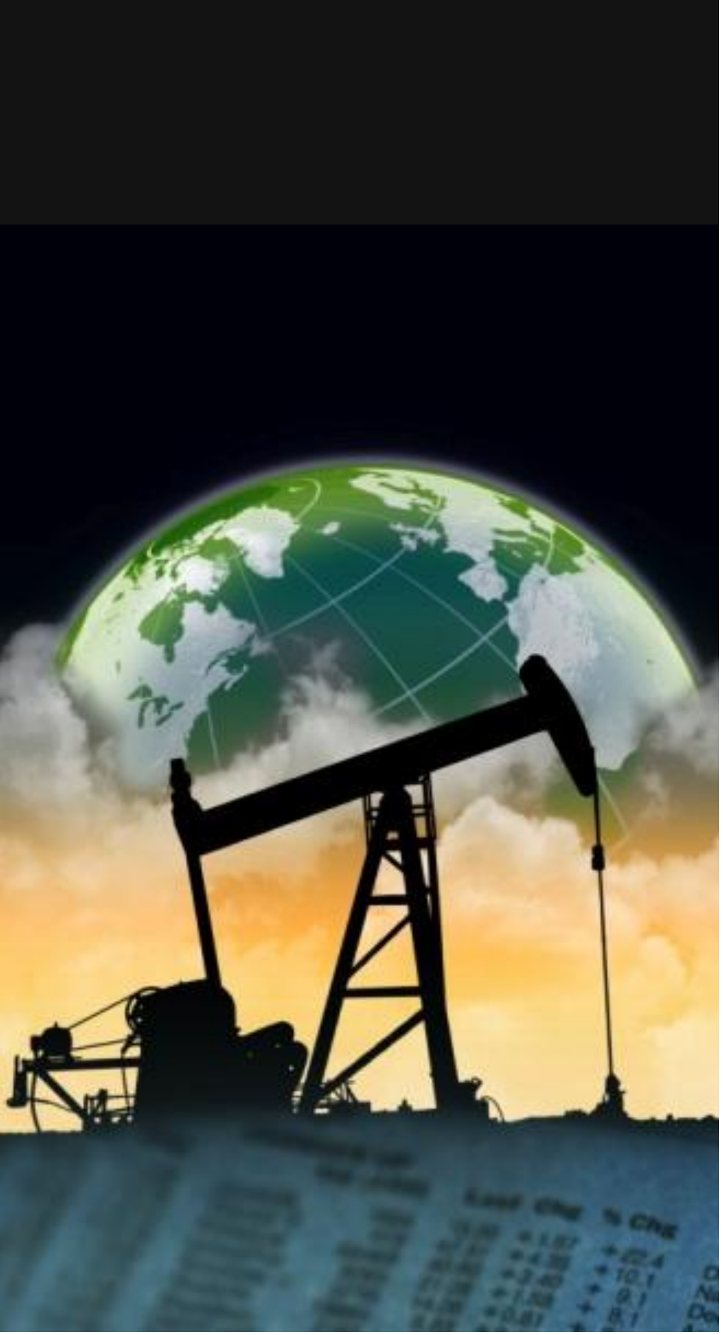

Discussion Slides: Alaska Senate Finance Committee

March 15, 2012

Gerald Kepes
Partner and Head of Upstream & Gas
PFC Energy

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Background – Key Fiscal Terms Concepts

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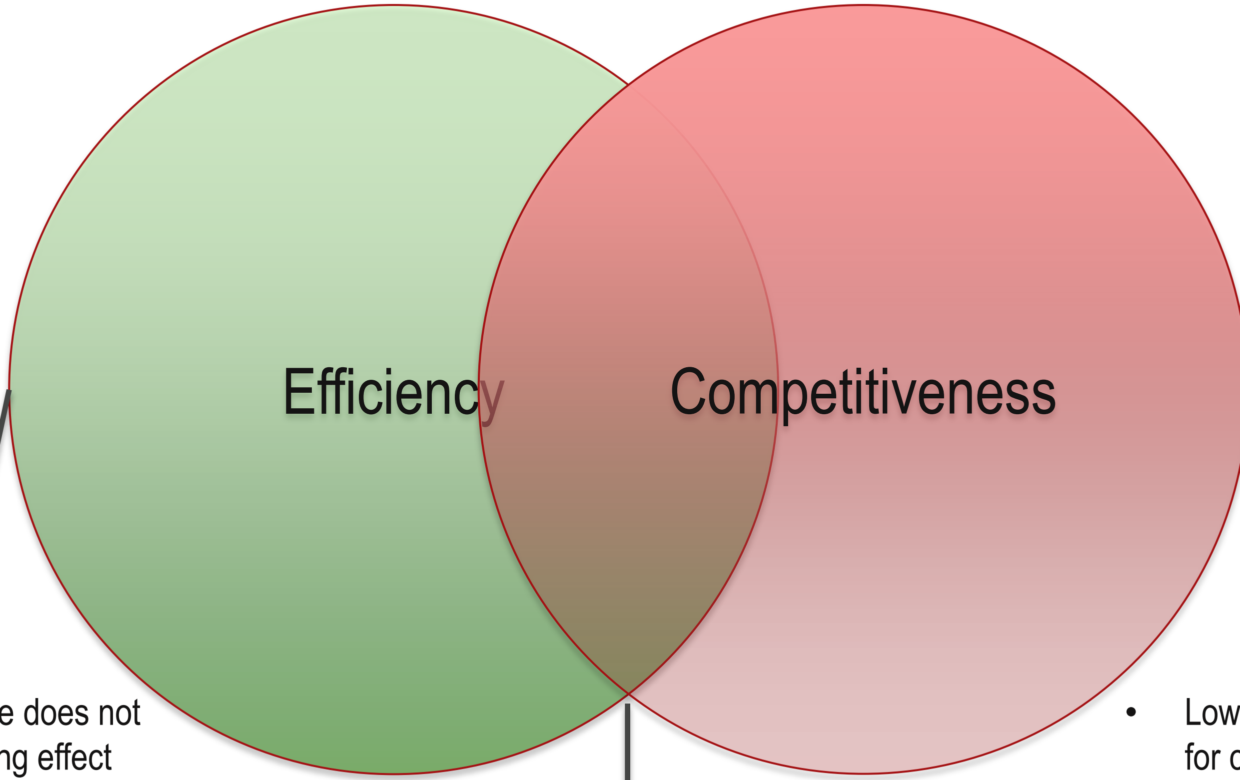
Fiscal Regime Design: Finding the Intersection of Efficiency and Competitiveness

- Fiscal regime design is fundamentally about maximizing State revenues, subject to two important constraints
  - **Efficiency:** Not distorting investment choices, or preventing marginal investments that would otherwise have been made
  - **Competitiveness:** There is a global market for upstream dollars

Fiscal Regime Design: Finding the Intersection of Efficiency and Competitiveness



- Efficient regime does not have a distorting effect on project economics
- If rates are too high, other jurisdictions could be more successful in attracting capital as a result

- Regime does not distort investment
- Rates are internationally competitive, given fundamental attractiveness of the opportunity

- Lower rates may mean for certain projects or asset types, the regime is highly internationally competitive

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Relative Government Take (Definition)

$$\textbf{Relative Government Take} = \frac{\text{Government Take}}{\text{Divisible Income}}$$

Divisible Income equals Gross Revenues less costs, including capex and transportation costs.

Government Take includes all payments the government mandates in its function as a sovereign:

- Royalties
- Land rental fees, property taxes
- Production taxes
- Income taxes

Government Take does not include amounts the government earns via a direct equity stake

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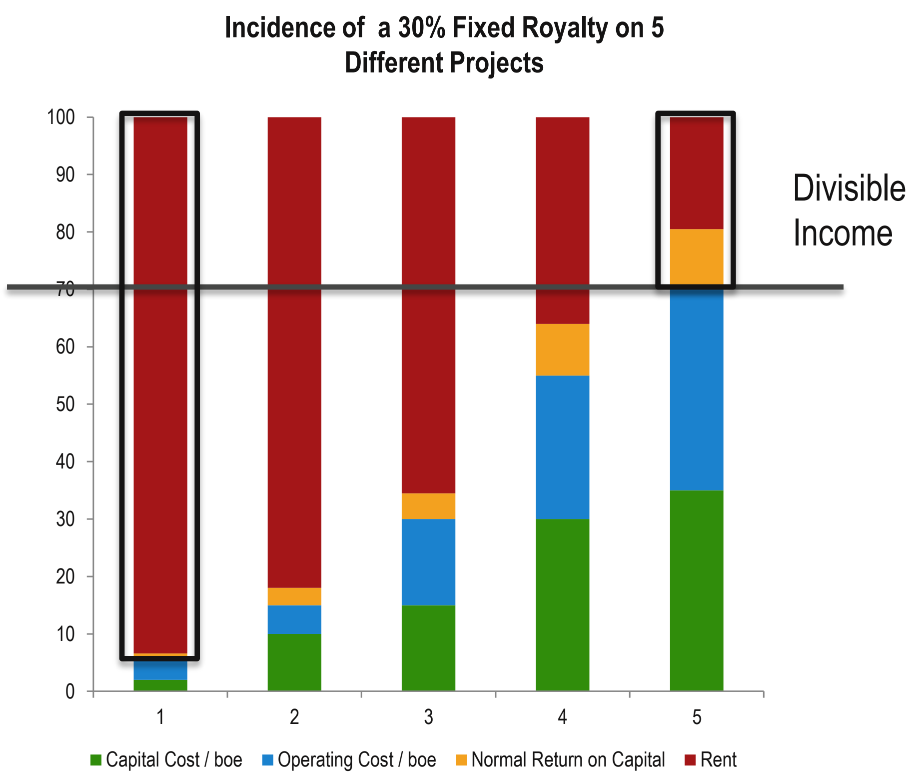
Fixed Royalty Systems: Inefficient, But Potentially Highly Competitive

- Given varying project costs, and varying prices, fixed percentage royalty systems are **inefficient** because they distort investment, making previously economic projects uneconomic at a given price
  - Government Take from a fixed royalty system can be very high when costs are high or prices are low – 100% in the example of project 5
- In high price environments, however, fixed royalty systems can be very competitive
  - Government Take can be very low when prices are high, or costs are low – only ~33% in the example of project 1



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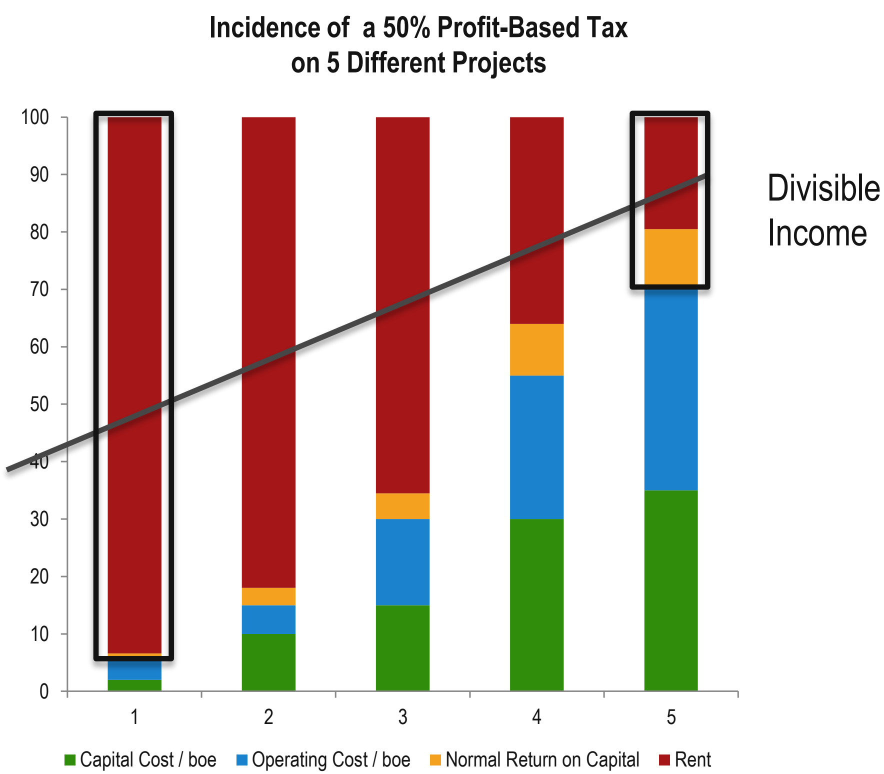
Profit-Based Fiscal Systems: More Efficient, But May Be Less Competitive

- A Profit-Based fiscal system may be
  - A contractual arrangement, such as a Production Sharing Contract
  - A tax which applies to revenues less costs
- Such systems can be capable of **raising greater revenue**, while **reducing inefficiency**
  - In low oil price environments, or high cost environments, Profit-Based Systems are less likely to make marginal projects non-economic
- By capturing more rent in high oil price environments, or low cost environments, however, they may also not compete with royalty regimes
  - Projects 1 and 2 would be significantly more attractive to undertake under a royalty regime



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Alaska's Oil & Gas Competitive Context

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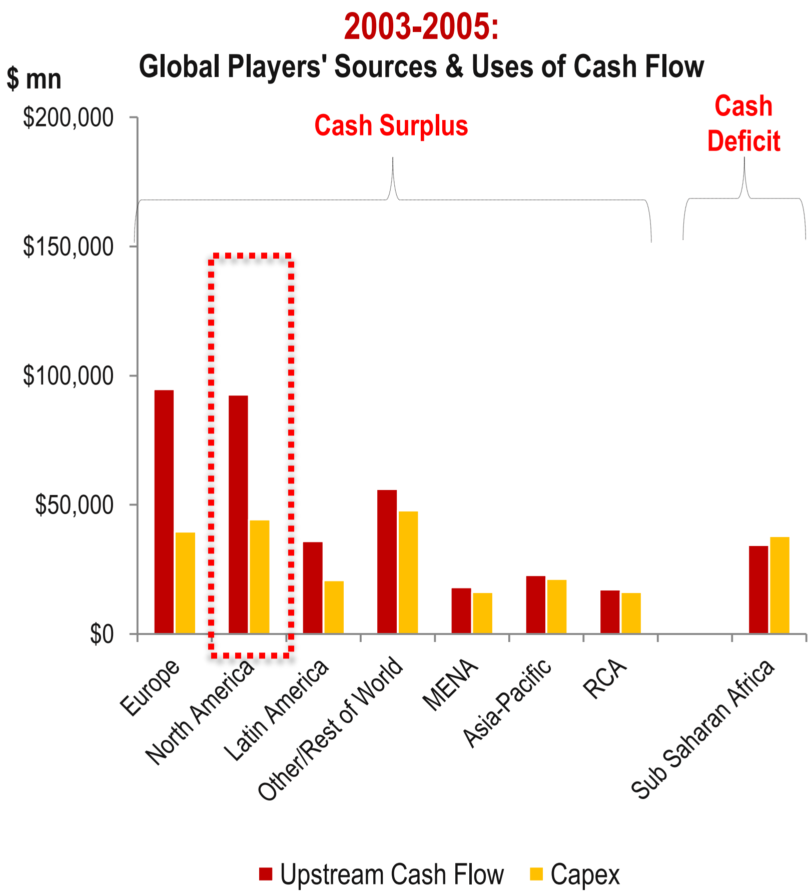
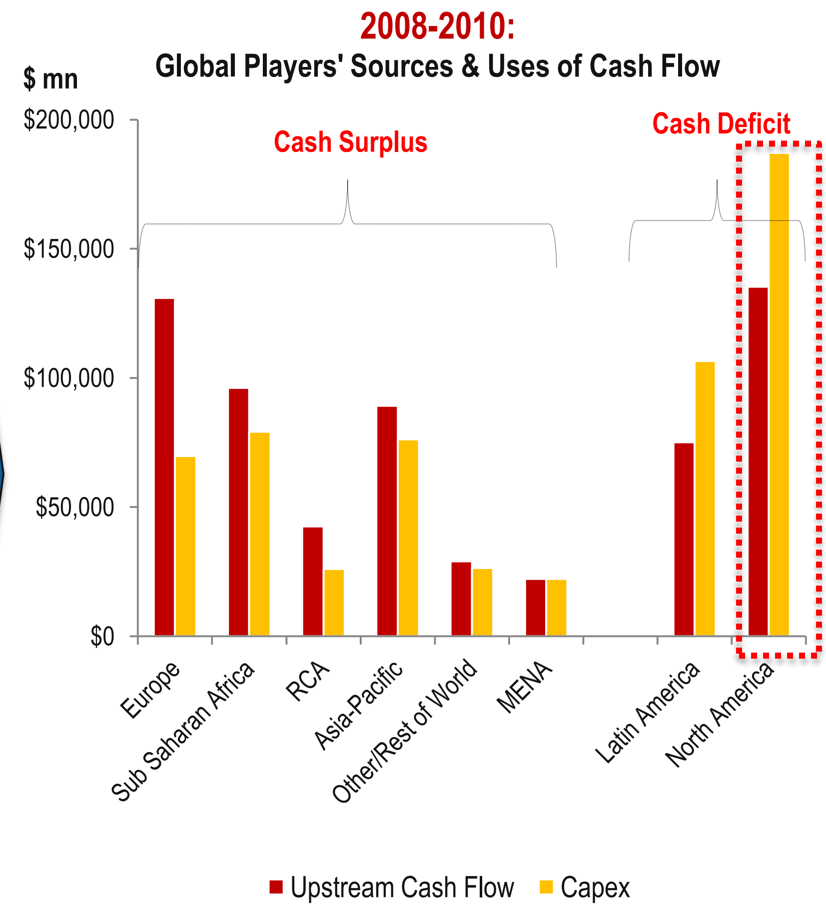
Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars





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

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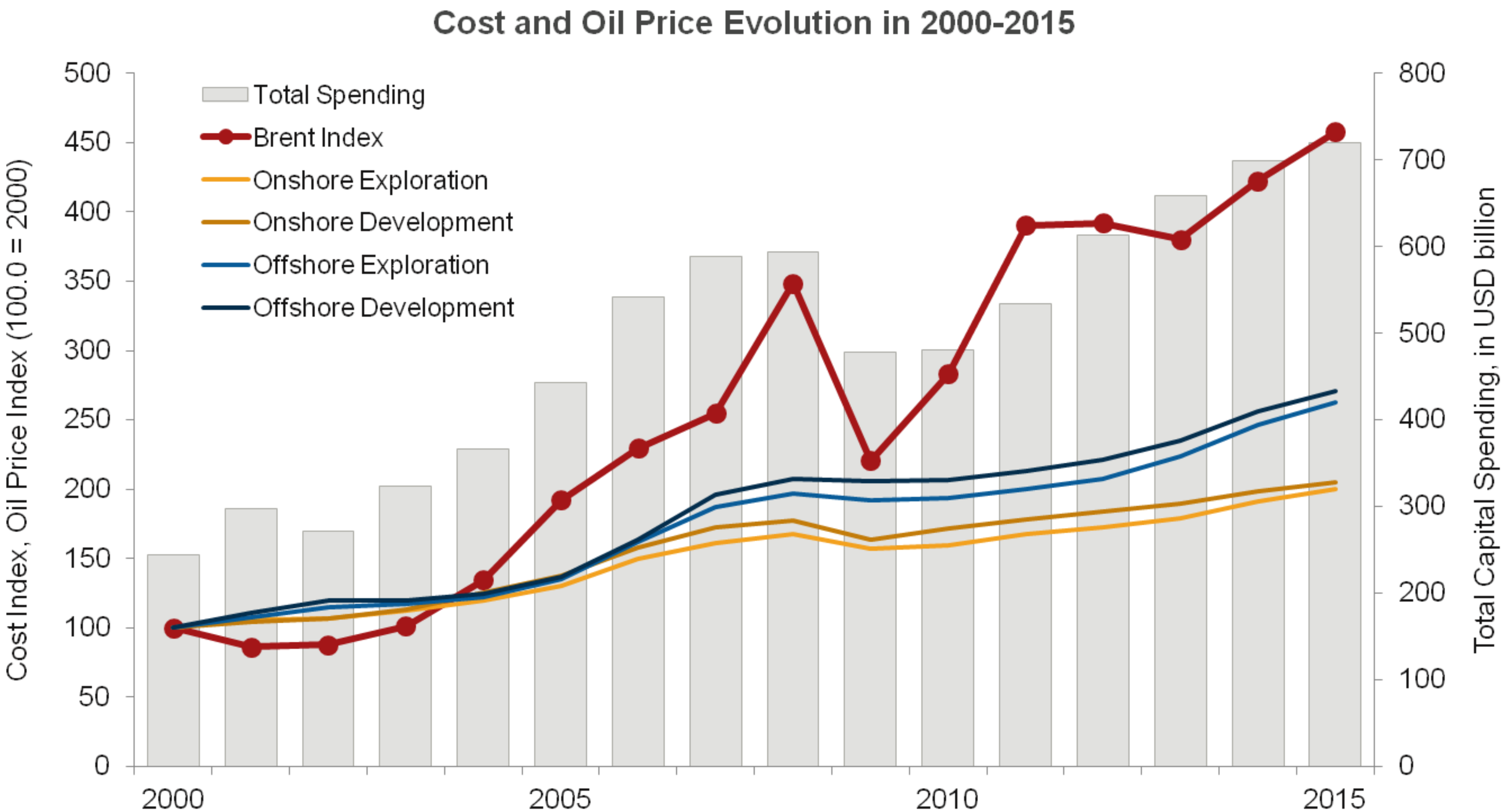
All eyes on the price .. But what about cost…

- Overall spending in the industry is mostly driven by Oil Prices, no so much by costs.
- Costs in 2015 expected to increase x2.5 times from 2000 standards …. Oil prices will increase 450%



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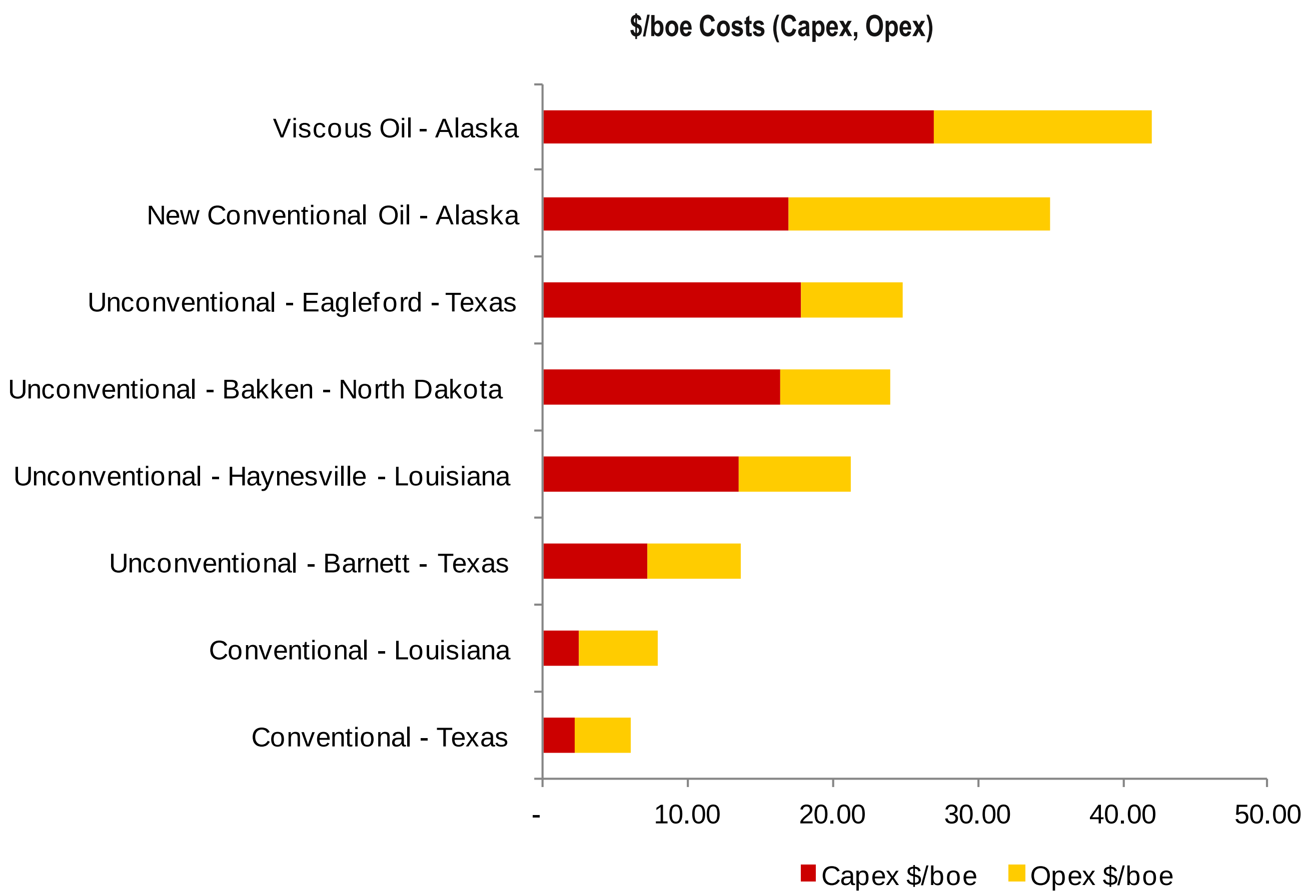
Alaska's Days of "Easy Oil" Are Gone: High Costs and High Government Take Present Challenges



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

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Evolution of the ACES fiscal regime

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Cost Assumptions Underlying Fiscal Analysis

- Two key forms of analysis have been undertaken on project economics and government take levels in this presentation
- **Existing Producer** Analysis examines the economics of the fiscal regime for an existing producer, producing 200 mb/d in 2012, with a 6% annual production decline rate, and with the following costs:
  - $12/ flowing bbl operating expenditure
  - $5/ flowing bbl maintenance capital expenditure
- **New Development** Analysis examines the development-forward lifecycle economics of the fiscal regime for the development of a new 10 mb/d development for a producer without existing base production. Assumed costs are:
  - $17/ flowing bbl operating expenditure
  - $17/bbl reserves development capital expenditure
  - $1/ flowing bbl maintenance capital expenditure

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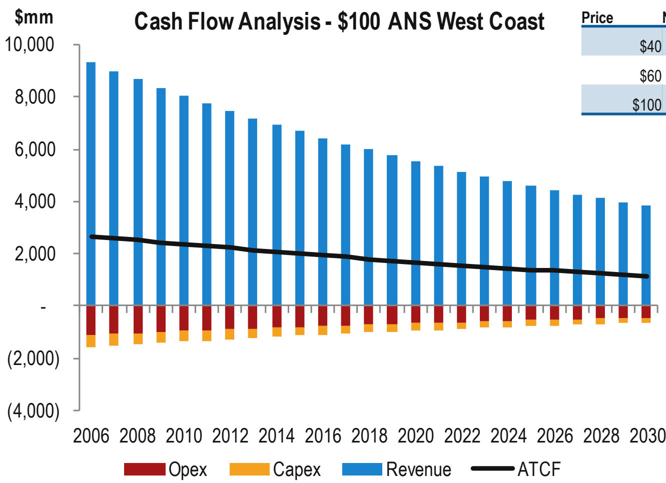
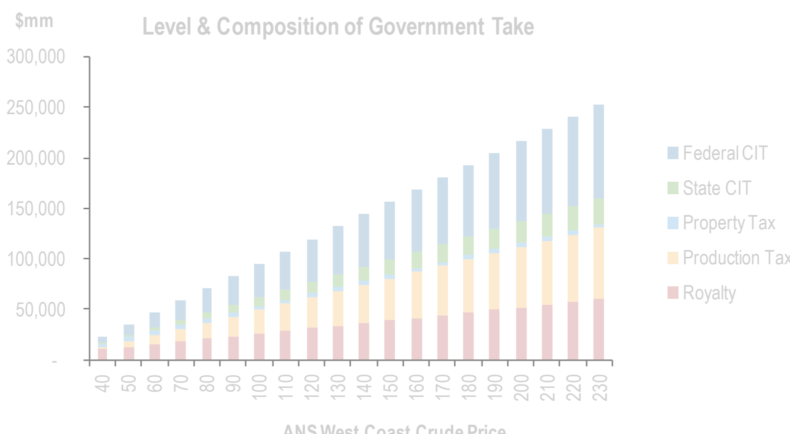
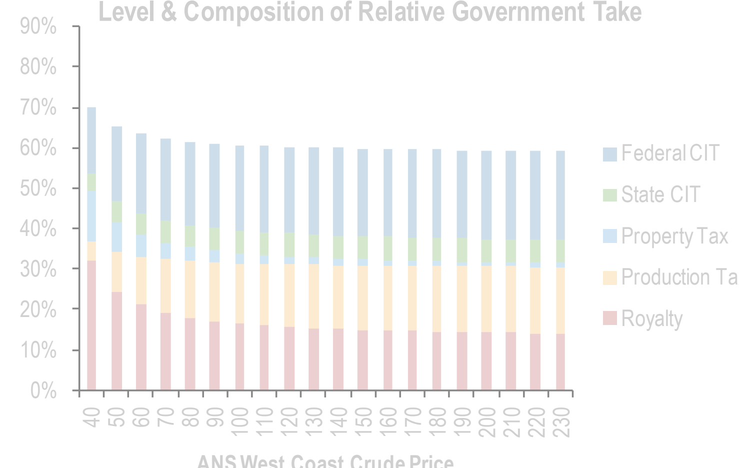
PPT As Originally Proposed (Existing Producer)



Price	NPV
$40	$ 2,976
$60	$ 8,672
$100	$ 20,066

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	5%	12%	4%	53%	17%	70%
50	24%	10%	8%	5%	47%	19%	65%
60	21%	12%	5%	5%	44%	20%	63%
70	19%	13%	4%	5%	42%	20%	62%
80	18%	14%	3%	5%	41%	21%	62%
90	17%	14%	3%	6%	40%	21%	61%
100	17%	15%	3%	6%	40%	21%	61%
110	16%	15%	2%	6%	39%	21%	60%
120	16%	15%	2%	6%	39%	21%	60%
130	15%	16%	2%	6%	38%	22%	60%
140	15%	16%	2%	6%	38%	22%	60%
150	15%	16%	2%	6%	38%	22%	60%
160	15%	16%	1%	6%	38%	22%	60%
170	15%	16%	1%	6%	38%	22%	60%
180	14%	16%	1%	6%	38%	22%	59%
190	14%	16%	1%	6%	38%	22%	59%
200	14%	16%	1%	6%	37%	22%	59%
210	14%	16%	1%	6%	37%	22%	59%
220	14%	16%	1%	6%	37%	22%	59%
230	14%	17%	1%	6%	37%	22%	59%





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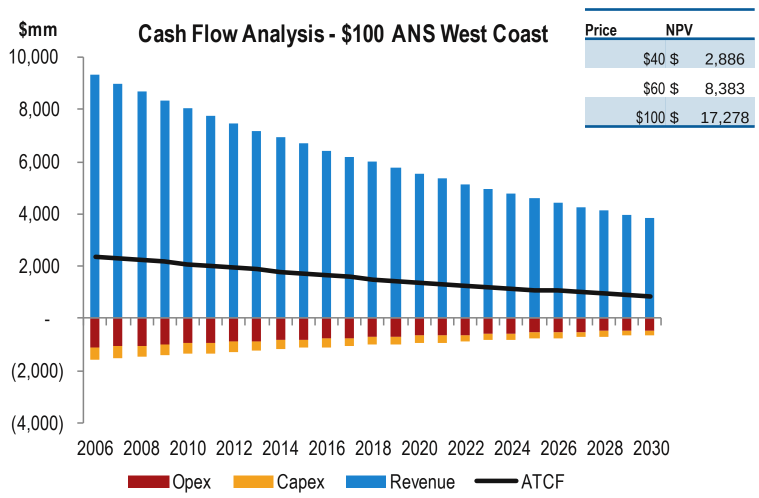
PPT As Enacted (Existing Producer)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	6%	12%	4%	55%	16%	71%
50	24%	11%	8%	5%	48%	18%	66%
60	21%	15%	5%	5%	46%	19%	65%
70	19%	18%	4%	5%	46%	19%	65%
80	18%	21%	3%	5%	48%	18%	66%
90	17%	25%	3%	5%	50%	18%	67%
100	17%	28%	3%	4%	52%	17%	69%
110	16%	31%	2%	4%	53%	16%	70%
120	16%	33%	2%	4%	55%	16%	71%
130	15%	35%	2%	4%	56%	15%	72%
140	15%	37%	2%	4%	57%	15%	72%
150	15%	38%	2%	4%	58%	15%	73%
160	15%	39%	1%	4%	59%	14%	74%
170	15%	40%	1%	4%	60%	14%	74%
180	14%	41%	1%	4%	60%	14%	74%
190	14%	42%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
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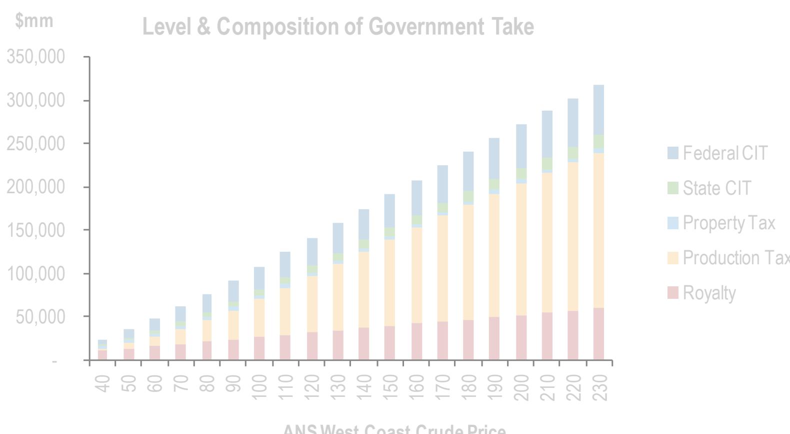

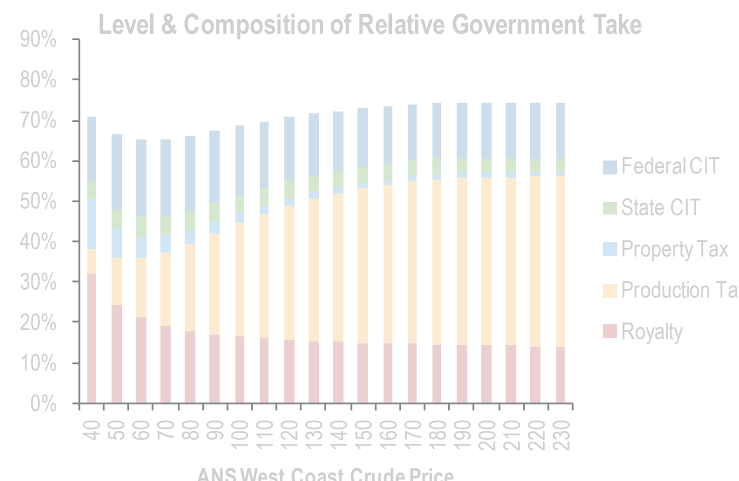

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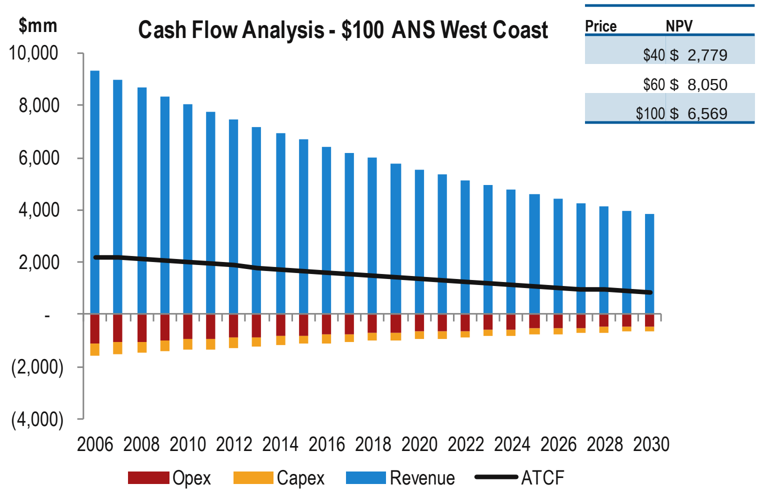
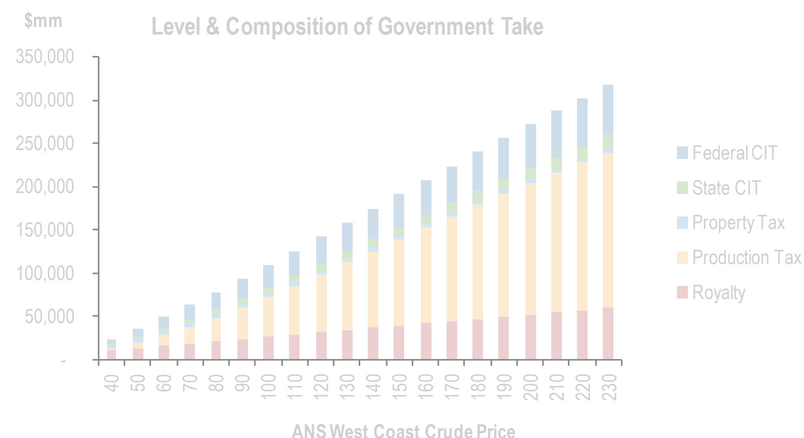
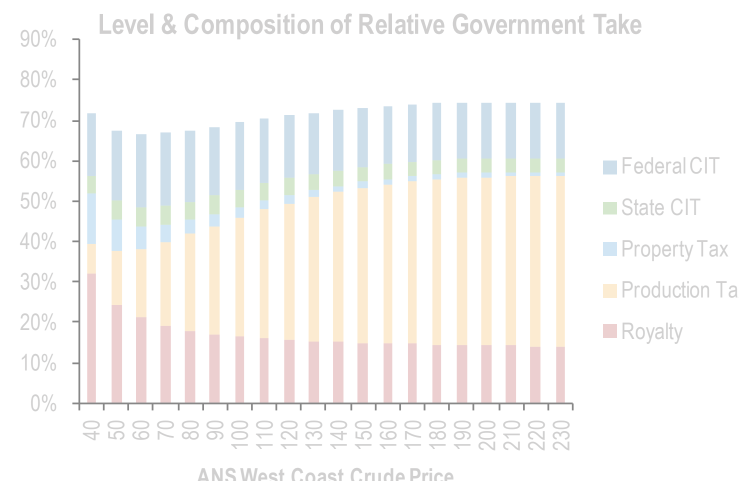
ACES As Proposed (Existing Producer)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	8%	12%	4%	56%	16%	72%
50	24%	13%	8%	5%	50%	18%	68%
60	21%	17%	5%	5%	48%	18%	67%
70	19%	21%	4%	5%	49%	18%	67%
80	18%	24%	3%	5%	50%	18%	68%
90	17%	27%	3%	4%	51%	17%	68%
100	17%	29%	3%	4%	53%	17%	69%
110	16%	32%	2%	4%	54%	16%	70%
120	16%	34%	2%	4%	56%	16%	71%
130	15%	36%	2%	4%	57%	15%	72%
140	15%	37%	2%	4%	58%	15%	73%
150	15%	38%	2%	4%	59%	15%	73%
160	15%	39%	1%	4%	59%	14%	74%
170	15%	40%	1%	4%	60%	14%	74%
180	14%	41%	1%	4%	60%	14%	74%
190	14%	41%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
220	14%	42%	1%	4%	61%	14%	74%
230	14%	42%	1%	4%	61%	14%	74%





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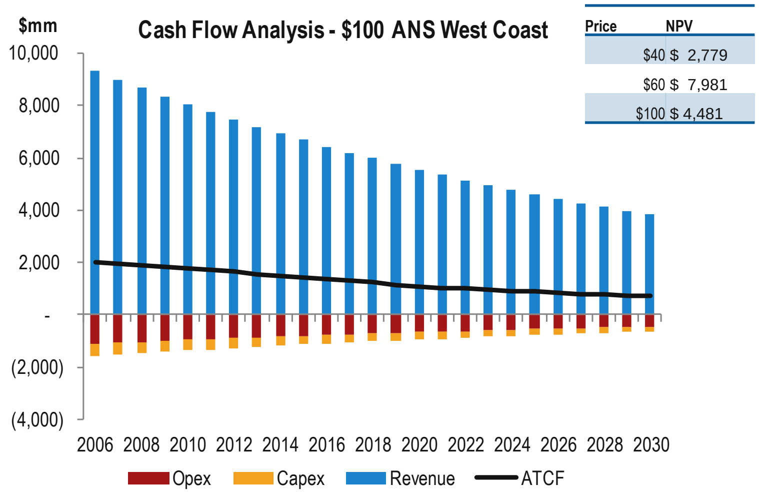
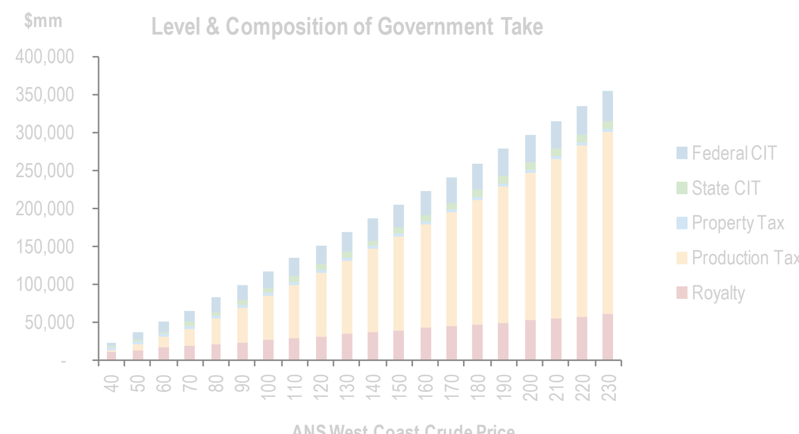
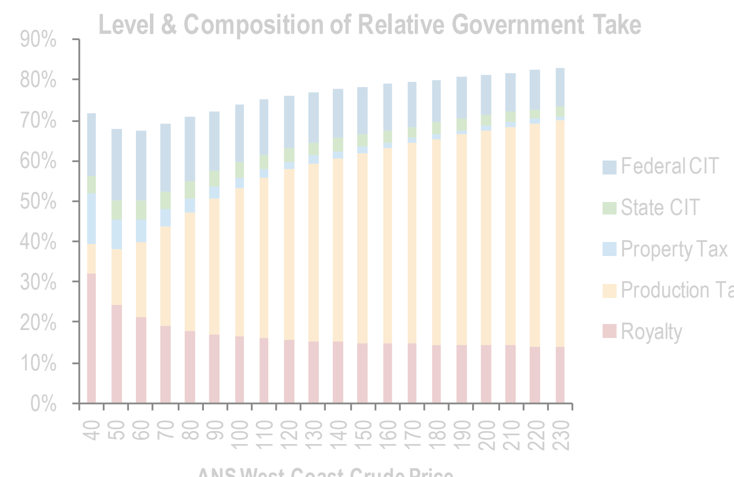
ACES As Enacted (Existing Producer)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	8%	12%	4%	56%	16%	72%
50	24%	14%	8%	5%	50%	18%	68%
60	21%	19%	5%	5%	50%	18%	68%
70	19%	24%	4%	4%	52%	17%	69%
80	18%	29%	3%	4%	55%	16%	71%
90	17%	33%	3%	4%	57%	15%	72%
100	17%	37%	3%	4%	60%	14%	74%
110	16%	40%	2%	4%	62%	13%	75%
120	16%	42%	2%	3%	63%	13%	76%
130	15%	44%	2%	3%	65%	12%	77%
140	15%	46%	2%	3%	66%	12%	78%
150	15%	47%	2%	3%	67%	12%	78%
160	15%	48%	1%	3%	68%	11%	79%
170	15%	50%	1%	3%	69%	11%	80%
180	14%	51%	1%	3%	69%	11%	80%
190	14%	52%	1%	3%	70%	10%	81%
200	14%	53%	1%	3%	71%	10%	81%
210	14%	54%	1%	3%	72%	10%	82%
220	14%	55%	1%	2%	73%	10%	82%
230	14%	56%	1%	2%	74%	9%	83%





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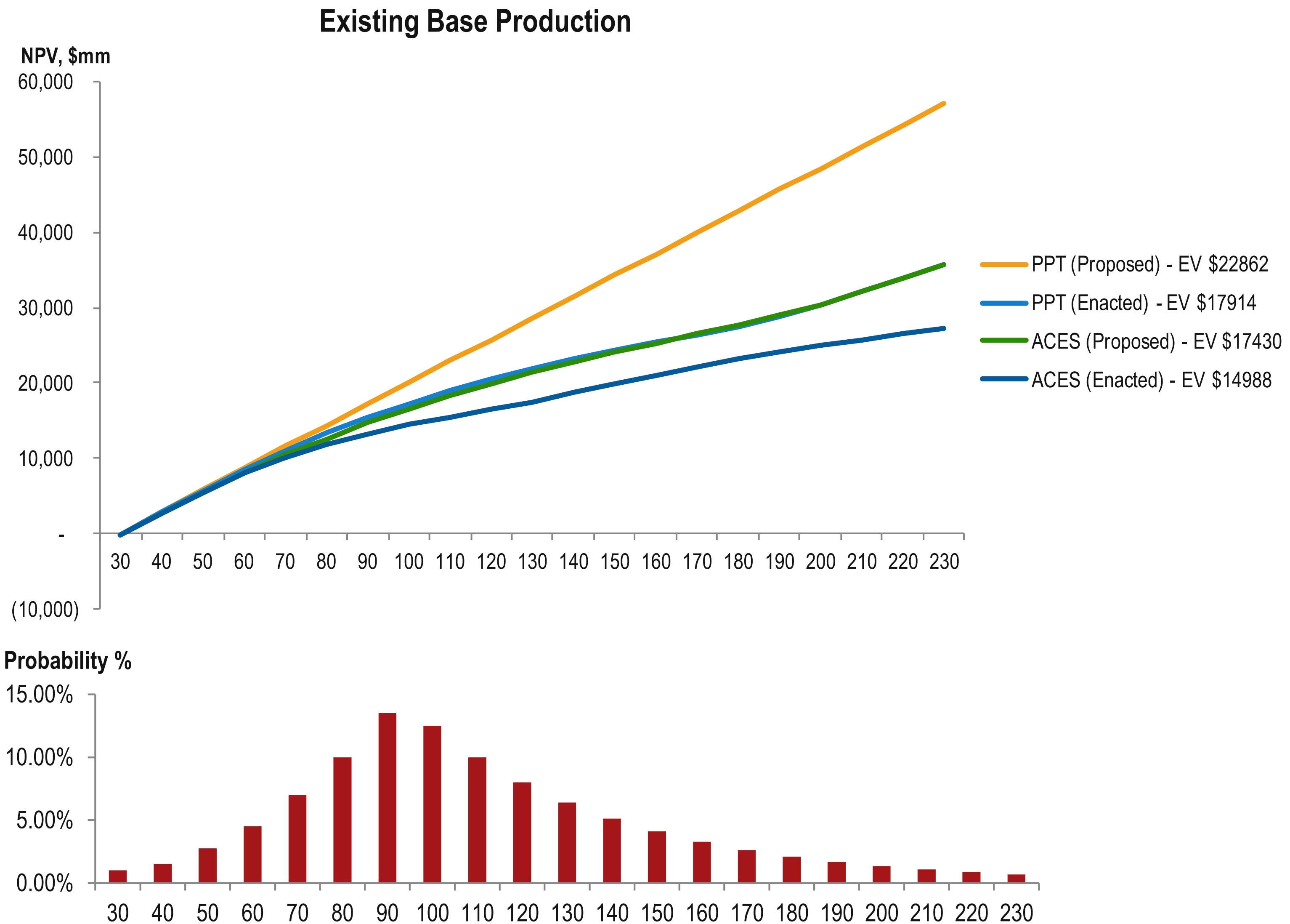
Limitations on Price Upside: A Probabilistic Approach



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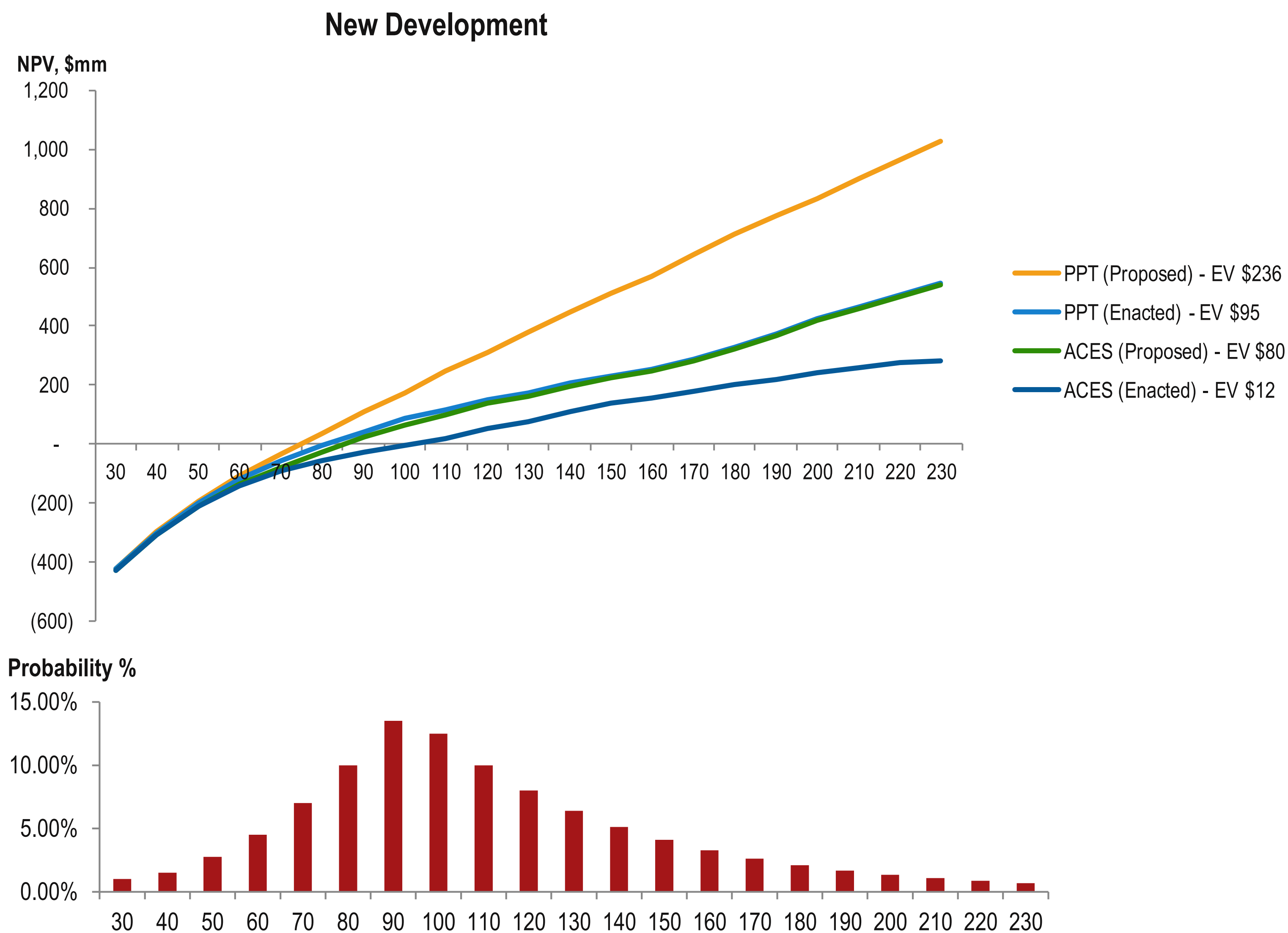
Limitations on Price Upside: A Probabilistic Approach



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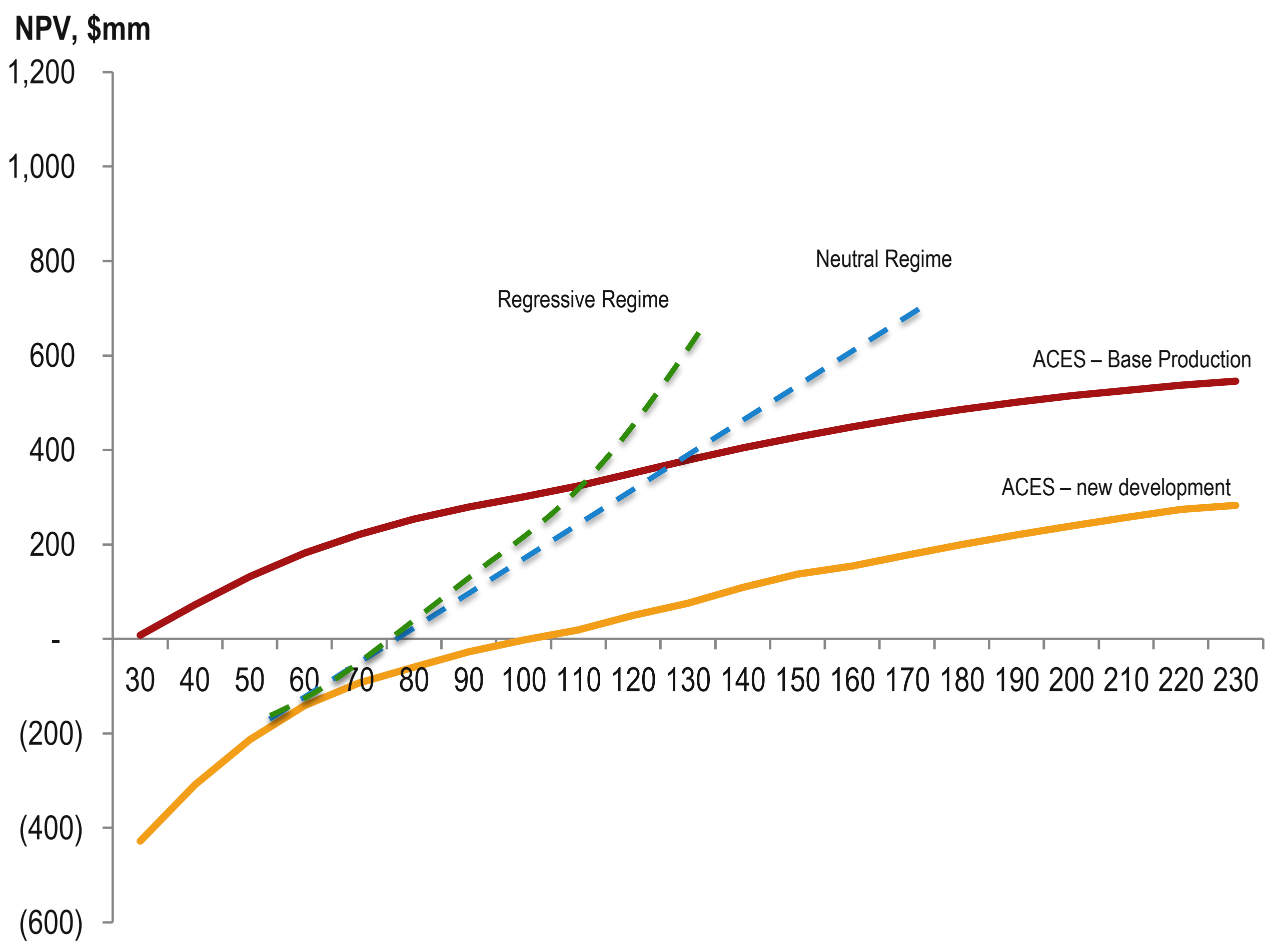
ACES Impact on Oil-Price Upside, and on High Cost Development Economics



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ACES: Global Competitiveness

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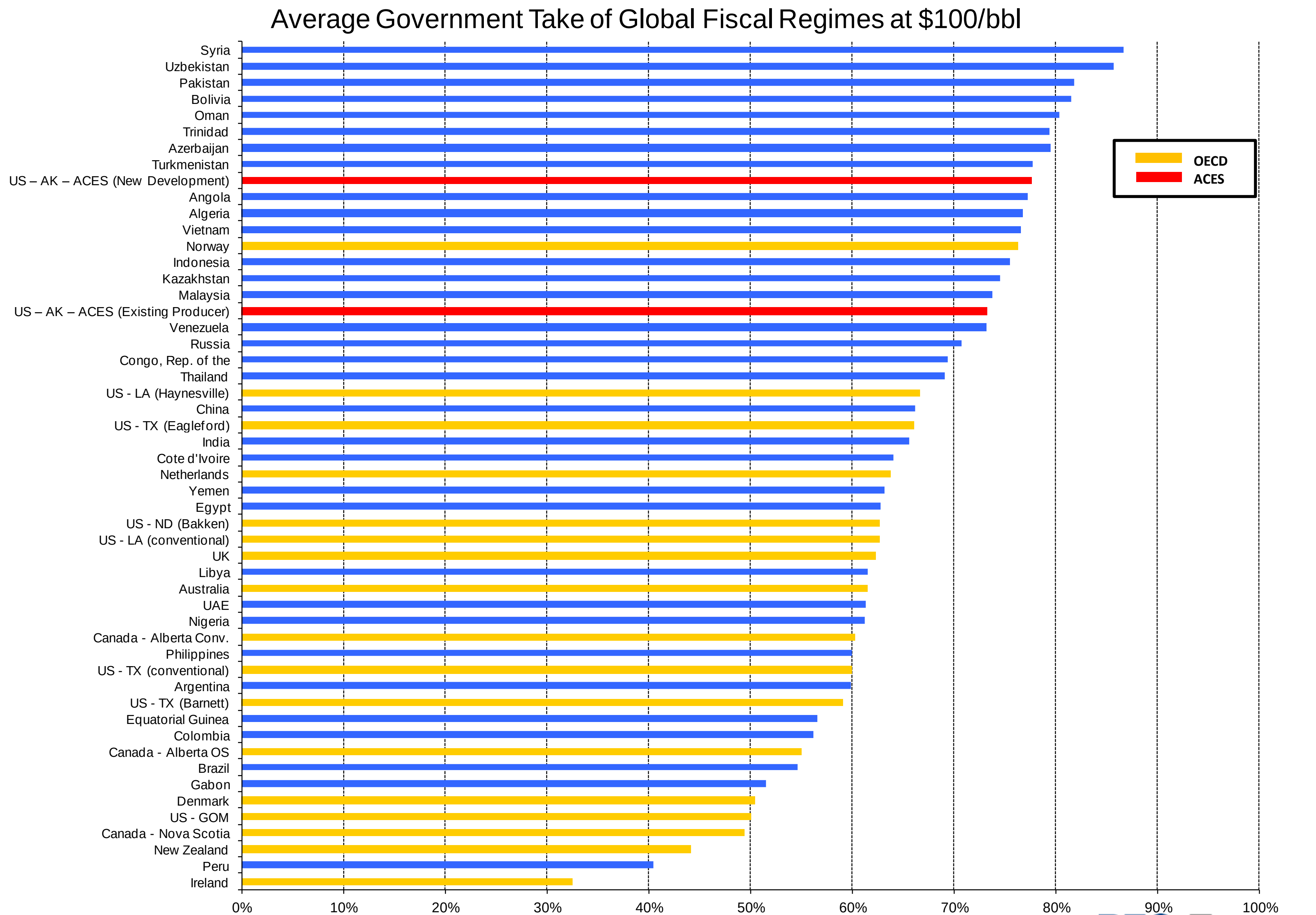
Regime Competitiveness: Average Government Take



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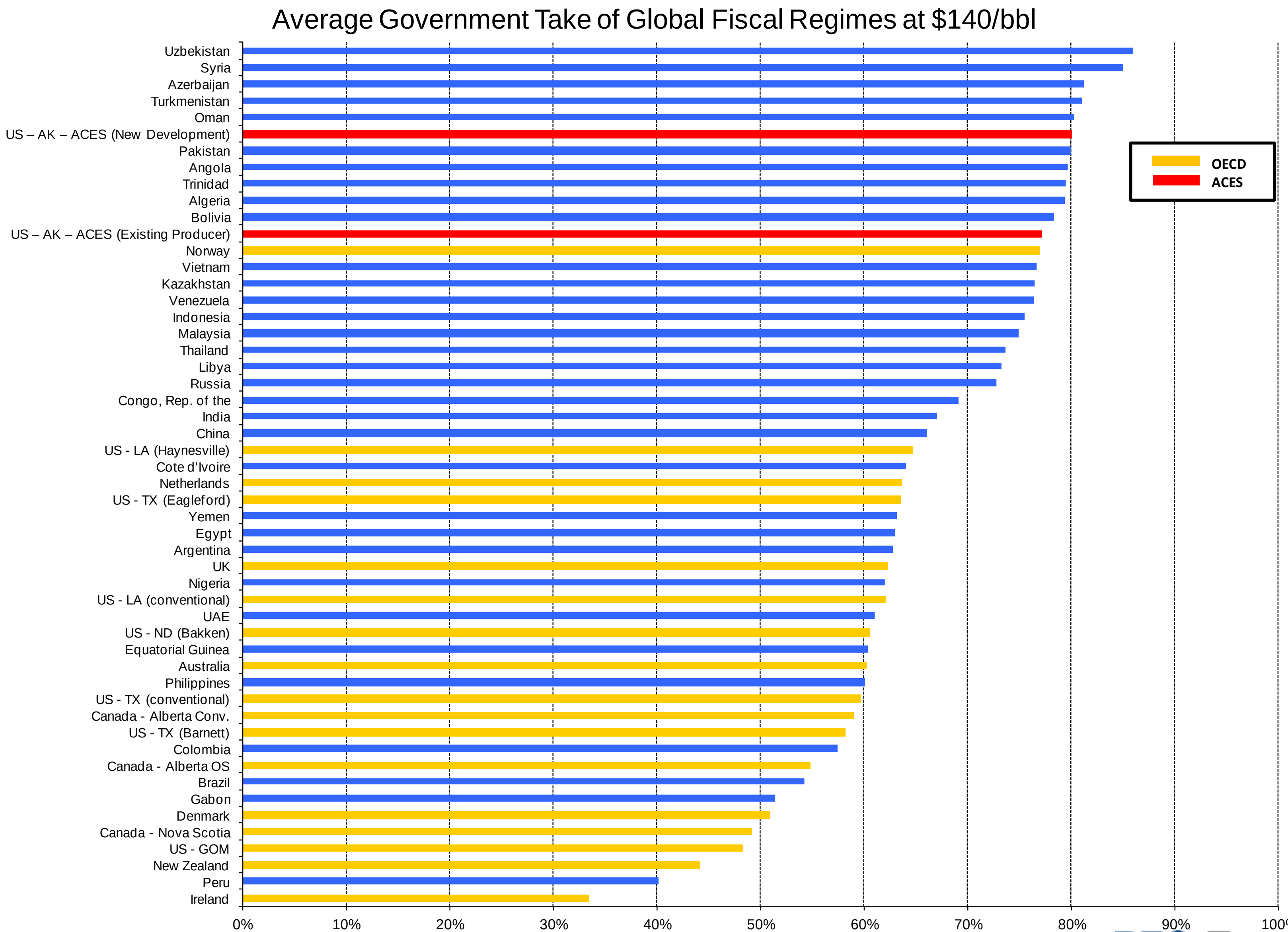
Regime Competitiveness: Average Government Take



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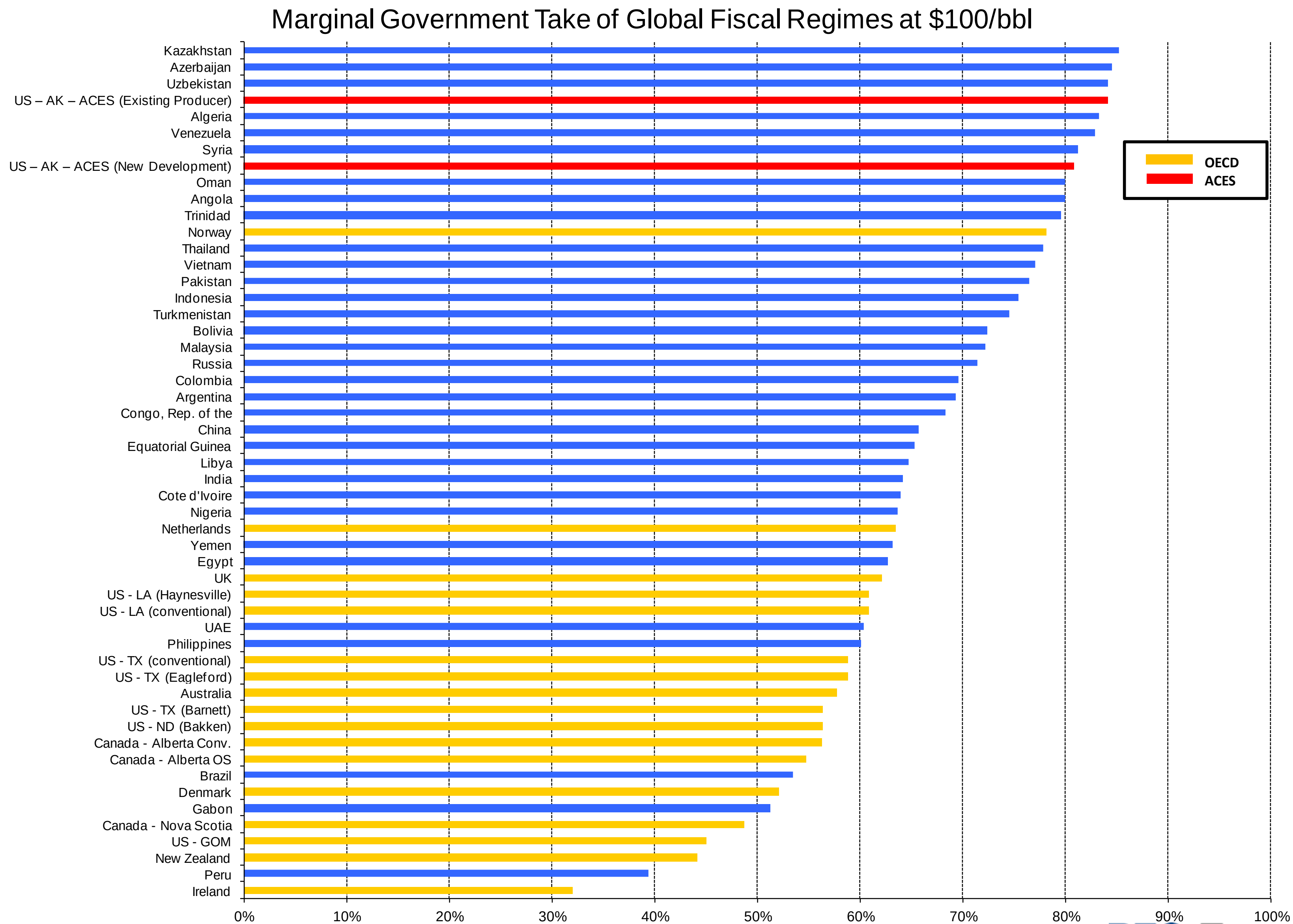
Regime Competitiveness: Marginal Government Take



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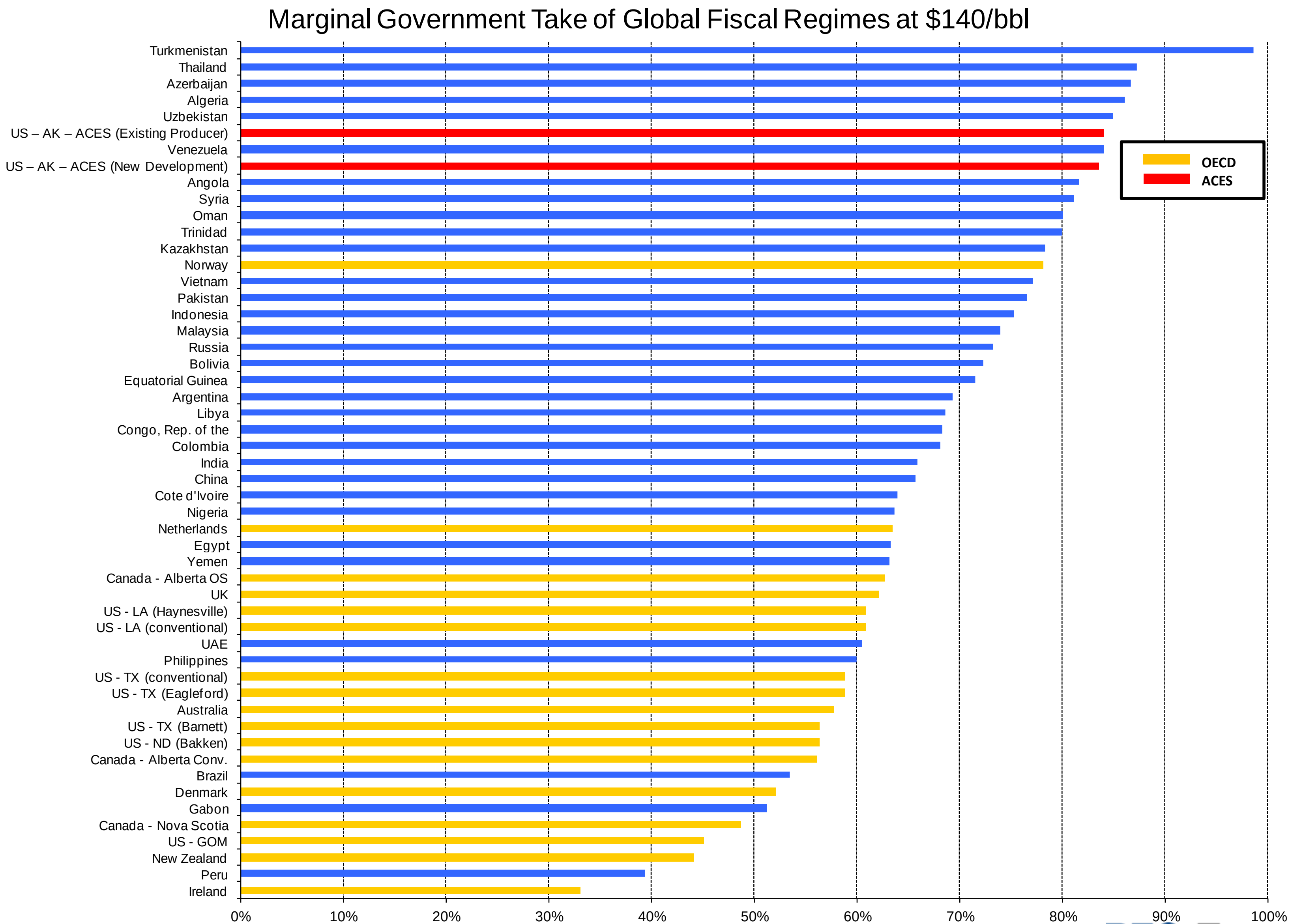
Regime Competitiveness: Marginal Government Take



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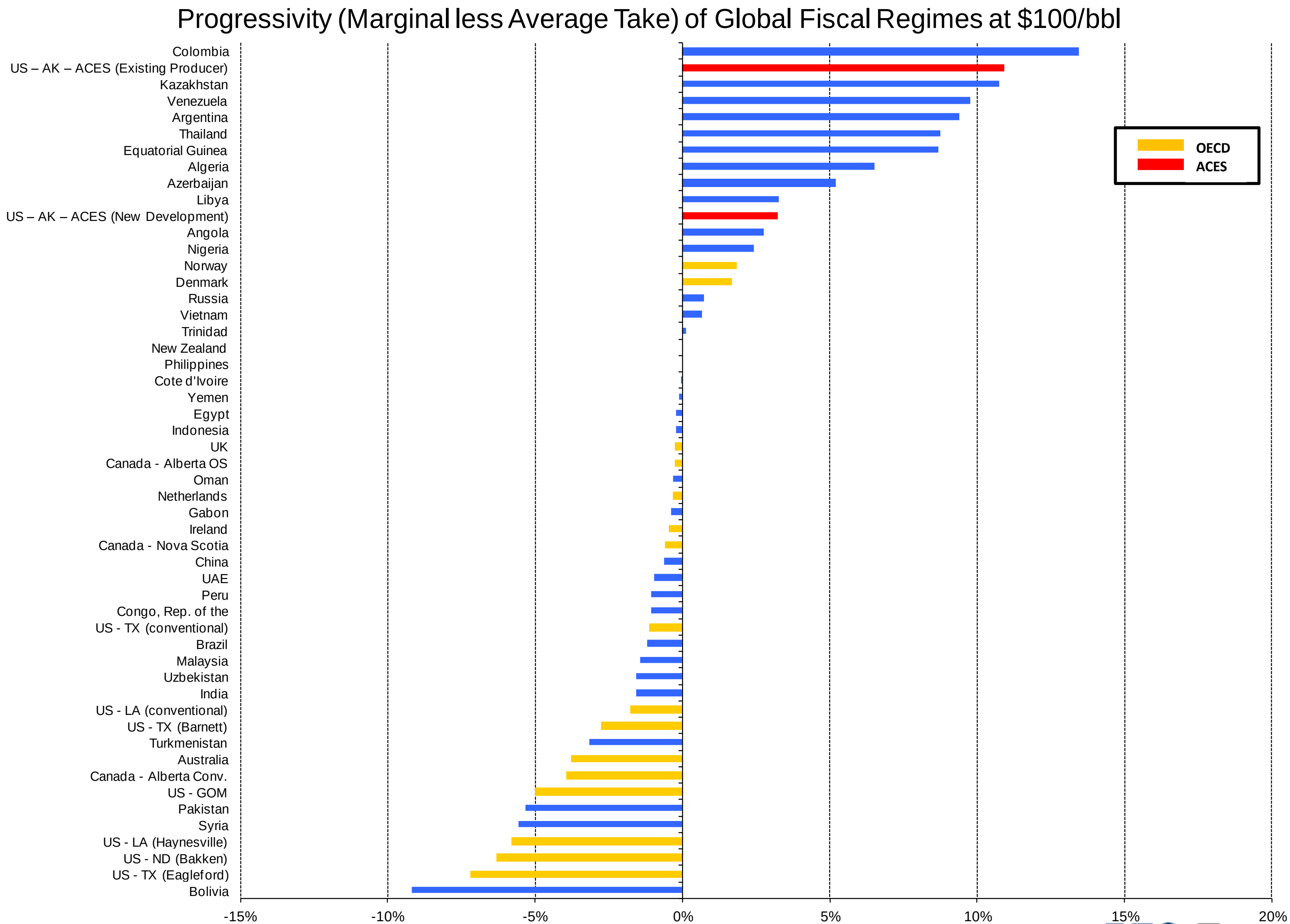
Benchmarking Progressivity for a Range of Global Regimes



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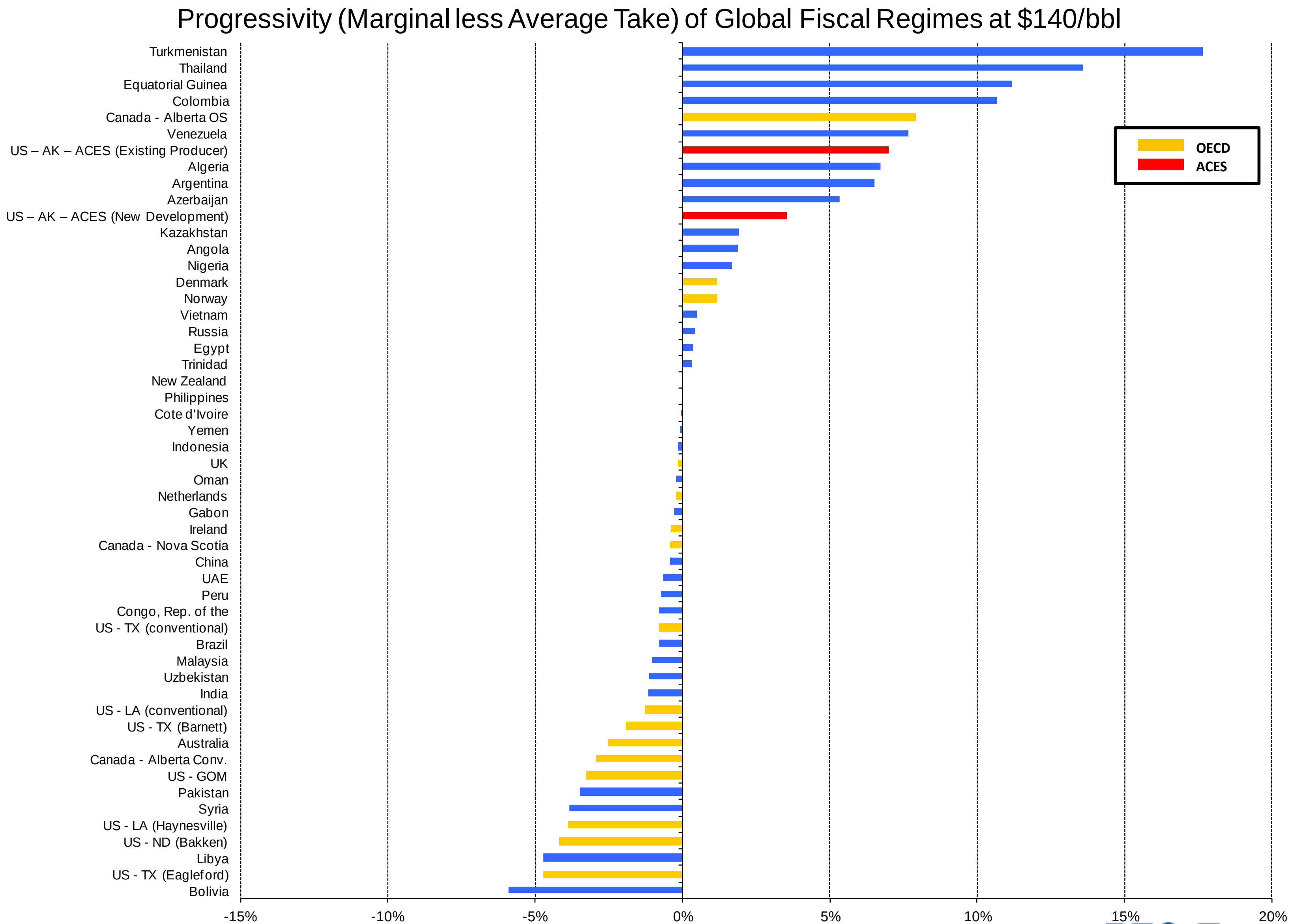
Benchmarking Progressivity for a Range of Global Regimes



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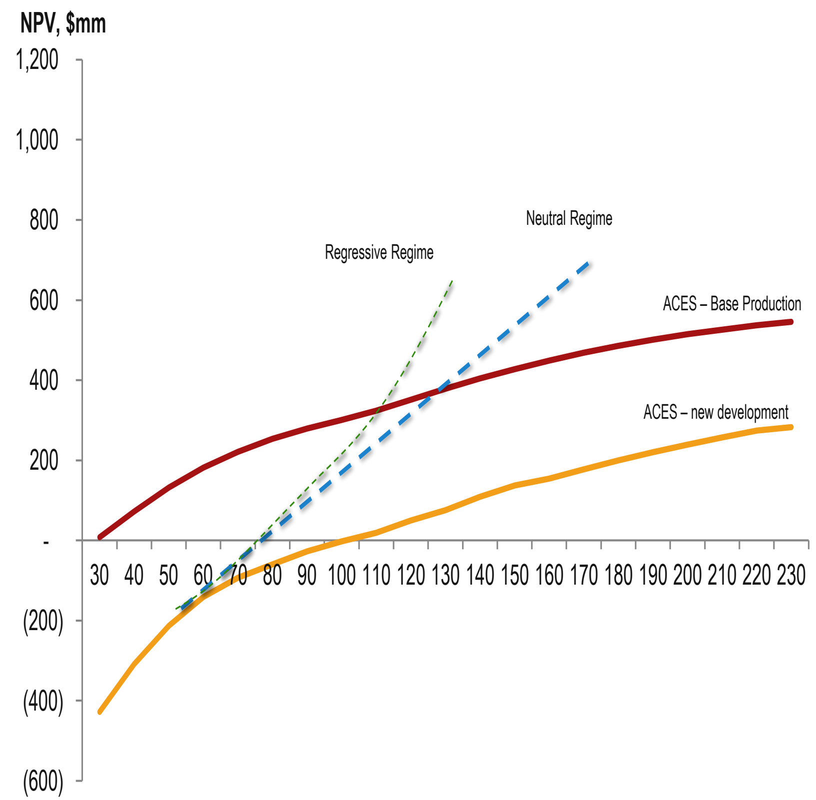
ACES – Effective as a Harvest Area Fiscal Regime

- ACES appears to work well as a “harvest” regime
  - Existing **mature fields remain profitable**, including capital work required to achieve ~6% decline (renewal capex)
  - **Maximum ‘rent’** extracted from a declining production base is captured for the state
- ACES inhibits the development of new projects and resources that might help stem or even reverse the decline
  - ACES is **not progressive with regard to costs**, so high government take applies even to very high cost projects
  - Existing system of capital credits etc appears to do more to encourage ‘renewal capex’ than it does new production spending
  - Progressivity can have a major **detrimental impact on breakeven prices** for high-cost projects at current oil prices



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Options to Spur New Developments

Approach	Implementation Options	Advantages	Disadvantages
Uniform lowering of Government Take	•Bracketing •Reduced Base Rate •Increased Progressivity Thresholds •Reduced Progressivity Rates •Progressivity Caps	•Does not require increased complexity •May present opportunities for simplification	•Incentivizing new high cost resources through this method alone requires giving substantial 'rent' back to producers on the mature producing assets
Differentiation between old and new production	•Allowance for New Oil •Switching in part away from Net Profits taxation to Gross Revenue Taxation, to enable different tax rates for different production streams without separate cost accounting and tax returns •Use of some combination of definitions for incremental production, ie base decline rate, regulator-agreed new programs, new areas	•Allows significant reductions in Govt Take on new and costlier developments (including heavy oil etc) without requiring significant reductions on the mature producing assets	•Administrative difficulties around definitions of 'new production'
Enhancements to cost progressivity of ACES	•Changes to allowable cost deduction or credits mechanism etc to provide greater 'uplift' for high capital and operating costs, while restricting negative Production Tax in marginal cases •Enhancements to royalty relief	•Does not require structural change away from ACES	•Increases already high complexity and opacity •May exacerbate problem of poor cost control incentives •Increases likelihood of unintended consequences •Likely less significant impact than new production differentiation

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Analysis of Committee Substitute for Senate Bill 192

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ACES v CSSB192

ACES					
Is Production Tax Bracketed?		No			
Are oil and gas assessed separately?		No			
Rates for non-bracketed system:				75%	maximum
<= 30	$ 30.00	PTV/BOE		25%	base
> 30 but <= 92.5	$ 92.50	PTV/BOE		0.40%	progressivity
> 92.5		PTV/BOE		0.10%	progressivity

CSSB 192					
Is Production Tax Bracketed?		No			
Are oil and gas assessed separately?		Yes			
Rates for non-bracketed system:				60%	maximum
<= 30	$ 30.00	PTV/BOE		25%	base
> 30 but <= 101.43	$ 101.43	PTV/BOE		0.35%	progressivity
> 101.43		PTV/BOE		0.10%	progressivity
Allowance for New Oil	$10				
Threshold for Increase:	Previous Year's Production				

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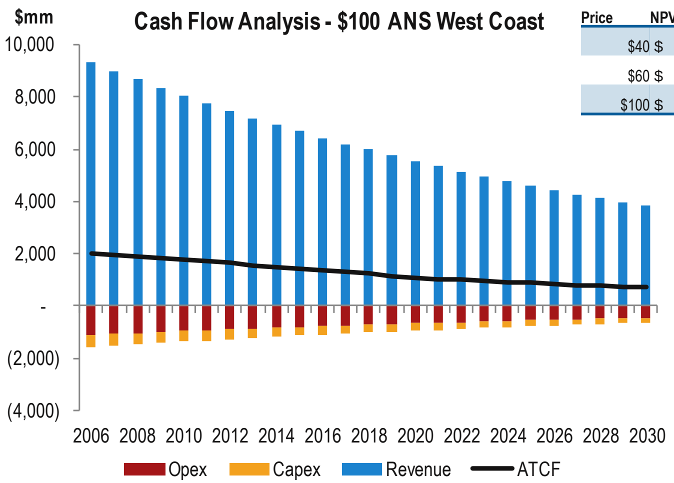
ACES (Existing Producer)



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70	19%	24%	4%	4%	52%	17%	69%
80	18%	29%	3%	4%	55%	16%	71%
90	17%	33%	3%	4%	57%	15%	72%
100	17%	37%	3%	4%	60%	14%	74%
110	16%	40%	2%	4%	62%	13%	75%
120	16%	42%	2%	3%	63%	13%	76%
130	15%	44%	2%	3%	65%	12%	77%
140	15%	46%	2%	3%	66%	12%	78%
150	15%	47%	2%	3%	67%	12%	78%
160	15%	48%	1%	3%	68%	11%	79%
170	15%	50%	1%	3%	69%	11%	80%
180	14%	51%	1%	3%	69%	11%	80%
190	14%	52%	1%	3%	70%	10%	81%
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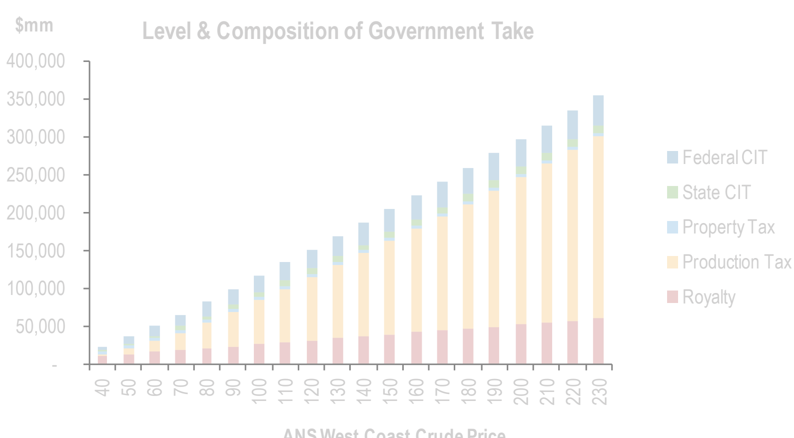

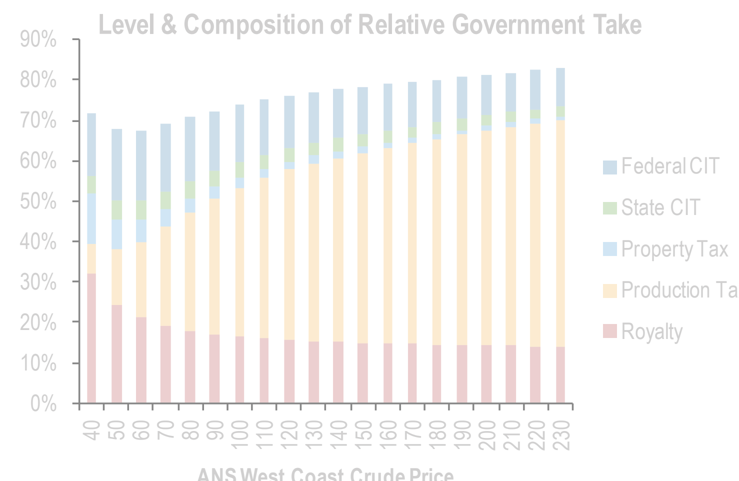

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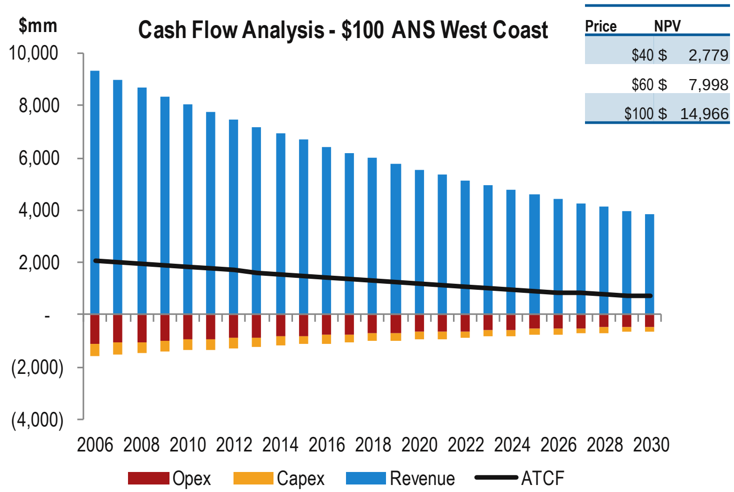
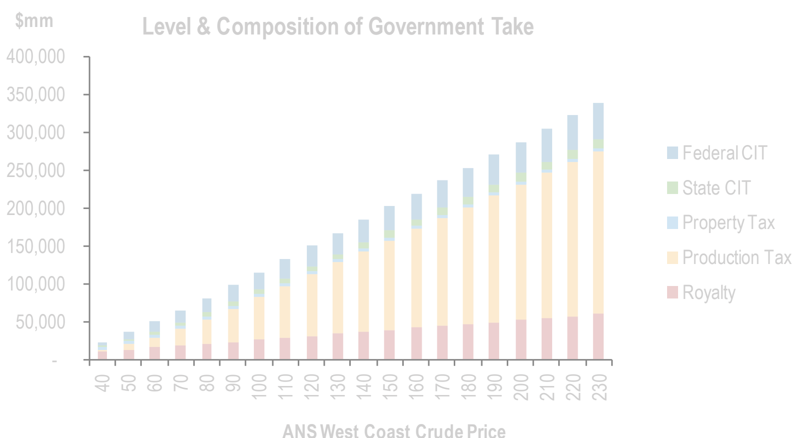
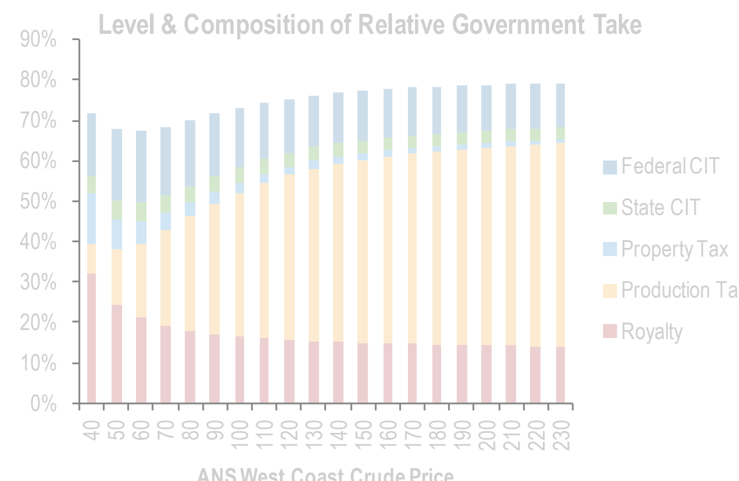
CSSB 192 (Existing Producer)



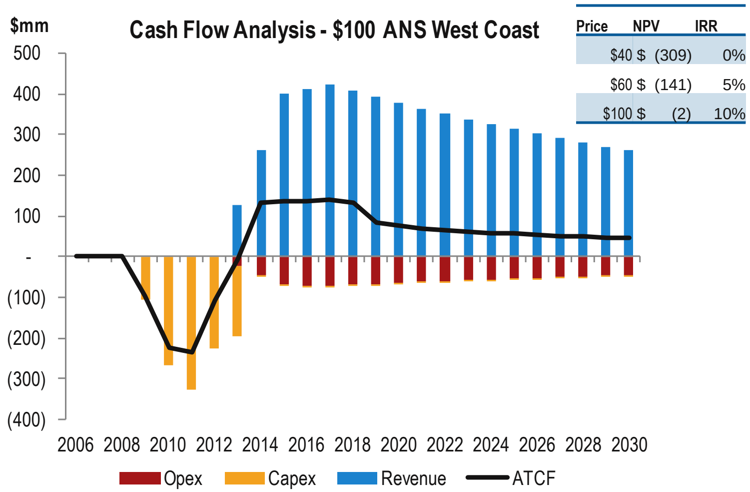
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	8%	12%	4%	56%	16%	72%
50	24%	14%	8%	5%	50%	18%	68%
60	21%	18%	5%	5%	50%	18%	67%
70	19%	24%	4%	4%	51%	17%	69%
80	18%	28%	3%	4%	54%	16%	70%
90	17%	32%	3%	4%	56%	15%	72%
100	17%	35%	3%	4%	58%	15%	73%
110	16%	38%	2%	4%	60%	14%	74%
120	16%	41%	2%	3%	62%	13%	75%
130	15%	43%	2%	3%	63%	13%	76%
140	15%	44%	2%	3%	64%	13%	77%
150	15%	45%	2%	3%	65%	12%	77%
160	15%	46%	1%	3%	66%	12%	78%
170	15%	47%	1%	3%	66%	12%	78%
180	14%	48%	1%	3%	67%	12%	78%
190	14%	49%	1%	3%	67%	12%	79%
200	14%	49%	1%	3%	67%	11%	79%
210	14%	50%	1%	3%	68%	11%	79%
220	14%	50%	1%	3%	68%	11%	79%
230	14%	50%	1%	3%	68%	11%	79%





PFC Energy

ACES (New Development)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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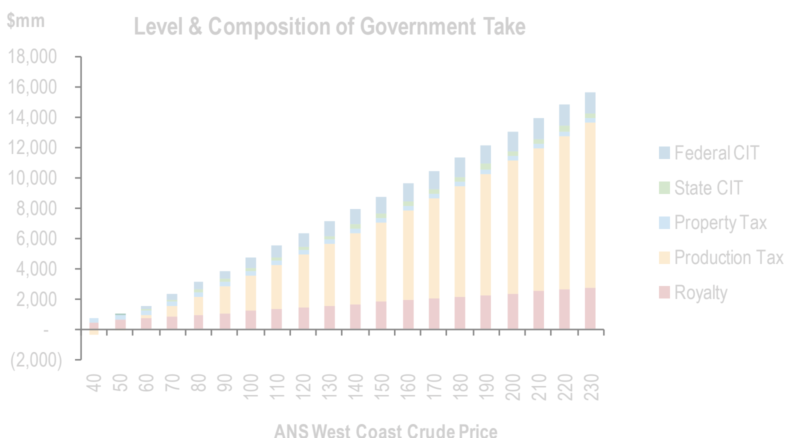
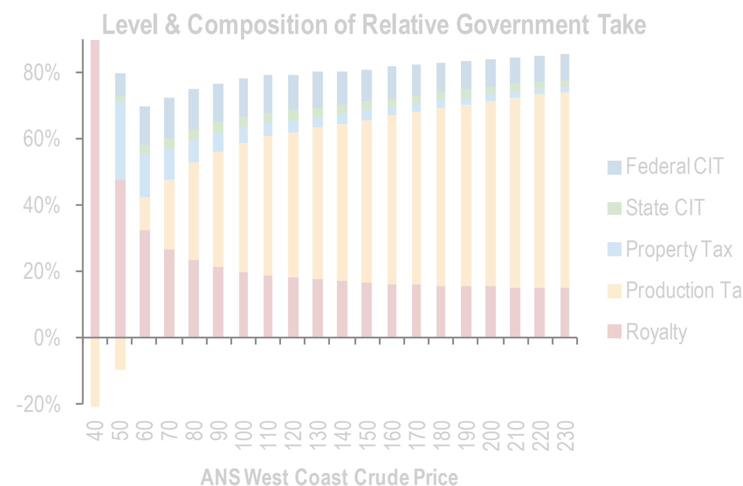
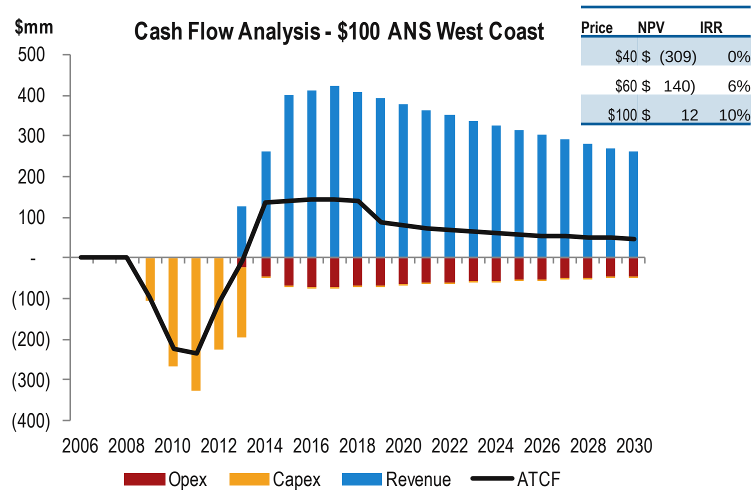
50	48%	-10%	23%	2%	63%	7%	70%
60	32%	10%	13%	3%	58%	11%	70%
70	26%	21%	9%	3%	60%	12%	73%
80	23%	29%	7%	3%	63%	12%	75%
90	21%	35%	6%	3%	65%	12%	77%
100	20%	39%	5%	3%	67%	11%	78%
110	19%	42%	4%	3%	68%	11%	79%
120	18%	44%	4%	3%	69%	11%	80%
130	17%	46%	3%	3%	69%	11%	80%
140	17%	48%	3%	3%	70%	10%	81%
150	17%	49%	3%	3%	71%	10%	81%
160	16%	51%	2%	3%	72%	10%	82%
170	16%	52%	2%	2%	73%	9%	83%
180	16%	54%	2%	2%	74%	9%	83%
190	16%	55%	2%	2%	75%	9%	84%
200	15%	56%	2%	2%	76%	8%	84%
210	15%	57%	2%	2%	76%	8%	85%
220	15%	58%	2%	2%	77%	8%	85%
230	15%	59%	2%	2%	78%	8%	85%





PFC Energy

CSSB 192 (New Development)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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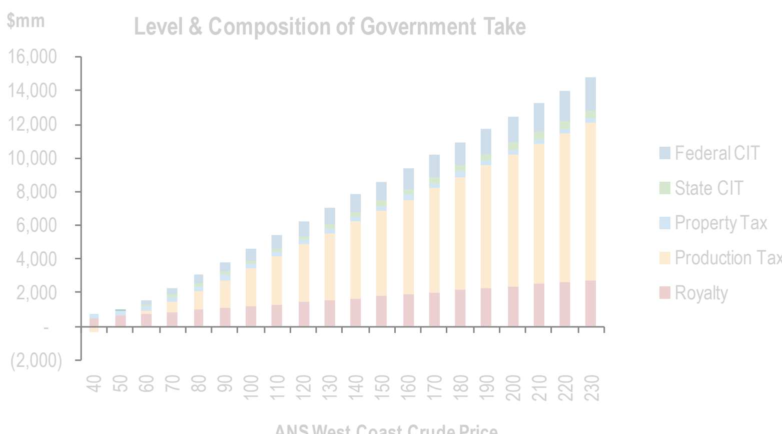
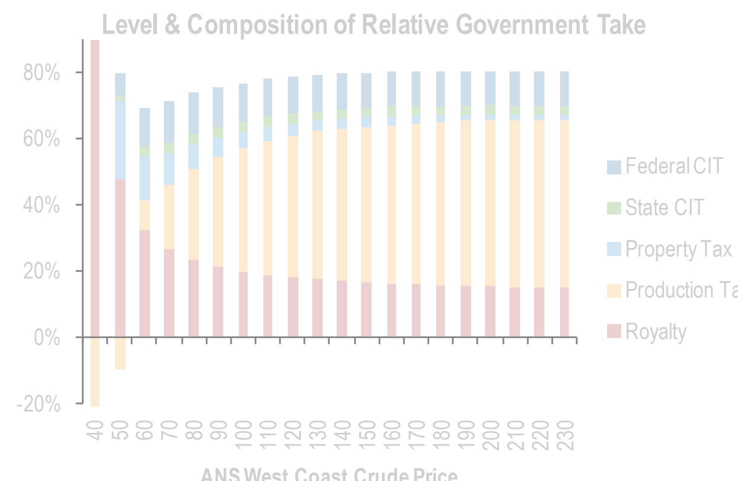
50	48%	-10%	23%	2%	63%	7%	70%
60	32%	9%	13%	3%	58%	12%	69%
70	26%	20%	9%	3%	59%	13%	72%
80	23%	28%	7%	3%	61%	13%	74%
90	21%	33%	6%	3%	63%	12%	76%
100	20%	37%	5%	3%	65%	12%	77%
110	19%	41%	4%	3%	67%	11%	78%
120	18%	43%	4%	3%	68%	11%	79%
130	17%	45%	3%	3%	68%	11%	79%
140	17%	46%	3%	3%	69%	11%	80%
150	17%	47%	3%	3%	69%	11%	80%
160	16%	48%	2%	3%	70%	11%	80%
170	16%	49%	2%	3%	70%	11%	80%
180	16%	49%	2%	3%	70%	10%	80%
190	16%	50%	2%	3%	70%	10%	80%
200	15%	50%	2%	3%	70%	10%	80%
210	15%	50%	2%	3%	70%	10%	80%
220	15%	51%	2%	3%	70%	10%	80%
230	15%	51%	2%	3%	70%	10%	80%





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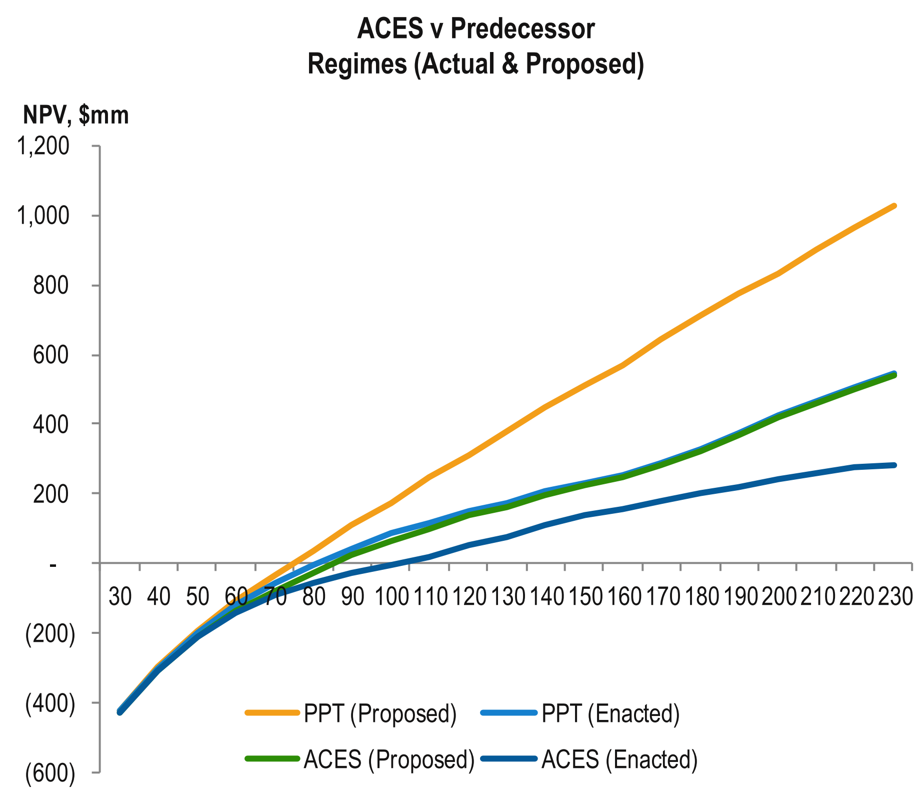
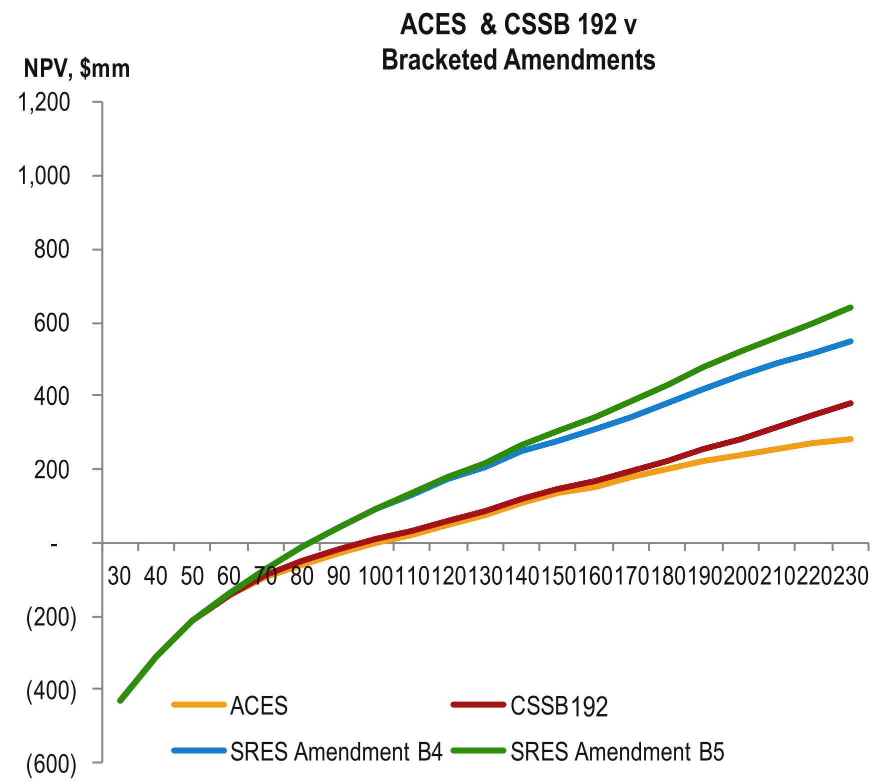
Progressivity Impact on New Development Project Economics





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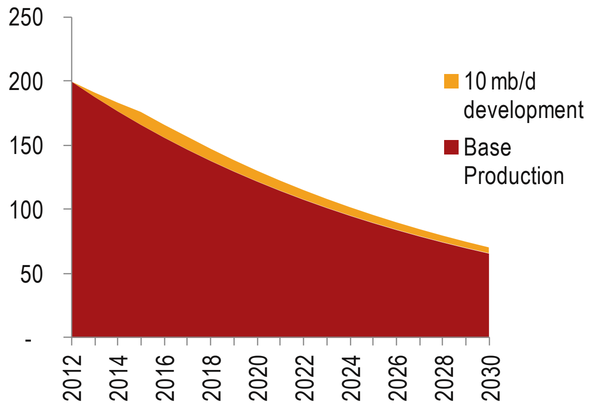
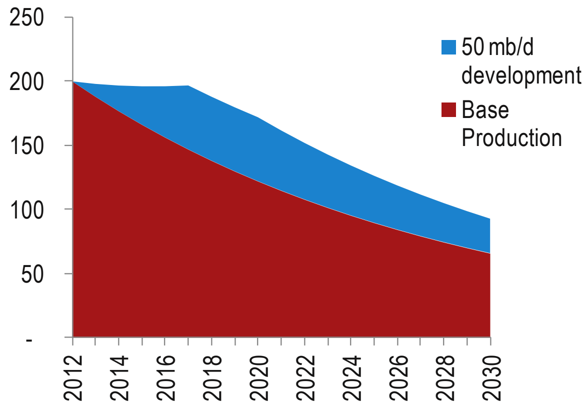
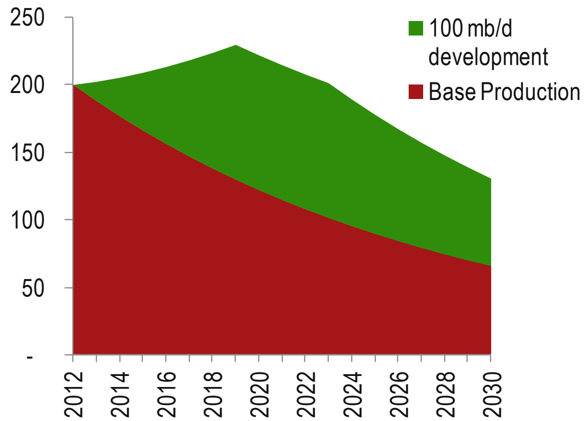
New Oil Allowance:
Incremental Production on a Declining Base

- Central to understanding the impact of the "allowance for 'new oil'" is an understanding of the impact of new source production on a company's total production volumes, when that new source production is added to a declining base portfolio
  - The charts below assume a 6% decline rate for an existing North Slope producer currently producing 200 mb/d, and examine hypothetical new source projects that peak at 10mb/d, 50 mb/d and 100 mb/d respectively(on a working interest basis)
  - Given the pace at which such projects typically reach peak production, only the100 mb/d peak production new source development is actually capable of adding production that is incremental to prior years' volumes







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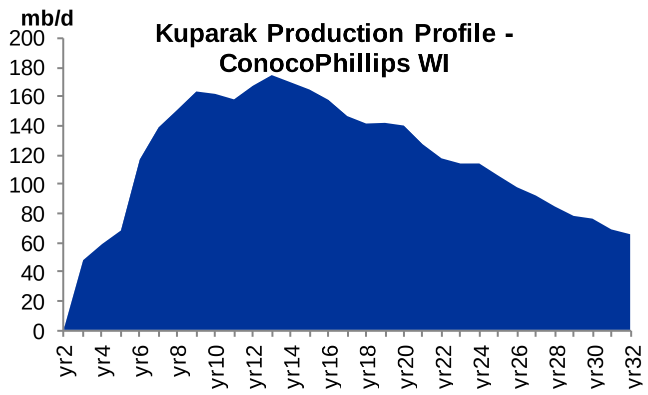
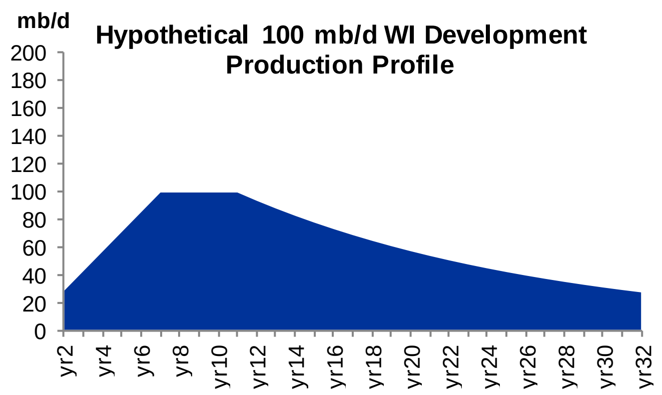
A Hypothetical 100 mb/d (Working Interest) development

- A new source development that produced 100 mb/d at peak for a working interest partner would be a very significant new development. By way of comparison, Kuparak, the second largest field in North America, peaked at ~320 mb/d gross production
  - This represented **working interest production** to ConocoPhillips (the operator and majority shareholder) of **170 mbo/d**
  - Kuparak took 11 years (from 1981 to 1992) to reach this peak level of production
- Since it would take a development on the scale of 100 mb/d (working interest) to achieve "new oil" for an existing producer under the terms of the amendment, a development of this size has been modeled in the following analysis
  - A 7 year ramp-up to peak production has been assumed
  - Such a development would likely eclipse today's production from Kuparak (122 mb/d gross, 66mb/d working interest to the majority shareholder)
  - It is important to note that this is a significantly more aggressive new-source production profile than is currently foreseen in recent statements by the major operators on their current development pipelines, even in the most optimistic circumstances





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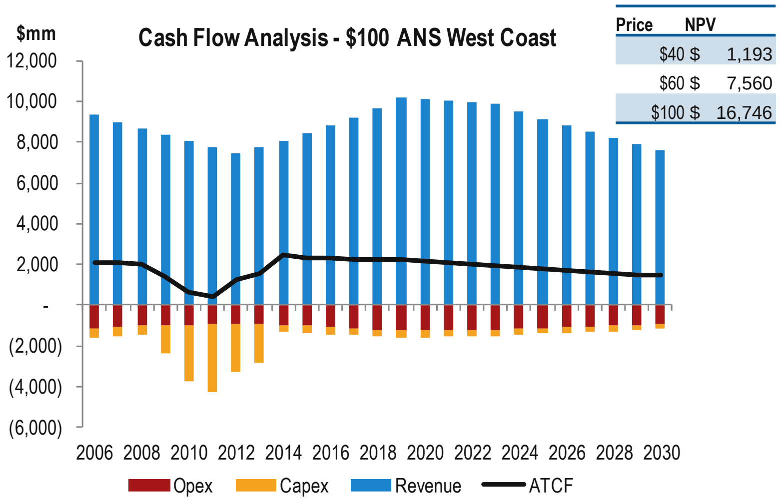
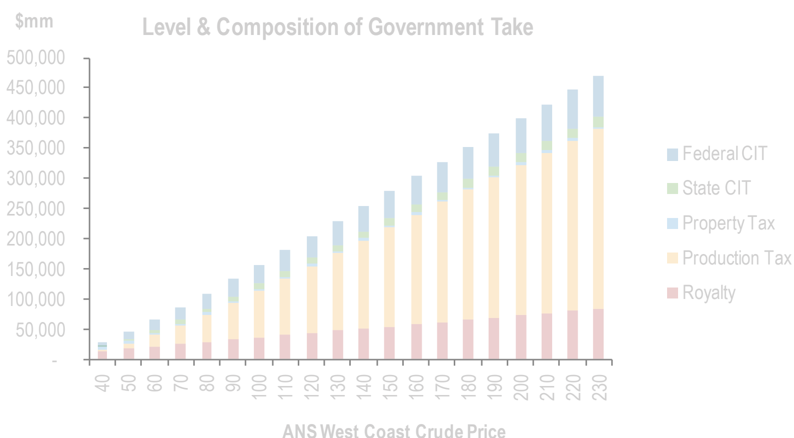
Assumptions

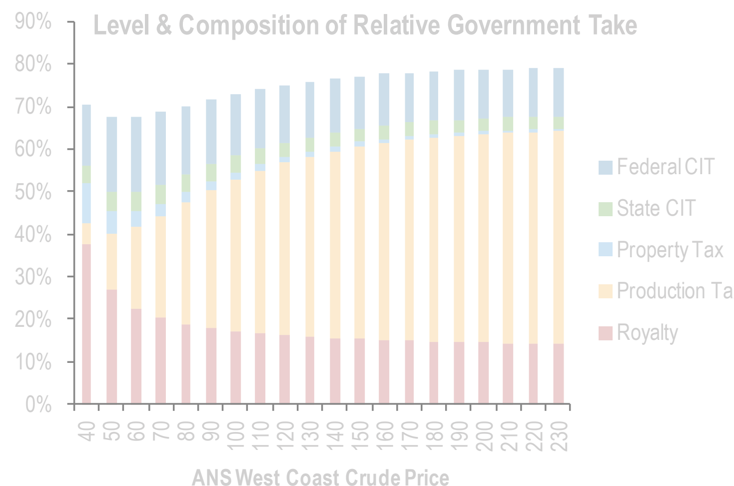
- The following analysis assumes
  - A 6% base portfolio decline, in the case of a producer currently producing 200 mb/d
  - Costs for the base production portfolio of:
    - $12/ flowing bbl operating expenditure
    - $5/ flowing bbl maintenance capital expenditure
  - Costs for the 100 mb/d (working interest) New Development project of:
    - $13/ flowing bbl operating expenditure
    - $13/bbl reserves development capital expenditure
    - $1/ flowing bbl maintenance capital expenditure
  - These costs are deliberately somewhat lower than the previously referenced 10 mb/d new development, since the hypothetical development modeled is significantly larger, and thus likely to have somewhat lower costs on a $/bbl basis

CSSB 192 Excluding New Oil Allowance (Existing Producer)



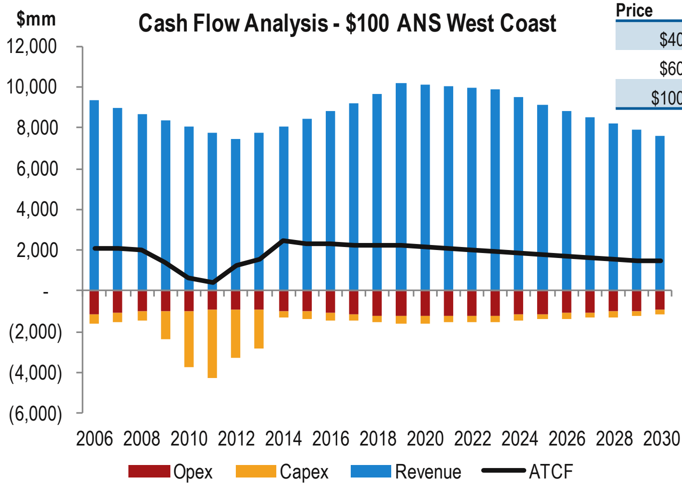
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	38%	5%	9%	4%	56%	15%	71%
50	27%	13%	5%	5%	50%	18%	68%
60	23%	19%	4%	5%	50%	18%	68%
70	20%	24%	3%	4%	52%	17%	69%
80	19%	29%	2%	4%	54%	16%	70%
90	18%	33%	2%	4%	56%	15%	72%
100	17%	36%	2%	4%	58%	15%	73%
110	17%	38%	2%	4%	60%	14%	74%
120	16%	41%	1%	4%	62%	14%	75%
130	16%	42%	1%	3%	63%	13%	76%
140	15%	44%	1%	3%	64%	13%	77%
150	15%	45%	1%	3%	65%	12%	77%
160	15%	46%	1%	3%	66%	12%	78%
170	15%	47%	1%	3%	66%	12%	78%
180	15%	48%	1%	3%	67%	12%	78%
190	15%	49%	1%	3%	67%	12%	79%
200	14%	49%	1%	3%	67%	12%	79%
210	14%	49%	1%	3%	67%	11%	79%
220	14%	50%	1%	3%	68%	11%	79%
230	14%	50%	1%	3%	68%	11%	79%





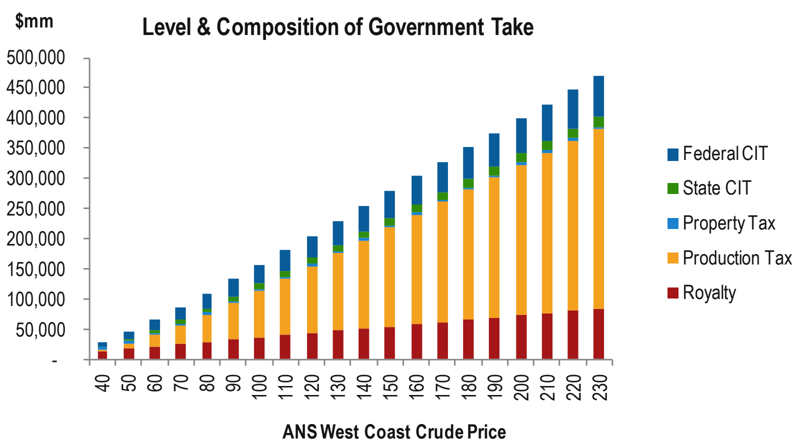
PFC Energy

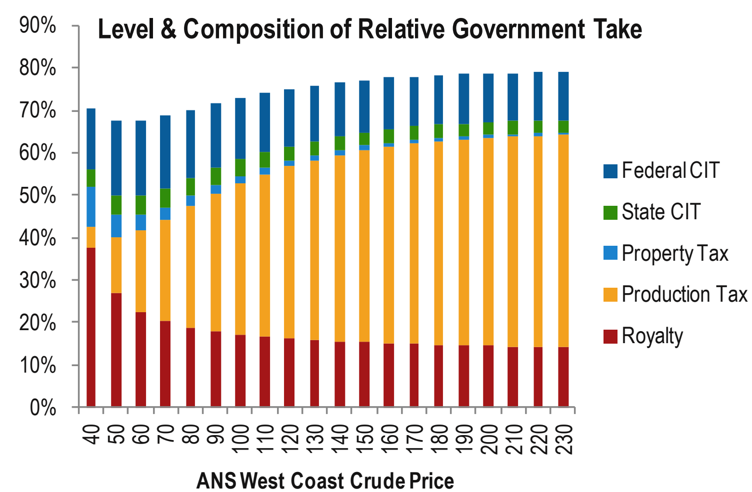
CSSB 192 Including $10 New Oil Allowance (Existing Producer)



Price	NPV
$40 $	1,193
$60 $	7,562
$100 $	16,752

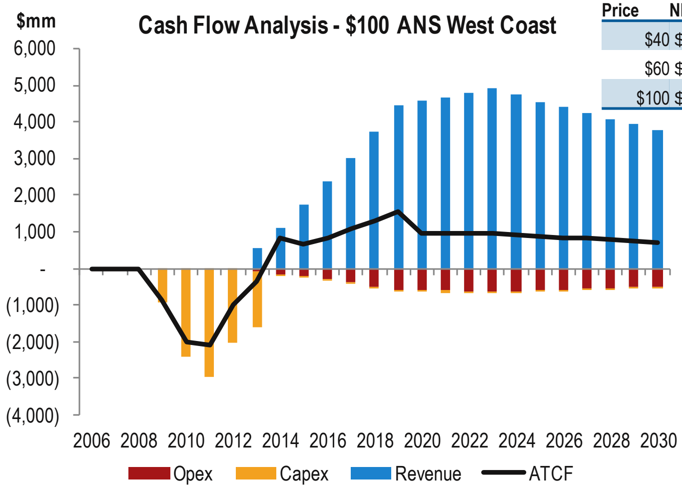
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	38%	5%	9%	4%	56%	15%	71%
50	27%	13%	5%	5%	50%	18%	68%
60	23%	19%	4%	5%	50%	18%	68%
70	20%	24%	3%	4%	52%	17%	69%
80	19%	29%	2%	4%	54%	16%	70%
90	18%	33%	2%	4%	56%	15%	72%
100	17%	36%	2%	4%	58%	15%	73%
110	17%	38%	2%	4%	60%	14%	74%
120	16%	41%	1%	4%	62%	14%	75%
130	16%	42%	1%	3%	63%	13%	76%
140	15%	44%	1%	3%	64%	13%	77%
150	15%	45%	1%	3%	65%	12%	77%
160	15%	46%	1%	3%	66%	12%	78%
170	15%	47%	1%	3%	66%	12%	78%
180	15%	48%	1%	3%	67%	12%	78%
190	15%	49%	1%	3%	67%	12%	79%
200	14%	49%	1%	3%	67%	12%	79%
210	14%	49%	1%	3%	67%	11%	79%
220	14%	50%	1%	3%	68%	11%	79%
230	14%	50%	1%	3%	68%	11%	79%





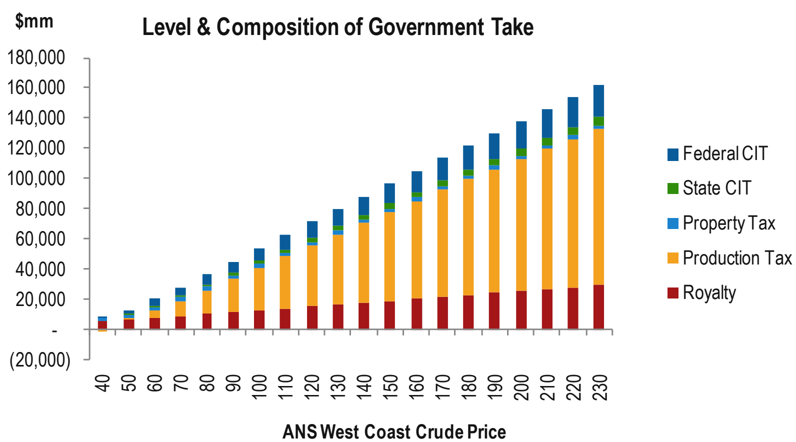
PFC Energy

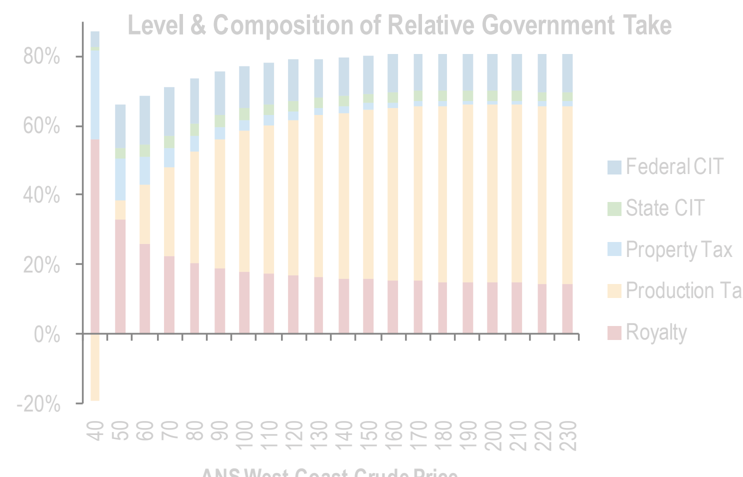
CSSB 192 Excluding New Oil Allowance (New 100 mb/d Development)



Price	NPV	IRR
$40	$ -2,224	3%
$60	$ -913	7%
$100	$ 276	11%

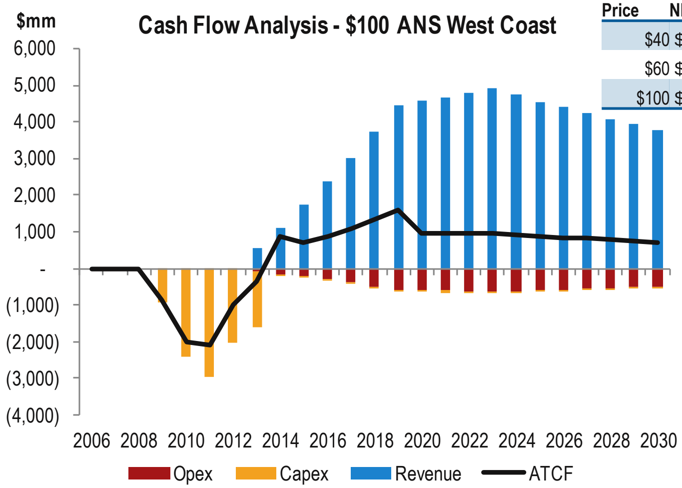
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	56%	-19%	25%	1%	64%	5%	68%
50	33%	5%	12%	3%	54%	13%	66%
60	26%	17%	8%	4%	55%	14%	69%
70	22%	25%	6%	4%	57%	14%	71%
80	20%	32%	5%	3%	60%	13%	74%
90	19%	37%	4%	3%	63%	12%	75%
100	18%	40%	3%	3%	65%	12%	77%
110	17%	43%	3%	3%	66%	12%	78%
120	17%	45%	3%	3%	67%	12%	79%
130	16%	46%	2%	3%	68%	11%	79%
140	16%	48%	2%	3%	69%	11%	80%
150	16%	49%	2%	3%	69%	11%	80%
160	16%	50%	2%	3%	70%	11%	80%
170	15%	50%	2%	3%	70%	11%	81%
180	15%	51%	2%	3%	70%	11%	81%
190	15%	51%	1%	3%	70%	11%	81%
200	15%	51%	1%	3%	70%	11%	81%
210	15%	51%	1%	3%	70%	11%	81%
220	15%	51%	1%	3%	70%	11%	81%
230	14%	51%	1%	3%	70%	11%	80%





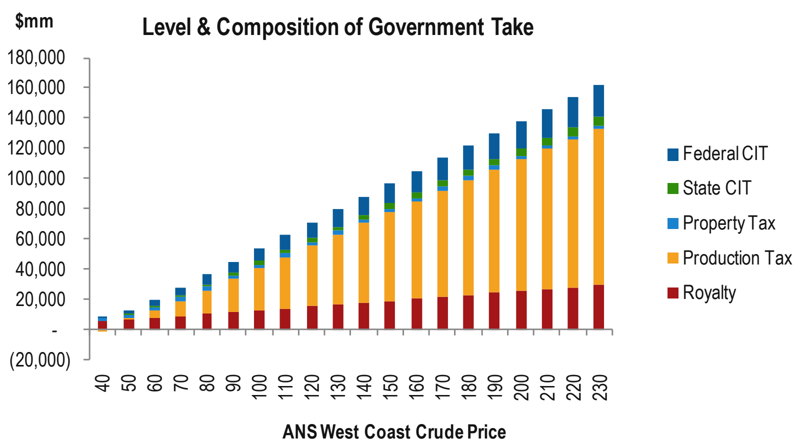
PFC Energy

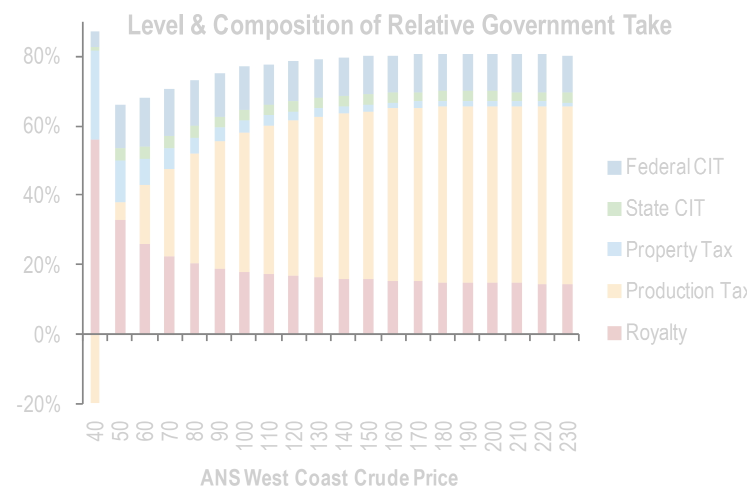
CSSB 192 Including $10 New Oil Allowance (New 100 mb/d Development)



Price	NPV	IRR
$40	$ -2,207	3%
$60	$ -879	7%
$100	$ 327	11%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	56%	-20%	25%	1%	63%	5%	68%
50	33%	5%	12%	3%	53%	13%	66%
60	26%	17%	8%	4%	54%	14%	68%
70	22%	25%	6%	4%	57%	14%	71%
80	20%	32%	5%	3%	60%	13%	73%
90	19%	37%	4%	3%	63%	12%	75%
100	18%	40%	3%	3%	65%	12%	77%
110	17%	43%	3%	3%	66%	12%	78%
120	17%	45%	3%	3%	67%	12%	79%
130	16%	46%	2%	3%	68%	11%	79%
140	16%	48%	2%	3%	69%	11%	80%
150	16%	49%	2%	3%	69%	11%	80%
160	16%	49%	2%	3%	69%	11%	80%
170	15%	50%	2%	3%	70%	11%	80%
180	15%	50%	2%	3%	70%	11%	80%
190	15%	51%	1%	3%	70%	11%	80%
200	15%	51%	1%	3%	70%	11%	81%
210	15%	51%	1%	3%	70%	11%	81%
220	15%	51%	1%	3%	70%	11%	80%
230	14%	51%	1%	3%	70%	11%	80%





PFC Energy

Oil / Gas Decoupling

- 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
- CSSB 192 includes a provision to de-couple the calculation of production tax value on North Slope gas sold out-of-state, in order to eliminate this impact of gas production
  - The impact of the decreased government take without decoupling is only pronounced with very low gas prices, and very large gas production
  - In order to illustrate the impact at the extreme, the following analysis thus assumes a $1/mcf net-back sale price for North Slope gas, and a 2018 1bcf/d gas project. Under less extreme scenarios, the difference with and without decoupling would be significantly less

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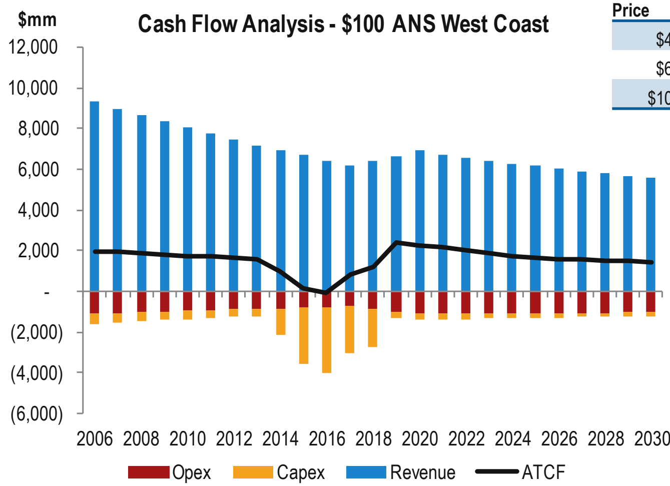
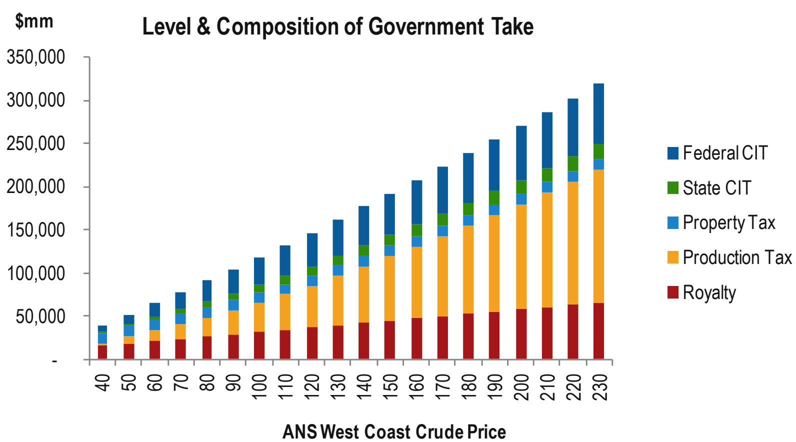
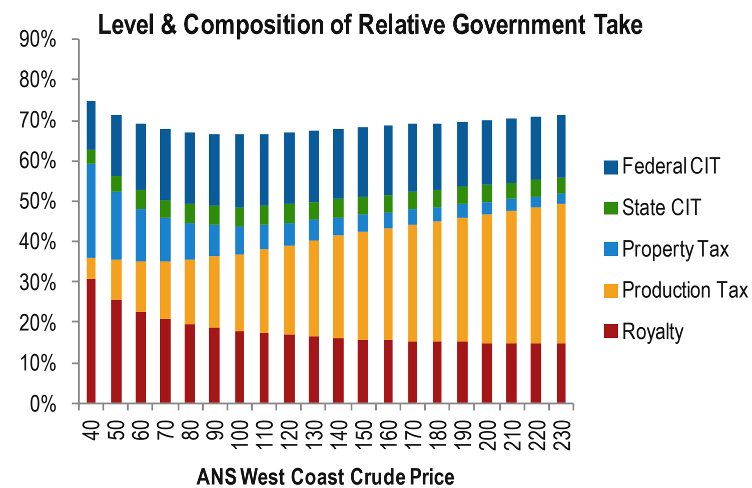
CSSB 192 – Existing Producer with 2018 Gas Project, No Decoupling



Price	NPV
$40	928
$60 $	6,298
$100 $	15,373

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	31%	5%	23%	3%	63%	12%	75%
50	25%	10%	17%	4%	56%	15%	71%
60	23%	13%	13%	4%	53%	17%	69%
70	21%	14%	11%	5%	50%	17%	68%
80	19%	16%	9%	5%	49%	18%	67%
90	19%	18%	8%	5%	49%	18%	67%
100	18%	19%	7%	5%	49%	18%	67%
110	17%	21%	6%	5%	49%	18%	67%
120	17%	22%	6%	5%	49%	18%	67%
130	16%	24%	5%	5%	50%	18%	67%
140	16%	25%	5%	5%	51%	17%	68%
150	16%	26%	4%	4%	51%	17%	68%
160	16%	28%	4%	4%	52%	17%	69%
170	15%	29%	4%	4%	52%	17%	69%
180	15%	30%	4%	4%	53%	17%	69%
190	15%	31%	3%	4%	53%	16%	70%
200	15%	32%	3%	4%	54%	16%	70%
210	15%	33%	3%	4%	55%	16%	71%
220	15%	34%	3%	4%	55%	16%	71%
230	15%	35%	3%	4%	56%	15%	71%





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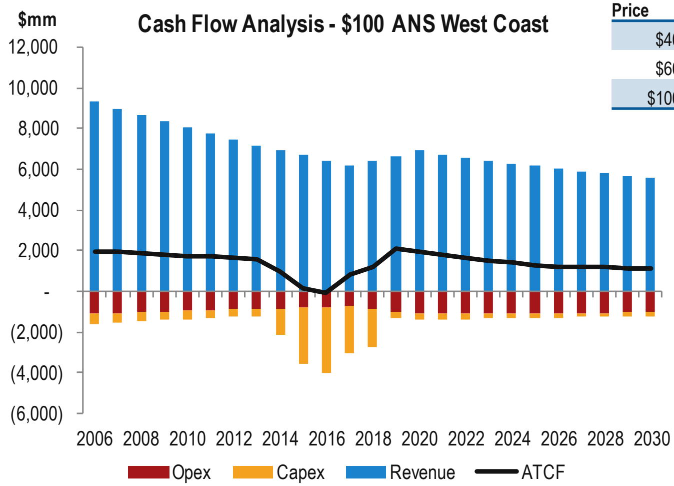
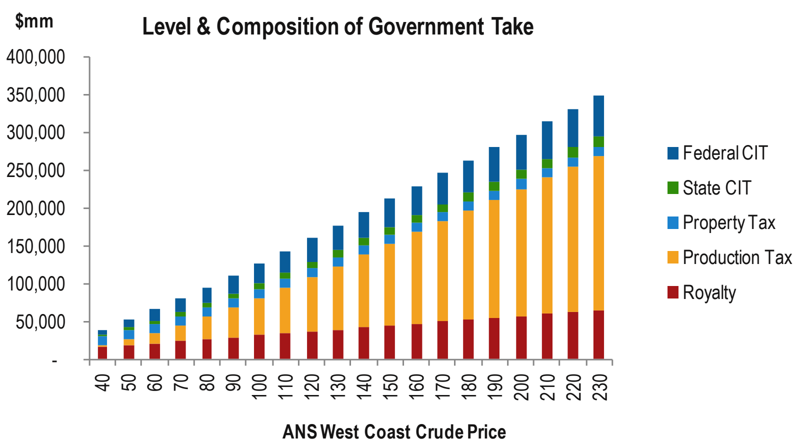
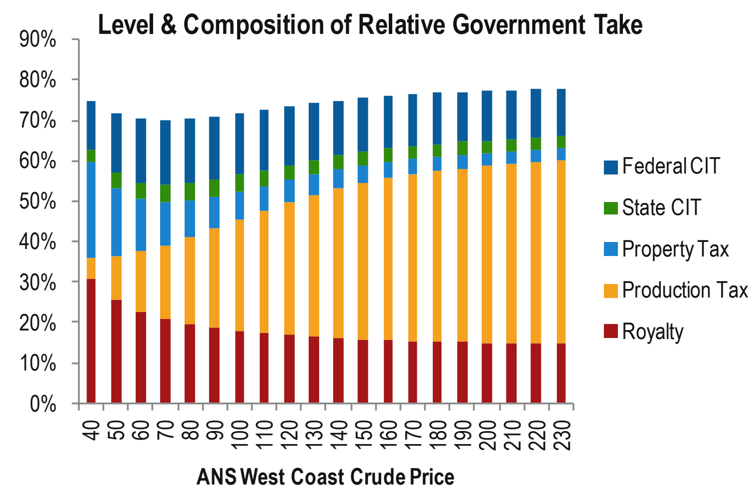
CSSB 192 – Existing Producer with 2018 Gas Project, Including Decoupling



Price	NPV
$40	928
$60 $	6,200
$100 $	14,455

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	31%	5%	23%	3%	63%	12%	75%
50	25%	11%	17%	4%	57%	15%	72%
60	23%	15%	13%	4%	55%	16%	71%
70	21%	18%	11%	4%	54%	16%	70%
80	19%	22%	9%	4%	54%	16%	70%
90	19%	25%	8%	4%	55%	16%	71%
100	18%	28%	7%	4%	56%	15%	72%
110	17%	30%	6%	4%	58%	15%	73%
120	17%	33%	6%	4%	59%	14%	73%
130	16%	35%	5%	4%	60%	14%	74%
140	16%	37%	5%	4%	61%	14%	75%
150	16%	39%	4%	3%	62%	13%	76%
160	16%	40%	4%	3%	63%	13%	76%
170	15%	41%	4%	3%	64%	13%	76%
180	15%	42%	4%	3%	64%	13%	77%
190	15%	43%	3%	3%	65%	12%	77%
200	15%	44%	3%	3%	65%	12%	77%
210	15%	44%	3%	3%	65%	12%	78%
220	15%	45%	3%	3%	66%	12%	78%
230	15%	46%	3%	3%	66%	12%	78%





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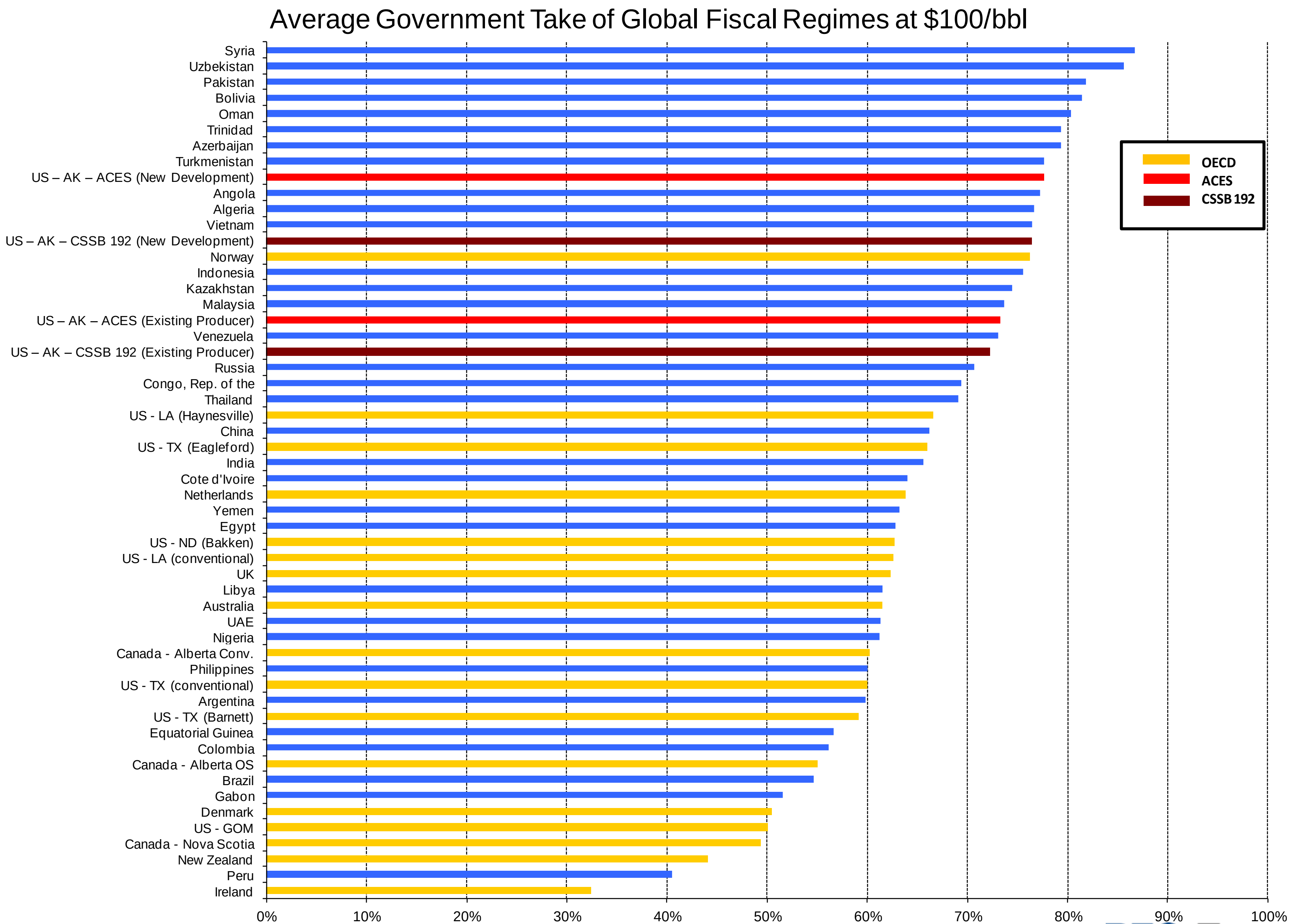
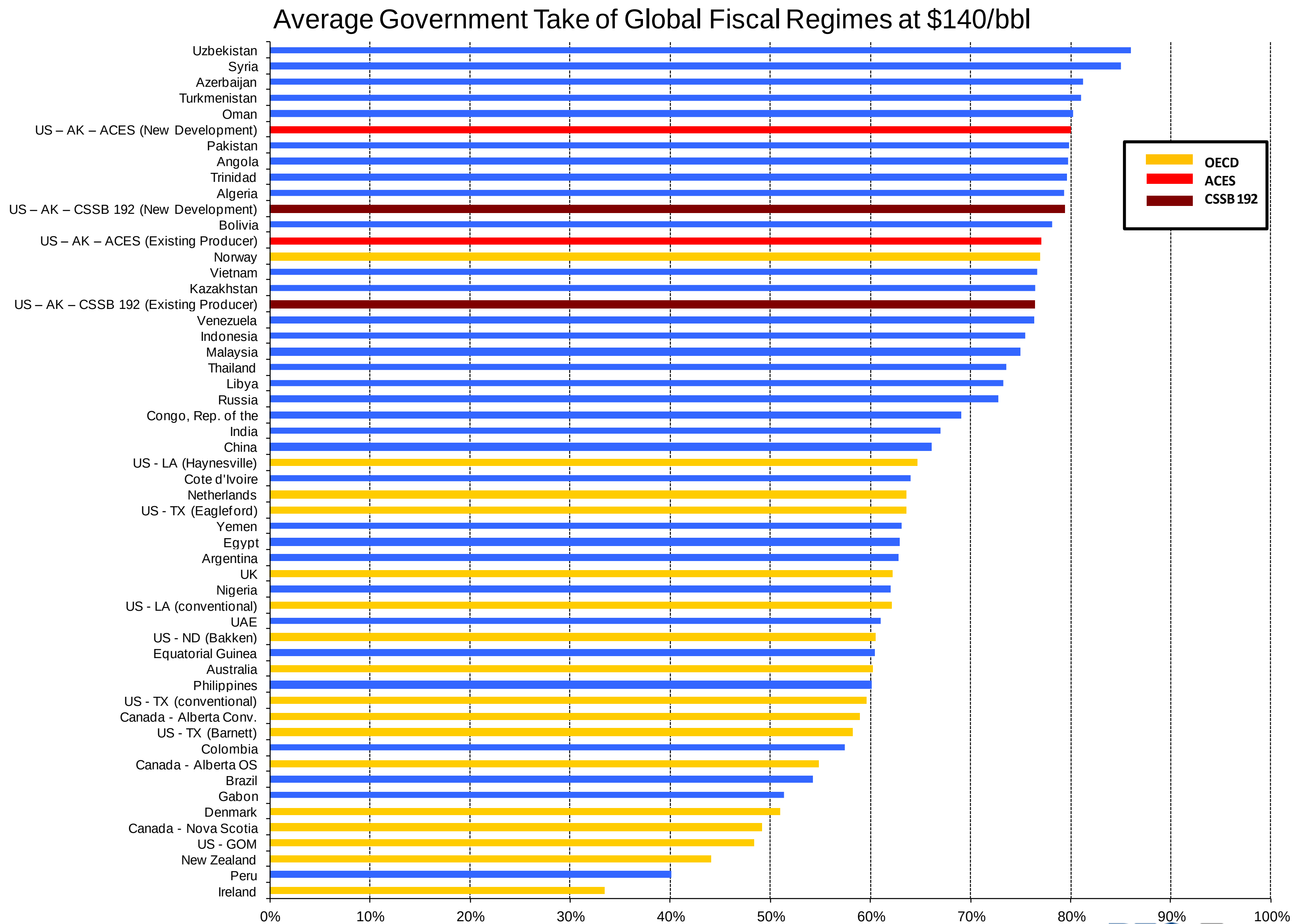
Regime Competitiveness: Relative Government Take



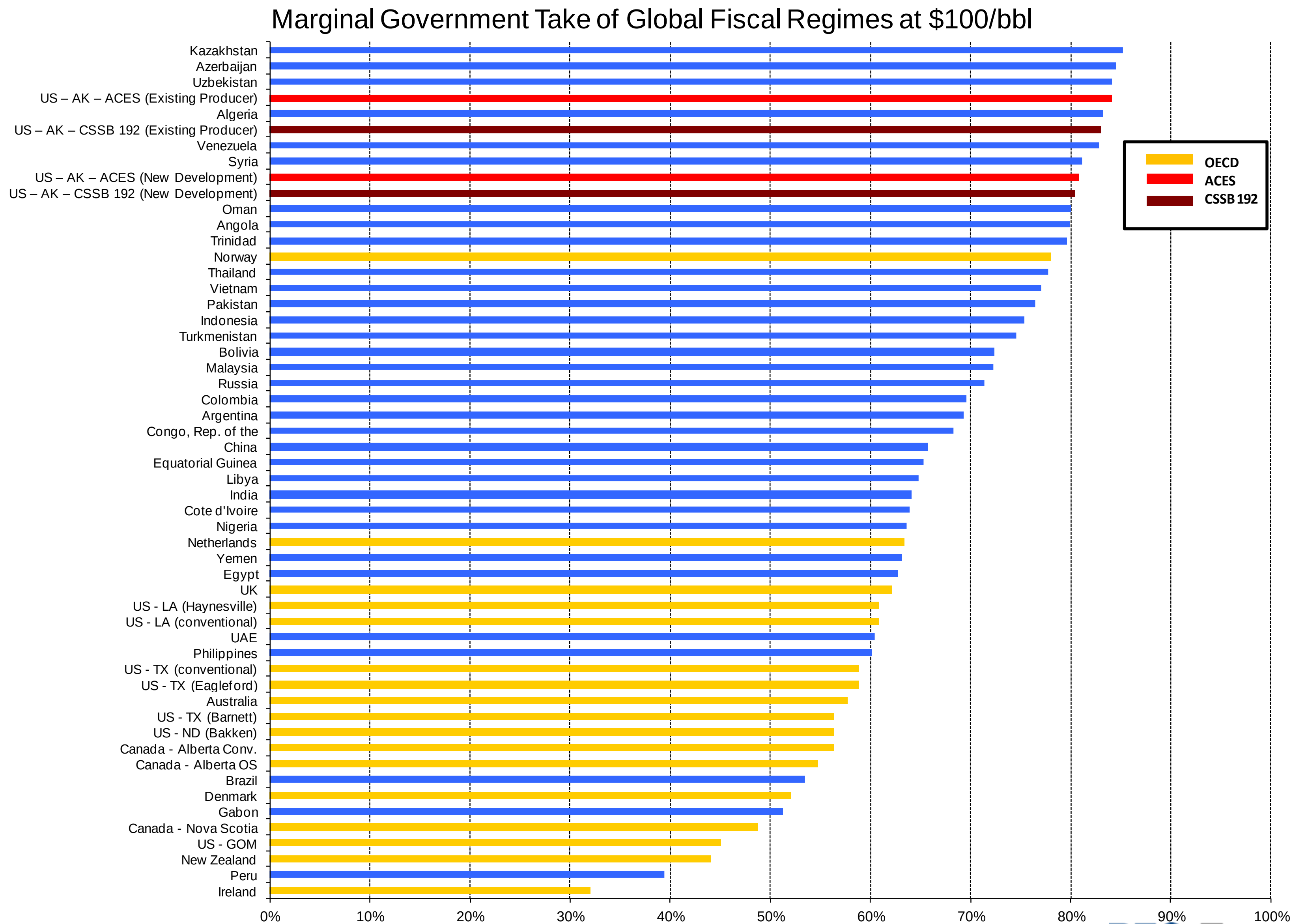
PFC Energy

Regime Competitiveness: Relative Government Take



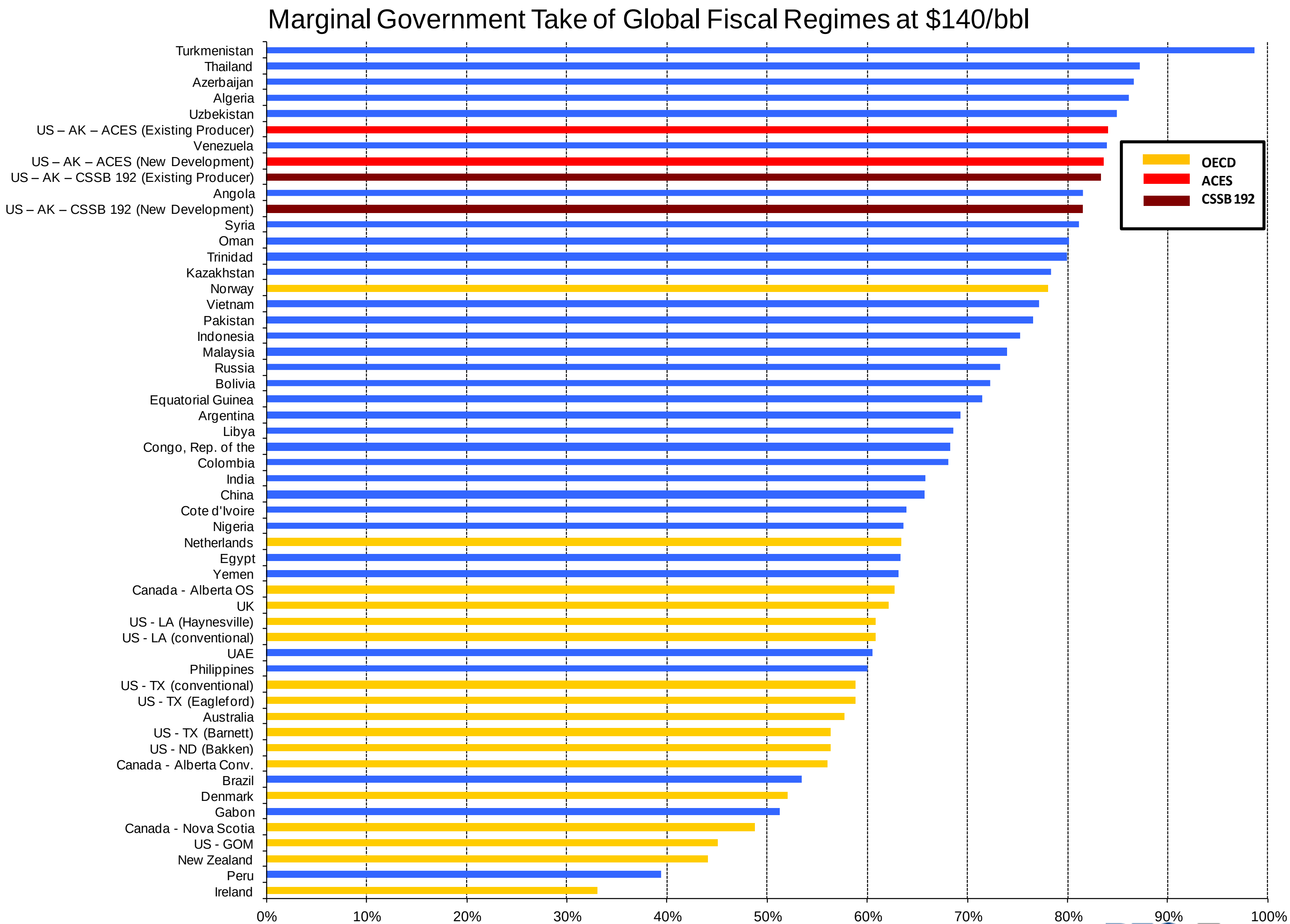
PFC Energy

Regime Competitiveness: Relative Government Take



PFC Energy

Regime Competitiveness: Relative Government Take



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Conclusions – Changes to Progressivity, Overall Government Take, and Oil/Gas Decoupling

- CSSB 192 uses two key mechanisms to reduce government take relative to ACES
  - A reduction in the rate of progressivity that applies above $30/bbl Production Tax Value (PTV) from a 0.4% increase for each one dollar increase in PTV, to a 0.35% increase
  - A reduction in the maximum rate of production tax, from 75% at $342 PTV, to 60% at $202 PTV
- The impact of the reduction in the progressivity coefficient on overall levels of government take and on project economics is limited to around a single percentage point of government take at $100 ANS crude
- The impact of the 60% maximum rate for production tax is more significant, but only at very high oil prices.
  - On a current-year basis, government take under CSSB 192 would be significantly lower than under ACES only at ANS crude oil prices above $230
  - On a project-lifecycle basis, that threshold may be lower, as a result of the impact of bracket-creep (since progressivity thresholds are specified in nominal terms) – but the impact on project economics at likely price levels remains negligible

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Conclusions – New Oil Allowance

- Even under highly aggressive assumptions regarding the potential for a new-source development for a given company, the impact of the $10 allowance for "new oil" is almost undetectable
  - In the context of both a development by an existing producer, and a development by a new producer, Relative Government Take changes only by fractions of a percentage point, at most
  - For an existing producer, portfolio NPV rises by only a tenth of a percentage point
  - For a new producer, the impact on project value is greater, but remains insignificant in the context of a $10 billion capital development
- The major reason for this is because rather than providing an ongoing allowance for new-source production, the amendment provides an allowance only for production that, in a given year, is incremental to the previous year's production
  - For an existing producer with declining base production, only a very large development is capable of producing "new oil" under this development at all
  - Even for a new producer, the value of the allowance remains highly limited
- An allowance which was instead provided for new-source production could potentially have a greater impact, however adequately defining such new-source production could be difficult in practice, particularly in an environment where most new production will come from existing areas

PFC Energy

Global Strategy & Portfolio Overview of Major Alaska Producers

PFC Energy

BP: Company Overview

Strategic Signature

- BP is a global integrated company, with production in 16 countries and upstream operations in an additional 10 countries.
- In 2010, total global production averaged ~3,773 mboe/d, making it the second largest company in the peer group (superseded by ExxonMobil (~4,450 mboe/d). The Russia & Central Asia (RCA) and North America regions accounted for ~55% of 2010 production.
- BP recorded a 4.5% drop in production in 2010 over 2009, reflecting the impact of asset sales, the post-Macondo slowdown in US GOM deepwater activity, and continued decline from the company's deepwater and mature shallow water assets.
- Much of the post-Macondo portfolio rationalization program (targeting $30 bn in asset sales including mid/downstream assets) has been completed. The result is a pared down and more focused geographic portfolio.
- BP expects growth of 1%-2% per annum through 2015. BP's growth strategy is three-pronged based on Deepwater Basins, Global Gas, and Giant Oilfield Development. BP's deepwater position is based on operations in the US GOM, Angola, Egypt and Brazil. The Global Gas position is principally comprised of US, Trinidad & Tobago, and North Sea. Giant oil fields are dispersed throughout the global portfolio. Based on PFC Energy projects, growth is unlikely before 2015.
- The growth strategy above includes ~$20 bn net investment commitment to 16 projects sanctioned over 2010-2011. This is expected to curb ROCE performance for the coming 2-3 years.
- With the burden of the Macondo oil spill and reparations continuing through the mid-term, BP will be hard pressed to outperform its peers on any key metrics, leaving the company open to calls for more radical restructuring.

Company Overview

- **HQ:** London
- **Employees:** 79,700
- **2010 Reserves:** 17,826 mmboe
- **2010 Production:** 3,773 mboe/d
- **3 Yr Production Growth:** 0.27% CAGR (2007-2010)
- **Nov 2011 Market Cap:** $137 bn
- **Nov 2011 P/E Ratio:** 6.03
- **2010 Corp Revenue:** $297 bn
- **2011 Upstream Capex (Est.):** $17 bn

Technological Competence

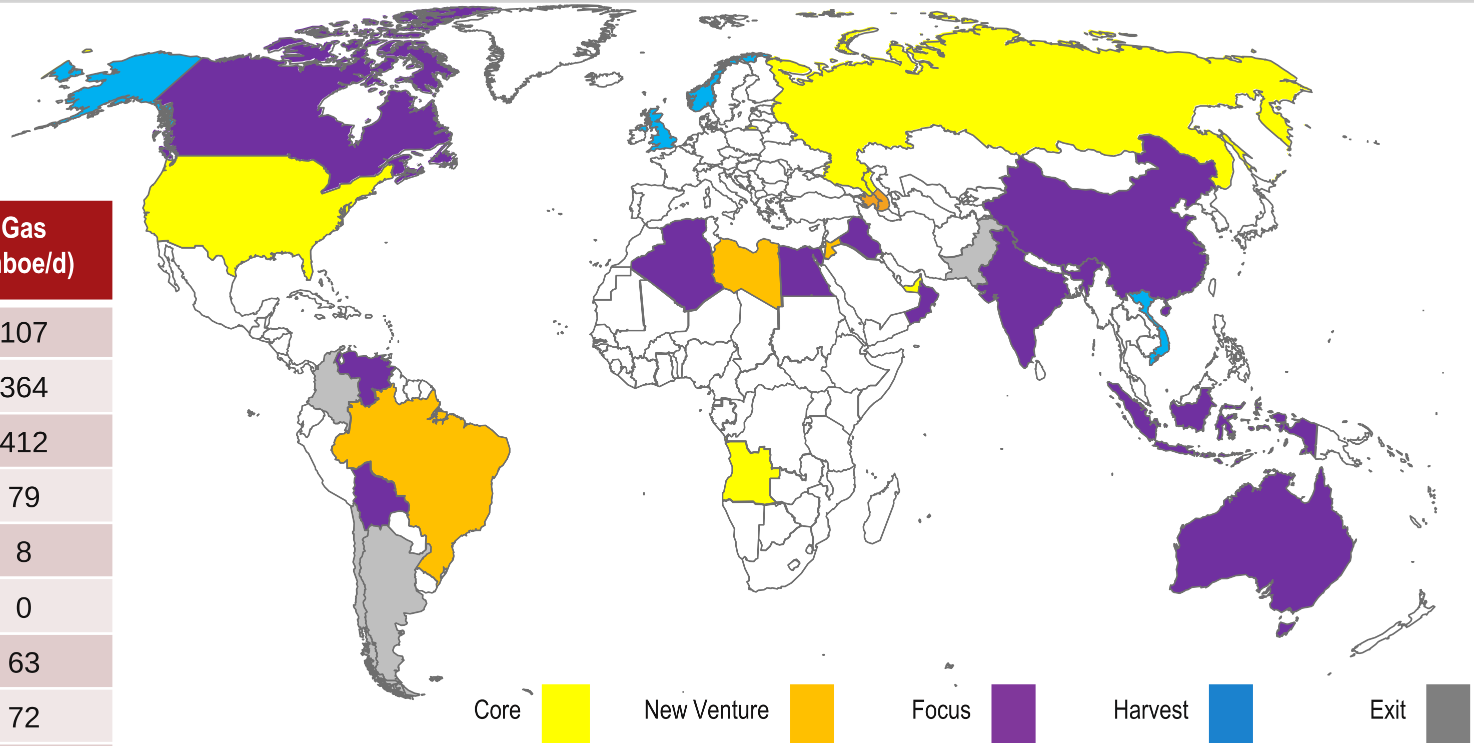
EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	LNG
✓	✓	✓	✓	✓	✓

Partnership History

Date	Partner	Region (or Country)	Type
2007	Husky	Canada	Sunrise Oil Sands
2008	Chesapeake	US	Unconventional
2009	CNPC	Iraq	Rumaila TSA
2011	Reliance	India	Offshore Gas

BP: Global Areas of Upstream Operations

	Liquids (mboe/d)	Gas (mboe/d)
Russia	856	107
US	594	364
T&T	36	412
UK	137	79
UAE	190	8
Angola	170	0
Argentina	75	63
Egypt	59	72
Azerbaijan	103	22
Australia	30	77
Indonesia	2	71
Norway	40	3
Canada	7	34
Algeria	17	21
Pakistan	10	25
Venezuela	23	2



	Liquids (mboe/d)	Gas (mboe/d)
China	0	16
Vietnam	0	13
Bolivia	0	2
Brazil	0	0
Chile	0	0

	Liquids (mboe/d)	Gas (mboe/d)
Iraq	0	0
Oman	0	0
Jordan	0	0
Libya	0	0
India	0	0

PFC Energy

BP Global Production Portfolio - 2010

Canada: modest conventional production, with future potential tied to oil sands

Russia: BP's largest producing country (963 mboe/d), representing ~26% of 2010 output. Substantial long term growth potential. Continued interest in Russia (and Arctic) expansion, despite limitations arising from the TNK-BP joint venture.

US: 2nd largest producing country, with core **deepwater** area. Activity slowed post-Macondo, yet expect strong future growth. **Onshore L48** is key gas area (~22% of 2010 global output), with focus on unconventionals. **Alaska** potential tied to commercialization of Prudhoe Bay resources.

UK: Declining position from mature offshore assets. High-value operating area, generating large cash flows.

Trinidad & Tobago: Core gas producing area tied to Atlantic LNG.

mboe/d

0
500
1,000
1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Azerbaijan: Participation in 2 large-scale projects: Azeri-Chirag-Guneshli & Shah Deniz.

UAE: Core position through equity affiliates, though concession are being re-negotiated

India: 2011 Partnership with Reliance for exploration in shallow and deepwater.

Australia and **Indonesia** are key gas producing areas tied to investments in LNG.

Argentina: onshore & shallow water assets (held by PAE) were to be sold to Bridas, but transaction failed in 4Q:11.

Angola: Sole presence in SSA is Angola deepwater. High growth from 2002-2009, now challenged with start-up of several unsanctioned projects

Iraq: Development of Rumailia oil field

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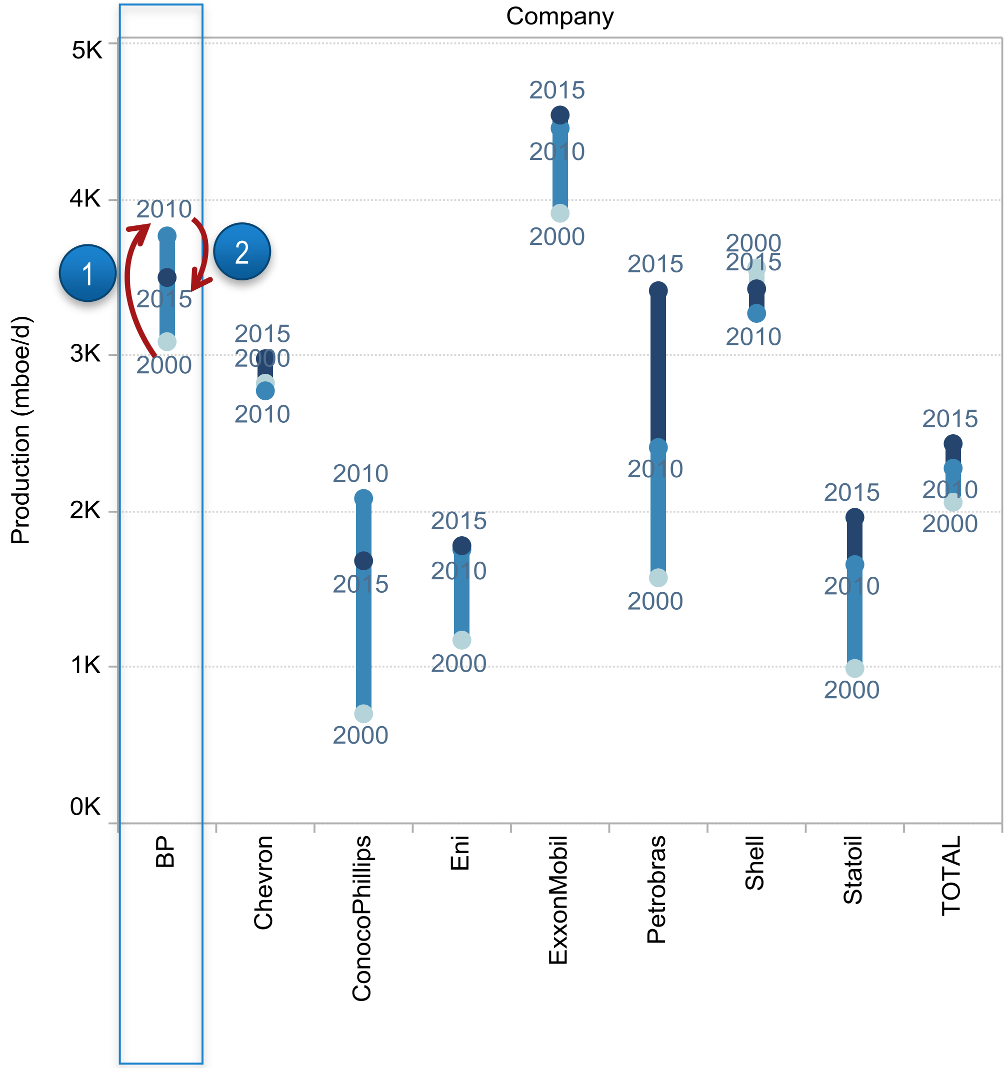
Total Portfolio Evolution: BP vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): BP and Peers



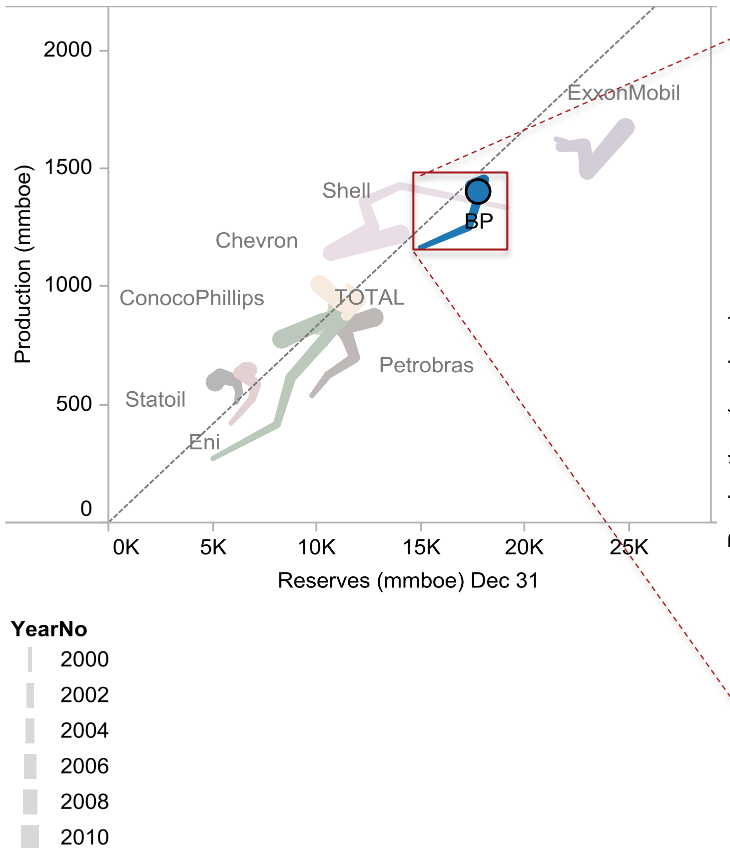
In 2010, BP was the second largest producer of the peer group. Yet, from 2010 to 2015, BP and COP are the only two companies to experience a reduction.

1. **2000-2010:** Production increases from ~3,080 mboe/d to ~3,780 mboe/d due to addition of Russia (~960 mboe/d), Trinidad & Tobago (~250 mboe/d) and Angola (~170 mboe/d). This expansion offsets declines from Europe (~660 mboe/d and North America ~350 mboe/d) .

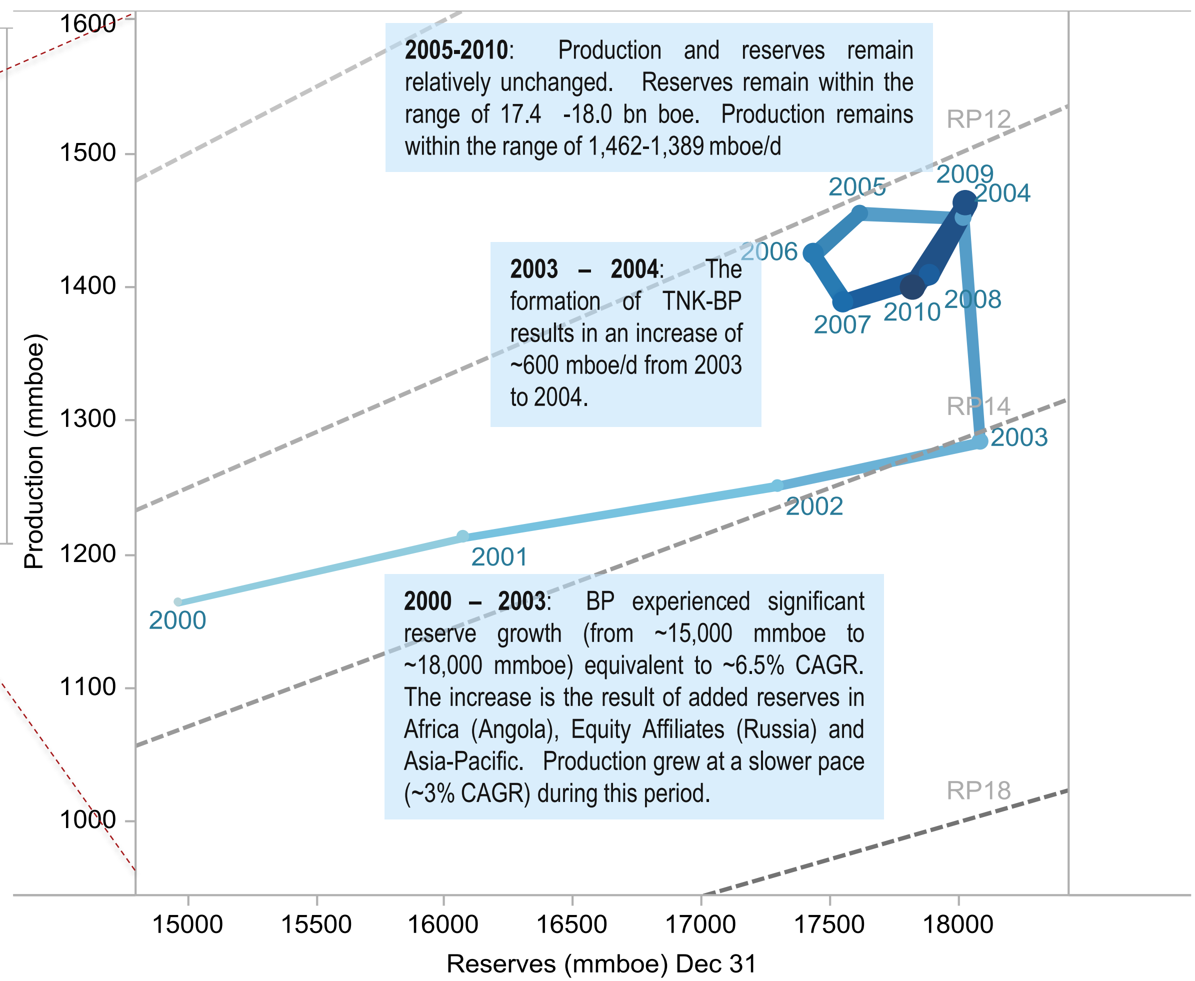
2. **2011-2015:** BP's production is expected to decline from 2000-2015, due mostly to the post-Macondo asset divestiture program, combined with curbed activity in the GOM deepwater.

PFC Energy

Reserves and Production: BP vis-à-vis the Competition



Reserves and Production (mmboe) 2000-2010: BP and Peers



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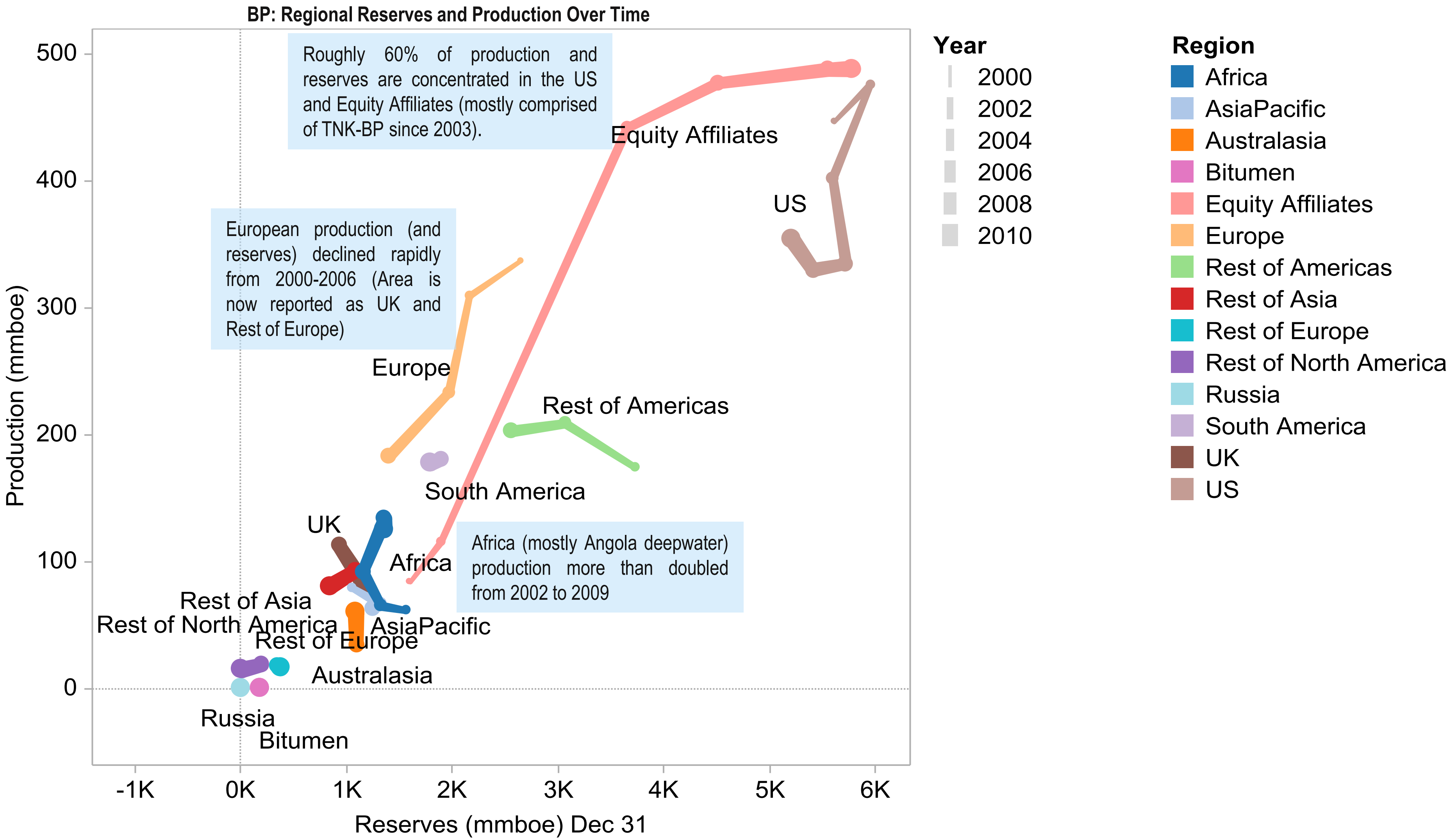
Reserves and Production: BP Intra-Portfolio Performance



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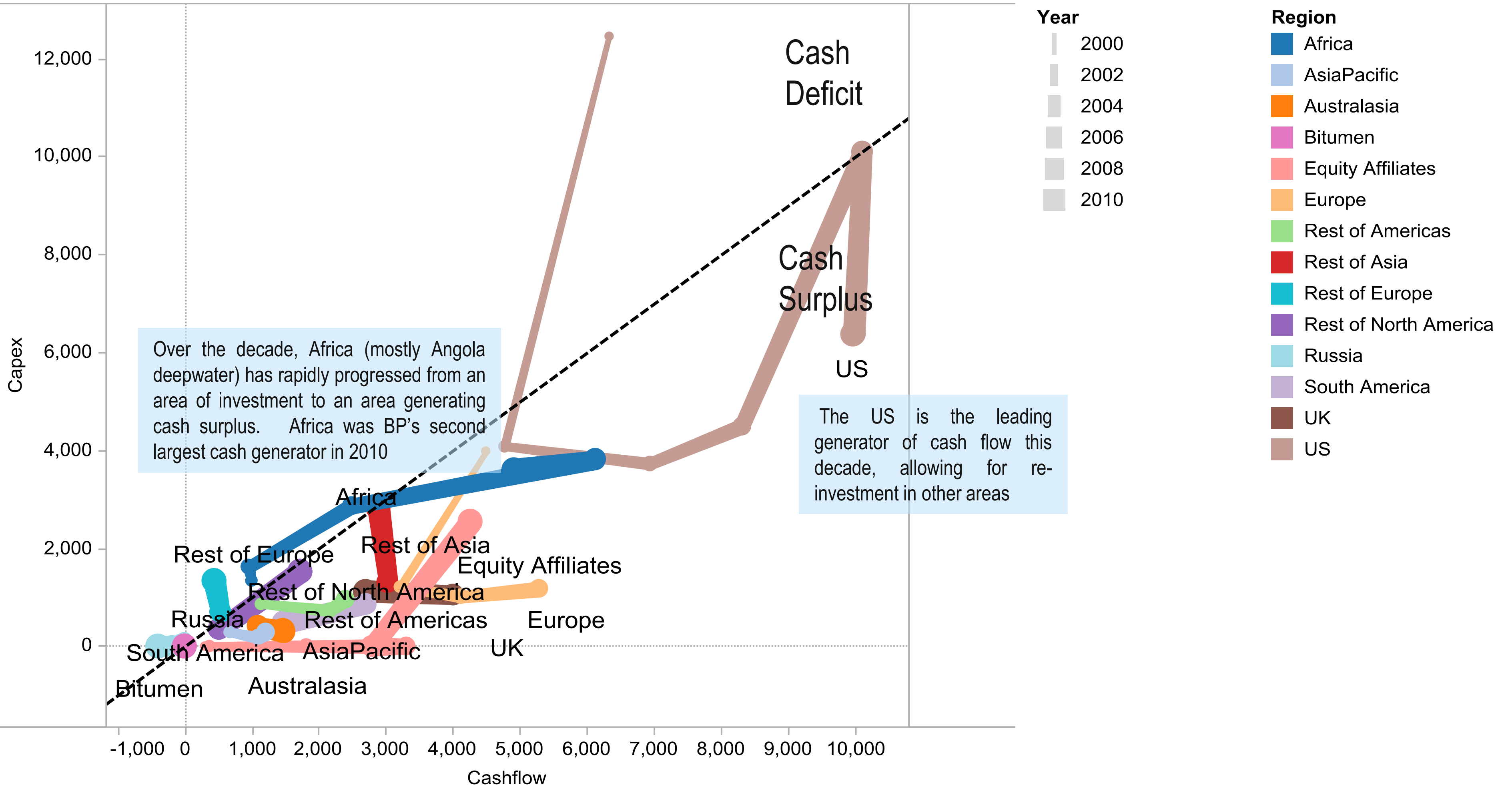
How the Portfolio is Financed: Sources and Uses of Cash

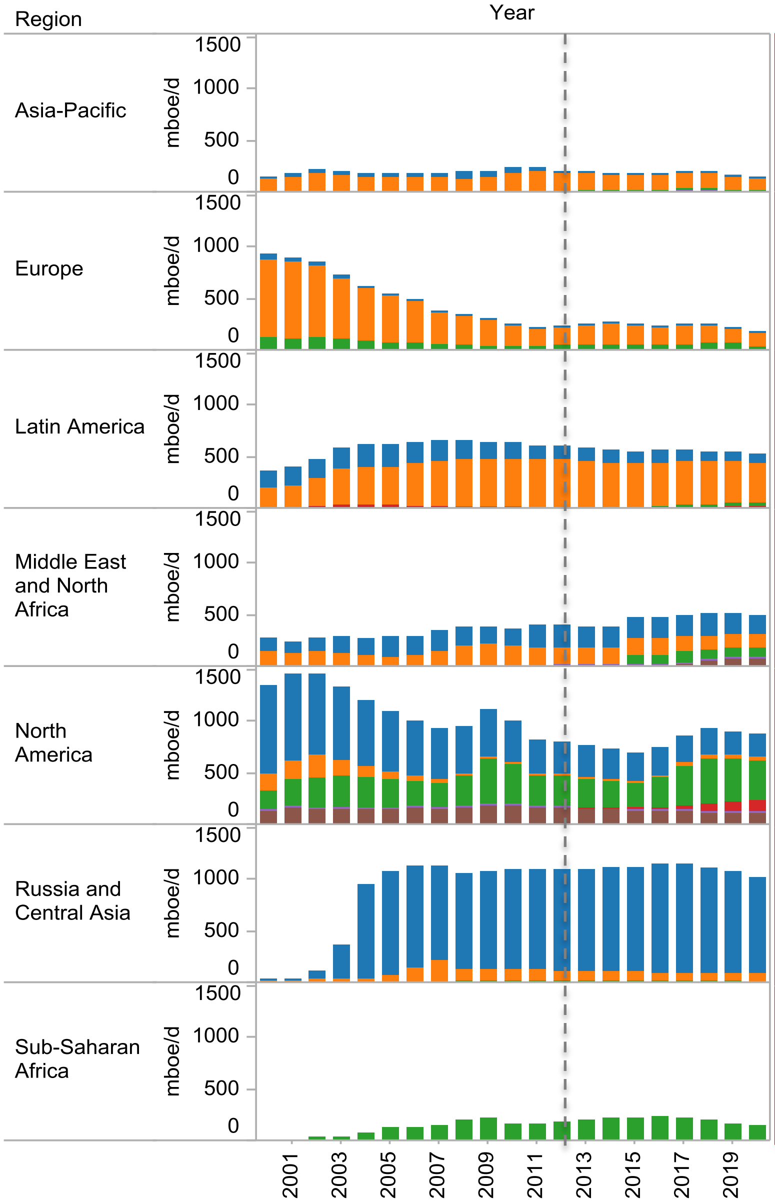


Over the decade, Africa (mostly Angola deepwater) has rapidly progressed from an area of investment to an area generating cash surplus. Africa was BP's second largest cash generator in 2010

The US is the leading generator of cash flow this decade, allowing for re-investment in other areas

PFC Energy

Global Production: Evolution of the Portfolio



Asia Pacific: Relatively small producing area (~6% of 2010 output). Production largely from offshore Australia and Indonesia with lesser volumes from China. Partnership with Reliance (India) creates exploration opportunities. Focus on deepwater and CBM. Divested assets in Pakistan and farmed down in Vietnam.

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Exploration and development projects are ongoing, often leveraging BP's existing infrastructure and assets in the region.

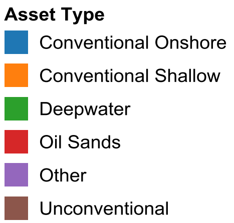
Latin America: Growth driven by shallow water gas developments in Trinidad & Tobago. Focus on onshore gas commercialization in Bolivia. Failed to sell Argentine assets (held through PAE) to Bridas in 2011. Brazil deepwater offers mid- to long-term potential from newly acquired deepwater acreage.

Middle East & North Africa: Position built from collaboration with NOCs (Adma-Opco, GUPCO, Sonatrach, LNOC, etc.). Substantial new source growth expected from Iraq, Egypt deepwater, offshore Oman. Exploration opportunities in Jordan.

North America: Second largest production region & largest cash flow generator. Deepwater GOM holds significant growth potential after years of investment. US L48 portfolio is material, yet declining, source of gas, with a growing emphasis on shale gas. Additional future growth from Canadian oil sands.

Russia & Central Asia: Principally comprised of TNK-BP venture created in 2003, now BP's largest source of production, characterized as long-life, slow decline output. In Azerbaijan, production is from large-scale ACG and Shah-Deniz. The Region is the largest source of new source volumes through 2015.

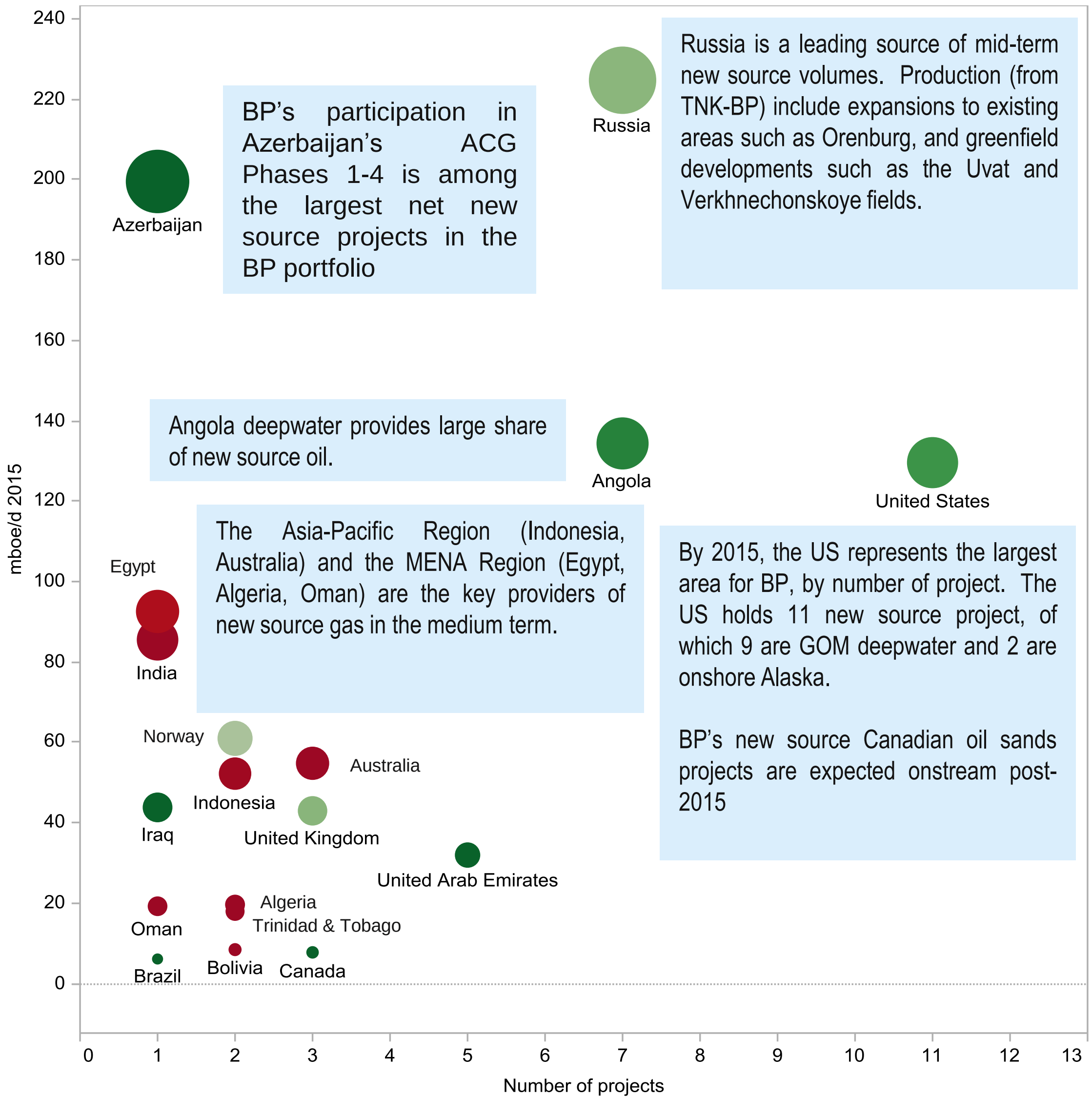
Sub-Saharan Africa: Operates only in the Angola deepwater play, which quickly emerged as a key oil-producing country. BP has collaborated with operators TOTAL (Block 17) and Chevron (Block 15). In the future, development of BP-operated blocks 31 and 18 is expected to reverse the recent decline in production.

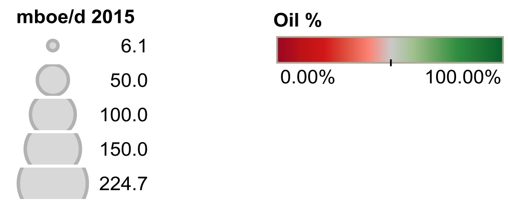


PFC Energy

Global Production:
Country Growth Project Analysis

BP: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split





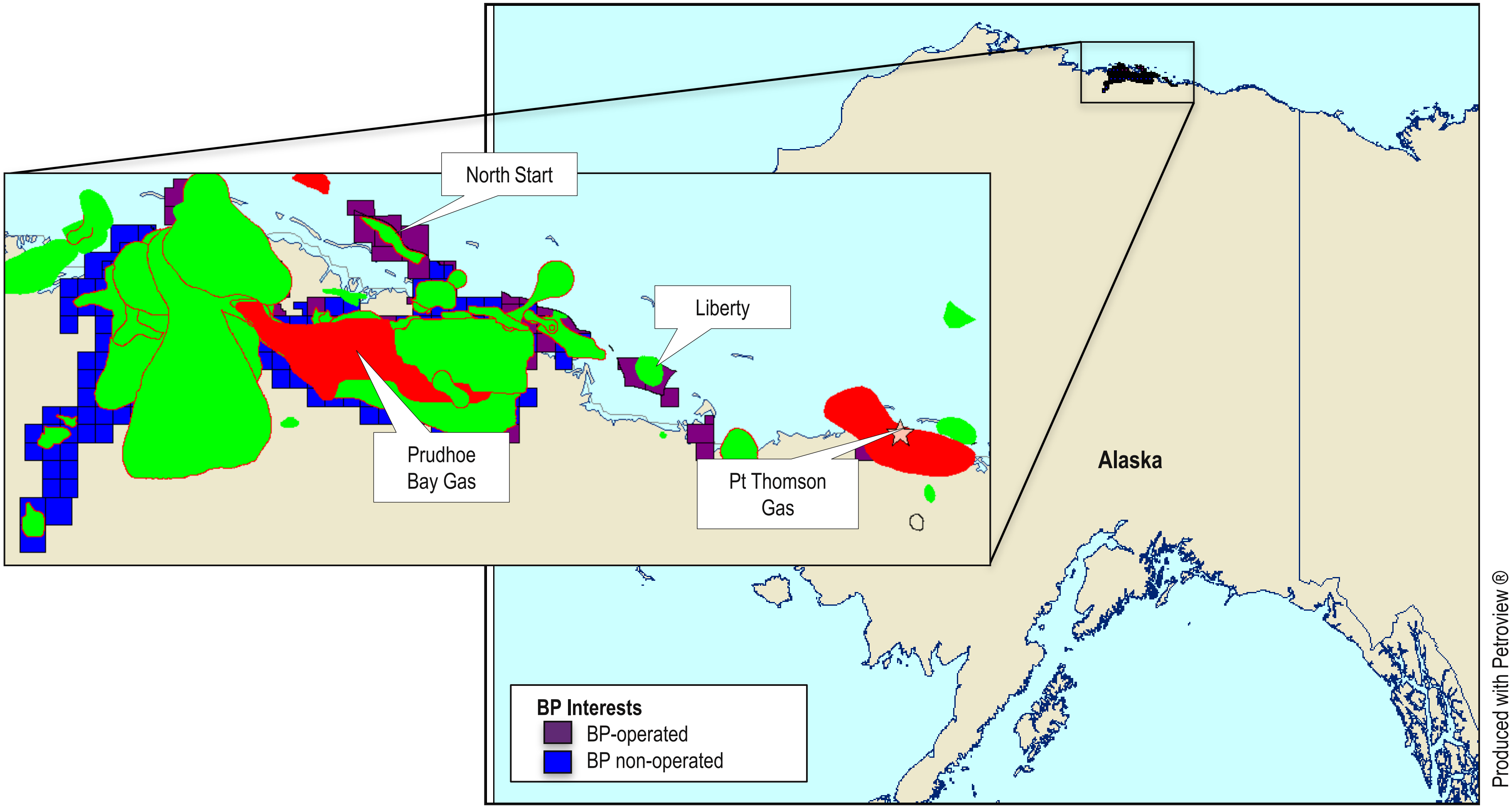
BP's new source portfolio is driven by (1) Deepwater projects (Angola and US GOM); and (2) Russia (mostly onshore oil).

The Asia-Pacific remains a mostly gas-production area.

Unconventional (Asia-Pacific and North America) and oil sands (Canada) projects are largely immaterial until 2020 or so.

PFC Energy

BP in Alaska



PFC Energy

BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• Most of BP's assets are located on the **North Slope**, where production volumes have generally declined because of the maturity of the asset base and/or gas infrastructure constraints. Liquid production has declined from ~224 mboe/d in 2006 to ~166 mboe/d in 2010, while gas production has fallen from ~67 mmcf/d to ~46 mmcf/d over the same period. • BP's largest source of production is the **Greater Prudhoe Area** (26% w.i., operated), covering ~150,000 acres with more than 1,000 active wells. Gas resources are currently stranded because of the lack of pipeline capacity to southern markets. BP and ConocoPhillips had teamed up to propose a new natural gas pipeline (**Denali**) to run from Prudhoe Bay through western Canada to US markets. However, in May 2011, the partners announced that plans for the pipeline had been terminated, citing the lack of long-term purchase contracts. The proposed pipeline would have accommodated 4 bcf/d of natural gas. • BP and partners are moving forward with the development of gas liquids on the ~8 tcf **Point Thomson** field (32% w.i., non-operator). The gas cycling project is expected to produce ~10 mb/d of liquids; first production is targeted for 2014. Full field development awaits gas transport infrastructure. • In the **Beaufort Sea**, BP has suspended work on the extended-reach drilling program on the **Liberty** oil field (100% w.i.), pending revision of project design and schedule. • BP is also seeking to develop viscous (**Kuparuk**) and heavy (**Milne**) oil resources on the North Slope.	**Current production volumes are modest and declining, yet significant potential lies in the long-term commercialization of Prudhoe Bay and Point Thomson gas resources. Cancellation of the Denali gas pipeline proposal leaves BP as a potential supplier to an alternative pipeline-export option, should one be approved and developed.**

PFC Energy

PFC-Identified Challenges

- Re-establish its operator profile in the global deepwater: While its competitors extend their commitments to global LNG, unconventional shale gas exploitation, and oil sands development in order to drive future portfolio growth, BP has deepened its commitment to the global deepwater play, despite the ongoing fallout from the Macondo oil spill. Expansion of its US GOM lease holdings (through the Devon portfolio acquisition), entry into the Brazil deepwater, and a material commitment to the K-G Basin deepwater play in India, together with phased field development offshore Angola and West Nile Delta in Egypt, positions BP as arguably the premier deepwater player in the Global Player peer group. BP will be under the spotlight regarding its future conduct and performance throughout the global deepwater basins.
- Resolve shareholder relationship issues within the TNK-BP JV: Accounting for ~26% of total worldwide production in 2010 (and ~36% of total worldwide oil production), the TNK-BP position is absolutely core to the BP portfolio from a volumetric perspective. However, the unsuccessful attempt to partner with Rosneft in the Russia Arctic raises concern over how much value TNK-BP can continue to create for BP. With TNK-BP now focused on international expansion, must BP settle for lower returns from what has until now been a highly lucrative position?
- Complete the portfolio rationalization process: The strength of the global asset transactions market prompted BP to expand its divestiture program from an initial $20 bn to $30 bn, divesting large swaths of its portfolio deemed non-Core and/or non-aligned with the company's growth focus. While the company did not plan on the depth of portfolio rationalization undertaken to date, this is a rare opportunity to high-grade asset holdings with the blessing of shareholders and analysts alike. BP is expecting to complete the divestiture process by end-2011.
- Determine a path forward in the Brazil deepwater: Having secured Brazil government approval to acquire the Devon asset portfolio, BP has established a foothold in the Brazil deepwater, with potentially the largest operated pre-salt portfolio outside Petrobras. The next step is to determine the appropriate approach to growth in the pre-salt play. With legislation now in place granting NOC Petrobras a minimum 30% w.i. and operatorship in all unlicensed pre-salt acreage, this may be another case of executing a strategic alliance (similar to that secured with Reliance in India and proposed with Rosneft in the Russia Arctic).
- Accelerate development of US Onshore unconventional gas resource: BP received a very competitive price for the Permian Basin and Western Canada conventional gas assets sold to Apache (totaling ~75 mboe/d of production and ~340 mmboe of reserves, equivalent to ~$24.60/boe of reserves in the ground or ~$109,000/flowing boe of production). This is particularly so given what is shaping up to be an extended period of gas price weakness in the North America market. To make up for lost volumes, BP may look to accelerate production from its ~10 tcf of reserves in the Woodford, Fayetteville, Haynesville, and Eagle Ford shale gas plays.
- Accelerate development of BP's oil sands leases: BP has built up a material oil sands lease portfolio in Western Canada, including 50% w.i. in the Sunrise in situ development project (sanctioned in November 2010), a 75% w.i. in the Terre de Grace in situ project (secured in March 2010 from Value Creation for ~$900 mn), and 50% w.i. in the Kirby in situ oil sands leases (with the other 50% divested to Devon in March 2010). Full development of these projects could represent 500-600 mbo/d of stable, long-life oil production, complementing the "Giant Oil Fields" growth platform and providing a portfolio buffer against the steep decline production profiles associated with deepwater developments.

PFC Energy

ConocoPhillips: Company Overview

Strategic Signature

- Following two years of corporate net income losses, steep decline in its share price, and a persistently high debt-to-capital ratio, in March 2010 ConocoPhillips announced a new strategic pathway, directing proceeds from a ~$15 bn asset and joint venture divestment program to reduce its debt-to-capital position, increase near-term shareholder returns, shift further out of the downstream, and position the company for future growth from a smaller but higher-value portfolio position.
- Since the announcement of the 2010-2012 Restructuring Plan, ConocoPhillips has executed on ~$7 bn in asset sales, divested its entire 20% equity interest in LUKOIL, and directed proceeds from these sales to debt reduction and share repurchase. In July 2011, ConocoPhillips announced the next step in its restructuring: the creation of two separate corporate entities, Downstream and a pure play, E&P.
- With production in 15 countries and upstream operations in an additional 7 countries, ConocoPhillips' most recent guidance suggests production reaching a low of ~1.5 mmboe/d in 2012, recovering to 1.64-1.69 mmboe/d by 2015. The company will rely on a large, diversified upstream portfolio positioned heavily in OECD countries (namely the US, Canada, Australia, UK, and Norway, which accounted for ~72% of worldwide production in 2010).
- Growth of 0.5% per annum from 2012 through 2015 is forecast to come from Global Gas/LNG, SAGD Oil Sands, and Unconventional developments. However, as ConocoPhillips now stands to compete with the Independent, non-integrated oil & gas companies, the company's future strategy remains uncertain.

Company Overview

- **HQ:** Houston, TX
- **Employees:** 29,600
- **2010 Reserves:** 8,310 mmboe
- **2010 Production:** 2,078 mboe/d
- **3 Yr Production Growth:** -3.7% CAGR (2007-2010)
- **Nov 2011 Market Cap:** $96.1 bn
- **Nov 2011 P/E Ratio:** 9.27
- **2010 Corp Revenue:** $189 bn
- **2011 Upstream Capex (Est.):** $12 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✔	✔		✔	✔	

Partnership History

Date	Partner	Region (or Country)	Type
2003	LUKOIL	Russia	Various
2006	Cenovus	Canada	Oil Sands
2008	Origin Energy	Australia	LNG

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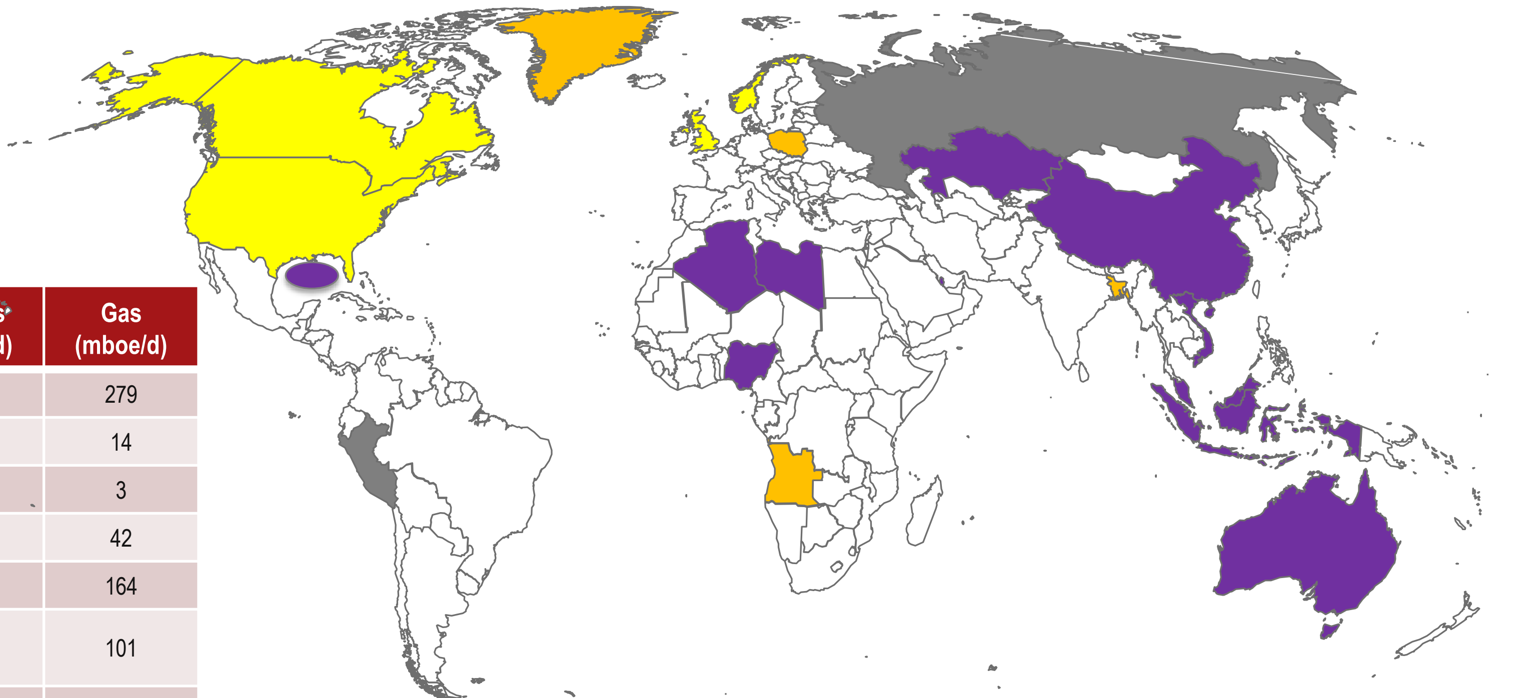
ConocoPhillips: Global Areas of Upstream Operations



Country	Liquids (mboe/d)	Gas (mboe/d)
USA L48	142	279
USA Alaska	230	14
USA GOM	18	3
Russia	336	42
Canada	109	164
United Kingdom	74	101
Norway	137	35
Indonesia	17	232
Australia/ Timor Sea	31	58
China	68	0
Libya	46	1
Nigeria	20	24
Vietnam	24	2
Algeria	13	0
Qatar	3	9

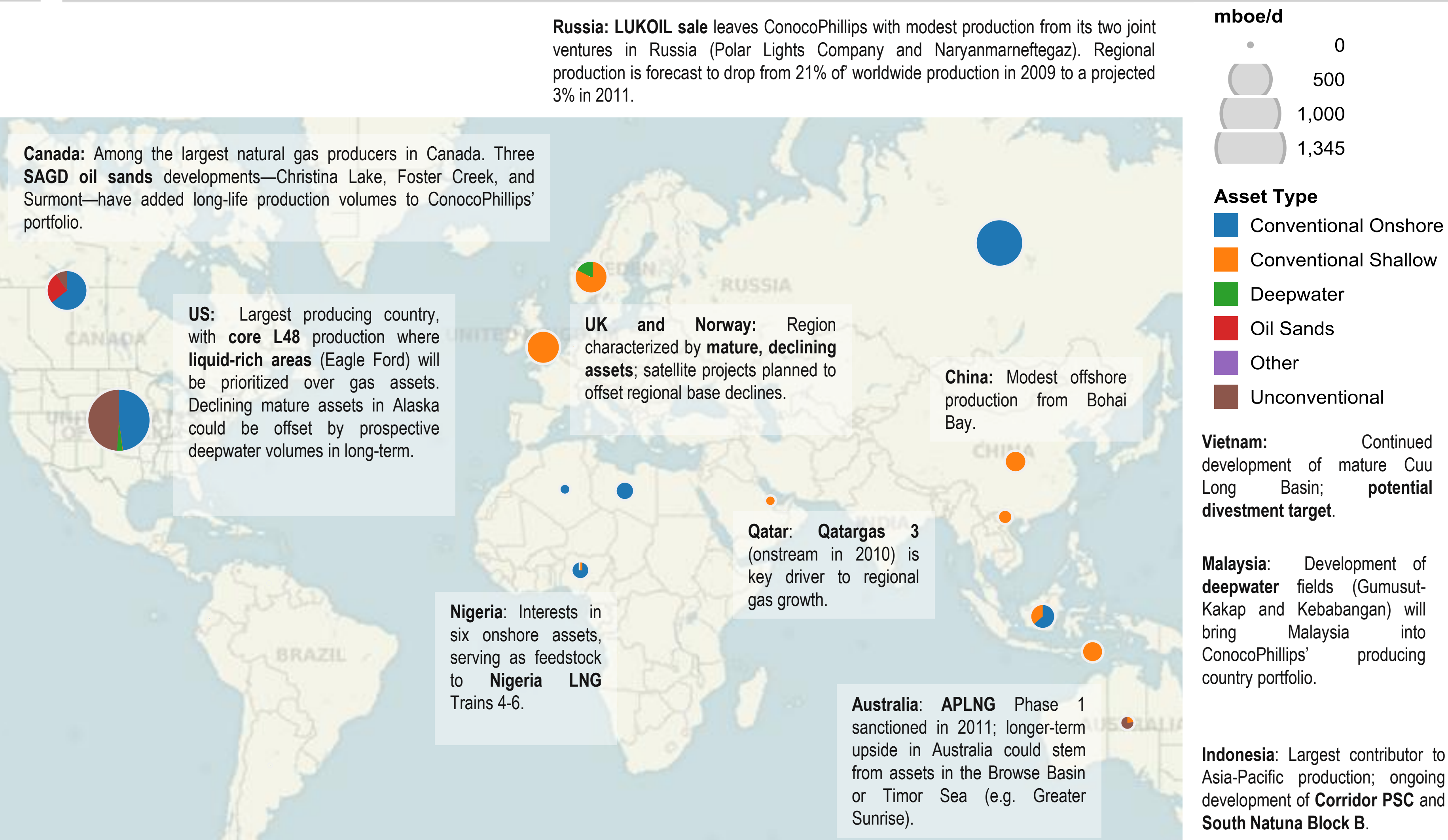
Country	Liquids (mboe/d)	Gas (mboe/d)
Angola	0	0
Bangladesh	0	0
Brunei	0	0
Greenland	0	0
Kazakhstan	0	0
Malaysia	0	0
Poland	0	0
Peru	0	0

Core
New Venture
Focus
Harvest
Exit

PFC Energy

ConocoPhillips Global Production Portfolio - 2010

Russia: LUKOIL sale leaves ConocoPhillips with modest production from its two joint ventures in Russia (Polar Lights Company and Naryanmarneftegaz). Regional production is forecast to drop from 21% of' worldwide production in 2009 to a projected 3% in 2011.



Canada: Among the largest natural gas producers in Canada. Three **SAGD oil sands** developments—Christina Lake, Foster Creek, and Surmont—have added long-life production volumes to ConocoPhillips' portfolio.

US: Largest producing country, with **core L48** production where **liquid-rich areas** (Eagle Ford) will be prioritized over gas assets. Declining mature assets in Alaska could be offset by prospective deepwater volumes in long-term.

UK and Norway: Region characterized by **mature, declining assets**; satellite projects planned to offset regional base declines.

China: Modest offshore production from Bohai Bay.

Vietnam: Continued development of mature Cuu Long Basin; **potential divestment target**.

Qatar: **Qatargas 3** (onstream in 2010) is key driver to regional gas growth.

Nigeria: Interests in six onshore assets, serving as feedstock to **Nigeria LNG** Trains 4-6.

Malaysia: Development of **deepwater** fields (Gumusut-Kakap and Kebabangan) will bring Malaysia into ConocoPhillips' producing country portfolio.

Australia: **APLNG** Phase 1 sanctioned in 2011; longer-term upside in Australia could stem from assets in the Browse Basin or Timor Sea (e.g. Greater Sunrise).

Indonesia: Largest contributor to Asia-Pacific production; ongoing development of **Corridor PSC** and **South Natuna Block B**.

Algeria: Onshore oil field production; additional volumes from El Merk (EMK) expected for 2012 start-up.

Libya: Legacy onshore Waha concession; above ground conflict will delay new source oil projects.

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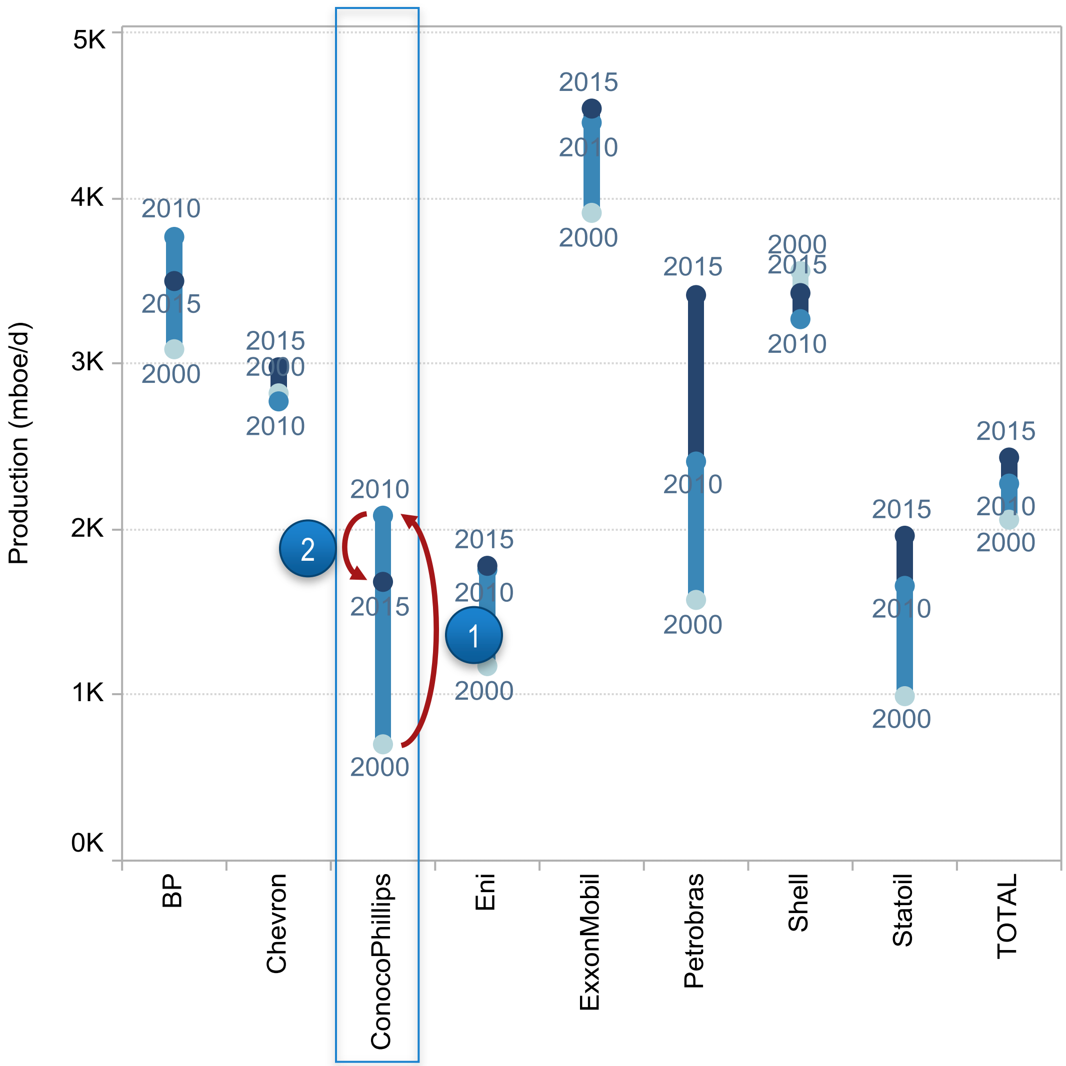
Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition



ConocoPhillips' 2010-2012 Restructuring Plan will see the company become the largest of the Independent, non-integrated international oil & gas companies, compared to its former position as the third-smallest of PFC Energy's expanded Global Player peer group.

1. **2000-2010:** Production increases largely driven by the merger of Conoco and Phillips in the beginning of the decade (growing volumes from 698 mboe/d in 2000 to 1,082 mboe/d in 2002) and the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006). The gradual acquisition of a 20% stake in LUKOIL was a key driver to mid-decade growth.

2. **2011-2015:** ConocoPhillips's production is expected to decline from 2010-2015, due to the company's intensive asset divestiture program (the initial ~$15 bn asset and joint venture divestment program was expanded in 2011 when ConocoPhillips announced it would shed an additional $5 bn-$10 bn in non-Core assets by end-2012). Volumes are forecast to decline from ~2,078 mboe/d in 2010 to ~1,674 mboe/d in 2015.

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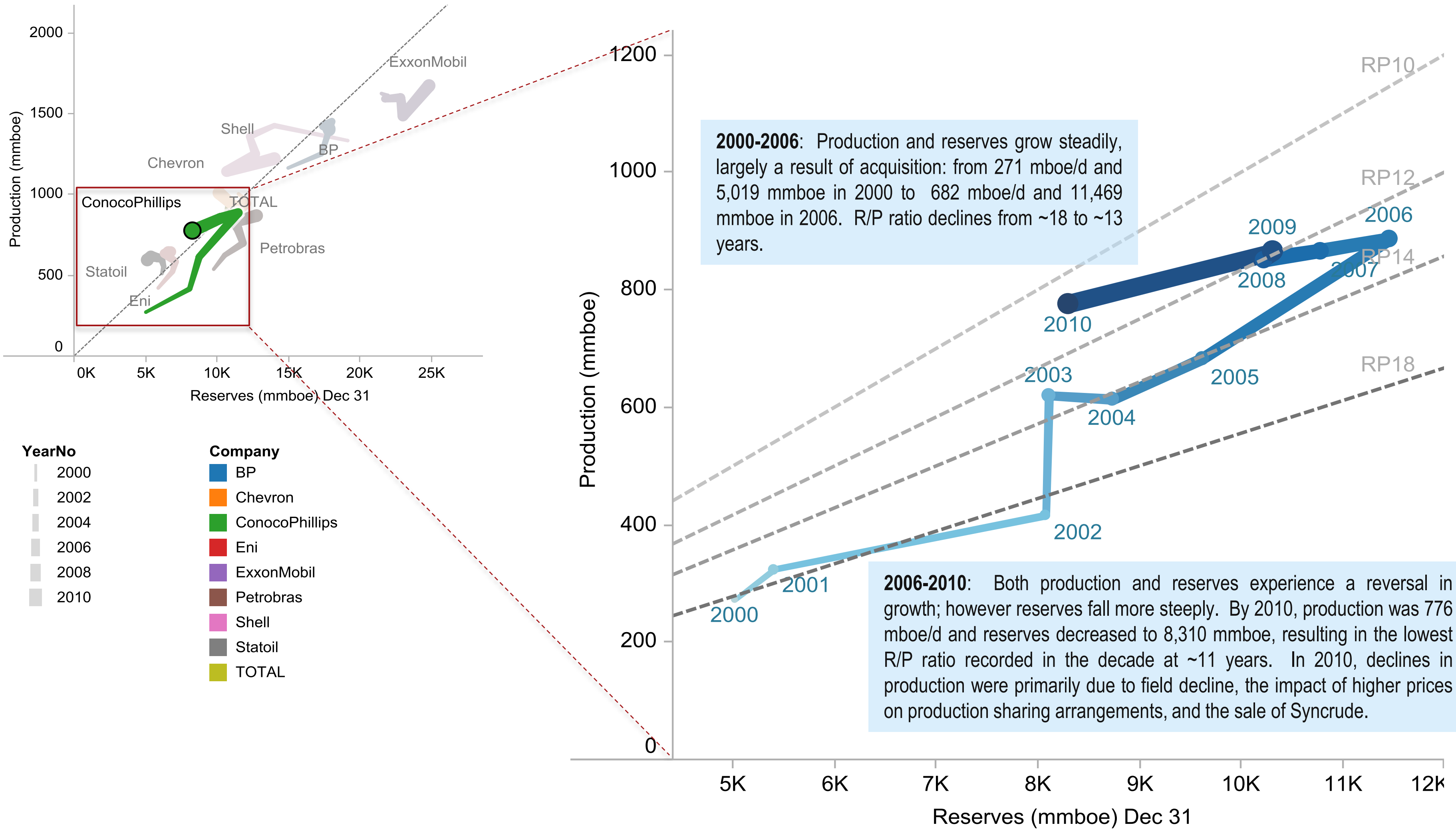
Reserves and Production: ConocoPhillips vis-à-vis the Competition

Reserves and Production (mmboe) 2000-2010: ConocoPhillips and Peers



2000-2006: Production and reserves grow steadily, largely a result of acquisition: from 271 mboe/d and 5,019 mmboe in 2000 to 682 mboe/d and 11,469 mmboe in 2006. R/P ratio declines from ~18 to ~13 years.

2006-2010: Both production and reserves experience a reversal in growth; however reserves fall more steeply. By 2010, production was 776 mboe/d and reserves decreased to 8,310 mmboe, resulting in the lowest R/P ratio recorded in the decade at ~11 years. In 2010, declines in production were primarily due to field decline, the impact of higher prices on production sharing arrangements, and the sale of Syncrude.

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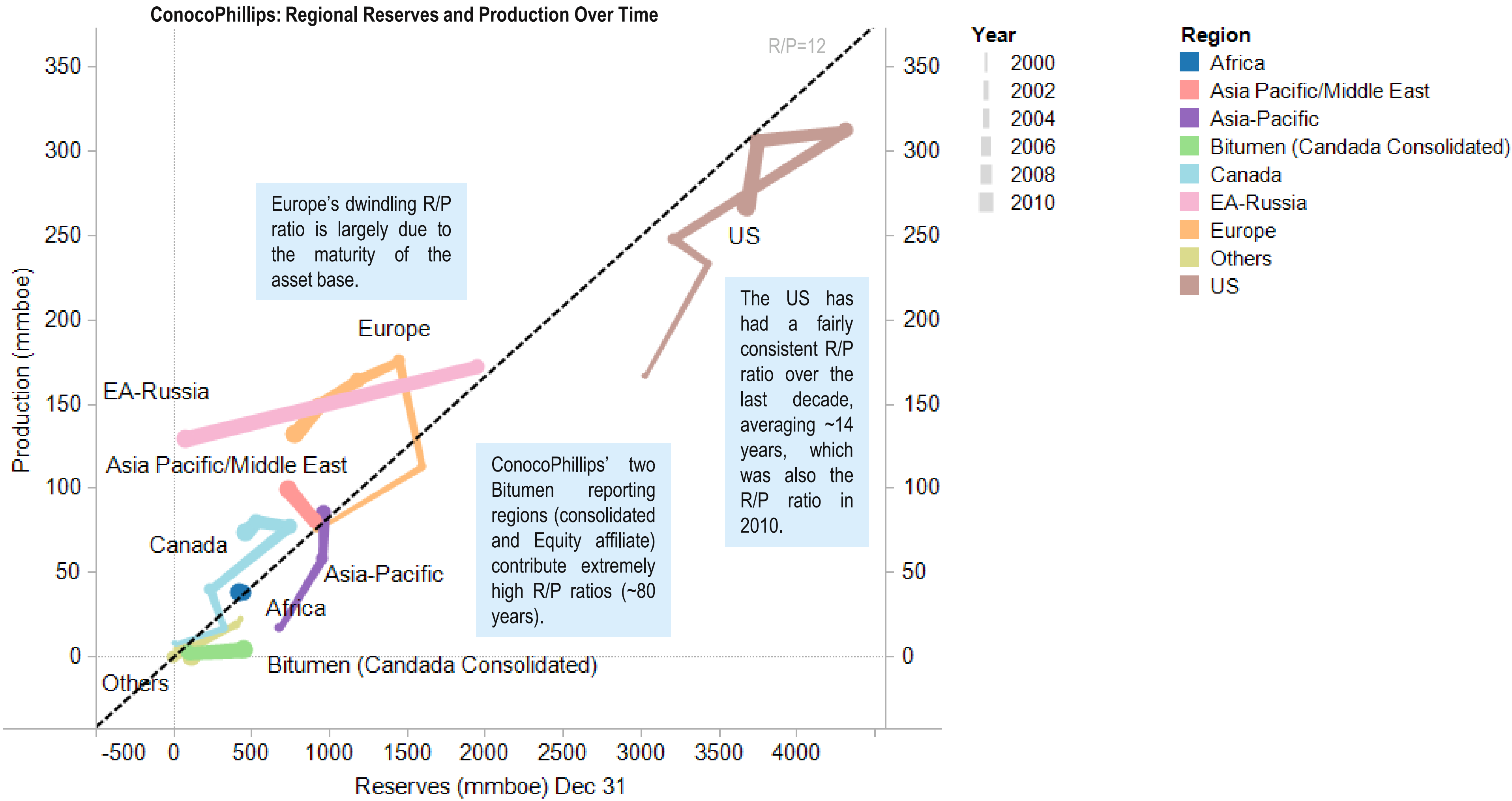
Reserves and Production: ConocoPhillips Intra-Portfolio Performance



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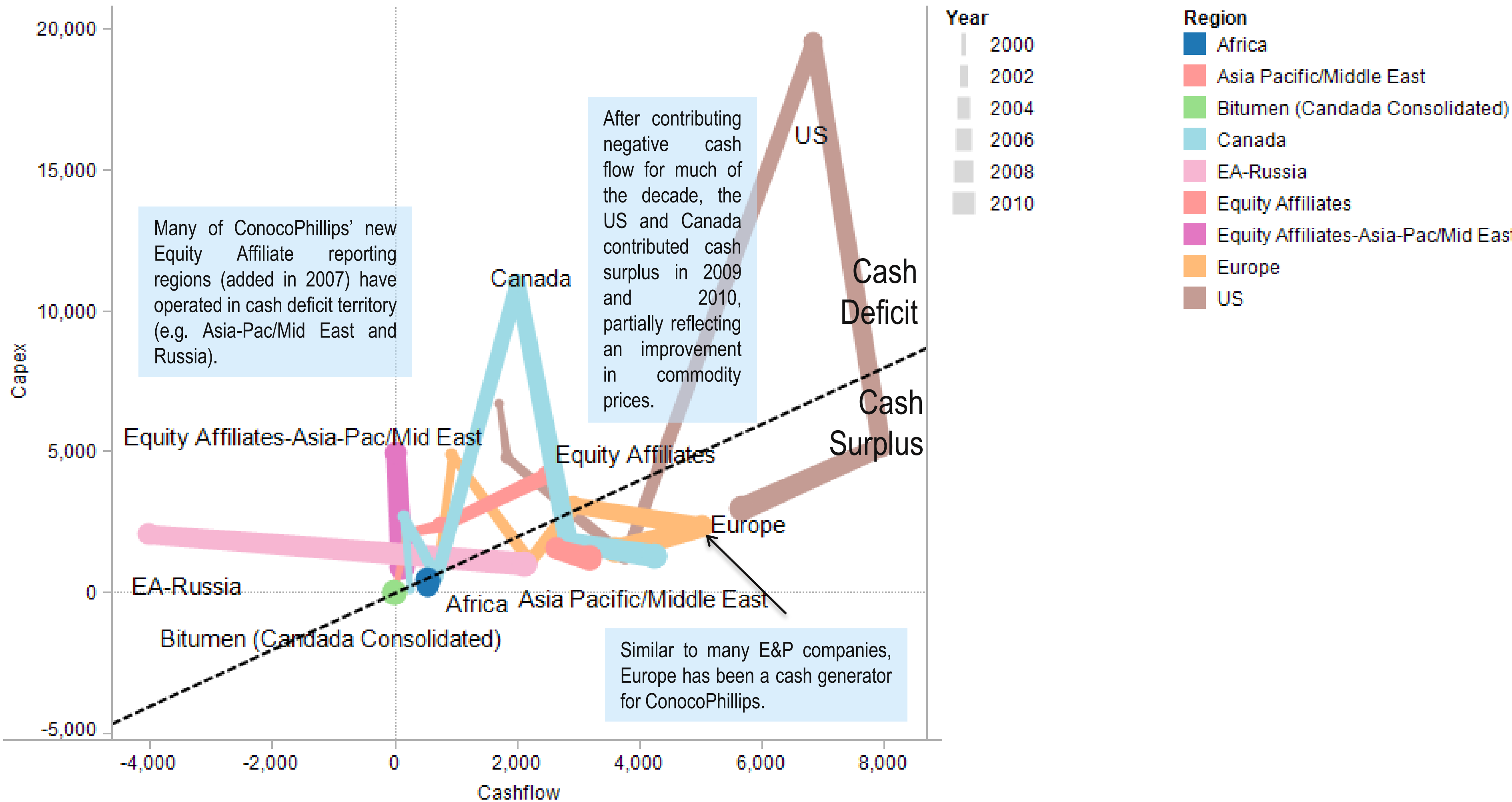
How the Portfolio is Financed: Sources and Uses of Cash



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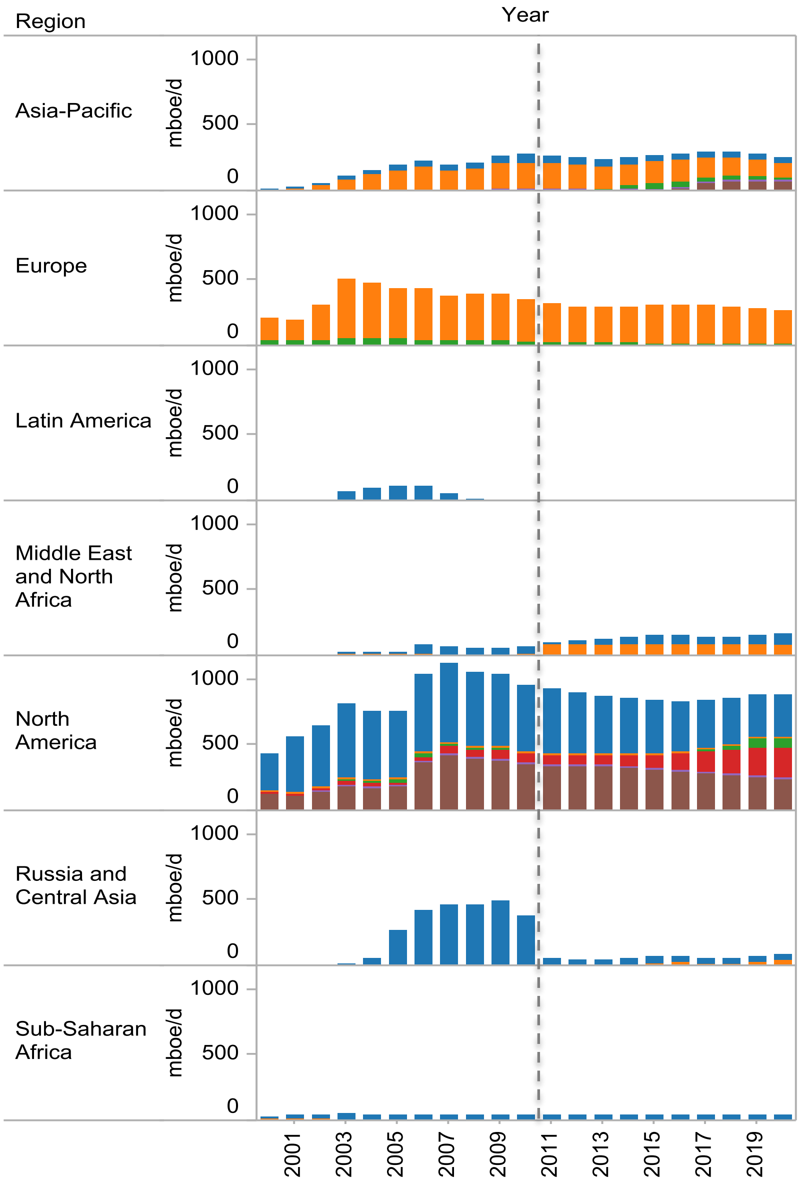
Global Production: Evolution of the Portfolio



Asia Pacific: Project queue 14 projects deep makes Asia-Pacific the largest development pipeline in all of ConocoPhillips' portfolio. Region estimated to occupy 20% of 2011 upstream capex. New projects in both legacy countries (Indonesia, Vietnam) are being complimented by start ups in Malaysia (Gumusut-Kekap, Kebabangan) and Australia (APLNG).

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Satellite projects poised to somewhat offset base declines.

Latin America: After reaching historic peak production in 2005, volumes fell to zero in 2009. The Latin America portfolio, largely acquired through the Burlington transaction, has never been a material part of ConocoPhillips' global operations. With no new volumes anticipated in the portfolio, a complete exit from the region could be likely.

Middle East & North Africa: Future growth is largely tied to the Qatargas 3 LNG project and El Merk (EMK) in Algeria. Longer-term growth is poised to stem from Libya (as yet unsanctioned joint NC 98 and North Gialo developments) assuming a timely re-commencement of upstream activities.

North America: Largest production region & cash flow generator. New growth initiatives focus on exploitation of Eagle Ford shale liquids and Canadian oil sands (Christina Lake, Foster Creek, and Surmont), which are projected to reverse the decline in Canadian production by 2014 and deliver medium- and long-term volume growth.

Russia & Central Asia: LUKOIL sale leaves ConocoPhillips with only modest production from its two joint ventures in Russia and few growth opportunities within the remaining portfolio. The sole growth asset is an 8.4% stake in the Kashagan field, which continues to face major challenges.

Sub-Saharan Africa: Onshore assets serve as feedstock to Nigeria LNG Trains 4-6. Longer-term upside tied to feedstock for the yet-to-be-sanctioned Brass LNG plant, while 2011 re-positioning in Angola could provide exploration opportunities critical to securing new source ventures for long-term growth.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

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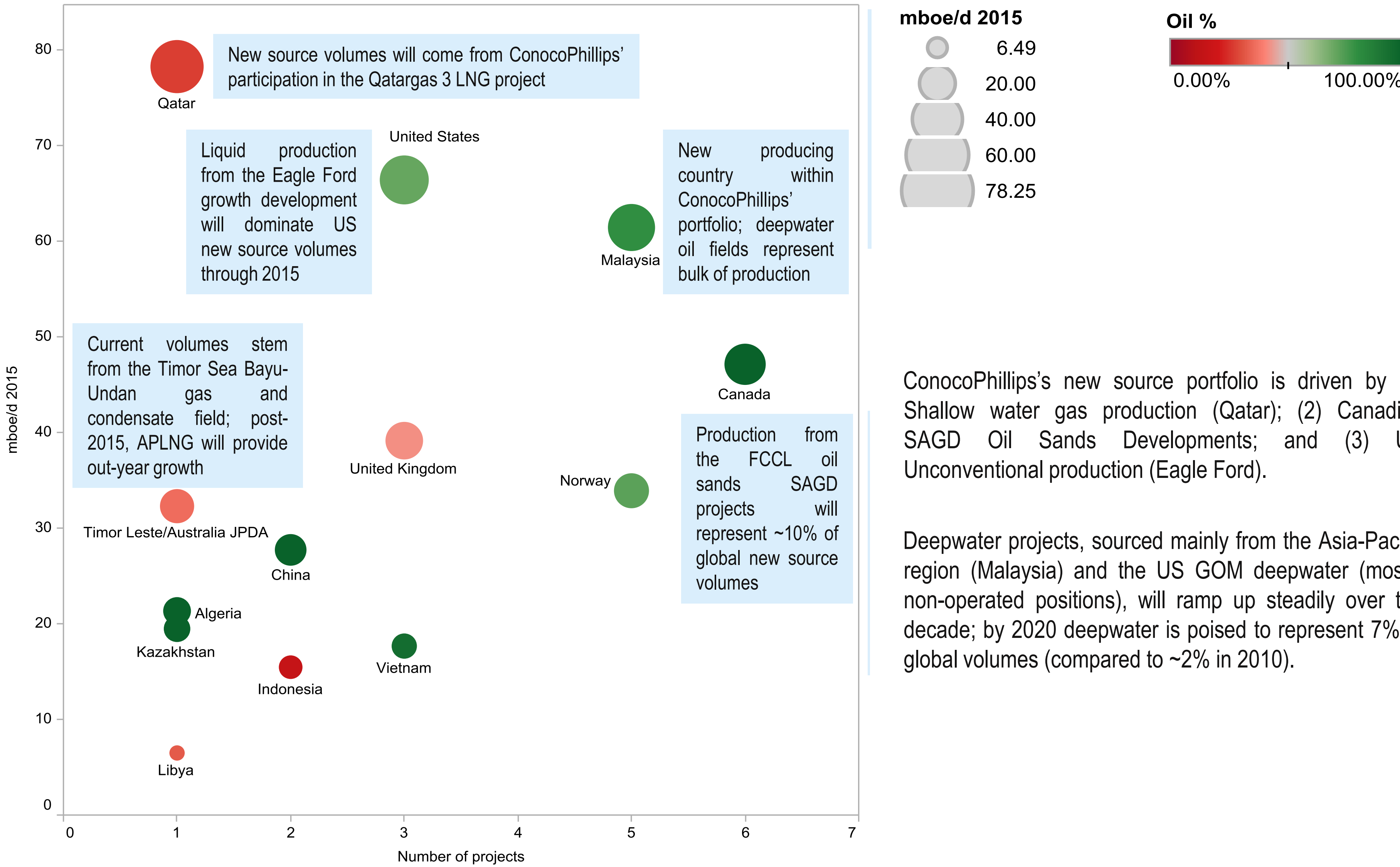
Global Production:
Country Growth Project Analysis

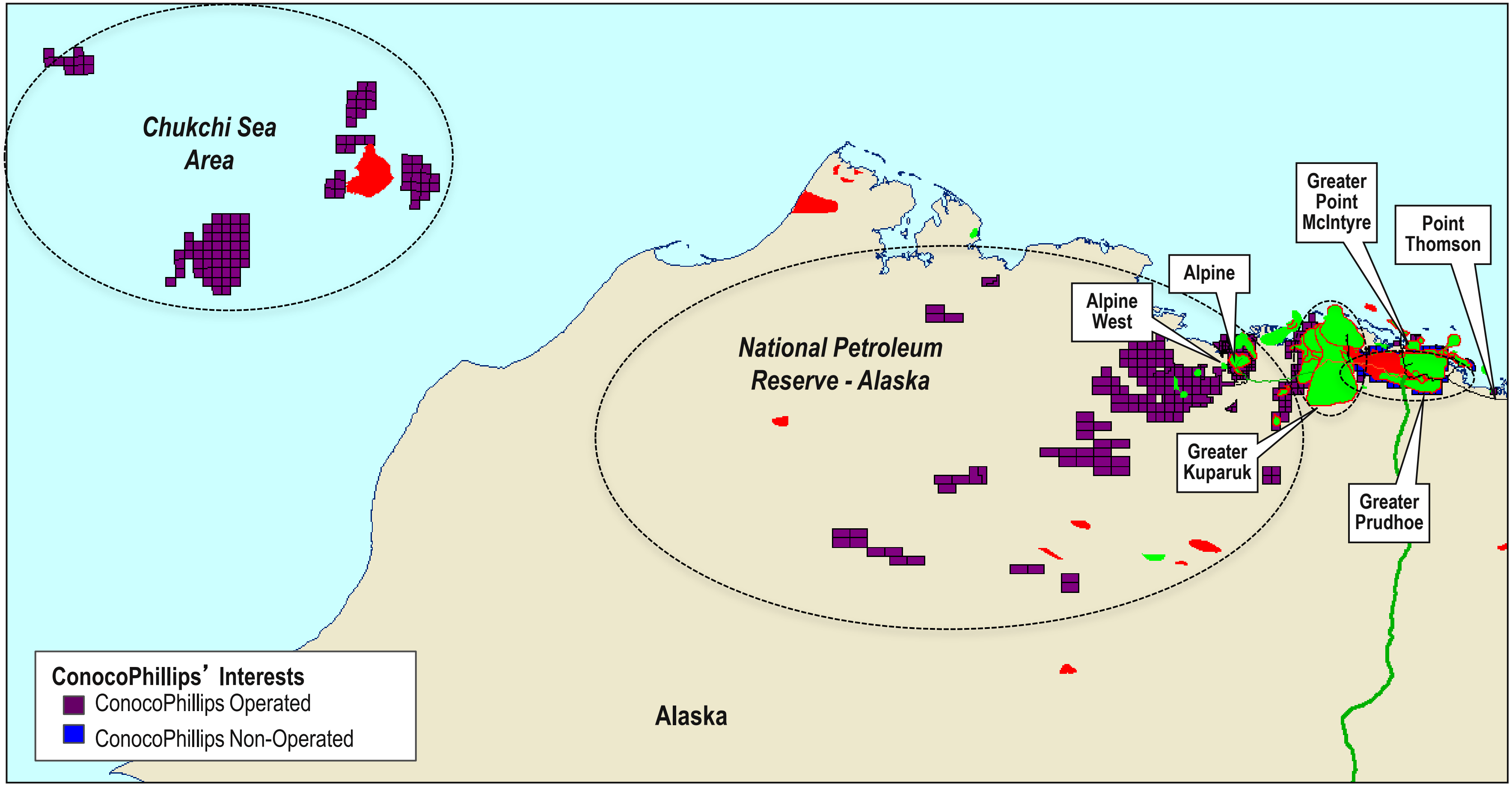
ConocoPhillips: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



ConocoPhillips's new source portfolio is driven by (1) Shallow water gas production (Qatar); (2) Canadian SAGD Oil Sands Developments; and (3) US Unconventional production (Eagle Ford).

Deepwater projects, sourced mainly from the Asia-Pacific region (Malaysia) and the US GOM deepwater (mostly non-operated positions), will ramp up steadily over the decade; by 2020 deepwater is poised to represent 7% of global volumes (compared to ~2% in 2010).

ConocoPhillips in Alaska – North Slope



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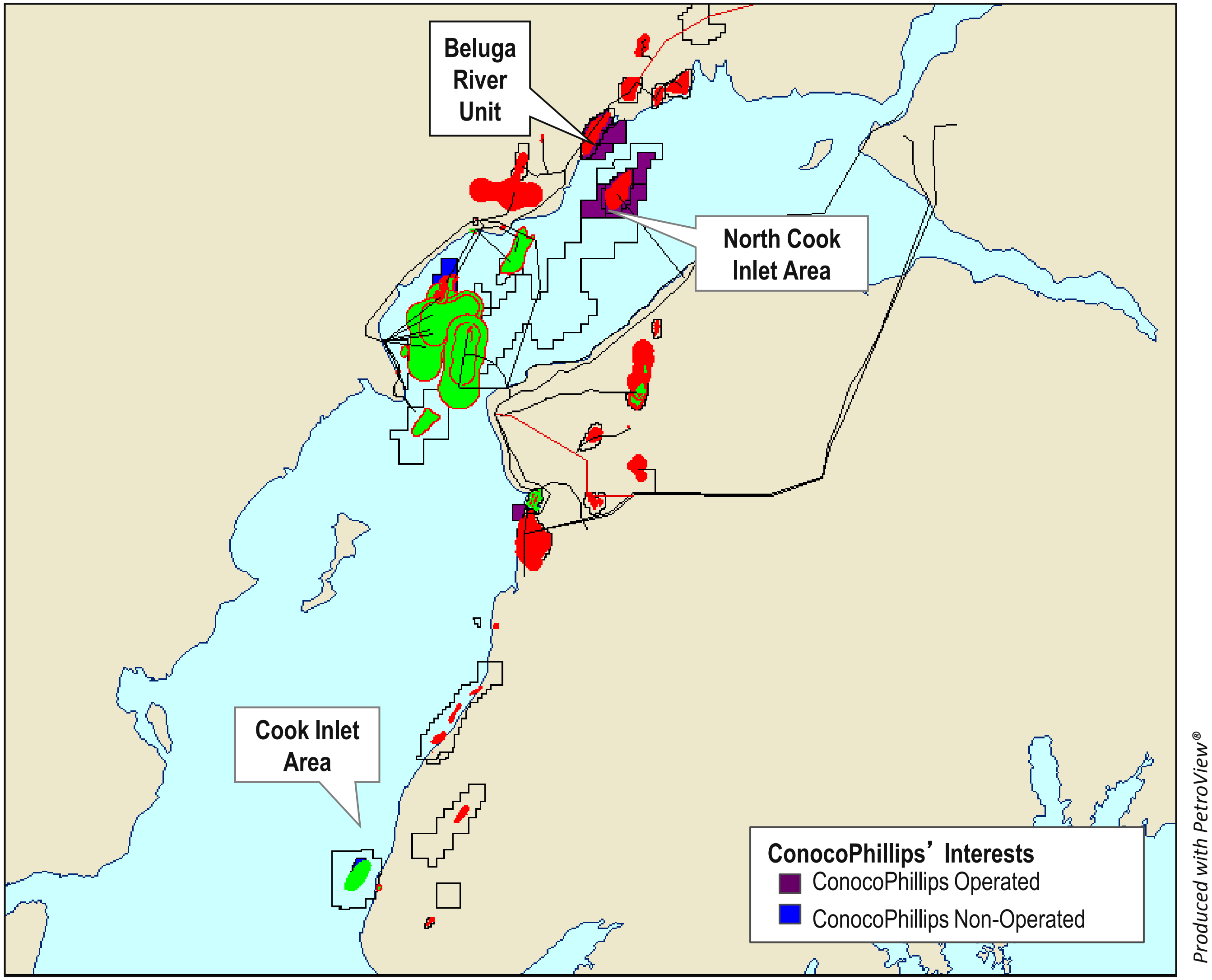
ConocoPhillips in Alaska – Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



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ConocoPhillips **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• ConocoPhillips' assets in Alaska are legacy assets acquired from Arco Alaska in 2000 and include the Greater Prudhoe Area, Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. The company's largest producing area in Alaska is the Greater Prudhoe Area, a collection of mature, long-life fields. Production from the mature Alaska portfolio has been in slow decline since 2004. In 2010, net production from Alaska averaged 230 mb/d of oil and 82 mmcf/d of gas, accounting for ~21% of US production. • ConocoPhillips and BP have been joint proponents of the **Alaska Gas Pipeline** (or **Denali Pipeline**), intended to accelerate commercialization of Prudhoe Bay gas through Western Canada and into US markets. In 2010, the partners officially withdrew their support for the proposed project, in response to continued US gas price weakness and absence of buyer commitments. This places substantial uncertainty around further commercialization of ConocoPhillips' Alaska gas resources. • Activity in the ConocoPhillips-operated Greater Kuparuk Area (GKA), has recently focused on development of viscous oil resources. The GKA, located 40 miles west of Prudhoe Bay on the North Slope, includes the Kuparuk field and its satellites: West Sak, Tarn, Tabasco, Meltwater, and Palm. Heavy oil resources **West Sak** and **Ugnu** (52.2% w.i., operated) are potential projects currently in the appraisal phase. Expected gross peak production is ~23 mboe/d.	As Alaska's largest oil and gas producer, ConocoPhillips holds a leading position in the region. Although the company continues to target smaller projects within the GKA (West Sak and Ugnu) and NPR-A (Alpine West, Greater Moose's Tooth unit and Fiord West), ConocoPhillips will ultimately need expanded access to Asia gas markets in order to reverse the downward production trend in Alaska.

PFC Energy

COP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• In the Western North Slope, ConocoPhillips faces regulatory challenges surrounding project development in the NPR-A region. In order to offset declines at the **Alpine** field (78% w.i., operated) and its three satellites, Nanuq, Fiord, and Qannik, ConocoPhillips is exploring development of additional satellite fields in the adjacent NPR-A, an area that requires distinct permit approval. **Alpine West** (or **CD-5**), a proposed Alpine satellite project, has been significantly delayed due to local opposition and regulatory barriers. Most recently, in early 2010, the U.S. Army Corps of Engineers denied a permit for a bridge that would provide access to the CD-5 site, a move that will further delay the project (originally planned for 2012) and several additional developments that would depend on the infrastructure. Other possible projects on the NPR-A include the **Greater Moose's Tooth** unit and **Fiord West**, which are both in appraisal phases. • While ConocoPhillips has three primary gas fields in the Alaska region–the North Cook Inlet, Beluga River, and Point Thomson–**Point Thomson** (5% w.i., non-operated) remains the only potential new source development. In 2010, development activities continued with the drilling of two appraisal wells. First production of gas liquids is anticipated in 2014. Longer-term growth potential lies in commercialization of the gas reserves, which is in turn dependent on construction of a long-distance gas trunk line. • In 2010, ConocoPhillips and Statoil engaged in an asset swap wherein ConocoPhillips sold a 25% w.i. in 50 of its **Chukchi Sea** leases to Statoil in exchange for financial payment and a 50% w.i. interest in 16 Statoil-operated Gulf of Mexico leases, as well as Statoil's 25% w.i. in five additional GOM leases already operated by ConocoPhillips. All of the involved GOM blocks are in the emerging Lower Tertiary play. ConocoPhillips plans to begin exploratory drilling on its Chukchi acreage in 2013.	

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PFC-Identified Challenges

- Competing as a “Pure Play” E&P Company: The separation of ConocoPhillips into two, stand-alone Upstream and Downstream entities is scheduled to be finalized in 1H:2012. The ~85% of total portfolio value residing in E&P assets will thereby become the largest “pure play” E&P Independent, a competitor landscape position the company held uncomfortably prior to the Burlington Resources acquisition in 2006. Can ConocoPhillips Upstream compete successfully in the Independent’s space by delivering either leading shareholder returns or leading production growth? Or has it simply re-established its original dilemma—too large to compete with the faster moving International Independents, and too small to compete with the Global Players? And if so, does it survive?
- Re-Establishing a Value Proposition: ConocoPhillips’ new strategic focus on Sustained Value Generation is intended to re-establish the company’s competitive advantage in the E&P space. In the near-term, the 2010-2013 Restructuring Plan will deliver a smaller company with limited medium-term production growth and improved, but unlikely to be leading, ROCE and financial performance. Clearly, the cannibalization of the company’s assets and recycling of proceeds to shareholders in order to shore up share valuation and total shareholder returns is a stop-gap strategy at best. Given continuing financial and operational challenges (ROCE, production cost, upstream net income, etc.), ConocoPhillips may struggle to deliver a value proposition that will compete successfully in either the Global Player or International Independents peer group.
- Improving Operational Performance: While showing improvement in finding and development costs, ConocoPhillips ranks at or near the bottom of the expanded Global Players peer group in net income/boe, production costs/boe, and Upstream ROCE. The current portfolio high-grading has already delivered Upstream ROCE improvement (from 7% in 2009 to 10% in 2010) and should deliver improvement in operational metrics; both Syncrude and the LUKOIL holdings were arguably underperforming positions. With long lead time, large scale, capital intensive developments like Qatargas 3, Jasmine, Kashagan Phase 1, and Surmont poised to deliver material production and cash flow, ConocoPhillips should see the flow-through benefits in terms of more competitive ROCE and operational metrics.
- Delivering Production Growth: The share repurchase program accompanying portfolio rationalization under the Restructuring Plan is projected to deliver ~3% growth in per share production in 2010 and 2011. However, physical volumes will decline in absolute terms over the 2010-2011 period—by ~208 mboe/d in 2010 from 2009 levels, and a further ~360 mboe/d in 2011 from 2010. The only region poised to deliver higher production volumes in 2020 versus 2010 is the relatively minor MENA region, projected to reach ~177 mboe/d in 2020 versus 72 mboe/d in 2010. New source volumes in Canada and the North Sea will struggle to offset mature asset declines, delivering flat production in the core North America and Europe regions, while the LUKOIL sell-down will dampen what was once considered a core driver of future growth for the company. While boasting a 10 bn boe resource base, it is not clear how ConocoPhillips will deliver the promised surge in organic growth over the 2015-2020 period from its captured portfolio—although the enhanced capex spend in the Eagle Ford play is a good starting point. Barring a material acquisition (certainly not out of the question), the company will be looking to its exploration portfolio to deliver a medium term “engine of growth”.

PFC Energy

ExxonMobil: Company Overview

Strategic Signature

- ExxonMobil is the largest global integrated company (volumes averaged ~4,450 mboe/d in 2010), with production in 21 countries and upstream operations in an additional 20 countries.
- ExxonMobil has long adhered to a growth strategy based on scale, basin dominance, and execution excellence, which has required the company to seek continuous access to investment opportunities of adequate size and materiality.
- In 2010, faced with the commissioning of the final elements of the company's Qatar project portfolio (the final four approved LNG trains at RasGas and Qatargas, and Phase 2 of the Al Khaleej gas project), declining production in Europe and Asia-Pacific, and already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.
- The 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation, with ~2.3 bcf/d and 87 mboe/d of production, proved reserves of ~2.3 bn boe, and a resource base of 7.5 bn boe. From a position of basin dominance in the US Onshore, ExxonMobil will seek to build a global unconventional portfolio; as such, the company has already begun purchasing prospective acreage in Argentina, Germany, Poland, Indonesia, and, most recently, China.
- Largely a result of the acquisition, ExxonMobil recorded a 13% increase in production in 2010 over 2009. The company will seek growth of 4-5% per annum over the 2009-2014 period.

Company Overview

- **HQ:** Irving, Texas
- **Employees:** 83,600
- **2010 Reserves:** 24,809 mmboe
- **2010 Production:** 4,447 mboe/d
- **3 Yr Production Growth:** 2.2% CAGR (2007-2010)
- **Nov 2011 Market Cap:** $386 bn
- **Nov 2011 P/E Ratio:** 9.71
- **2010 Corp Revenue:** $370 bn
- **2011 Upstream Capex (Est.):** ~$28 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✓	✓		✓	✓	✓

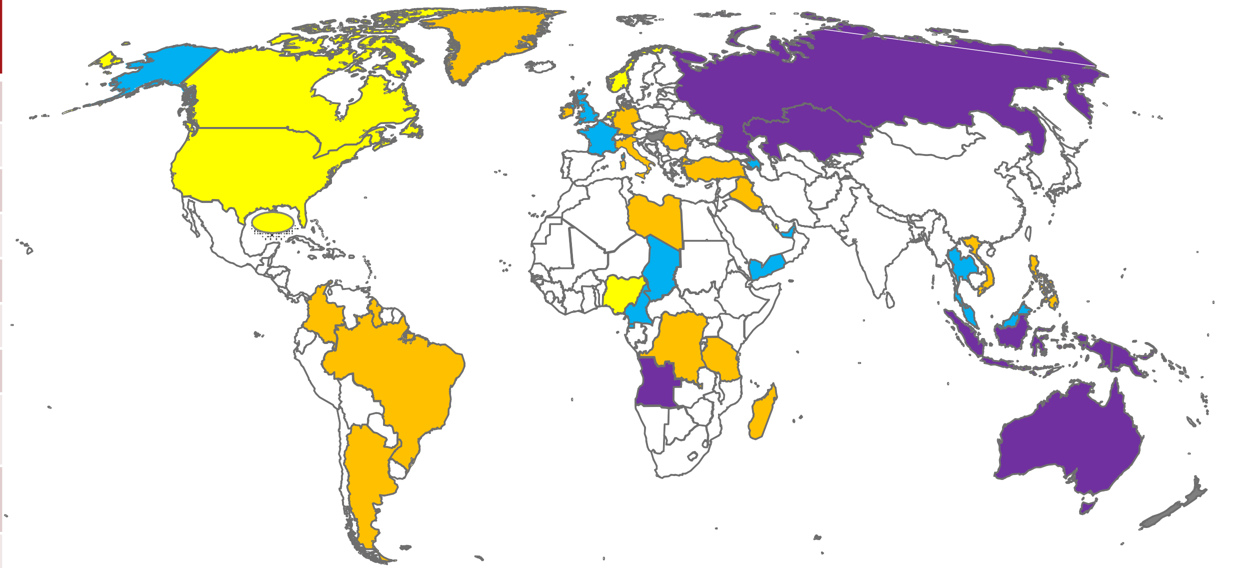
Partnership History

Date	Partner	Region (or Country)	Type
2011	Sinopec	China	Unconventional
2011	Rosneft	Russia	Offshore Oil & Gas

ExxonMobil has a limited history of partnership, preferring instead to purchase and operate material positions independently

ExxonMobil: Global Areas of Upstream Operations

Country	Liquids (mboe/d)	Gas (mboe/d)
Qatar	232	644
USA	408	433
Nigeria	391	2
Norway	246	117
Netherlands	0	340
Canada	242	86
UAE	246	0
United Kingdom	80	92
Kazakhstan	127	24
Angola	141	0
Malaysia	48	86
Australia	51	55
Germany	0	91
Equatorial Guinea	53	0
Russia	43	8
Indonesia	13	36
Chad	43	0
Azerbaijan	21	0
Argentina	0	9
Papua New Guinea	7	0
Thailand	0	4



Country	Liquids (mboe/d)	Gas (mboe/d)
Brazil	0	0
Cameroon	0	0
Colombia	0	0
Congo	0	0
Greenland	0	0
Guyana	0	0
Hungary	0	0
Iraq	0	0
Ireland	0	0
Italy	0	0
Libya	0	0

Country	Liquids (mboe/d)	Gas (mboe/d)
Madagascar	0	0
New Zealand	0	0
Philippines	0	0
Poland	0	0
Romania	0	0
Tanzania	0	0
Turkey	0	0
Vietnam	0	0
Yemen	0	0

Core
New Venture
Focus
Harvest
Exit

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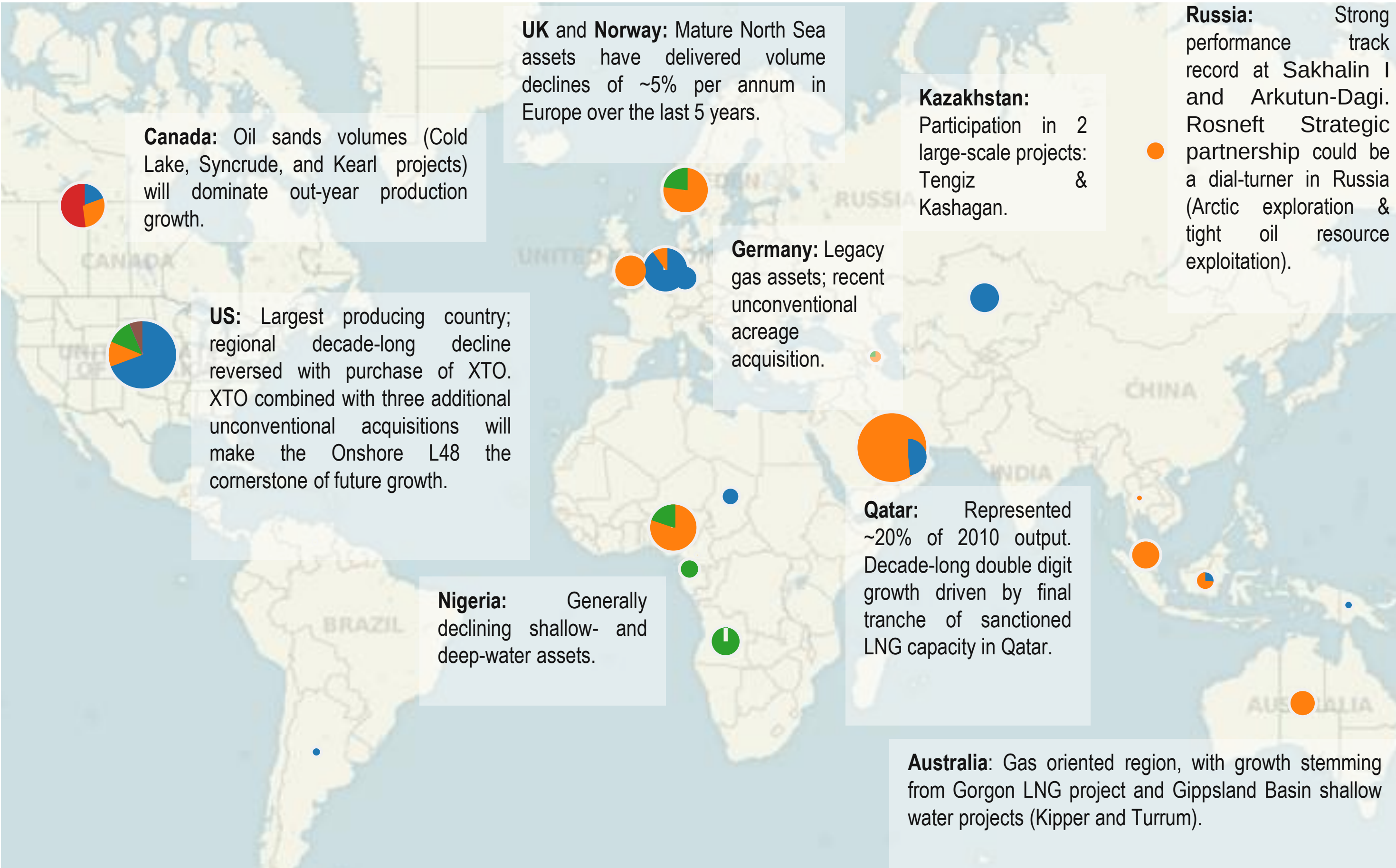
ExxonMobil Global Production Portfolio - 2010



mboe/d

- 0
- 500
- 1,000
- 1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Indonesia: Near-term gas volumes will hold production steady as ExxonMobil positions for new ventures in the unconventional space (coal bed methane).

Malaysia: Key gas producing area; focus on enhanced oil recovery (EOR) and field life extension schemes.

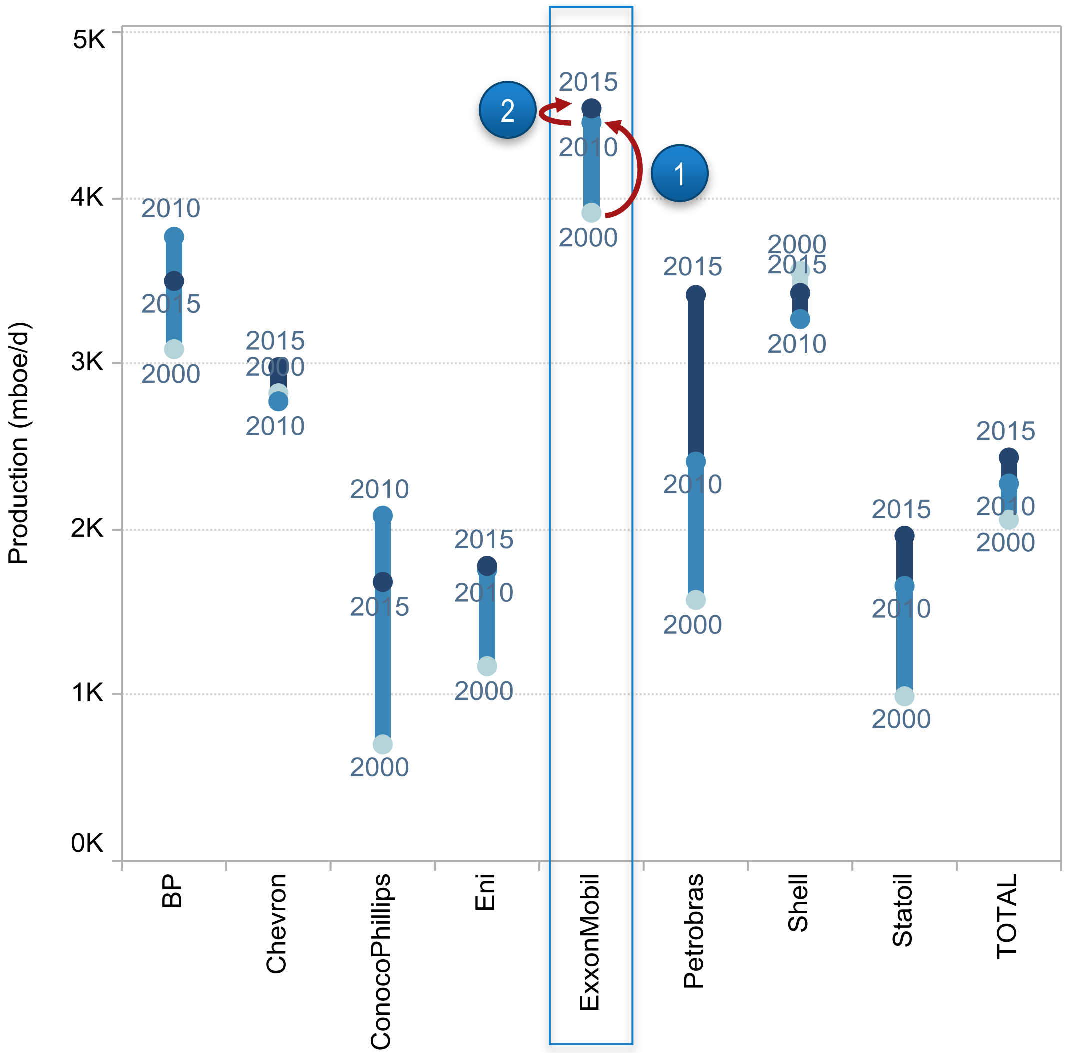
Argentina: legacy, declining gas assets; recent acreage positioning in prospective shale Neuquen Basin.

Angola: Multi-field new source developments (Kizomba Satellites Phase 1, Pazflor, and CLOV) drive regional growth.

Papua New Guinea: Formerly small contributor to the ExxonMobil portfolio, PNG will rise in prominence within the portfolio through the monetization of gas reserves at PLNG.

Total Portfolio Evolution: ExxonMobil vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): ExxonMobil and Peers



Averaging ~4.45 mmboe/d in 2010, ExxonMobil continues to lead its peer group in terms of production.

1 **2000-2010:** For much of the last decade, production oscillated, rising between 2000 and 2002 and then again 2005-2007; however, by 2009 production volumes were only slightly above levels recorded at the start of the decade, averaging ~3.92 mmboe/d. In 2010, ExxonMobil secured production growth of ~13% (~6% excluding the XTO acquisition), reaching ~4.45 mmboe/d. For a company that has prided itself on organic reserves and production growth, the XTO acquisition marks a considerable departure in growth strategy for ExxonMobil.

2 **2011-2015:** ExxonMobil's production is forecast to grow modestly between 2010 and 2015, reaching only ~4.54 mmboe/d in 2015. While PFC Energy estimates are lower than ExxonMobil targets, the absence of guidance regarding growth projects associated with the XTO portfolio make the pace of future growth uncertain.

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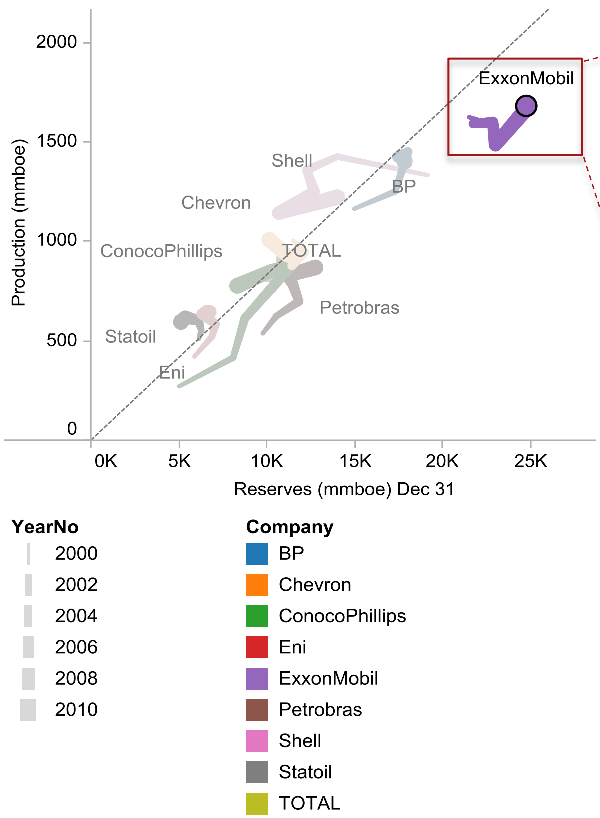
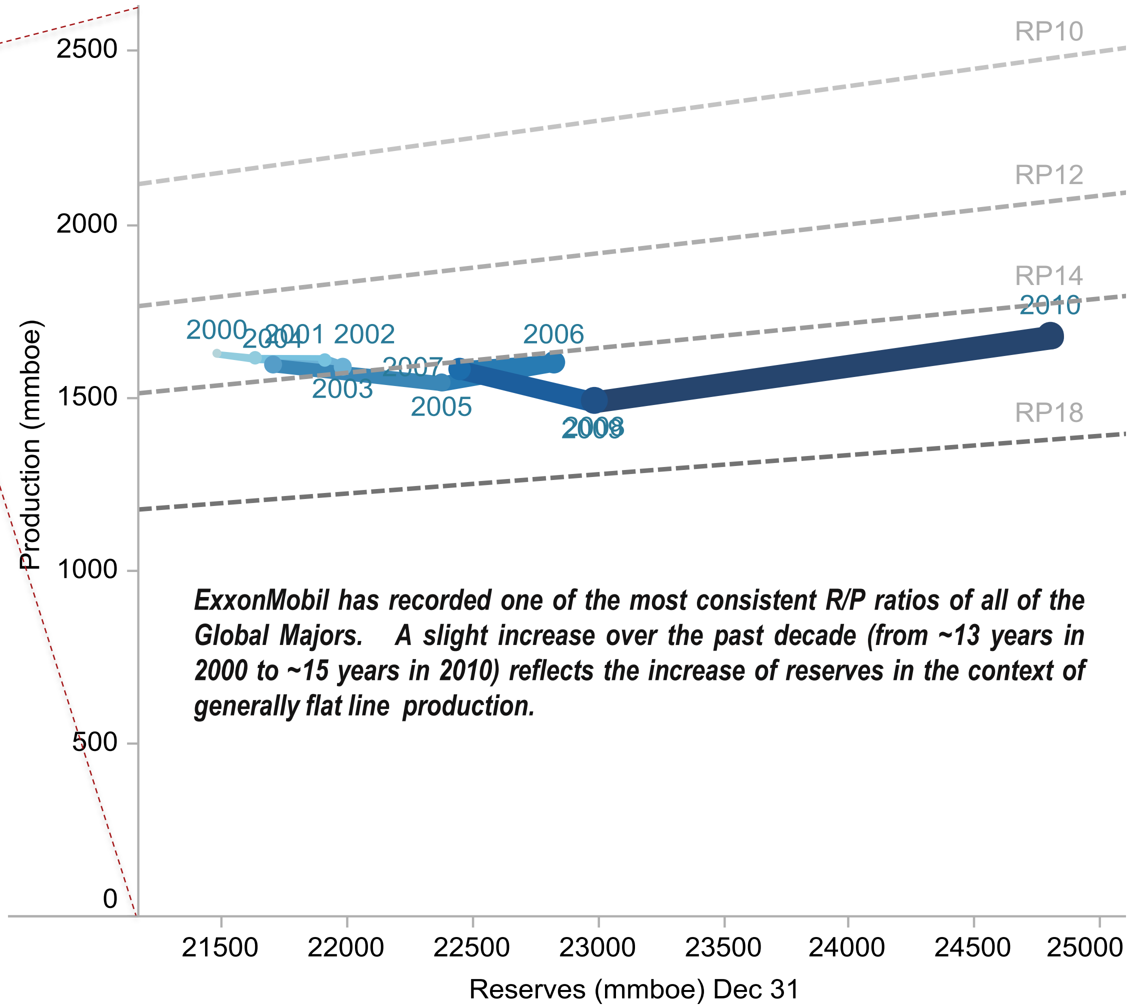
Reserves and Production: ExxonMobil vis-à-vis the Competition

Reserves and Production (mmboe) 2000-2010: ExxonMobil and Peers





ExxonMobil has recorded one of the most consistent R/P ratios of all of the Global Majors. A slight increase over the past decade (from ~13 years in 2000 to ~15 years in 2010) reflects the increase of reserves in the context of generally flat line production.

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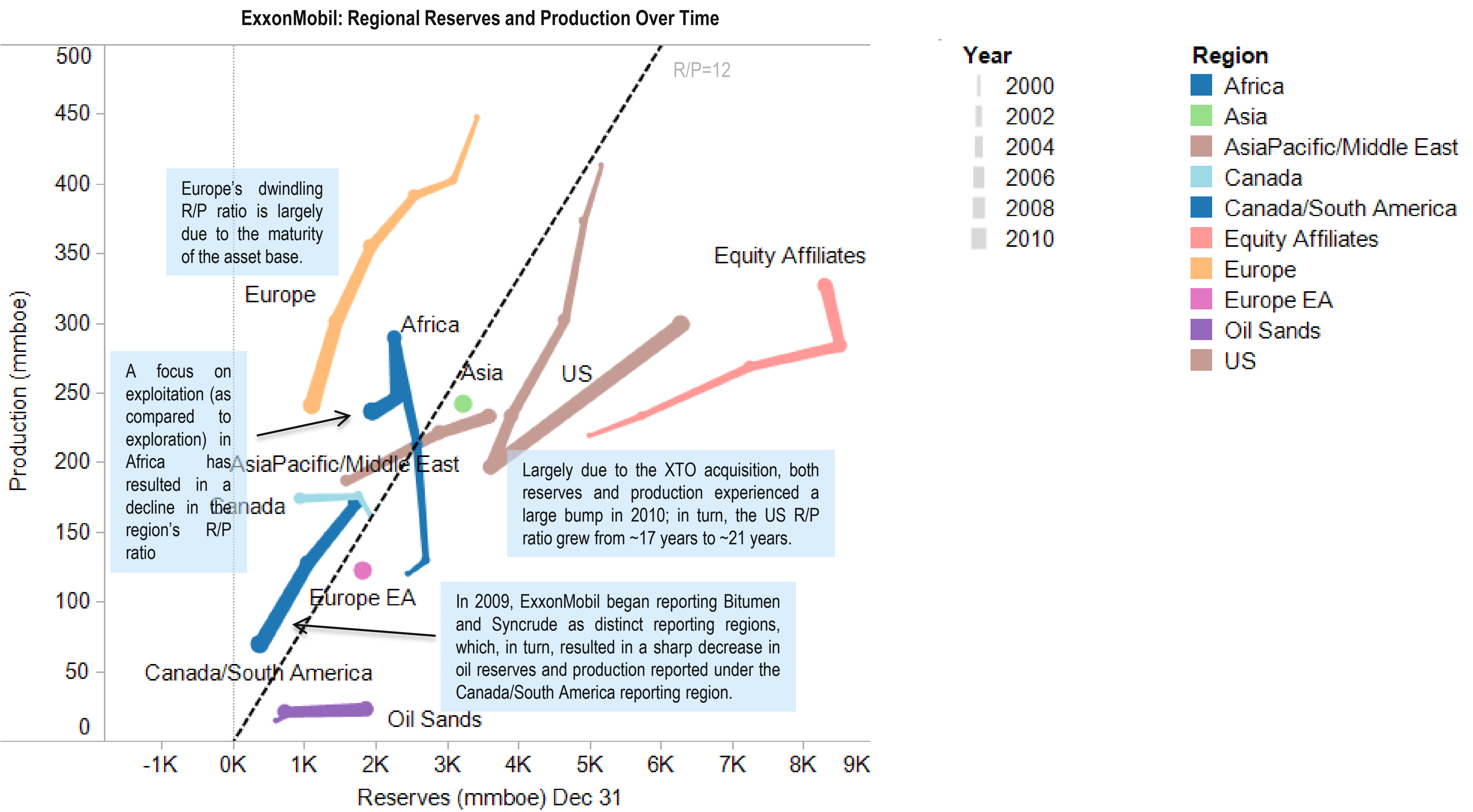
Reserves and Production: ExxonMobil Intra-Portfolio Performance



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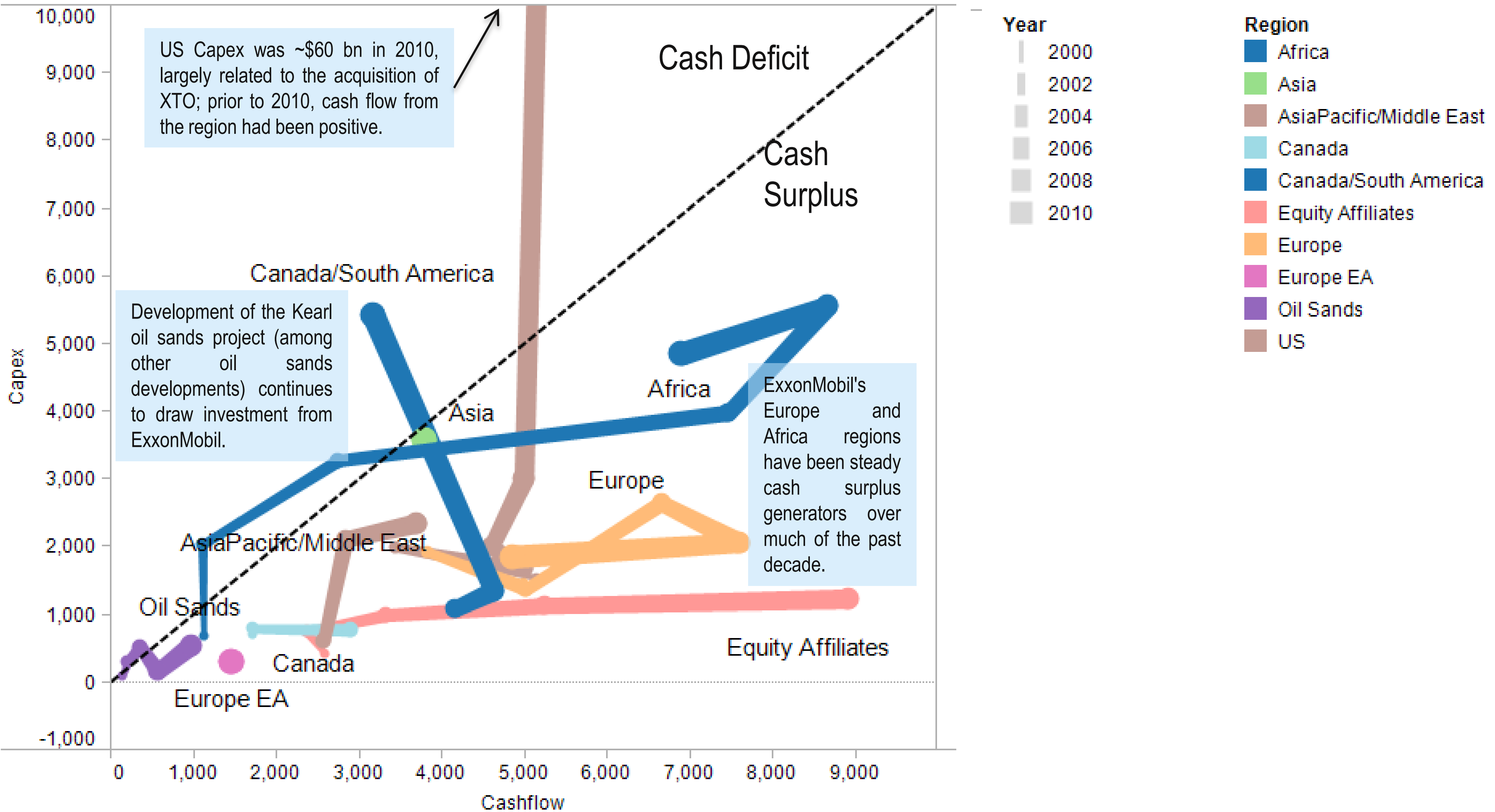
How the Portfolio is Financed: Sources and Uses of Cash



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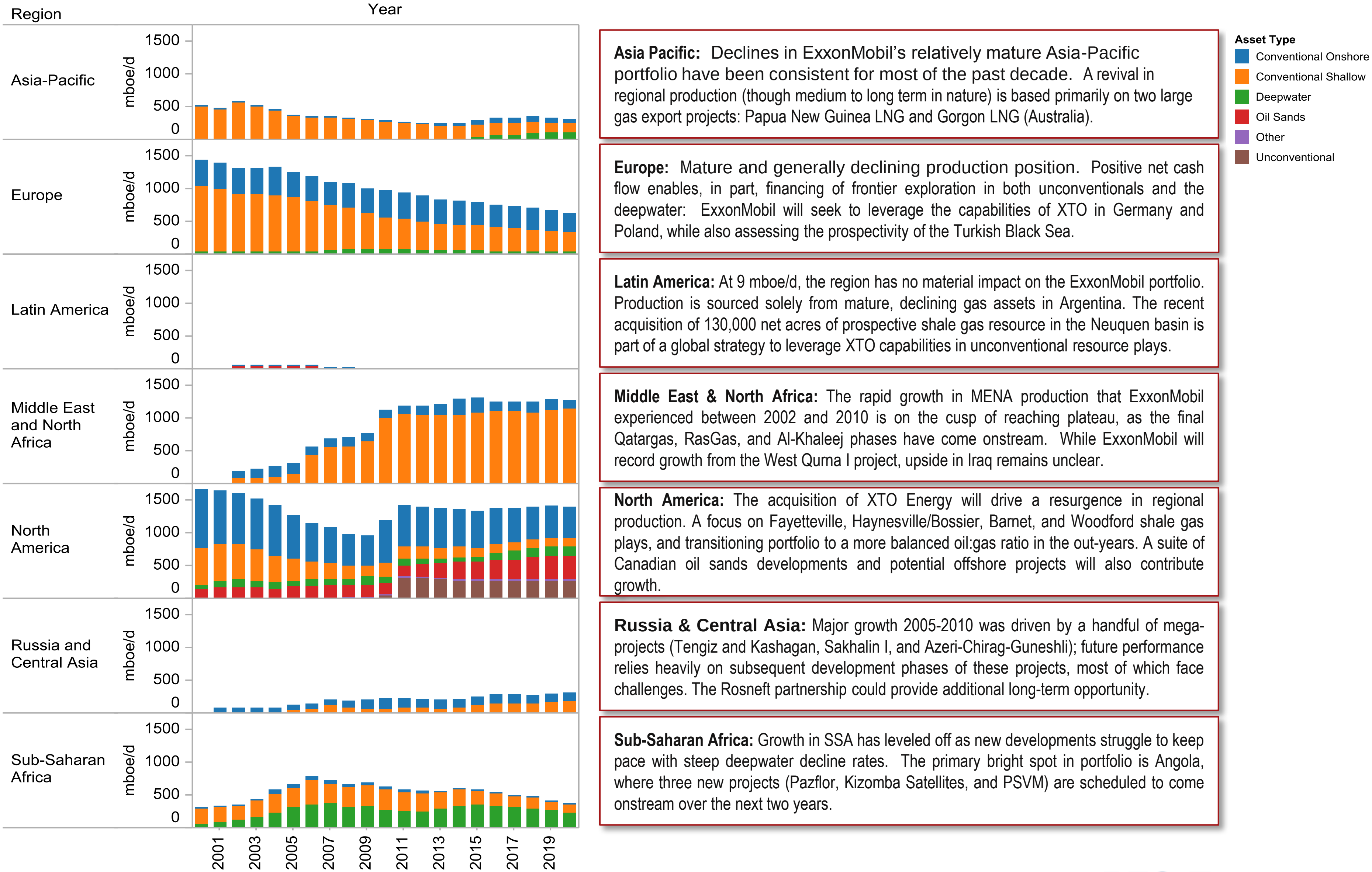
Global Production: Evolution of the Portfolio



Asia Pacific: Declines in ExxonMobil's relatively mature Asia-Pacific portfolio have been consistent for most of the past decade. A revival in regional production (though medium to long term in nature) is based primarily on two large gas export projects: Papua New Guinea LNG and Gorgon LNG (Australia).

Europe: Mature and generally declining production position. Positive net cash flow enables, in part, financing of frontier exploration in both unconventionals and the deepwater: ExxonMobil will seek to leverage the capabilities of XTO in Germany and Poland, while also assessing the prospectivity of the Turkish Black Sea.

Latin America: At 9 mboe/d, the region has no material impact on the ExxonMobil portfolio. Production is sourced solely from mature, declining gas assets in Argentina. The recent acquisition of 130,000 net acres of prospective shale gas resource in the Neuquen basin is part of a global strategy to leverage XTO capabilities in unconventional resource plays.

Middle East & North Africa: The rapid growth in MENA production that ExxonMobil experienced between 2002 and 2010 is on the cusp of reaching plateau, as the final Qatargas, RasGas, and Al-Khaleej phases have come onstream. While ExxonMobil will record growth from the West Qurna I project, upside in Iraq remains unclear.

North America: The acquisition of XTO Energy will drive a resurgence in regional production. A focus on Fayetteville, Haynesville/Bossier, Barnet, and Woodford shale gas plays, and transitioning portfolio to a more balanced oil:gas ratio in the out-years. A suite of Canadian oil sands developments and potential offshore projects will also contribute growth.

Russia & Central Asia: Major growth 2005-2010 was driven by a handful of mega-projects (Tengiz and Kashagan, Sakhalin I, and Azeri-Chirag-Guneshli); future performance relies heavily on subsequent development phases of these projects, most of which face challenges. The Rosneft partnership could provide additional long-term opportunity.

Sub-Saharan Africa: Growth in SSA has leveled off as new developments struggle to keep pace with steep deepwater decline rates. The primary bright spot in portfolio is Angola, where three new projects (Pazflor, Kizomba Satellites, and PSVM) are scheduled to come onstream over the next two years.

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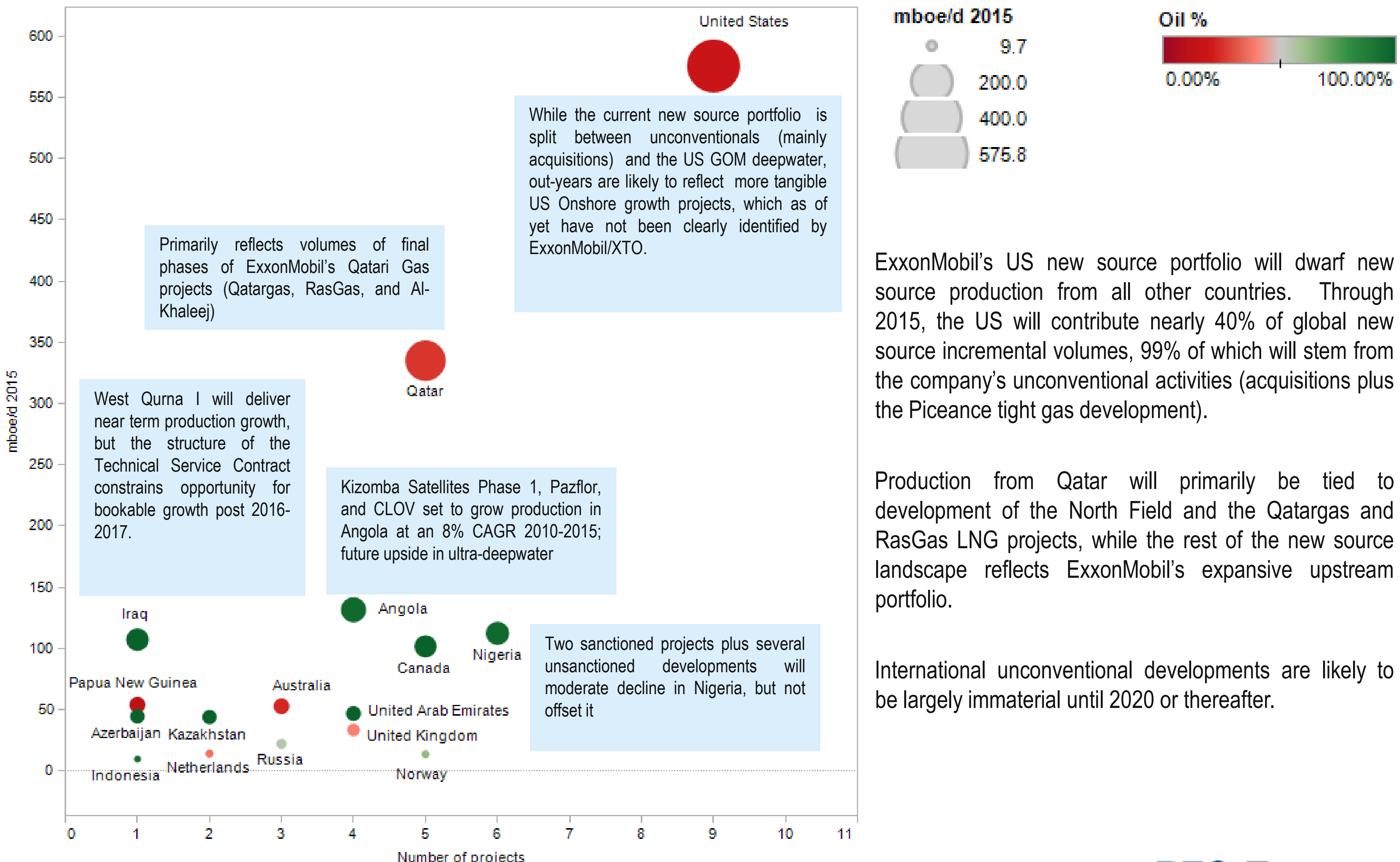
Global Production: Country Growth Project Analysis

ExxonMobil: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



ExxonMobil's US new source portfolio will dwarf new source production from all other countries. Through 2015, the US will contribute nearly 40% of global new source incremental volumes, 99% of which will stem from the company's unconventional activities (acquisitions plus the Piceance tight gas development).

Production from Qatar will primarily be tied to development of the North Field and the Qatargas and RasGas LNG projects, while the rest of the new source landscape reflects ExxonMobil's expansive upstream portfolio.

International unconventional developments are likely to be largely immaterial until 2020 or thereafter.

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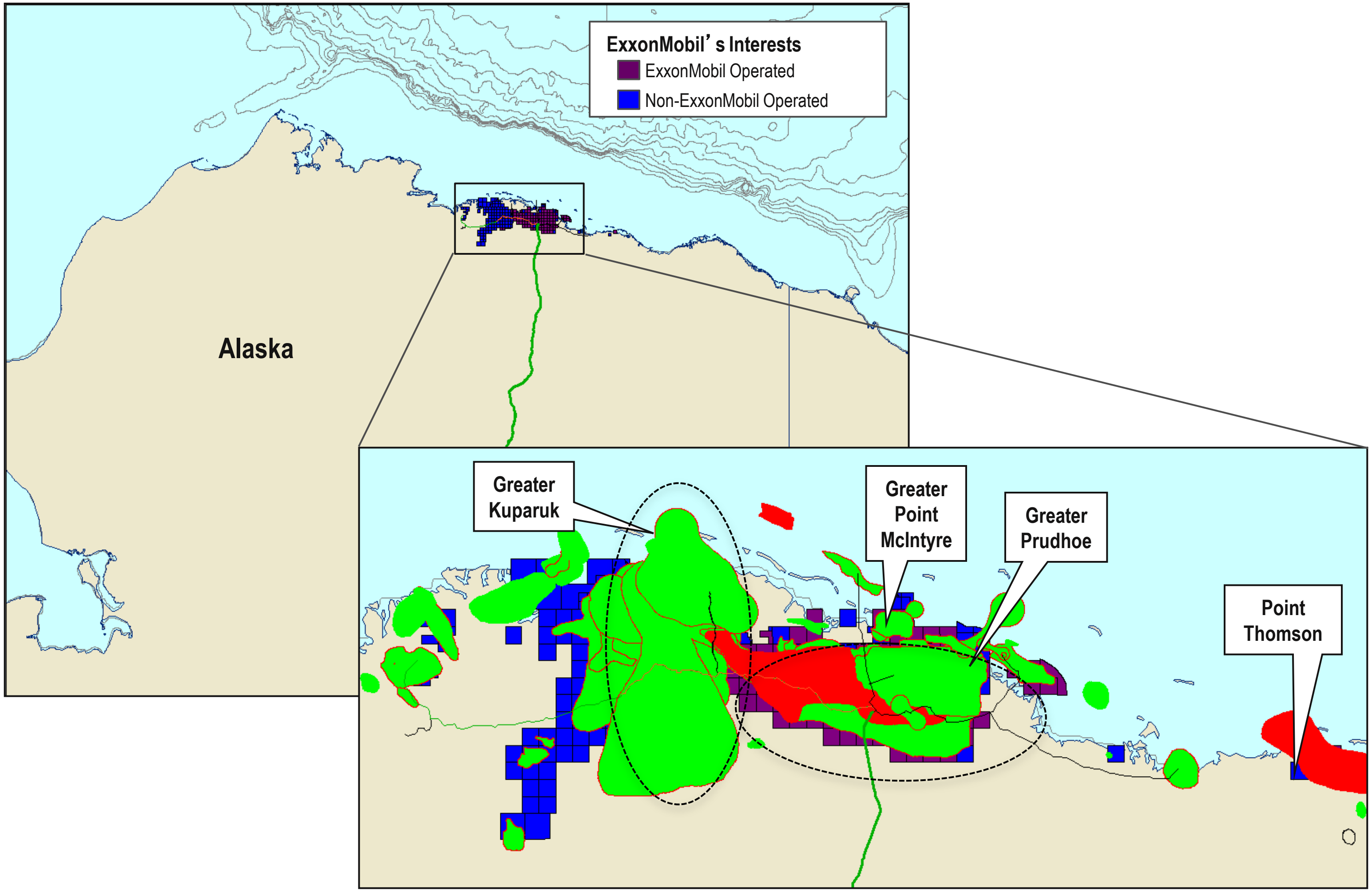
ExxonMobil in Alaska – North Slope



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ExxonMobil **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• In Alaska, ExxonMobil holds interests in the **Greater Prudhoe**, **Greater Point McIntyre**, and **Greater Kuparuk** areas. The company is one of the largest North Slope producers, although production from the region is declining; 2010 net production averaged 117 mb/d of liquids. • Development activities continued at **Point Thomson** in 2010 (35% w.i., operated), and first production of gas liquids is anticipated in 2014. The longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline.	**Material harvest position.** As the largest holder of discovered gas resources on the North Slope and a co-operator of the Prudhoe Bay Western Region development, ExxonMobil holds a leading position in Alaska.

PFC-Identified Challenges

- Deliver on unconventional resource positioning: The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play. That said, the company has provided limited guidance on pace of forward development despite continued acreage accumulation. Furthermore, given the weak US gas price environment, it is unclear how rapidly ExxonMobil's management will grow sales volumes. ExxonMobil is counting on additional long-term value arising from the XTO transaction through development of its expanding portfolio of International unconventional resource holdings.
- Execute on Asia-Pacific LNG Projects: ExxonMobil has a queue of LNG developments in Asia-Pacific, including Gorgon LNG (operated by Chevron), PNG LNG, and the potential Scarborough gas field development, all of which are poised to generate longer-term volume growth. Each of these projects comes with significant technical challenges—CO_2 capture and disposal at Gorgon LNG, remote gas field development and long distance pipeline transport in the case of PNG LNG, and the remote offshore location of the Scarborough field in the Carnarvon Basin (which may result in the field being dedicated as feedstock supply to the Pluto or Wheatstone LNG projects, rather than a greenfield LNG development). Performance will be critical to ensuring long-term regional portfolio growth.
- Maintain leadership in share buy-back and dividend performance: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~$19.7 bn through dividends and share buy-backs in 2010 and spending ~$114 bn on share repurchase over the 2006-2010 period. With the increased emphasis being placed on unconventional gas resources to deliver future volume growth, shareholders will be looking for ExxonMobil to continue its leading dividend and share buy-back performance, as the core differentiator from its faster growing (in volumetric terms) peer group companies.
- Replace volume growth from Qatar North Field commercialization: With full ramp-up of the final four liquefaction trains at the RasGas and Qatargas LNG complexes, and continued imposition of a development moratorium for the North Field resource by the Qatar government, ExxonMobil will be challenged to deliver material global growth.
  - It is not clear how aggressively ExxonMobil will look to develop its US Onshore unconventional gas resources, given current and projected gas pricing in the North America market;
  - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta) continues to face delays in the form of regulatory hurdles (recently removed for the Mackenzie Valley gas pipeline project) and gas market supply-demand balances;
  - Development of captured oil reserves in the Caspian region have experienced significant delays and cost over-runs, and are coming under increased political risk through accelerating resource nationalism;
  - ExxonMobil was successful in securing a growth position in Iraq through the West Qurna-1 redevelopment project, but will have to share the larger Iraqi resource prize with a number of IOCs and NOCs. It is not clear that Iraq can become a Core growth area for the company.

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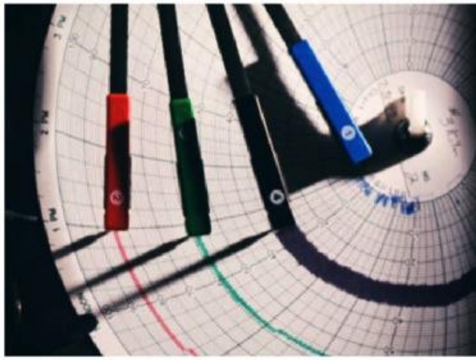

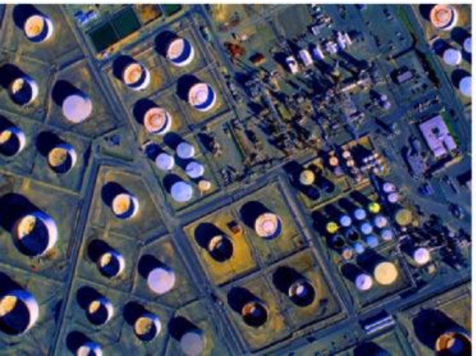

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