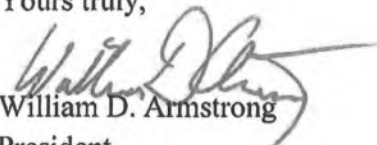
1. Keep the Qualified Capital Expenditure Credit and the cash purchase of the same in place until January 1, 2015. This will allow those projects that are based on a business plan that incorporates this concept time to transition more smoothly to the new system.
2. Extend the ability to utilize the Loss Carry Forward Credit from ten (10) years to fifteen (15) years. We believe this is very important given how long it takes to:
a) sanction a project for development, b) successfully drill and complete wells on the North Slope and c) bring production on line.
3. Increase the Gross Revenue Exclusion for new fields from twenty percent (20%) to twenty five percent (25%). This will assist new entrants economics in overcoming the high costs and long lead times associated with getting a new project sanctioned.

Please note we believe that this is the minimum the legislature should do to incentivize new production on the North Slope. The activity level on the North Slope will be driven by the oil and gas production tax and ease of permitting for projects. Further any accommodation made for

new field development will result in a gain in revenue for the state as currently the state is receiving no revenue in these areas.

Armstrong thanks you for the opportunity to comment on House Bill 72. We look forward to the passage of meaningful tax reform which will pave the way for us and our partner to work towards sanctioning developments which will boost the state's revenue, increase the life of TAPS and provide high paying jobs for Alaskans.

Yours truly,


William D. Armstrong
President

Petroleum: Jobs and Revenues

by

Scott Goldsmith

Institute of Social and Economic Research

University of Alaska Anchorage

afosg2@uaa.alaska.edu

Alaska State Legislature

House Resources Committee

February 25, 2013

Juneau, Alaska

Institute of Social and Economic Research
University of Alaska Anchorage

Petroleum: Jobs and Revenues

Primary Financial Support from



Basis for a Prosperous Economy



The Alaska Economy Runs on \$\$\$ From Outside

- Sale of Resources
- Tourists
- Federal Spending
- Retirees



As Those \$\$ Circulate Thru the Economy, They Support These Other Types of Businesses



What is the Impact on Jobs and Revenues from a Cut in Petroleum Taxes?

- State Revenues from Currently Anticipated Production Fall
- Budget Cuts Reduce Public and Private Jobs
- Increase in Petroleum Industry Investments Increases Private Jobs
- Increase in Oil Production increases state revenues
- Higher state revenues increases Public and Private Jobs



Not a Prediction



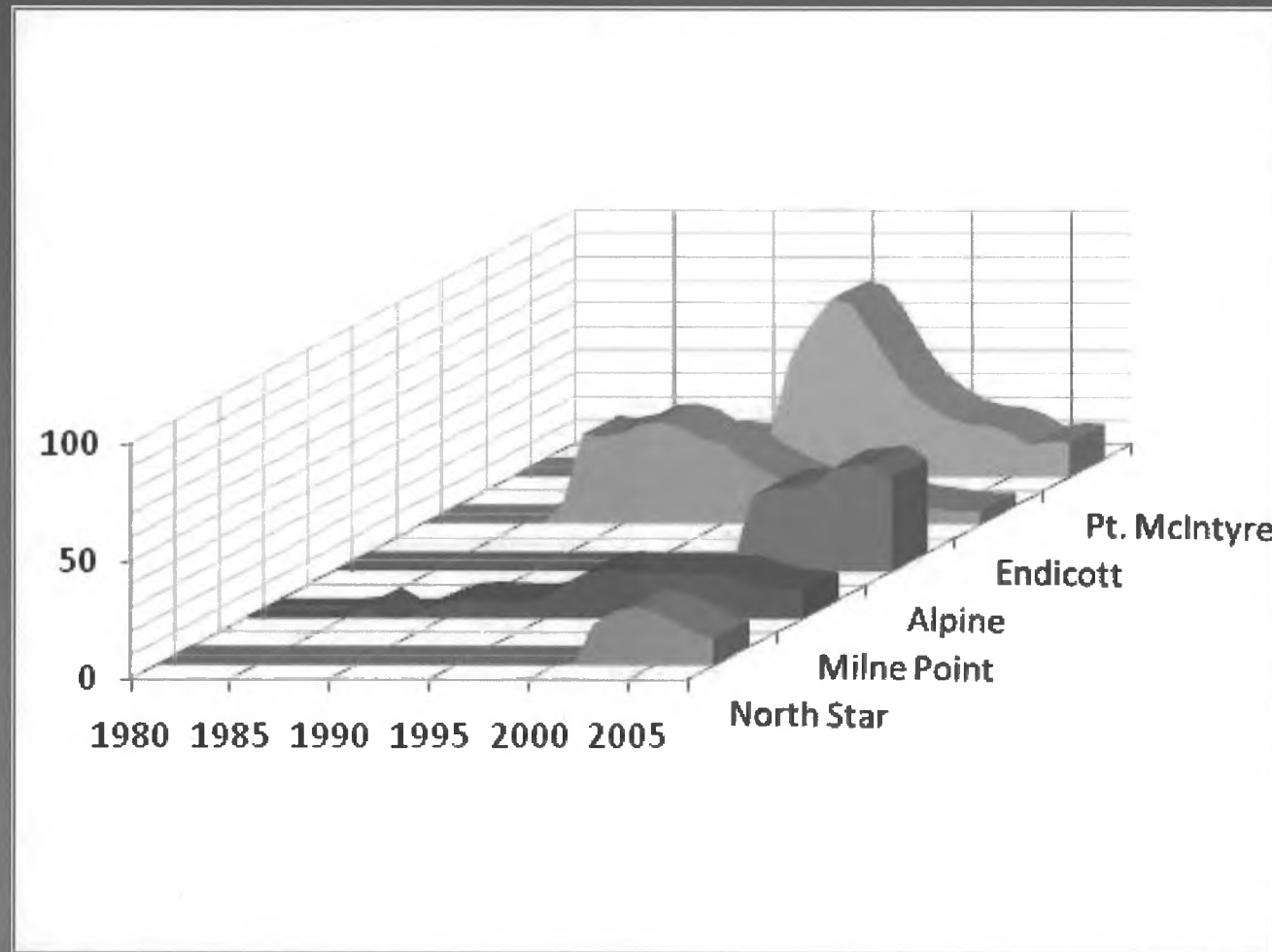
What Happens to Investment When taxes Cut \$1 Billion?

If Alberta cuts its tax rates, will oil
companies take that money and
come to Alaska to invest?

Or, Is Alaska different from every
other oil rich region?

LEVERAGE

Oil Development & Production: Each Project Unique



Jobs to Production Relationship



How Does the State Spend its Money?

Responsible and Responsive



ALASKA'S FISCAL YEAR 2014 BUDGET PROPOSAL

Alaska's Budget by Source of Funds



The FY 2014 Budget Proposal Supports Alaska's Priorities:

Resource/Energy Development

Alaska's resources provide Alaskans with opportunity.

- Roads to Resources \$18 million
- Gasline Development \$50 million
- Geologic Materials Center \$15 million
- Chinook Salmon Research \$10 million
- Strategic Minerals \$2.7 million
- Permitting and Statewide Mapping \$7.3 million
- Sustainable Energy Fund \$1.25 million
- Susitna-Watana Hydro Project \$95 million
- Interior Energy \$50 million
- Weatherization/Home Energy \$51.5 million
- Renewable Energy \$25 million

Education

Alaska's K-12 public education system prepares students for success in college or job-training programs.

- K-12 Education \$1.25 billion
- Alaska Performance Scholarships \$8 million
- Alaska Digital Learning Initiative \$5.9 million
- Early Learning \$14.6 million
- School Construction \$46.2 million
- Major Maintenance \$22.3 million

Transportation/Infrastructure

Alaska's economy depends on access and infrastructure to support development.

- Statewide Highway and Aviation \$971 million
- Alaska Marine Highway \$182 million
- Municipal Water and Sewer Projects \$34 million
- Village Safe Water \$56.5 million
- State Funds to leverage federal and local \$141 million

Public Safety

The budget prioritizes safe homes and strong families.

- Choose Respect Initiative \$14.8 million
- 18 New Alaska State Troopers \$3.7 million
- 15 New Village Public Safety Officers \$2.7 million
- Investigate/Prosecute child sexual abuse \$1.6 million
- Emergency - Blood Bank of Alaska \$7 million

Military Support

We honor Alaska's military community.

- Interior Alaska Veterans Cemetery \$2.5 million
- Homeland Security \$19.6 million
- Alaska Military Youth Academy \$11.1 million
- Veterans Services and Outreach \$2 million

"Our fiscal plan is built on our state's resources and spending discipline. We focus on priorities that grow our economy and strengthen our families - for Alaskans today and tomorrow."

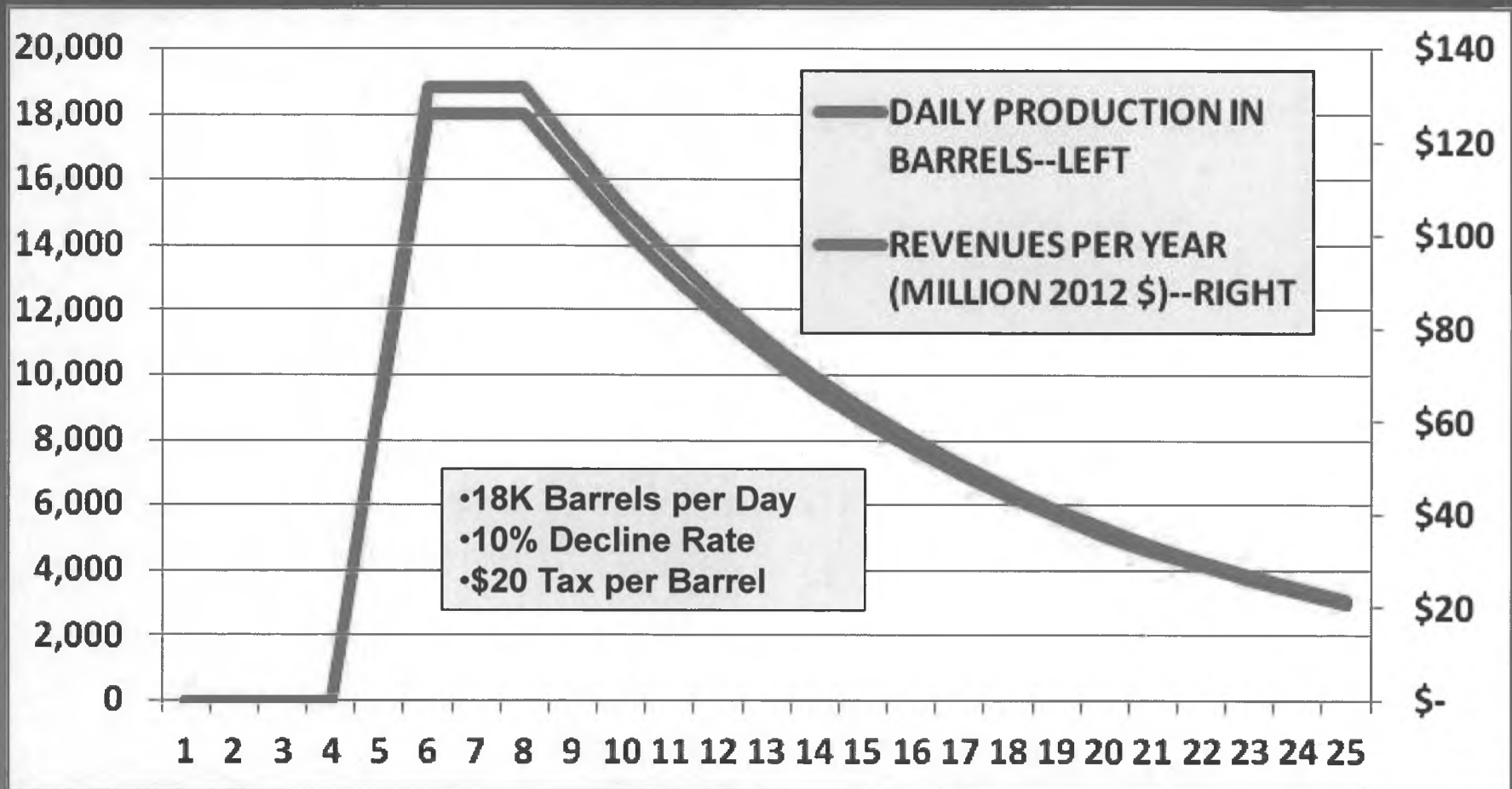
Sean Parnell
GOVERNOR



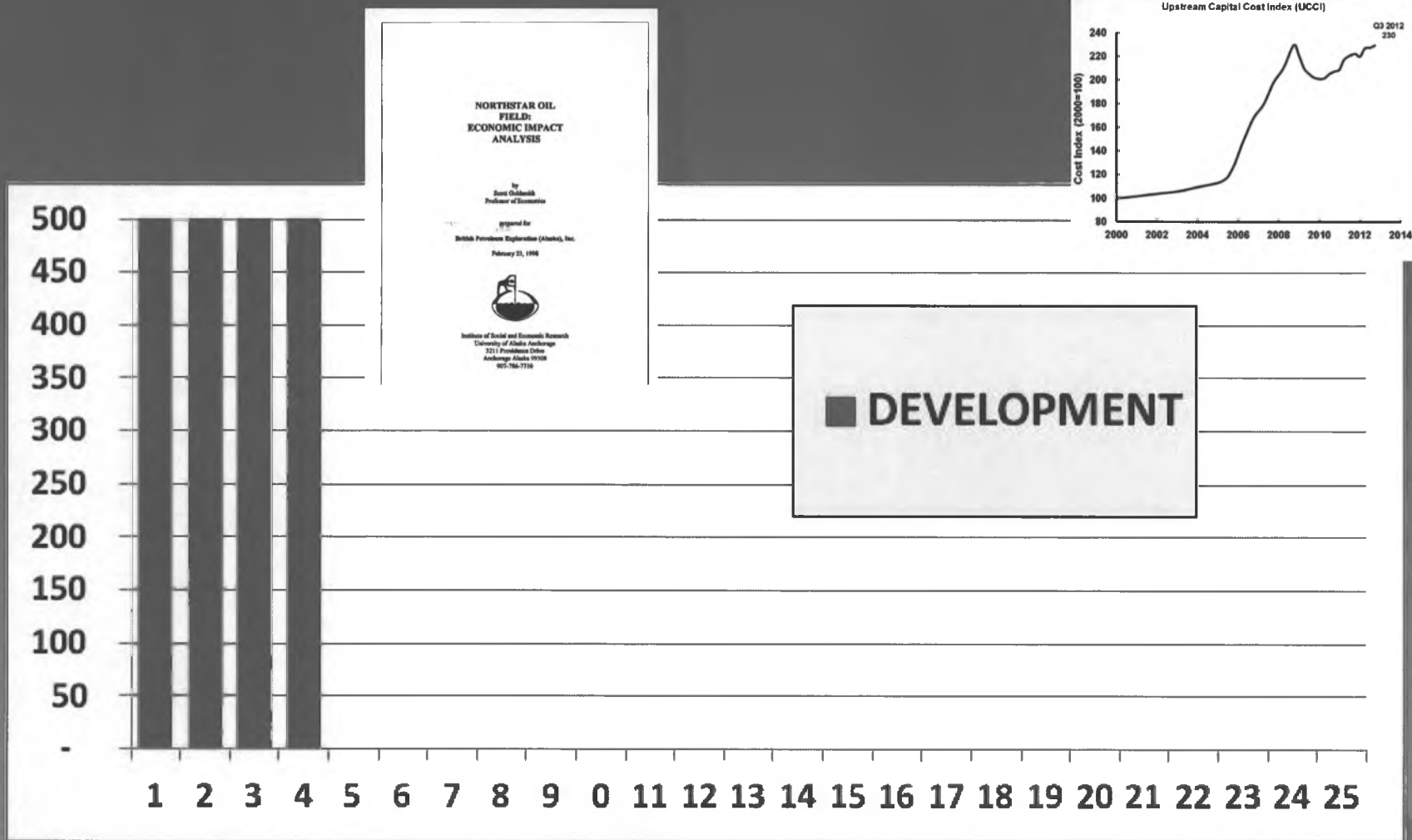
Responsible and Responsive • Alaska's FY 2014 Budget Proposal

For more information, go to omb.alaska.gov

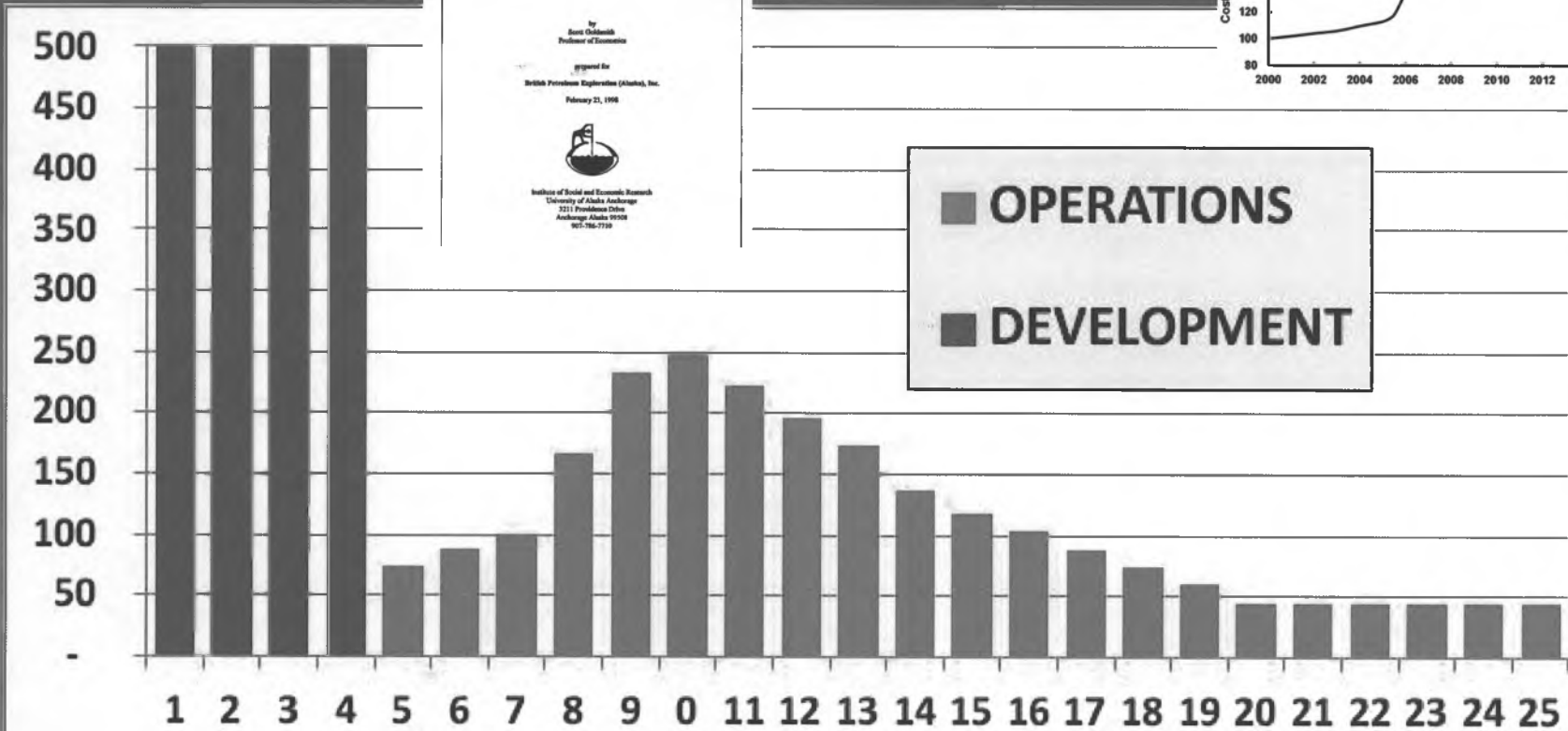
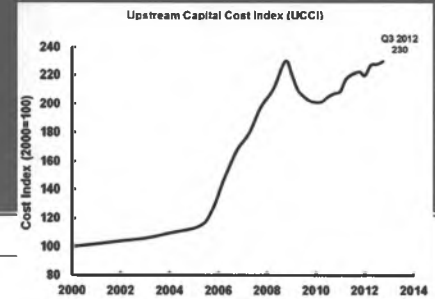
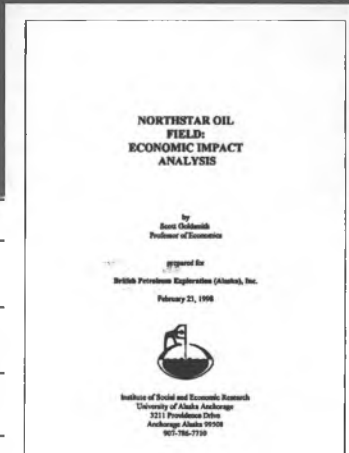
Hypothetical \$1 Billion Field



New Field: Direct Jobs



New Field: Direct Jobs



25 Year Cumulative Totals

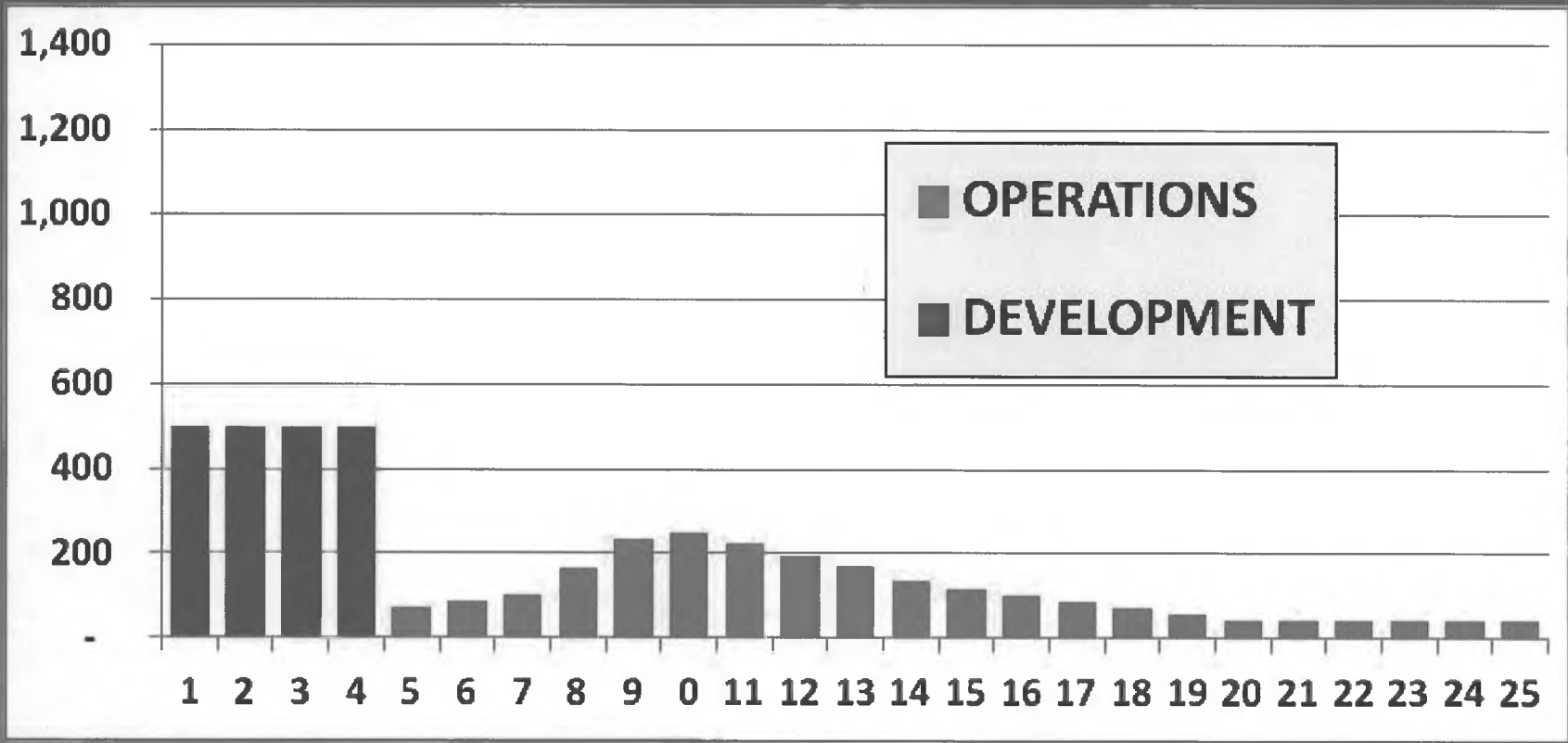
Production = 72 Million Barrels

Revenues = \$1.445 Billion (2012 \$)*

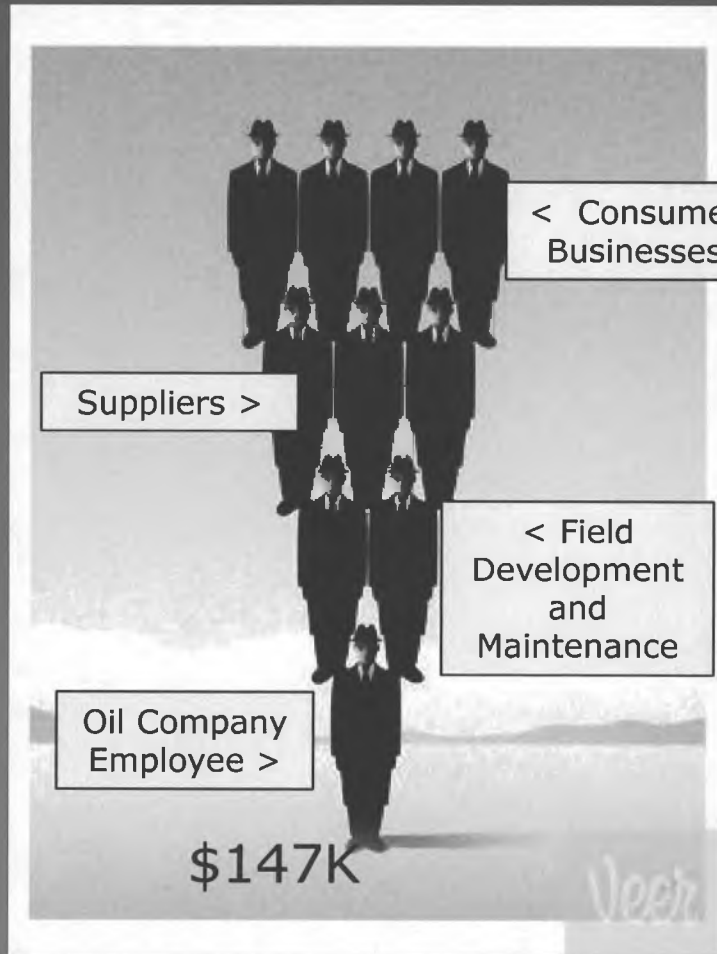
Direct Oil Patch Jobs = 4,349

* NPV @ 5% = \$827 Million

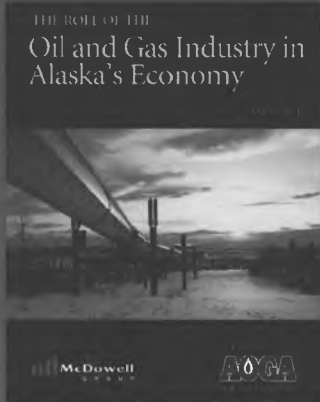
Hypothetical Field: Make Room on Graph for Other Jobs



Petroleum Job Pyramid: The Economic “MULTIPLIER”



- Advertising
- Air Carriers
- Arctic Engineering
- Arctic Gear
- Aviation Fuel
- Catering
- Communications
- Chemicals
- Hazardous Waste
- Commercial Diving
- Construction Equipment
- Project Management
- General Contractors
- Control Systems
- Corrosion Control
- Drilling
- Electrical Contracting
- Employee Services
- Environmental Engineering
- Engineering Services
- Heavy Hauling
- Expediting
- Oilfield Supplies
- Geophysical Services
- Geological Services
- Hydraulic Supply
- Industrial Gases
- Inspection Services
- Instrumentation Services
- Machining
- Logistics
- Maps
- Medical Services
- Mat Systems
- Mud
- Permitting
- Photography
- Plumbing
- Soil Stabilization
- Safety Equipment
- Rigging Supplies
- Security
- Seismic
- Steel Fabrication
- Storage Space
- Tank Fabrication
- Welding
- Vessel Charter



Petroleum “MULTIPLIER”

$$45/4=10$$

$$45/(4+8) = 4$$

$$45/(4+8+7)=2.4$$

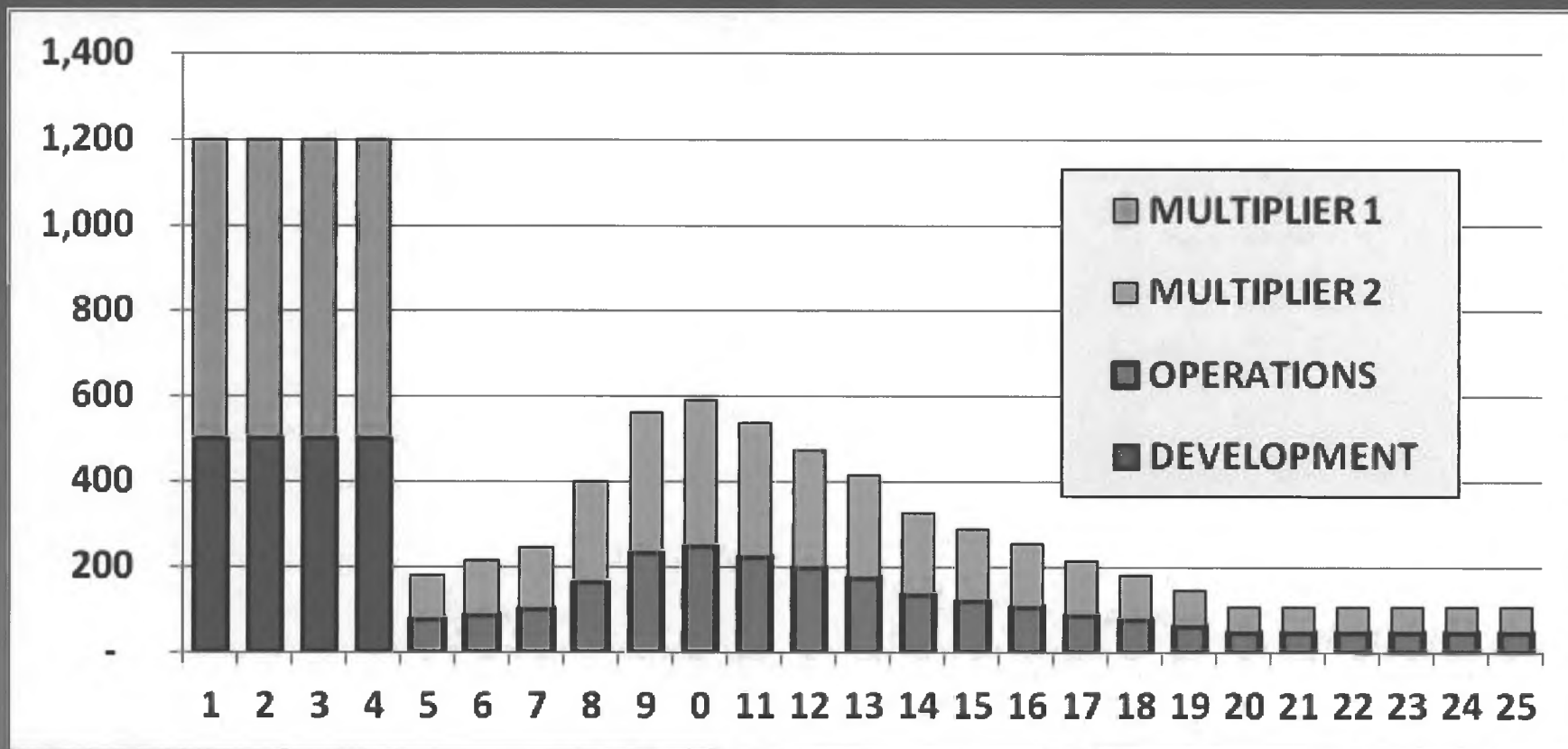
$$2.4 = 1 + 1.4$$

Alaska Resident Employment and Labor Income in the Oil and Gas Industry, 2010

	Employment
Direct Impacts	
Primary Companies	3,997
Indirect Impacts	
Reported Oil & Gas Industry Support Services*	7,670
Other Support Services**	7,100
Other Indirect and Induced Impacts	
All Other Indirect and Induced	26,033
Grand Total (Direct, Indirect, and Induced)	44,800

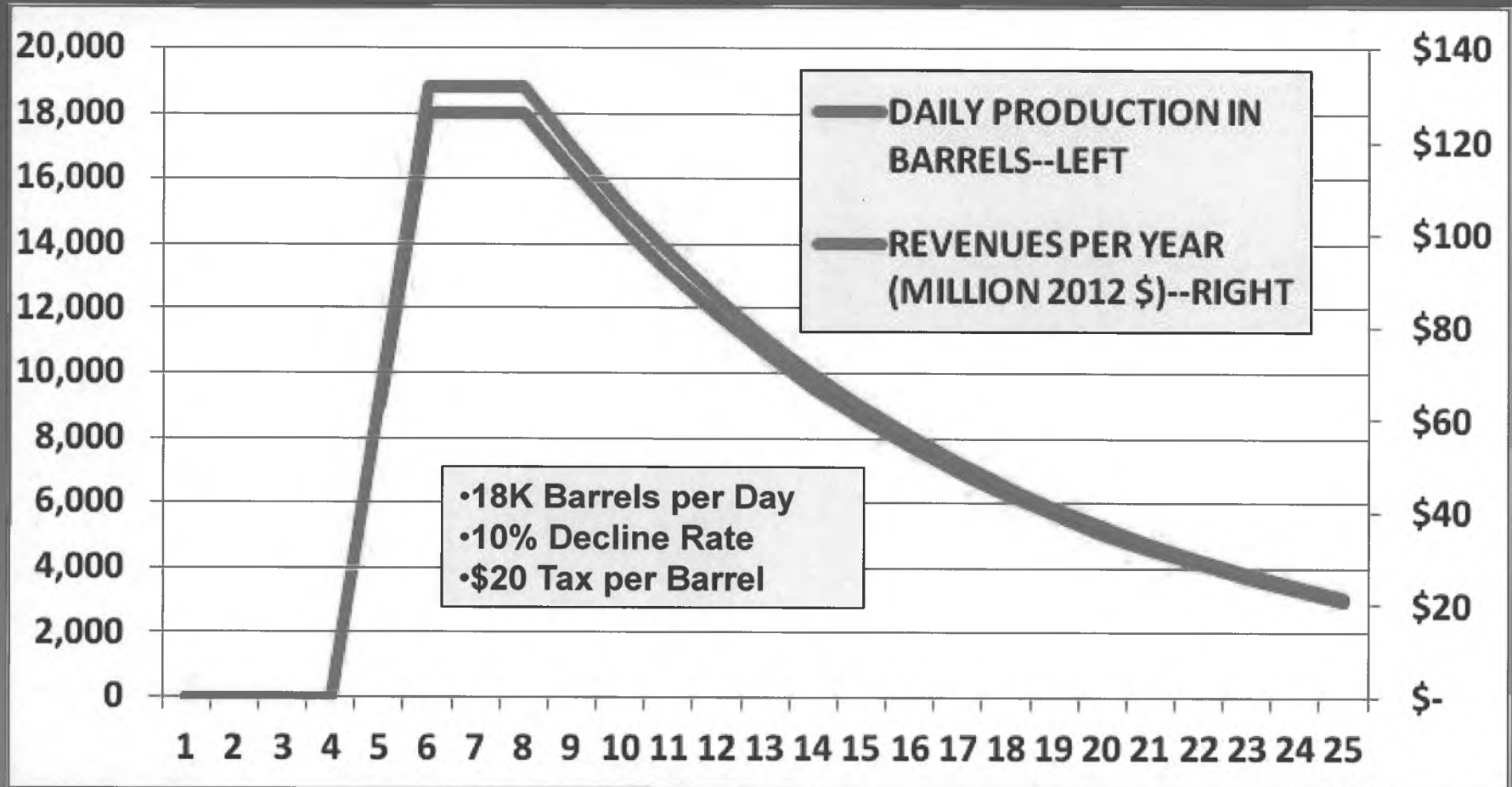
*Includes ADOLWD Oil and Gas Support Services Sectors Z13111 and Z13112.
 **Other Support Services includes construction, transportation services, engineering and a variety of other business and professional services provided under contract to P

New Field: Total Oil Patch Jobs

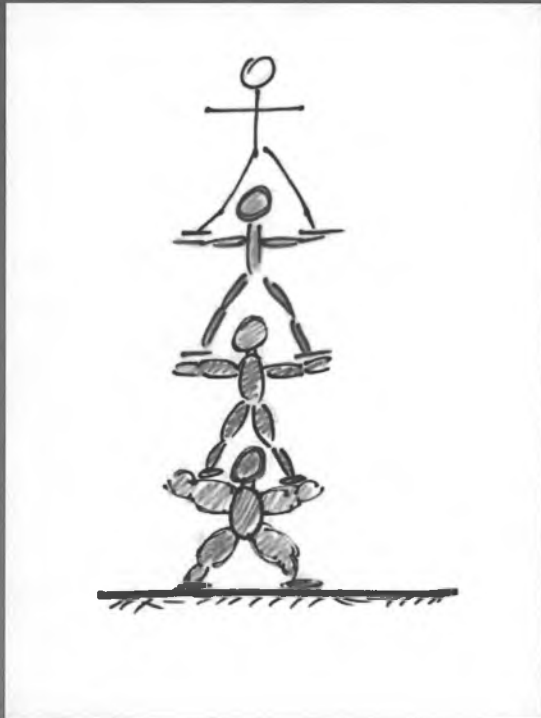


Add 6,088 for total of 10,437

Hypothetical \$1 Billion Field



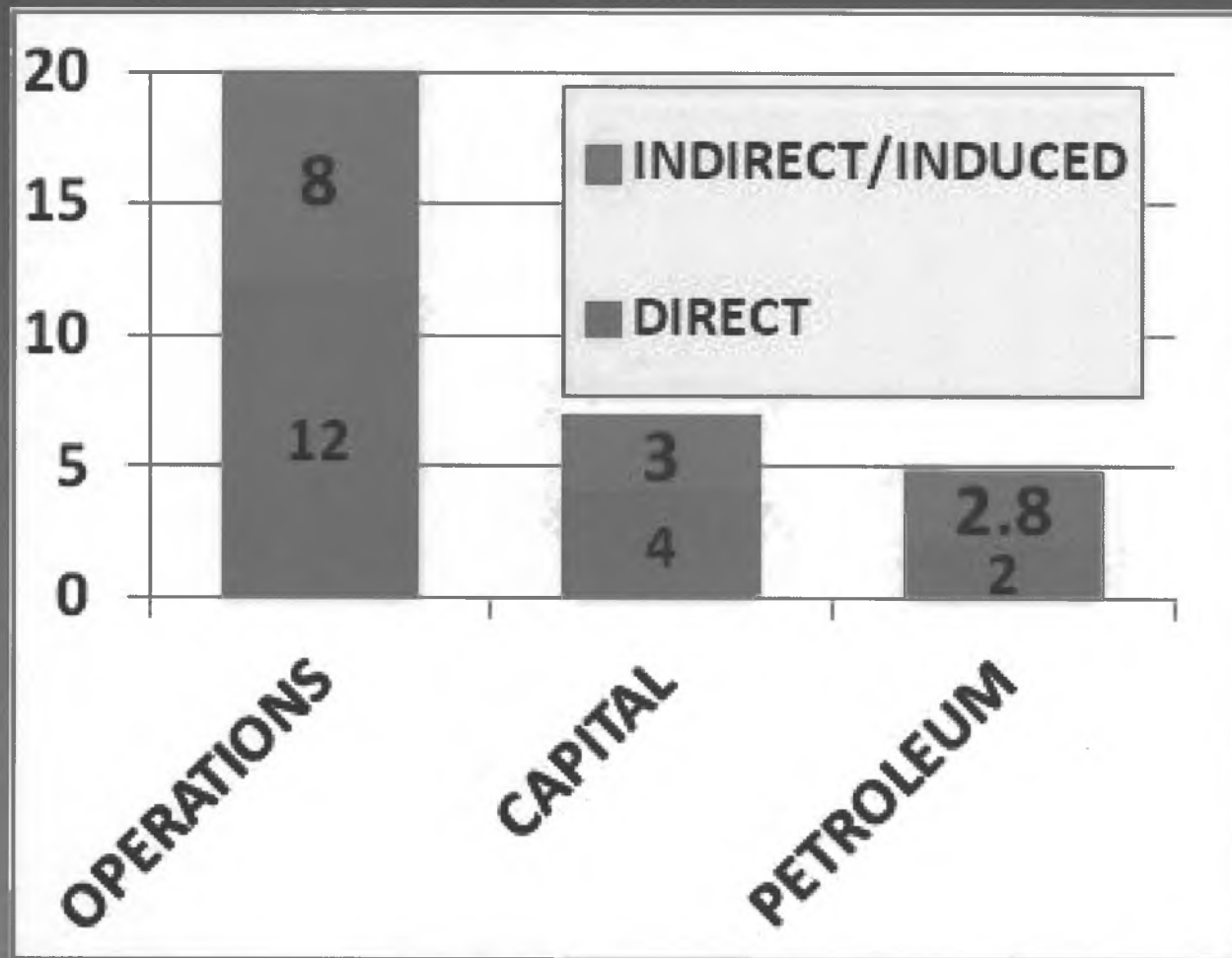
State Spending Bang per Buck & Multipliers



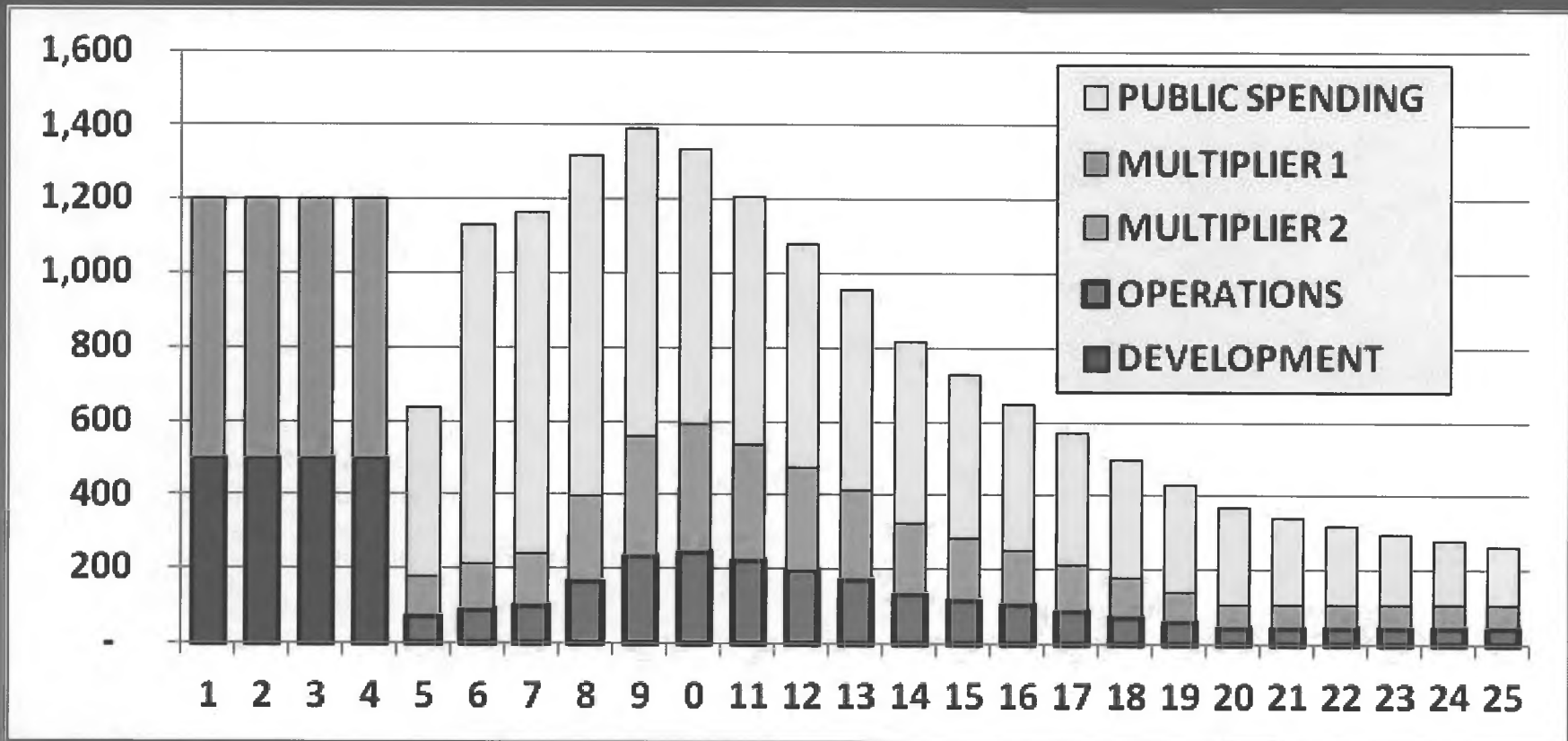
OPERATIONS
 $20/12 = 1.66$

CAPITAL
 $7/4 = 1.75$

Bang per Buck & Multipliers

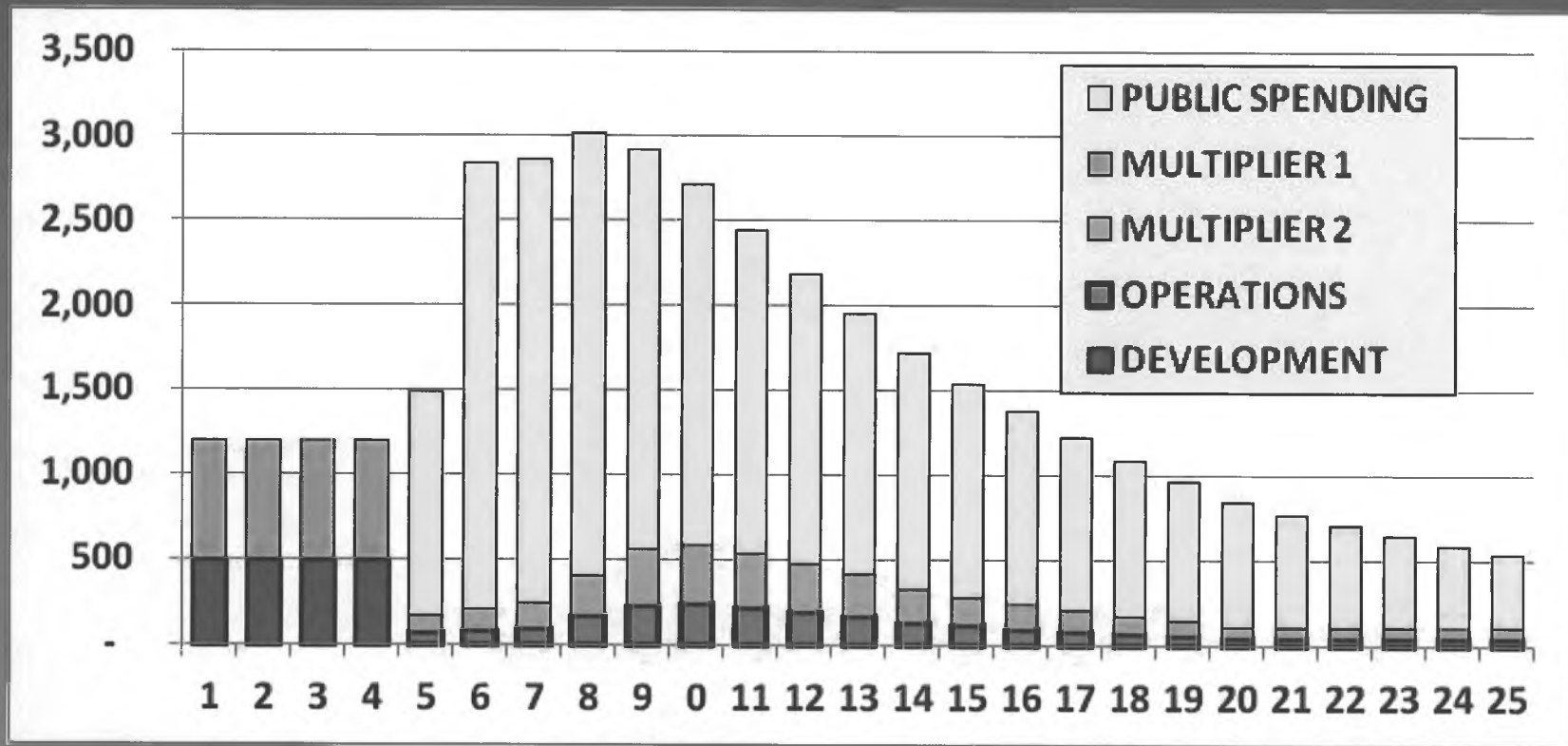


New Field: Total Jobs including Public Capital Spending



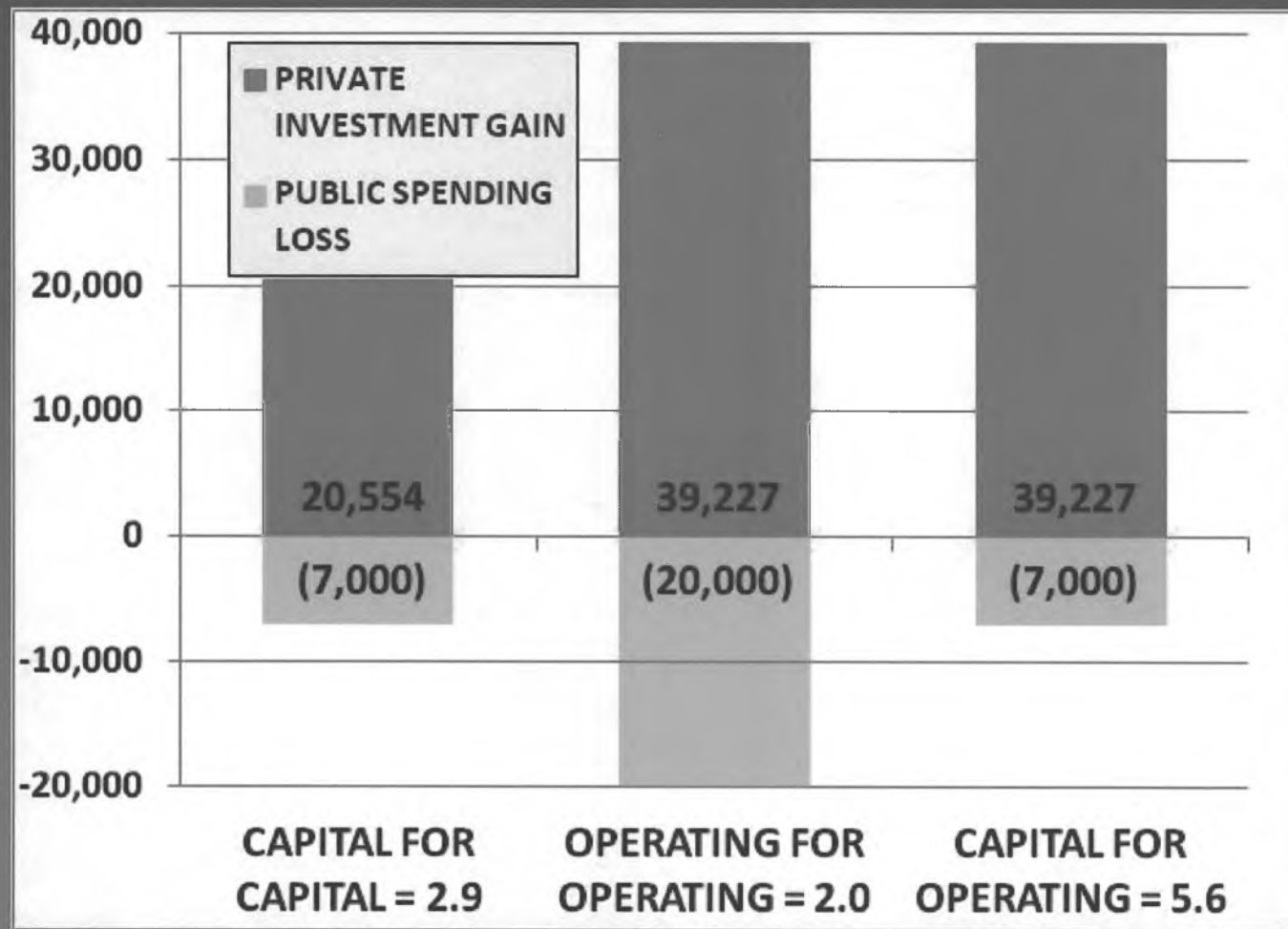
Add 10,117 for grand total of 20,554

New Field: Total Jobs including Public Operations Spending

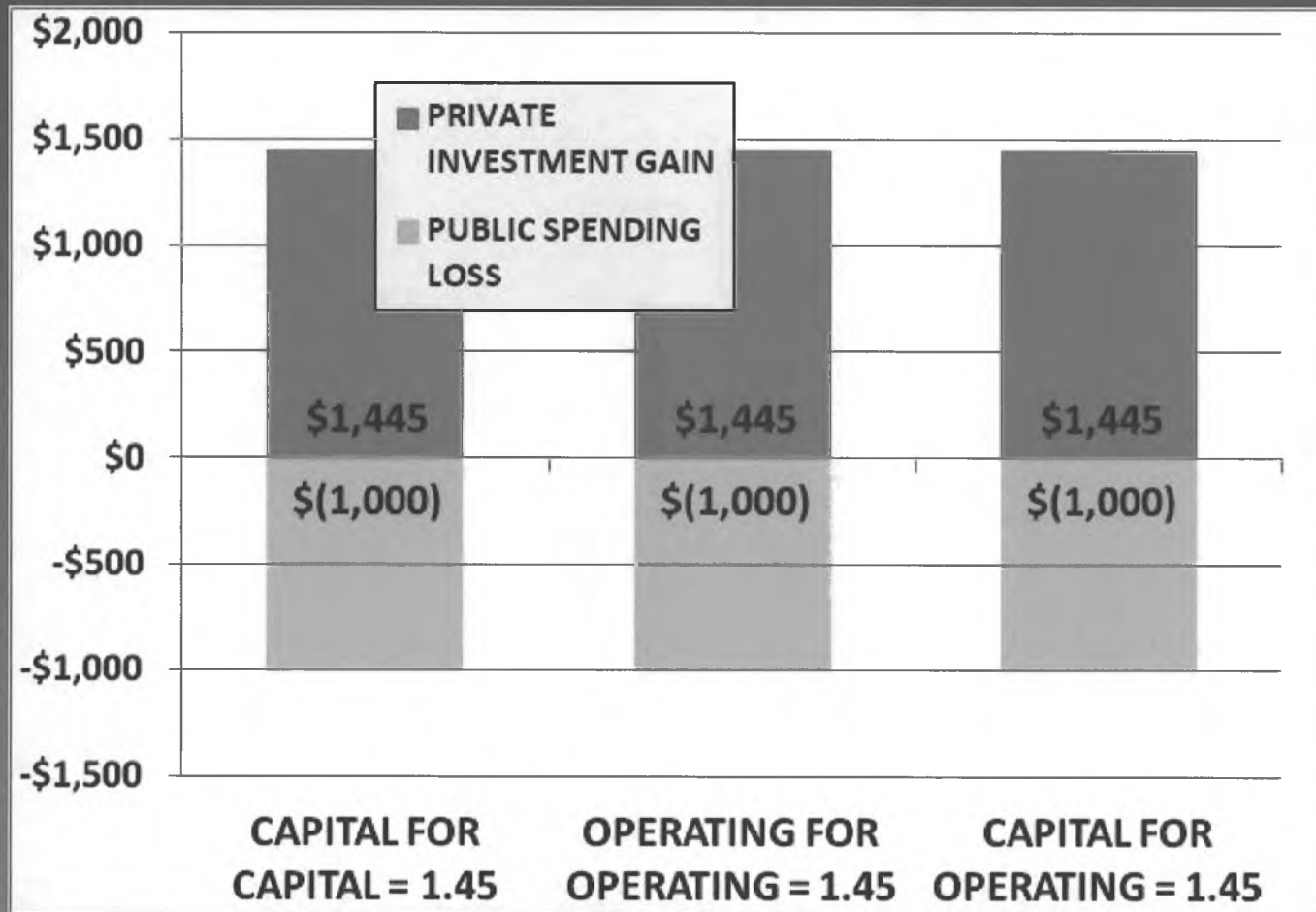


Add 28,790 for grand total of 39,227

Cumulative Jobs Generated

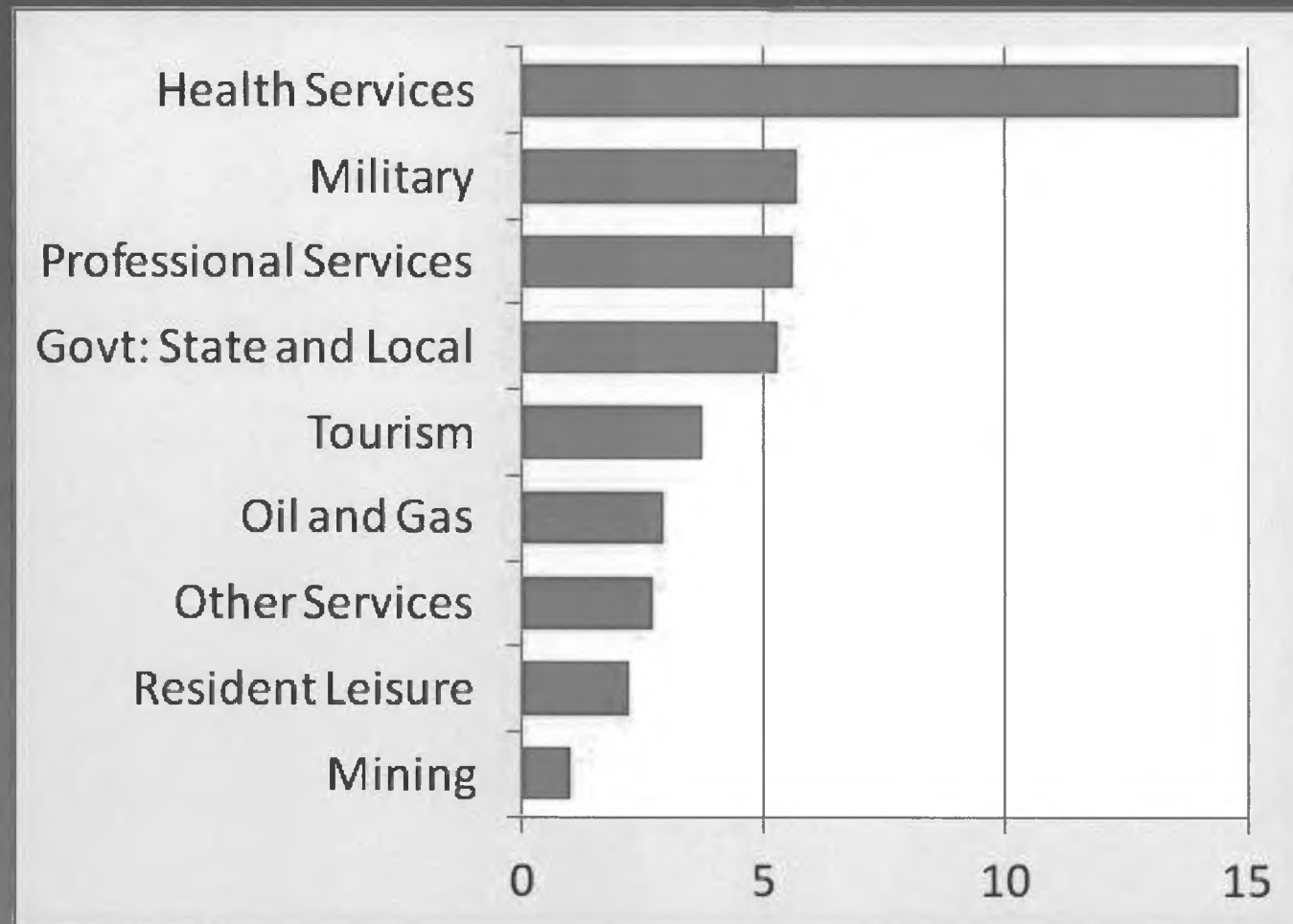


Cumulative Revenues Generated (Million 2012 \$)

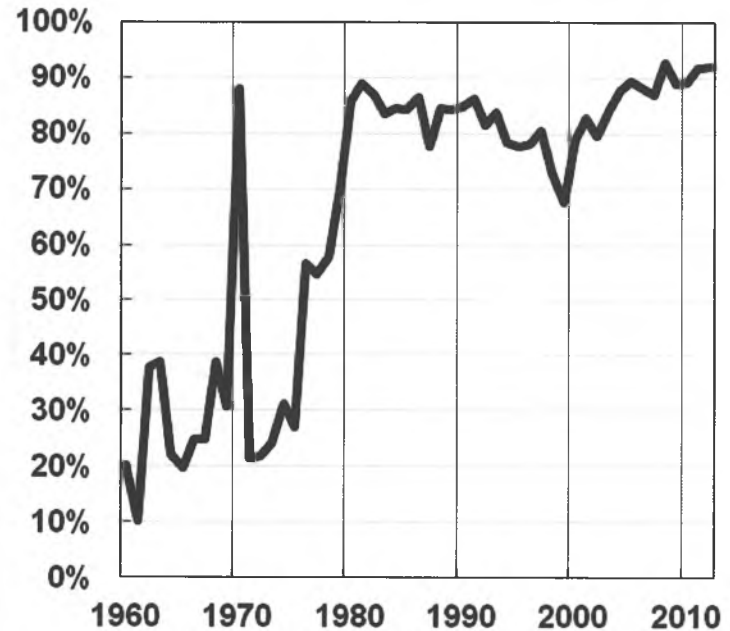
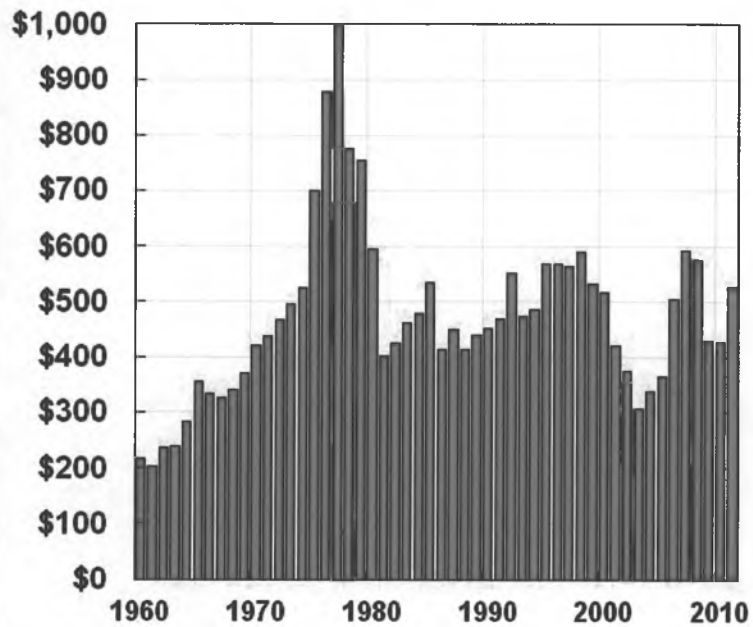


Job Growth Since 2001

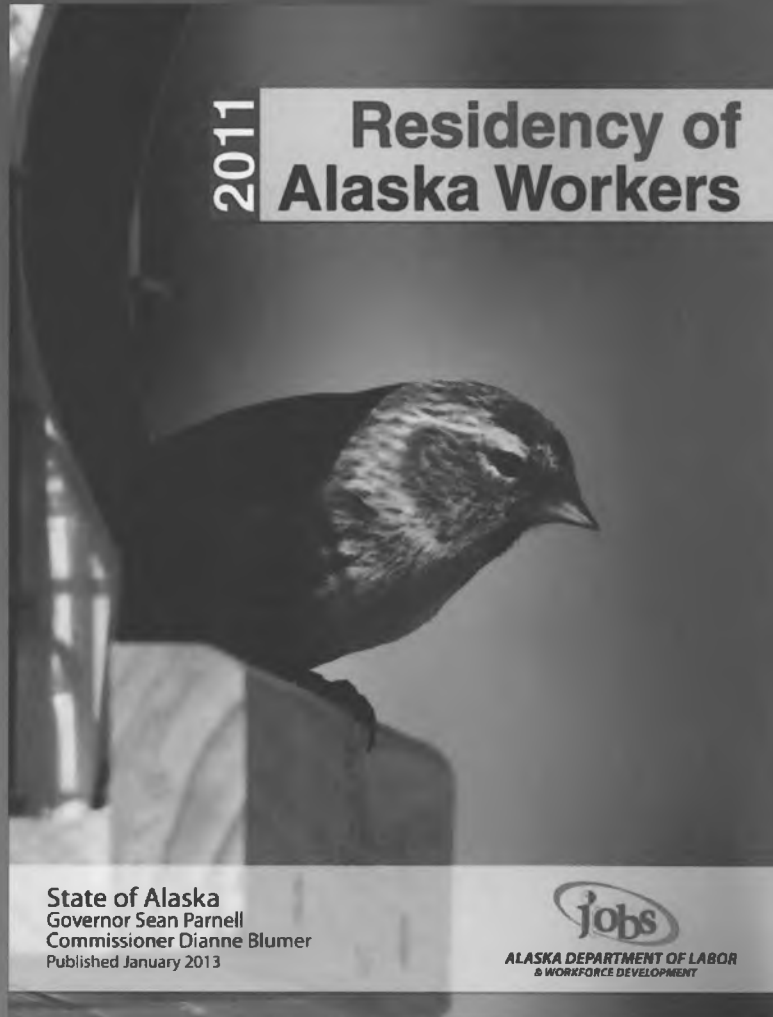
How Much Due to Govt Investment?



Progress Toward Fiscal Diversification

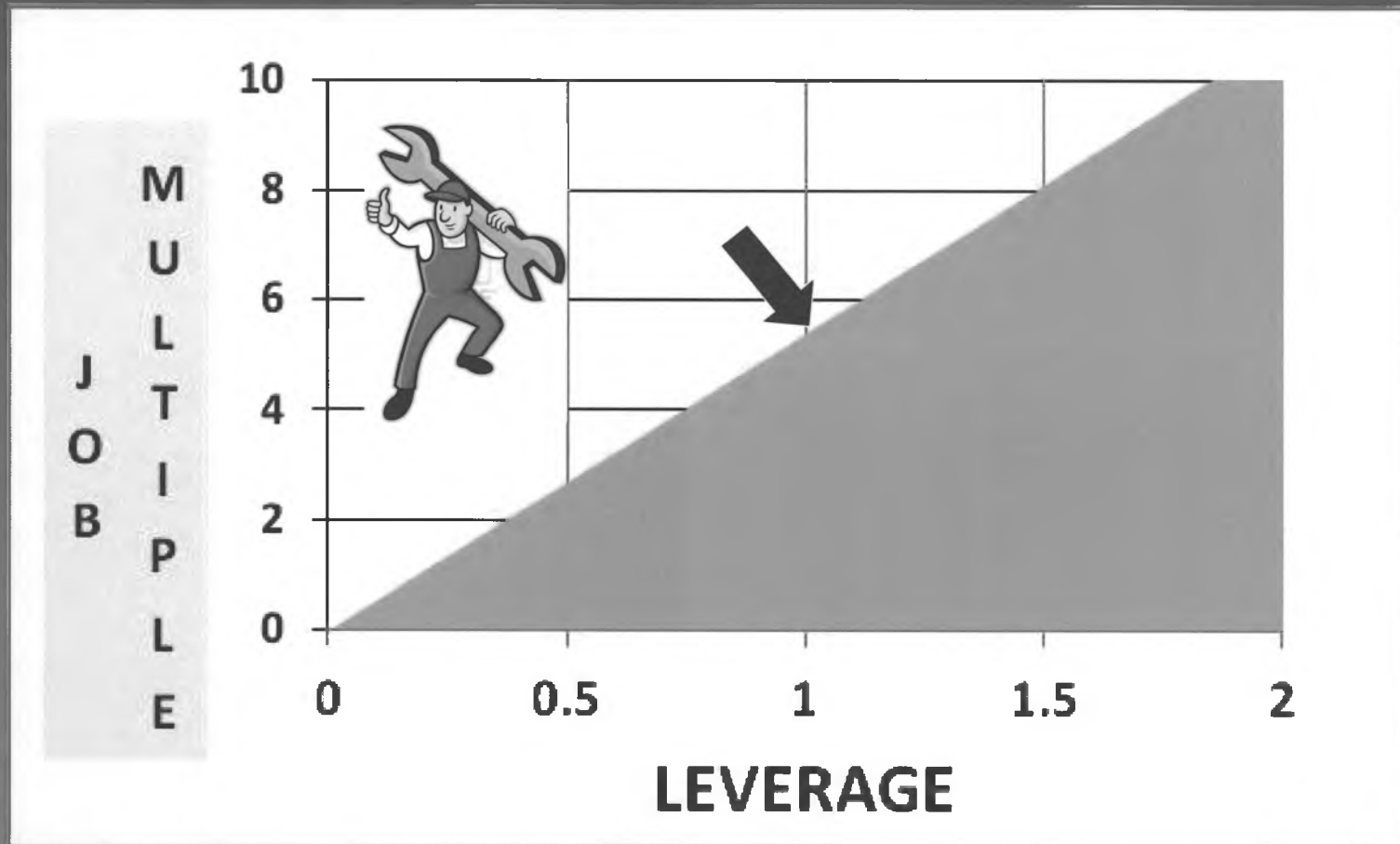


Non-Residents?

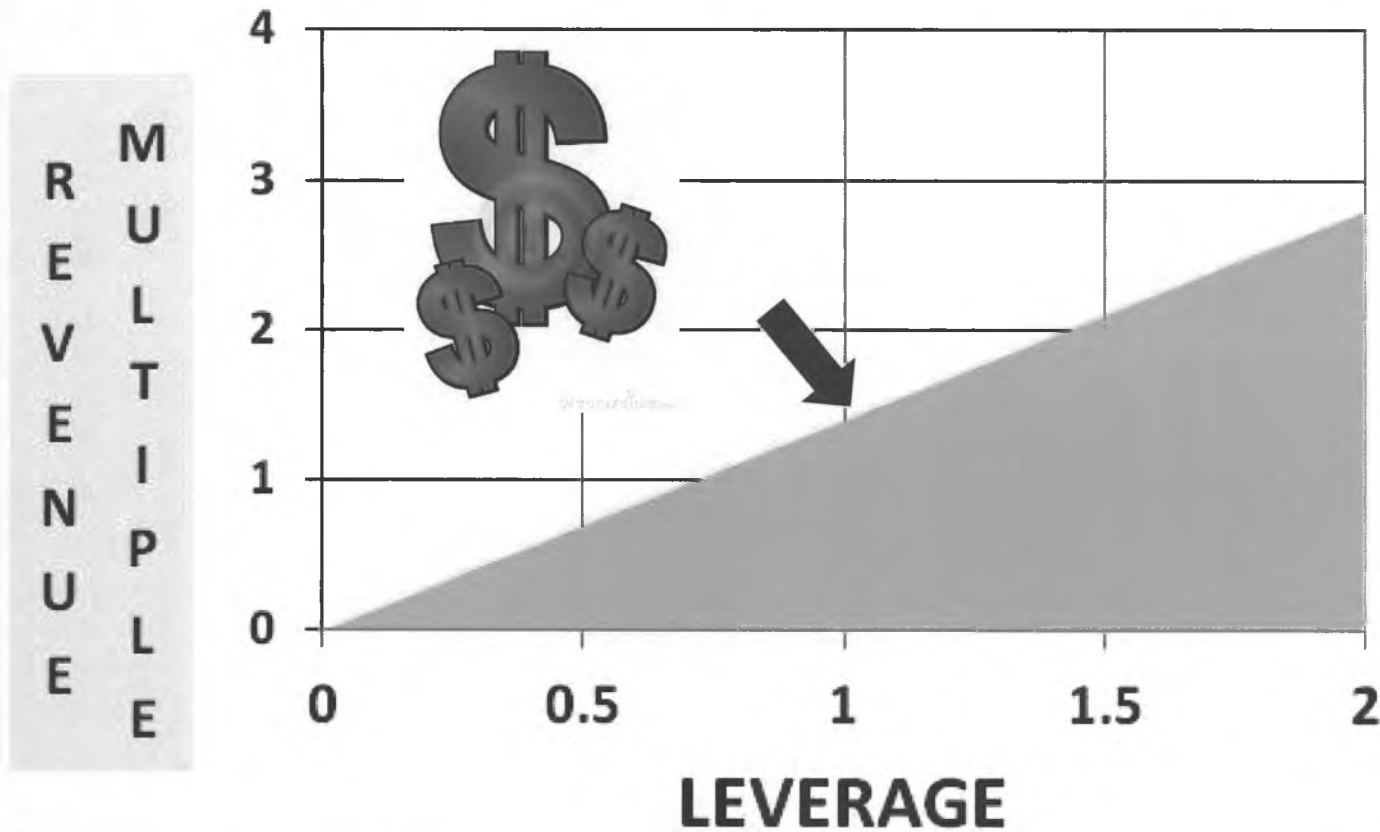


Non-Resident Worker Share	Industry
77	Seafood Processing
42	Visitor (Accommodations)
35	Metal Mining
31	OIL AND GAS
20	Construction
7	State Govt

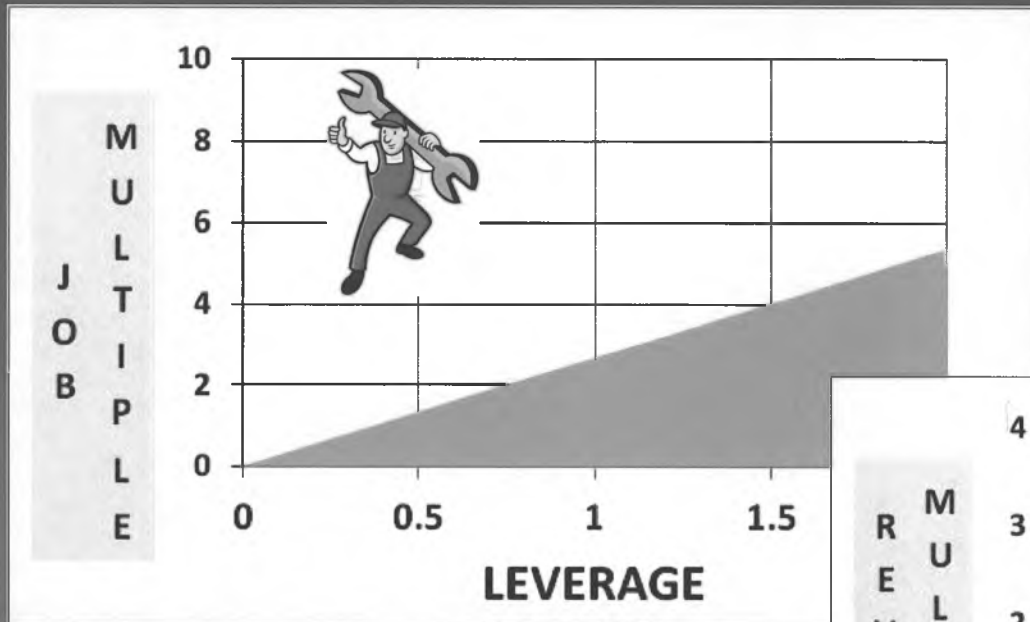
Jobs Sensitivity to “Leverage”



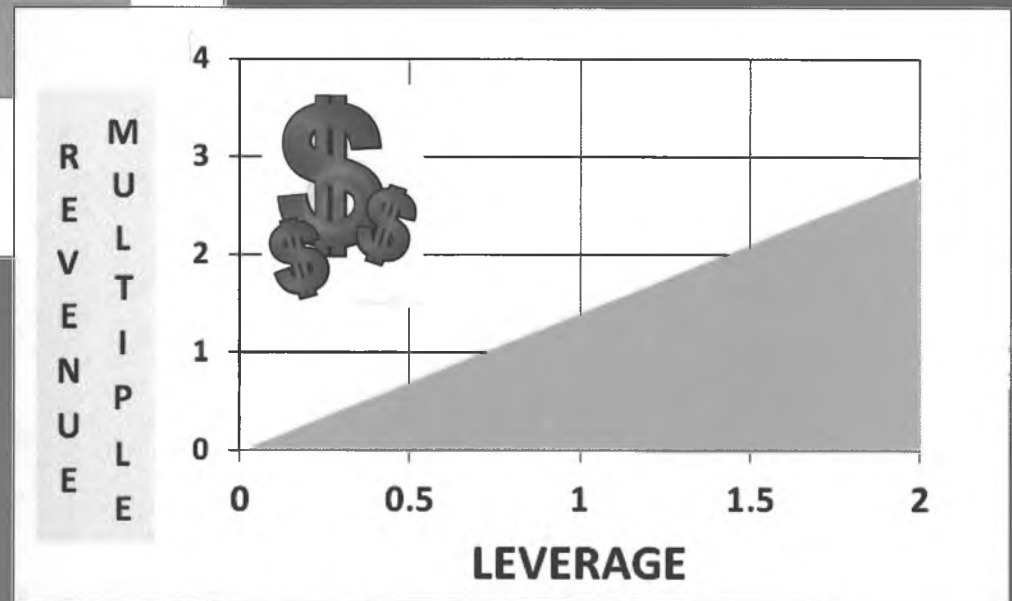
Revenues: Sensitivity to “Leverage”



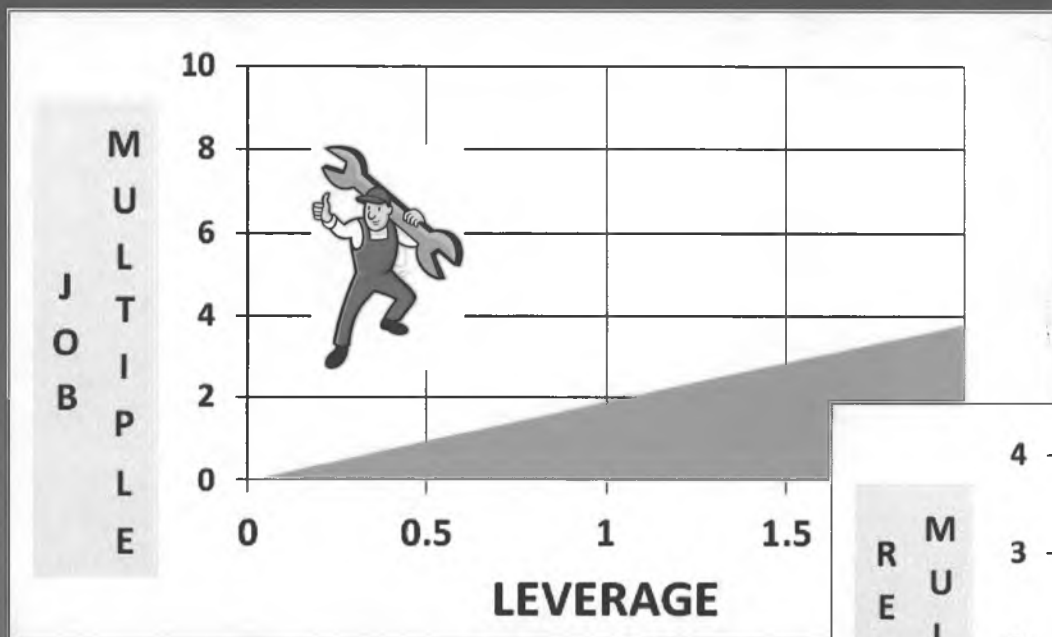
Sensitivity to Leverage



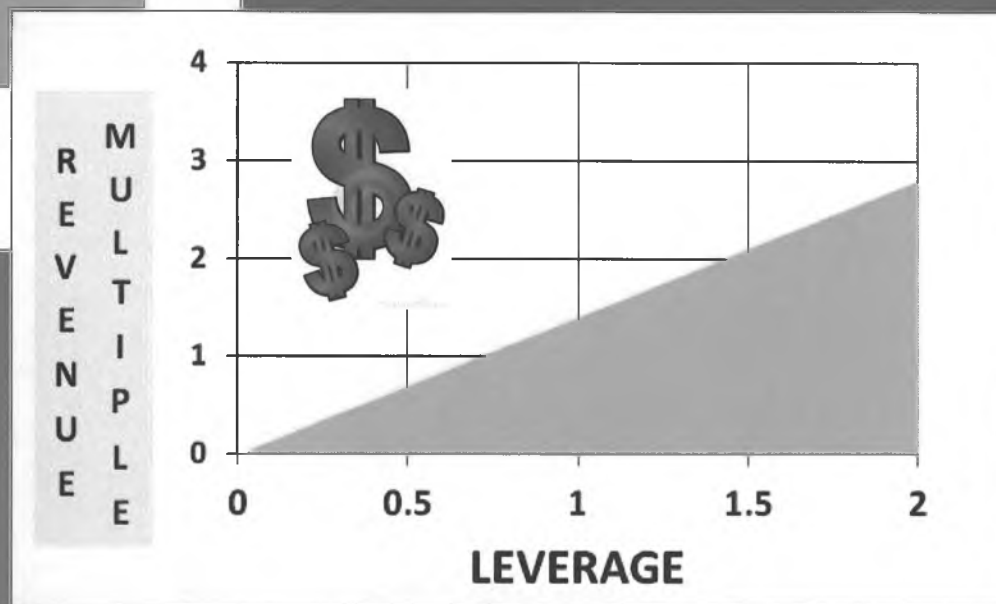
CAPITAL
SPENDING



Sensitivity to Leverage



OPERATIONS
SPENDING



State of Alaska

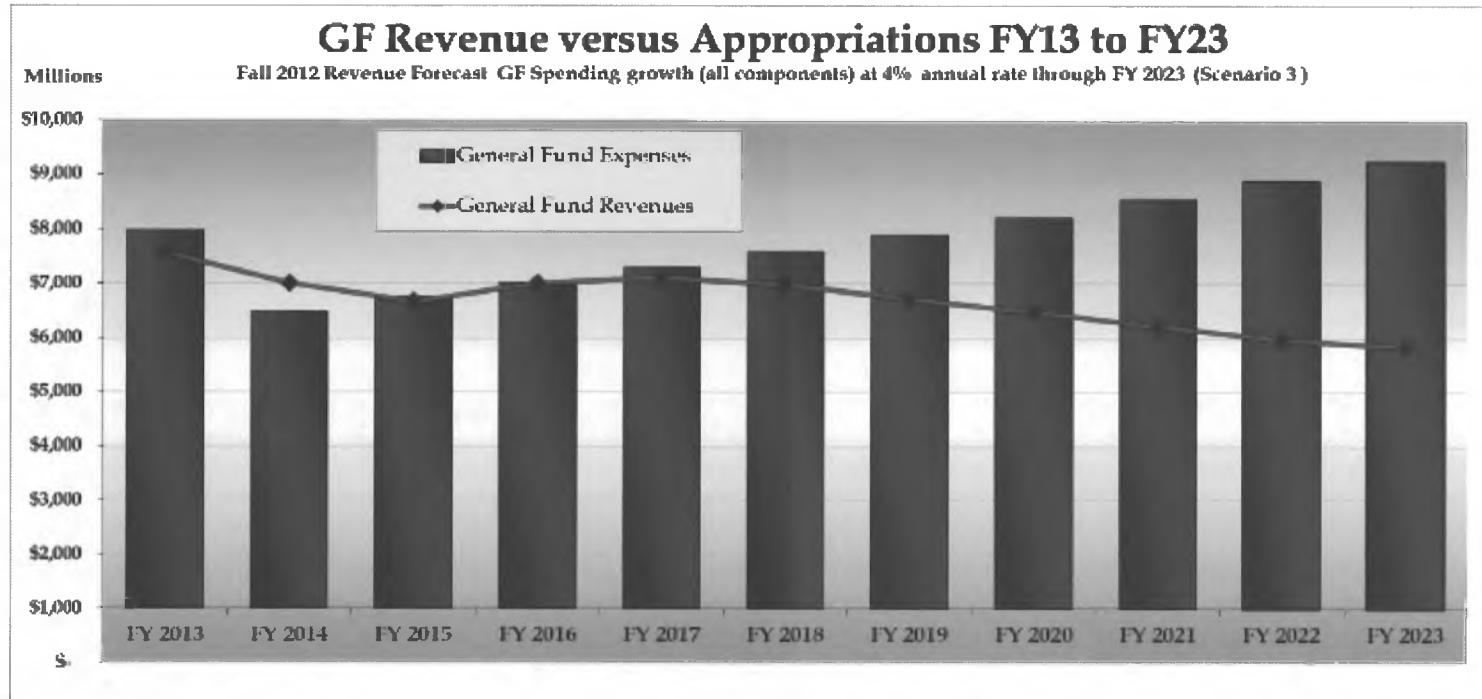
FY2014 10-Year Plan

Governor's Office of Management and Budget
Karen J. Rehfeld, Director

FY2014

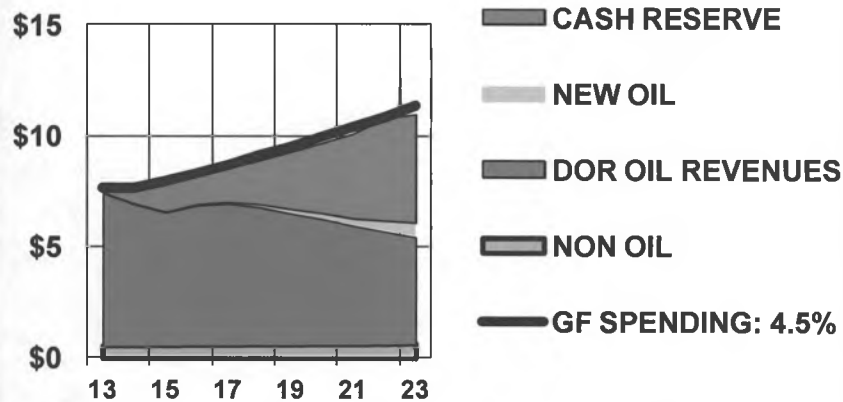
State Fiscal Plan

Scenario 3: Governor's FY2014 Budget with 4% Annual GF Expenditure Growth beginning in FY2015

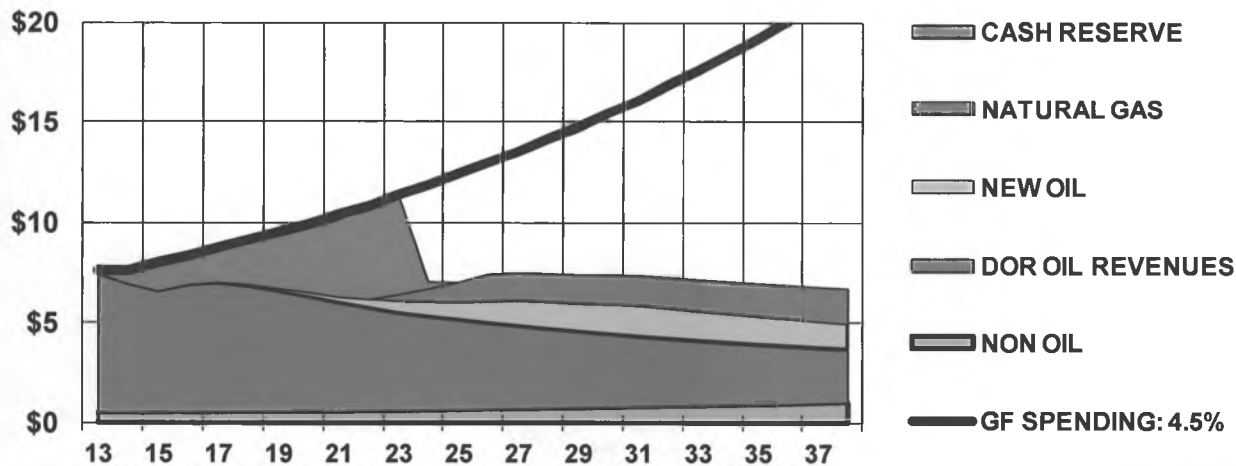


Looking Beyond 10 Years

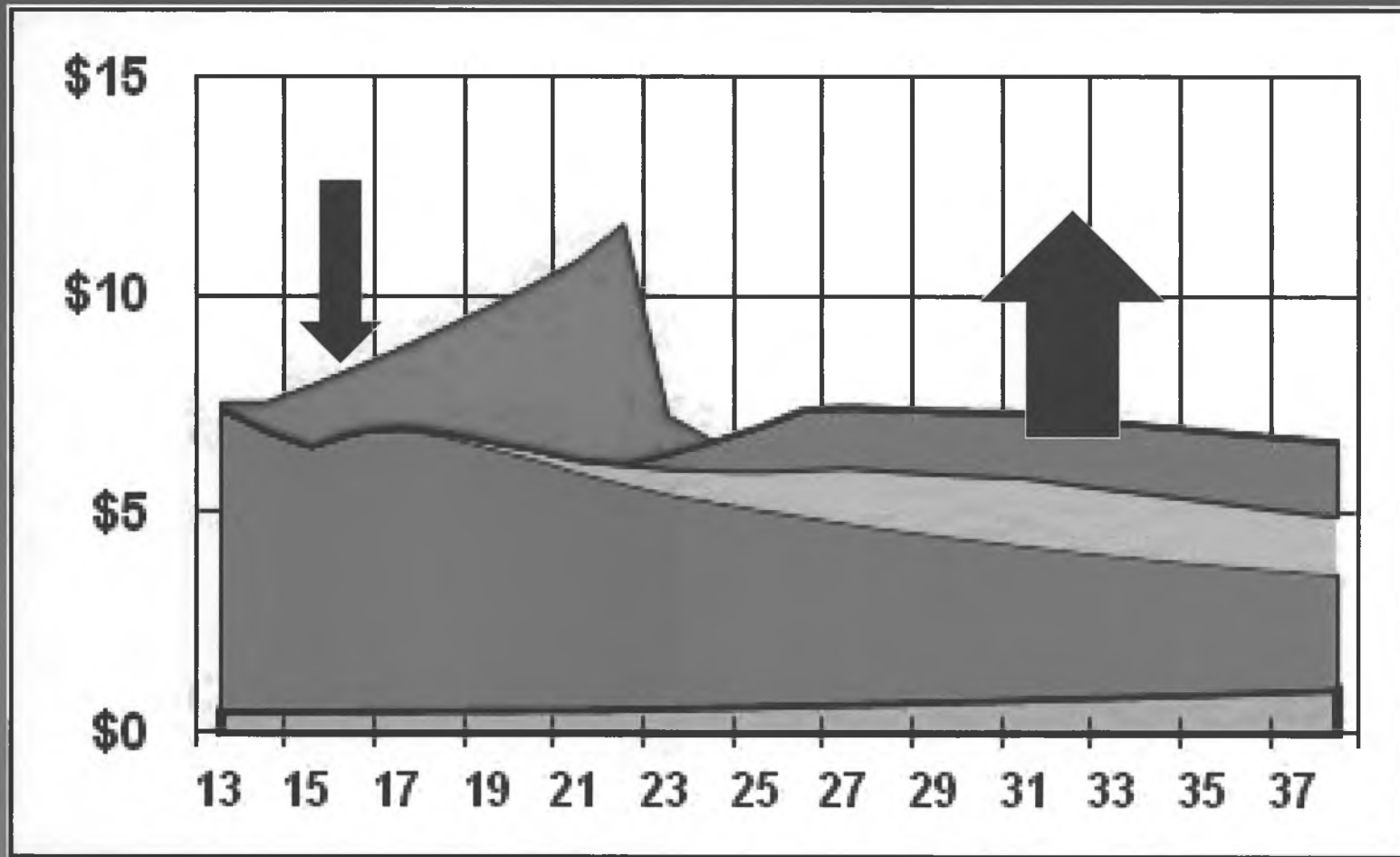
ALASKA 10-YEAR FISCAL PLAN



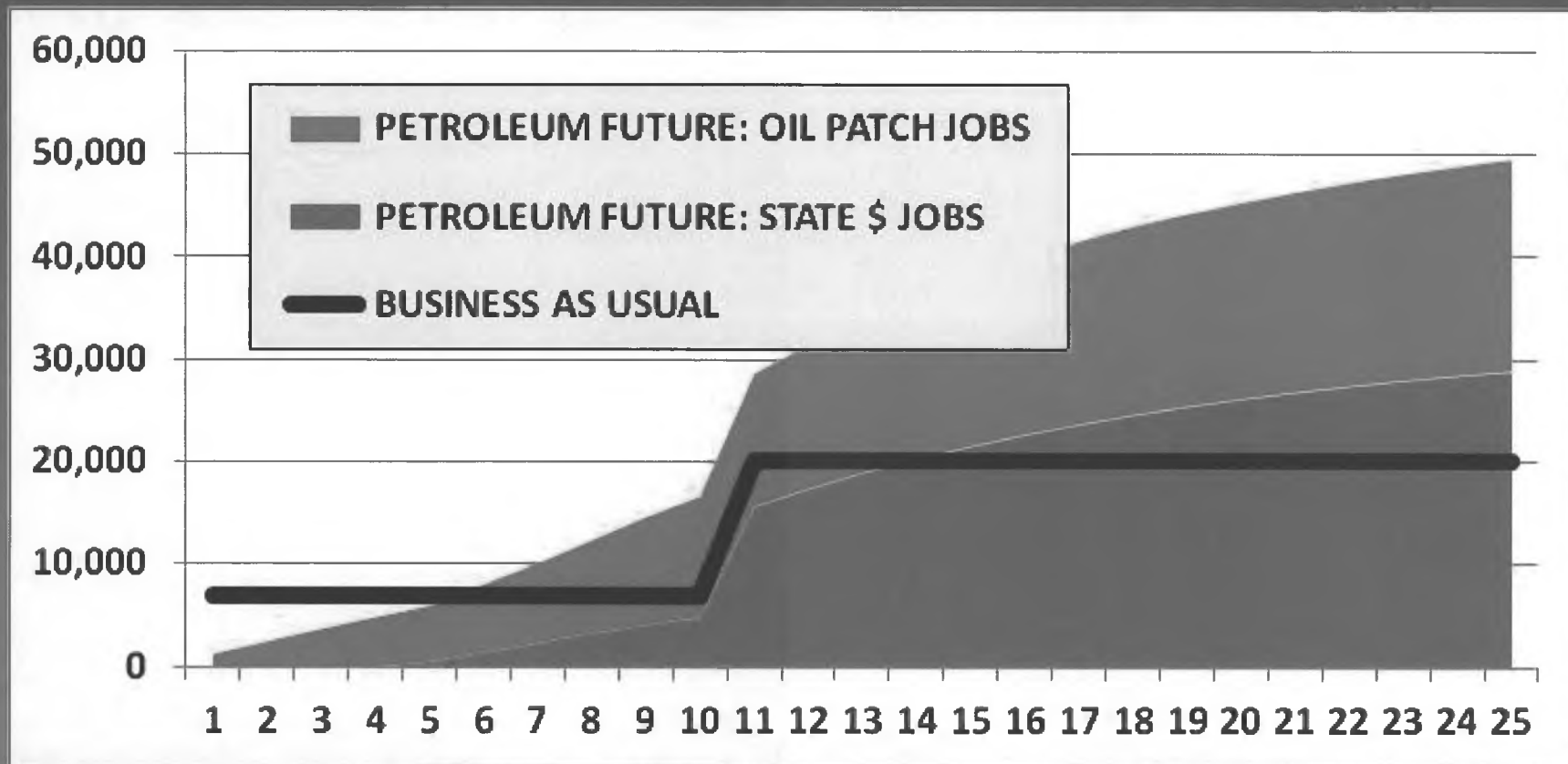
LOOKING BEYOND THE 10-YEAR HORIZON



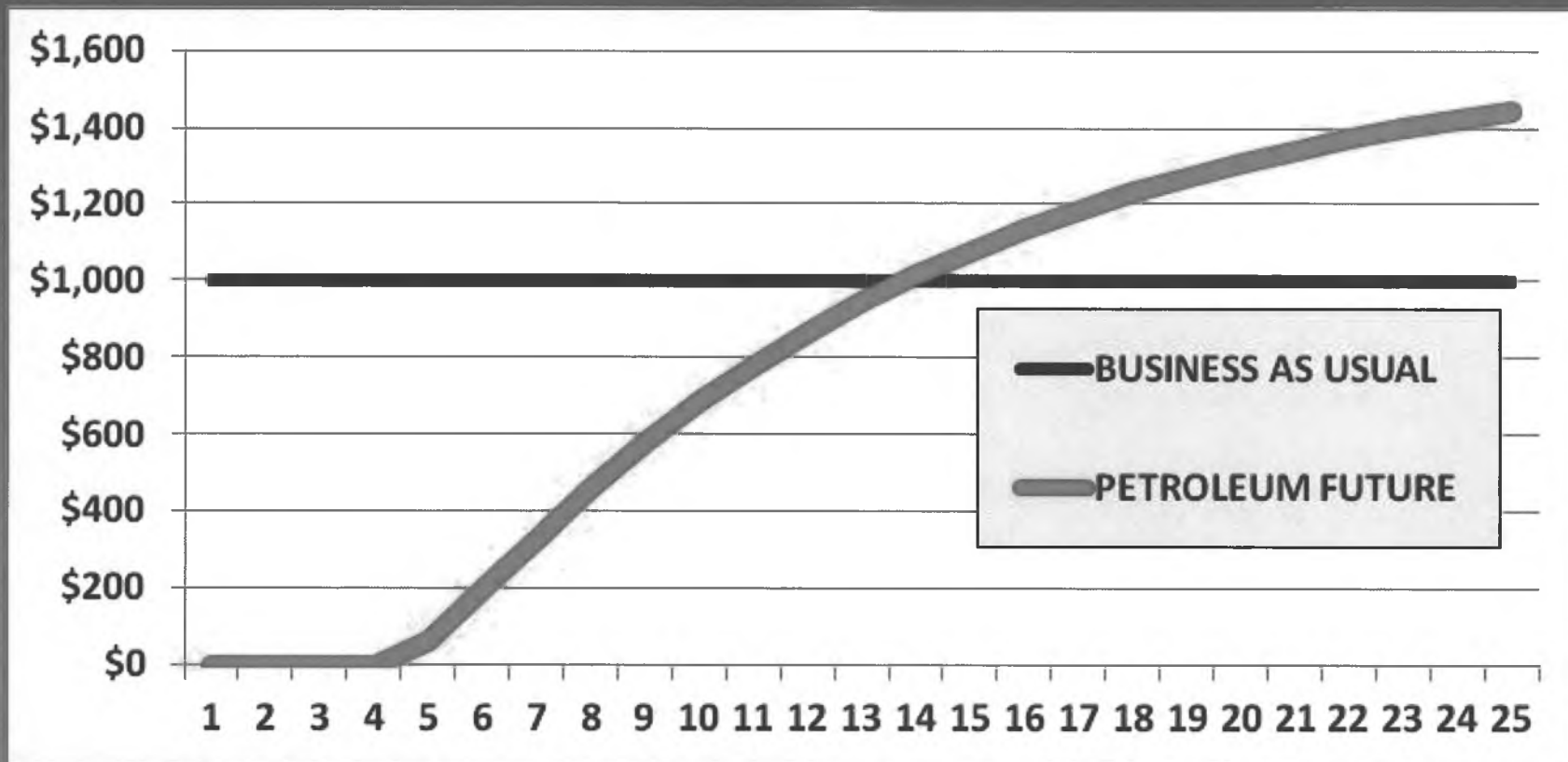
Move Towards Sustainability



Continuous Spending for 25 Years: Jobs



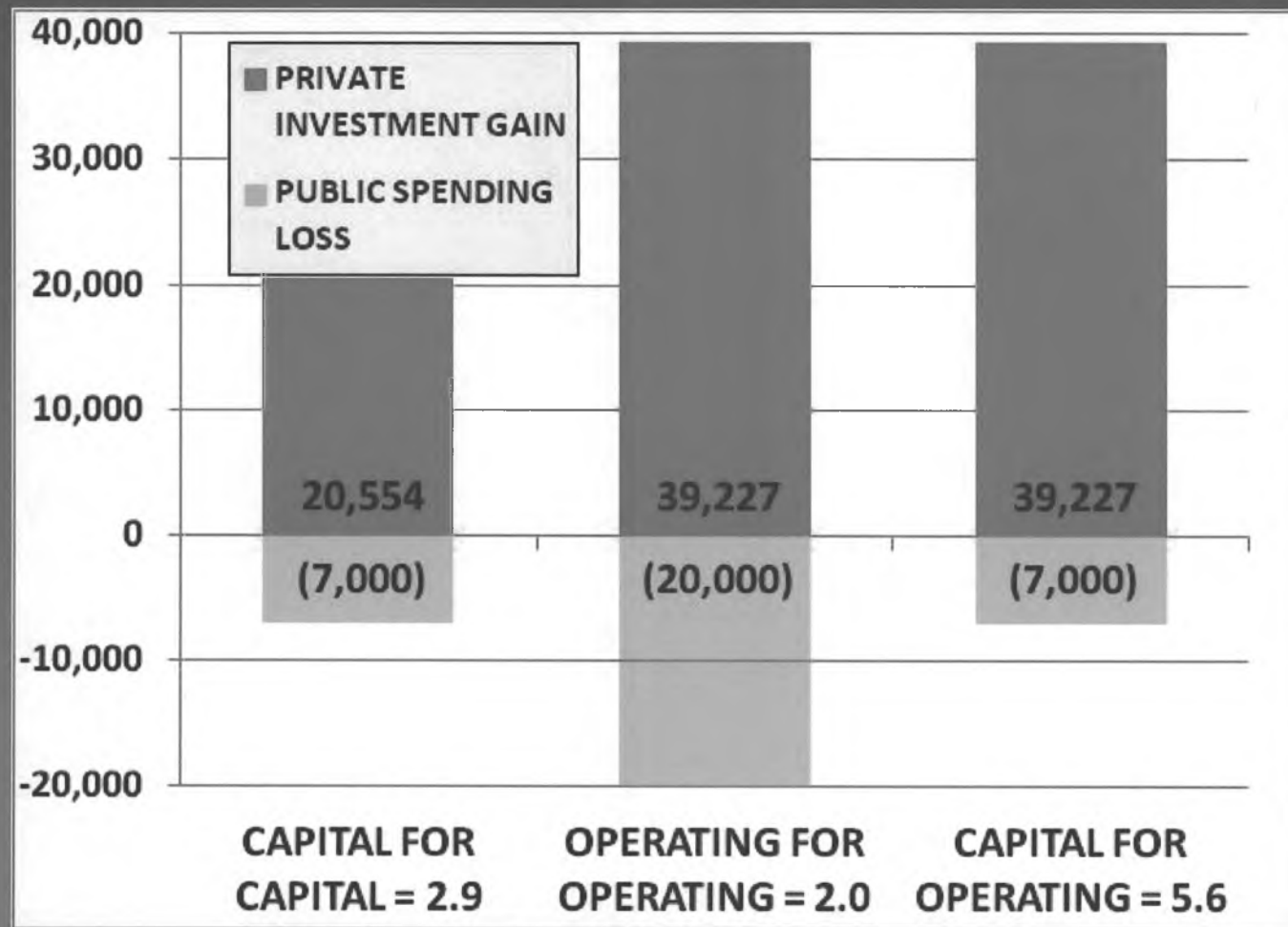
Continuous Spending for 25 Years: Revenue



Non-Petroleum Strategies for Continuing Economic Prosperity

- Natural Resource Development
- Value Added Processing
- Economic Diversification
- Infrastructure Investments in Power and Transportation
- Footloose Industry
- Renewable Energy

Cumulative Jobs Generated



Petroleum: Jobs and Revenues

by

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Alaska State Legislature

House Resources Committee

February 25, 2013

Juneau, Alaska

Institute of Social and Economic Research
University of Alaska Anchorage

*Taps
throughput
Committee
Dist. to
HRES
Members*



Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal

Econ One Research, Inc.

January 24, 2013

Presentation Structure

- I. Introduction**
- II. The Petroleum Industry in Alaska**
- III. History of North Slope Production, Development and Tax Systems**
- IV. North Slope Activity Over The Past Decade**
- V. Benchmarking North Slope Activity Against Other Areas**
- VI. Attractiveness of Investments Under ACES**
- VII. The Administration's Proposed Changes**

I. Introduction

Econ One: Who We Are

- **Economic Research and Consulting Firm**
 - **Offices in Los Angeles, Houston, Sacramento and Washington D.C.**
 - **Provide Economic Analysis In Energy and Other Industries**
- **The Econ One Team Is Led By Barry Pulliam**
 - **Includes Washington Lem, Lisa McGuff, Tasha Reese and Dr. Anthony Finizza**
- **Advised the State of Alaska on Petroleum Related Matters For Over Two Decades**
- **Worked With the Cowper, Hickel, Knowles, Murkowski, Palin, and Parnell Administrations**
- **Assisted the Legislature Between 2005 and 2008 on Tax and Gas Development Issues**
- **Energy-Related Work Outside Alaska**
 - **State Governments: Texas, Louisiana, New Mexico, Oklahoma, California**
 - **Federal Government Agencies: Department of Interior, Federal Trade Commission**
 - **Producers, Refiners, Pipelines and Chemical Companies**

Overview of Analysis

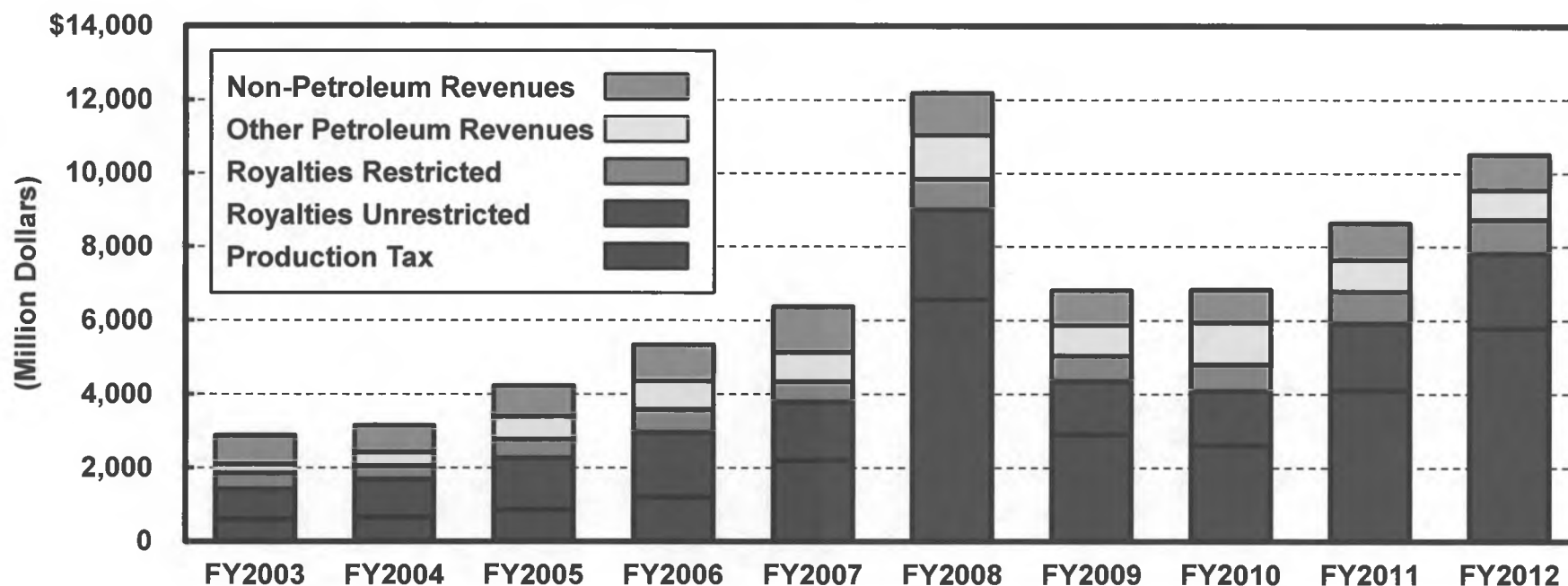
- **North Slope Development, Production, and Resources**
- **Evolution of Alaska's Fiscal and Tax System**
 - **Gross Tax (ELF), Net Tax (PPT, ACES)**
- **Examination of North Slope Activity Over The Past Decade**
 - **Production, Employment, Spending, Drilling**
- **Benchmarking the North Slope Against Other Areas**
 - **Key Producing Areas in OECD Countries**
 - **Lower-48, Canada, North Sea, Australia**
- **Examination of North Slope Investment Opportunities**
 - **Across Alaska's Gross and Net Tax Systems**
 - **Relative to Benchmark Areas**
- **Examination of Proposed Changes to Tax System**
 - **Rationale and Implications**
 - **Impact on Investment Opportunities**

II. The Petroleum Industry in Alaska

Impact of Petroleum on State Revenues

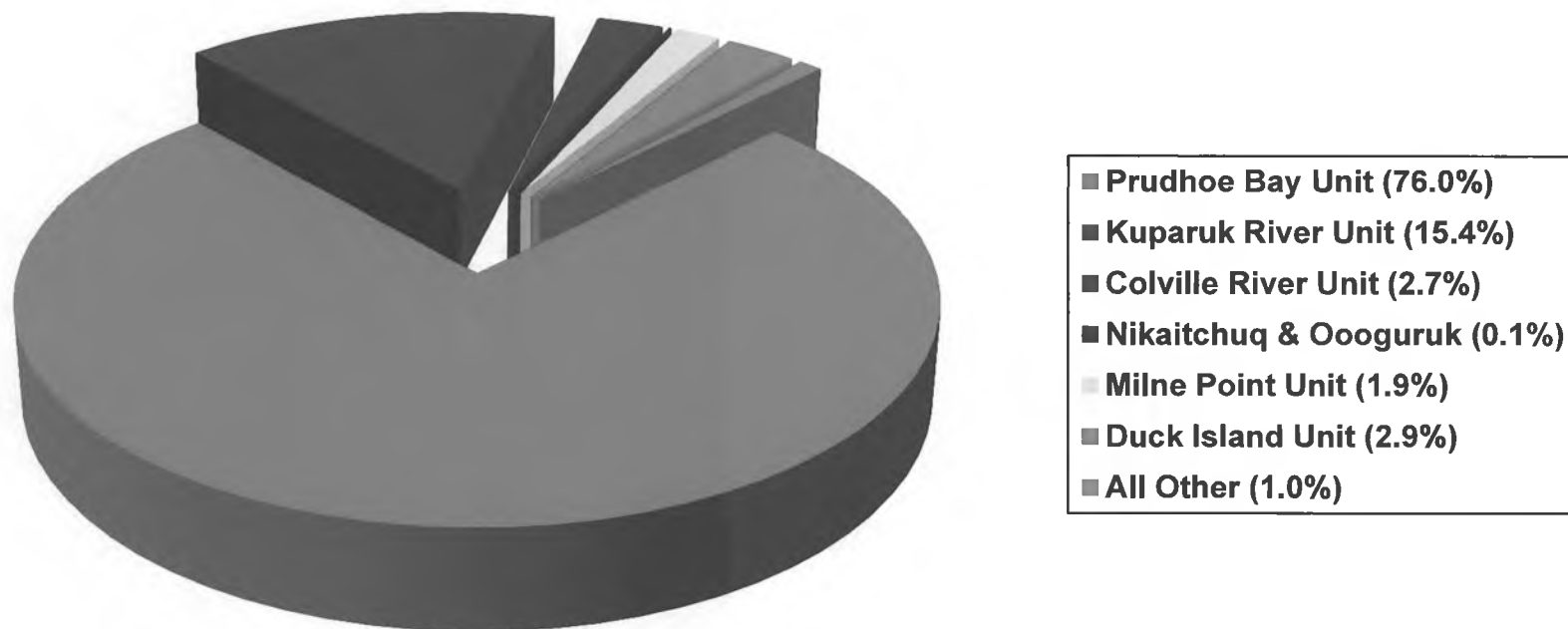
Total State Revenues Excluding Federal and Investment FY2003 - FY2012

- **Petroleum Industry is Largest Contributor to State Economy**
- **Industry Accounted For 92% of Unrestricted Revenues and 86% of Restricted and Unrestricted Revenues Over the Past Decade**
- **Production Taxes Accounted for 61% of Petroleum Revenues In FY2012, Up From 27% Prior to FY2007**



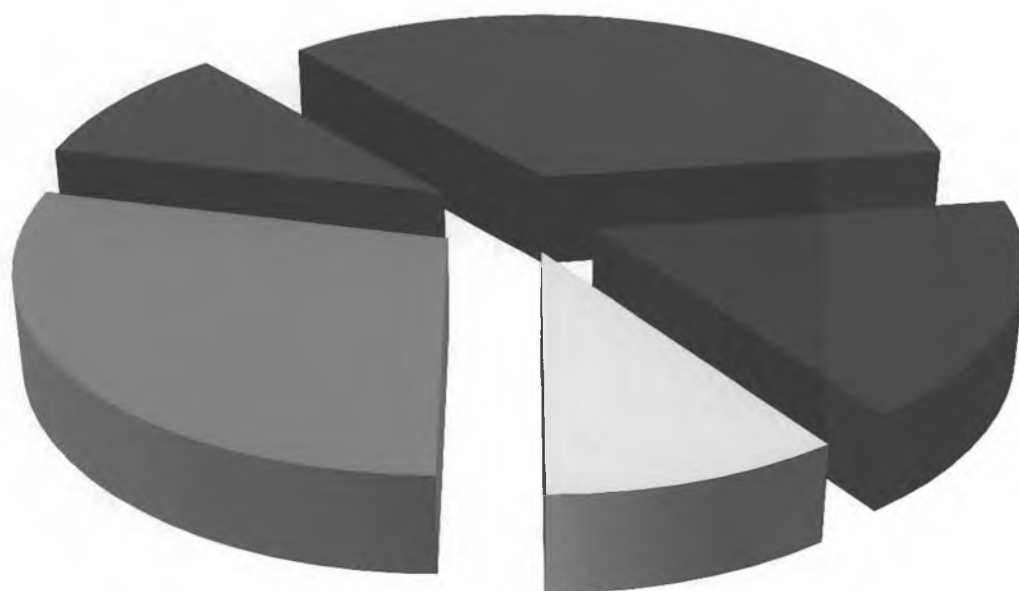
Alaska North Slope: An Overview

- **The North Slope Has Produced Approximately 16 Billion Barrels of Crude Oil Since 1977**
- **The Vast Majority of North Slope Production Has Come From Two Giant “Legacy” Fields, Prudhoe Bay and Kuparuk, Discovered in the 1960s. Production From These Two Fields is Naturally Declining Over Time, Though the Decline Has Been Partially Offset by the Addition of Smaller Discoveries.**



Alaska North Slope: An Overview (cont'd)

- **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**
(19.2 BBO est.)
- **ANWR**
(9.9 BBO est.)
- **Unconventional Resources**
(5.5 BBO est.)

Alaska North Slope: An Overview (cont'd)

- **While the Potential is Great, These Remaining Resources are Not “Low-Hanging” Fruit**
 - **The Exploration and Development Costs on the North Slope are High Relative to Much of the Rest of the World**
 - **The North Slope is a Physically Challenging Environment, With Much of the Remaining Resources Located Offshore**
 - **And Much of the Remaining Resources are Located on Federal Properties, Where Development Has Been and May Continue to be Delayed Due to Legal Challenges and Changing Federal Policies and Requirements**

- **In Addition, the North Slope has Significant Natural Gas Resources That Have Yet to be Commercialized**

Estimated Undiscovered Conventional Oil Resources on Alaska North Slope

	Technically Recoverable Resources			Economically Recoverable	Expected Typical
	P95	Mean	P5	@ \$90/bbl	Field Size
	(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
<u>ANWR</u>	<u>5,900</u>	<u>10,400</u>	<u>15,200</u>	<u>9,900</u>	<u>64 - 128</u>
<u>Total</u>		<u>38,300</u>		<u>29,100</u>	

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)

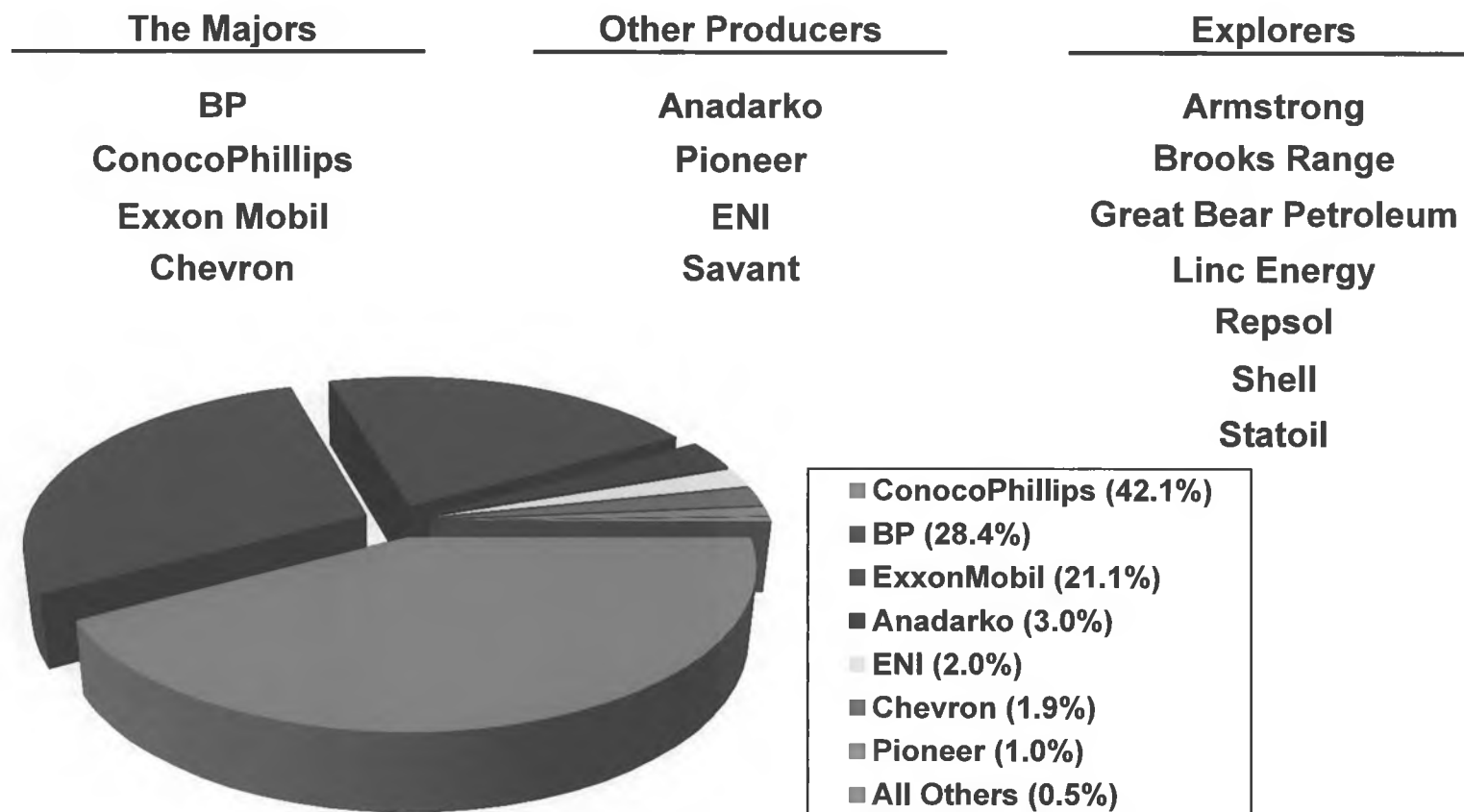
Economically Recoverable

3.6 - 5.6 Billion Bbls

(Assuming 15% Average Recovery)

Current and Potential ANS Producers

- **Three Large Producers Account for Most of the State's Current Production. However, in Recent Years, Alaska Has Attracted a Number of New Participants, With Several Developing and Operating Fields on Their Own**



Current and Potential ANS Producers

The Majors

- **Account for Approximately 9.5 Million BOED of Production Worldwide**
- **Account for More Than 90% of North Slope Production, About 0.4 Million BOED Net in Alaska**
- **Activity in Alaska**
 - **BP: Developing Resources From Existing Fields; Facility Renewal; Liberty Suspended**
 - **ConocoPhillips: Developing Kuparuk, Colville River and Expansion**
 - **ExxonMobil: Developing Point Thomson**
 - **Not Actively Exploring Outside These Areas**
- **Outside of Alaska**
 - **BP: High Margin Areas: Angola, Azerbaijan, Gulf of Mexico, North Sea**
 - **ConocoPhillips: High Margin Areas: Unconventional Lower-48, North Sea, Canada, Asia Pacific**
 - **ExxonMobil: Russia; Recent Offshore Discoveries in Gulf of Mexico (Hadrian) and Newfoundland (Hebron)**

Current and Potential ANS Producers Other Producers / Explorers

- **Pioneer and ENI Operating and Continuing to Develop Oooguruk and Nikaitchuq, Respectively**
 - **First Operators on North Slope Other Than Majors**
 - **Combined Resource Potential Greater Than 250 Million BOE**
- **Anadarko is Fourth Largest Interest Owner on North Slope; Acquired Additional Foothill Leases This Year**
- **Repsol Partnering With Affiliate of Armstrong Oil and Gas**
 - **Announced \$768 Million Multi-Year Budget; Drilled 3 Exploration Wells in 2012**
- **Brooks Range Developing Mustang: Estimated P2 Reserves Between 40 and 50 Million BOE**
 - **Working With AIEDA on Initial Financing**
- **Great Bear Exploring Shale Potential**
- **Linc Energy Exploring Umiat in NPRA**
- **Savant Operating and Developing Badami; Took Over From BP in 2011**

Current and Potential ANS Producers Offshore Explorers

- **Shell Spent \$2.1 Billion to Acquire Chukchi and Beaufort Sea Leases in 2008**
 - **Estimated Spending of \$4.5 Billion to Date**
 - **First Drilling in 2012**

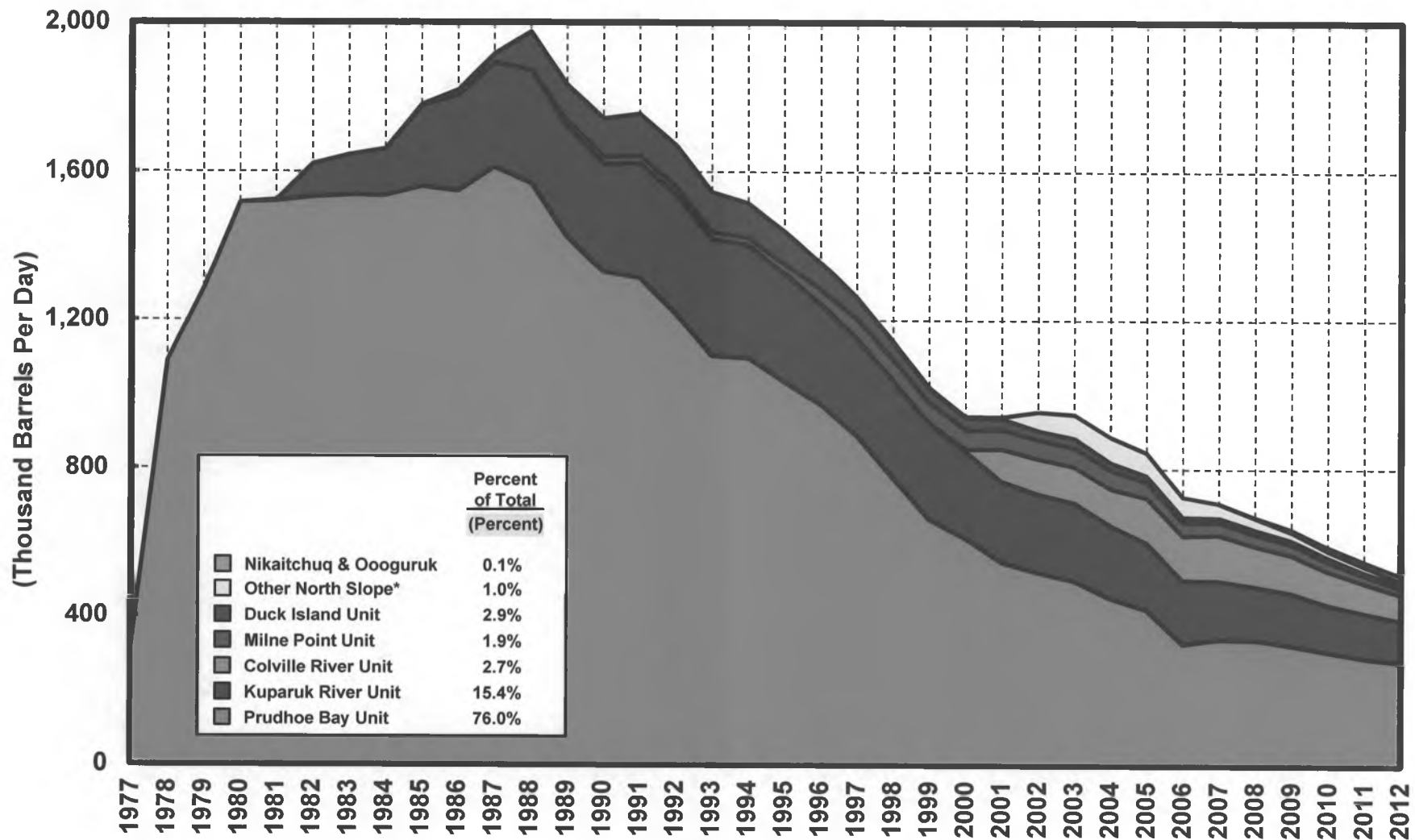
- **ConocoPhillips Spent \$500 Million on Chukchi Leases**
 - **Plans Drilling Activity in 2014**

- **Statoil Spent \$23 Million on Offshore Leases**
 - **Watching Shell for Now**

III. History of North Slope Production, Development and Tax Systems

Historical Volumes by Year and Field

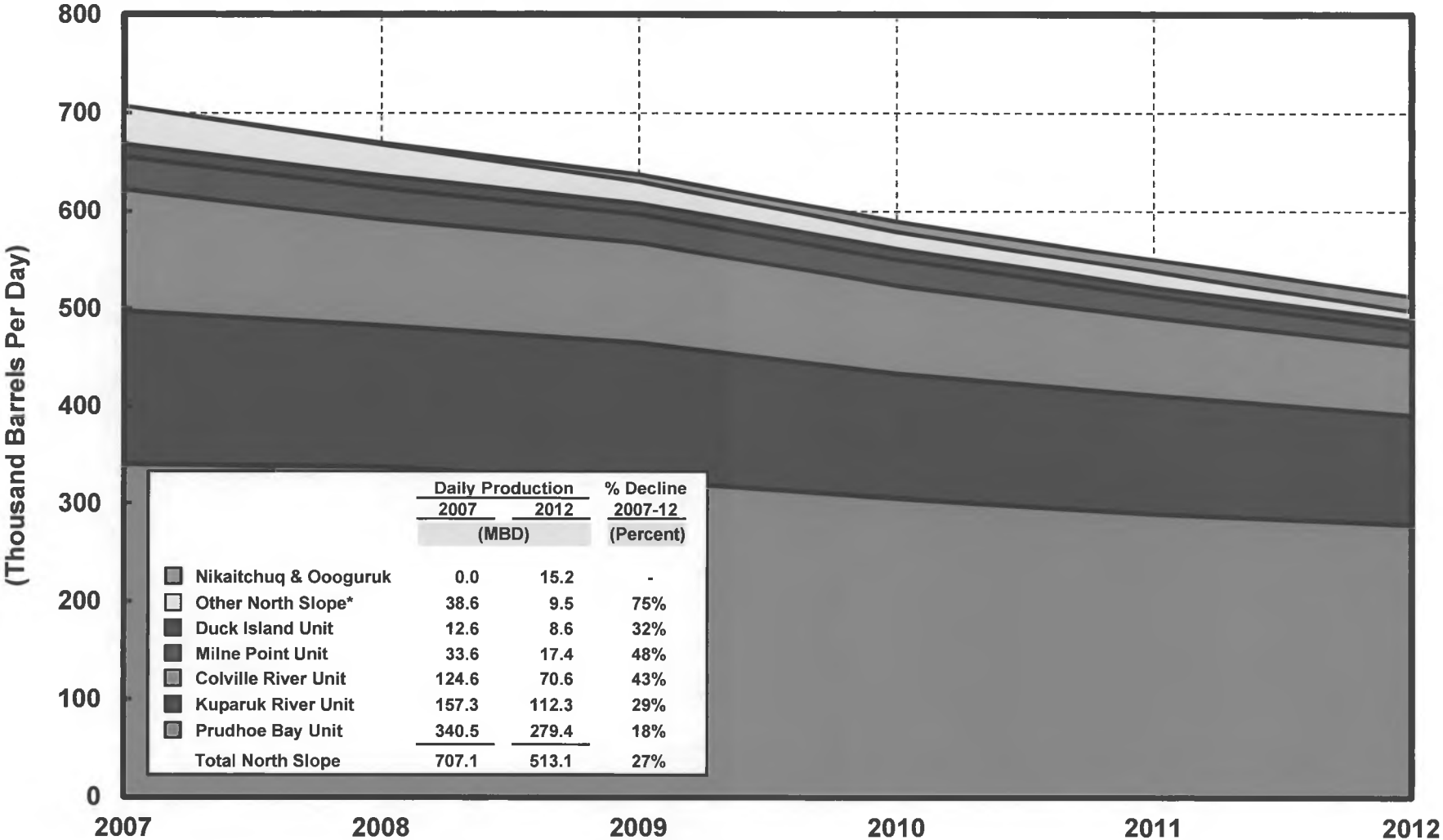
1977 - 2012



* Badami and Northstar.
Source: AOGCC.

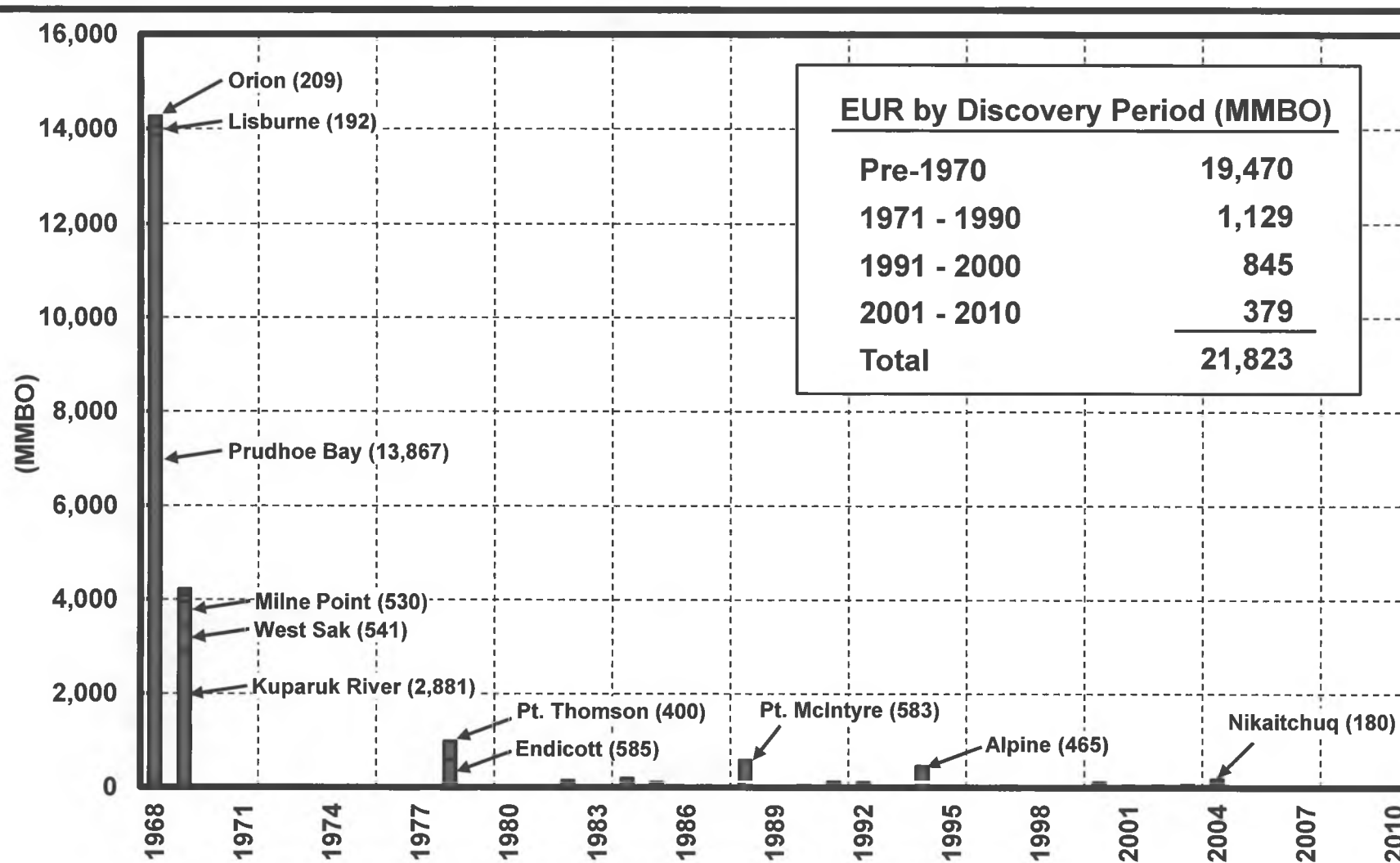
Historical Volumes by Year and Field

2007 - 2012



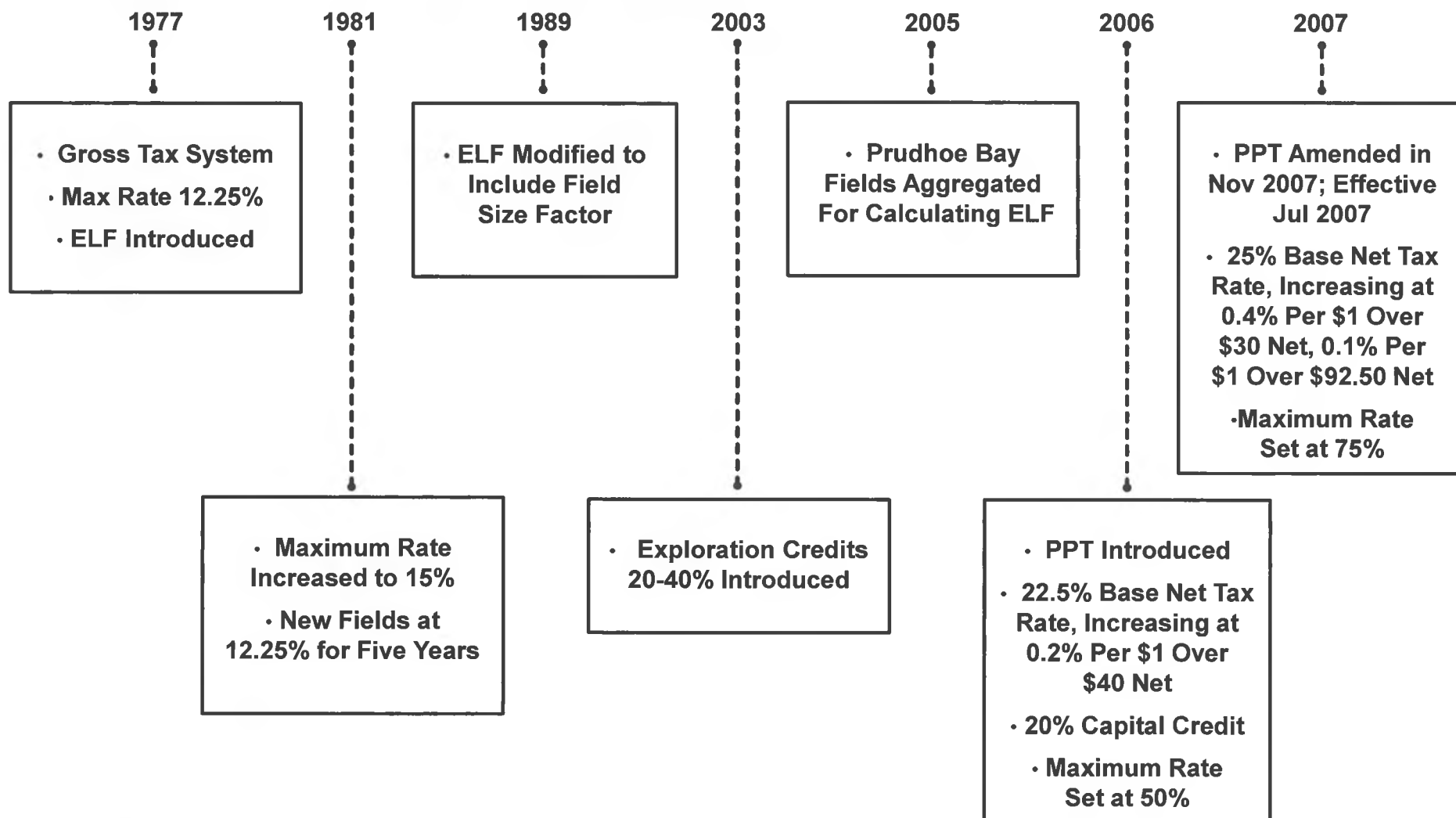
* Badami and Northstar.
Source: AOGCC.

Alaska North Slope Estimated Ultimate Oil Recovery (EUR) by Discovery Year (1969 – 2010)

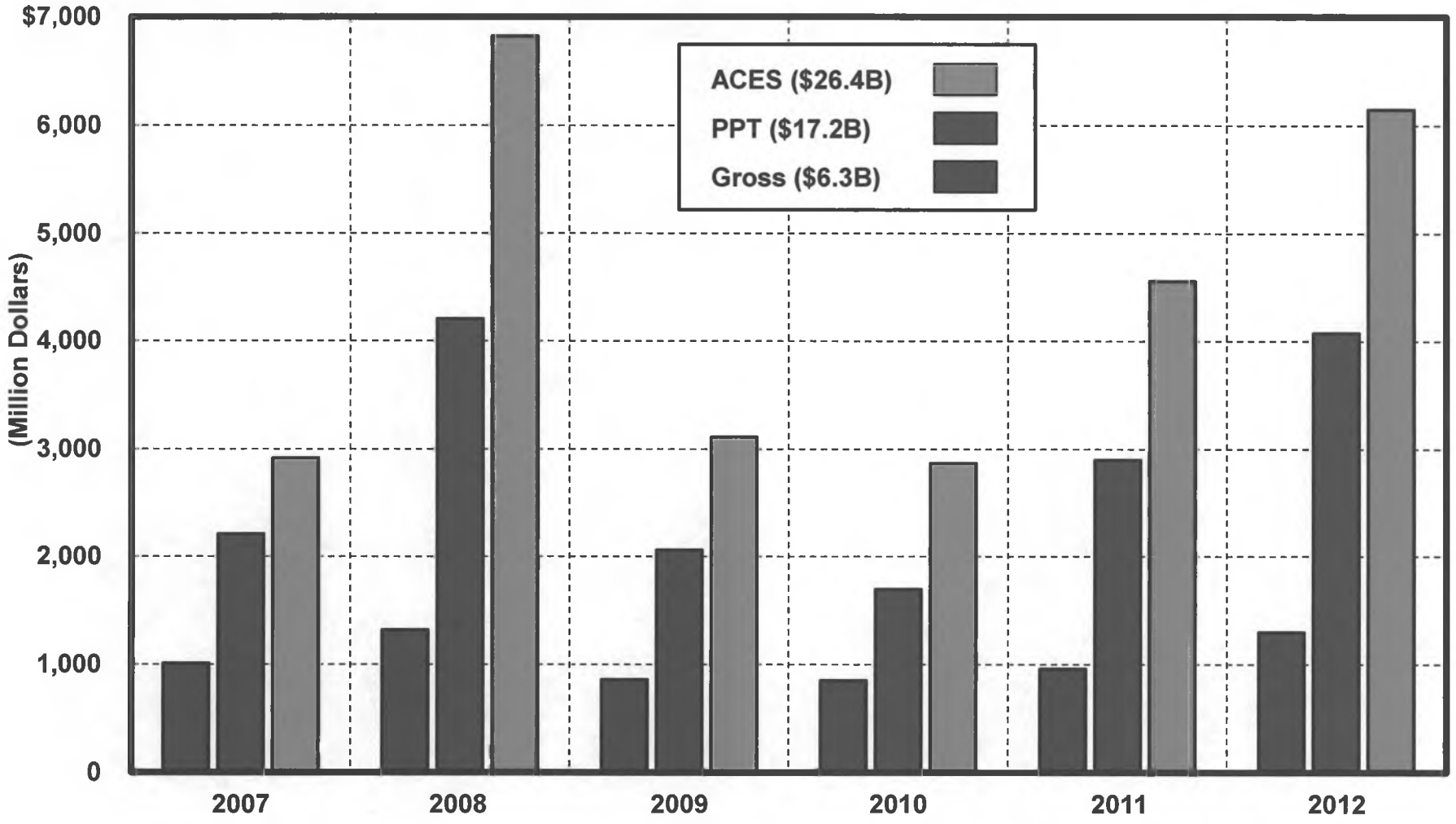


Source: DNR: The Historical Resource and Recovery Growth in Developed Fields, Arctic Slope of Alaska, 2004; DOE/NETL-2009/1385; AOGCC.

A History of Alaska's Production Tax System: North Slope



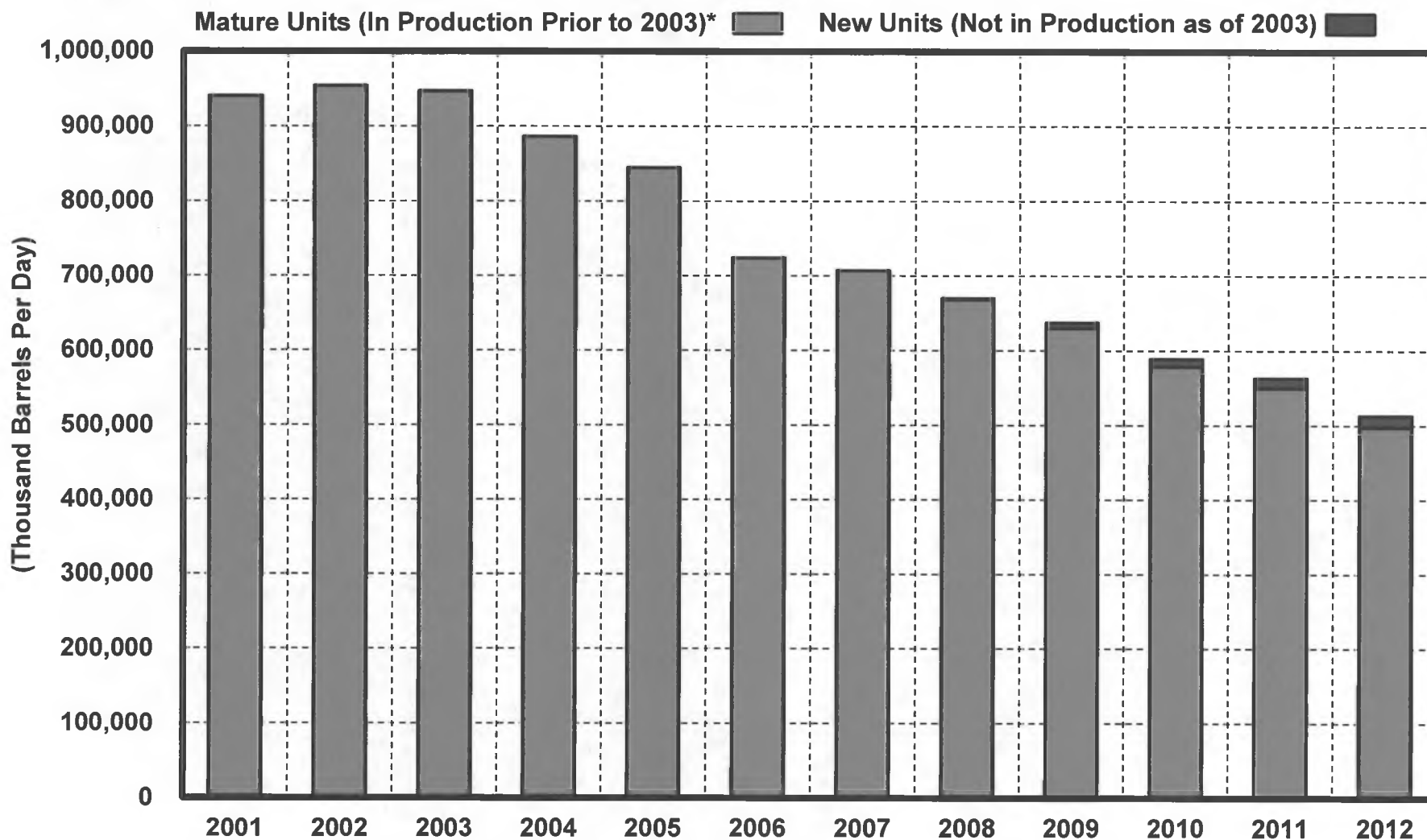
Estimated Production Tax Revenue (Assuming No Production Changes Across Systems) FY2007 - FY2012



Note: ACES figures are actual amount collected; figures for PPT and Gross are estimated based on application of terms under these tax systems to actual production and prices.
Source: DOR.

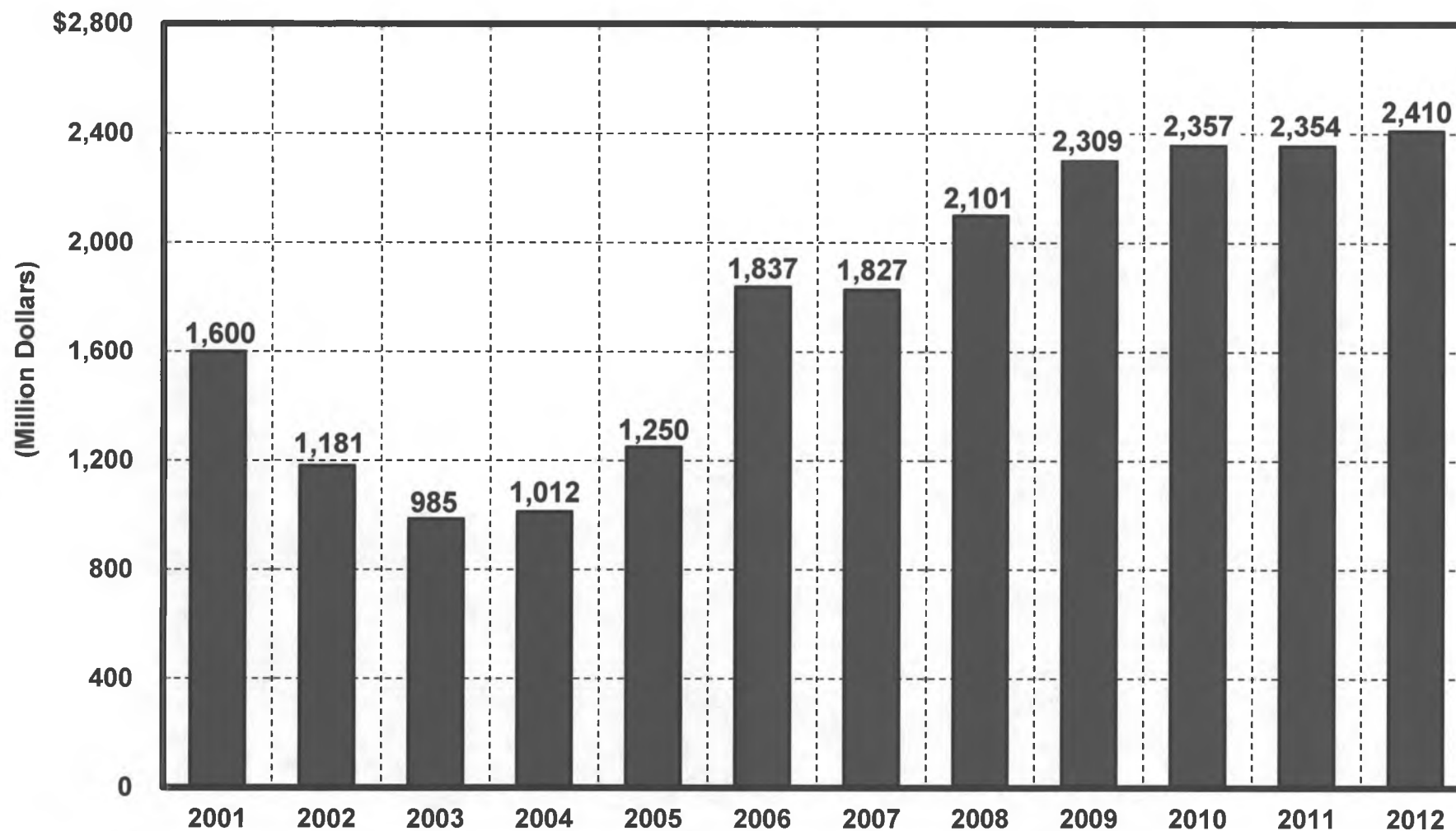
IV. North Slope Activity Over the Past Decade

Alaska North Slope Production by Unit 2001 - 2012



* Comprised of Prudhoe Bay, Kuparuk, Colville River, Badami, Northstar, Duck Island, Milne Point
Source: AOGCC.

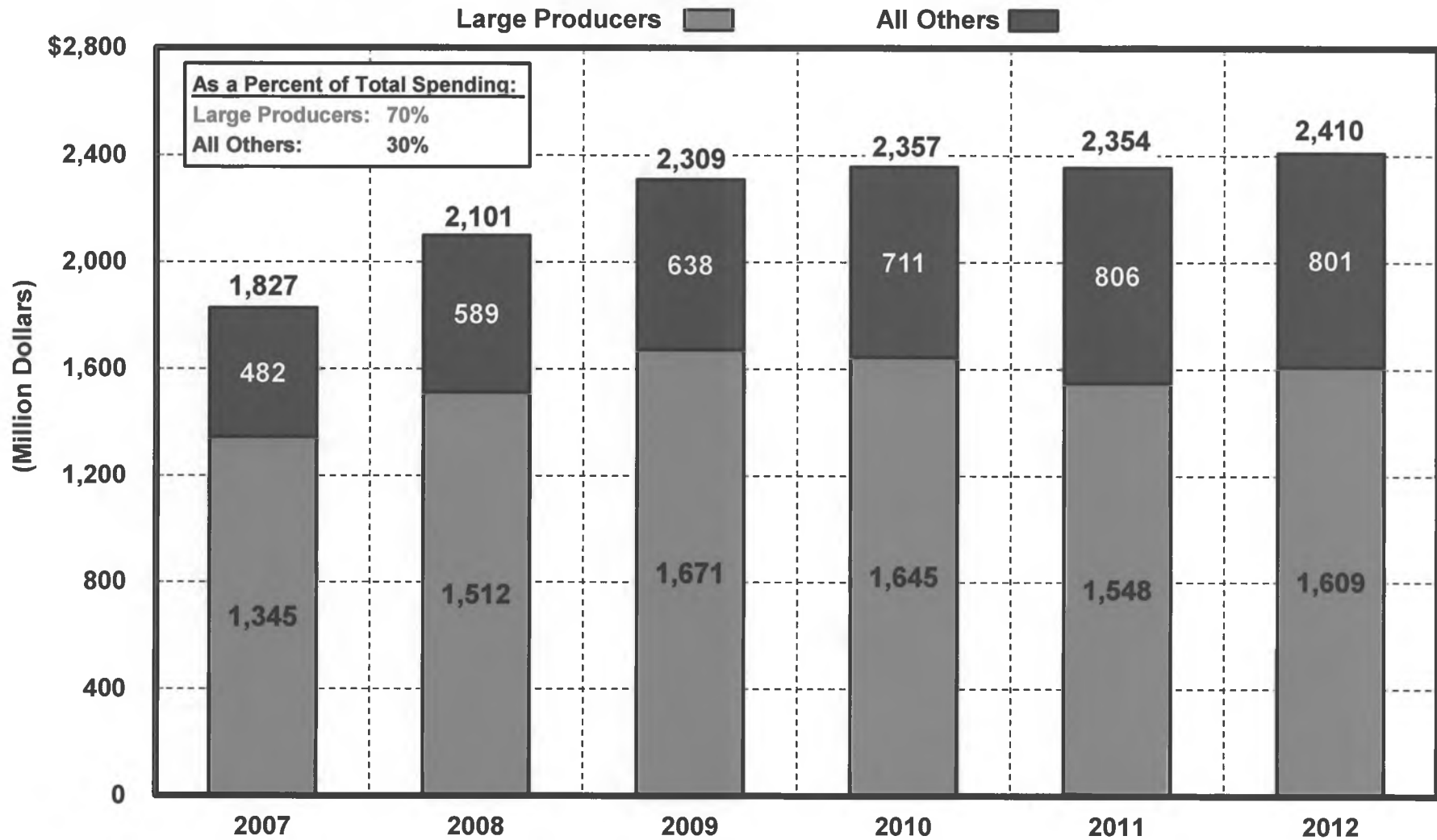
Reported Capital Spending for Alaska North Slope CY2001 - CY2012*



* Does not include expenditures associated with offshore federal properties.; 2012 estimated from preliminary data.

Source: DOR.

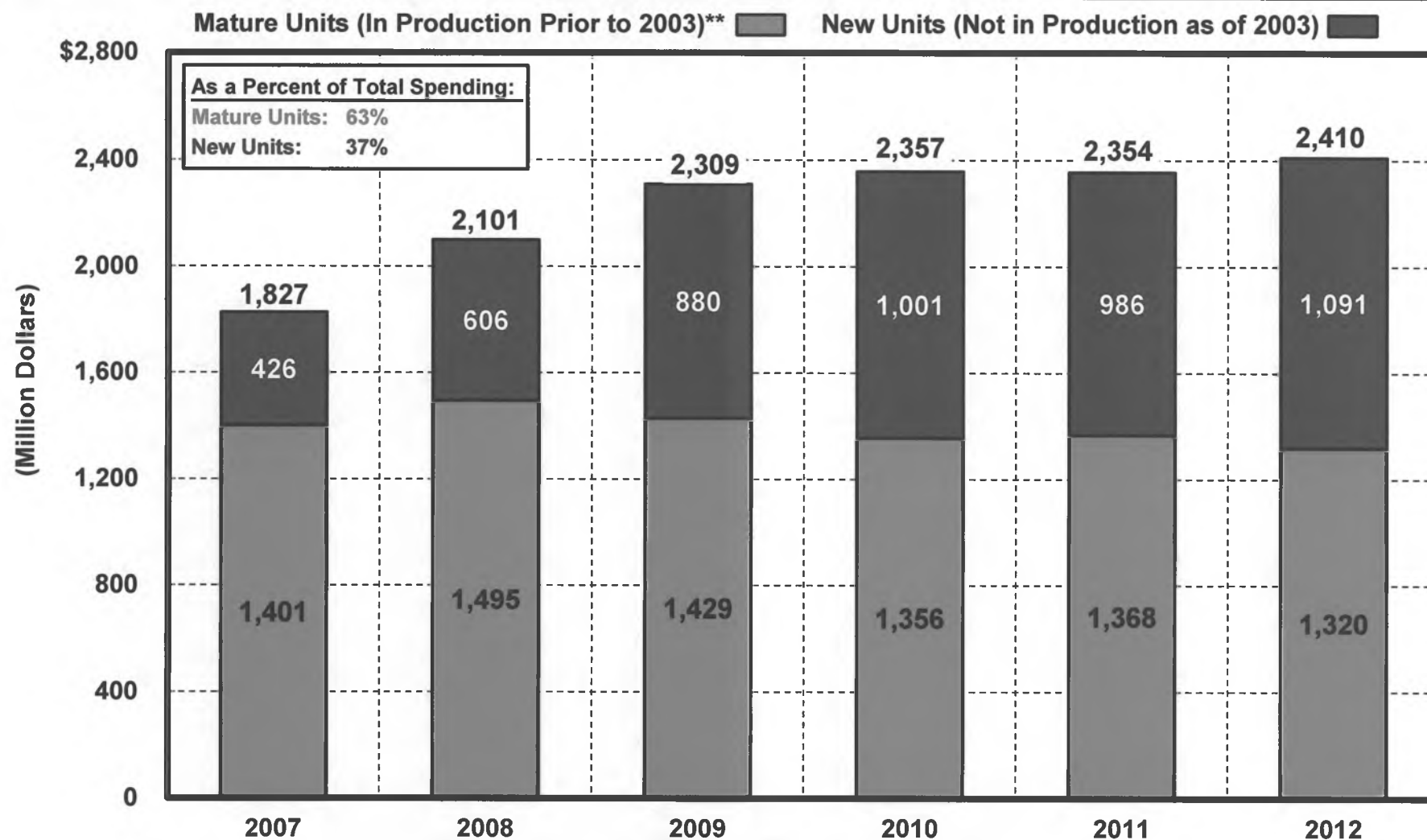
Reported Capital Spending by Alaska North Slope Producers CY2007 - CY2012*



* Does not include expenditures associated with offshore federal properties.; 2012 estimated from preliminary data.

Source: DOR.

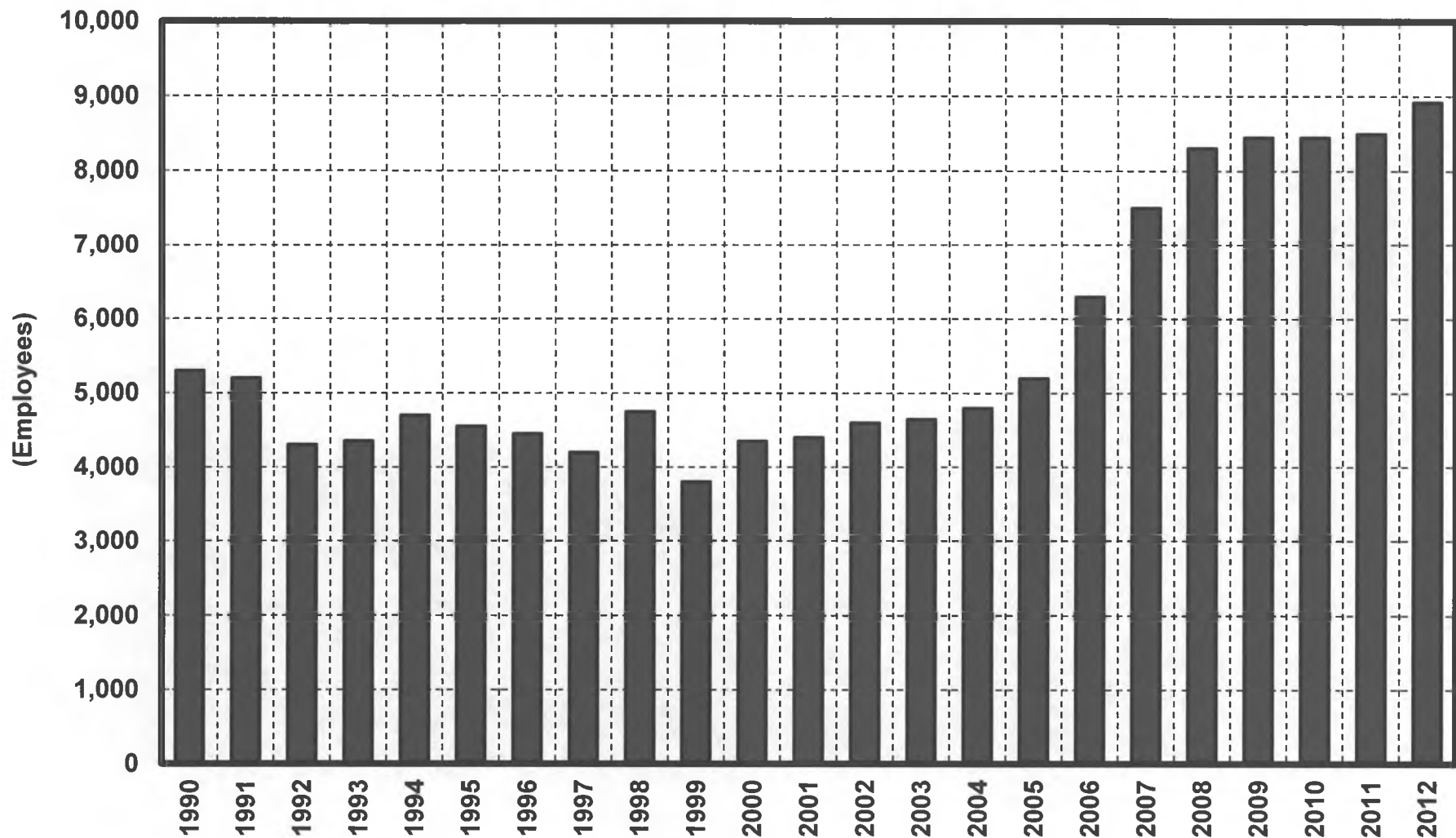
Reported Capital Spending by Alaska North Slope Producers by Unit CY2007 - CY2012*



* Does not include expenditures associated with offshore federal properties.; 2012 estimated from preliminary data.

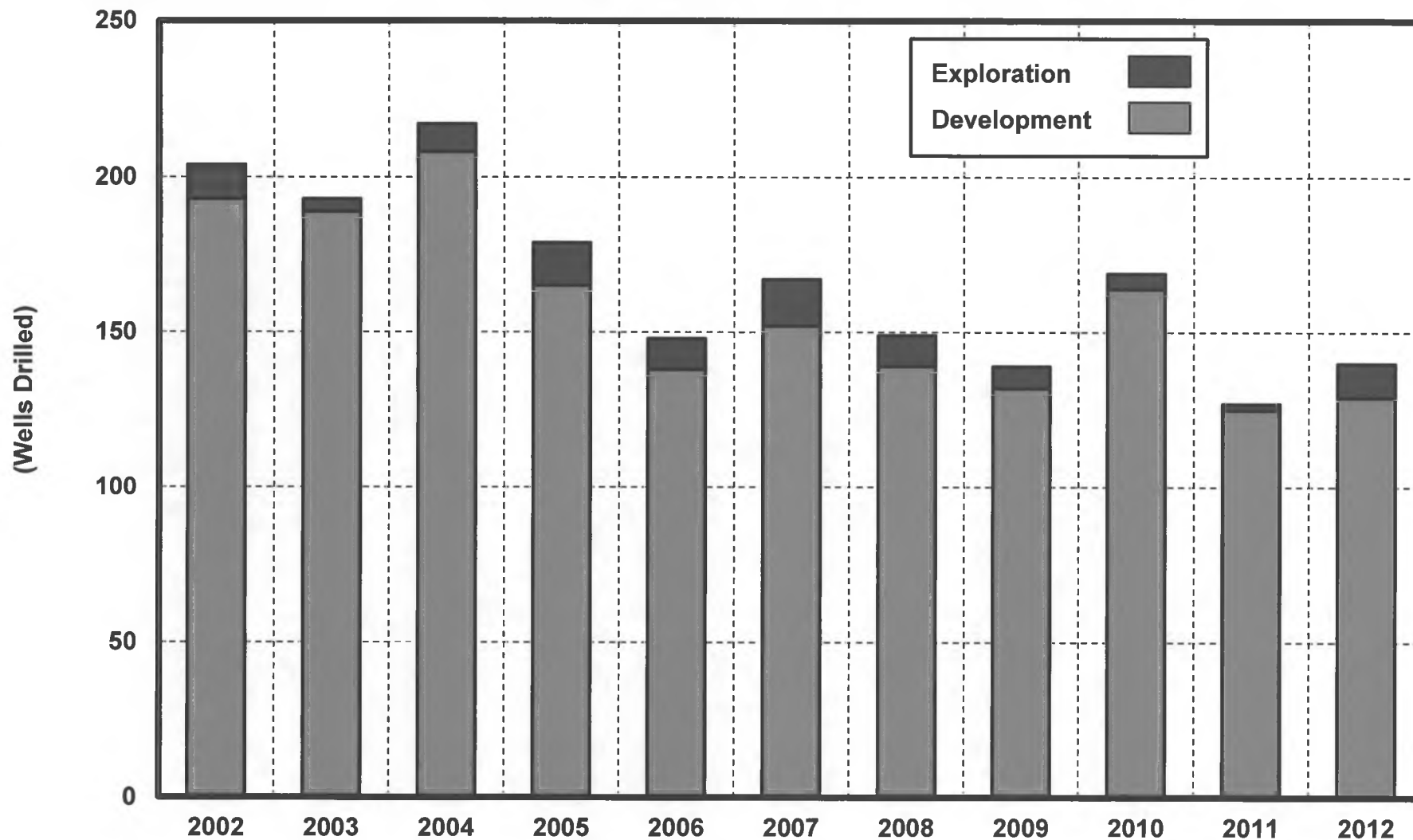
** Comprised of Prudhoe Bay, Kuparuk, Colville River, Badami, Northstar, Duck Island, Milne Point
 Source: DOR.

Alaska North Slope Oil and Gas Industry Employment 1990 - 2012



Source: Alaska Department of Labor.

Alaska North Slope Wells Drilled 2002 - 2012



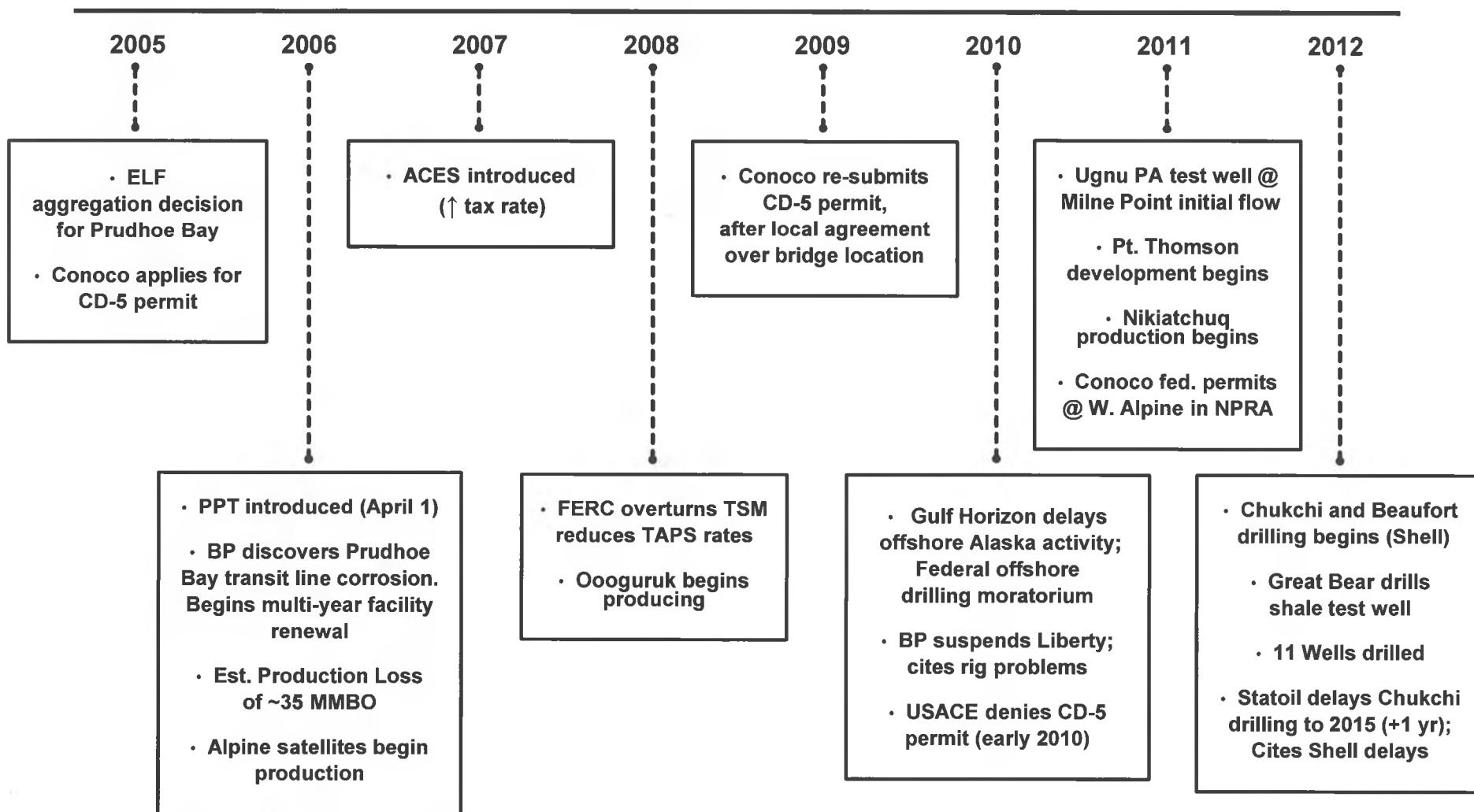
Source: 2002-2010: DNR; 2011-2012: AOGCC.

Drilling Activity in Alaska North Slope: By Well Completed Date January 2005 - December 2012

	2005	2006	2007	2008	2009	2010	2011	2012	Total
Development*									
BPXA	98	72	80	85	82	83	48	49	669
ConocoPhillips	67	65	72	49	40	65	61	56	522
ENI (inc. Kerr-McGee)	-	-	-	-	2	7	9	15	33
Pioneer	-	-	-	4	9	8	5	6	32
Brooks	-	-	-	-	-	-	-	-	-
Anadarko	-	-	-	-	-	-	-	-	-
Repsol	-	-	-	-	-	-	-	-	-
ExxonMobil	-	-	-	-	-	-	-	-	-
Others	-	-	-	-	-	1	2	3	6
Total	165	137	152	138	133	164	125	129	1,262
Exploratory									
BPXA	-	-	5	1	-	-	-	-	6
ConocoPhillips	5	5	2	2	2	-	1	1	18
ENI (inc. Kerr-McGee)	6	1	4	-	-	-	-	-	11
Pioneer	-	2	-	-	1	-	-	2	5
Brooks	-	-	1	4	-	2	1	3	11
Anadarko	-	-	1	2	3	-	-	-	6
Repsol	-	-	-	-	-	-	-	3	3
ExxonMobil	-	-	-	-	-	2	-	-	2
Others	3	3	7	9	5	3	-	2	32
Total	14	11	20	18	11	7	2	11	94
Total									
BPXA	98	72	85	86	82	83	48	49	675
ConocoPhillips	72	70	74	51	42	65	62	57	540
ENI (inc. Kerr-McGee)	6	1	4	-	2	7	9	15	44
Pioneer	-	2	-	4	10	8	5	8	37
Brooks	-	-	1	4	-	2	1	3	11
Anadarko	-	-	1	2	3	-	-	-	6
Repsol	-	-	-	-	-	-	-	3	3
ExxonMobil	-	-	-	-	-	2	-	-	2
Others	3	3	7	9	5	4	2	5	38
Total	179	148	172	156	144	171	127	140	1,356

* Development includes service wells.
Source: AOGCC.

Timeline of Significant Events on Alaska North Slope Since 2005



V. Benchmarking North Slope Activity Against Other Areas

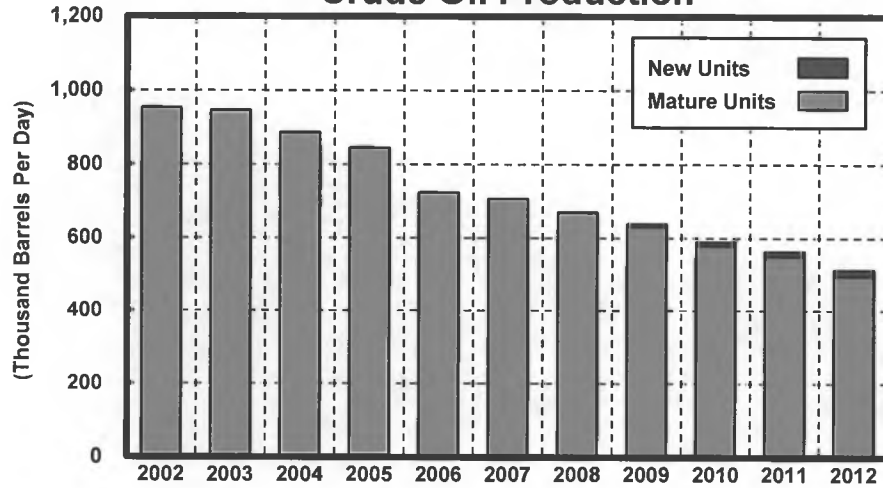
Benchmarking

- **Benchmarking Allows Us to Evaluate Activity in Alaska by Controlling for Significant Variables That are Common to All Oil Producing Properties, Such as Price and General Economic Conditions**
 - **No Two Producing Areas are Exactly Alike. Mindful of This, We Attempt to Choose Locations That Share a Number of Similar Characteristics, Allowing for the Most Meaningful Comparisons**
 - **We Benchmark the North Slope Against Several Areas Located in OECD Countries**
 - **The North Sea**
 - **The U.S. and Several Key Producing States / Areas**
 - **Canada and Producing Provinces**
 - **Australia**
 - **All of These OECD Areas Share Many of the Same, Characteristics With the North Slope**
 - **Similar Political and Legal Structure / Risk**
 - **Significant Prospectivity**
 - **But, Much of the “Low-Hanging” Fruit Has Been Produced**
 - **Development of Remaining Resources are Largely High-Cost, Either Conventional or Unconventional**
 - **Resources are Developed in Large Part by the Private Sector**
-

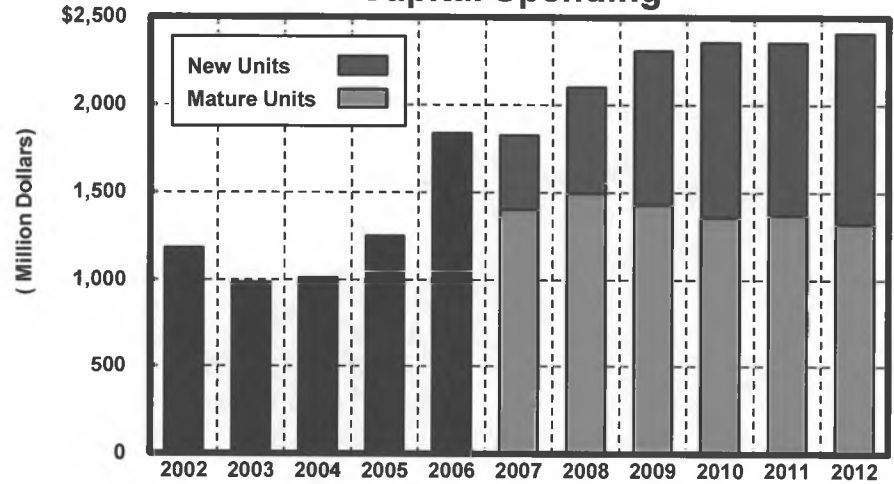
Country/Area Profile

Alaska North Slope

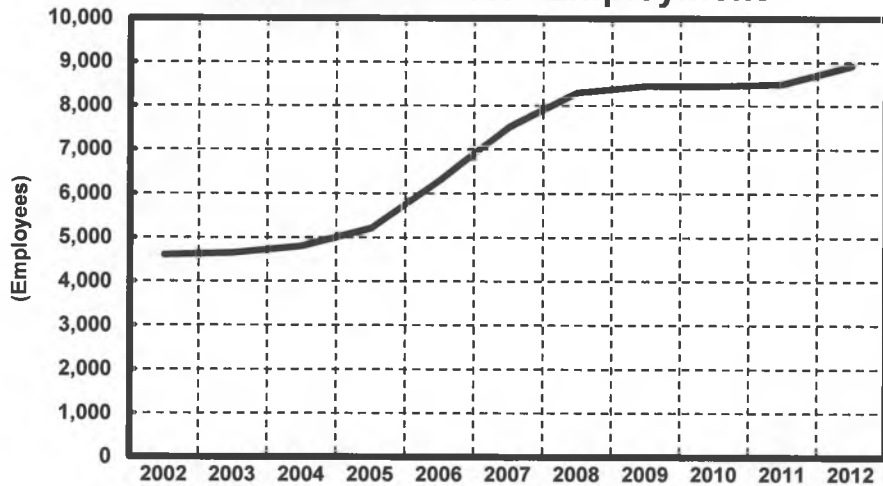
Crude Oil Production



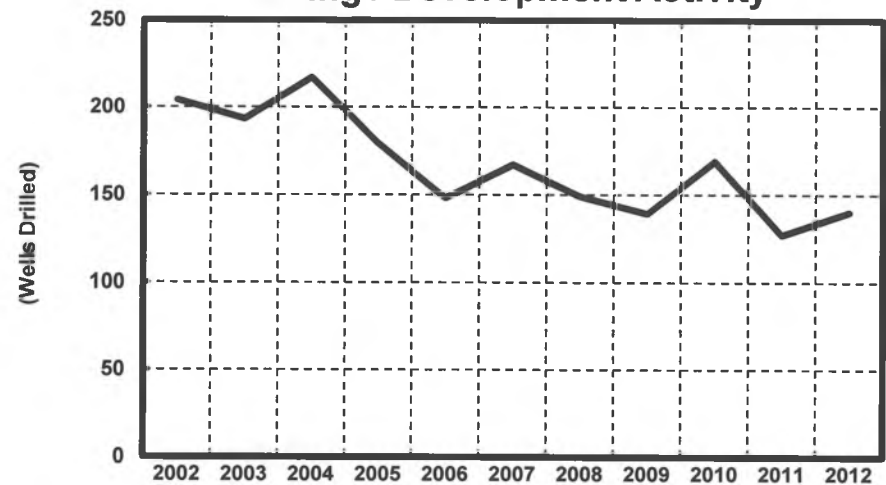
Capital Spending



Petroleum Sector Employment

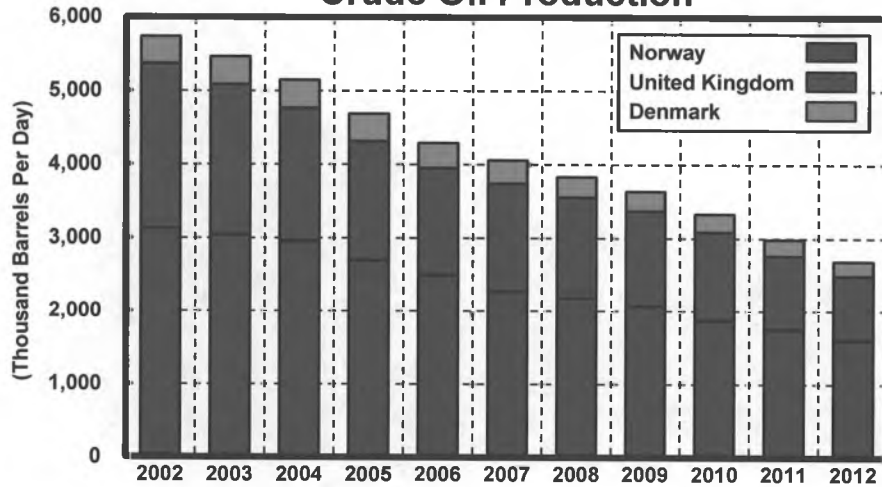


Drilling / Development Activity

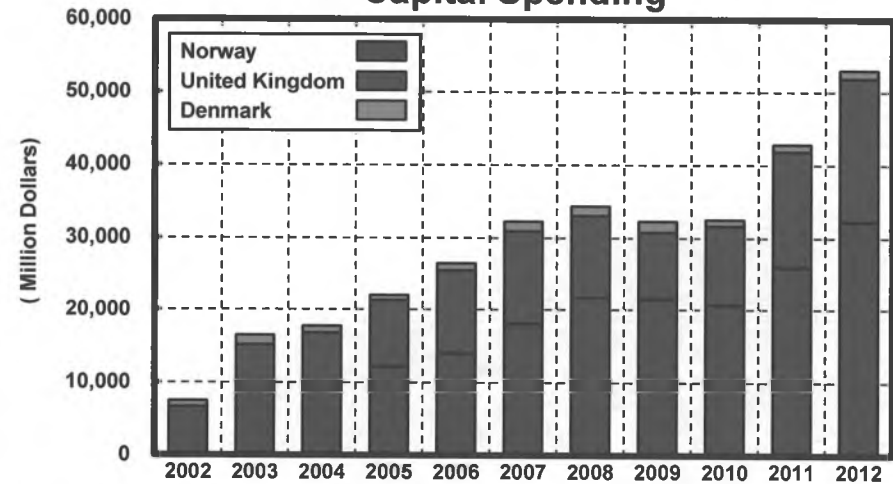


Country/Area Profile Northwest Europe (North Sea)

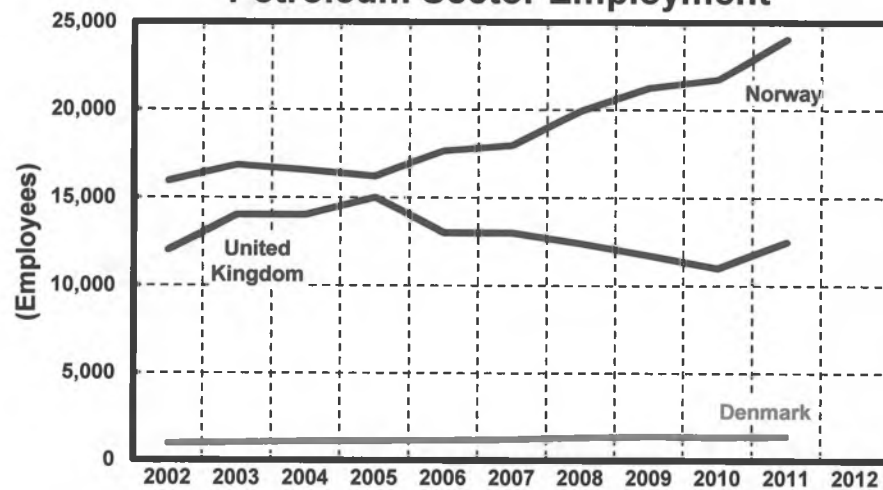
Crude Oil Production



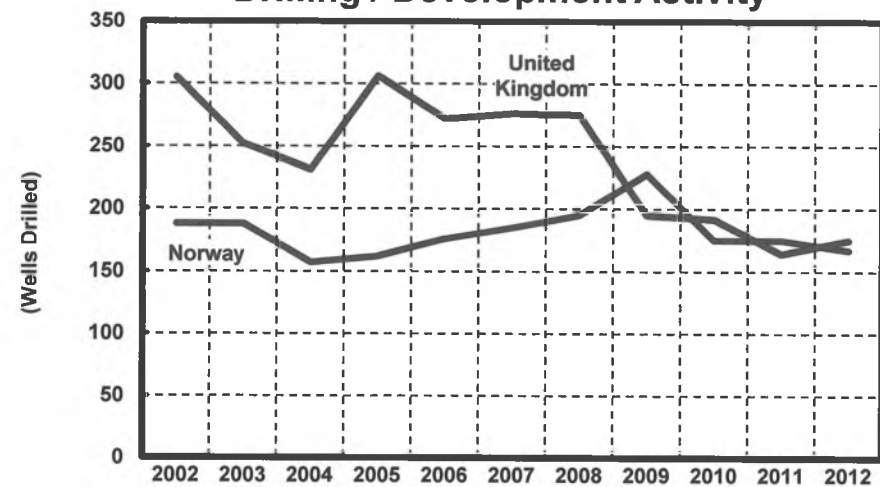
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity

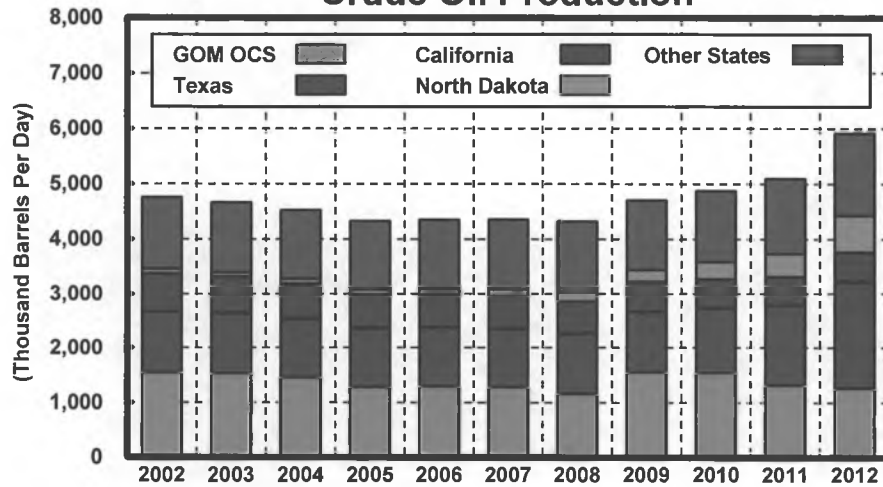


Note: 2012 figures are preliminary.

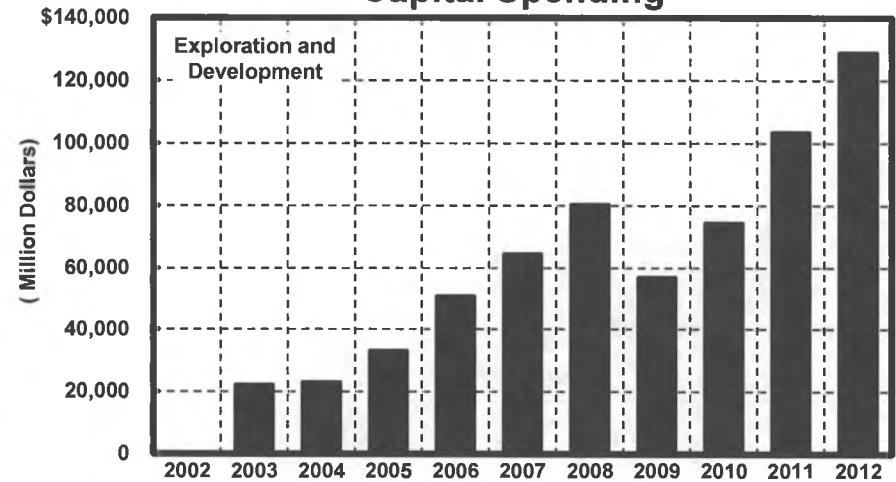
Country/Area Profile

United States Excluding Alaska North Slope

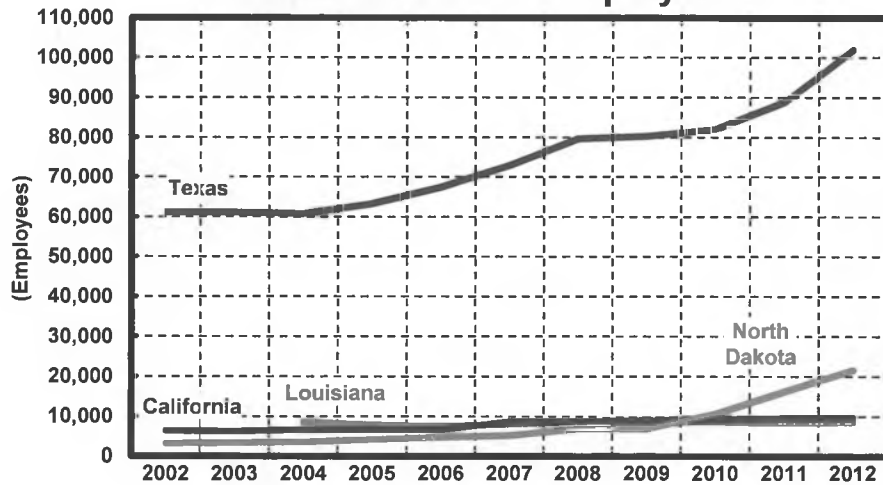
Crude Oil Production



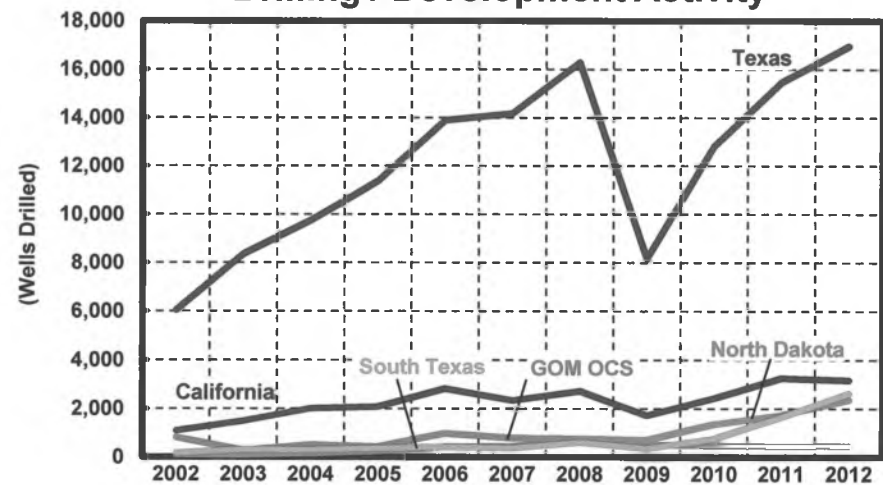
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity

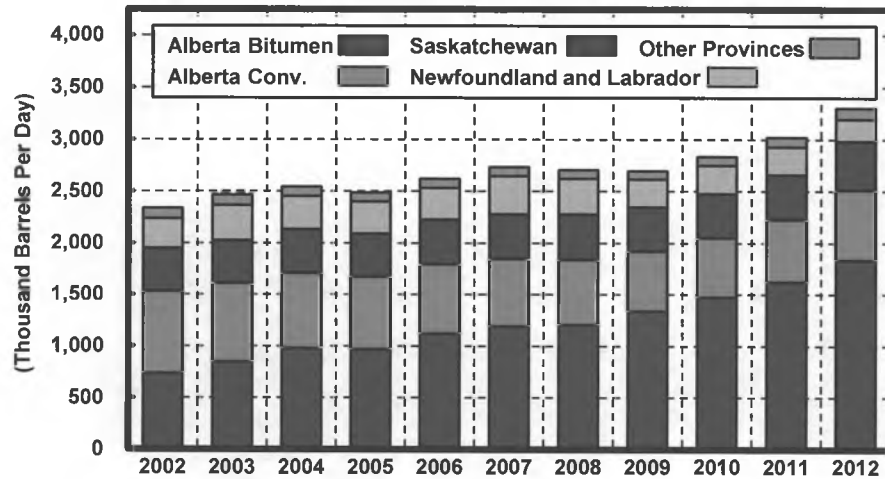


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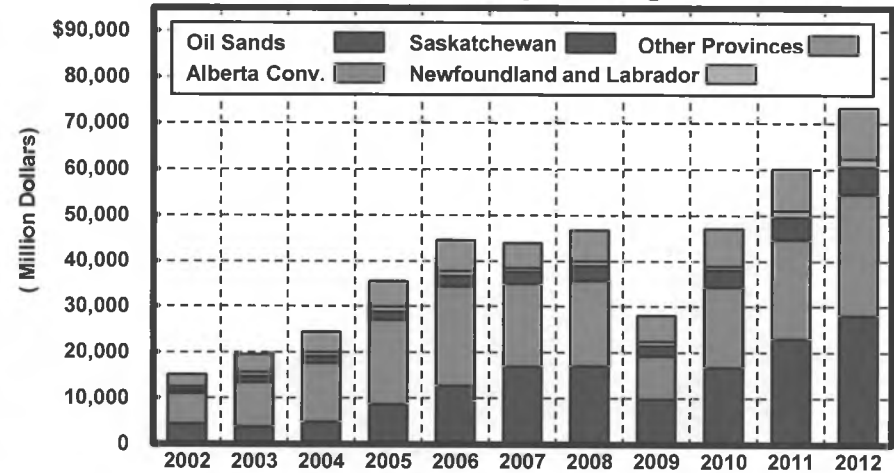
Country/Area Profile

Canada

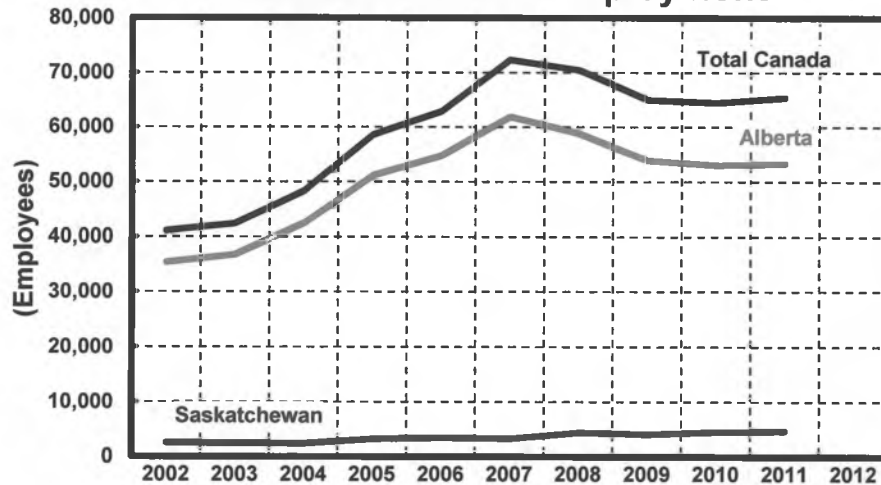
Crude Oil Production



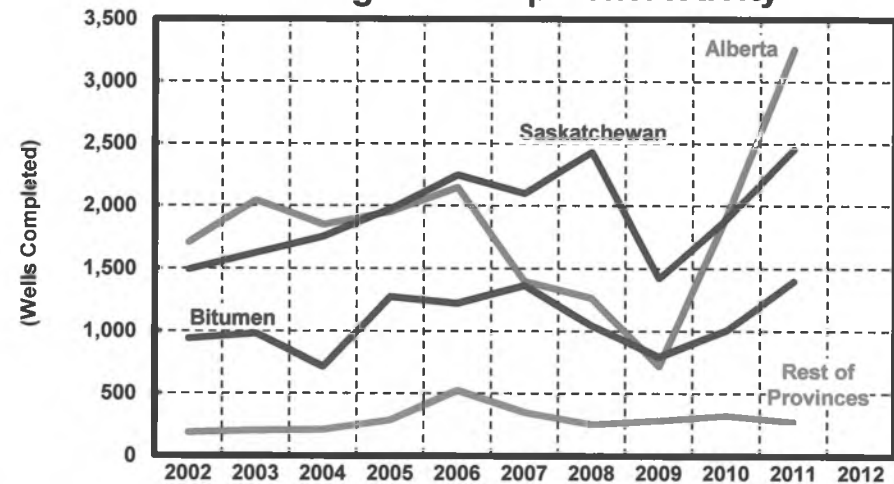
Capital Spending



Petroleum Sector Employment



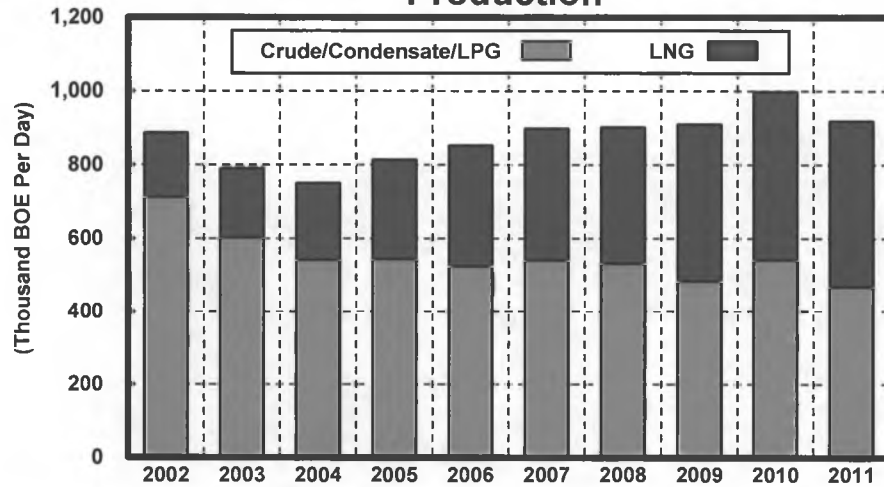
Drilling / Development Activity



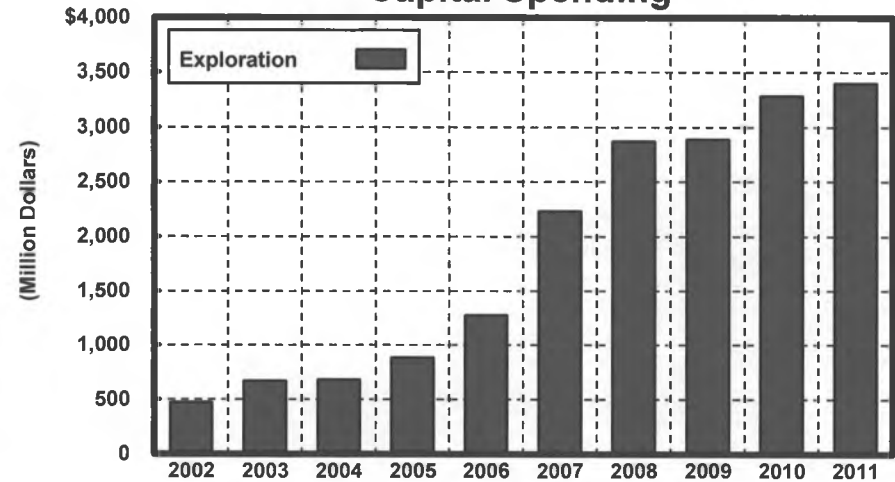
Note: 2012 figures are preliminary.

Country/Area Profile Australia

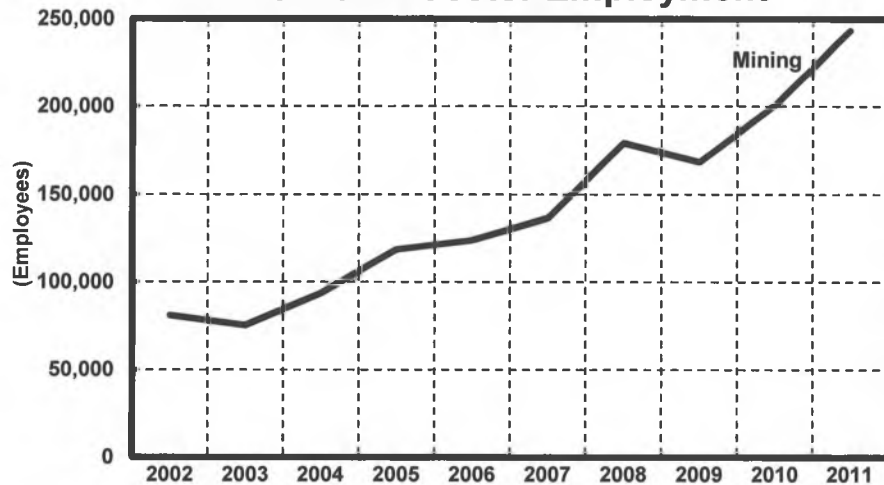
Production



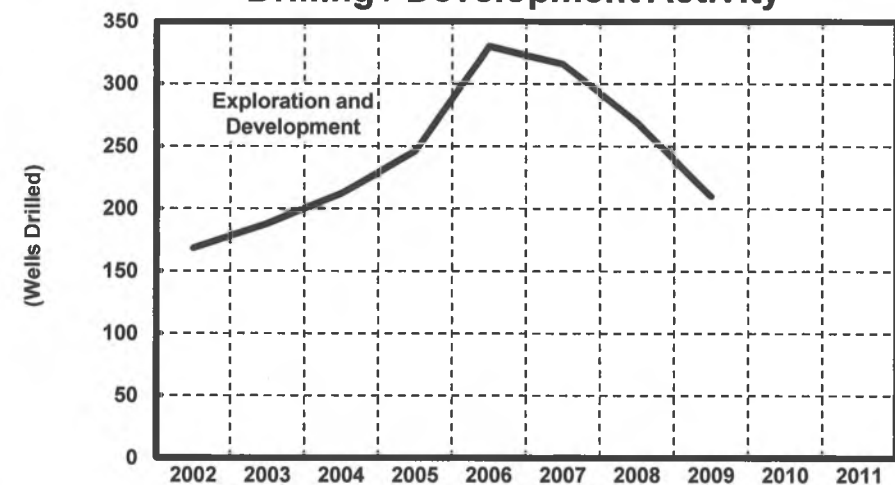
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity

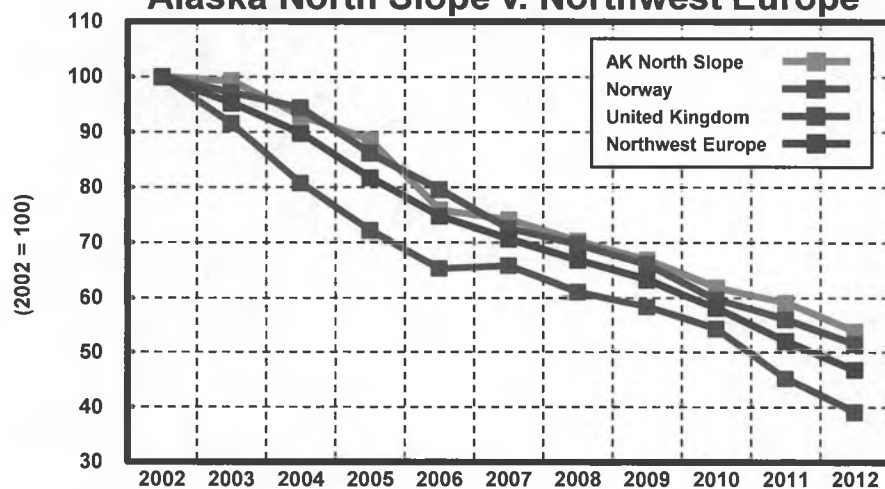


Comparisons Across Locations: Indexing

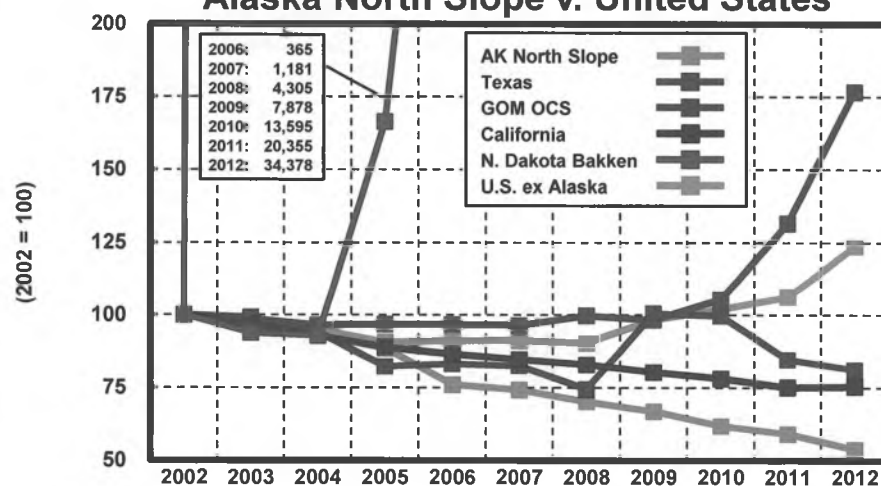
Year	Daily Production			Index Value		
	Alaska North Slope	California	Texas	Alaska North Slope	California	Texas
	(Thousand Barrels Per Day)			(2002 = 100)		
2002	954	707	1,112	100 <small>= (954/954)*100</small>	100 <small>= (707/707)*100</small>	100 <small>= (1,112/1,112)*100</small>
2006	724	612	1,075	76 <small>= (724/954)*100</small>	87 <small>= (612/707)*100</small>	97 <small>= (1,075/1,112)*100</small>
2010	513	552	1,171	62 <small>= (513/954)*100</small>	78 <small>= (552/707)*100</small>	105 <small>= (1,171/1,112)*100</small>

Crude Oil Production Comparisons to Alaska

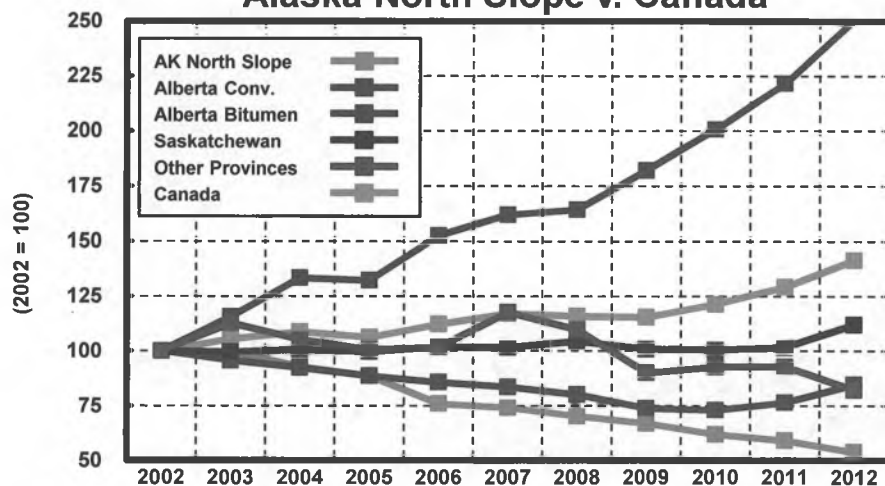
Alaska North Slope v. Northwest Europe



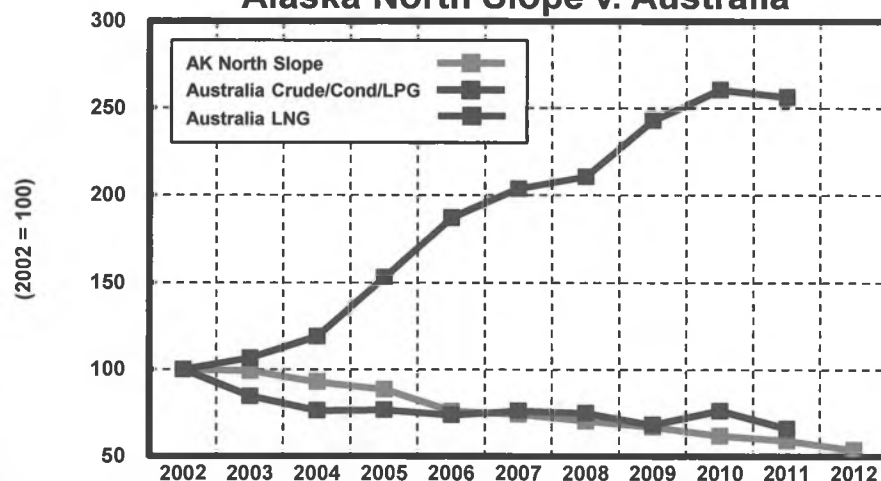
Alaska North Slope v. United States



Alaska North Slope v. Canada

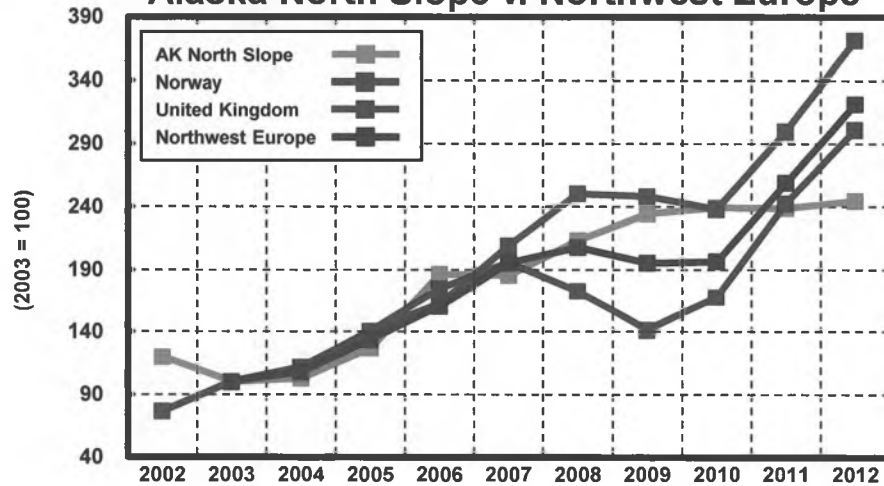


Alaska North Slope v. Australia

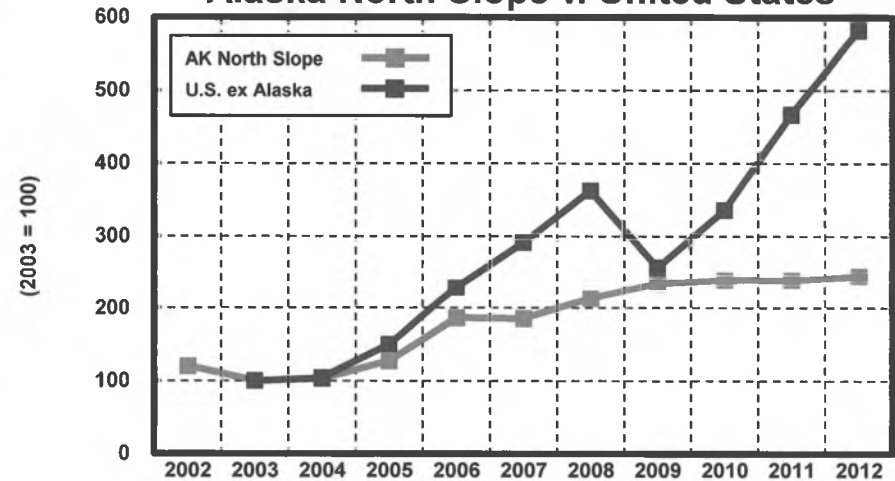


Capital Spending Comparisons to Alaska

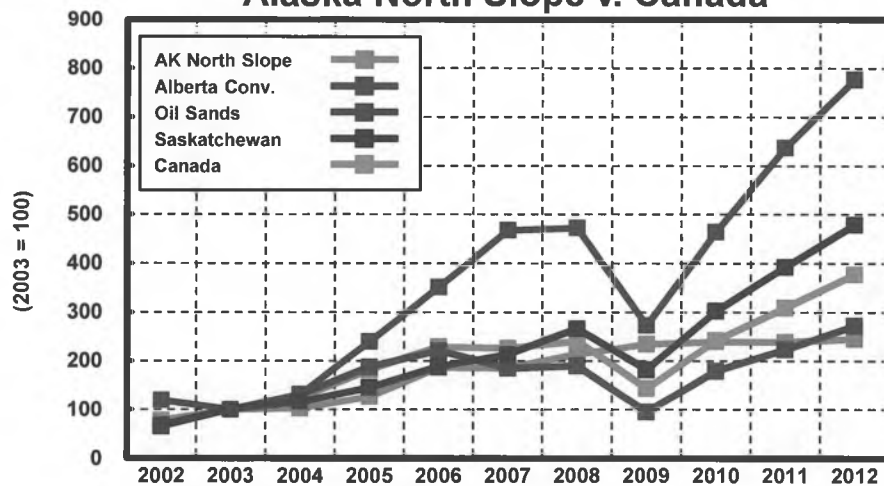
Alaska North Slope v. Northwest Europe



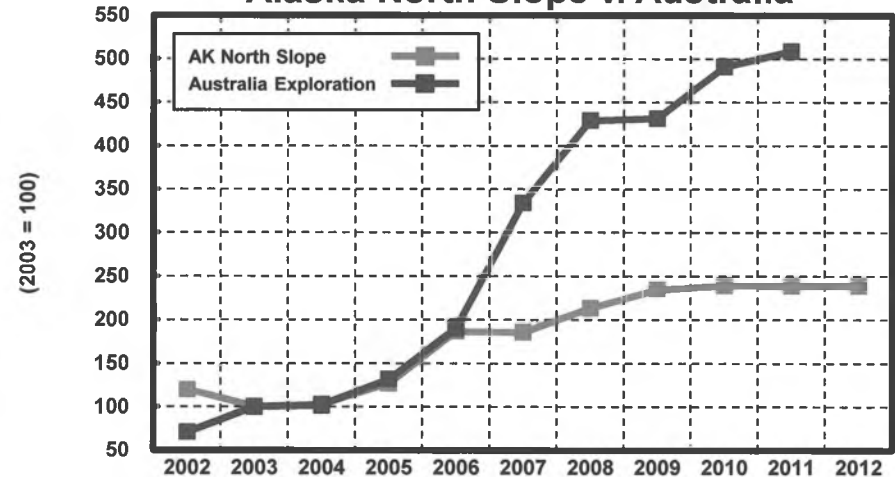
Alaska North Slope v. United States



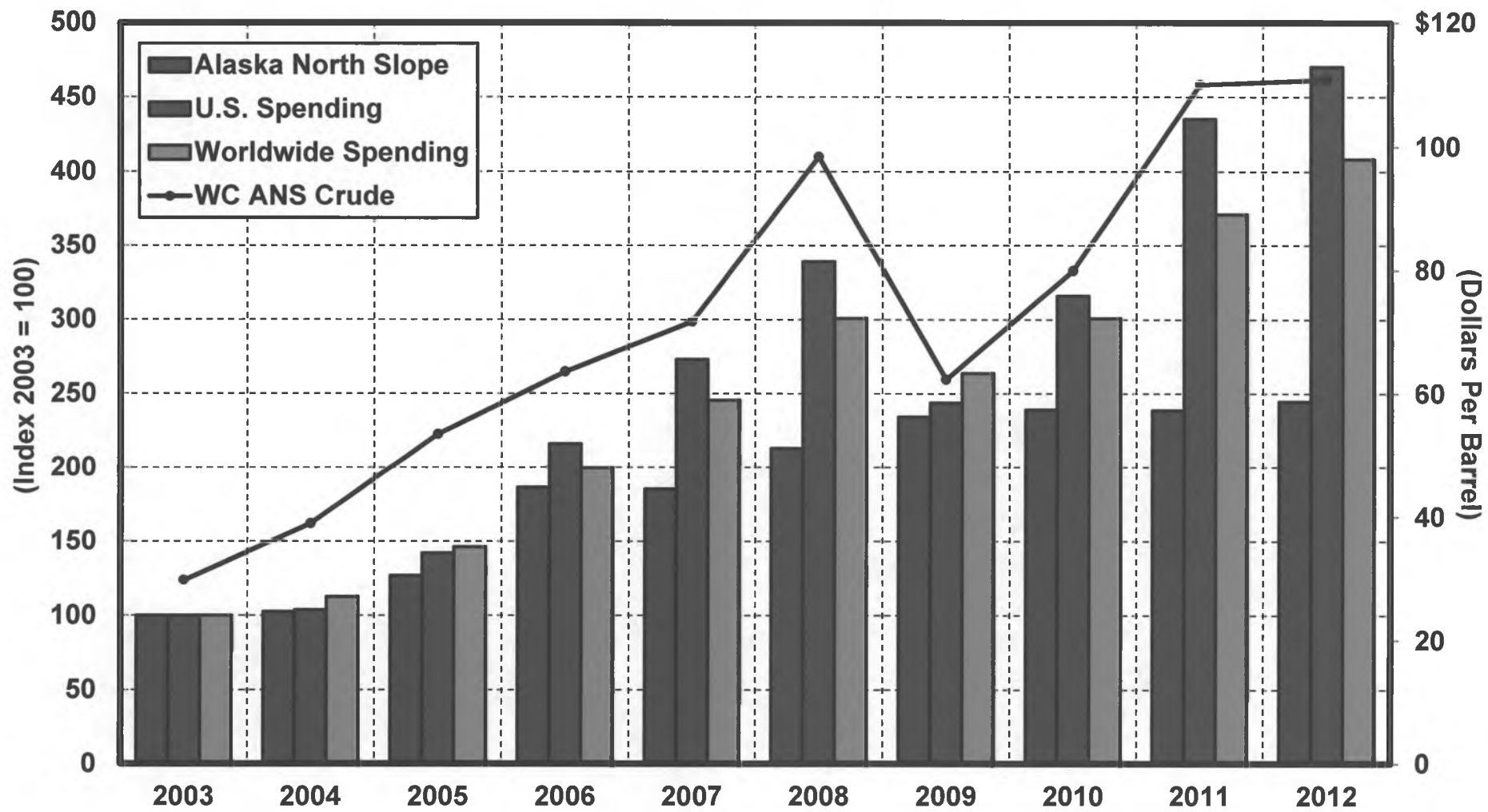
Alaska North Slope v. Canada



Alaska North Slope v. Australia



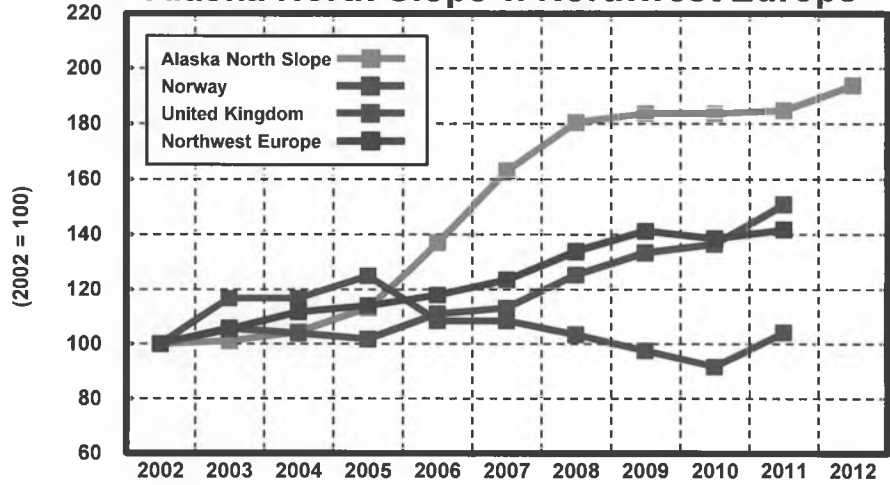
Estimated Capital Spending for Exploration and Development Alaska North Slope vs. U.S. and Worldwide Spending* 2003 - 2012



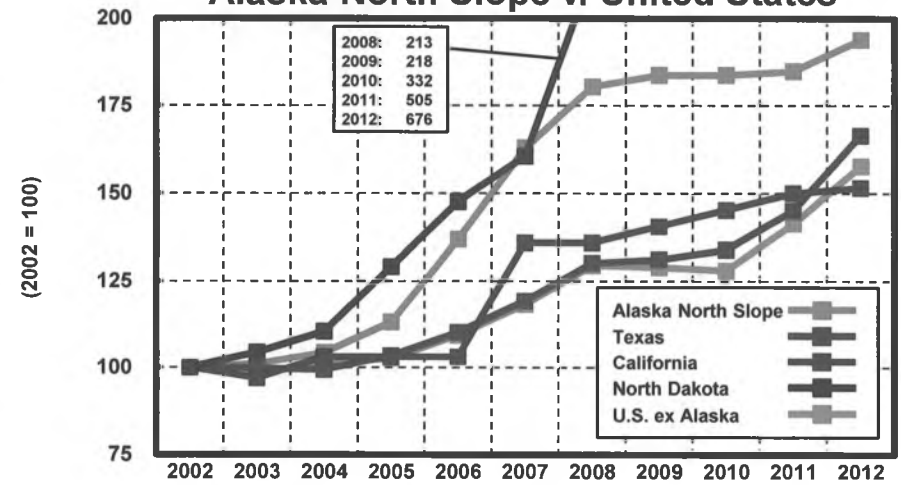
* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

Employment Comparisons to Alaska

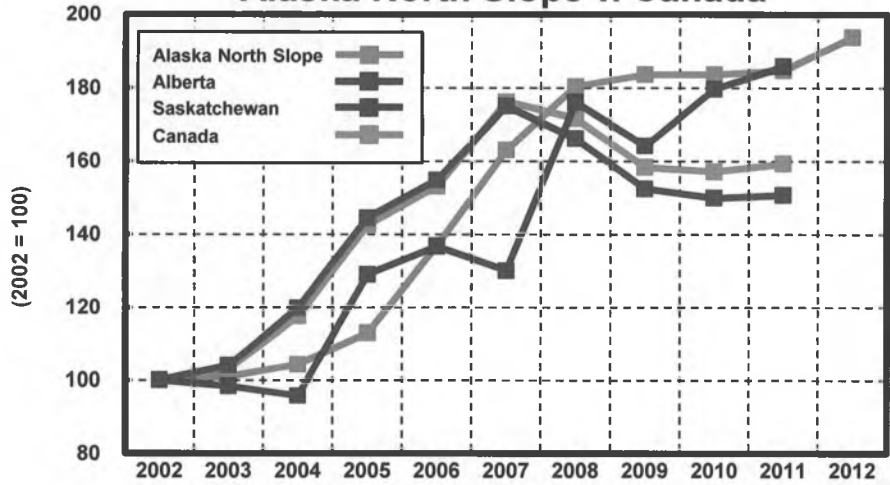
Alaska North Slope v. Northwest Europe



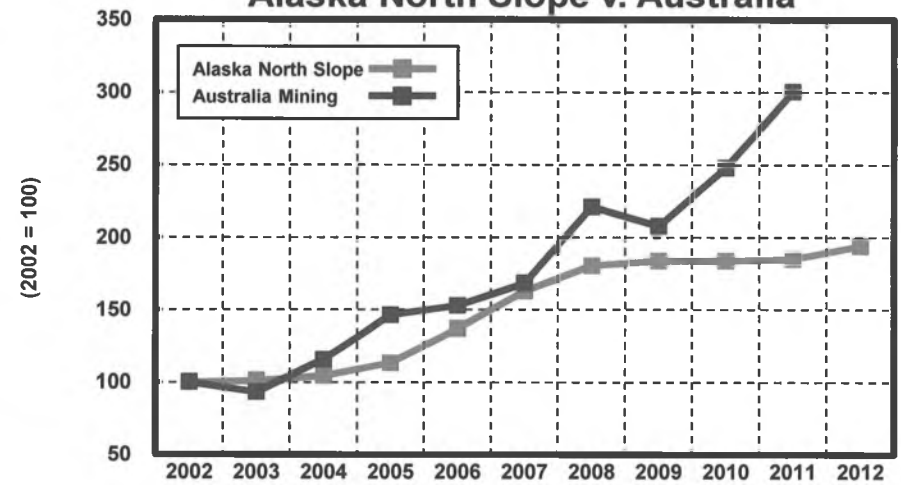
Alaska North Slope v. United States



Alaska North Slope v. Canada

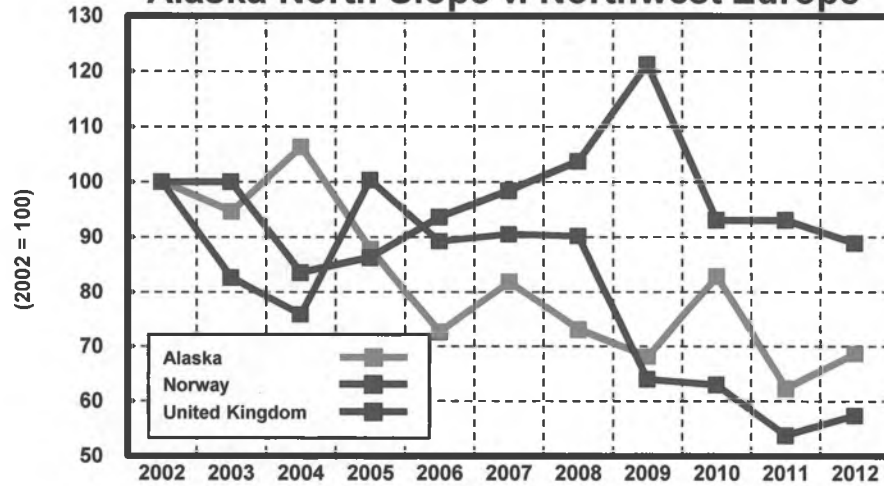


Alaska North Slope v. Australia

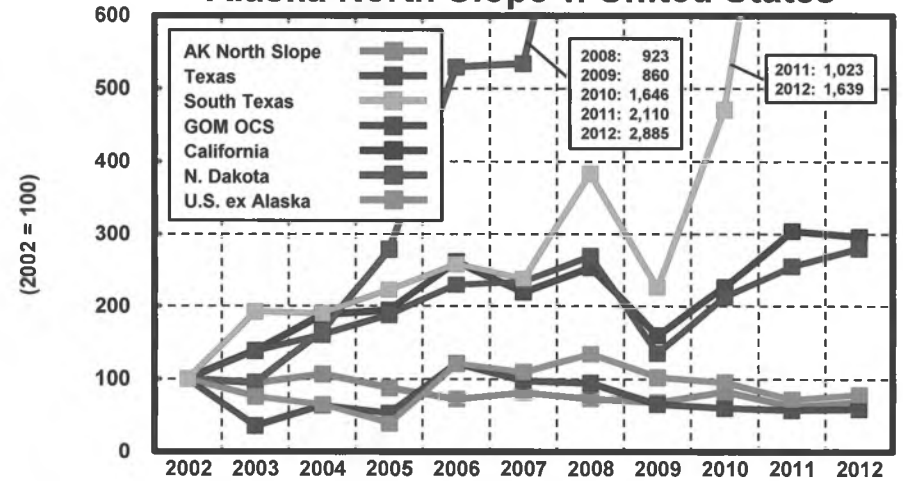


Drilling / Development Activity Comparisons to Alaska

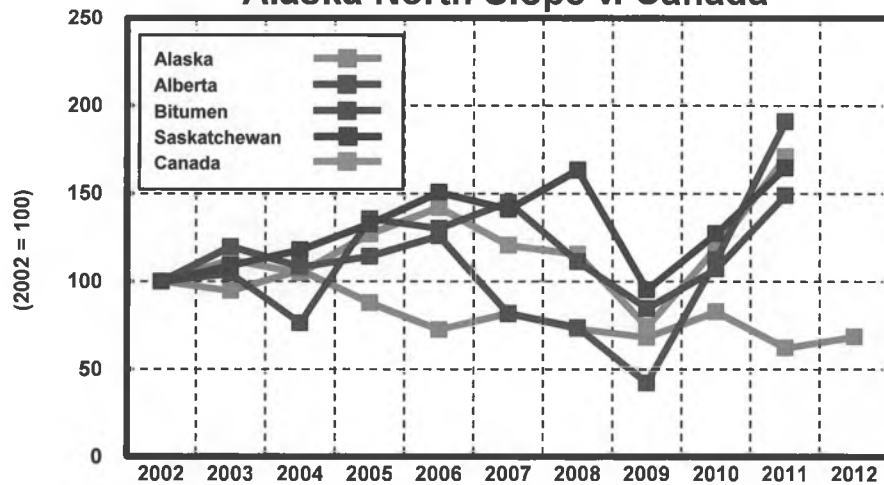
Alaska North Slope v. Northwest Europe



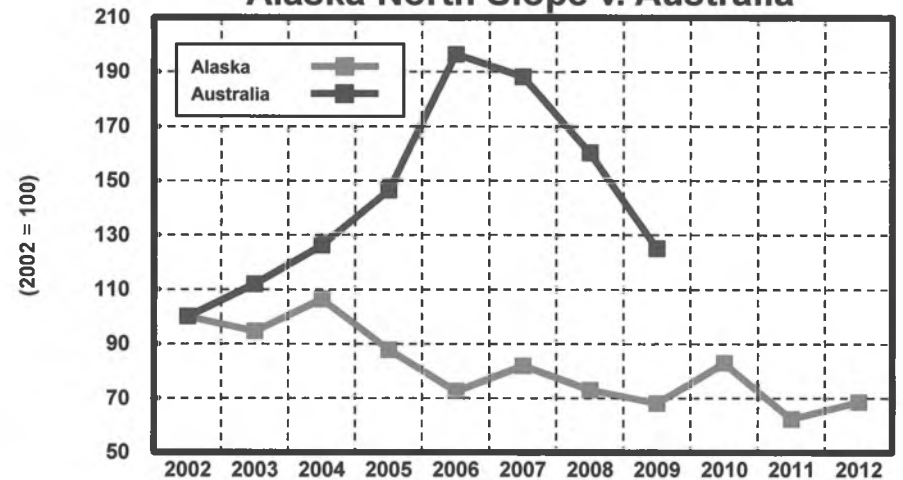
Alaska North Slope v. United States



Alaska North Slope v. Canada



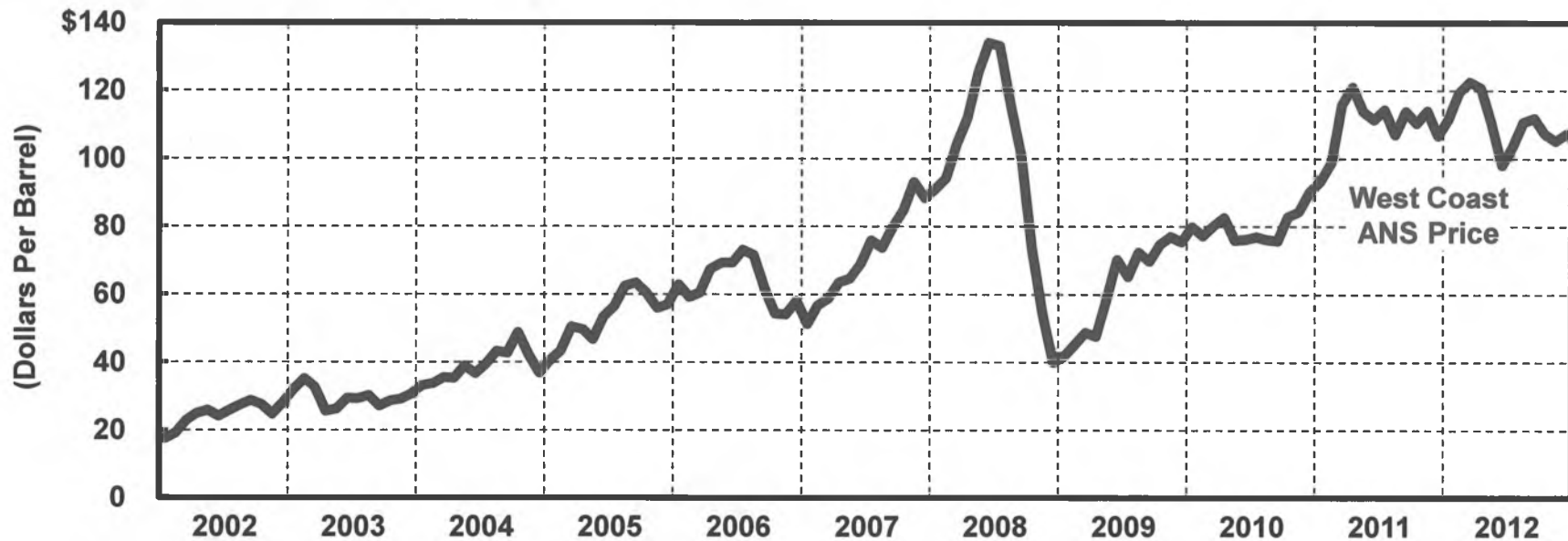
Alaska North Slope v. Australia



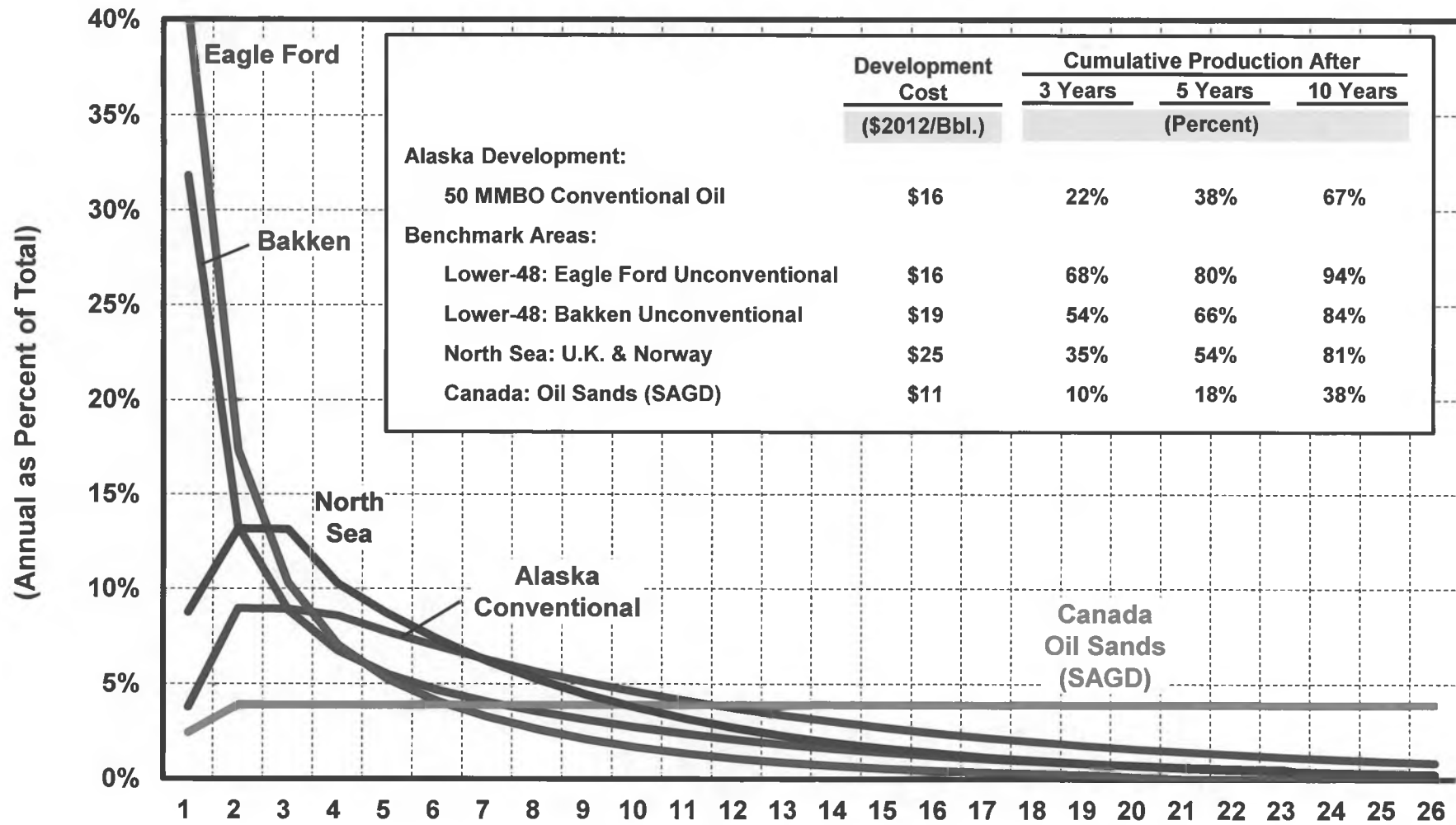
VI. Attractiveness of Investments Under ACES

Crude Oil Prices Used for Analysis

- Likely Long Term Sustainable Range Between \$80/Bbl and \$130/Bbl Real
- Prices May Move Out of This Range for Periods of Time
- Sustained Prices Below Range Makes Many Projects Uneconomic; Supplies Reduced
- Sustained Prices Above Range Starts to Attract More Oil Supply, Reduces Demand for Petroleum Products (e.g., Gasoline Prices Above \$5/Gal.) and Encourages Substitutes
- Producers Will “Stress Test” Projects Near Lower End of Range



Summary of Production Profiles Examined For Alaska and Benchmark Developments

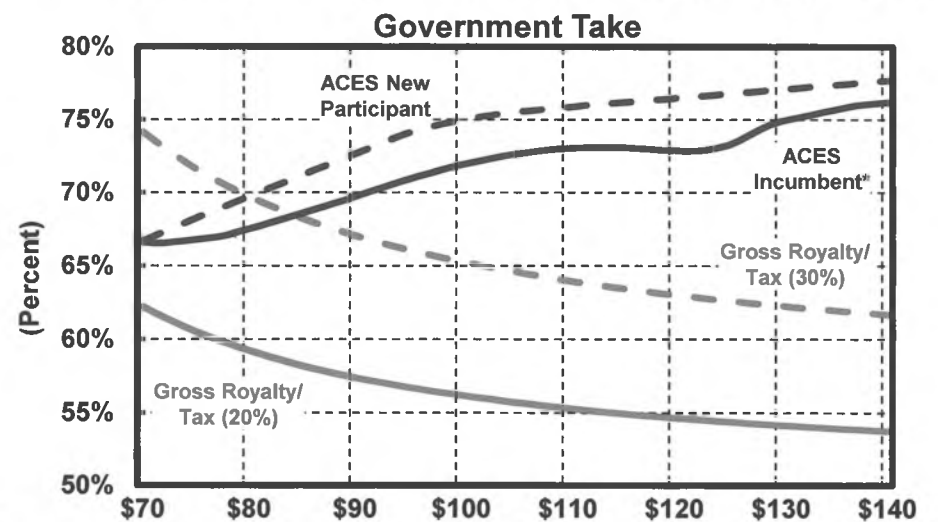
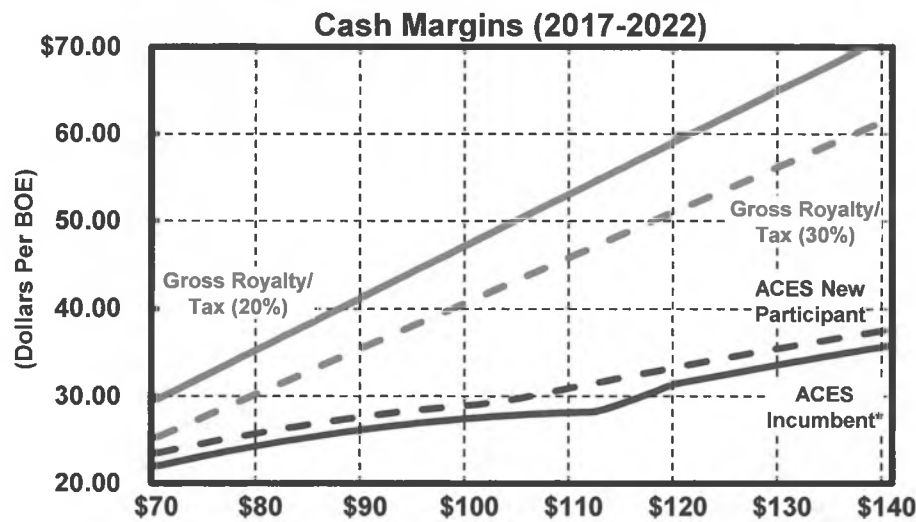
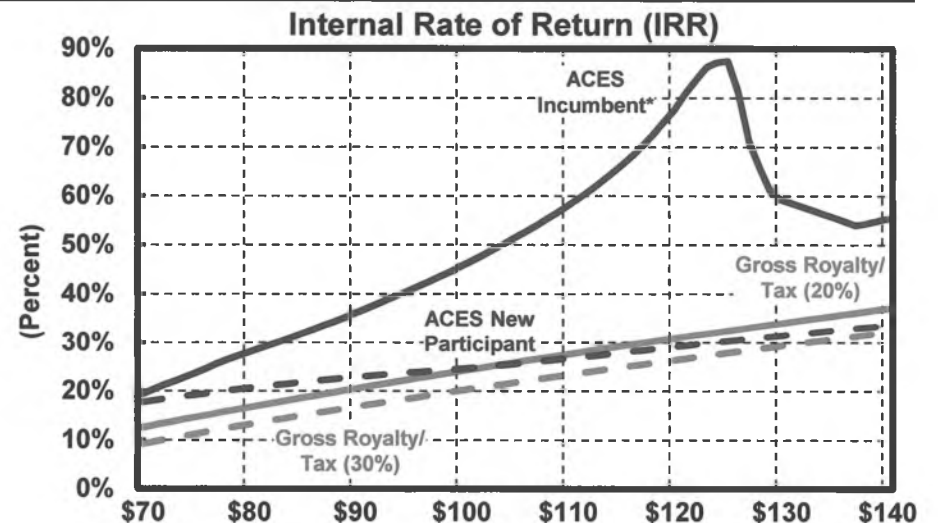
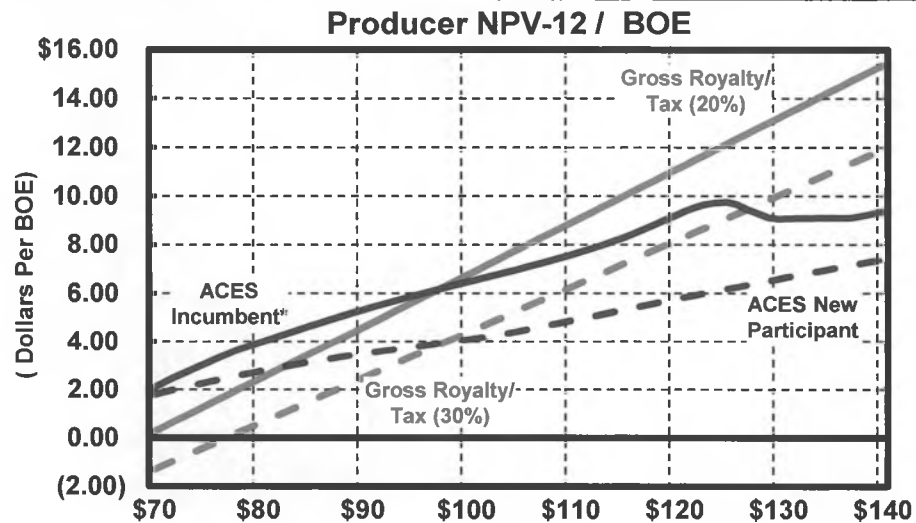


Investment Measures Analyzed

- **Producer NPV-12 Per BOE**
- **Internal Rate of Return (IRR)**
- **5-Year Cash Margins**
- **Profitability Index-12**
- **Government Take**
- **State NPV-12 Per BOE**

Investment Measures

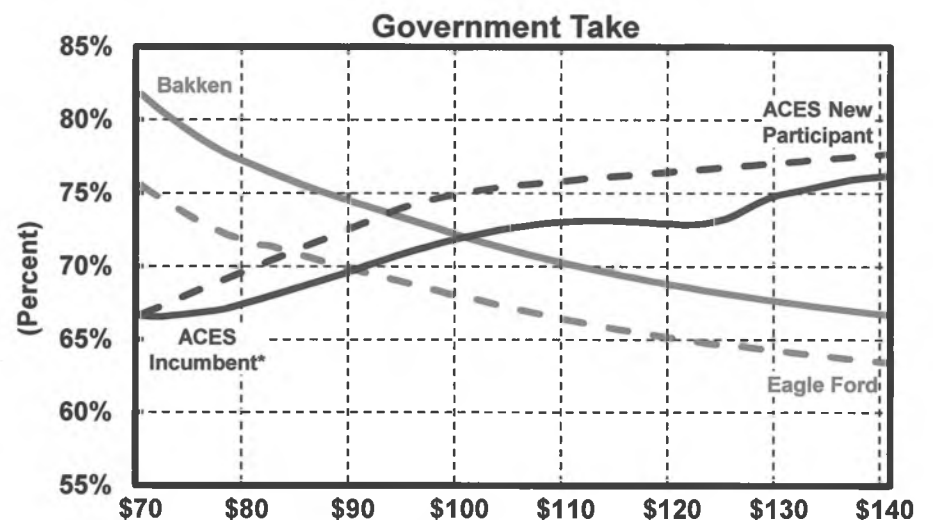
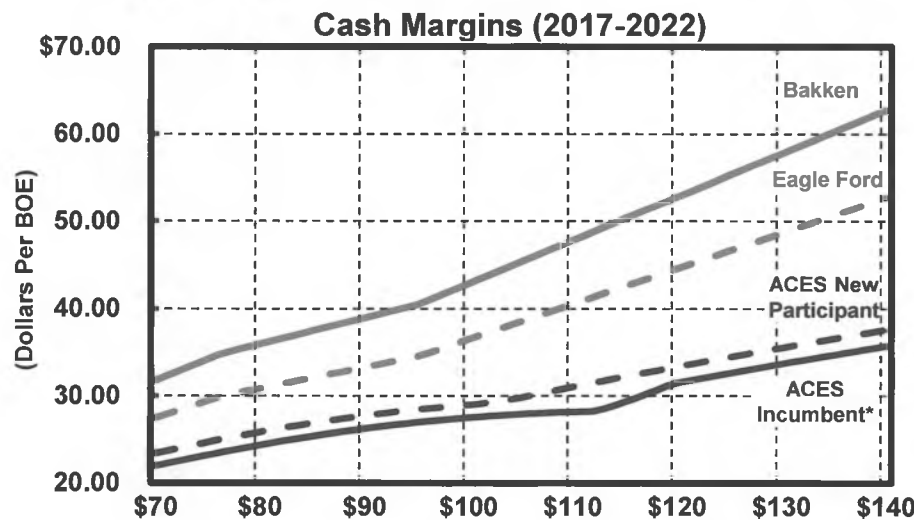
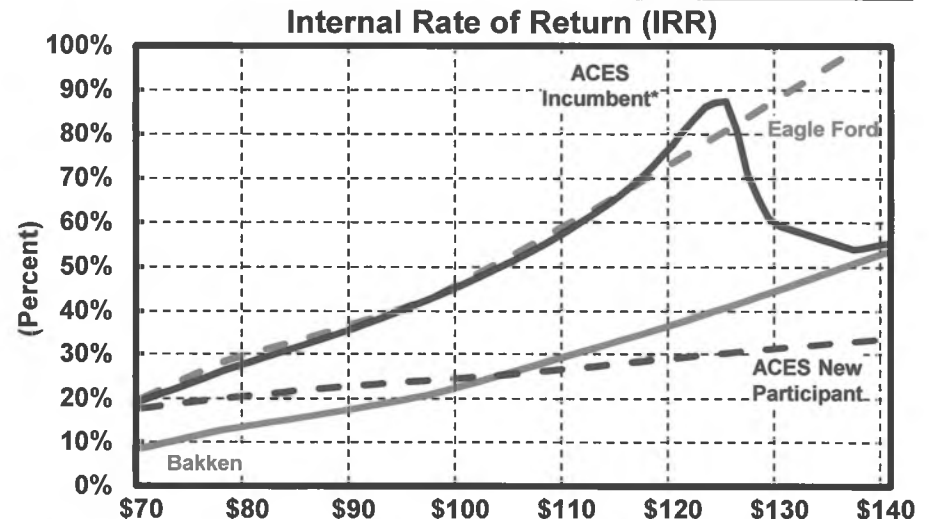
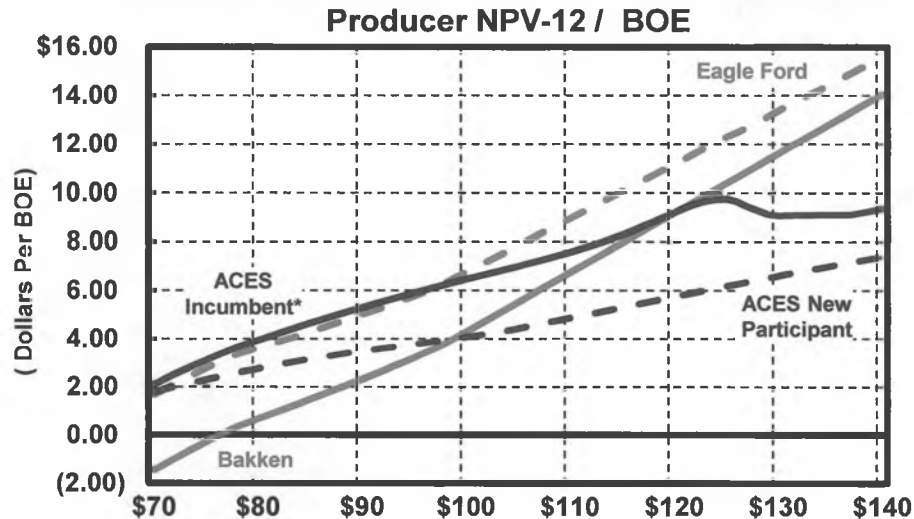
Development of Conventional Oil Reserves



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

Investment Measures

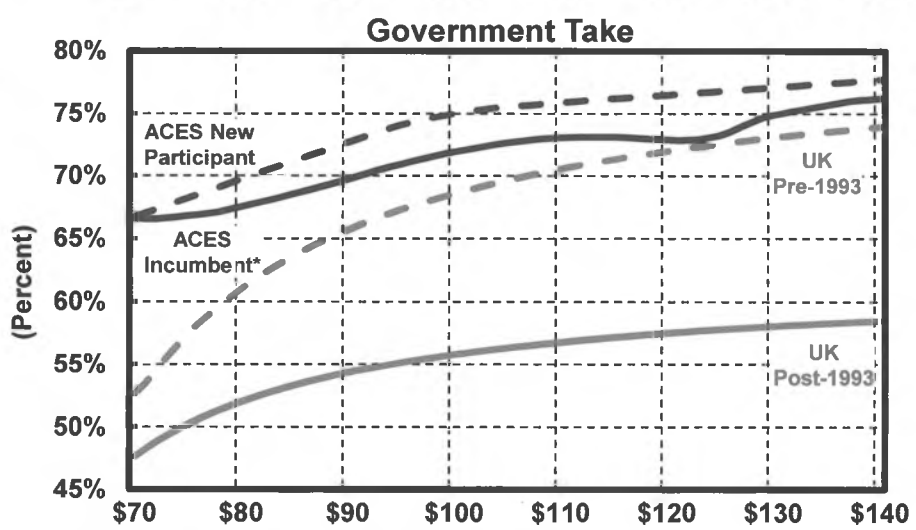
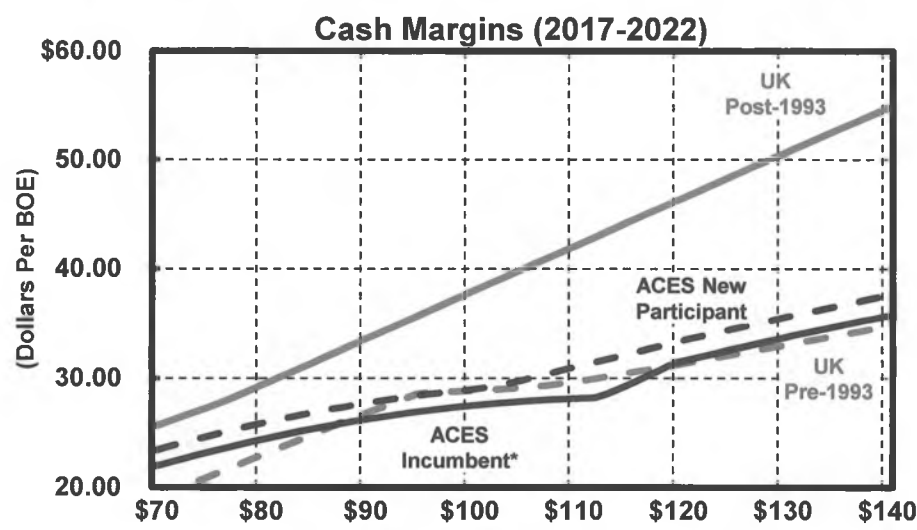
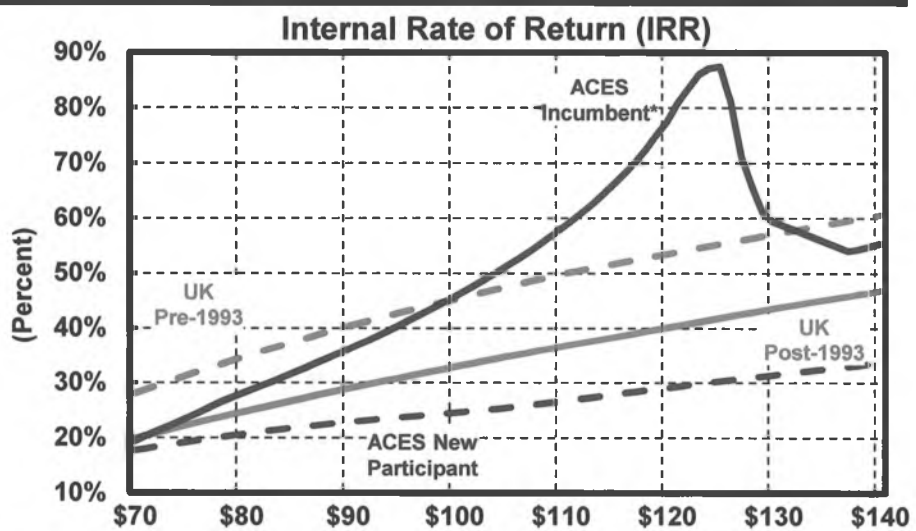
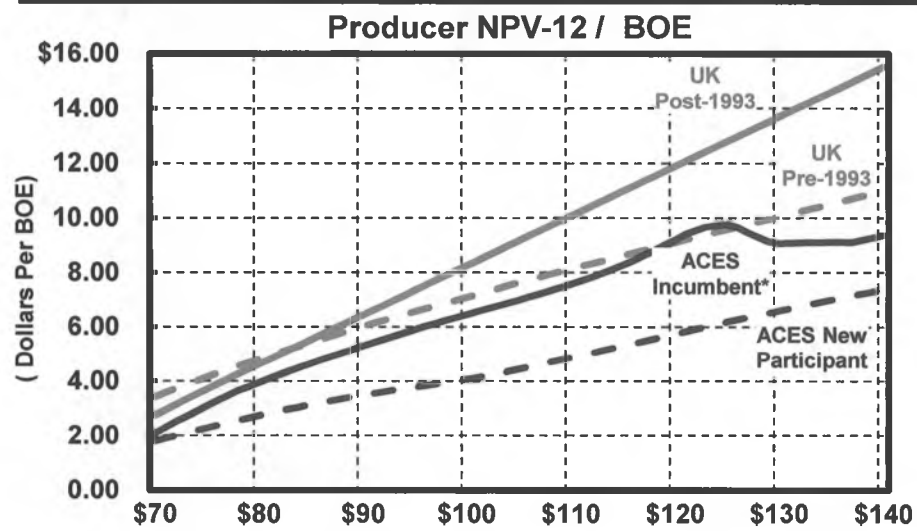
Conventional Oil Alaska Development v. Unconventional Lower-48



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

Investment Metrics

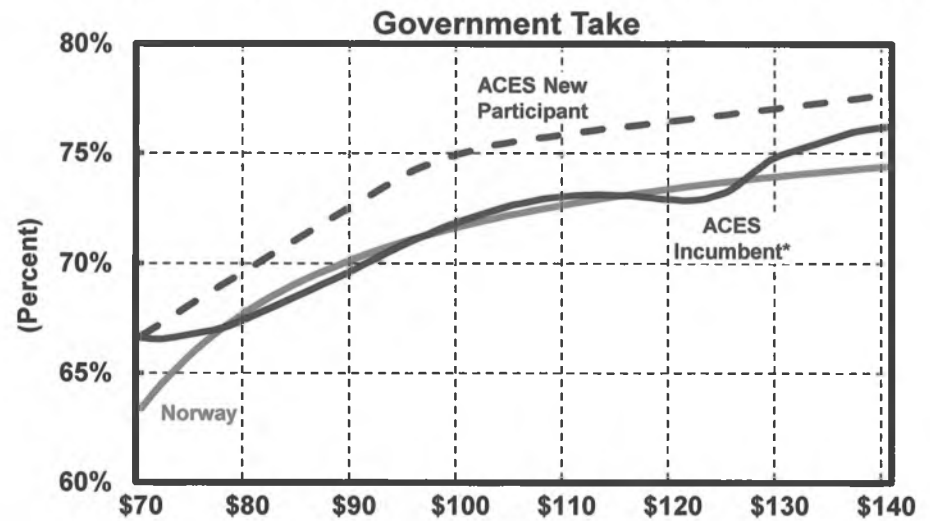
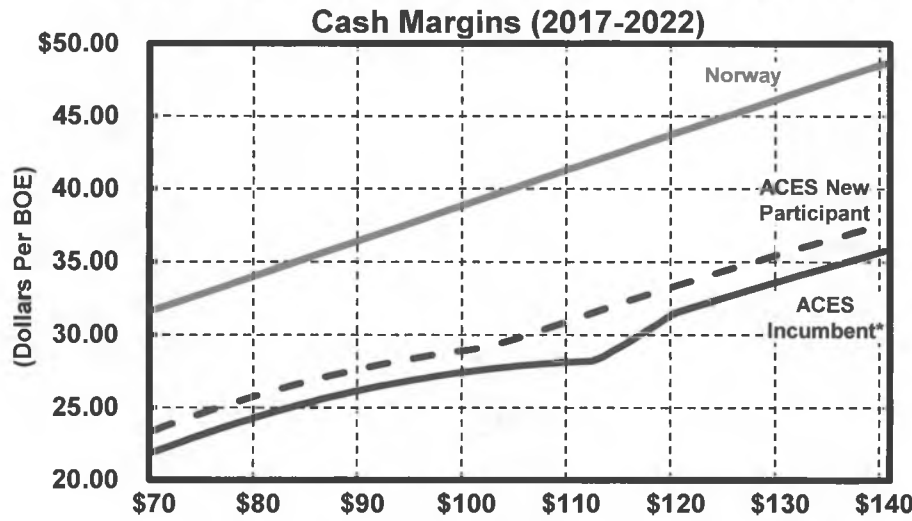
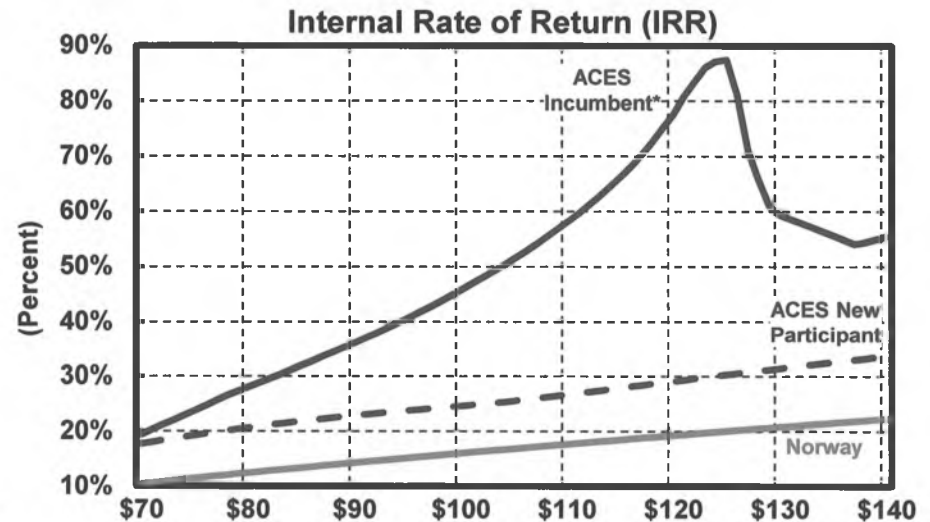
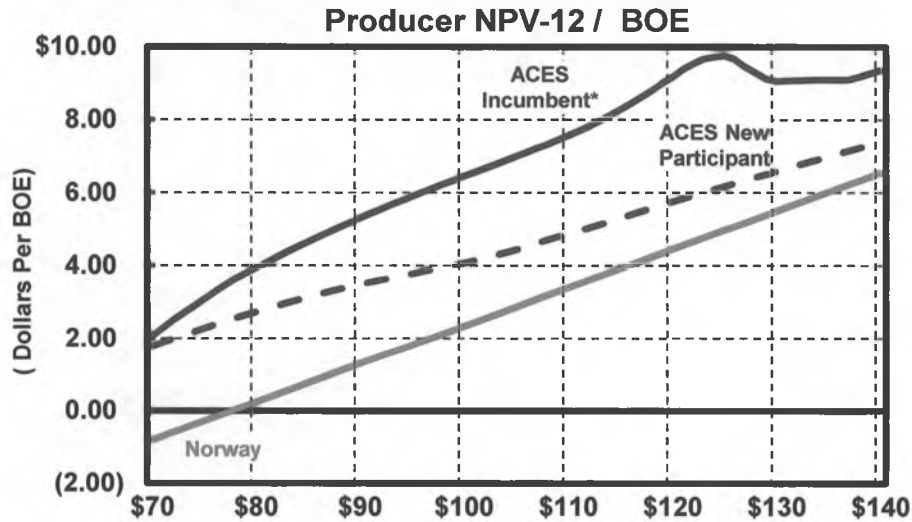
Conventional Oil Alaska Development v. North Sea (United Kingdom with Brownfield Allowance)



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

Investment Metrics

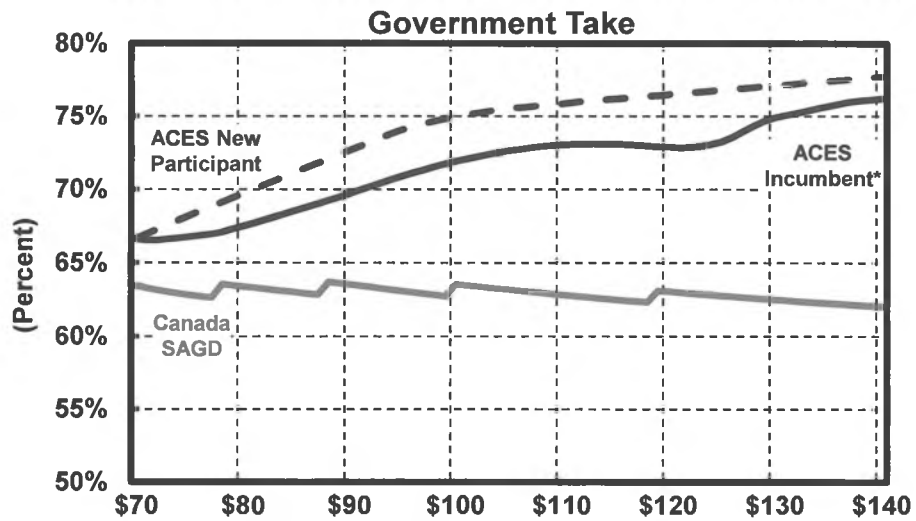
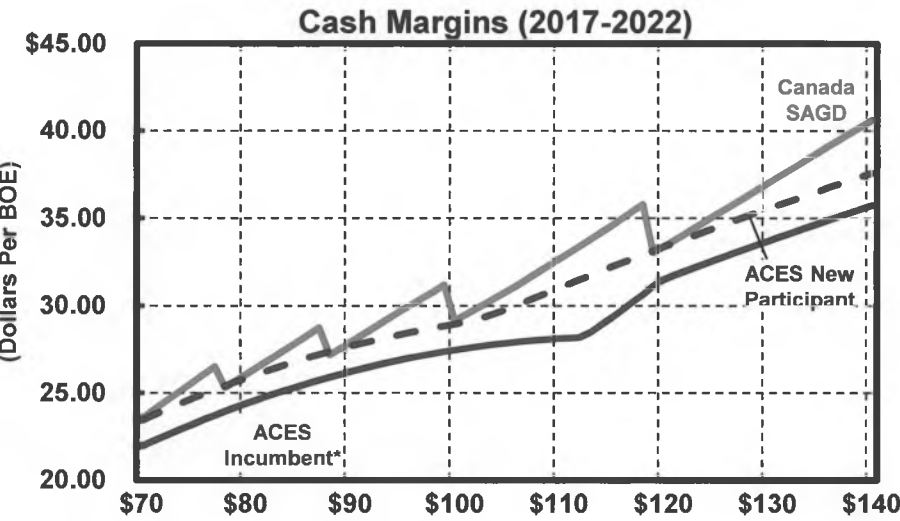
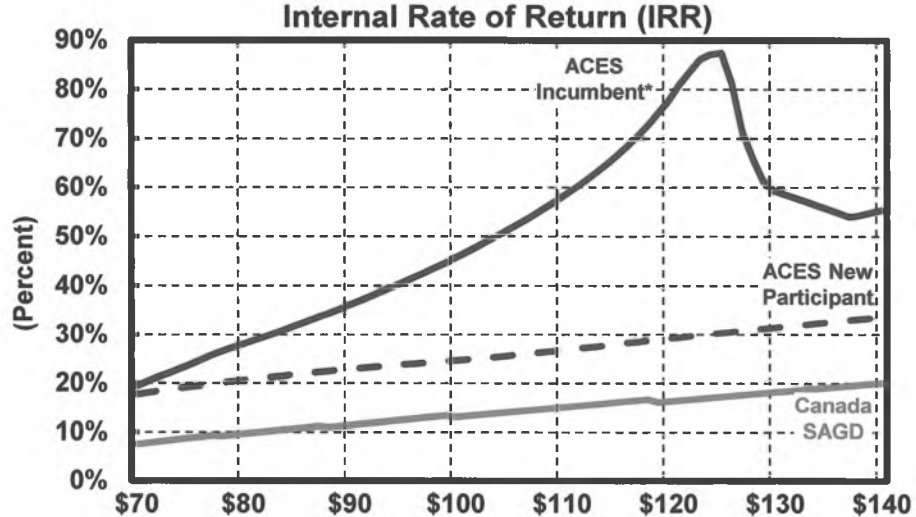
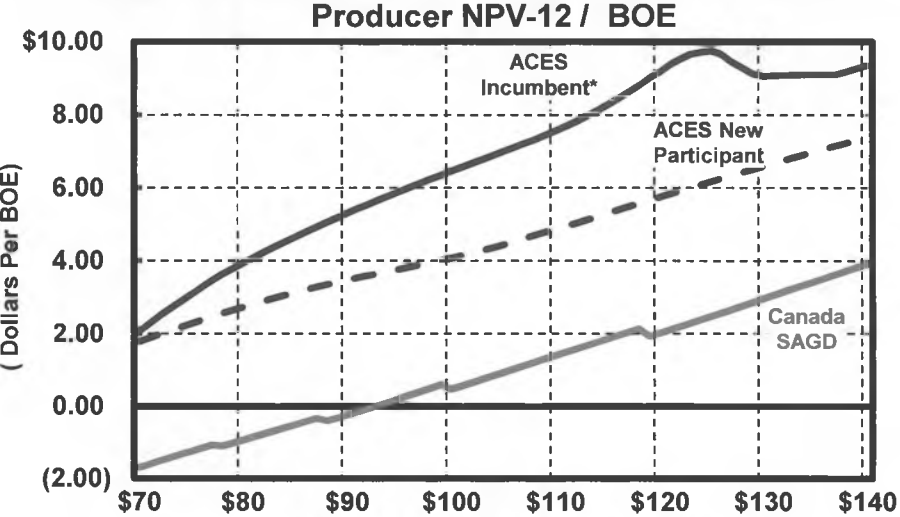
Conventional Oil Alaska Development v. North Sea (Norway)



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

Investment Metrics

Conventional Oil Alaska Development v. Canada Oil Sands (SAGD)



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

Summary of Investment Measures

West Coast ANS Price	Alaska 50 MMBO Conventional Oil		Unconventional Lower-48	Canada			U.K. Development & Fiscal System			
	New Participant	Incumbent Participant		Oil Sands SAGD	Norway	Pre-1993	Pre-1993 w/ Brownfield Allowance*	Post-1993	Post-1993 w/ Brownfield Allowance*	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Producer NPV-12 / BOE (Dollars Per BOE)										
\$80	\$2.73	\$3.93	\$2.14	(\$0.93)	\$0.24	\$1.20	\$4.81	\$2.41	\$4.62	
\$100	\$4.07	\$6.45	\$5.52	\$0.46	\$2.34	\$3.02	\$7.09	\$6.04	\$8.25	
\$120	\$5.74	\$9.17	\$10.17	\$2.01	\$4.44	\$4.83	\$9.09	\$9.67	\$11.88	
Profitability Index-12										
\$80	1.21	1.30	1.15	0.88	1.01	1.06	1.22	1.11	1.21	
\$100	1.31	1.49	1.37	1.06	1.14	1.14	1.33	1.28	1.38	
\$120	1.43	1.69	1.69	1.26	1.27	1.22	1.42	1.45	1.55	
IRR (Percent)										
\$80	20.6%	27.9%	21.8%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%	
\$100	24.6%	45.7%	34.5%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%	
\$120	29.1%	77.6%	55.3%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%	
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
\$80	\$25.85	\$24.38	\$33.41	\$26.07	\$34.11	\$12.45	\$22.94	\$24.91	\$29.35	
\$100	\$28.95	\$27.48	\$39.69	\$29.14	\$38.96	\$16.69	\$28.85	\$33.38	\$37.82	
\$120	\$33.35	\$31.50	\$48.71	\$33.37	\$43.81	\$20.93	\$31.29	\$41.86	\$46.30	
Government Take (Percent)										
\$80	69.7%	67.5%	74.4%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%	
\$100	75.0%	71.9%	70.0%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%	
\$120	76.5%	72.9%	66.9%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%	
State NPV-12/BOE (Dollars Per BOE)										
\$80	\$5.95	\$4.10	-	-	-	-	-	-	-	
\$100	\$12.54	\$8.88	-	-	-	-	-	-	-	
\$120	\$18.61	\$13.34	-	-	-	-	-	-	-	

* Brownfield Allowance applied to 100 MMBOE development.

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

VII. The Administration's Proposed Changes

Key Aspects of Administration's Proposal

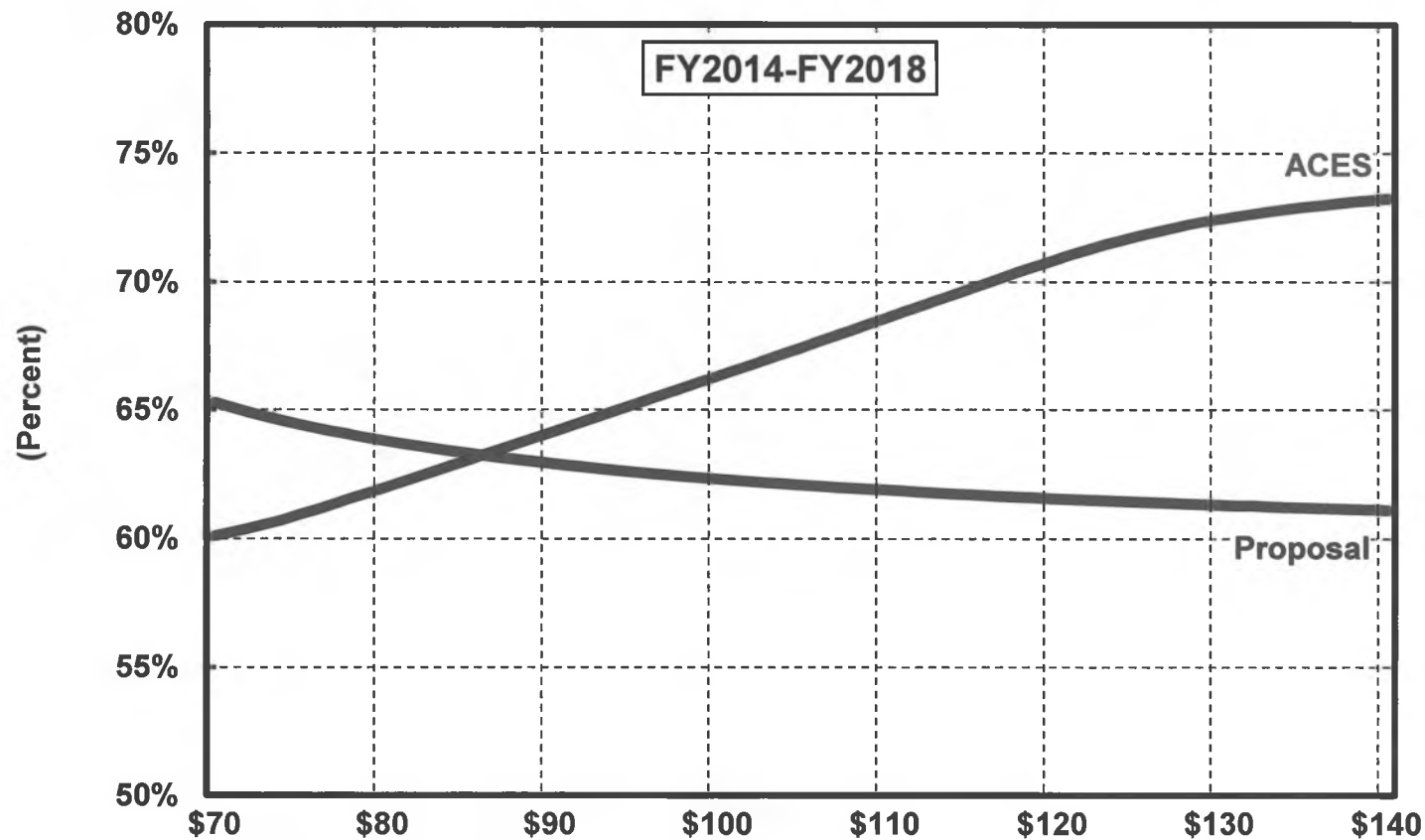
- **Establishes 25% Flat Net Tax Rate; No Progressivity**
- **Eliminates Capital Credit and State Purchase of Losses**
- **Establishes 20% Gross Revenue Exclusion (GRE) to Incent Production of New Oil**
- **Losses May be Carried Forward and Applied Against Tax Obligation When Production Occurs**
- **Extends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

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

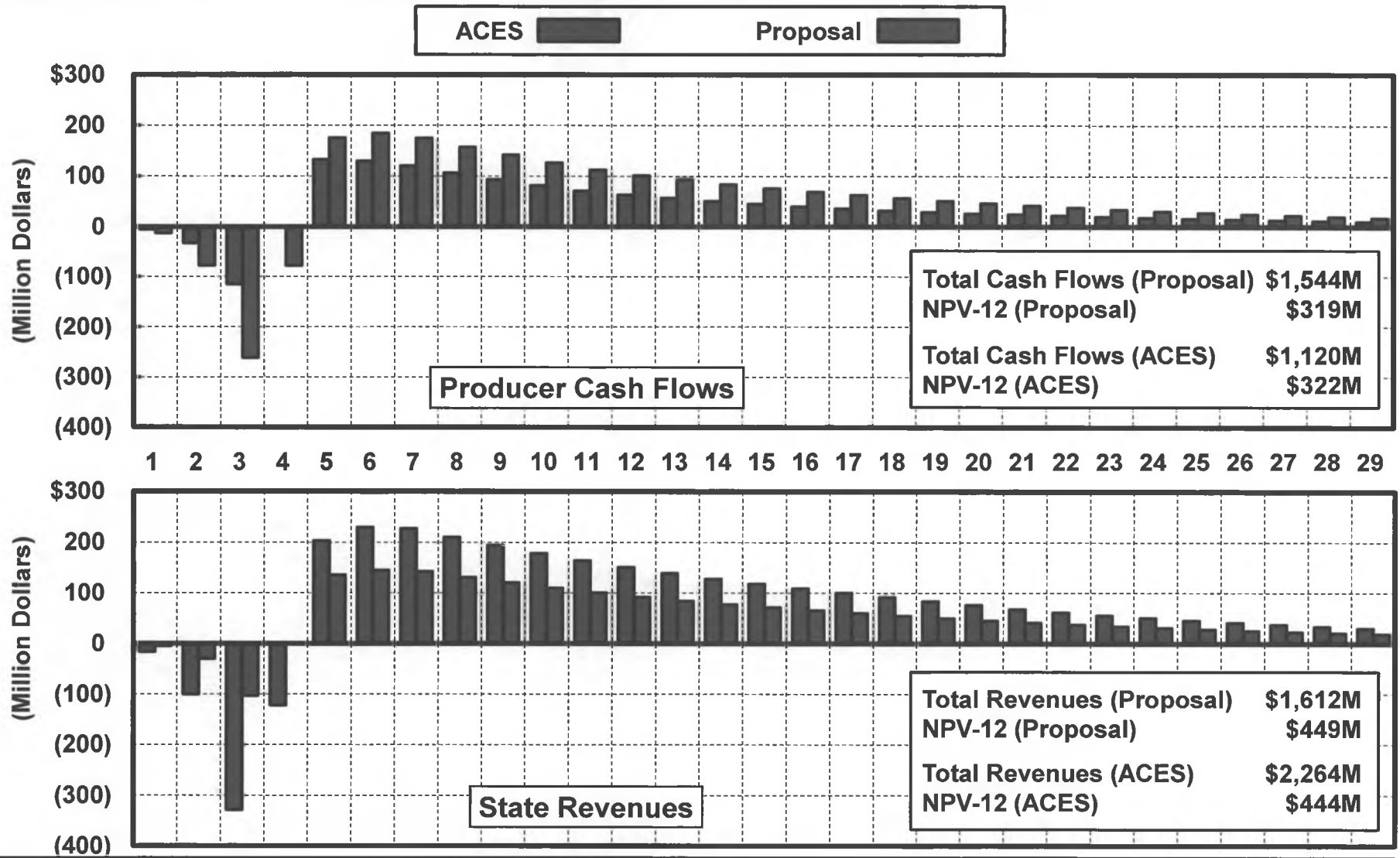
- **Provides Balance Between State and Producers**
 - Reduction of Tax Rates at High Prices, Balanced with Elimination of Credits
 - State Continues to Receive Largest Percentage of Oil Production Revenues at Any Price
 - Provides Tax Relief and Higher Margins in Sustainable Price Ranges
 - **Simplifies 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 Aspects of Administration's Proposal (cont'd)

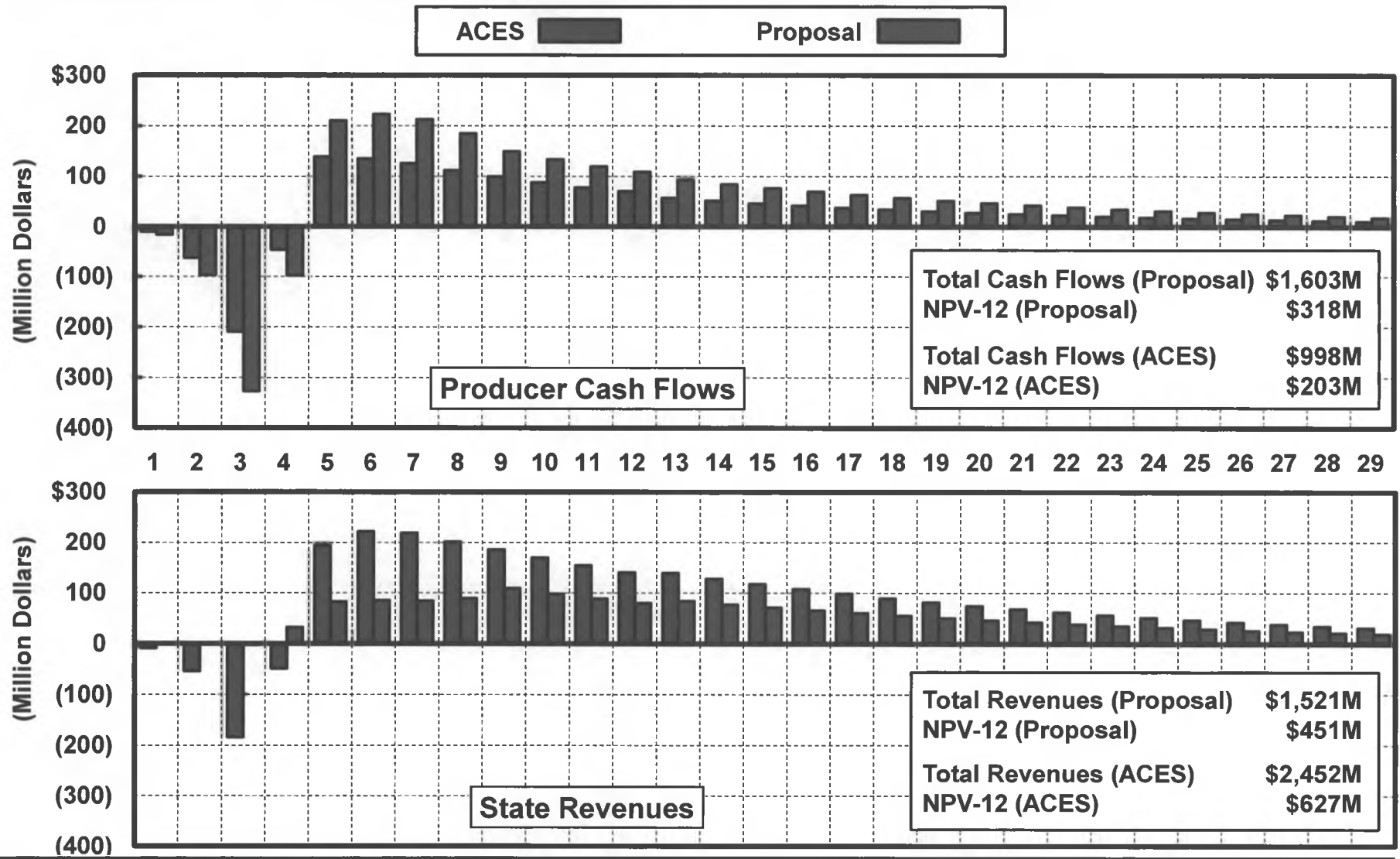
- **Average Government Take Moves From Progressive to Relatively Neutral Under Proposal**



Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS 50 MMBO Conventional Oil Alaska Development Incumbent Participant in Alaska



Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS 50 MMBO Conventional Oil Alaska Development New Participant in Alaska



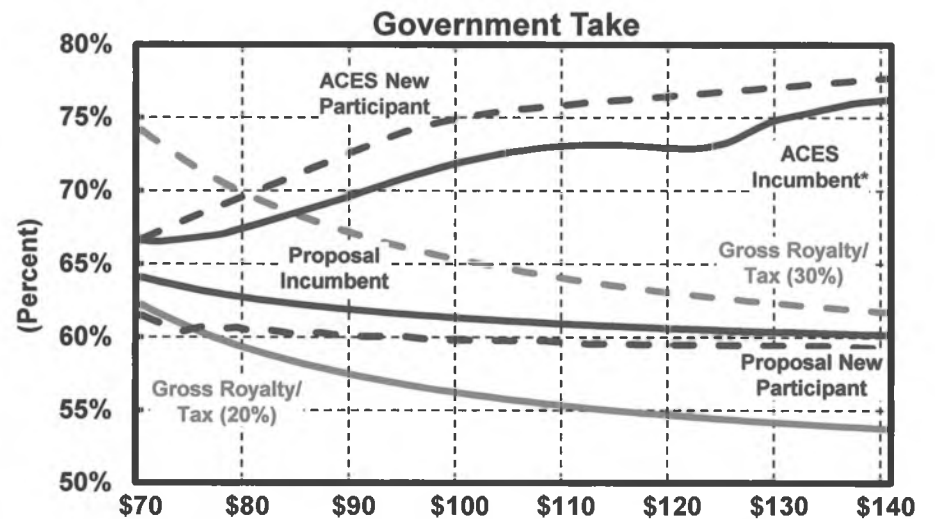
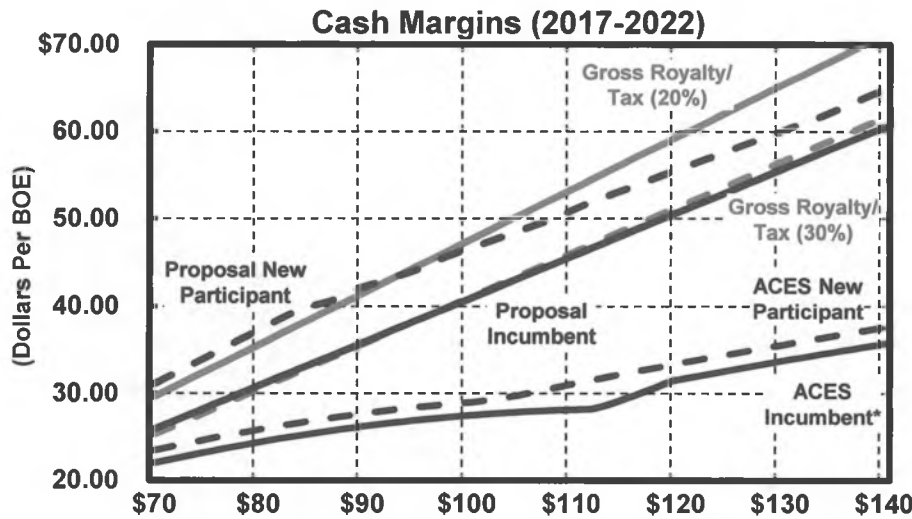
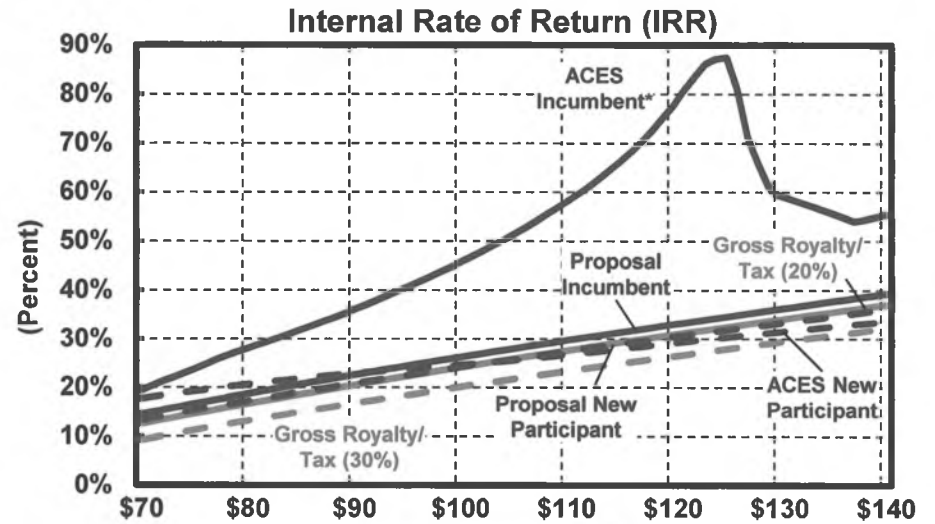
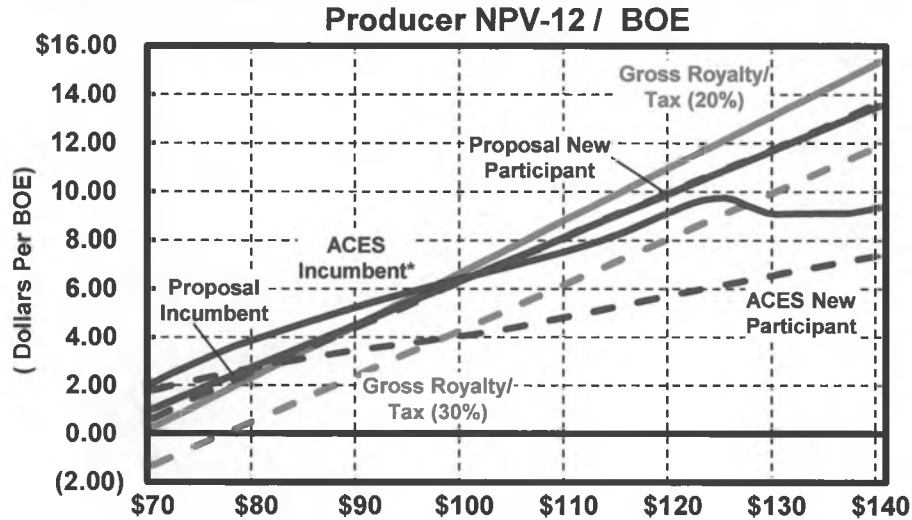
Summary of State Revenues and Producer Cash Flows Totals and NPV-12 50 MMBO Conventional Oil Alaska Development



West Coast ANS Price	New Participant		Incumbent Participant	
	ACES	Proposal	ACES	Proposal
	(1)	(2)	(3)	(4)
Producer Cash Flows (Million Dollars)				
\$80	\$806	\$1,053	\$865	\$993
\$100	\$998	\$1,603	\$1,120	\$1,544
\$120	\$1,250	\$2,153	\$1,440	\$2,094
Producer NPV-12 (Million Dollars)				
\$80	\$136	\$130	\$196	\$140
\$100	\$203	\$318	\$322	\$319
\$120	\$287	\$500	\$458	\$498
State Revenues (Million Dollars)				
\$80	\$1,422	\$1,042	\$1,331	\$1,133
\$100	\$2,452	\$1,521	\$2,264	\$1,612
\$120	\$3,390	\$2,001	\$3,098	\$2,091
State NPV-12 (Million Dollars)				
\$80	\$298	\$307	\$205	\$292
\$100	\$627	\$451	\$444	\$449
\$120	\$931	\$602	\$667	\$606

Investment Measures

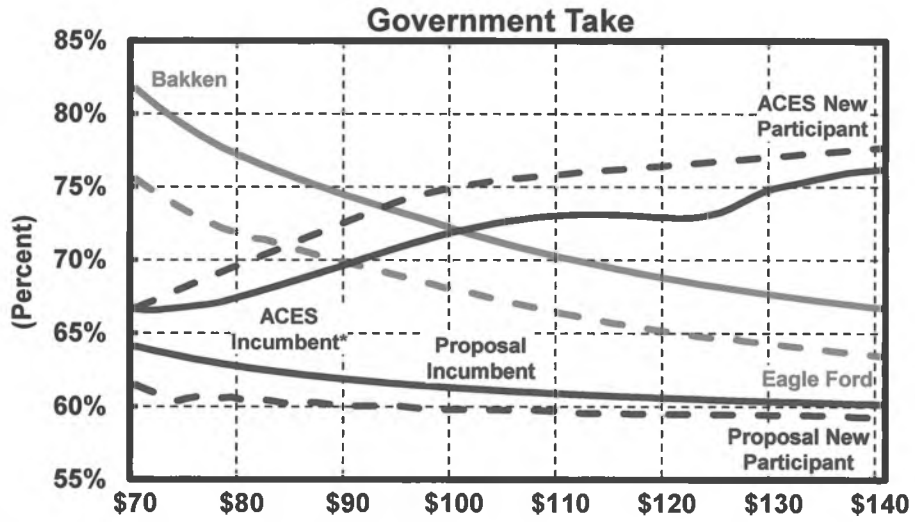
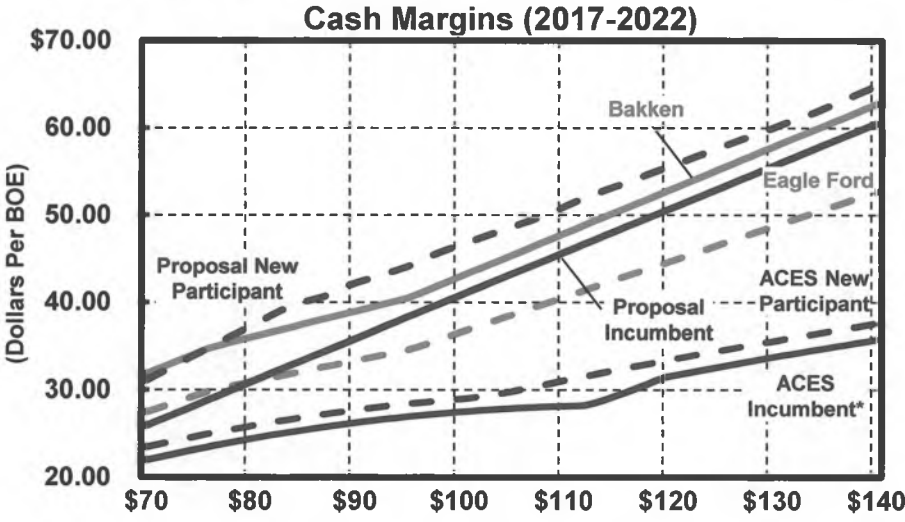
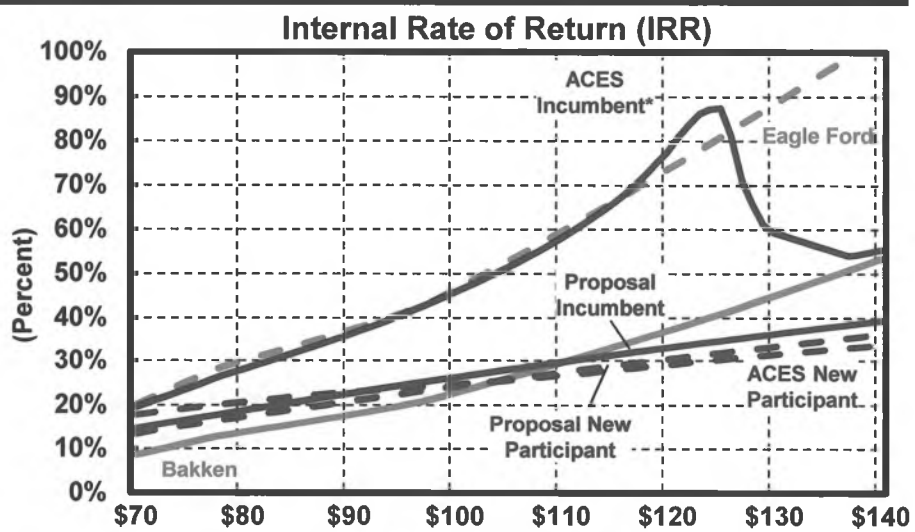
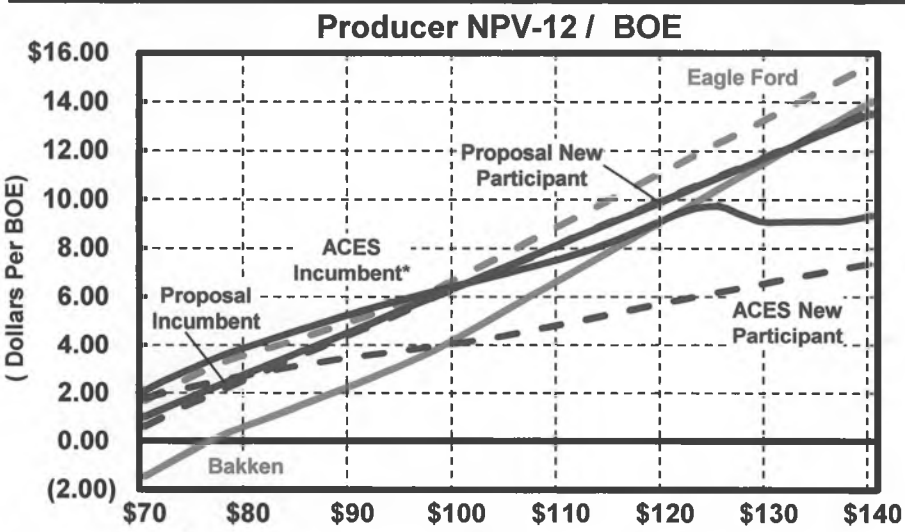
Development of Conventional Oil Reserves



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

Investment Measures

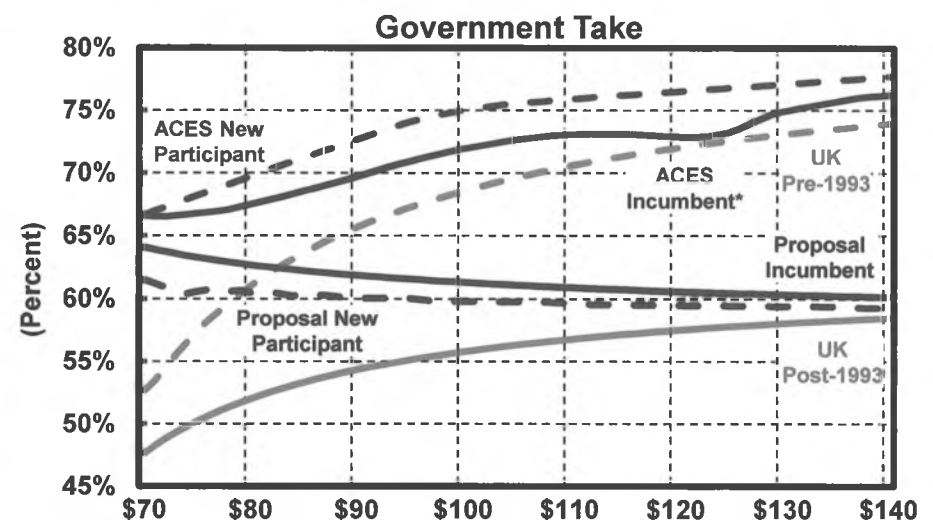
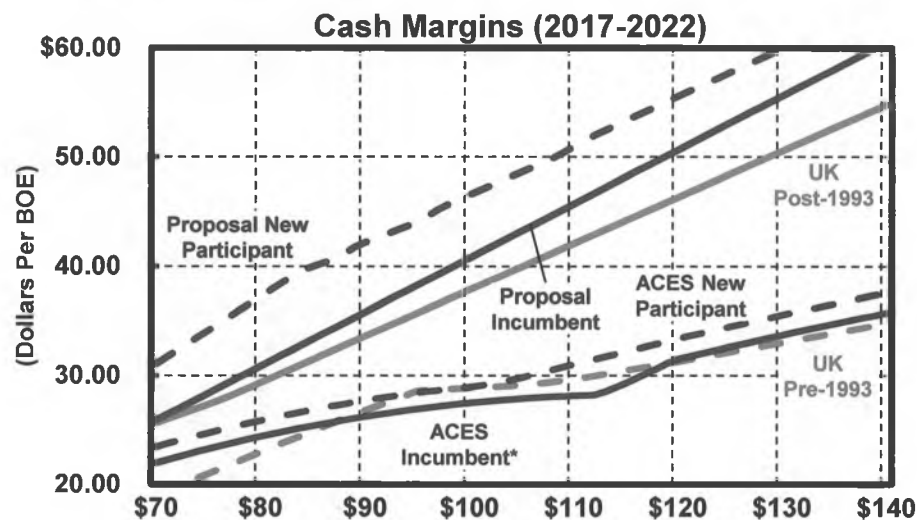
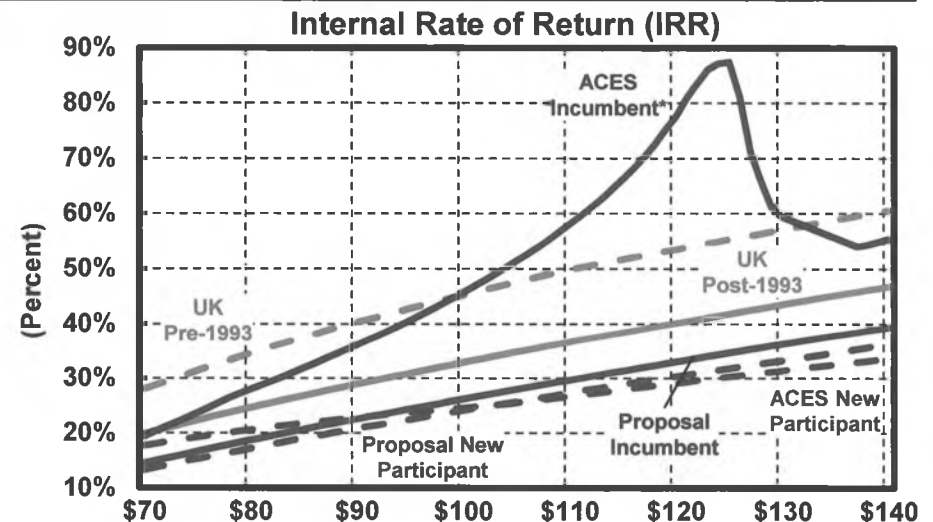
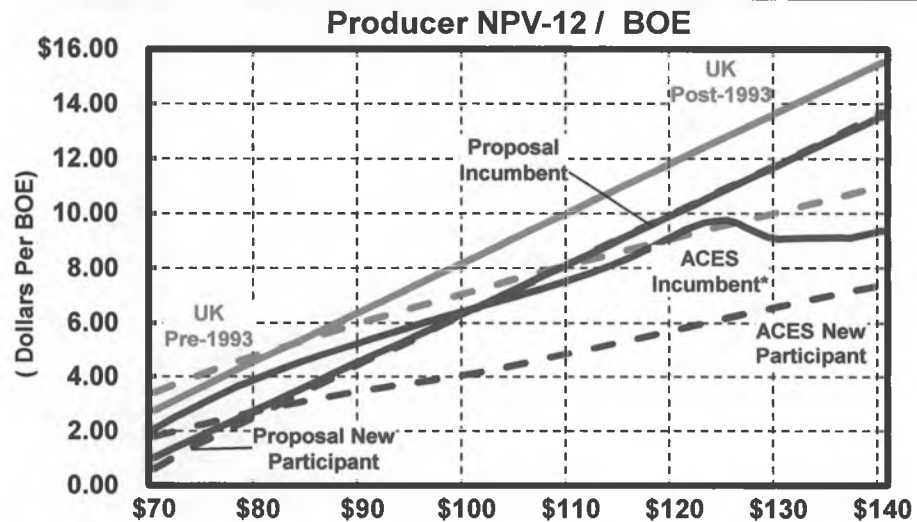
Conventional Oil Alaska Development v. Unconventional Lower-48



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

Investment Metrics

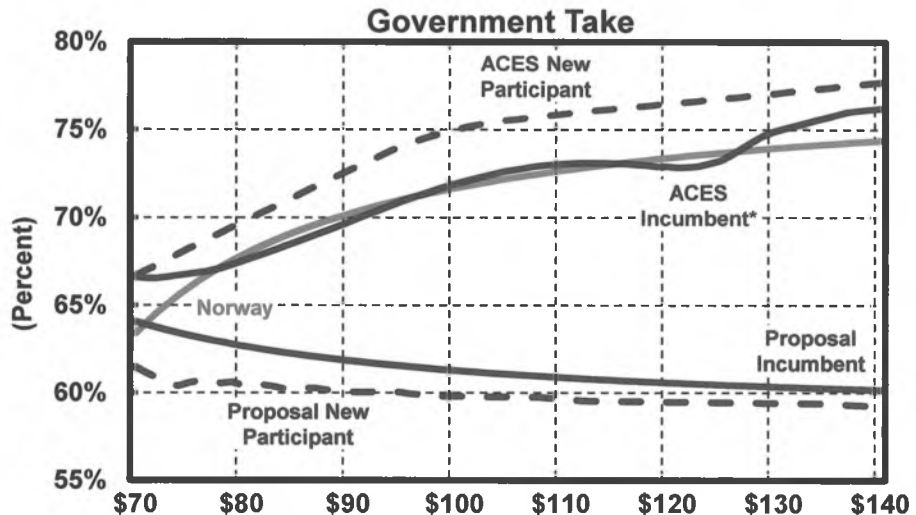
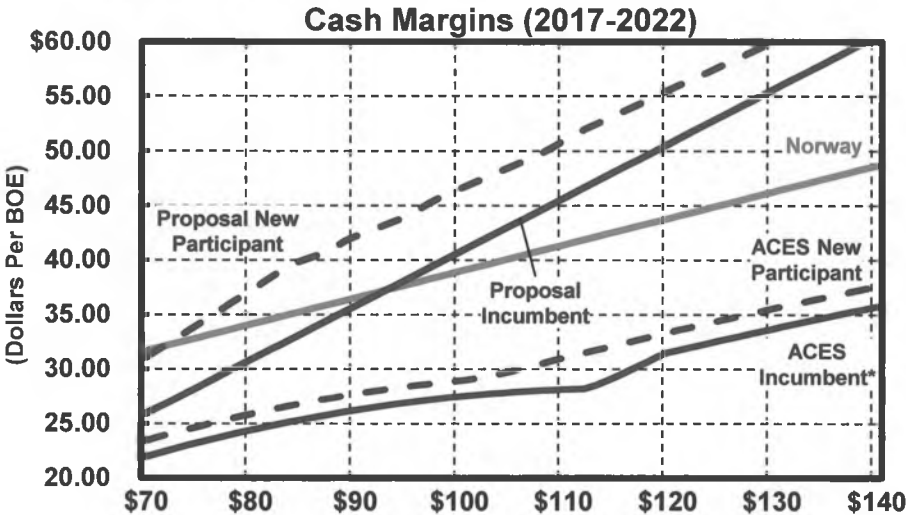
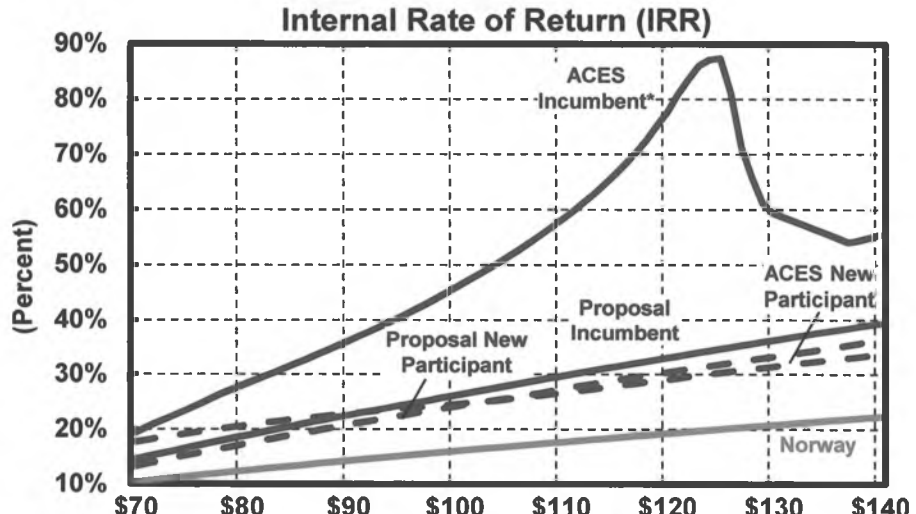
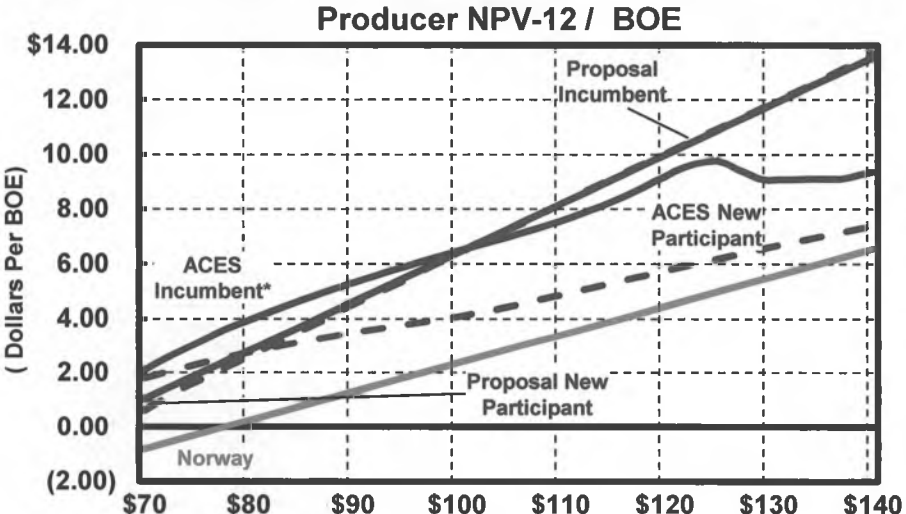
Conventional Oil Alaska Development v. North Sea (United Kingdom with Brownfield Allowance)



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

Investment Metrics

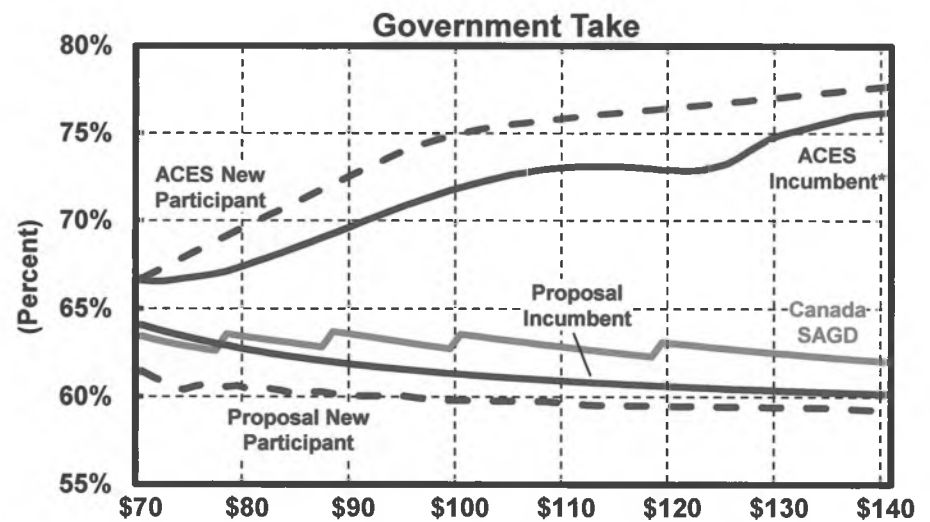
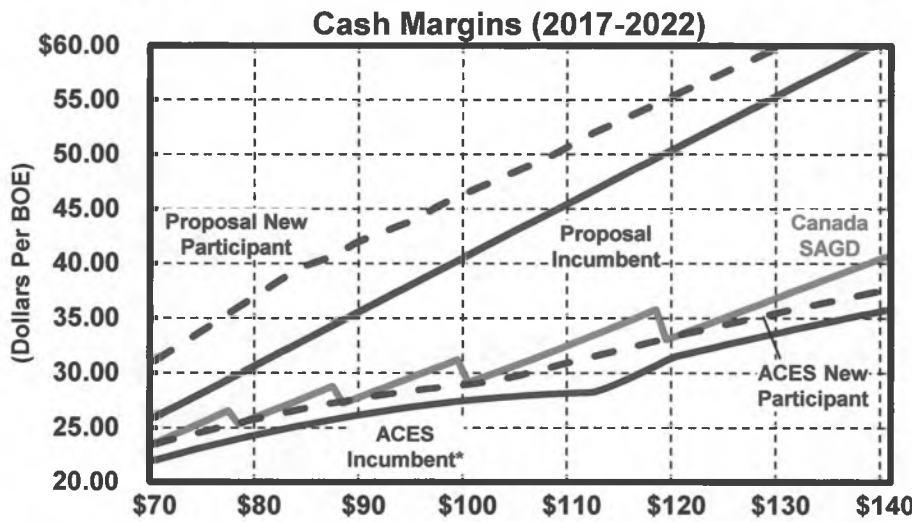
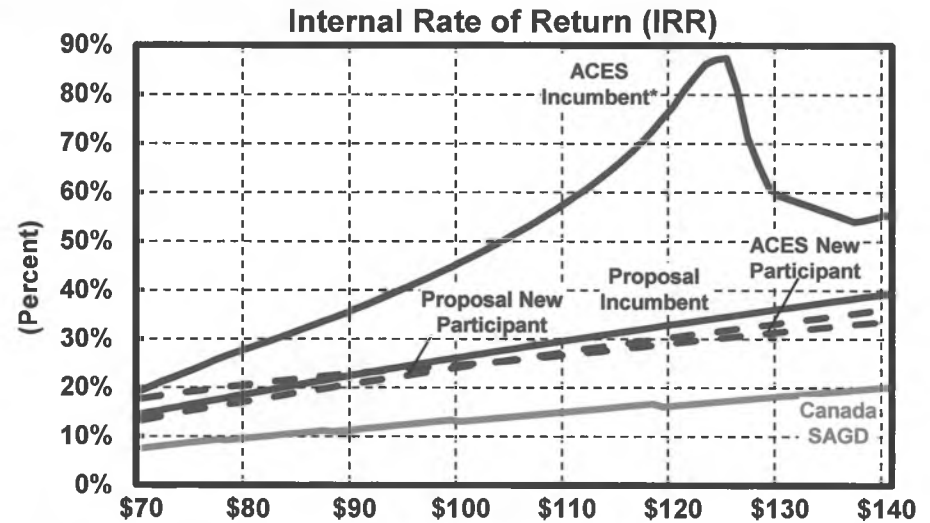
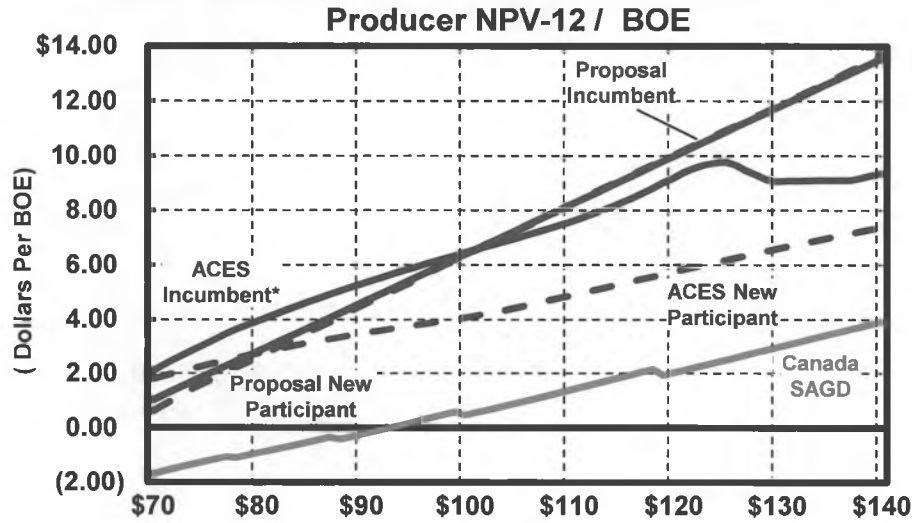
Conventional Oil Alaska Development v. North Sea (Norway)



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

Investment Metrics

Conventional Oil Alaska Development v. Canada Oil Sands (SAGD)



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

Summary of Investment Measures for New Participant Conventional Oil Alaska Development ACES and Proposal v. Benchmark Areas



West Coast ANS Price	ACES	Proposal		Unconventional Lower-48	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System			
		With GRE	Without GRE				Pre-1993	Pre-1993 w/ Brownfield Allowance*	Post-1993	Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Producer NPV-12 / BOE (Dollars Per BOE)										
\$80	\$2.73	\$2.60	\$1.98	\$2.14	(\$0.93)	\$0.24	\$1.20	\$4.81	\$2.41	\$4.62
\$100	\$4.07	\$6.35	\$5.49	\$5.52	\$0.46	\$2.34	\$3.02	\$7.09	\$6.04	\$8.25
\$120	\$5.74	\$10.01	\$8.95	\$10.17	\$2.01	\$4.44	\$4.83	\$9.09	\$9.67	\$11.88
Profitability Index-12										
\$80	1.21	1.20	1.15	1.15	0.88	1.01	1.06	1.22	1.11	1.21
\$100	1.31	1.48	1.41	1.37	1.06	1.14	1.14	1.33	1.28	1.38
\$120	1.43	1.75	1.67	1.69	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)										
\$80	20.6%	17.2%	16.2%	21.8%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
\$100	24.6%	24.2%	22.8%	34.5%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
\$120	29.1%	30.3%	28.9%	55.3%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
\$80	\$25.85	\$37.22	\$34.68	\$33.41	\$26.07	\$34.11	\$12.45	\$22.94	\$24.91	\$29.35
\$100	\$28.95	\$46.51	\$43.11	\$39.69	\$29.14	\$38.96	\$16.69	\$28.85	\$33.38	\$37.82
\$120	\$33.35	\$55.53	\$51.62	\$48.71	\$33.37	\$43.81	\$20.93	\$31.29	\$41.86	\$46.30
Government Take (Percent)										
\$80	69.7%	60.4%	64.8%	74.4%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
\$100	75.0%	59.8%	63.5%	70.0%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
\$120	76.5%	59.5%	62.8%	66.9%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State NPV-12/BOE (Dollars Per BOE)										
\$80	\$5.95	\$6.15	\$7.10	-	-	-	-	-	-	-
\$100	\$12.54	\$9.02	\$10.35	-	-	-	-	-	-	-
\$120	\$18.61	\$12.04	\$13.67	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Summary of Investment Measures for Incumbent Conventional Oil Alaska Development ACES and Proposal v. Benchmark Areas



West Coast ANS Price	ACES	Proposal		Unconventional Lower-48	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System			
		With GRE	Without GRE				Pre-1993	Pre-1993 w/ Brownfield Allowance*	Post-1993	Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Producer NPV-12 / BOE (Dollars Per BOE)										
\$80	\$3.93	\$2.80	\$2.09	\$2.14	(\$0.93)	\$0.24	\$1.20	\$4.81	\$2.41	\$4.62
\$100	\$6.45	\$6.38	\$5.46	\$5.52	\$0.46	\$2.34	\$3.02	\$7.09	\$6.04	\$8.25
\$120	\$9.17	\$9.96	\$8.83	\$10.17	\$2.01	\$4.44	\$4.83	\$9.09	\$9.67	\$11.88
Profitability Index-12										
\$80	1.30	1.21	1.16	1.15	0.88	1.01	1.06	1.22	1.11	1.21
\$100	1.49	1.48	1.41	1.37	1.06	1.14	1.14	1.33	1.28	1.38
\$120	1.69	1.75	1.67	1.69	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)										
\$80	27.9%	18.7%	17.1%	21.8%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
\$100	45.7%	26.2%	24.4%	34.5%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
\$120	77.6%	33.0%	31.0%	55.3%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
\$80	\$24.38	\$30.83	\$28.72	\$33.41	\$26.07	\$34.11	\$12.45	\$22.94	\$24.91	\$29.35
\$100	\$27.48	\$40.73	\$38.00	\$39.69	\$29.14	\$38.96	\$16.69	\$28.85	\$33.38	\$37.82
\$120	\$31.50	\$50.63	\$47.28	\$48.71	\$33.37	\$43.81	\$20.93	\$31.29	\$41.86	\$46.30
Government Take (Percent)										
\$80	67.5%	62.7%	66.9%	74.4%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
\$100	71.9%	61.3%	65.0%	70.0%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
\$120	72.9%	60.6%	64.0%	66.9%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State NPV-12/BOE (Dollars Per BOE)										
\$80	\$4.10	\$5.84	\$6.94	-	-	-	-	-	-	-
\$100	\$8.88	\$8.98	\$10.40	-	-	-	-	-	-	-
\$120	\$13.34	\$12.11	\$13.85	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

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