House Resources Committee

Alaska Fiscal System Discussion Slides

February 15 2013

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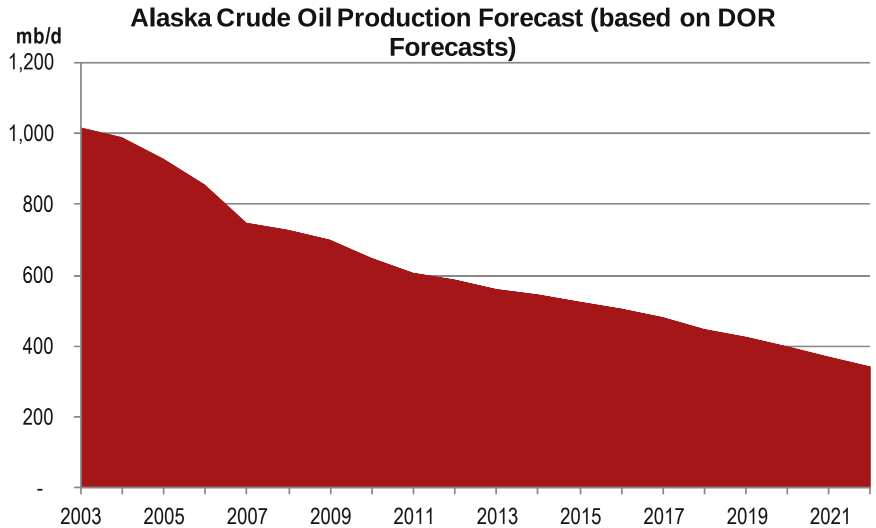
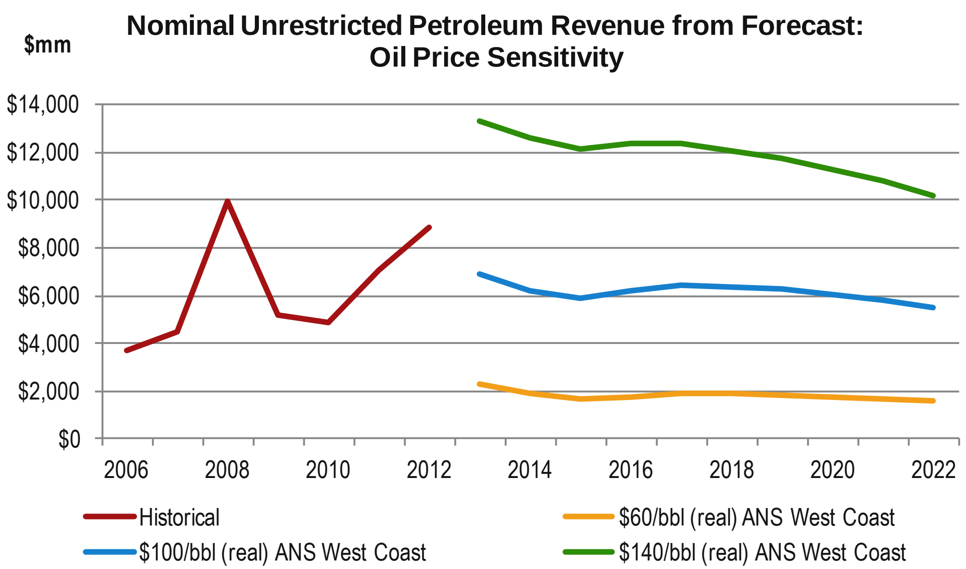
PFC Energy

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

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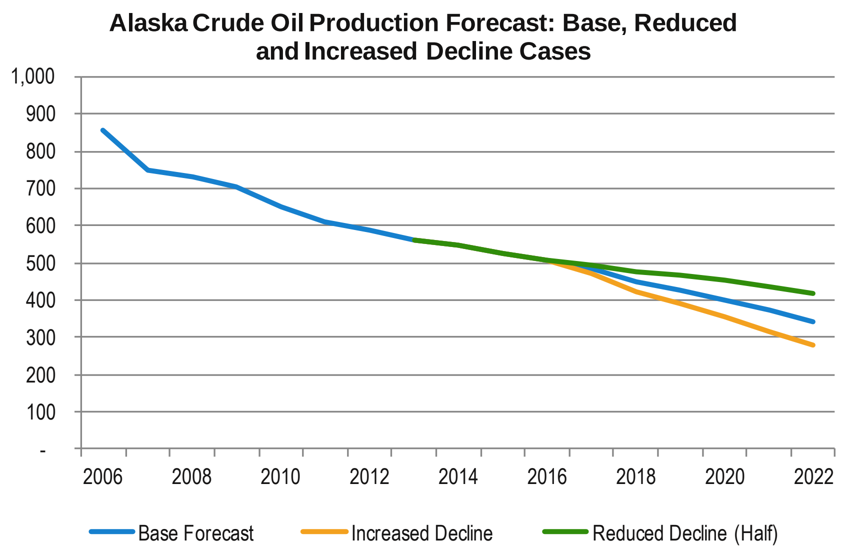
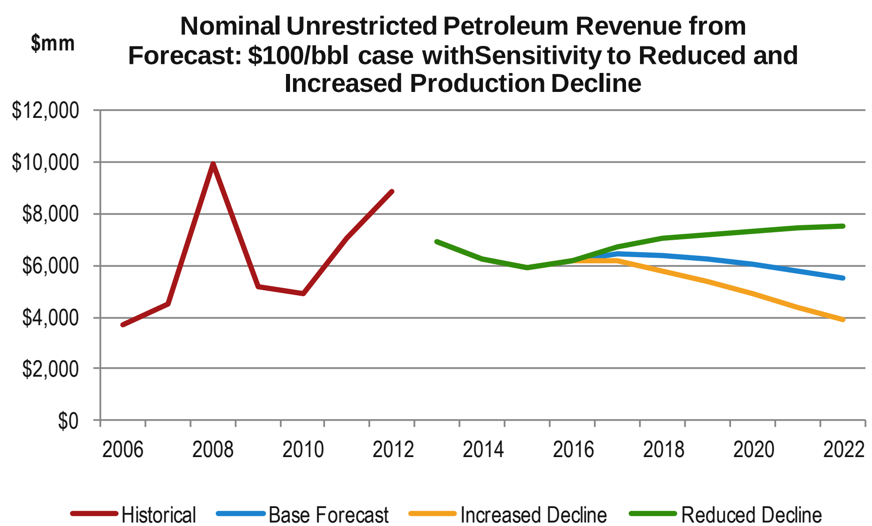
Decline Rate is the Other Major Determinant





- 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

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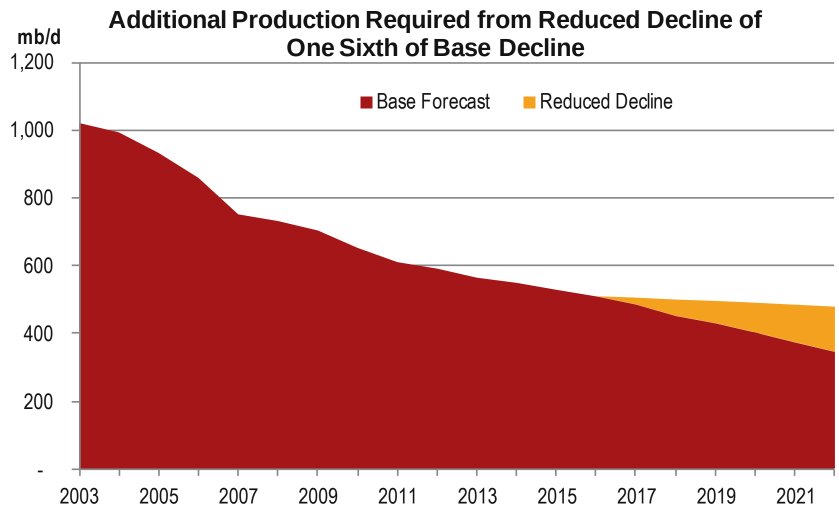
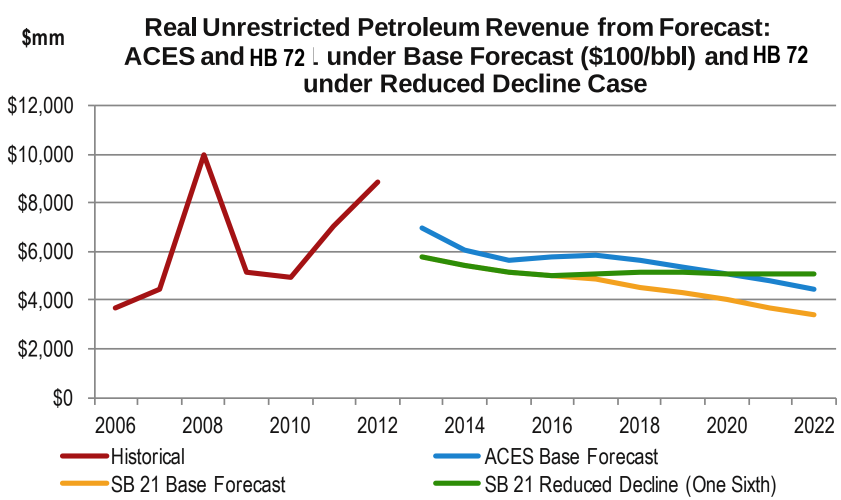
Fiscal Terms Changes and Investment Impacts





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%**

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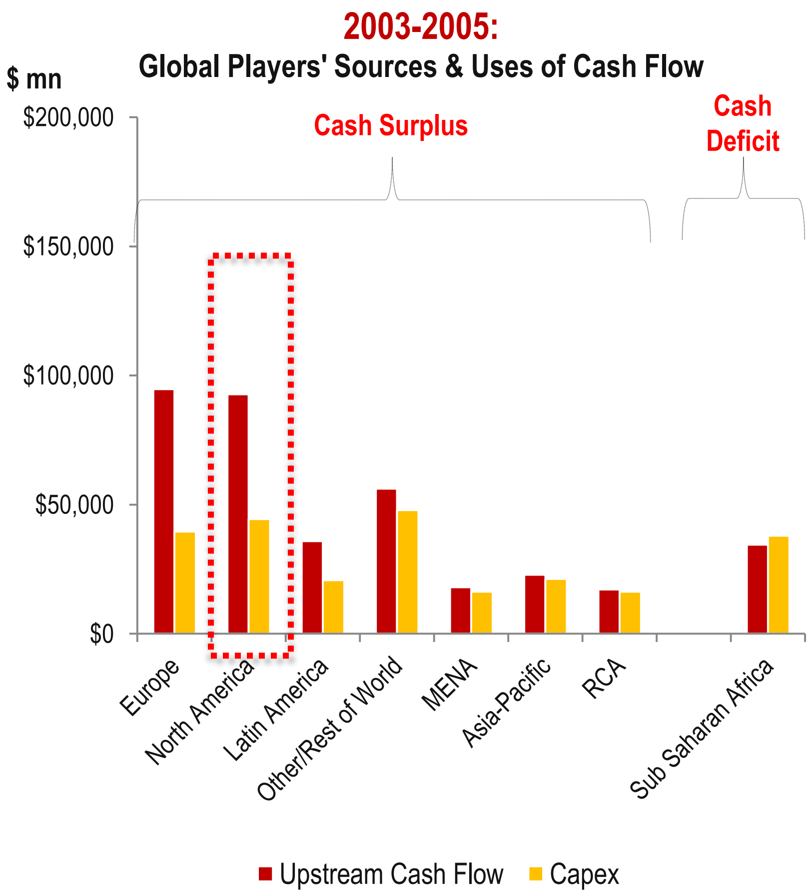
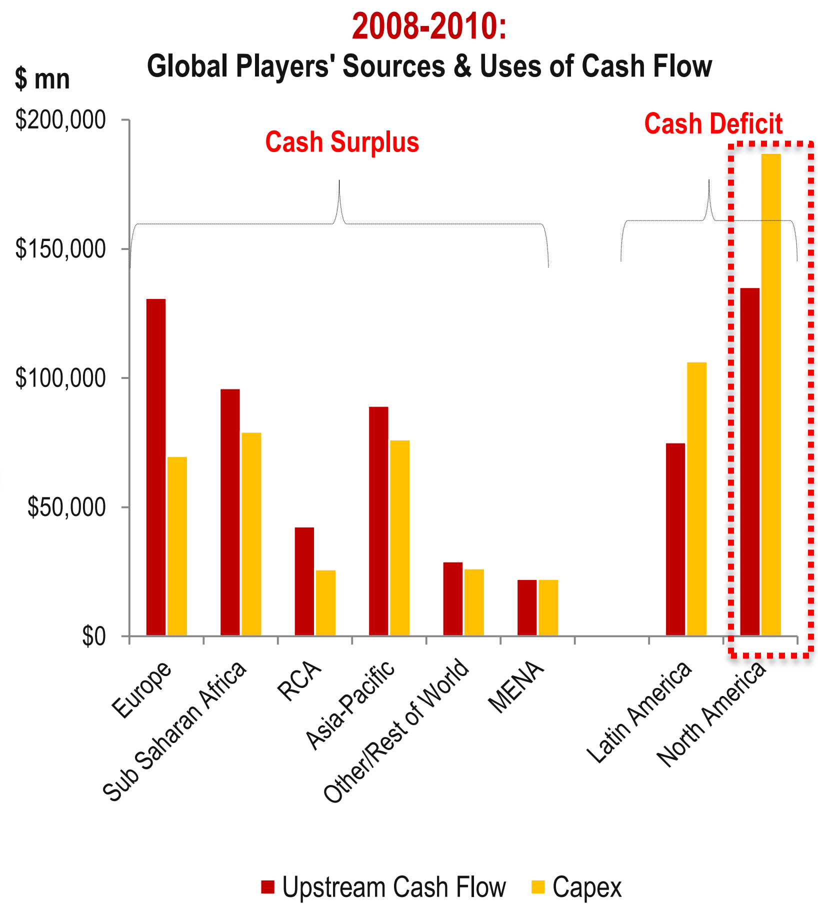
Context: Investment Competition & Global Oil Price Environment

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

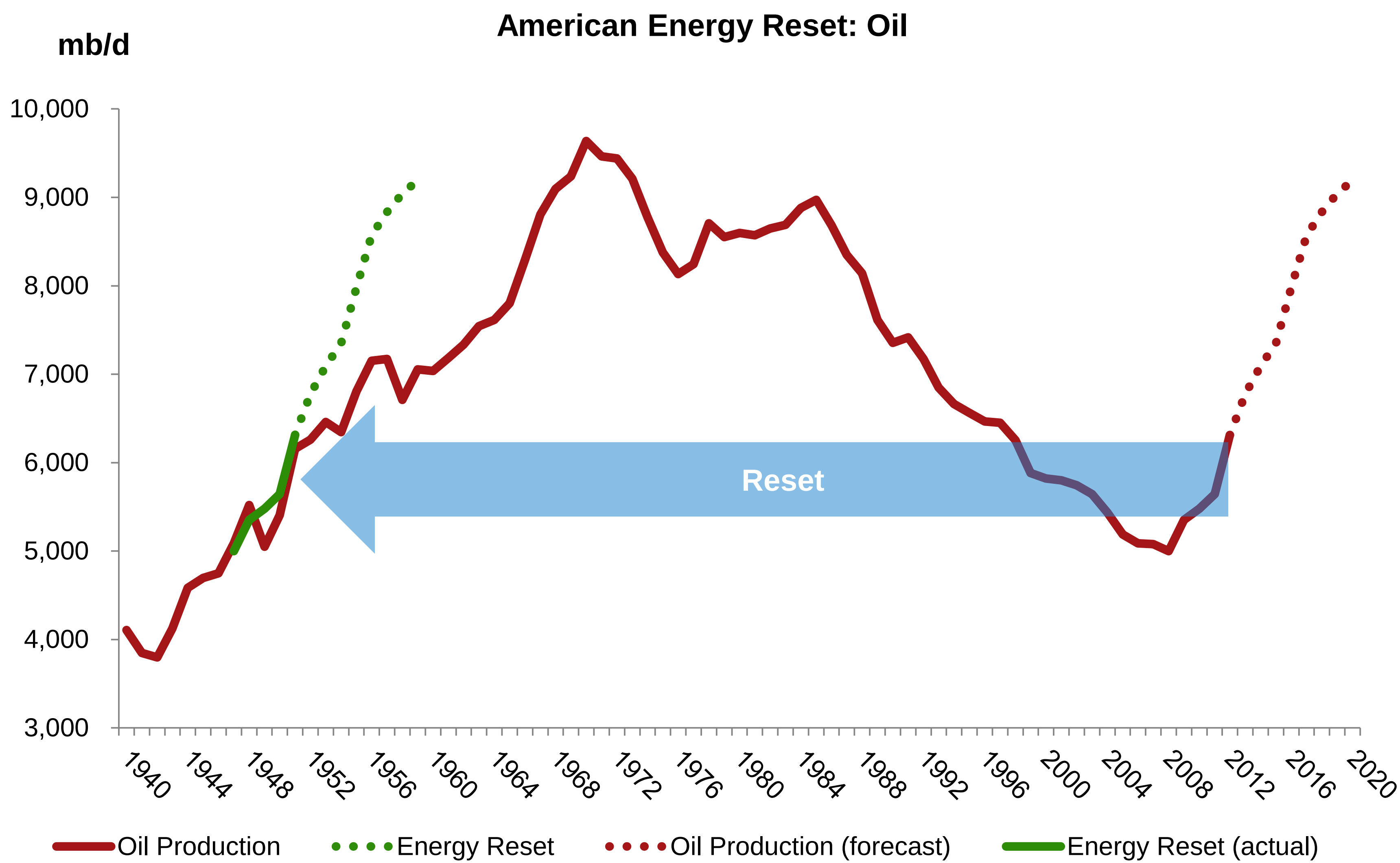




It is now an exception not to be targeting unconventionals in North America as a major growth platform.

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

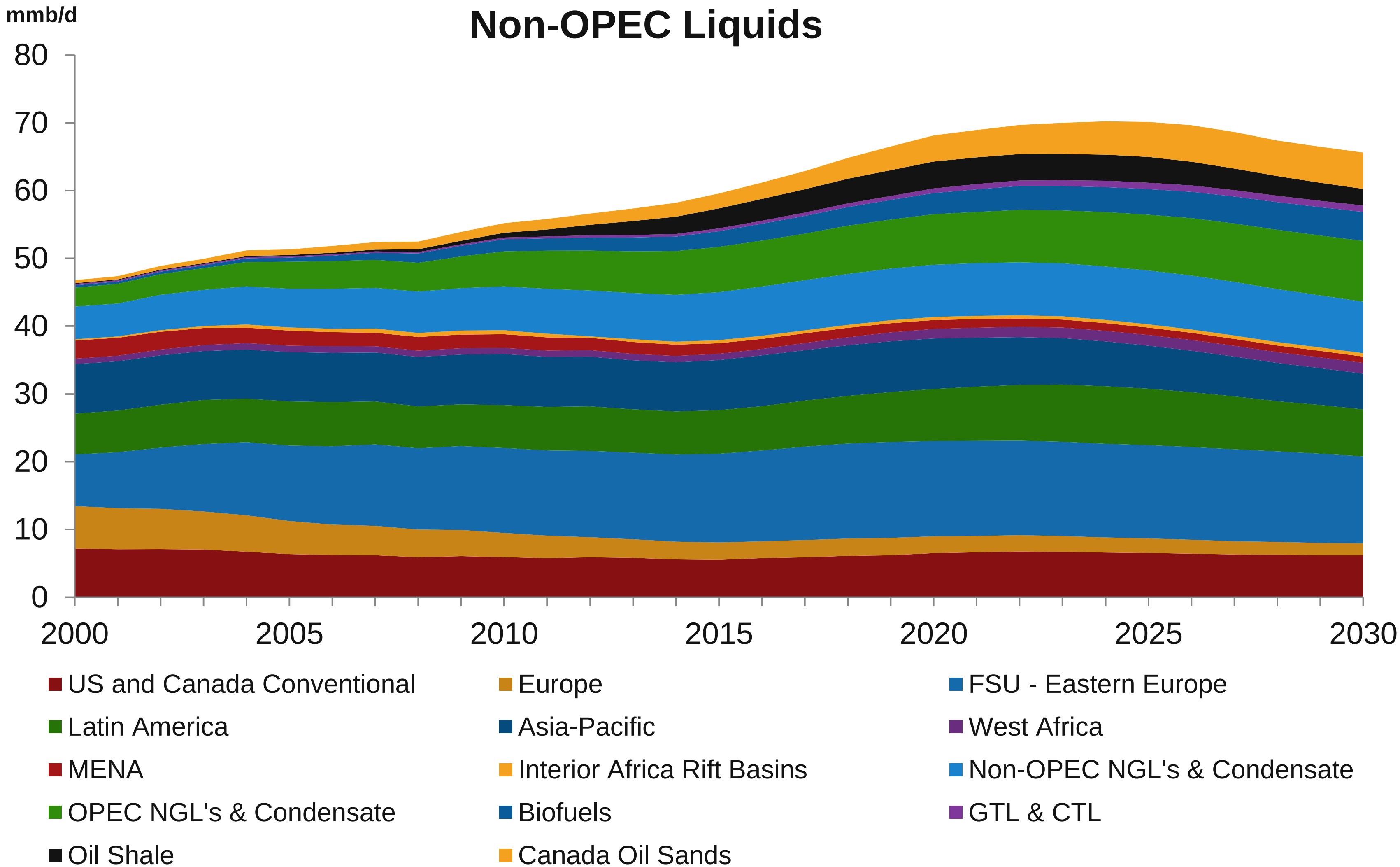
OPEC Crude

- 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

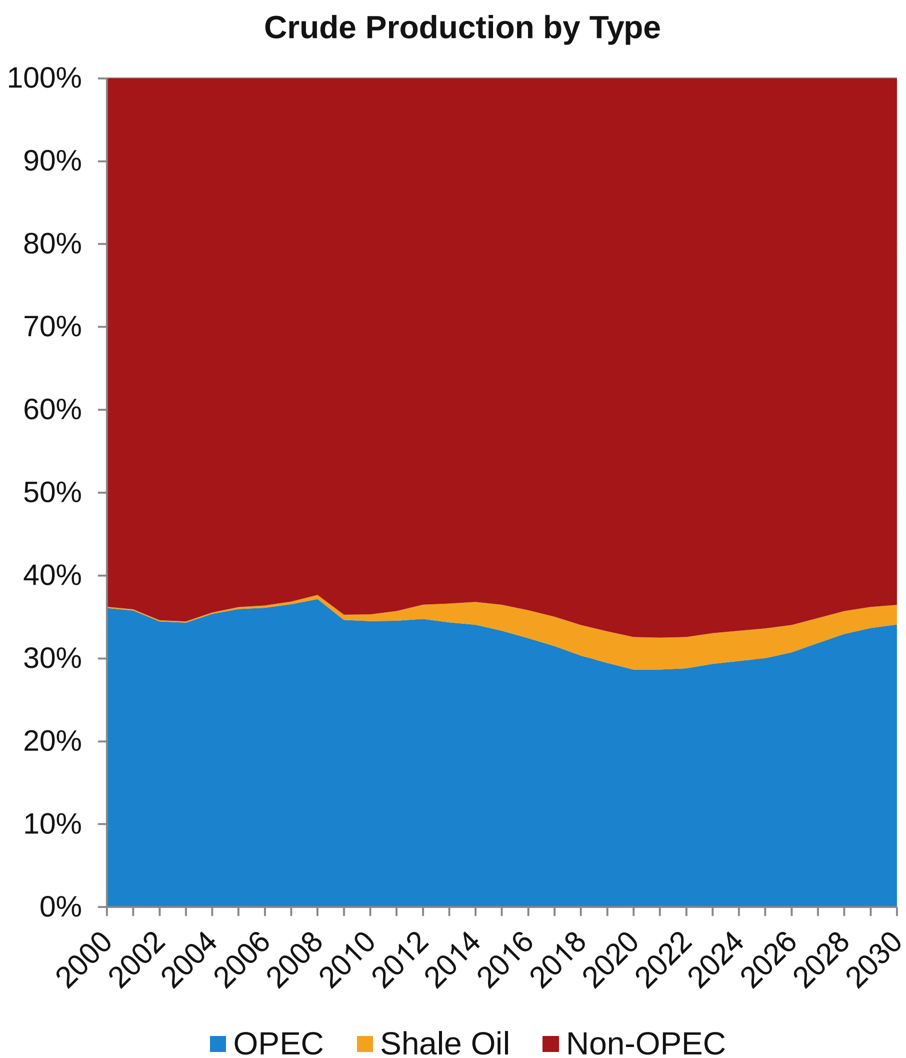
In the past production not affected by price swings



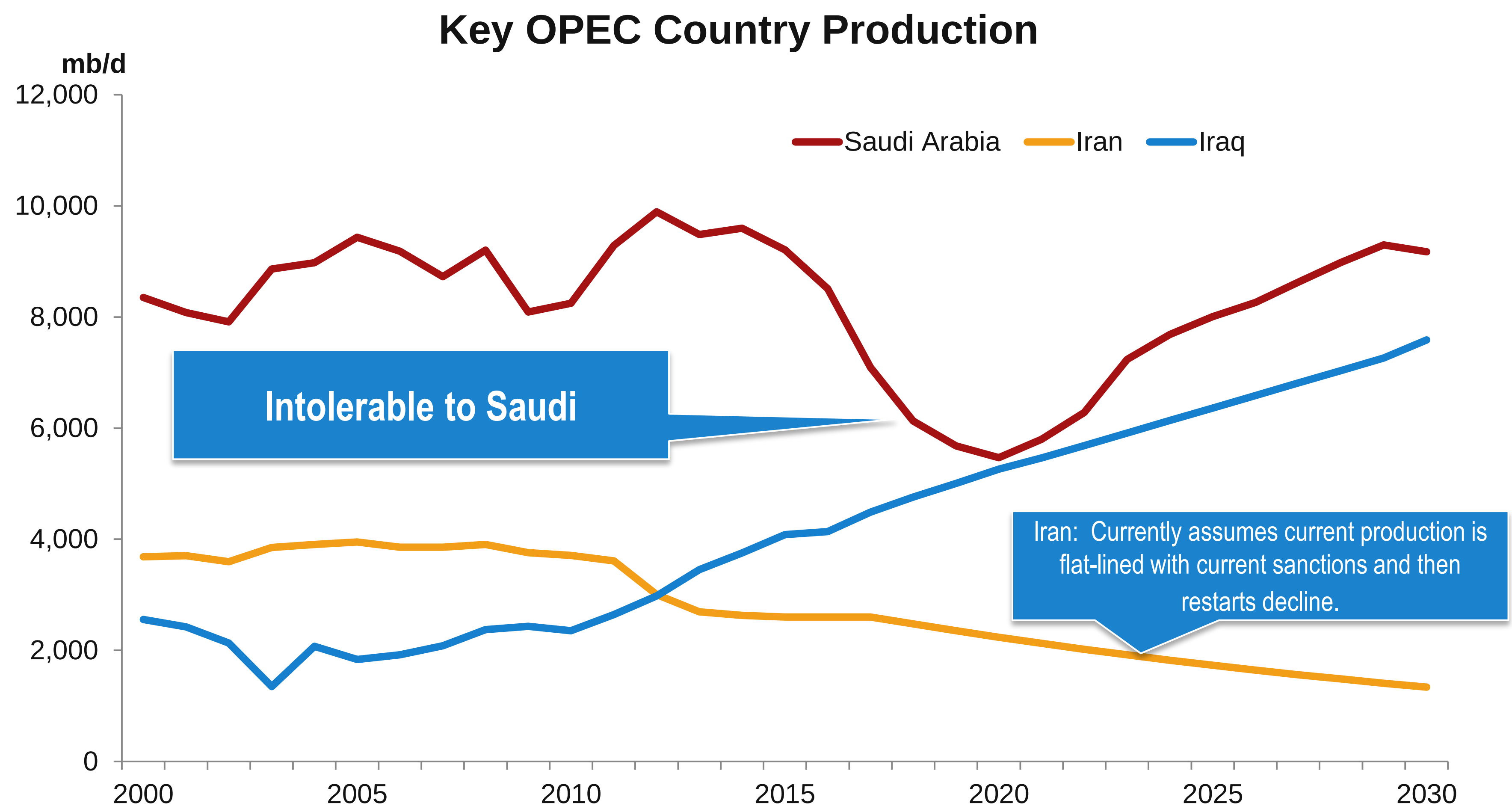
Shale Oil Major Factor in Reducing OPEC's Share

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

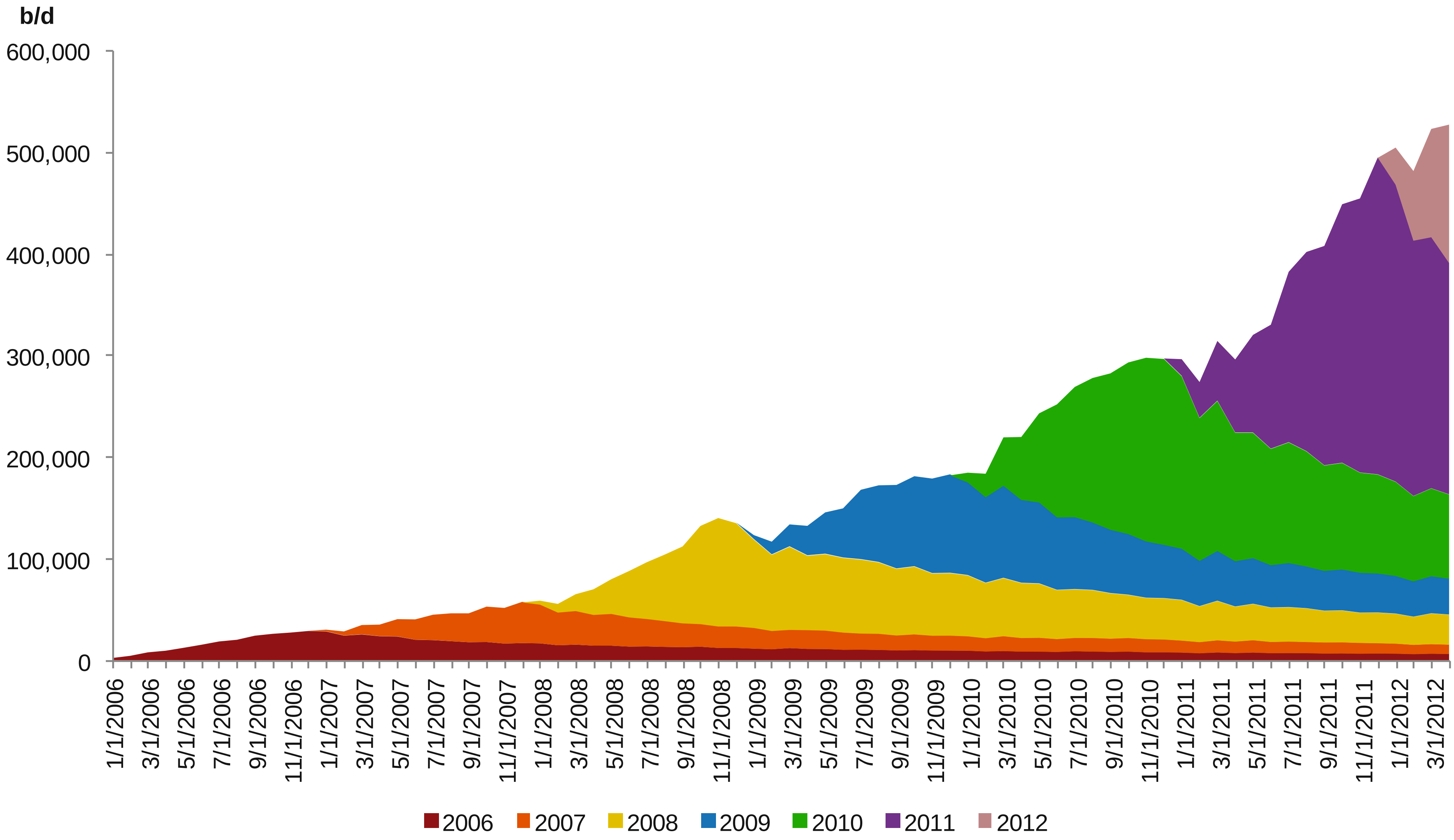


A diplomatic solution that brings Iran back into the oil markets makes OPEC management worse via increased volumes

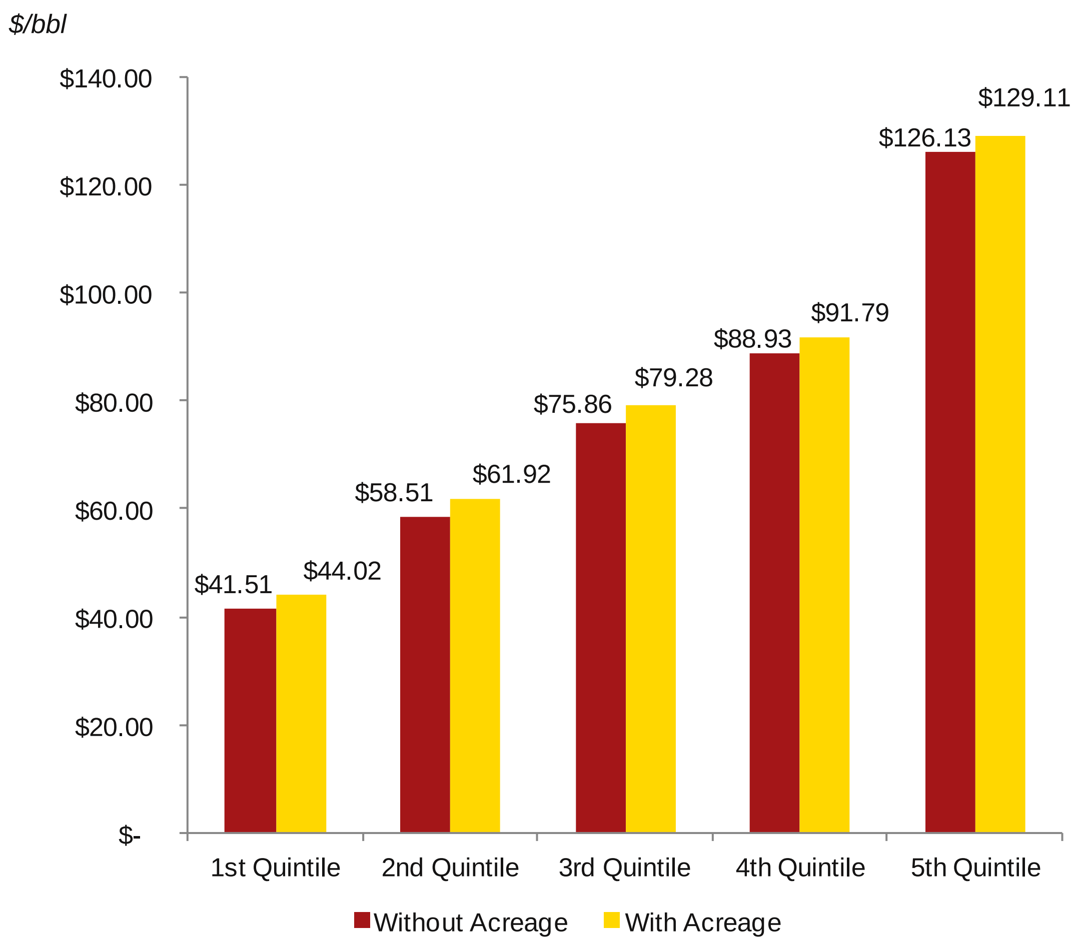
Character of US Growth Changing

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%

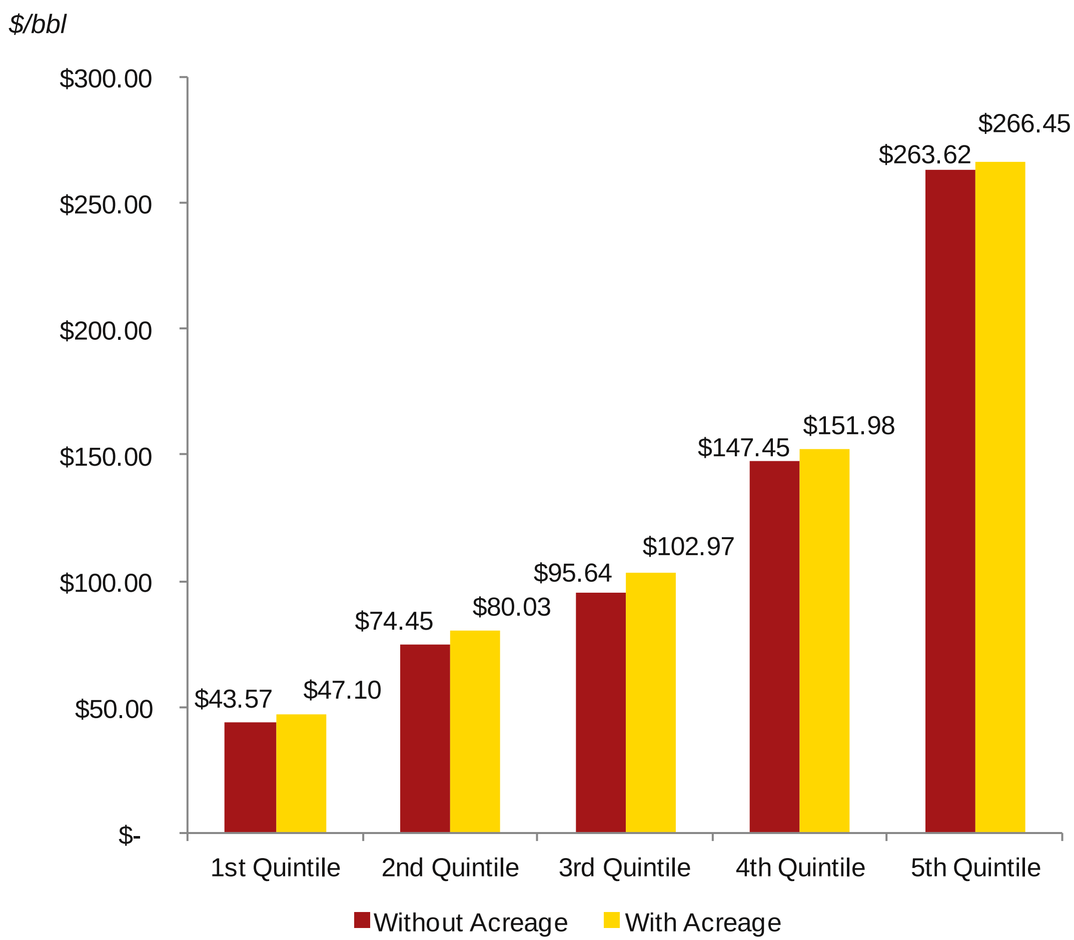
Fed taxes: 35%

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%

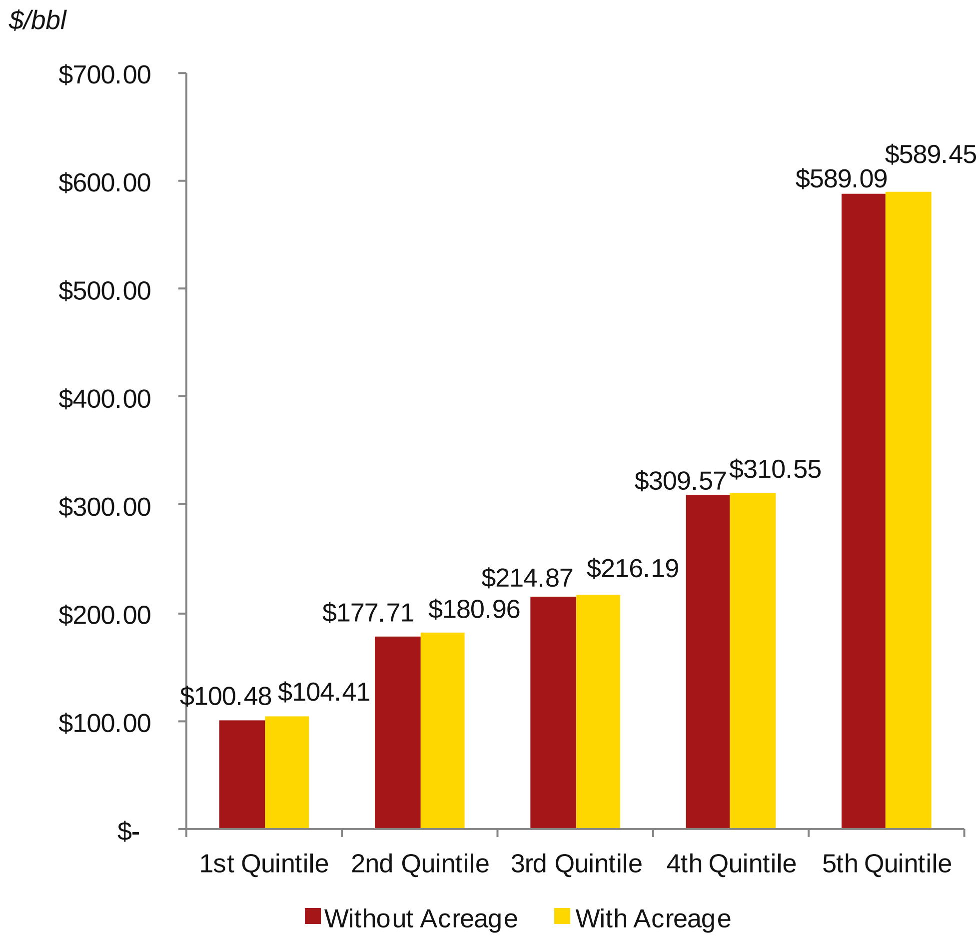
Fed taxes: 35%

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

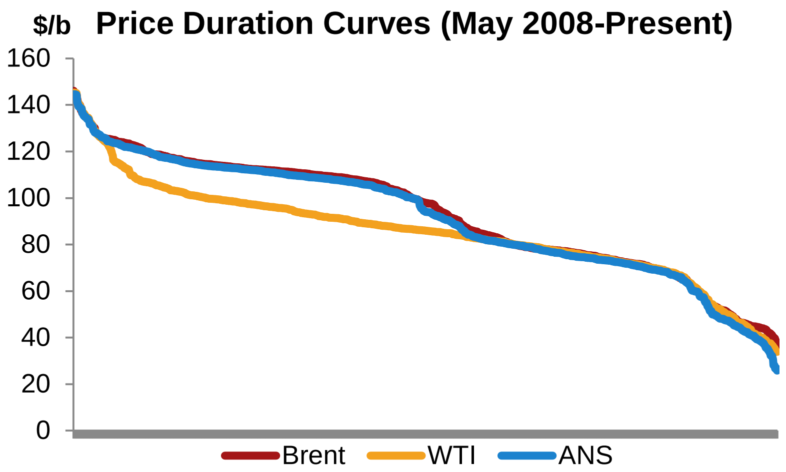
Royalty Rates:
Q 1: 1/6
Q 2: 1/6
Q 3: 1/6
Q 4: 1/8
Q 5: 1/8

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 form $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.



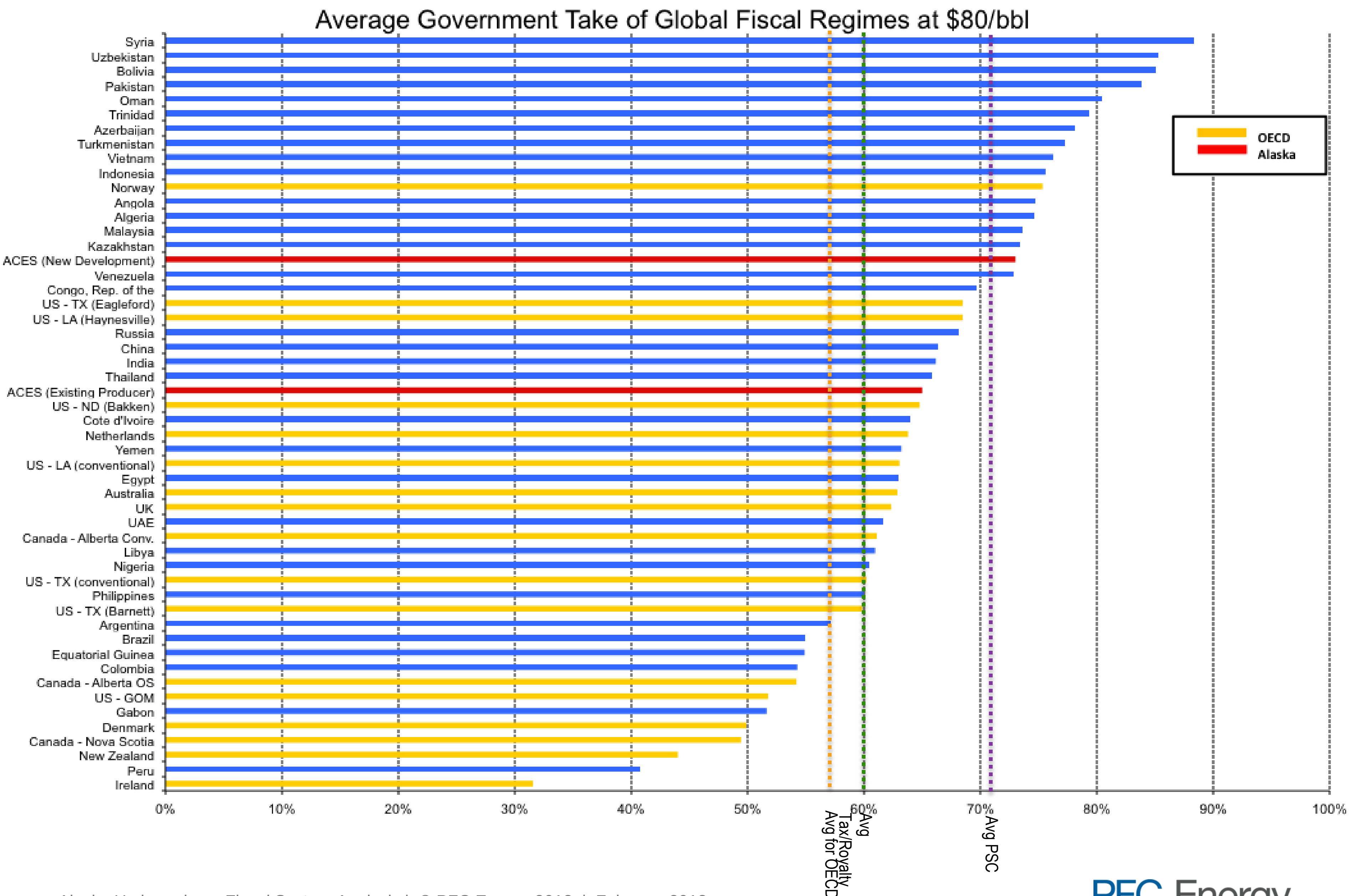
- **In the medium- to long-term, the floor price is near the cost of the marginal barrel**:
  – If US constrained, potential for $55-60/b
  – If global (and assuming US production does not again surprise to the upside), the price floor is higher at $70-75/b

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



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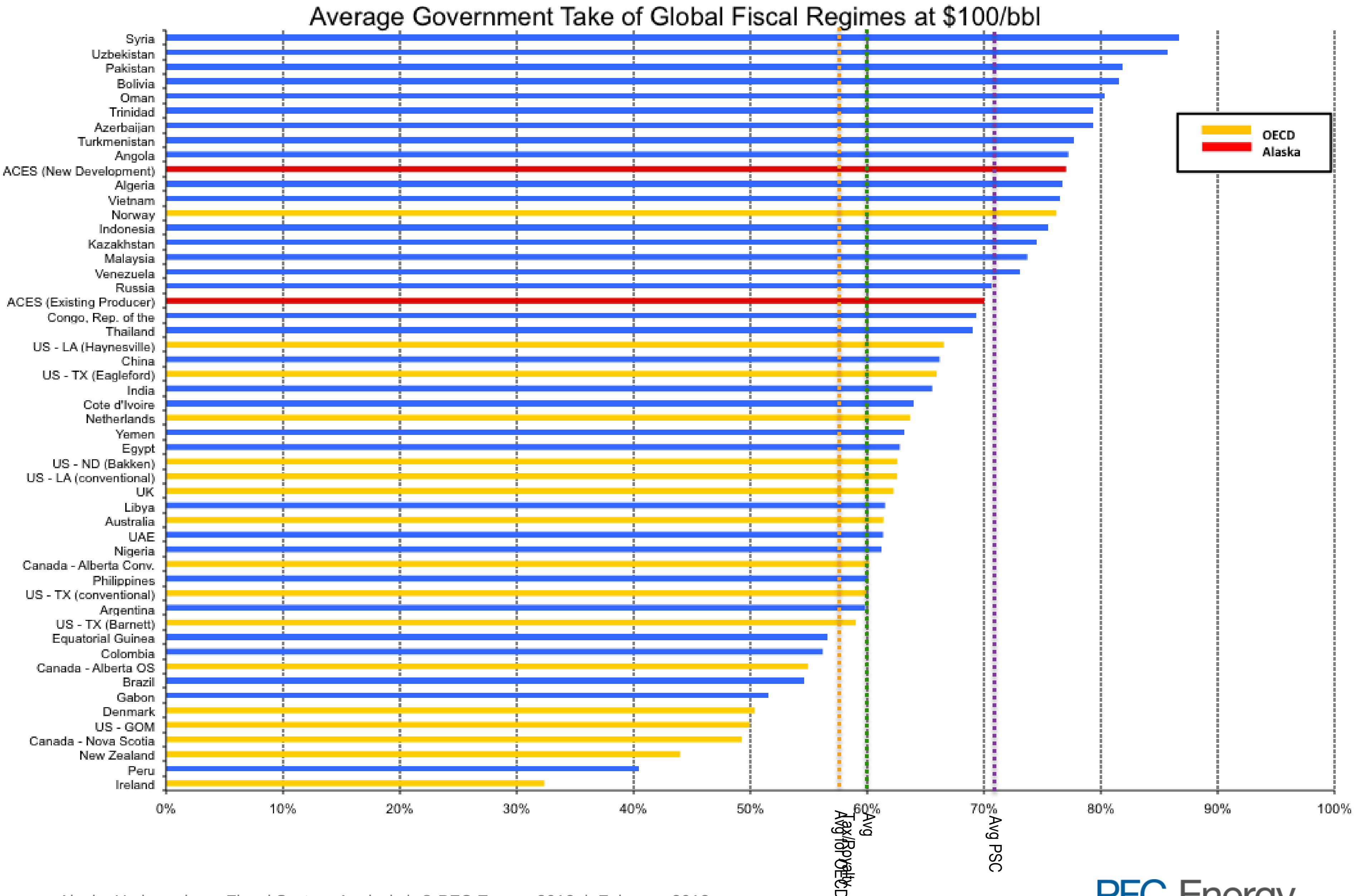
Regime Competitiveness: Average Government Take at $100/bbl



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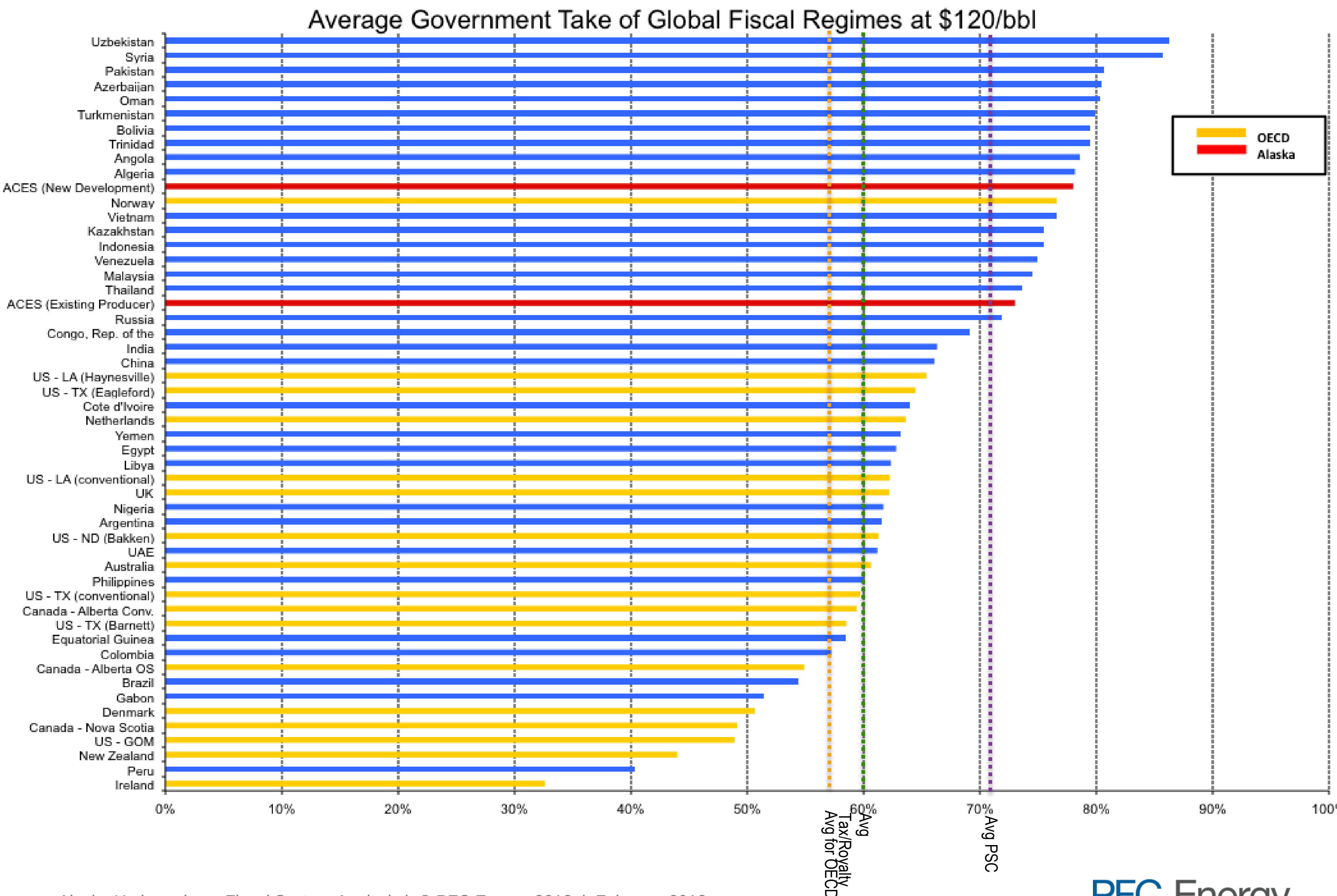
Regime Competitiveness: Average Government Take at $120/bbl



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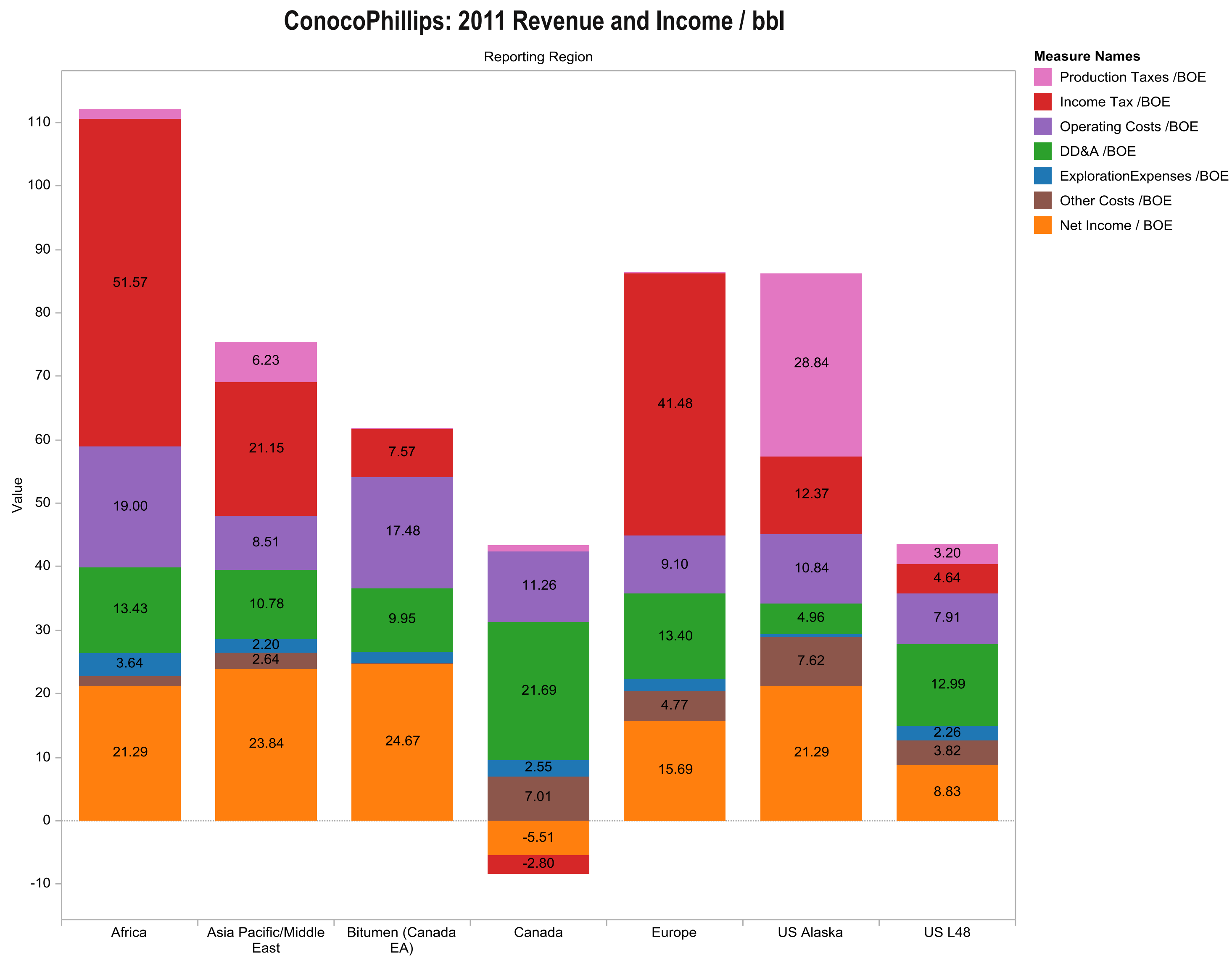
Difference Between New Investment vs Base Production is Critical



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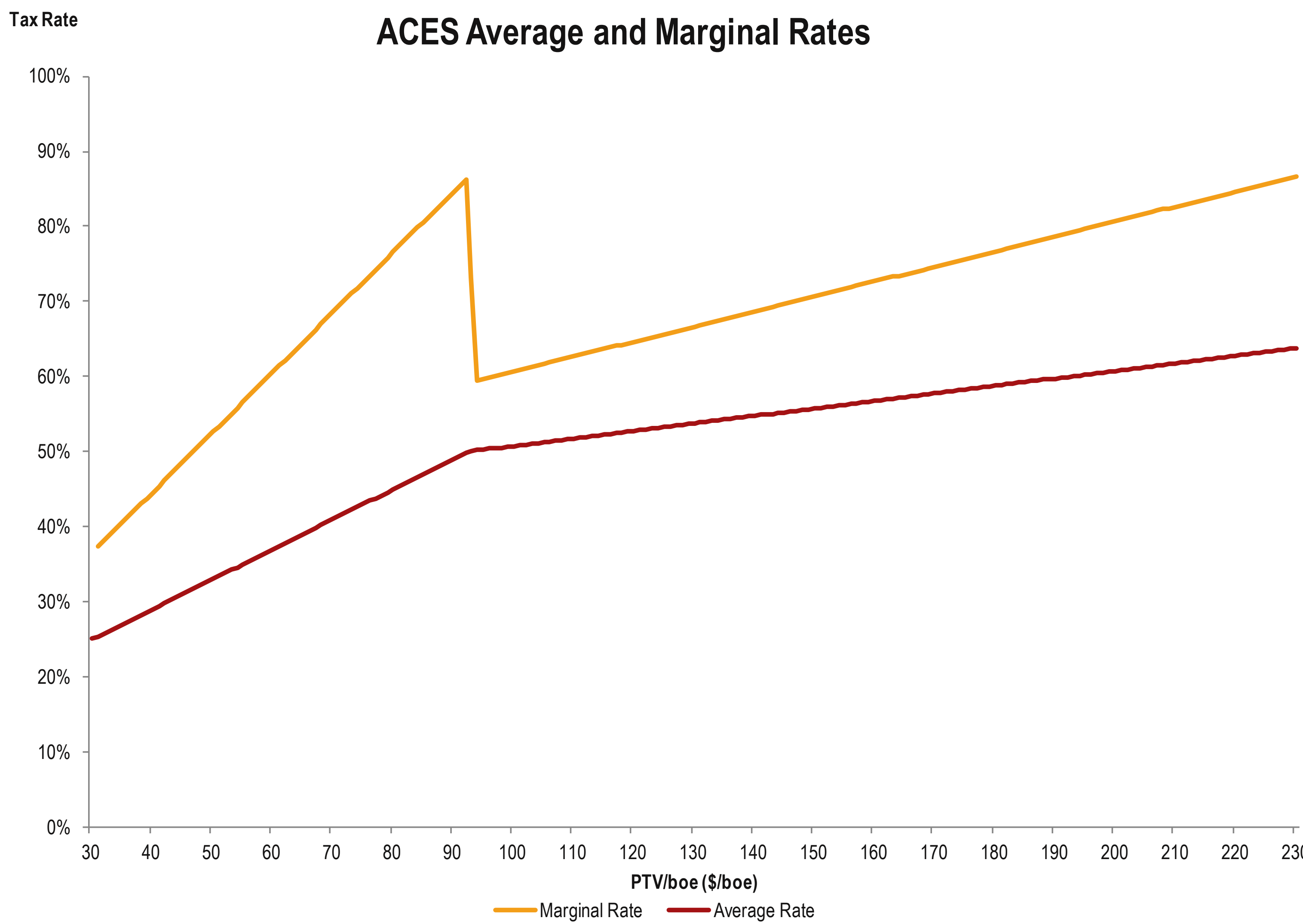
ACES: Average and Marginal Production Tax Rates



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%

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Source: Econ One Presentation, February 13 2013

ACES: 5 key problems

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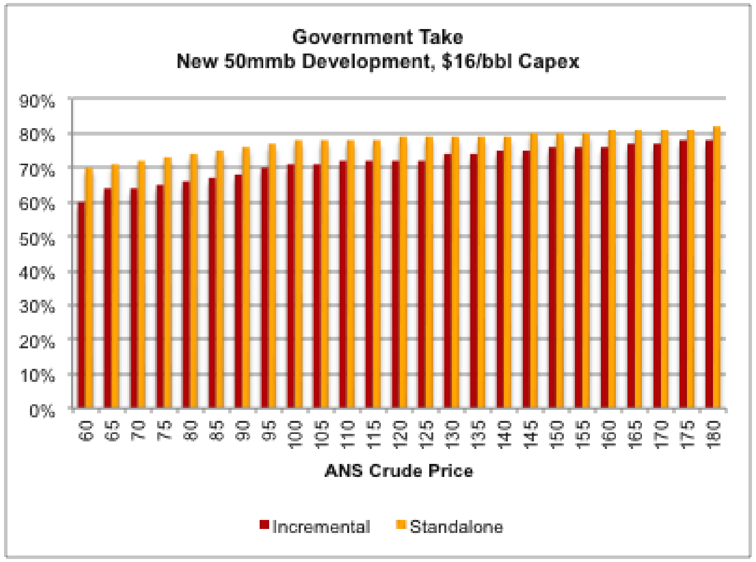
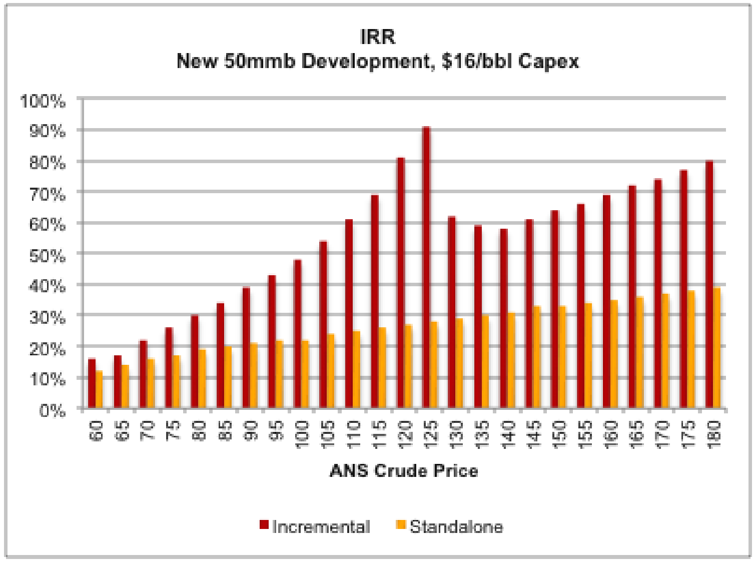
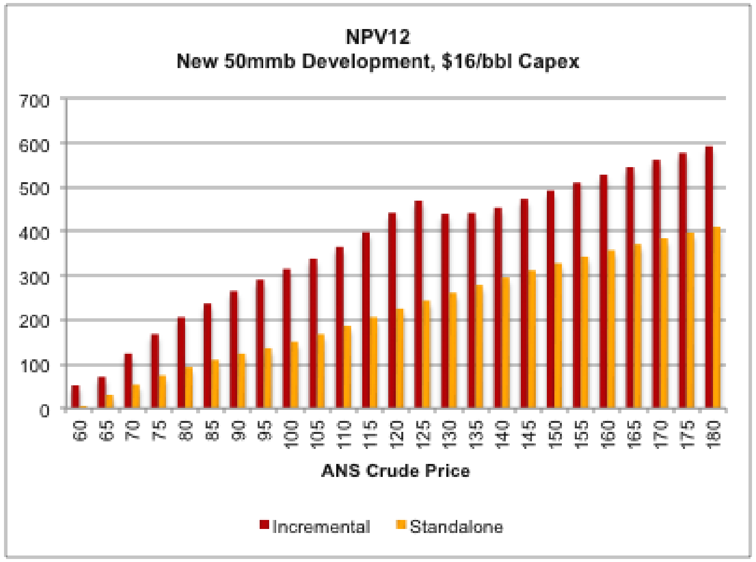
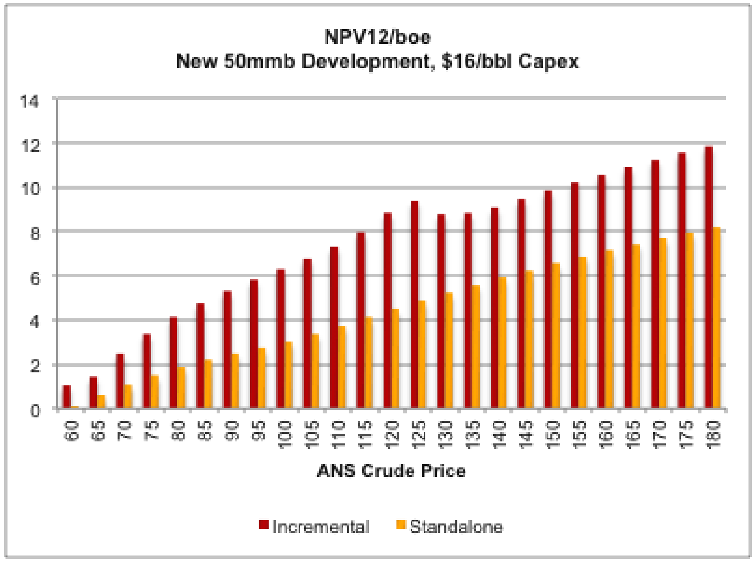
ACES: Standalone vs Incremental









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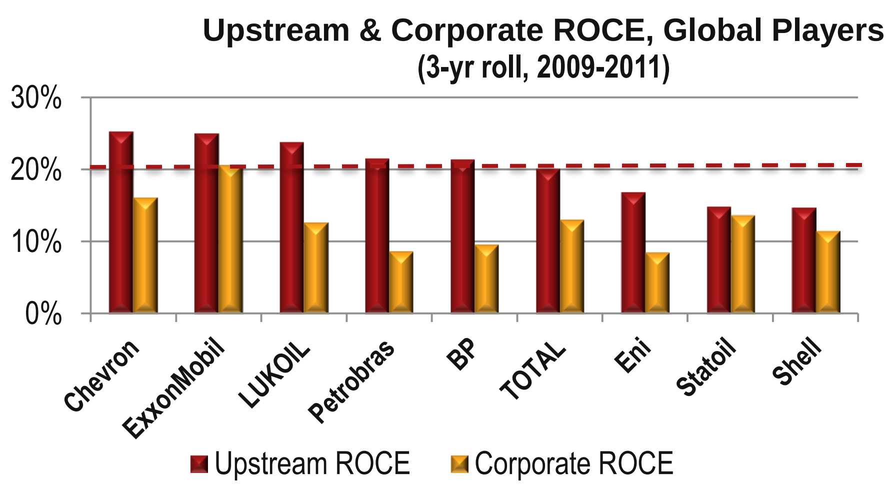
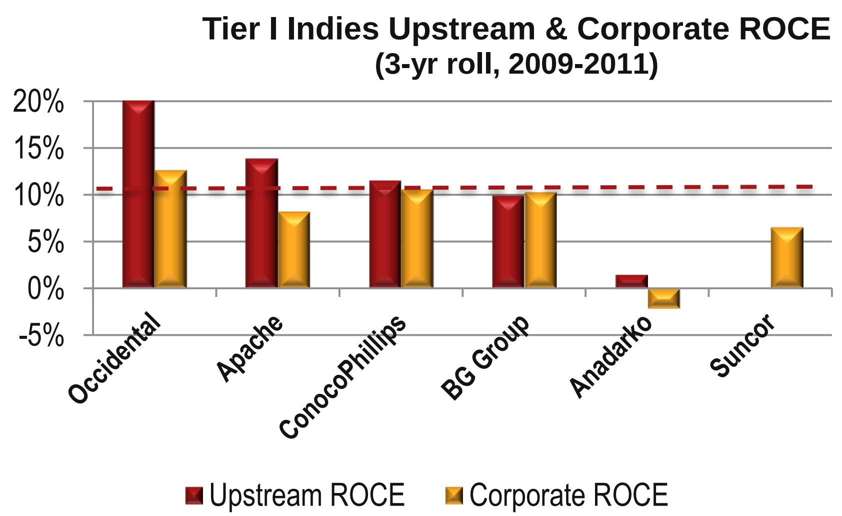
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **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





Global Players Average Upstream ROCE: 20.4%
Tier I Independents Average Upstream ROCE: 11.4%

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ACES: 5 key problems

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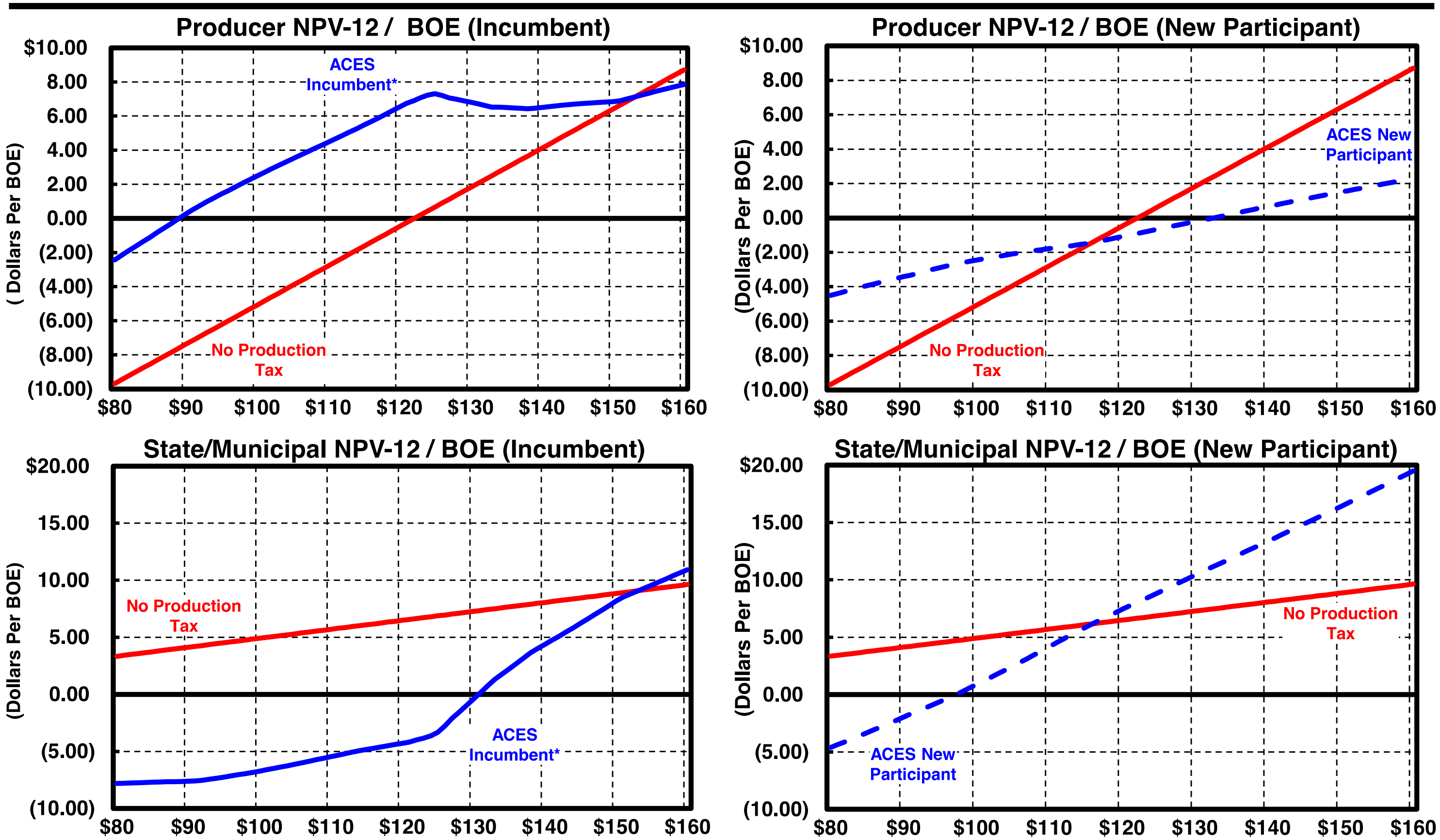
- **Significant state exposure in low price environments, and for high-cost developments**
- Impact of large-scale gas sales on tax rates

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.

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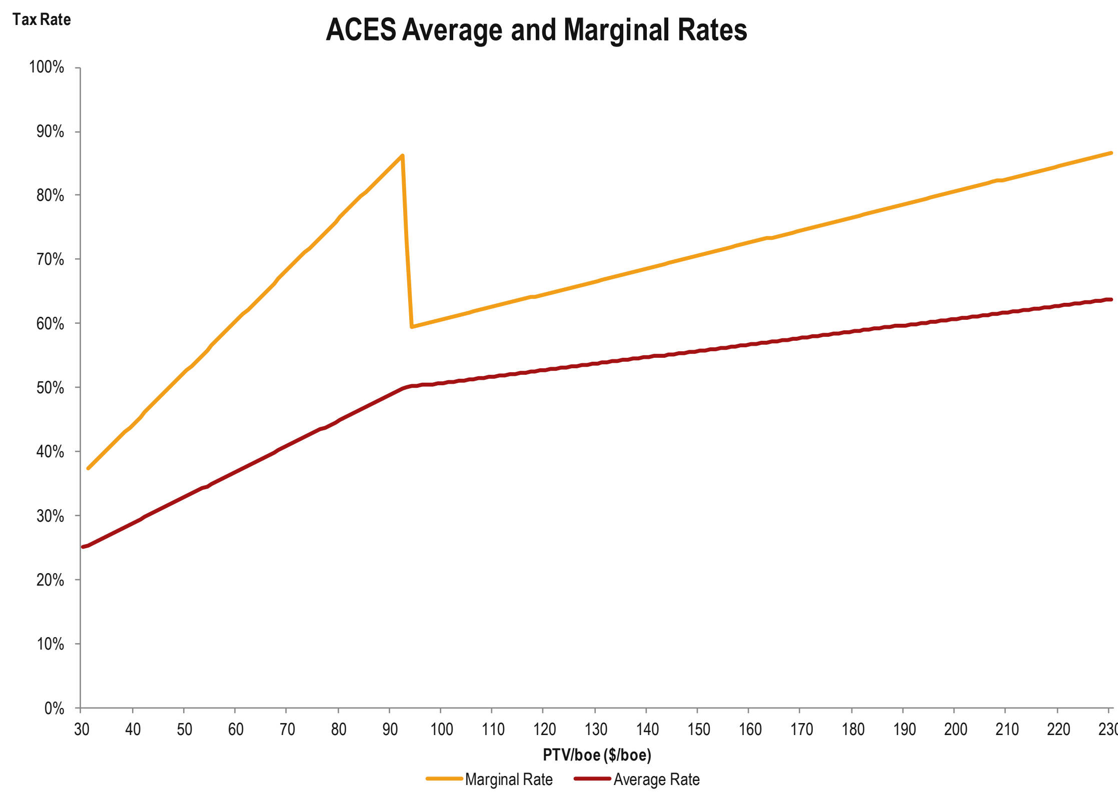
- **Impact of large-scale gas sales on tax rates**

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
  - *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
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  - ***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*

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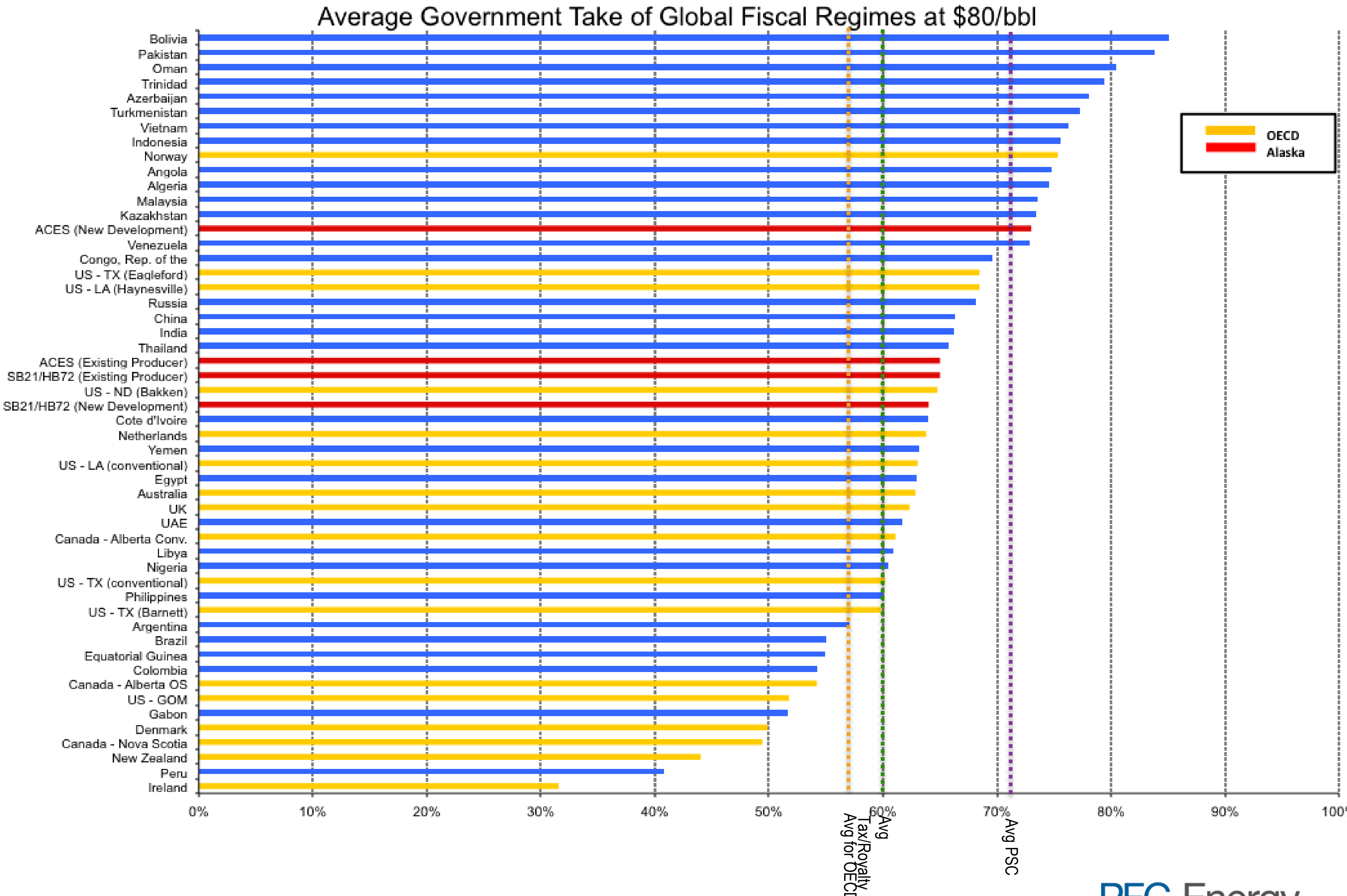
Regime Competitiveness: Average Government Take at $80/bbl



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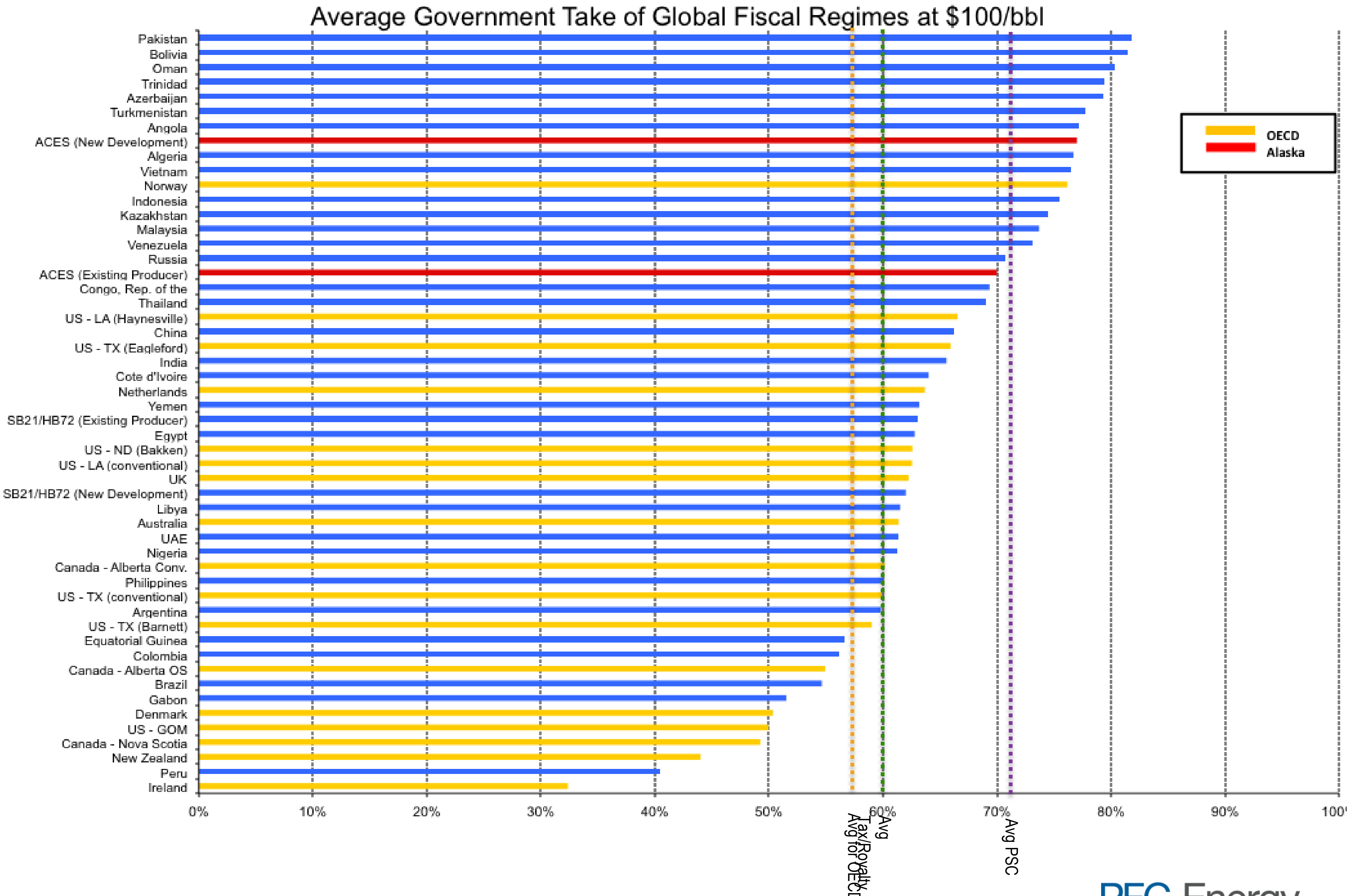
Regime Competitiveness: Average Government Take at $100/bbl



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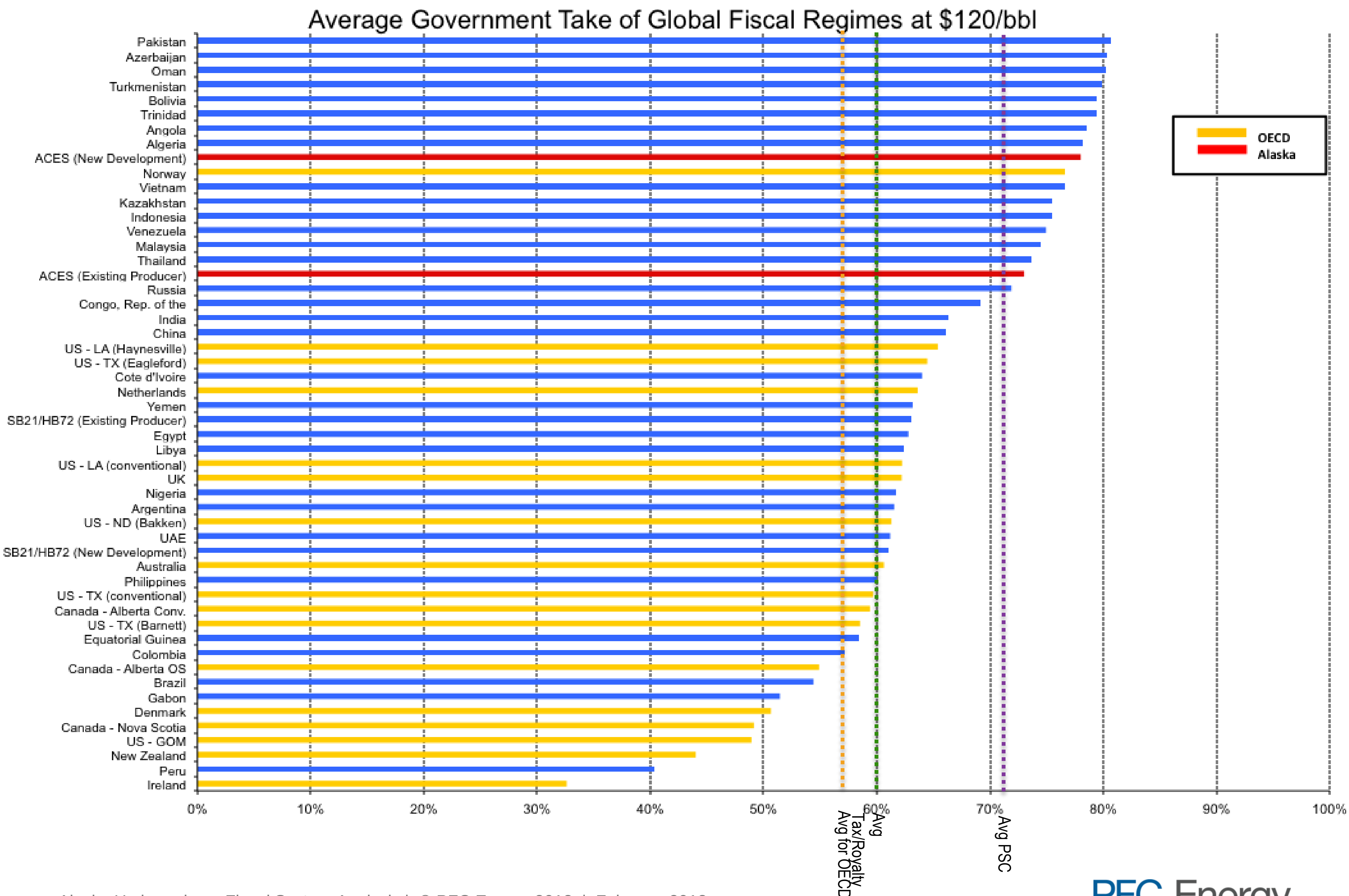
Regime Competitiveness: Average Government Take at $120/bbl



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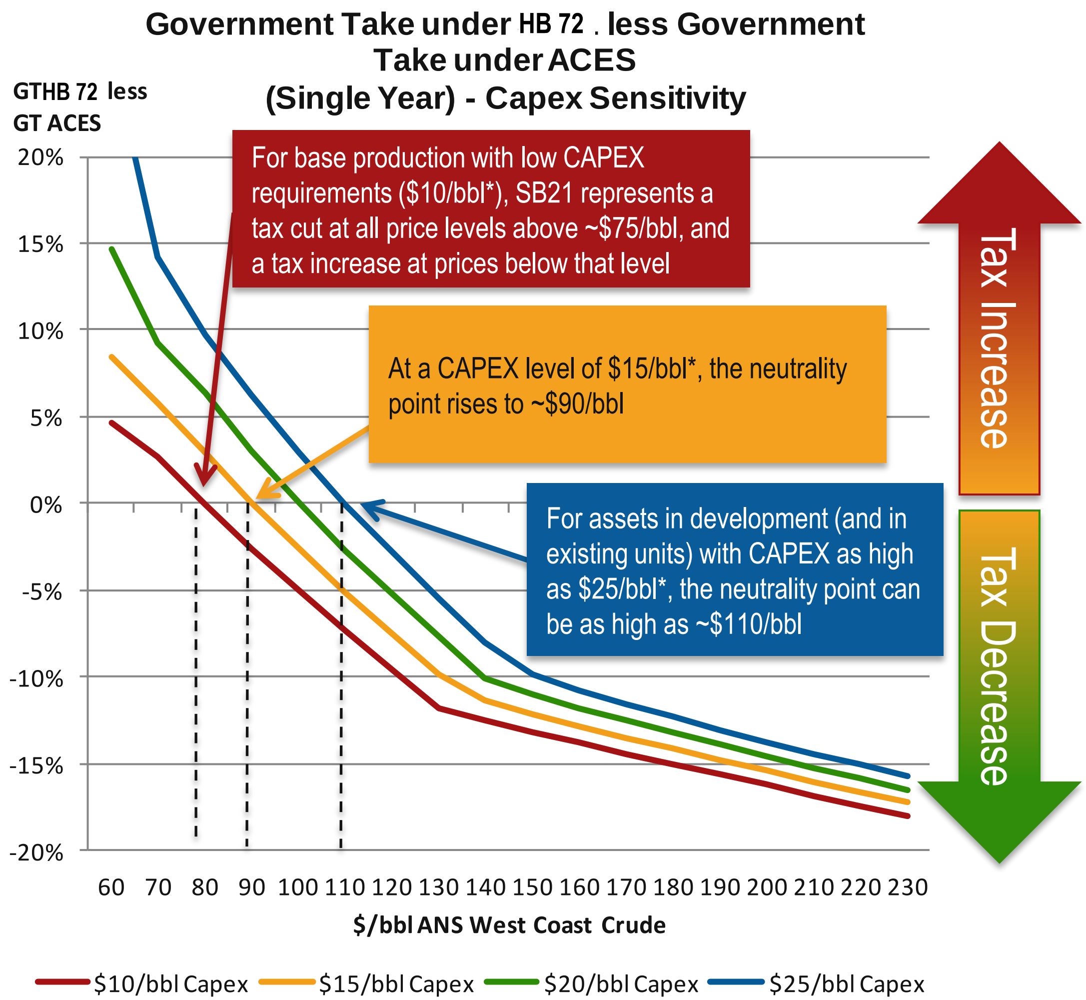
Government Take under SB21/HB72 and ACES – Capex Sensitivity



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

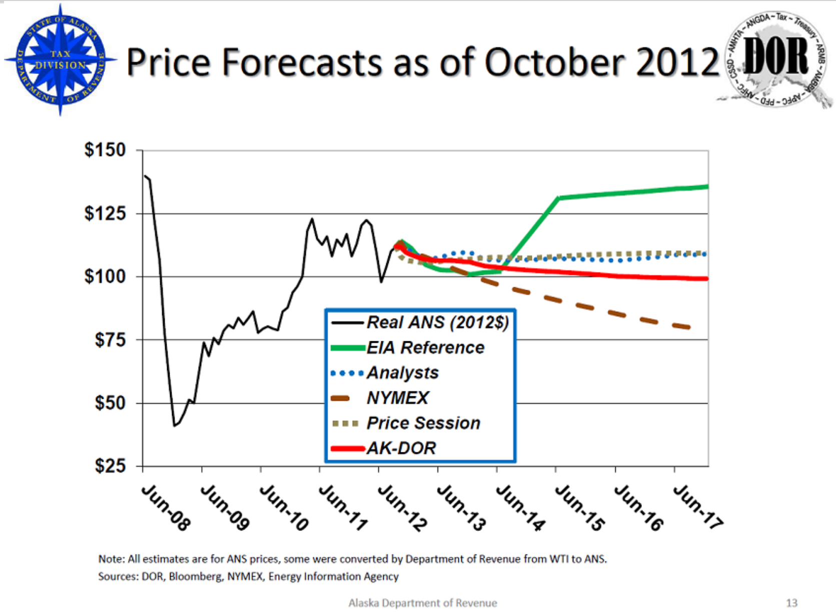
- As noted in PFC Energy testimony on 1/31/13, at low oil prices, Relative Government Take under SB 21 is higher than under ACES, due to the impact of low or no progressivity, combined with the elimination of the 20% capital credit under SB 21
- The **oil price level** at which this occurs is highly **sensitive to annual levels of capital spending**, since CAPEX both reduces the oil price level at which progressivity kicks in under ACES, and determines the size of the available capital credit under ACES
- Looking at a **single year of production** also slightly raises this neutrality point, since over many years, inflation reduces the real price level at which progressivity starts under ACES
- For mature, producing assets with a low ongoing CAPEX requirement ($10/bbl), SB21 represents a **reduction in government take at prices above ~$75**, however for capital intensive new developments in existing units, that neutrality **point can be as high as $110/bbl**
- It is thus important to understand that one impact of the removal of the 20% capital credit under SB 21 is that for companies with high development costs relative to overall production, it **can represent a tax increase at current prices**

PFC Energy

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.**

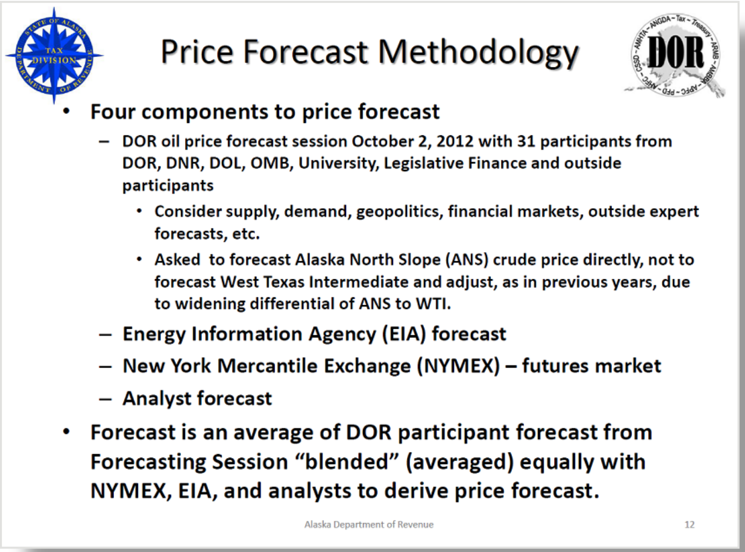


- A "good forecast" forecast must still be understand to hold a great deal of uncertainty with each data point (month) forecasted and the range of error grows the further into the future the forecast extends.
- Successfully managing forecast uncertainty requires:
  - Understanding the magnitude of the 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



Price Forecast Methodology

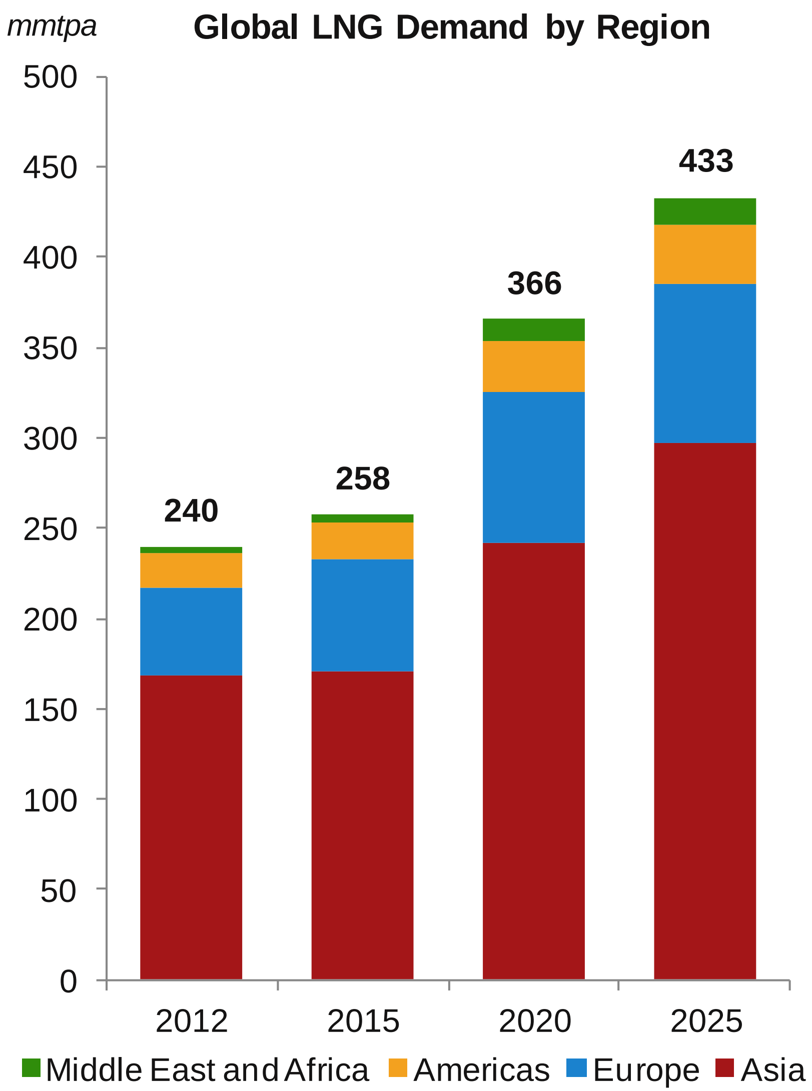
- Four components to price forecast
  - DOR oil price forecast session October 2, 2012 with 31 participants from DOR, DNR, DOL, OMB, University, Legislative Finance and outside participants
    - Consider supply, demand, geopolitics, financial markets, outside expert forecasts, etc.
    - Asked to forecast 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

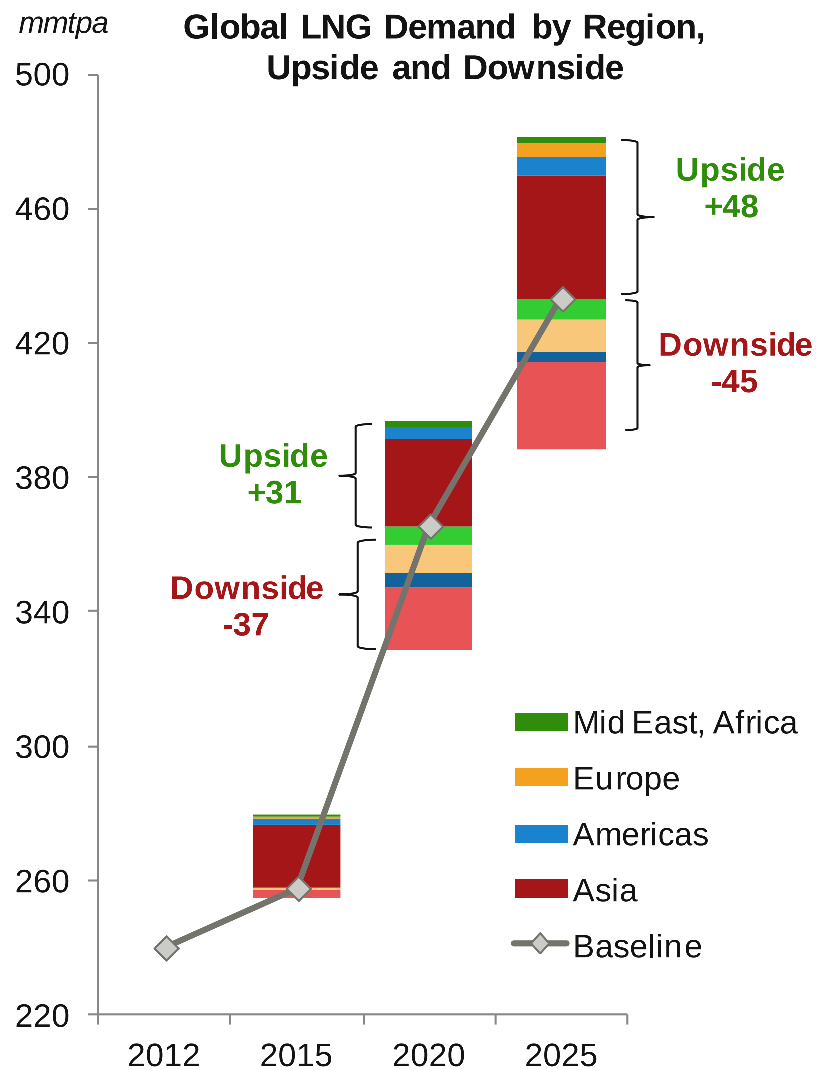
Risks of Methodology

- 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.

Global LNG Demand Driven by Asia

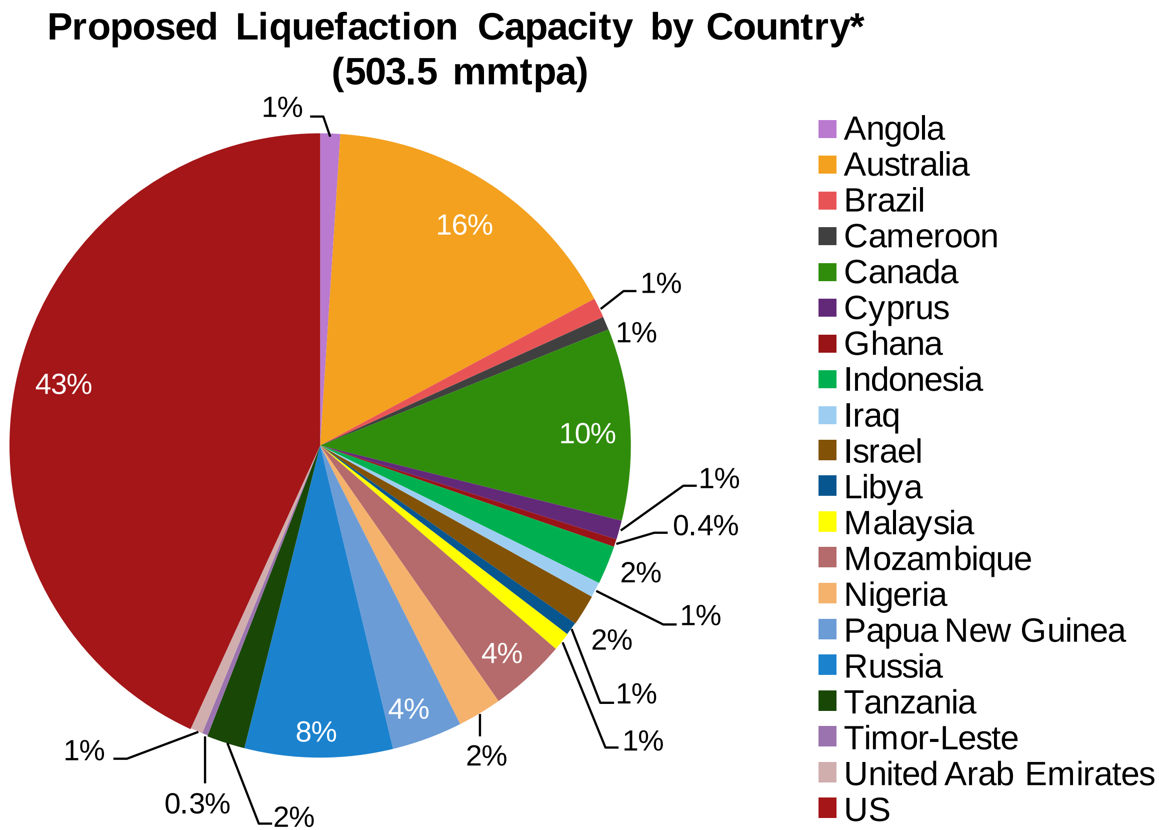


Source: PFC Energy Global LNG Service



Source: PFC Energy Global LNG Service

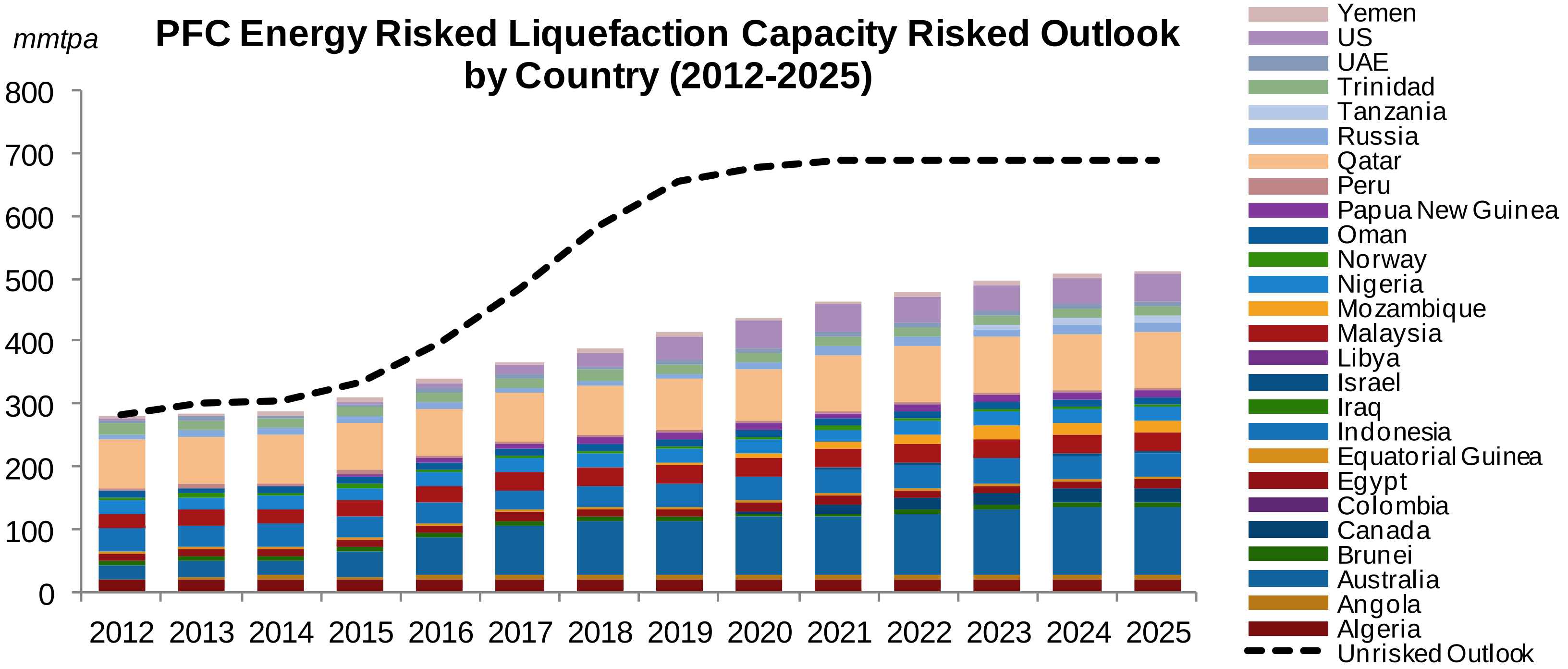
Proposed LNG Capacity by Country



** Includes all projects that are not currently under construction.*

- 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)	▪ 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)	▪ 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	▪ 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	▪ 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	▪ The government's preference to satisfy growing domestic gas needs has threatened the longevity of existing projects and the viability of new ones
Malaysia	▪ Malaysia's new projects are often farther removed from existing infrastructure ▪ Sustaining and growing volumes will depend on exploration success
Papua New Guinea	▪ 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	▪ No new liquefaction capacity additions have been planned.

MENA

Country	Main Risks
General	▪ 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	▪ Ability to develop exports will hinge on overcoming challenges such as financing, offtake, and a political hesitation towards exports.
Qatar	▪ 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	▪ 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)	▪ 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)	▪ ***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	▪ 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

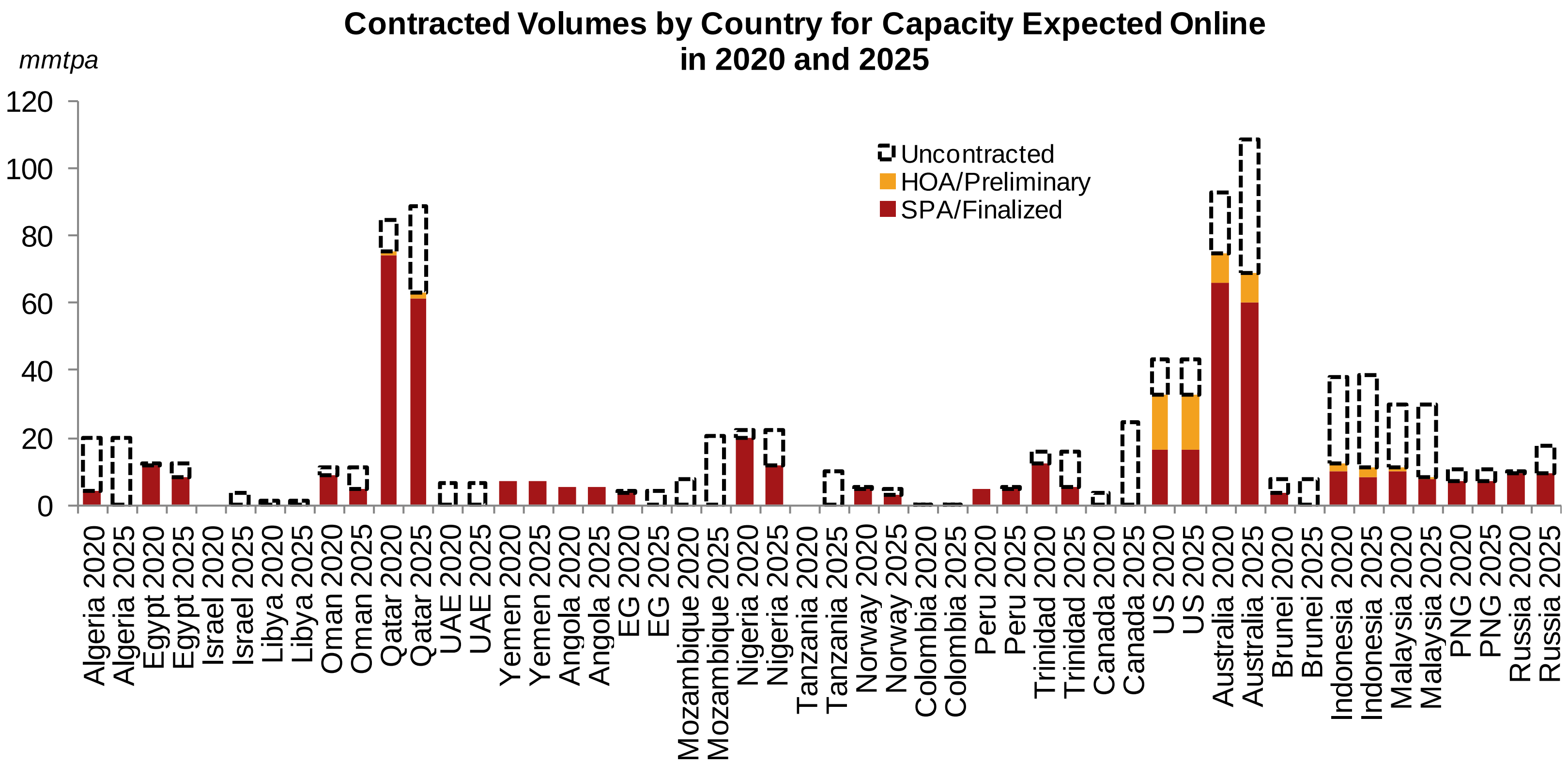
Sub-Saharan Africa

Country	Main Risks
Mozambique	▪ 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	▪ 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	▪ 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

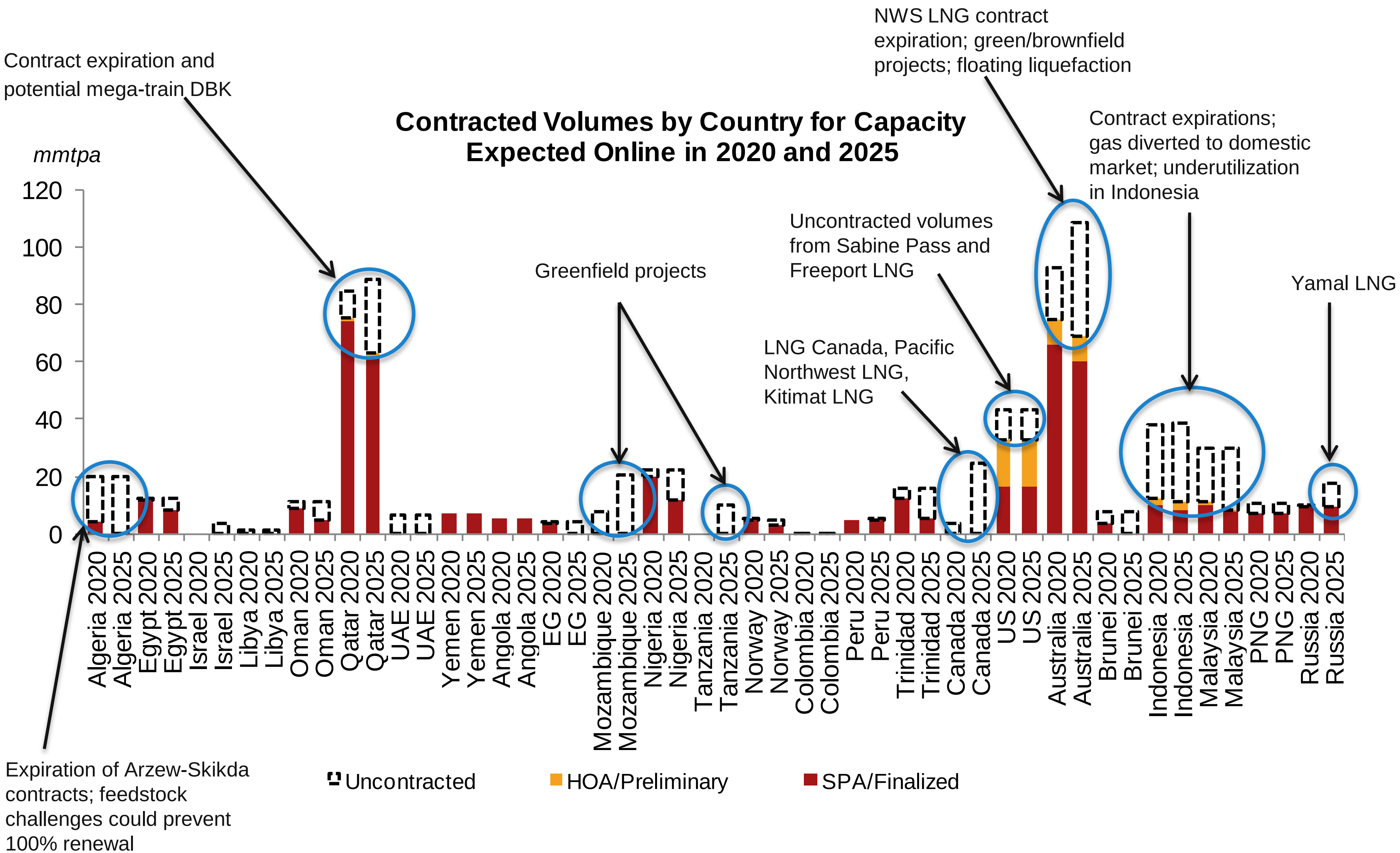
Country	Main Risks
Trinidad	▪ Unlikely to add liquefaction capacity due to uncertainty over gas reserves
Peru	▪ The government is anxious to meet domestic demand and current plant may not be utilized fully ▪ The government has announced that it intends to reallocate reserves currently feeding the Peru LNG project to the domestic market
Colombia	▪ 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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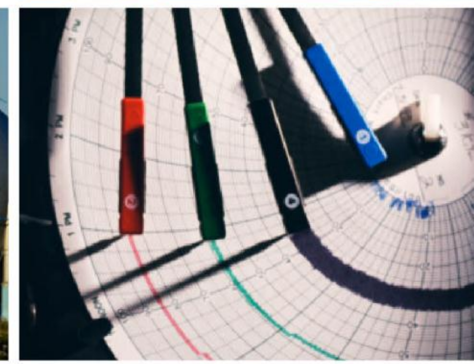

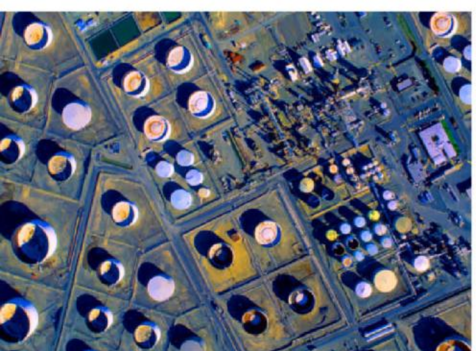

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