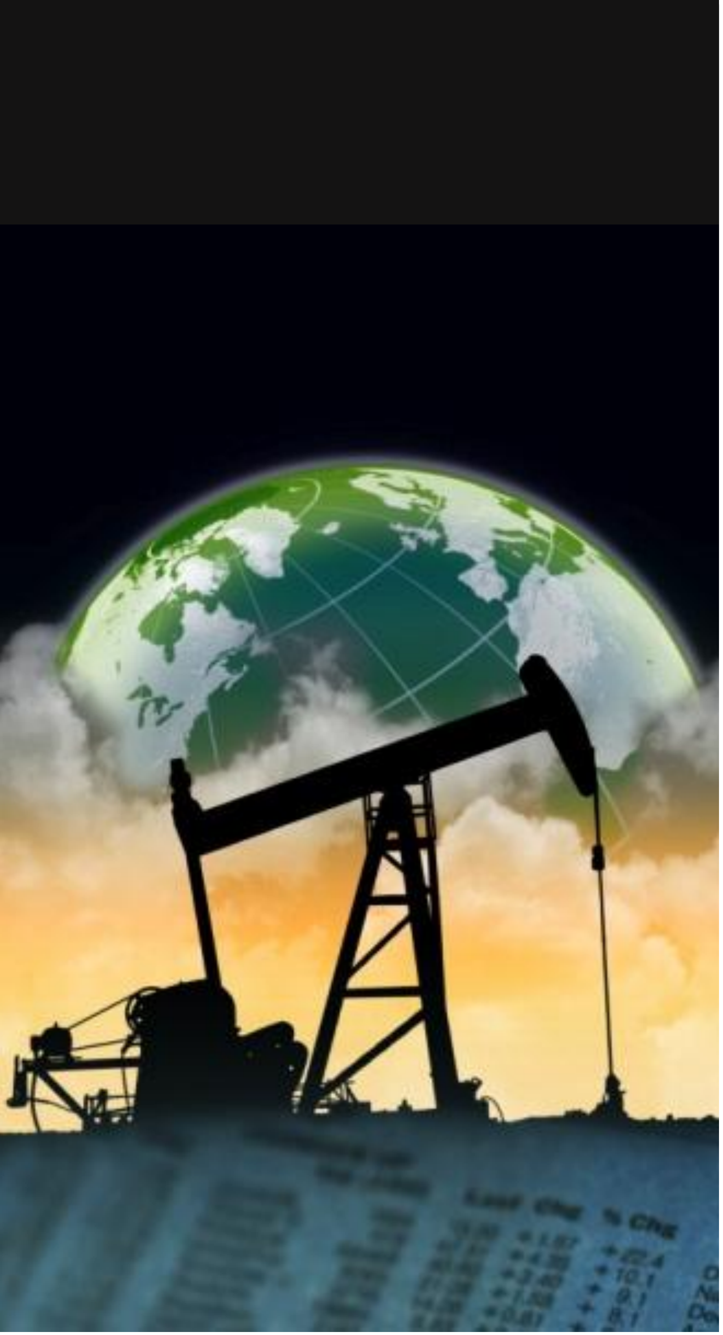


Senate TAPS Throughput Committee

Alaska Hydrocarbons Fiscal Systems

January 31 2013

Janak Mayer
Manager, Upstream
PFC Energy

Tony Reinsch
Senior Director, Upstream
PFC Energy

Part 1:

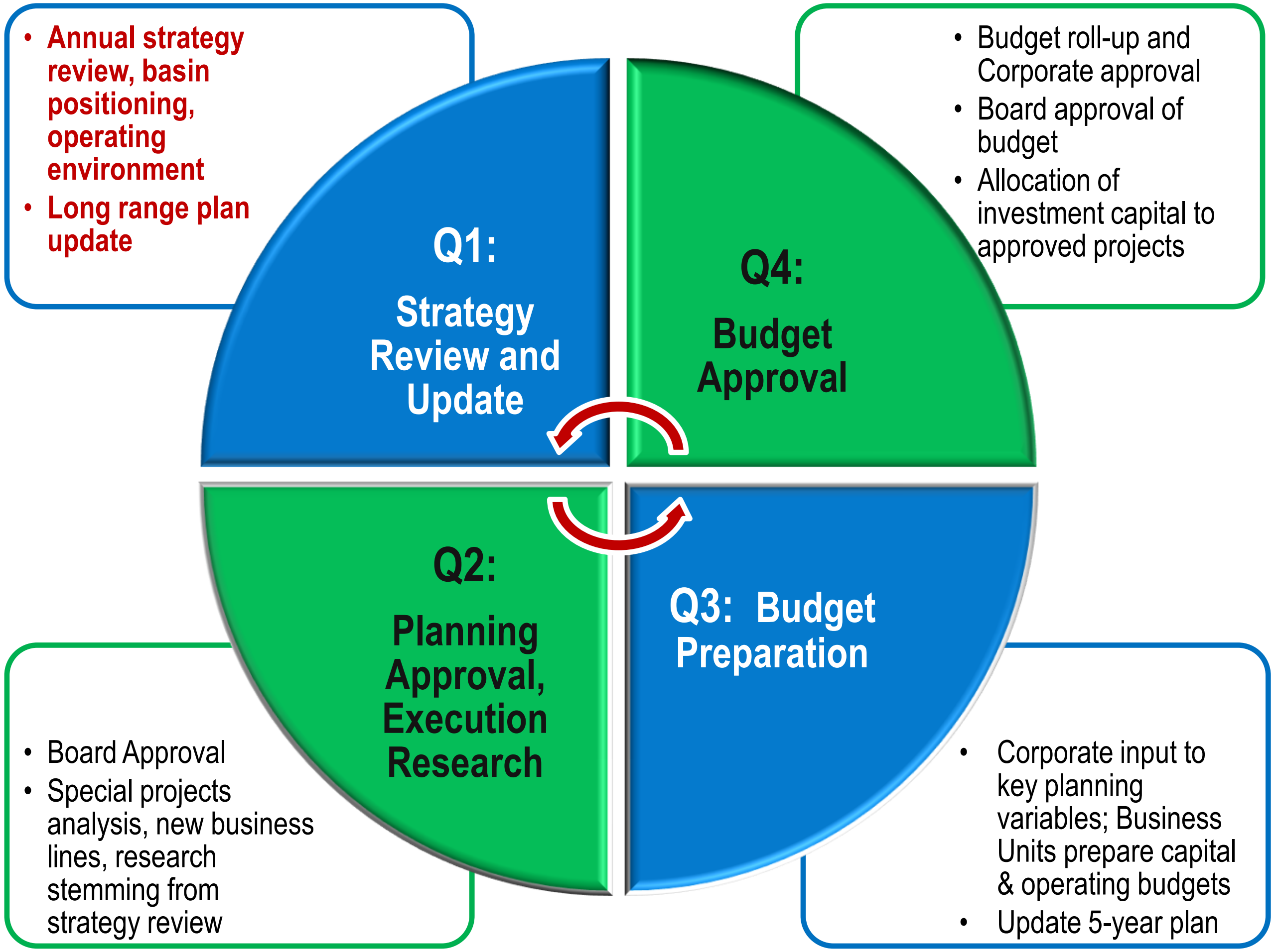
Oil & Gas Company Decision Making: Capital Allocation, Budget, and Long-Range Planning

Points to Address: Discussion of Company Behaviors and Decision Making

- Key considerations for companies in making investment decisions, including decisions on whether to develop particular resources in the near term or postpone development
- Key metrics including ROCE, NPV, IRR, consideration of asset metrics versus portfolio metrics, and differences between integrated vs non-integrated companies

Annual Planning Cycle

Oil and gas companies follow a standardized process linking the annual Budget cycle to the Long Range Plan and corporate Strategy



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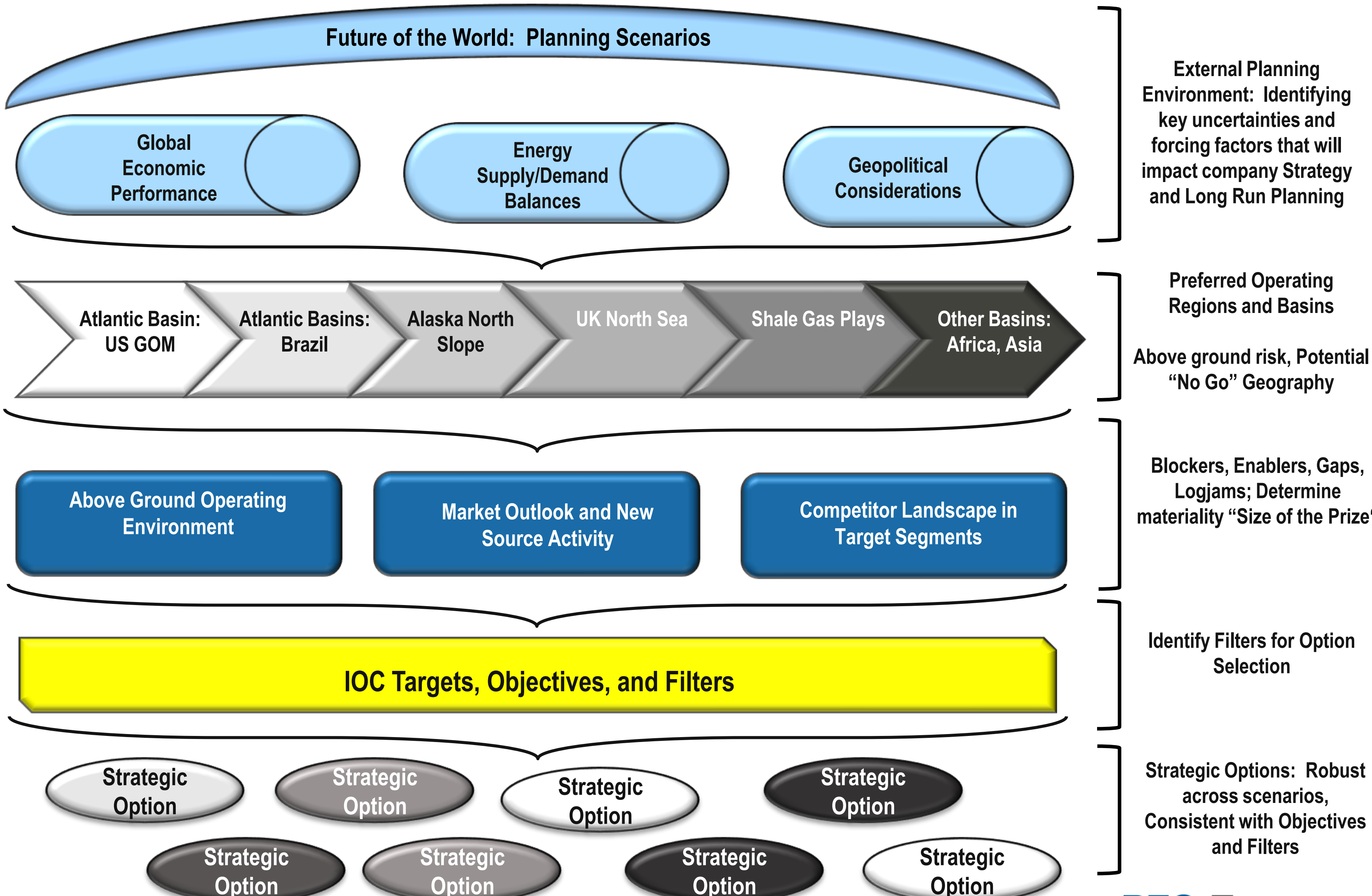
Strategy, Planning and Positioning



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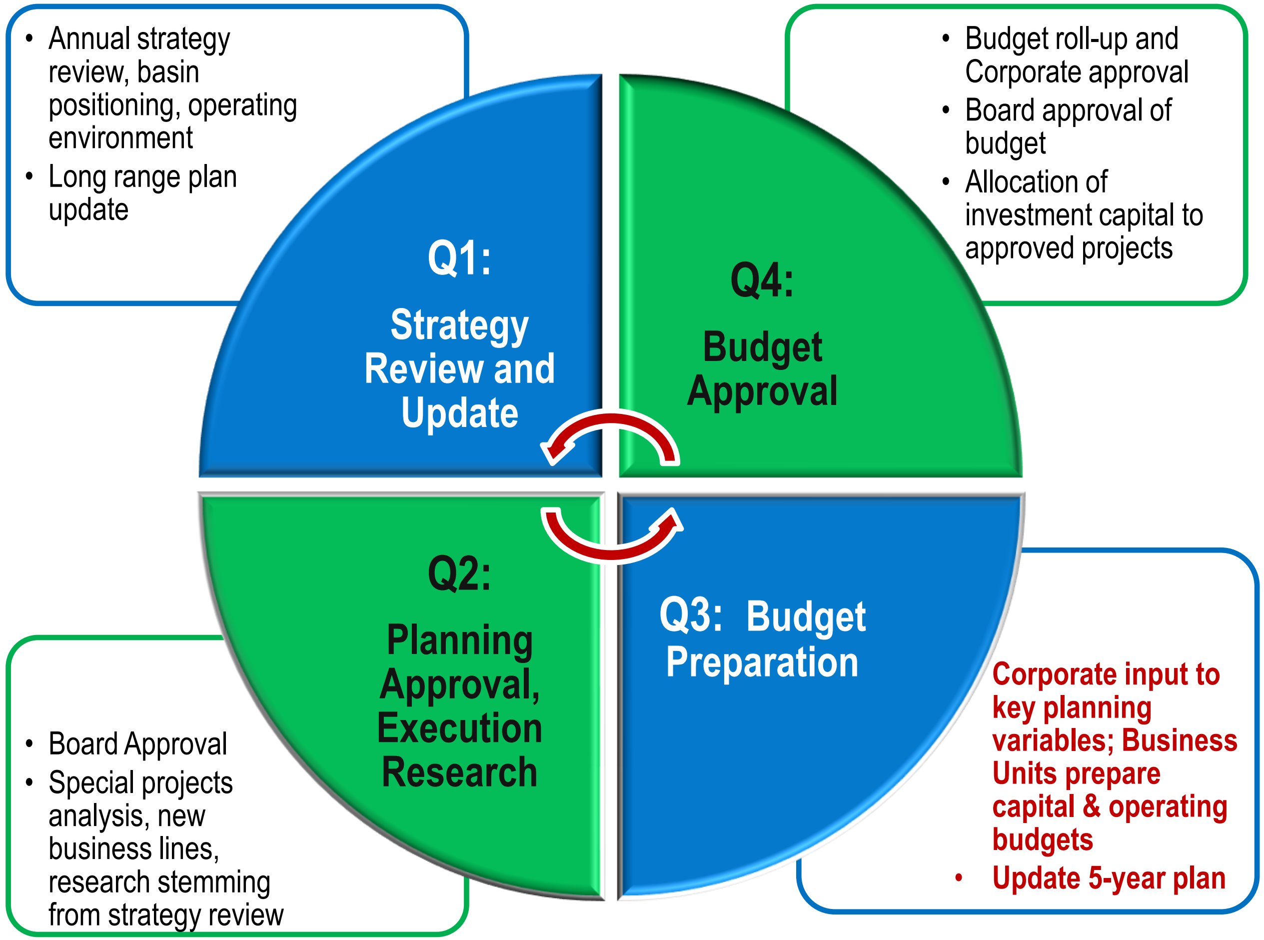
Annual Planning Cycle



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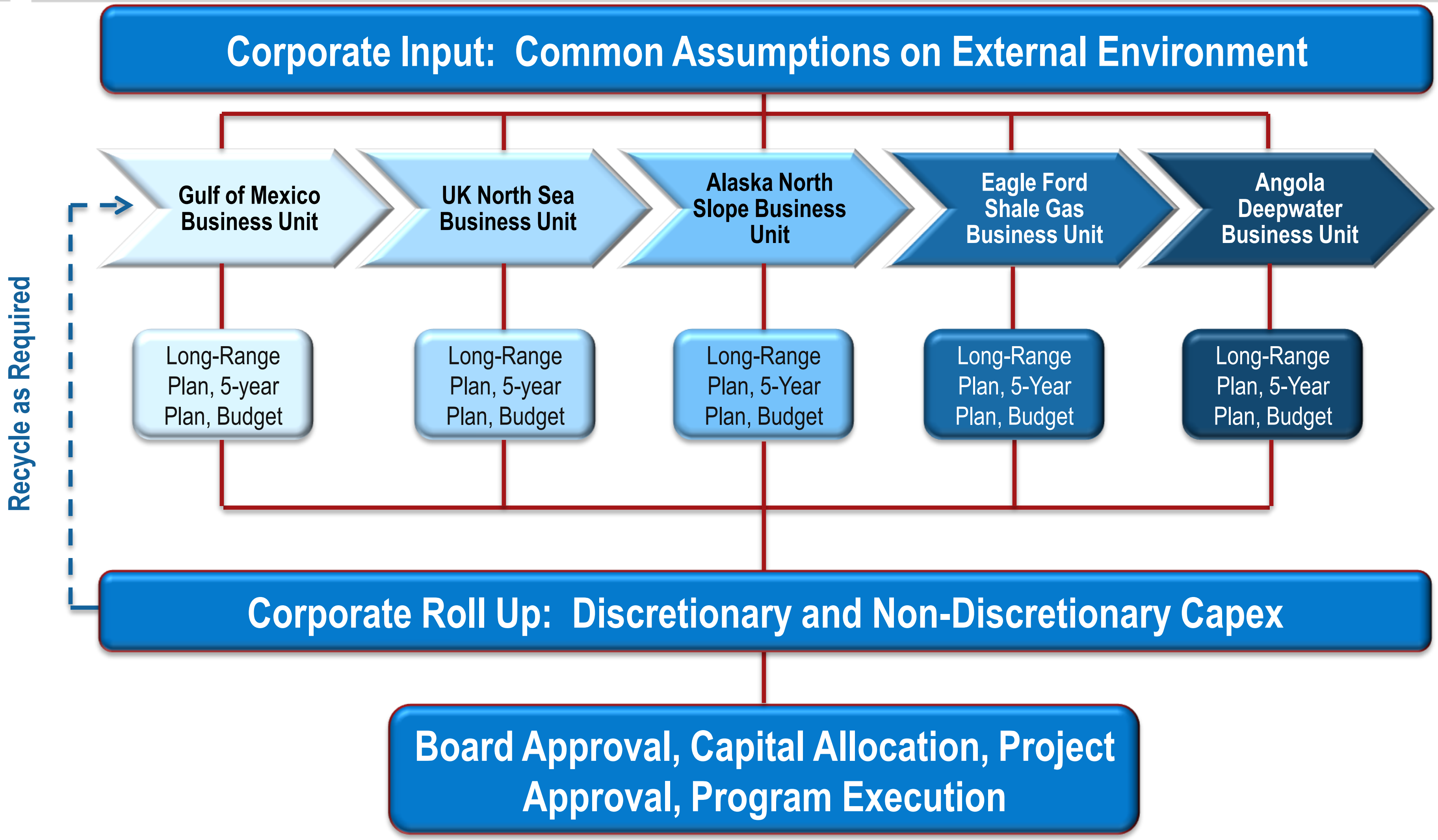
Planning Cycle and Capital Allocation



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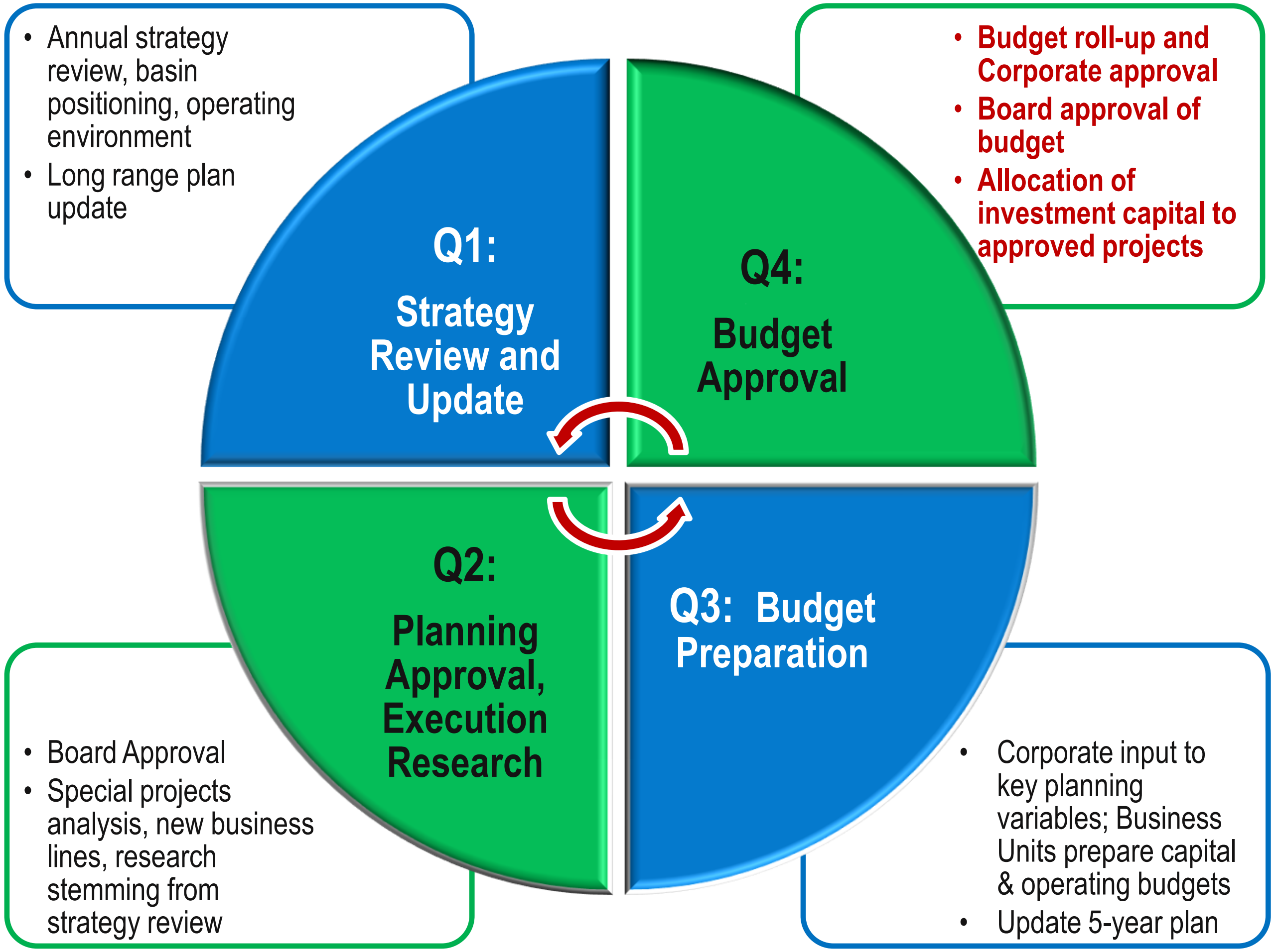
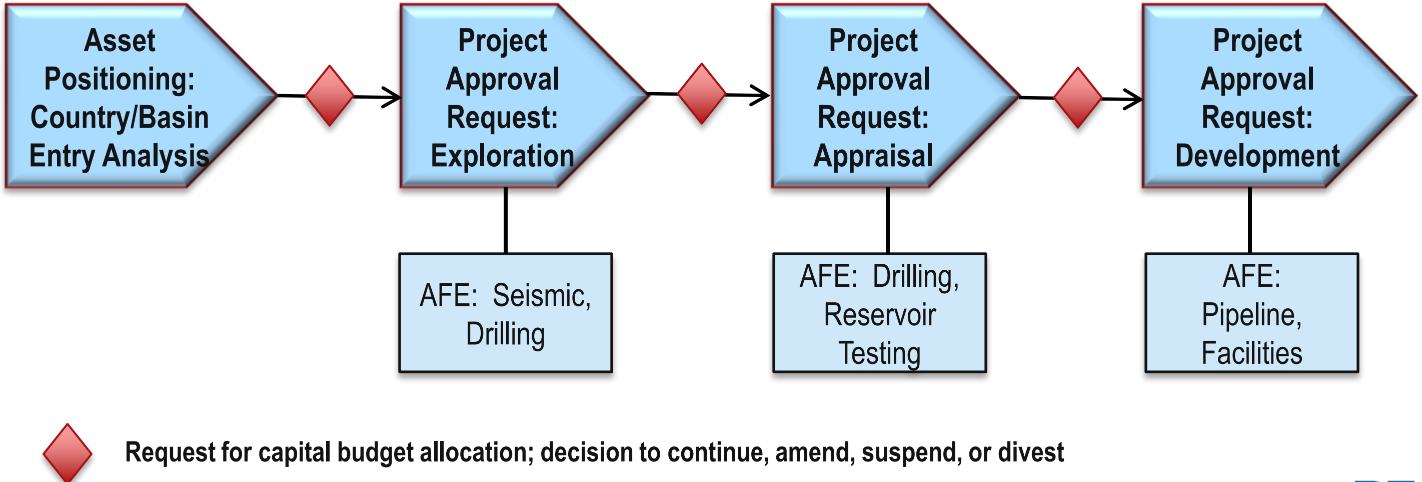
Annual Planning Cycle



Attracting Capital: The Project Approval Process

- Materiality, total capex exposure, full-cycle economics/metrics, are all considerations in determining whether an IOC will position, or continue to invest, in a particular asset or basin.
- Each project is disaggregated into "discrete investment decisions", in the form of Project Approval Requests (PARs), creating a natural *stage-gate* for capital approval and allocation.
  - A PAR can extend beyond a single fiscal year budget, depending on scope of the work program. Represents ***non-discretionary*** capex at the start of the budget year
  - Each PAR has one or a series of associated ***Approval for Expenditure (AFE)*** documents for a specific activity or capex element
  - Sum of AFEs for a calendar year = ***capital Budget***
- Each stage-gate creates an opportunity for Management/Board to determine whether to *continue, amend, suspend, or exit/divest*

Asset Modelling and Decision Process: Materiality and Total Capex Exposure



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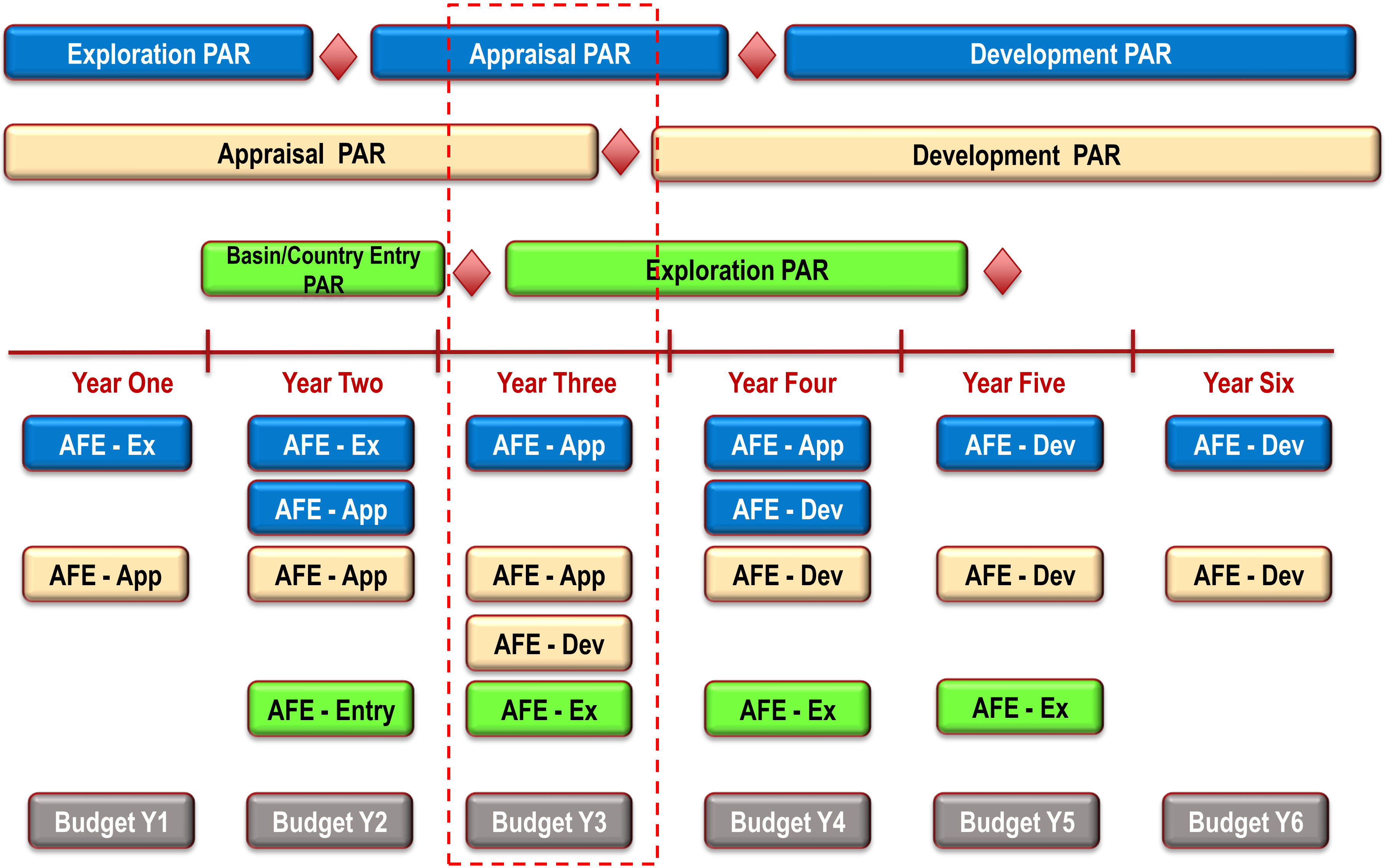
Business Control Architecture:
PAR => AFE => Budget



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Question: On what basis does an E&P company allocate investment capital to opportunities?

- **There are a core set of metrics that allow comparison of projects and investments *within* a given basin/area, and *across* the portfolio of available investment opportunities**
- **For example, an enhanced recovery project in Alaska will compete for capital against:**
  - **Capex investments in Alaska;**
  - **Enhanced recovery projects elsewhere in the portfolio;**
  - **Capex investments elsewhere in the portfolio**
- **Capital programs must also compete against debt repayment, share buyback, and dividend policies**

Upstream Financial Metrics: Measuring Performance

- **Growth** .. Ability to manage the "top line"
  - CAGR in Production and Reserves relative to target
  - Quality of growth .. Where, how, consistent or not (room to run)
  - Plowback Rate. .. Showing relative growth intentions between different regions
- **Profitability** .. Ability to manage the "bottom line"
  - Upstream Cash Flows
  - Upstream Net Income
  - Upstream Production Costs

  Absolute and "per boe" basis
- **Efficiency** .. Ability to manage capital
  - Upstream ROCE
  - Finding costs, F&D costs, Replacement Costs
- **Cash Flow** .. Ability to manage investment/re-investment in the portfolio
  - Financial Strategy (debt targets, debt/capital ratio, dividend requirements)
  - Self-financing nature of portfolio (free cash flow versus capex: regional and global)
- **Risk** .. Ability to manage a diversified portfolio
  - Financial Risk: Debt-to-Capital ratio, financial flexibility
  - New Source Risk: Thinner margin barrels dominating new source volumes

Project Selection and Decision Metrics

Energy companies employ a variety of Benchmarks or Metrics to rank investment opportunities and to allocate financial capital. Some of the more common include:

- Pay-out period; length of time required to recoup financial capital being placed at risk. Simplest selection metric, important to firms with scarce capital resources. No reference to project value after pay-out
- Internal Rate of Return; discount rate at which PV of costs = PV of revenues
- Net Present Value; PV of costs less PV of revenue flows (using discount rate reflecting cost of capital, cost of borrowing, or other);
  - NPV/boe; measure of investment efficiency
  - NPV/Investment (or PVPI); assessment of return to the investment dollar.
- Recycle Ratio: Profit per boe divided by F&D cost per boe. A measure of project or corporate profitability (target >1)
- Discounted and Undiscounted Net Cash Flow Profiles; measure of availability of free cash flow for follow on or alternative investments
- Maximum Negative Cash Flow Exposure; useful in situations where access to financial capital is an issue. Measures the maximum exposure being committed to by the firm
- Net Booked Reserves; contribution of the projects to corporate value (based on bookable reserves, amongst other measures)
- Capex/boe; cost per barrel of production capacity. Burdens the projects by the cost of infrastructure, facilities, etc. Tends to favor less complex, more mature capex alternatives

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Project Metrics: Net Present Value

- **Net Present Value (NPV)**: The estimated value of a project when all future net cash flows are discounted to the present at an appropriate rate (the "discount factor").
- NPV > 0 => project is expected to deliver a return greater than the cost of development, including a return on capital invested (accounted for in the discount factor).
- Advantages:
  - **Time value at corporate rate included**
  - **Can be calculated exactly**
  - **Can accommodate risk through discounting of costs and/or revenue flows**
  - **Useful for valuing projects**
  - **Discount factor reflects corporate preference for opportunity cost of investment capital (e.g., market interest rate, cost of equity capital, weighted average cost of capital (debt and equity))**
- Disadvantages:
  - **Difficult to rank projects. Significantly different capital and expenditure profiles can deliver the same NPV, due to the effect of discounting.**
    - **E.g., very large cash flows in a future time period can have the same "present value" as small cash flows in forward years. This may not, however, have the same impact and value for the company treasury**

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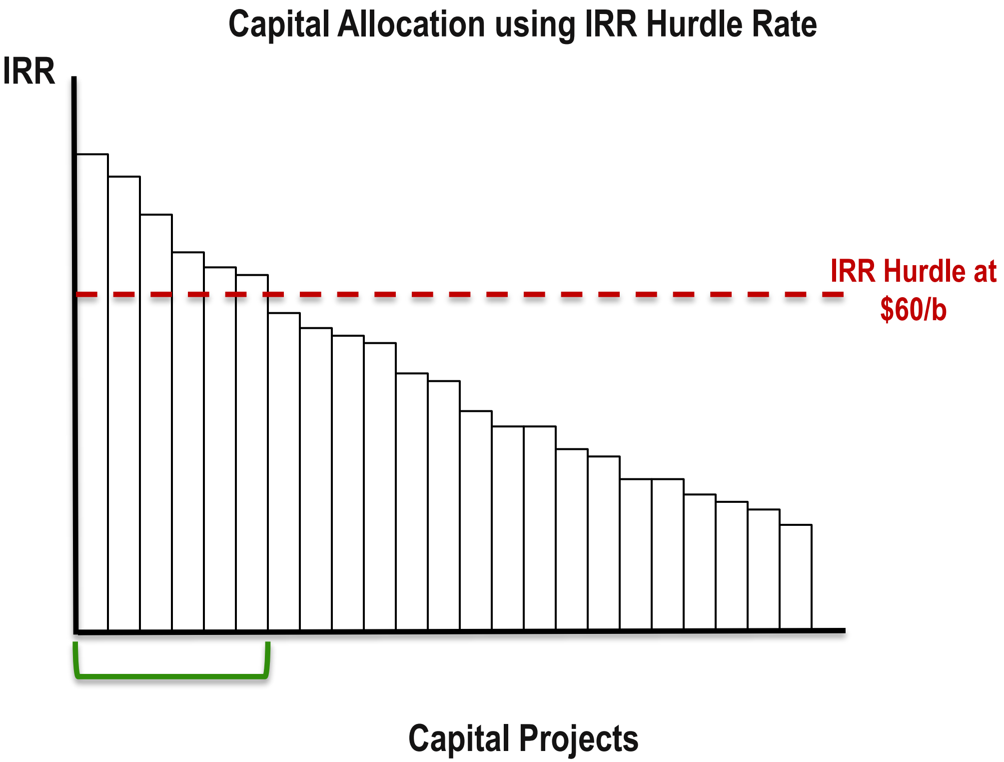
Project Decision Variables: Internal Rate of Return

- **Internal Rate of Return (IRR)**: The discount rate that equates all future cash inflows to outflows at a point in time (usually the present)
- Advantages:
  - **Easy to understand.**
  - **Incorporates time value**
  - **Can be compared to a required minimum (or hurdle rate)**
  - **Independent of magnitude of cash flows.**
- Disadvantages:
  - **Multiple rates of return are possible in cases of material cash flow volatility (e.g., large positive and negative swings over project life); uncomfortable for decision makers looking for unique decision criteria**
  - **Doesn’t measure absolute worth of the project**
  - **Not useful for single project analysis**
  - **Implicit assumption that interim cash flow is invested at calculated IRR (issue for high return projects) => overstates the true project value**

Capital Allocation: IRR Hurdle Rate

- Eligible projects ranked by IRR:
  - **"Eligibility" normally a function of a number of discrete project metrics within each PAR**
  - **Examples:**
    - **NPV10 > 0**
    - **PVPI > 1.3**
    - **Payback < 3 years**
  - **NOTE: These metrics will change over the project cycle, as risks are addressed and estimates become more certain (e.g., 60:40 to 80:20)**
- Corporate establishes a "hurdle" IRR number. Projects with IRR's in excess of the hurdle rate attract budget capital, while those below the hurdle rate are not funded



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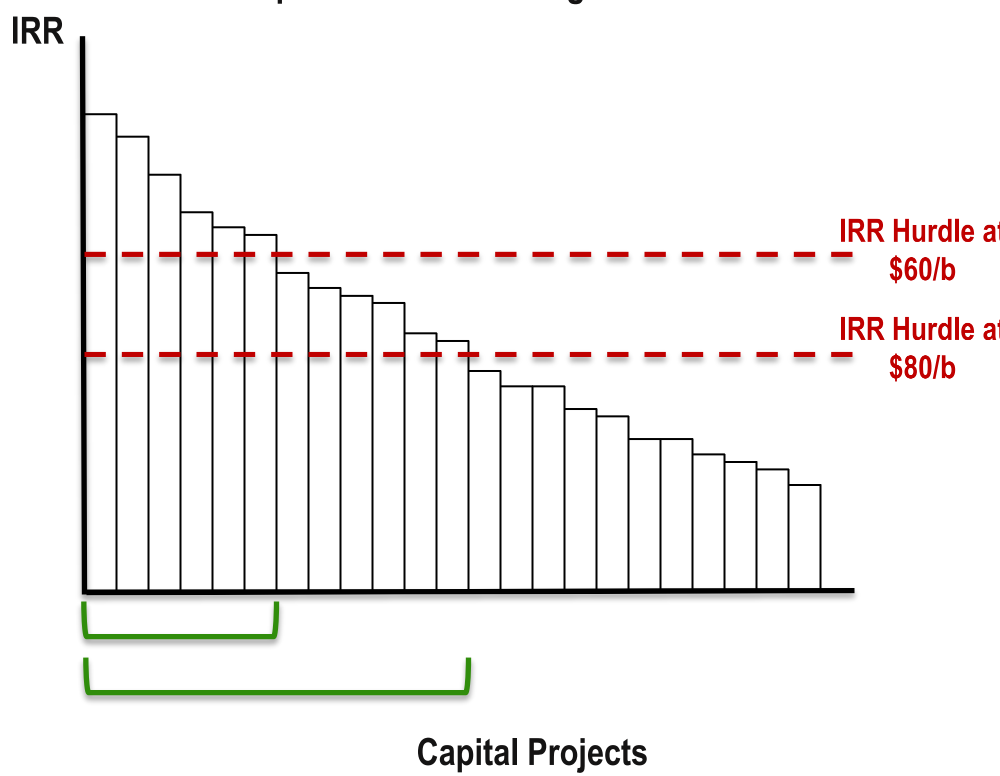
Capital Allocation: IRR Hurdle Rate

- Issues with IRR Hurdle Rate:
  - Increase in free cash flow (due to, say, rise in energy prices) => increased capital budget => lower Hurdle rate in order to undertake additional projects => reduce overall portfolio quality and lower efficiency of capital employed.
  - Evidenced in *cycles of value destruction* within the industry
    - E&P companies will create capital scarcity by increasing share buyback programs, paying down debt, and/or increasing dividends
  - *Gaming the system*: Project managers have an incentive to overstate the "size of the prize" or understate costs, in order to attract investment capital to proposed projects
  - IRR ranking does not speak to *materiality* => equivalent IRR's can have substantially different capex and revenue profiles

Capital Allocation using IRR Hurdle Rate



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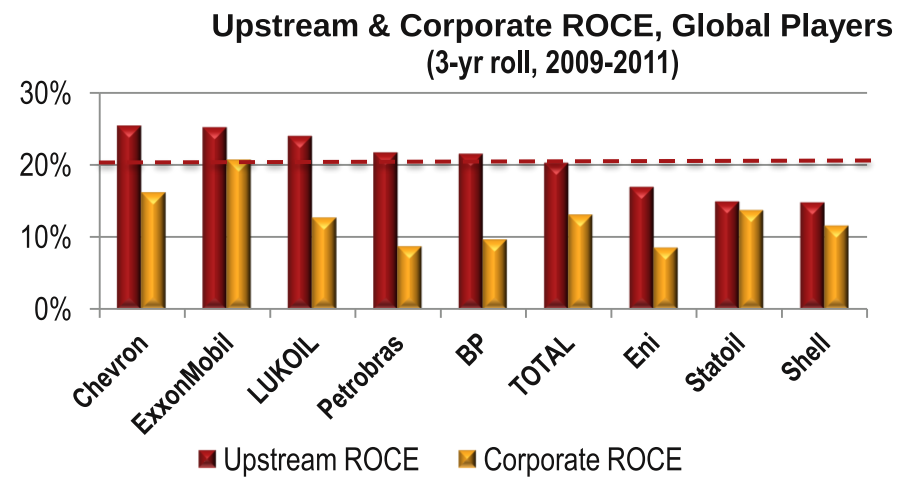
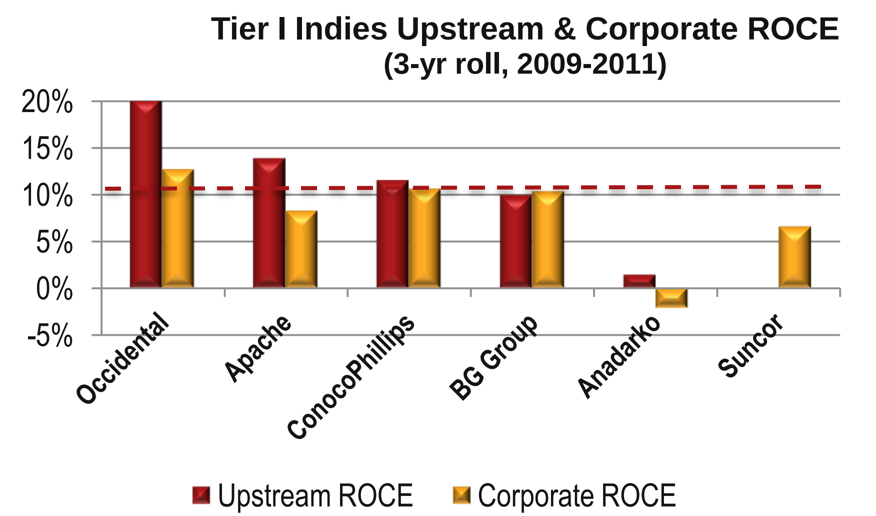
Portfolio Efficiency: Return on Capital Employed (ROCE)

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





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

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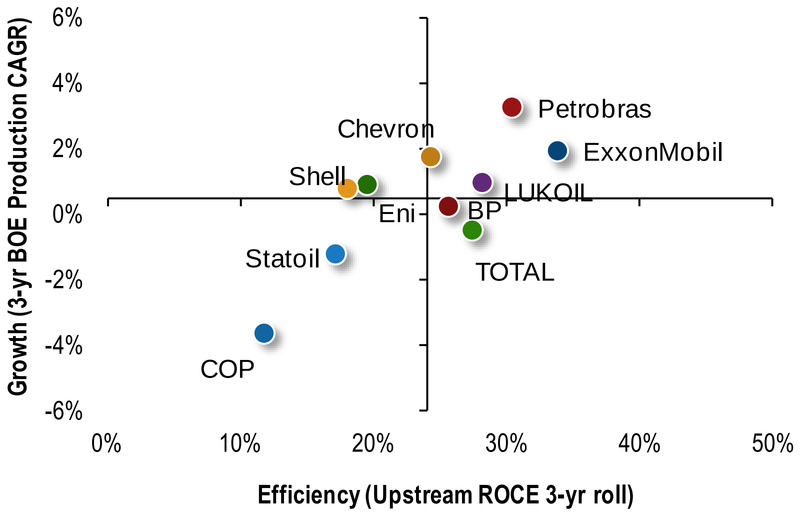
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **Issues with ROCE**:
  - Major capital project investments increase the denominator in advance of revenue (profit) impacts in the numerator => *penalizes the IOC for major capital investment undertakings*
    - Explains in part why it is unusual to find companies with high ROCE and high growth metrics
  - Once commissioned, the scale of major capital project investments tend to deliver superior ROCE performance => *bias toward large asset portfolios*
    - Exception is deepwater developments, where high, short plateaus and steep production declines can result in highly volatile ROCE outcomes
  - Depreciation creates *bias in favor of mature portfolio*: More mature the asset base, the lower the denominator (capital exposed) and the higher the ROCE (all else being equal)

Global Players Peer Group: Growth v Efficiency



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Questions & Discussion

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Part 2:

Global Strategy & Portfolio Overview of Major Alaska Producers

- BP
- ConocoPhillips
- ExxonMobil

Points to Address: Discussion of Portfolio Composition and Growth/Capex Focus

- Where are these companies looking to grow. Which plays and basins are attracting investment capex
- What is the position and role of Alaska within these portfolios

BP: Company Overview

Strategic Signature

- Global integrated company; production in 23 countries, upstream operations in an additional 6 countries.
- 2011 worldwide production of ~3,400 mboe/d, making it the second largest company in the peer group (after ExxonMobil with ~4,513 mboe/d).
  - The Russia & Central Asia (RCA) and North America regions = ~55% of 2011 production.
- Post-Macondo portfolio rationalization program (~$28 bn in asset sales and ~$17 bn in GOM production allocation to Macondo fund) completed in 2013. The result is a pared down and more focused geographic portfolio.
- Executing on a 3-pronged growth strategy:
  - **Deepwater Basins**: US GOM, Angola, Egypt, Brazil
  - **Global Gas**: US, Trinidad & Tobago, North Sea
  - **Giant Oil Fields**: Alaska, Iraq, others.
- Committed ~$20 bn net investment to 16 projects sanctioned over 2010-2011. Will curb ROCE performance for the coming 2-3 years.
- Sale of TNK-BP (~$22 bn proceeds) => ~1 mmboe/d production decline in 2013 from 2012. BP will be hard pressed to outperform its peers on any key metrics.

Company Overview

- **HQ:** London
- **Employees:** 83,400
- **2011 Reserves:** 17,750 mmboe
- **2011 Production:** 3,400 mboe/d
- **3 Yr Production Growth:** -3.53% CAGR (2009-2011)
- **Jan 2013 Market Cap:** $141 bn
- **Jan 2013 P/E Ratio:** 8
- **2011 Corp Revenue:** $375 bn
- **2011 Upstream Capex:** $17 bn

Technological Competence

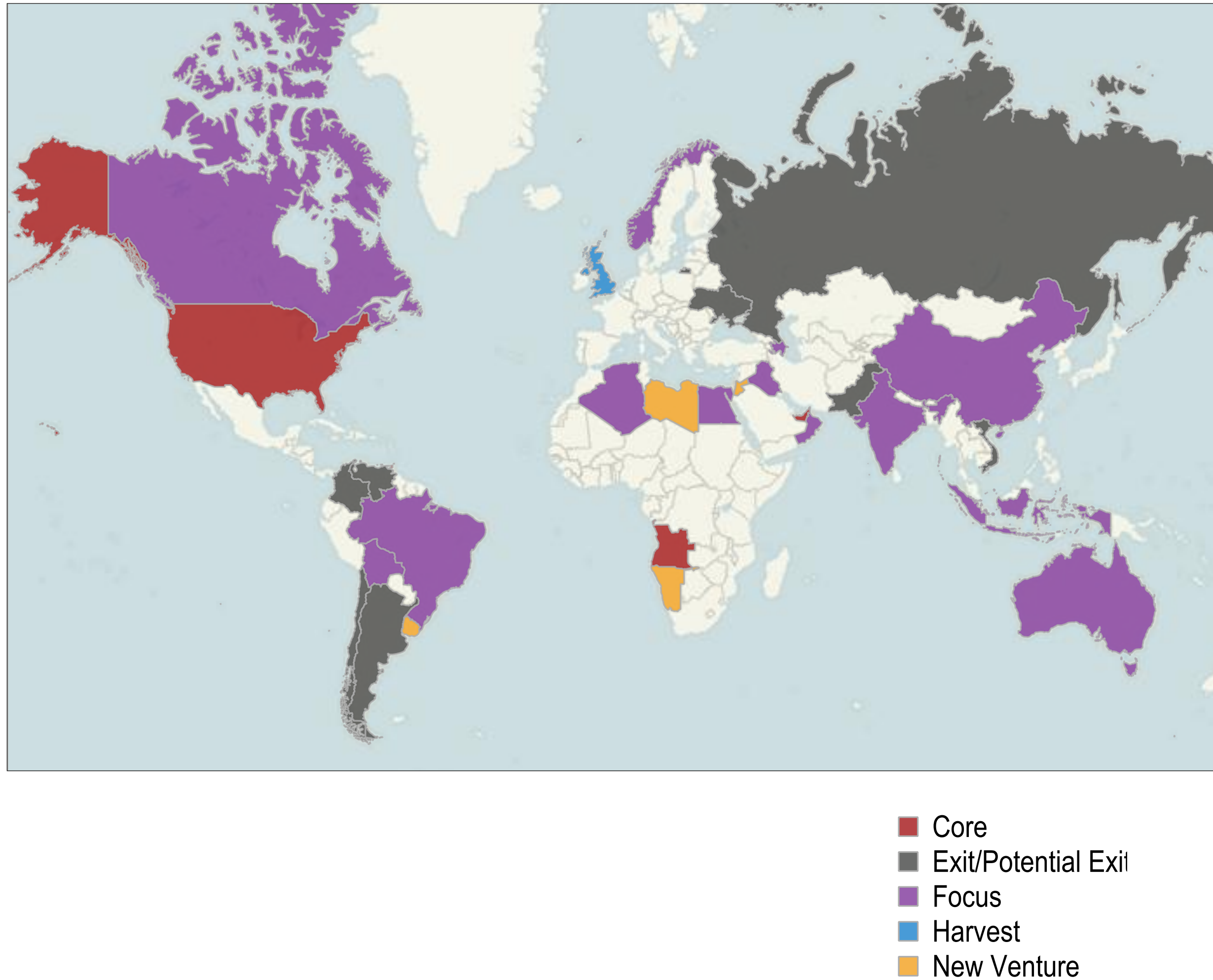
EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	LNG
✓	✓	✓	✓	✓	✓

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

Designation	Country	2011 Total (mboe/d)
Core	United States	760
	Trinidad & Tobago	397
	United Arab Emir..	216
	Angola	123
Exit/Potential Exit	Russia	982
	Argentina	136
	Venezuela	17
	Pakistan	17
	Vietnam	13
	Colombia	2
	Chile	
	Ukraine	
Focus	Egypt	119
	Azerbaijan	117
	Australia	99
	Indonesia	73
	Algeria	41
	Norway	34
	Iraq	31
	India	24
	China	12
	Brazil	7
	Canada	4
	Oman	3
	Bolivia	2
Harvest	United Kingdom	172
New Venture	Jordan	
	Libya	
	Namibia	
	Uruguay	



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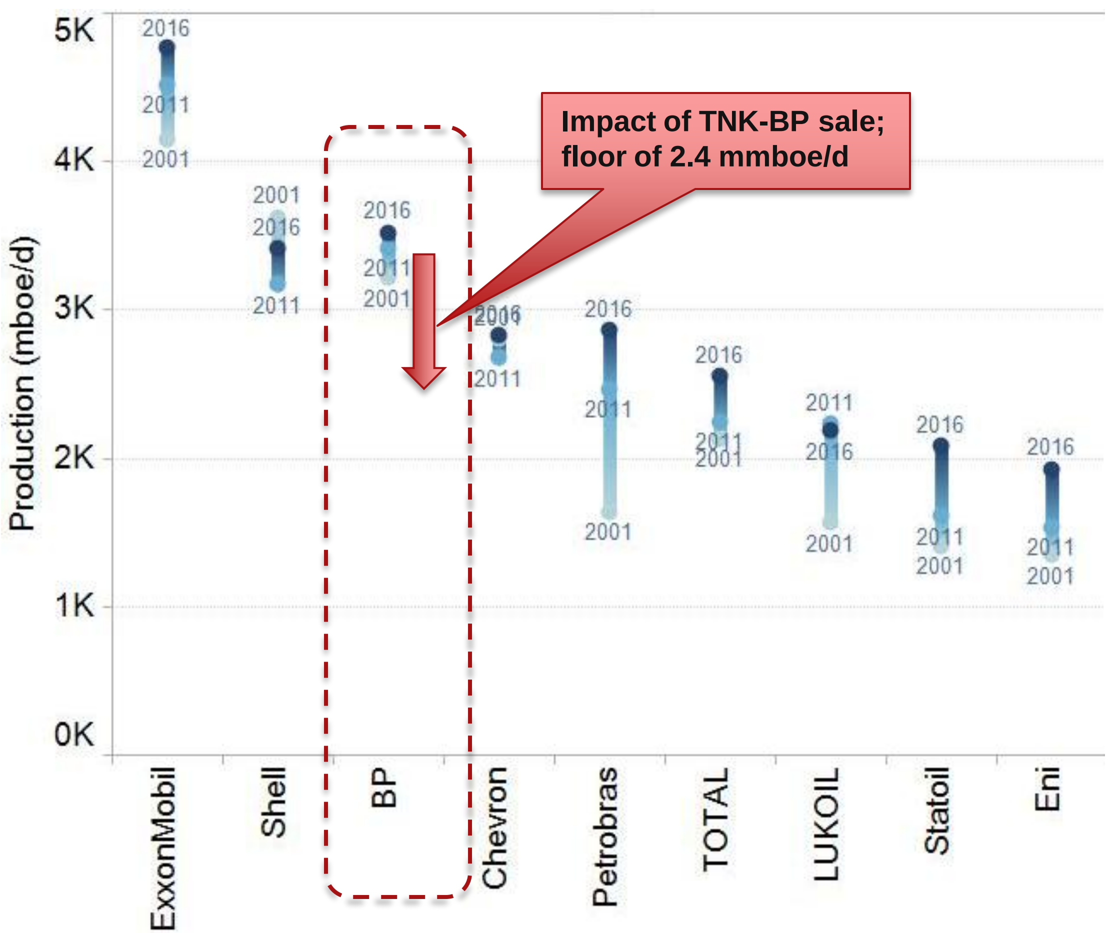
Total Portfolio Evolution: BP vis-à-vis the Competition

Production (mboe/d) in 2001, 2011 and 2016 (PFC Forecast): BP and Peers

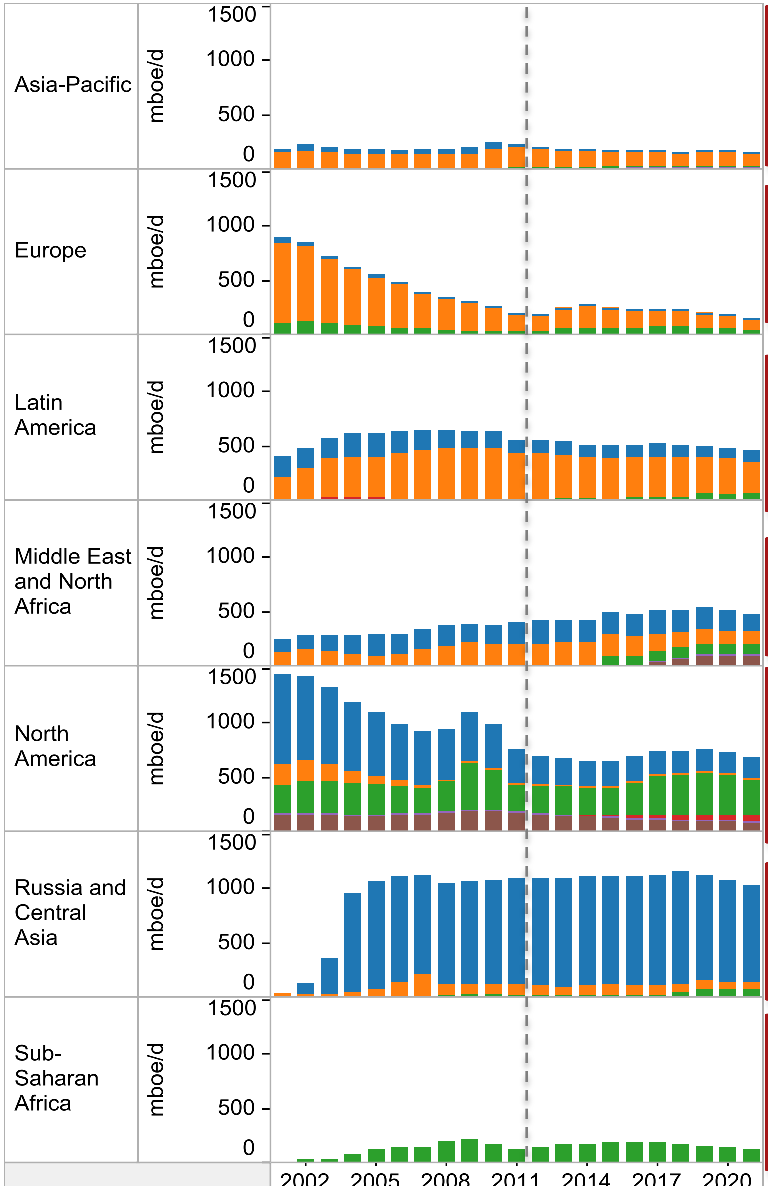


In 2011, BP was the second largest producer of the peer group. BP and COP are the only two companies forecast to deliver production declines over the 2010-2015 period.

2001-2011: Production increases from ~3,080 mboe/d to ~3,400 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), and portfolio divestitures .

2012-2016: BP was forecast to show modest production gains over the period. The sale of its stake in TNK-BP lowers this outlook by ~1 mmboe/d, a volume that would be offset (with improved upside) should the 19.74% equity positioning in Rosneft be concluded

BP: Regional Trajectories



Asia-Pacific: ~246 mboe/d in 2011, centered on LNG feedstock. Expanding deepwater exploration acreage and a growing exposure to CBM. Reliance partnership in India offshore coinciding with divestiture of Pakistan and Vietnam portfolios.

Europe: ~206 mboe/d in 2011; Mature offshore asset portfolio in UK and Norway. Steep fall from ~895 mboe/d in 2001. Harvest Area with near-term production gains through a series of field redevelopment projects.

Latin America: ~561 mboe/d in 2011 (~34% of global gas volumes). Sale of assets in Colombia, reduced exposure in Venezuela (sold to TNK-BP); shift in regional strategy to South Atlantic deepwater exploration and development (Brazil, Uruguay).

Middle East & North Africa: ~410 mboe/d in 2011, a decade high. Large development portfolio (Iraq, Oman, Egypt deepwater) challenged by above ground issues.

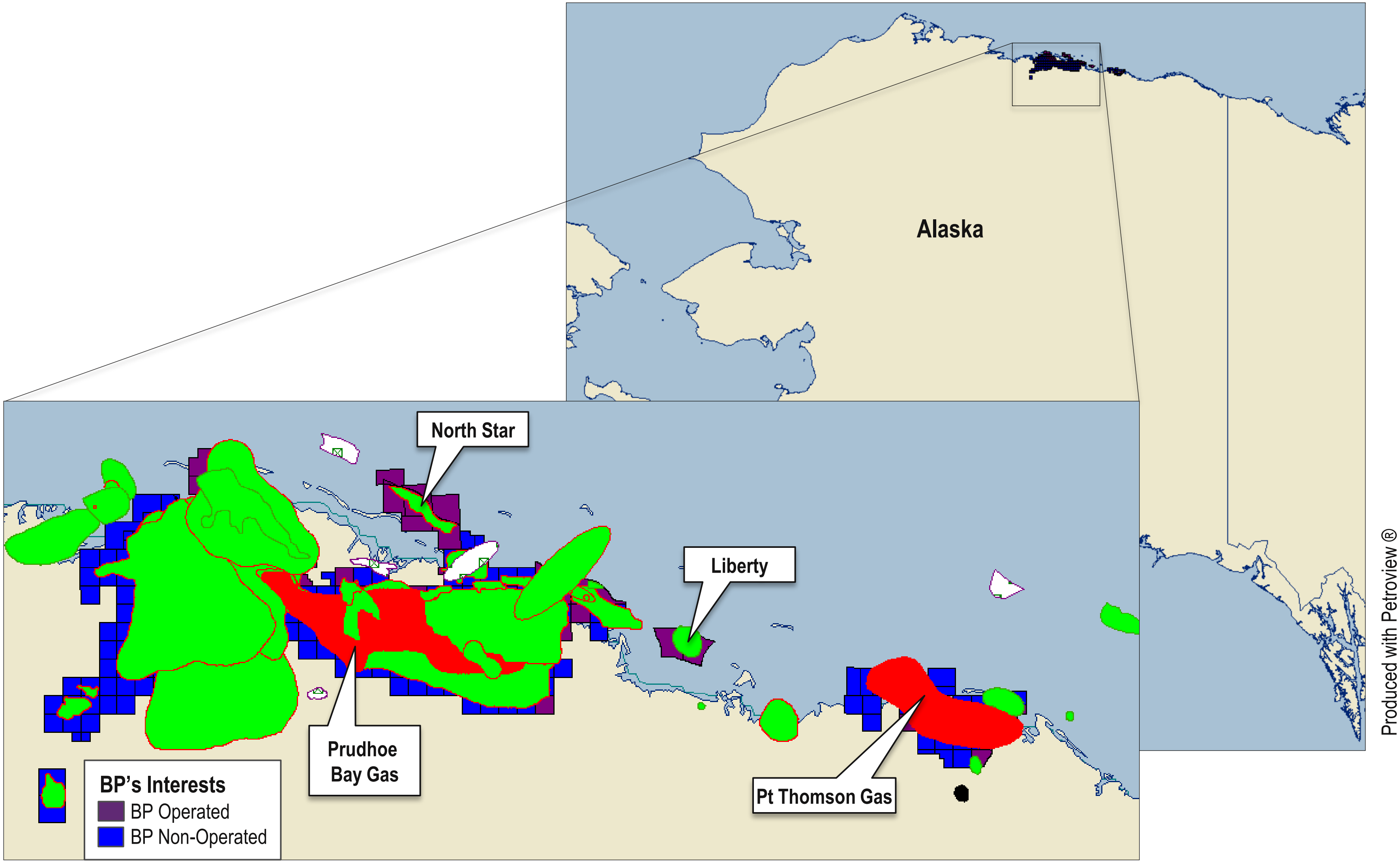
North America: ~764 mboe/d in 2011, 2nd largest production region, focused on Deepwater GOM. Sale of conventional oil and gas assets in Onshore L48, growing focus on shale gas and oil sands development(first oil from the in-situ (SAGD) Sunrise project expected in 2014).

Russia & Central Asia: ~1,099 mboe/d in 2011; dominated by TNK-BP in Russia (divested 2013). Leave Azerbaijan as the sole source of medium-term volume growth.

Sub-Saharan Africa: ~123 mboe/d in 2011, sourced from Angola deepwater. New source volumes from a suite of multi-field deepwater development projects. Positioned to test the pre-salt analog in the Kwanza basin in Angola and further south in Namibia.

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

BP in North America: Alaska



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BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• Asset concentration 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 ~153 mboe/d in 2011, while gas production has fallen from ~67 mmcf/d to ~22 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. BP and ConocoPhillips withdrew the 4 bcf/d **Denali** pipeline proposal (Prudhoe Bay => western Canada => US markets) in May 2011, citing the lack of long-term purchase contracts. • In March 2012 ExxonMobil, ConocoPhillips and BP settled litigation with the Alaskan government over the development of Point Thomson gas reserves, publicly announcing their interest in gas commercialization and export opportunities from Alaska • 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. 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/LNG export option, should one be approved and developed.**

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PFC-Identified Challenges

- **Bring a close to the portfolio rationalization process**: With ~$16 bn in upstream asset divestitures announced since June 2010 and another $17 bn in royalty over-rides redirected to the Deepwater Horizon Oil Spill Reparation Fund, BP indicated in 2Q:2012 a further ~$12 bn in total portfolio asset sales before end-2013 – excluding the net ~$22 bn from the TNK-BP sale. The portfolio repositioning represents an exchange of secure production and proved reserves for higher-risk, less certain, but potentially more material future growth opportunities (Krishna-Godavari basin offshore India, Kwanza pre-salt analog offshore Angola, Equatorial Margin analog offshore northern Brazil). Both analysts and shareholders are looking for a clearer read of where this repositioned portfolio will lead BP over the coming years.
- **Secure a new Core Area**: With positioning in both Russia and the UAE in question, BP faces the prospect of a diminished number of Core areas capable of delivering material, sustained production and free cash flow. This places significant pressure on the transitioning of Focus areas into larger, stable Core operations in order to remain above the targeted 2.3 mmboe/d production floor (ex-TNK-BP volumes). BP is betting heavily on the potential of nascent deepwater plays in the South Atlantic and Asia-Pacific – a strategy that will hinge on exploration success and performance of newly established and uncertain partnerships.
- **Execute the exit from TNK-BP JV and Repositioning in Russia**: Russia production tied to TNK-BP accounted for ~29% of BP's global production in 2011 (and ~25% of total production since 2004), and the second largest source of free cash flow after the US. BP will look to secure a position in Russia's emerging Arctic Resource play through equity positioning (19.74%) in Rosneft – a move with greater upside than TNK-BP, but markedly less control.
- **Develop deepwater partnership with Petrobras**: Having secured Brazil government approval for its acquisition of the Devon asset portfolio (potentially the largest operated pre-salt portfolio outside Petrobras), BP has moved to deepen its ties with the Brazil NOC, farming into Petrobras operated licenses in the pre-salt analog basin areas offshore Angola and Namibia. Subsequent partnering in the Brazil Equatorial Margin suggests a budding deepwater strategic alliance between the two premier deepwater developers, with the prospects of substantial, long term rewards.
- **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.

ConocoPhillips: Company Overview

Strategic Signature

- March 2010: new strategic pathway => ~$15 bn asset and joint venture divestment program, targeting:
  - Debt reduction;
  - Near-term shareholder returns;
  - Shift out of downstream; and
  - Growth from smaller, higher-value portfolio position.
- 2010-2012 Restructuring Plan:
  - ~$7 bn in asset sales
  - Divested i20% equity interest in LUKOIL
  - Proceeds to debt reduction and share repurchase.
- July 2011: Announces restructuring into ***two separate corporate entities***, Downstream (Phillips 66) and a pure play, E&P company (ConocoPhillips).
- Net impact:
  - Production decline to ~1.5 mmboe/d in 2012, recovering to 1.64-1.69 mmboe/d by 2015.
  - Portfolio focus in OECD countries (US, Canada, Australia, UK, and Norway, which accounted for ~75% of worldwide production in 2011).
- Grow 0.5% per annum from 2012 through 2015 from ***Global Gas/LNG, SAGD Oil Sands, and Unconventional Resource*** developments.

Company Overview

- **HQ:** Houston, TX
- **Employees:** ~16,000
- **2011 Reserves:** 8,387 mmboe
- **2011 Production:** 1,610 mboe/d
- **3 Yr Production Growth:** -30.68% CAGR (2008-2011)
- **Jan 2013 Market Cap:** $74 bn
- **Jan 2013 P/E Ratio:** 7.5
- **2011 Corp Revenue:** $235 bn
- **2011 Upstream Capex:** $13.5 bn

Technological Competence

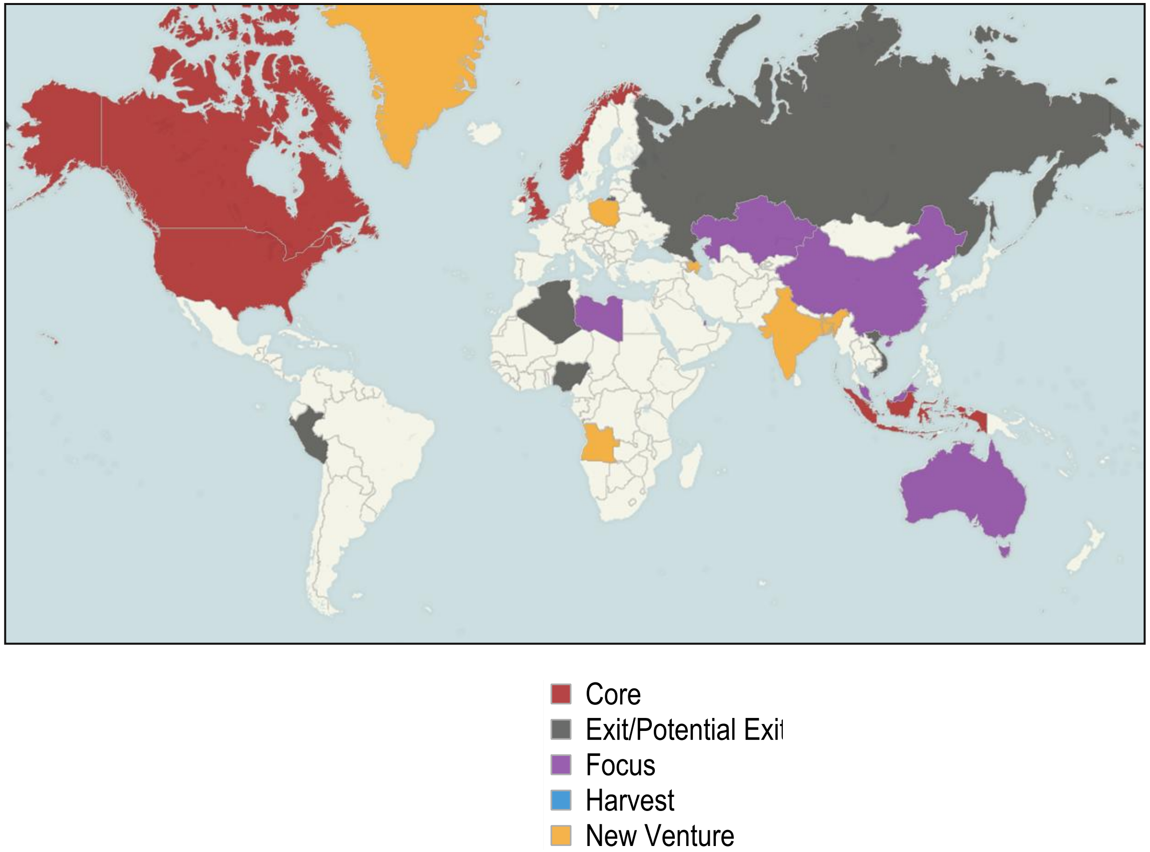
EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✔	✔		✔	✔	

Partnership History

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

ConocoPhillips: Global Areas of Upstream Operations

Designation	Country	2011 Total (mboe/d)
Core	United States	653
	Canada	250
	Norway	147
	United Kingdom	132
	Indonesia	86
Focus	Qatar	85
	Timor Leste/Australia JPDA	63
	China	52
	Australia	26
	Libya	8
	Kazakhstan	
	Malaysia	
Exit/Potential Exit	Nigeria	45
	Russia	29
	Vietnam	20
	Algeria	13
	Peru	
New Venture	Angola	
	Bangladesh	
	Brunei	
	Greenland	
	India	
	Poland	
Grand Total		1,610



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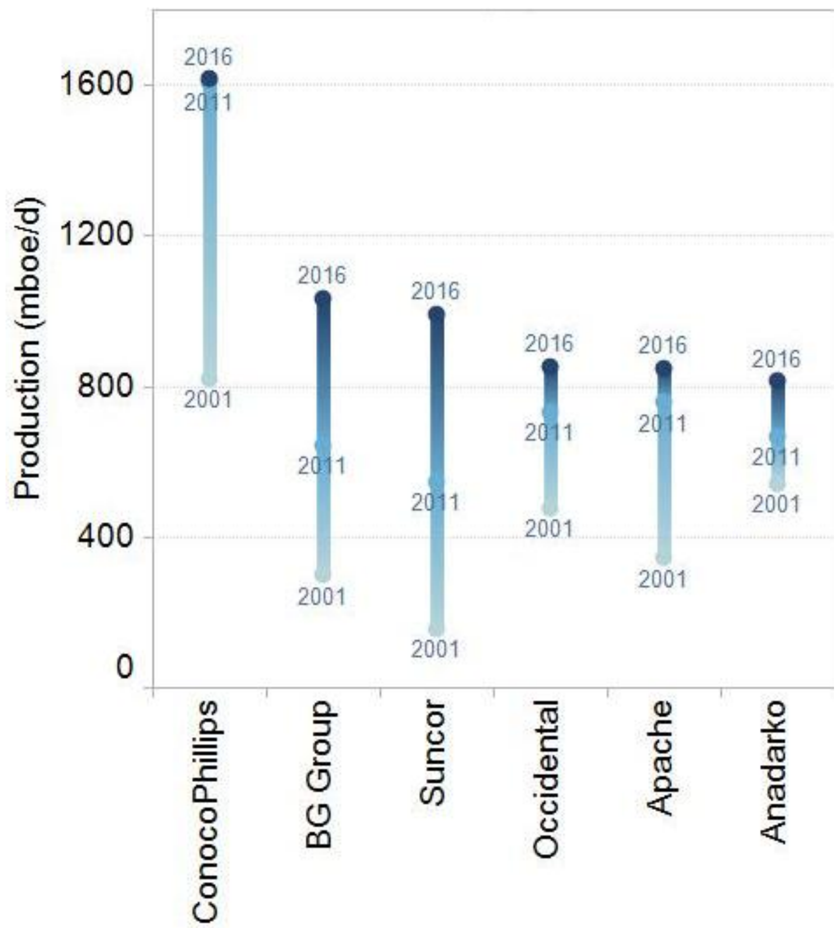
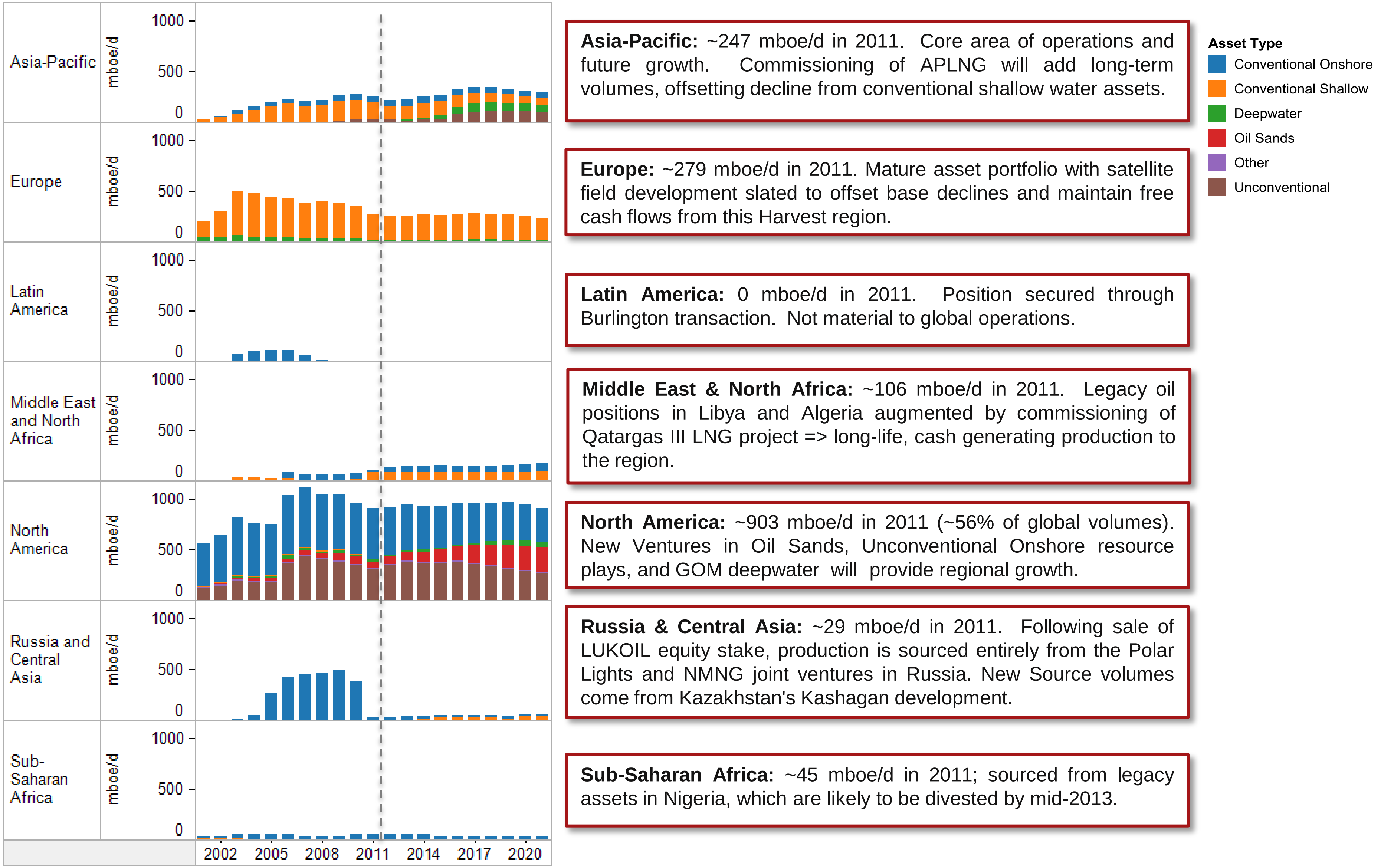
Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition

Tier I International Independents Production 2001, 2011 and 2016 (PFC Forecast)



- The Tier I peer group is comprised of Independents with portfolios capable of delivering ~1 mmboe/d of production over the next 5-7 years
- ConocoPhillips joined the Tier I peer group following its de-integration. Will see production continue to slide, before recovering to slightly above 2011 levels by 2016
- Production increases over 2001-2011 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); the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006); and the gradual acquisition of a 20% stake in LUKOIL later in the decade

ConocoPhillips: Regional Trajectories



Asia-Pacific: ~247 mboe/d in 2011. Core area of operations and future growth. Commissioning of APLNG will add long-term volumes, offsetting decline from conventional shallow water assets.

Europe: ~279 mboe/d in 2011. Mature asset portfolio with satellite field development slated to offset base declines and maintain free cash flows from this Harvest region.

Latin America: 0 mboe/d in 2011. Position secured through Burlington transaction. Not material to global operations.

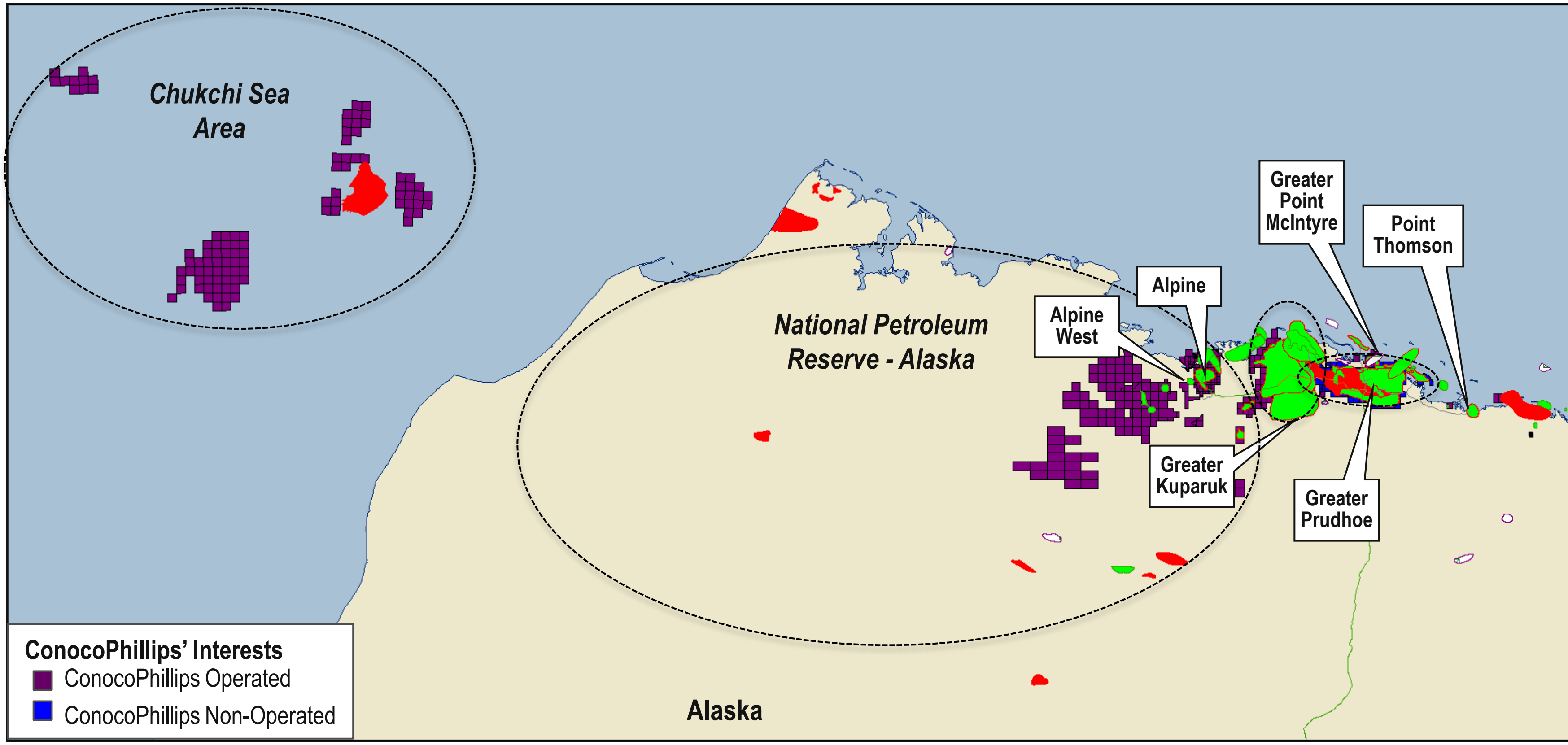
Middle East & North Africa: ~106 mboe/d in 2011. Legacy oil positions in Libya and Algeria augmented by commissioning of Qatargas III LNG project => long-life, cash generating production to the region.

North America: ~903 mboe/d in 2011 (~56% of global volumes). New Ventures in Oil Sands, Unconventional Onshore resource plays, and GOM deepwater will provide regional growth.

Russia & Central Asia: ~29 mboe/d in 2011. Following sale of LUKOIL equity stake, production is sourced entirely from the Polar Lights and NMNG joint ventures in Russia. New Source volumes come from Kazakhstan's Kashagan development.

Sub-Saharan Africa: ~45 mboe/d in 2011; sourced from legacy assets in Nigeria, which are likely to be divested by mid-2013.

ConocoPhillips in North America—Alaska



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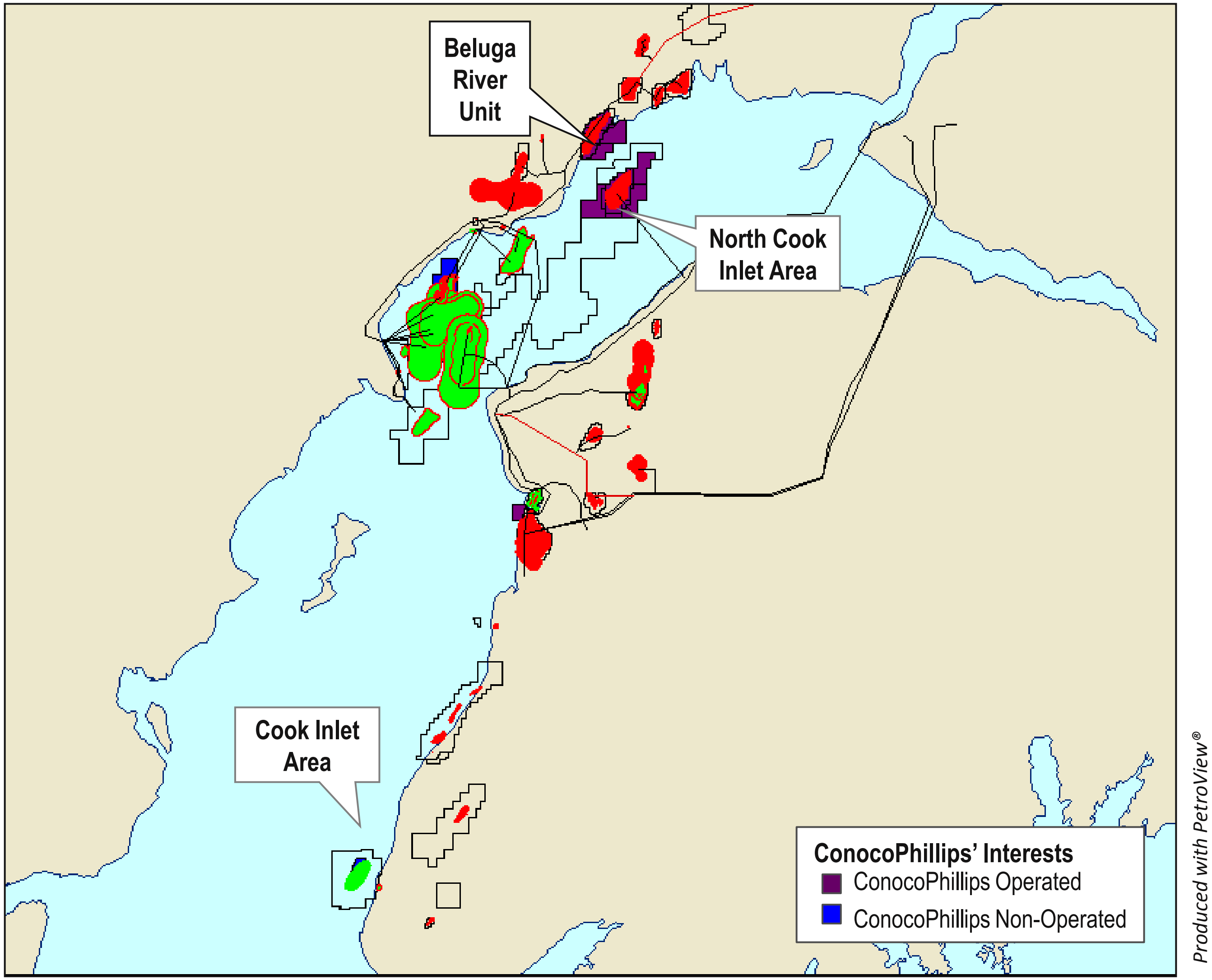
ConocoPhillips in North America—Alaska Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



PFC Energy

ConocoPhillips **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• Legacy portfolio acquired from Arco Alaska in 2000; includes the Greater Prudhoe Area (largest production), Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. • Production from the mature Alaska portfolio has been in slow decline since the late 1980s. In 2011, net production from Alaska averaged 215 mb/d of oil and 61 mmcf/d of gas, accounting for ~35% of US production. • 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. • 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 2015-2016. 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.	**Alaska's largest oil and gas producer. While continuing 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. • 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 2014.	

PFC Energy

PFC-Identified Challenges

- **Competing as a "Pure Play" E&P Company**: Repositioned as the largest Independent E&P company by a considerable margin. In the near-term, COP is a smaller company with limited near-term production growth and improved, but unlikely to be leading, ROCE and financial performance.
  - Has the company simply re-introduced its prior dilemma—too large to compete with the smaller International Independents on volume growth, and too small to compete effectively with the Global Players on efficiency metrics? Or can the company successfully deliver both volume and value/efficiency performance form its high-graded, down-sized asset portfolio?
- **Effectively Positioning in High Value Assets**: Sale of low margin, non-core (and largely non-OECD) assets => loss of optionality and diversity within its portfolio that can act as a hedge against commodity cycles and changing market conditions over the long term. Targeting of low risk (OECD) and high margin assets (such as US unconventional oil plays) raises the risk of destroying value by overpaying for competitive assets.
- **Defining Operational Strengths**: Strong partnerships => majority of growth will come from non-operated and/or JV related activity with specialized developers – FCCL JV with Cenovus in the Canadian Oil Sands; Australia Pacific LNG JV with Origin Energy; non-operated assets in the US GOM; Shell in the Malaysia deepwater. Also building considerable expertise in unconventional resource exploitation (both shale gas and tight oil) in the US Onshore.
  - Successful leveraging to unconventional resource plays outside North America could deliver the differentiating competitive advantage and volume growth required for ConocoPhillips to compete effectively within the Independent E&P peer group over the long term.
- **Effectively Managing Base Production**: Minimizing the decline in production from the company's base portfolio—which has a high proportion of gas production exposed to continued weak North American gas prices—is essential for the company to deliver simultaneous production and margin growth.
- **Delivering Production Growth**: Production has fallen by 30% since 2009 (2,286 mboe/d to 1,610 mboe/d in 2011). New source developments basically keep pace with mature asset declines in the MENA, Europe, and RCA regions => material net growth must come from ***North America and Asia Pacific***. US Onshore unconventional liquids plays are currently projected to deliver ~22% of total worldwide new source volumes in 2021

PFC Energy

ExxonMobil: Company Overview

Strategic Signature

- Largest of the Global Players
  - ~4,513 mboe/d in 2011; production in 21 countries, with upstream operations in an additional 20 countries.
- Growth strategy based on scale, basin dominance, and execution excellence => continuously seek access to investment opportunities of adequate size and materiality.
- Move into unconventional resource plays was a default for ExxonMobil:
  i. Commissioning of the final elements of the company's Qatar project portfolio in 2011
  ii. Declining production from its Europe and Asia-Pacific portfolios
  iii. Roadblocks to materiality in Brazil deepwater, Venezuela extra-heavy, and Equatorial Margin
  iv. Already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.
- 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation (~2.3 bcf/d and 87 mboe/d of production, proved reserves of ~2.3 bn boe, resource base of 7.5 bn boe).
- Leveraging XTO into a global unconventional portfolio.

Company Overview

- **HQ:** Irving, Texas
- **Employees:** 83,600
- **2011 Reserves:** 24,922 mmboe
- **2011 Production:** 4,513 mboe/d
- **3 Yr Production Growth:** 4.53% CAGR (2008-2011)
- **Jan 2013 Market Cap:** $415 bn
- **Jan 2013 P/E Ratio:** 9.6
- **2011 Corp Revenue:** $486 bn
- **2011 Upstream Capex:** ~$28 bn

Technological Competence

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

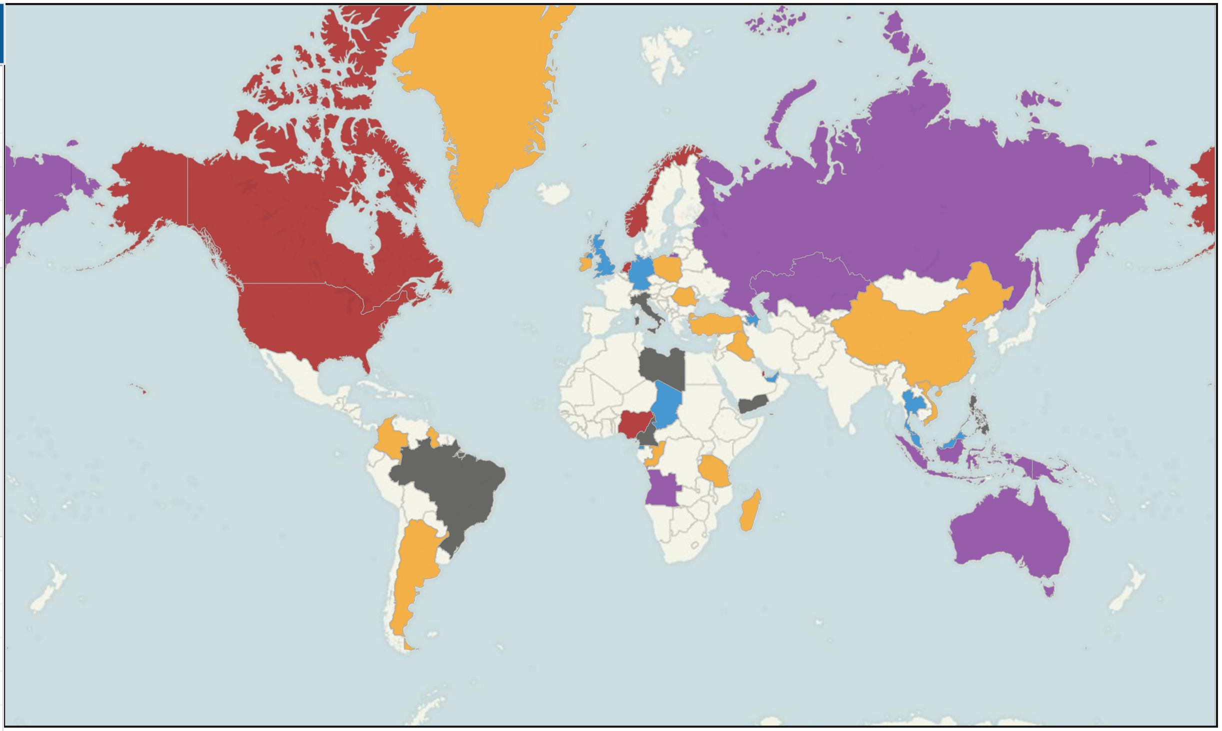
Partnership History

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

Designation	Country	2011 Total (mboe/d)
Core	United States	1,076
	Qatar	972
	Nigeria	325
	Norway	315
	Canada	313
	Netherlands	311
Harvest	United Arab Emirates	278
	United Kingdom	129
	Malaysia	108
	Germany	89
	Equatorial Guinea	45
	Chad	40
	Azerbaijan	21
	Thailand	3
Focus	Kazakhstan	151
	Australia	100
	Angola	99
	Russia	57
	Indonesia	39
	Papua New Guinea	6
New Venture	Iraq	27
	Argentina	8
	China	
	Colombia	
	Congo, Republic of the (Brazz..	
	Greenland	
	Guyana	
	Ireland	
	Madagascar	
	Poland	
	Romania	



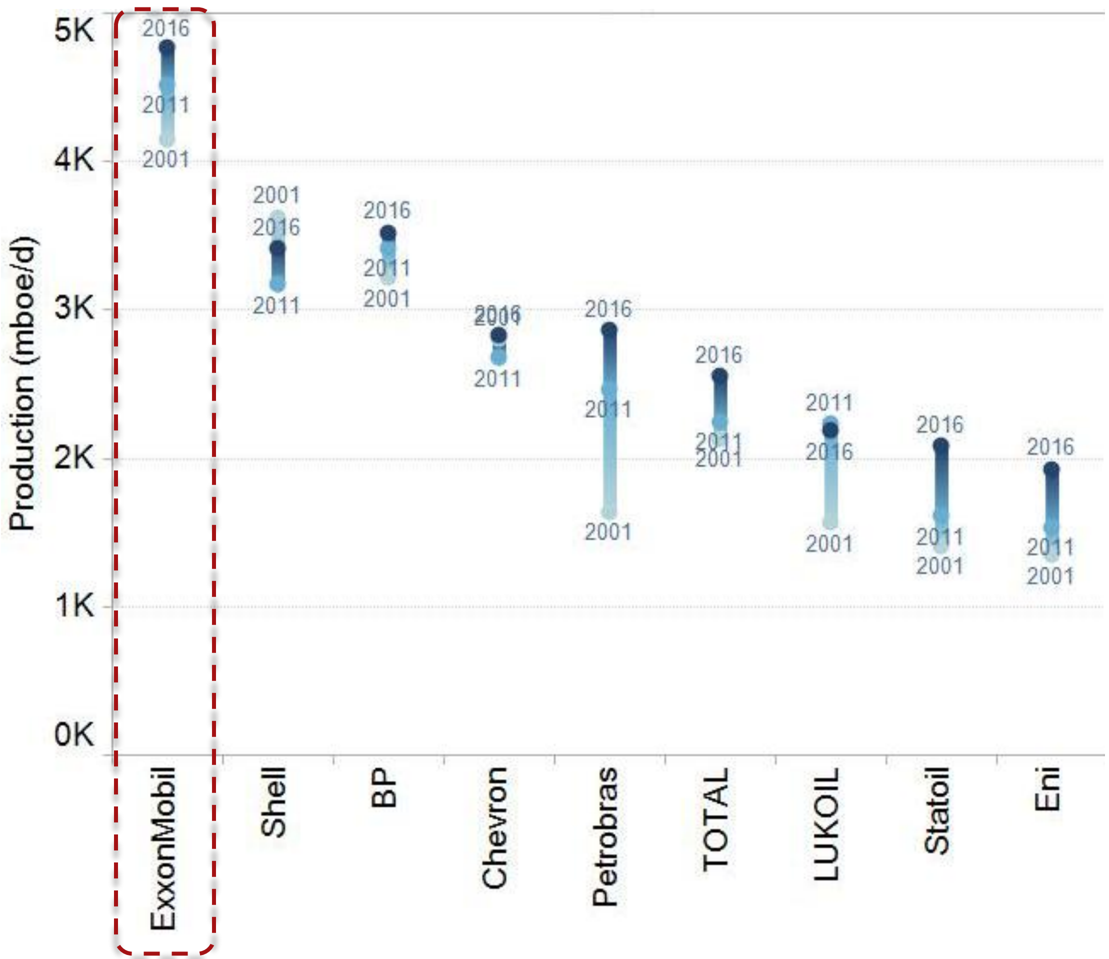
Designation	Country	2011 Total (mboe/d)
New Venture	Tanzania	
	Turkey	
	Vietnam	
Exit/Potential Exit	Brazil	
	Cameroon	
	Italy	
	Libya	
	Philippines	
	Yemen	
Grand Total		4,513

- Core
- Exit/Potential Exit
- Focus
- Harvest
- New Venture

PFC Energy

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

Production (mboe/d) in 2001, 2011 and 2016 (PFC Forecast): XOM and Peers

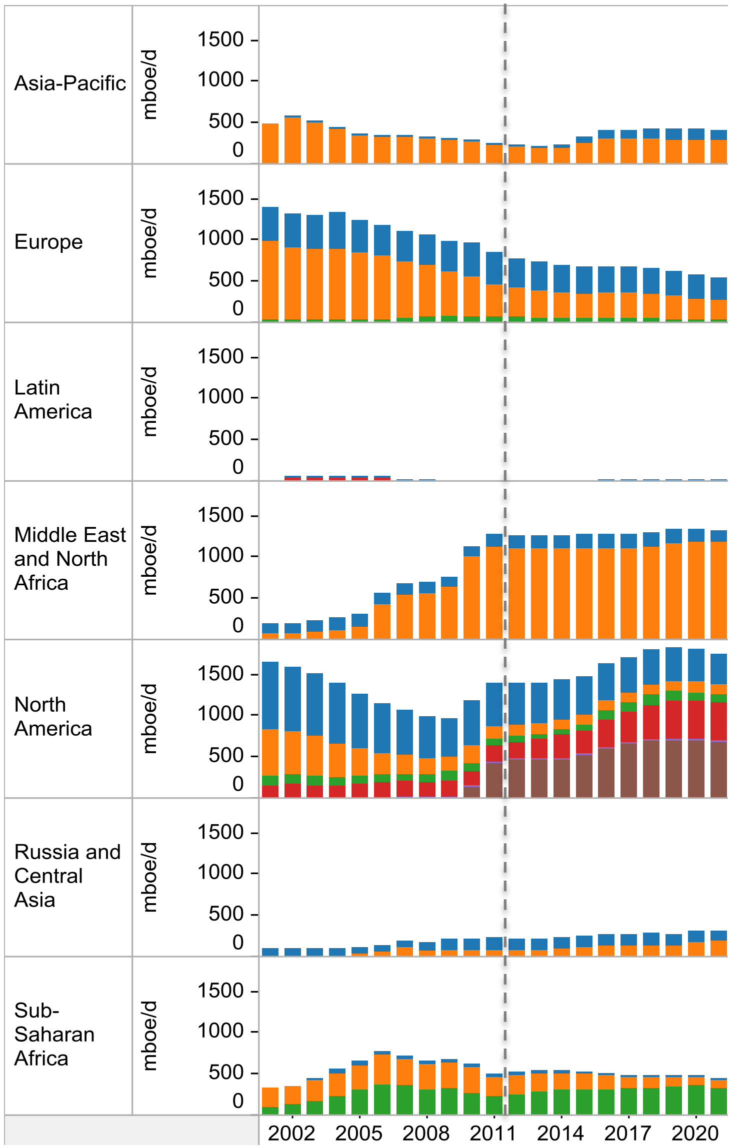


Averaging ~4.5 mmboe/d in 2011, ExxonMobil continues to lead its peer group in terms of production.

2001-2011: Production oscillated through the decade, landing in 2009 at roughly the same level as 2001 (~4.0 mmboe/d), before rising 13% in 2010 (~6% excluding the XTO acquisition) to ~4.45 mmboe/d. The XTO acquisition marked a considerable departure from ExxonMobil's longstanding organic growth strategy.

2011-2016: Modest volume growth, reaching ~4.69 mmboe/d in 2016. While PFC Energy estimates are lower than ExxonMobil targets, the absence of guidance regarding growth projects associated with the XTO portfolio makes the pace of future growth uncertain.

ExxonMobil: Regional Trajectories



Asia-Pacific: ~256 mboe/d in 2011. Focus on strengthening gas position in the region, to offset rapidly declining oil production base. Several MT/LT gas export projects including Gorgon and PNG LNG.

Europe: ~845 mboe/d in 2011. Mature asset decline and accelerating divestiture program have eroded region production from 1,393 mboe/d in 2001. New source volumes not expected to reverse this downward trend.

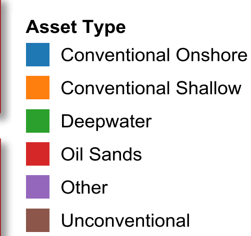
Latin America: ~8 mboe/d in 2011. Sole new source production is forecast from Argentina's Neuquen Basin, where ExxonMobil is a relatively early entrant to the unconventional shale gas play

Middle East & North Africa: ~1,277 mboe/d in 2011. Growth over the last decade driven by LNG projects in Qatar (stalled by ongoing moratorium on North Field development). Large legacy position in the UAE, a challenged upstream position in southern Iraq, and new exploration in Kurdistan.

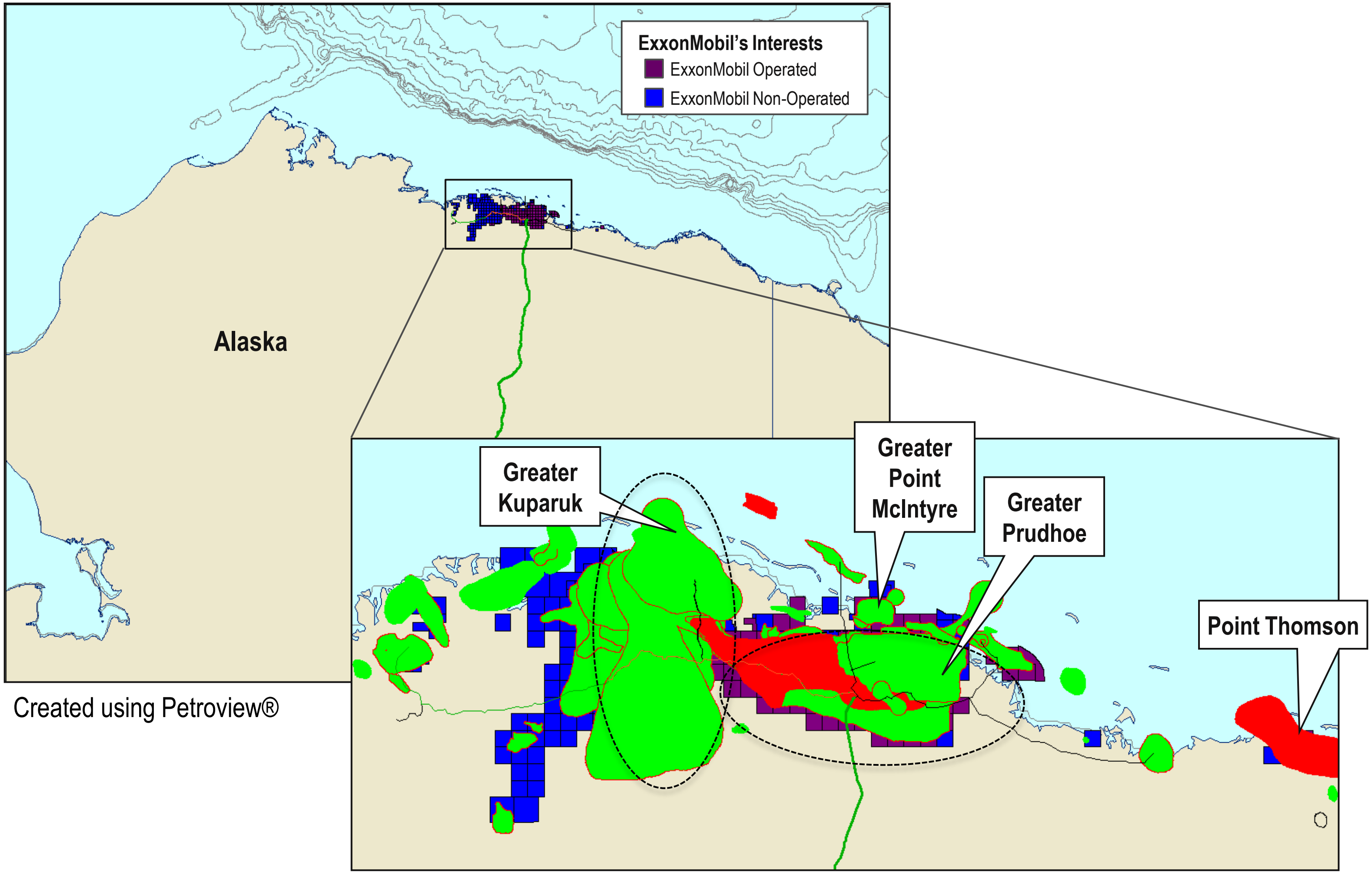
North America: ~1,389 mboe/d in 2011. Expanded positioning in the US Onshore shale gas plays, material deepwater US GOM portfolio, development projects in the Canadian Oil Sands combine to deliver material production growth over the long term.

Russia & Central Asia: ~229 mboe/d in 2011. Growth from a small portfolio of large-scale assets, most of which face above ground challenges. Project execution on unsanctioned development queue remains critical.

Sub-Saharan Africa: ~509 mboe/d in 2011. A "treadmill" operation, with robust new source volumes centered in deepwater Nigeria and Angola keeping pace with field declines.



ExxonMobil in North America: Alaska



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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 114 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 2015-2016. Longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline and accessing export markets.	**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. Maintaining and growing upstream investment increasingly hinges on a gas commercialization/export scheme.**

PFC Energy

PFC-Identified Challenges

- **Adapting to the unconventional resource play business environment** : The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play, shifting growth focus to a business model that is quite different from the large-scale, major capital projects that have driven core growth for the company over the last decade. With more than two-thirds of its unconventional resource acreage holdings (excluding the oil sands) positioned in gas plays, the company is clearly challenged by the ongoing weakness in natural gas realizations in North America. This is reflected in the company's growing interest in US LNG exports—both from Alaska and the US Onshore. However, this is a long-term fix for a near-term challenge, and one with considerable arbitrage risk in the form of firming Henry Hub gas prices over the latter half of the decade.
- **Delivering on a new growth strategy based on strategic partnerships and frontier exploration opportunities**. The development moratorium on the Qatar North Field has left ExxonMobil searching for new engines of growth. One response has been a shift in strategy towards strategic partnerships and frontier exploration – reflected in the Rosneft strategic agreement covering frontier exploration in the Russia Arctic.
- **Execution or rationalization of challenged reserves and/or developments positions**. These include:
  - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta);
  - Development of captured oil reserves in the Caspian region, plagued by delays, cost over-runs, and accelerating resource nationalism;
  - Delivering on the West Qurna I redevelopment project in Iraq, which remains challenged by export infrastructure constraints. The securing of six exploration licenses in the northern Kurdistan region is the latest signal of ExxonMobil's concern over the ability of Iraq to evolve into a Core area for the company.
- **Maintain leadership in share buy-back and dividend performance**: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~$29 bn through dividends and share buy-backs in 2011 and spending ~$109 bn on share repurchase over the 2007-2011 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.

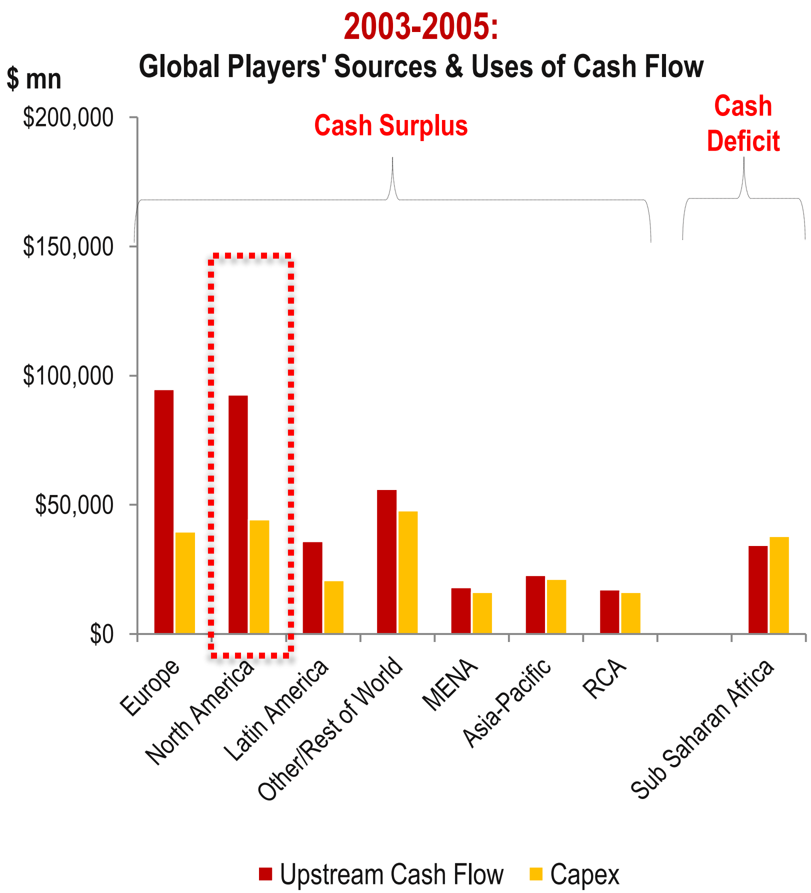
PFC Energy

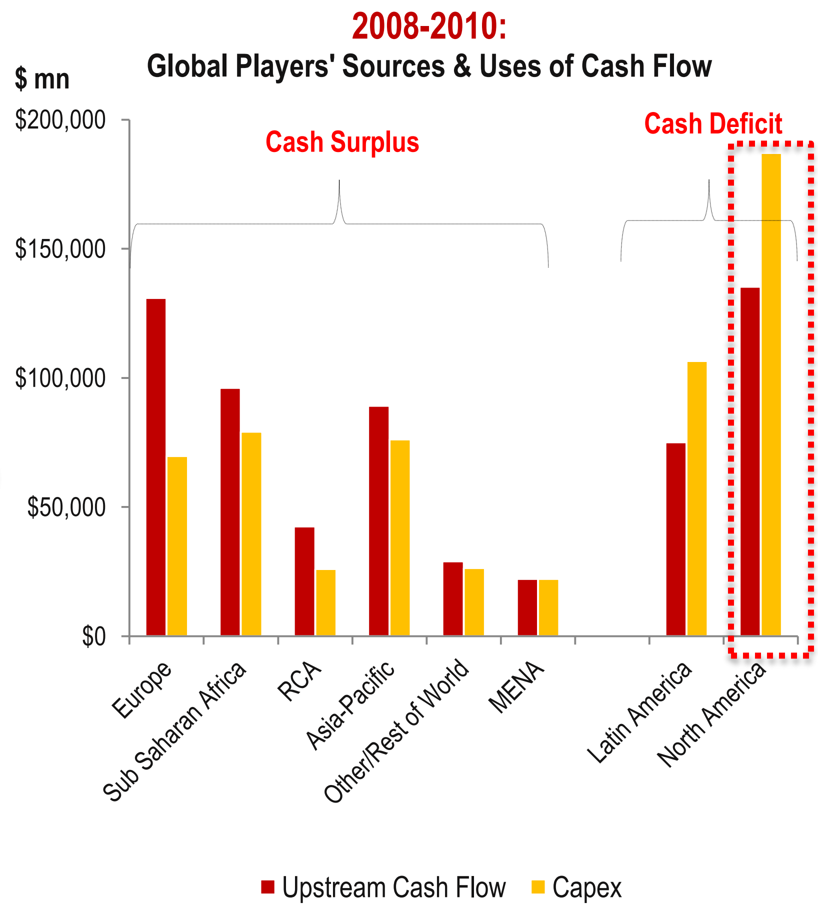
Questions & Discussion

2011	Alaska	% US	% Global	% Trend
BP	173 mboe/d	17	5	↓
COP	244 mboe/d	36	14	↑
XOM	117 mboe/d	14	3	↓

Alaska's Fiscal Regime in a Global Competitive Context

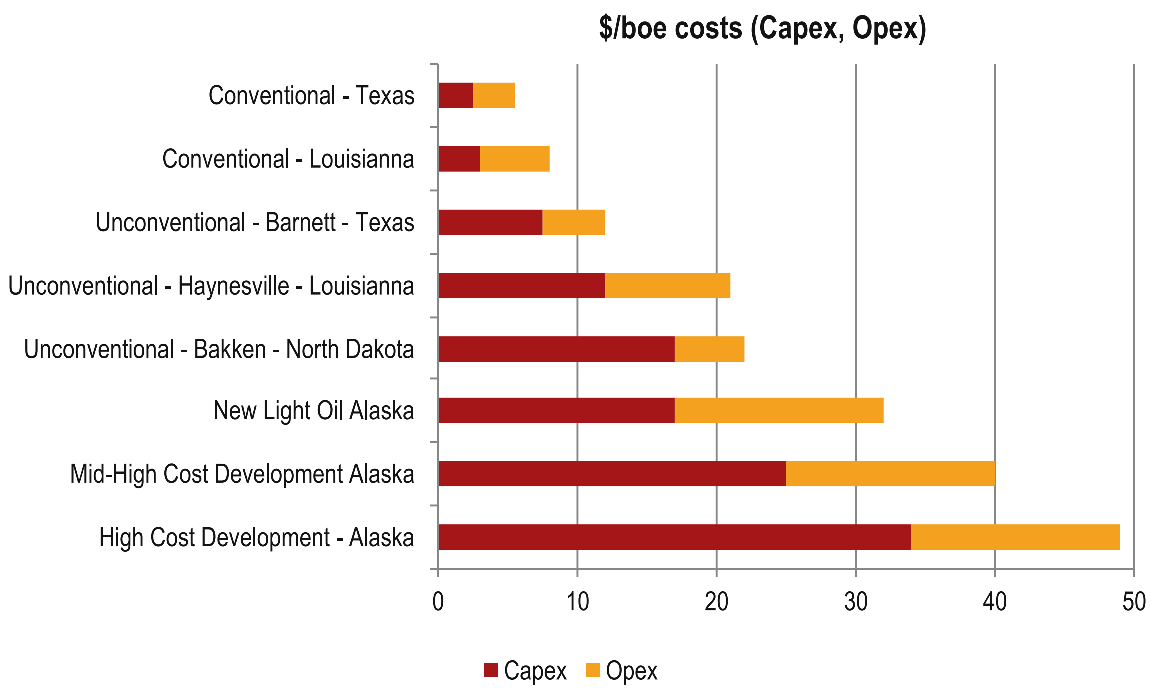
Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars





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

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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Relative Government Take (Definition)

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

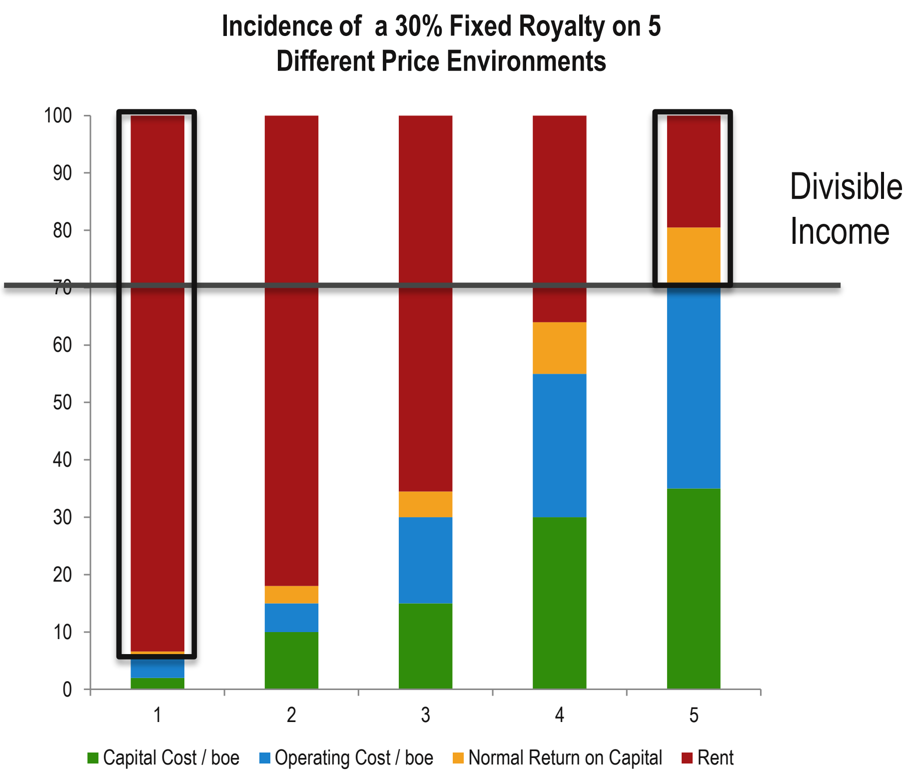
Divisible Income equals Gross Revenues less costs, including capex and transportation costs.

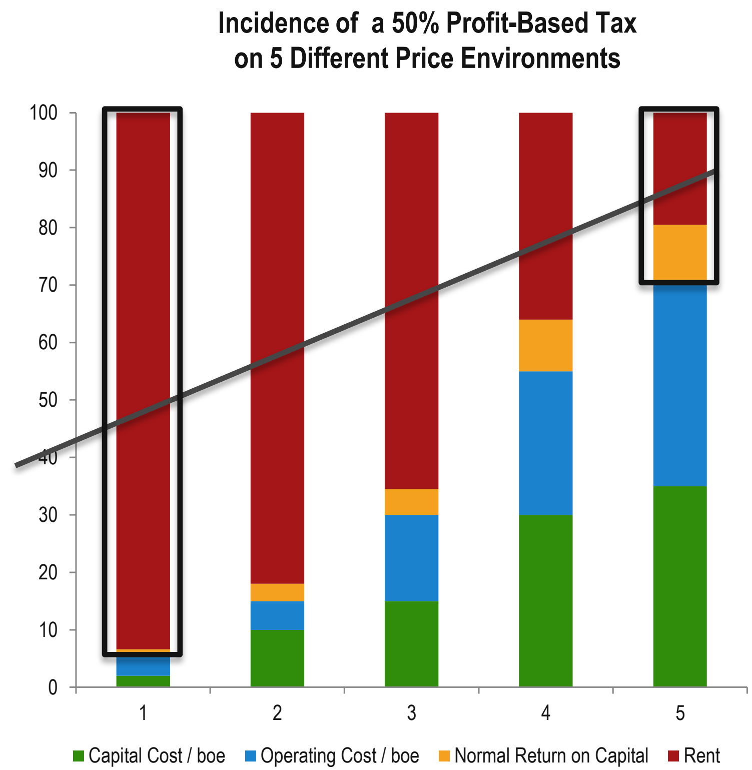
Government Take includes all payments the government mandates in its function as a sovereign:

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

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

Fixed Royalty v Profit Based Fiscal Systems





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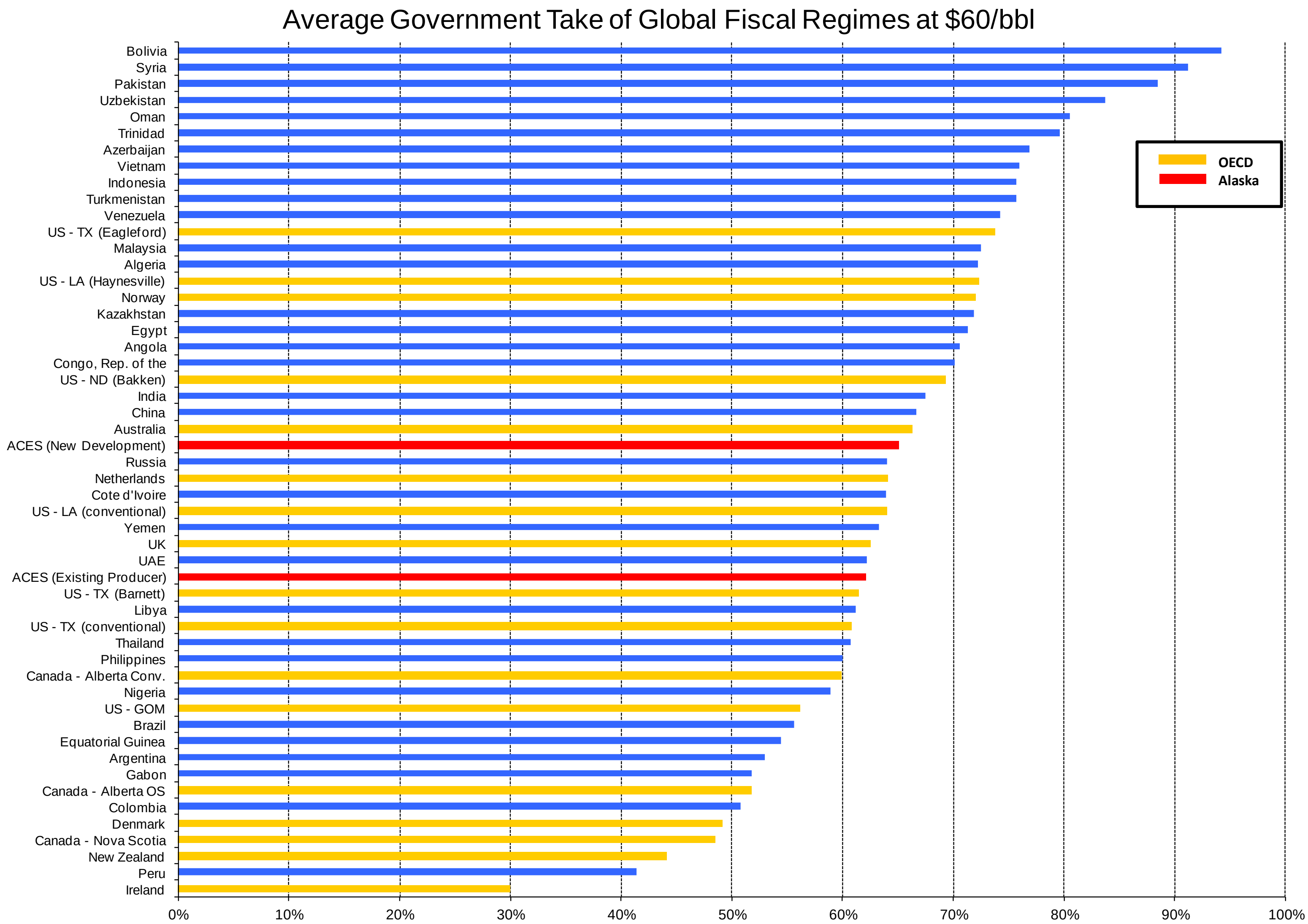
Regime Competitiveness: Average Government Take at $60/bbl



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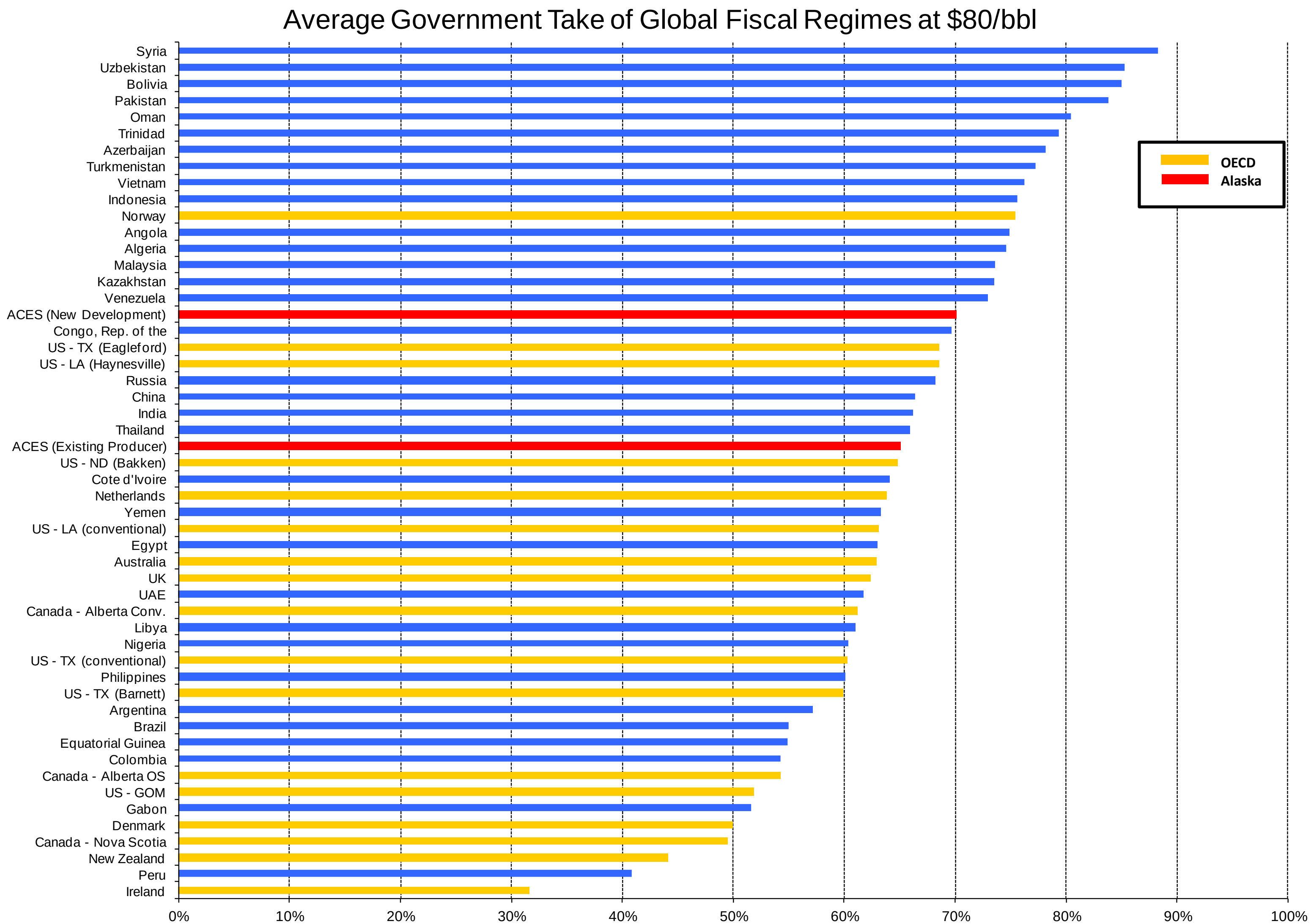
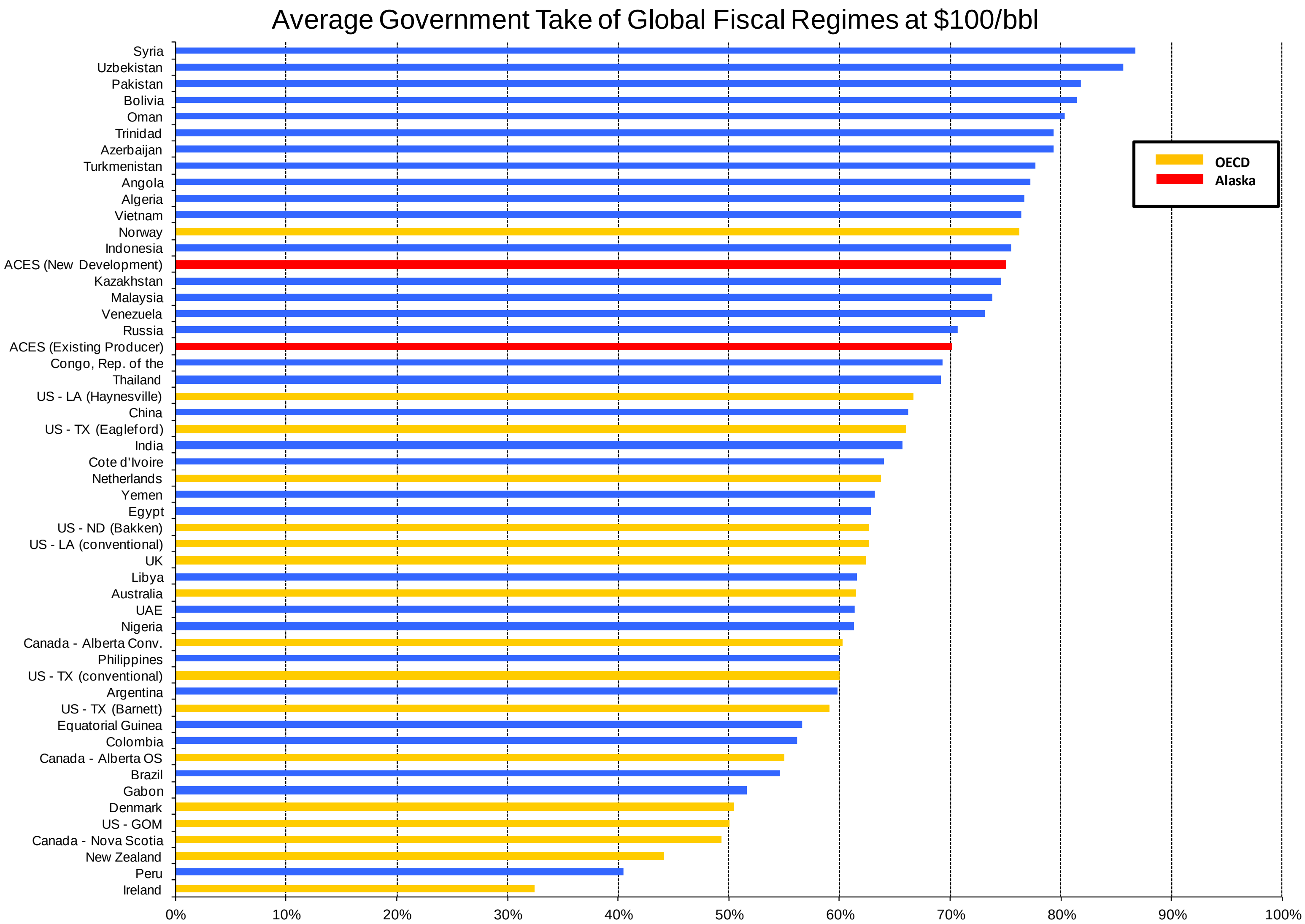
Regime Competitiveness: Average Government Take at $80/bbl

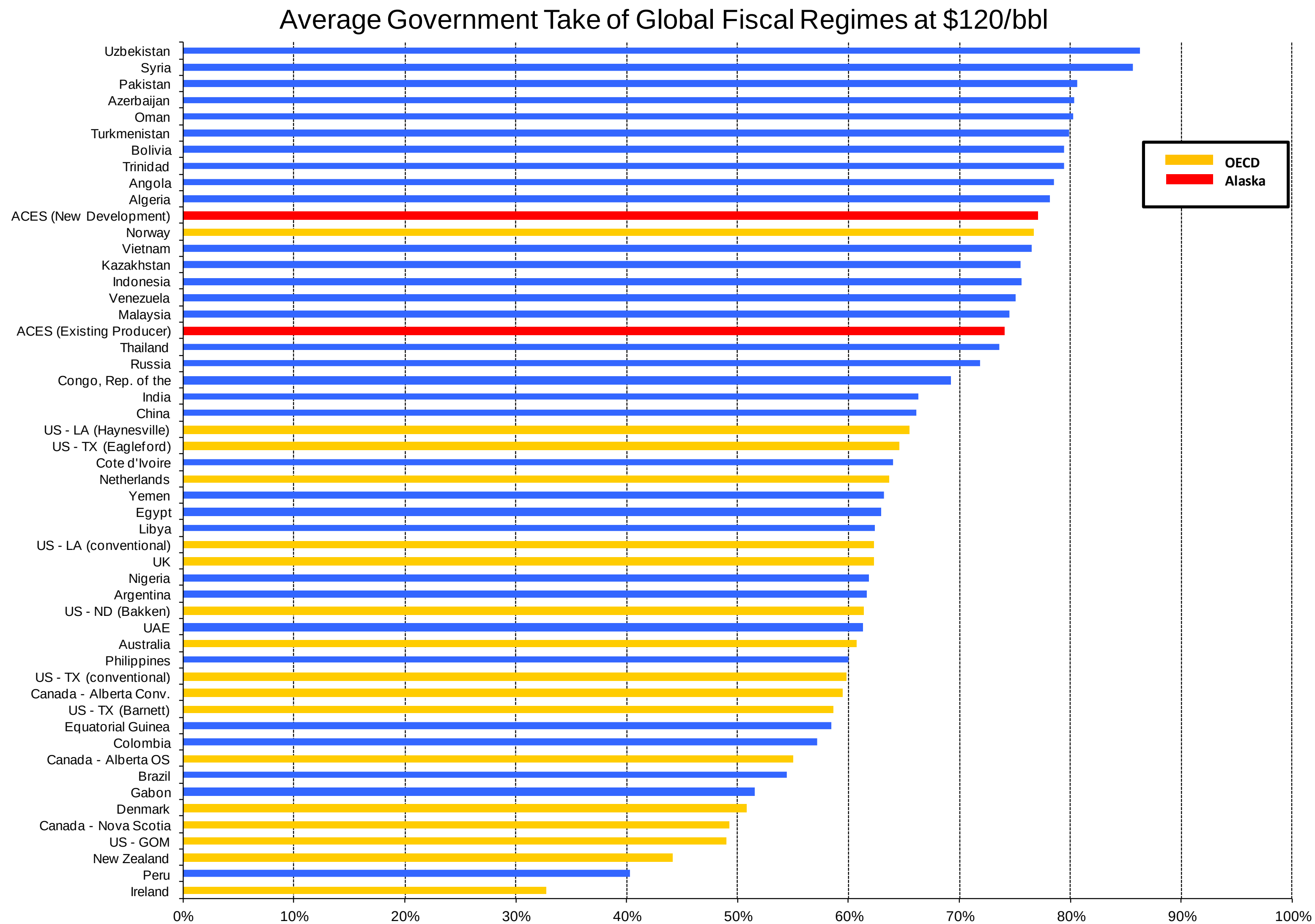


PFC Energy

Regime Competitiveness: Average Government Take at $100/bbl

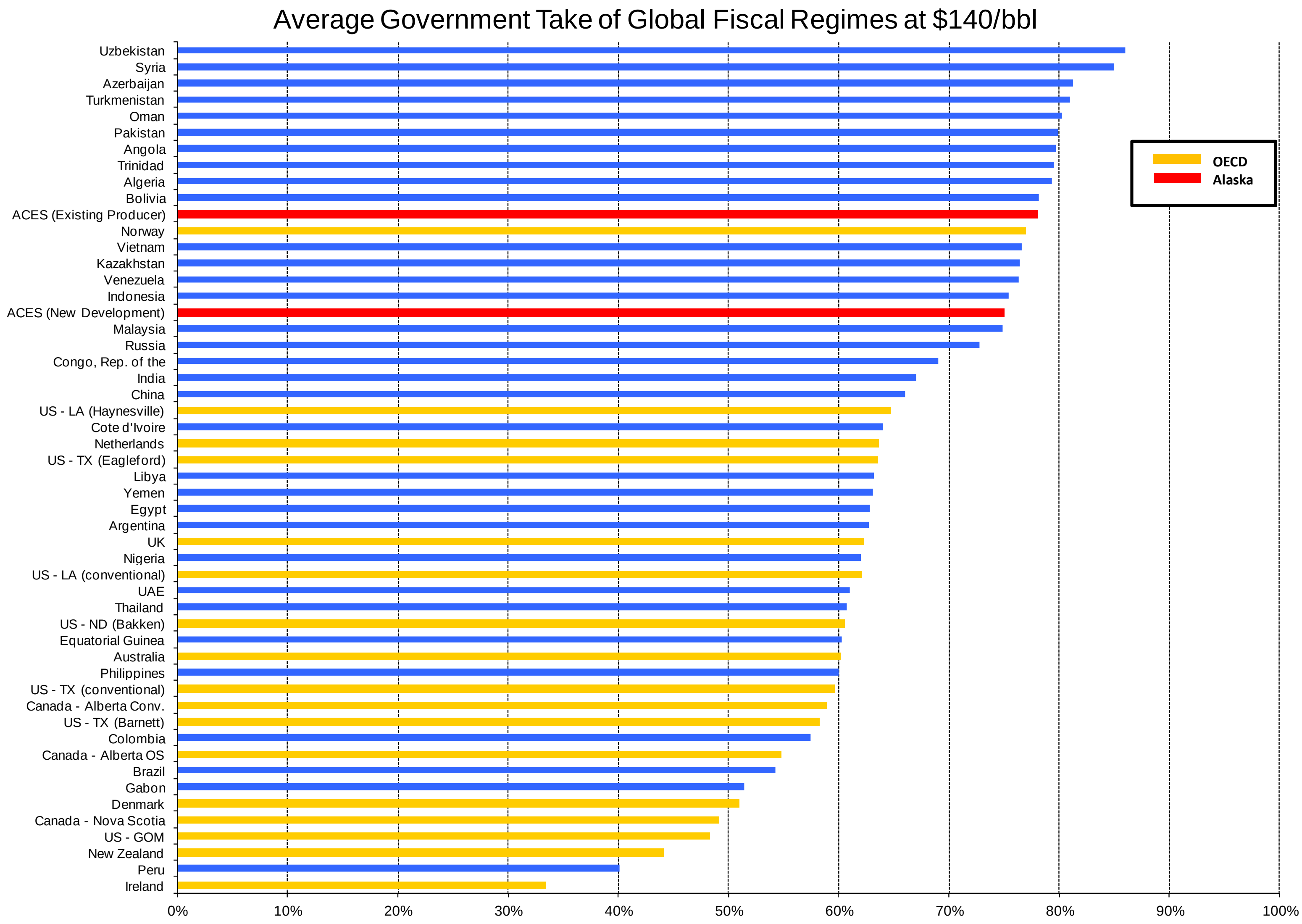


Regime Competitiveness: Average Government Take at $120/bbl

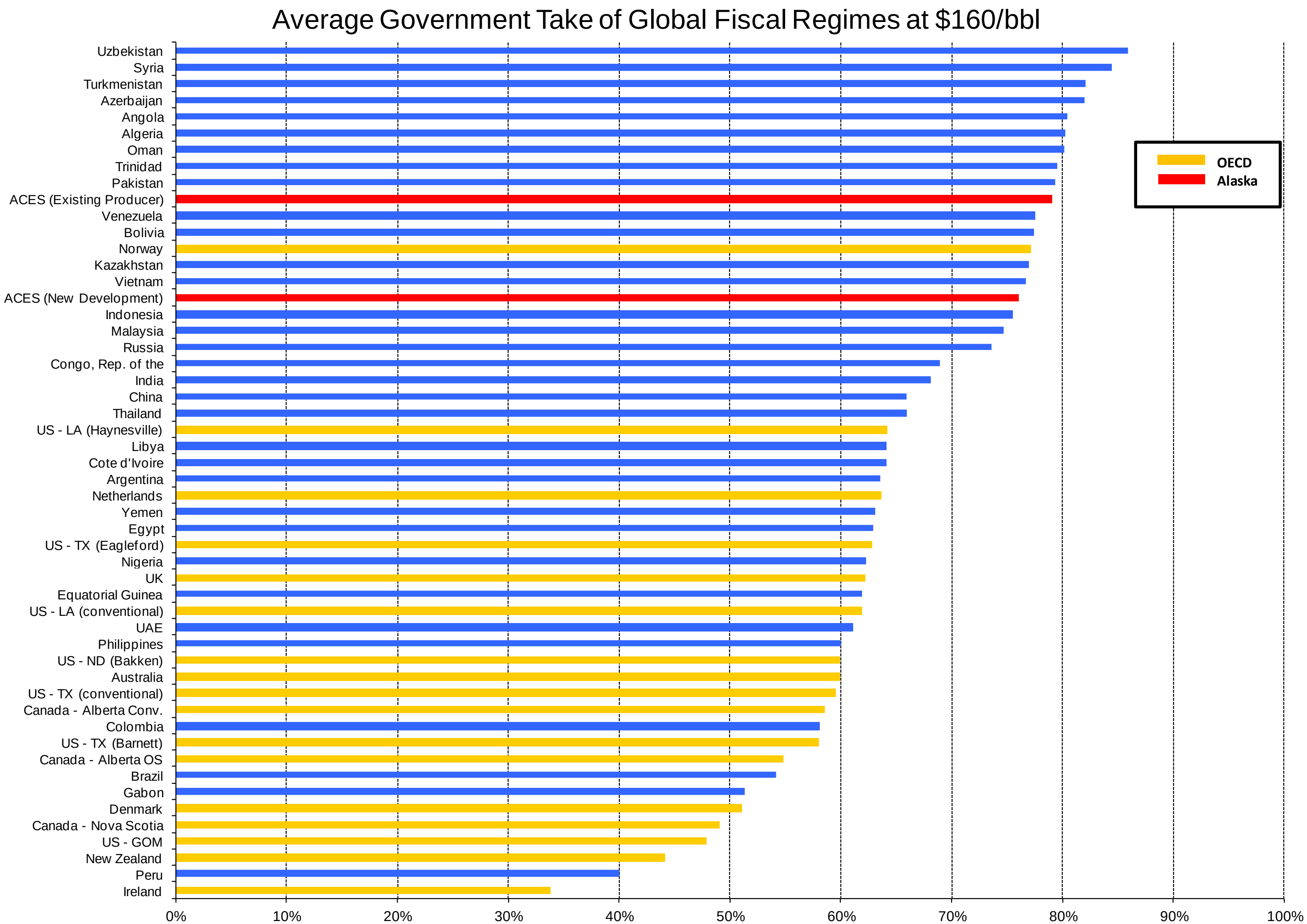


PFC Energy

Regime Competitiveness: Average Government Take at $140/bbl



Regime Competitiveness: Average Government Take at $160/bbl



ACES & SB 21

ACES – Existing Production – Government Take

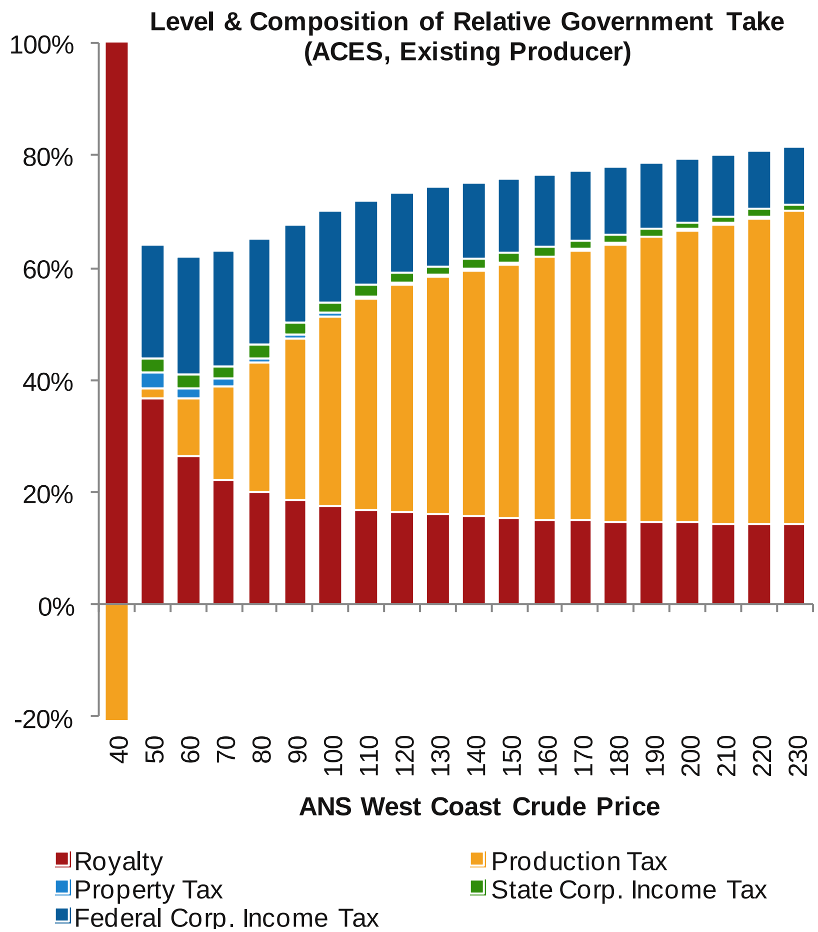


Table 1: Level & Composition of Relative Government Take (ACES, Existing Producer)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	104%	-24%	11%	2%	**93%**	14%	**107%**
50	37%	2%	3%	2%	**44%**	21%	**64%**
60	26%	10%	2%	3%	**41%**	21%	**62%**
70	22%	17%	1%	2%	**43%**	20%	**63%**
80	20%	23%	1%	2%	**46%**	19%	**65%**
90	19%	29%	1%	2%	**50%**	18%	**68%**
100	18%	34%	1%	2%	**54%**	16%	**70%**
110	17%	38%	1%	2%	**57%**	15%	**72%**
120	16%	40%	0%	2%	**59%**	14%	**74%**
130	16%	42%	0%	2%	**60%**	14%	**74%**
140	16%	44%	0%	2%	**61%**	14%	**75%**
150	15%	45%	0%	2%	**63%**	13%	**76%**
160	15%	47%	0%	2%	**64%**	13%	**76%**
170	15%	48%	0%	1%	**65%**	12%	**77%**
180	15%	49%	0%	1%	**66%**	12%	**78%**
190	15%	51%	0%	1%	**67%**	12%	**79%**
200	15%	52%	0%	1%	**68%**	11%	**79%**
210	14%	53%	0%	1%	**69%**	11%	**80%**
220	14%	55%	0%	1%	**70%**	10%	**81%**
230	14%	56%	0%	1%	**71%**	10%	**81%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

PFC Energy

ACES – New Development – Government Take

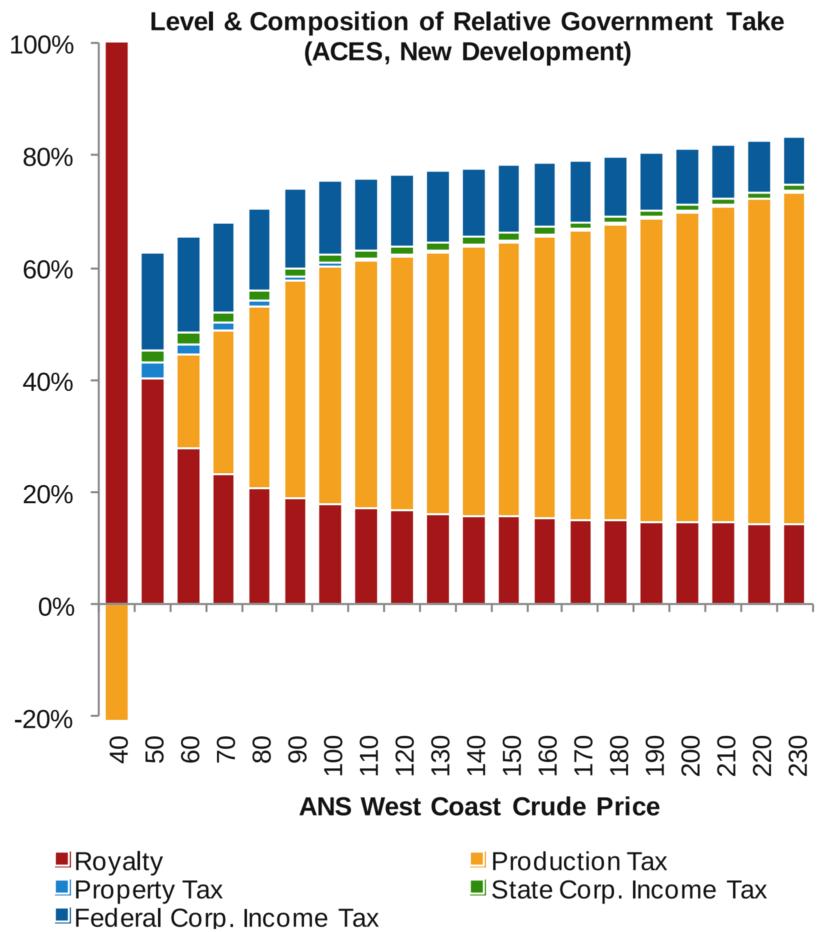
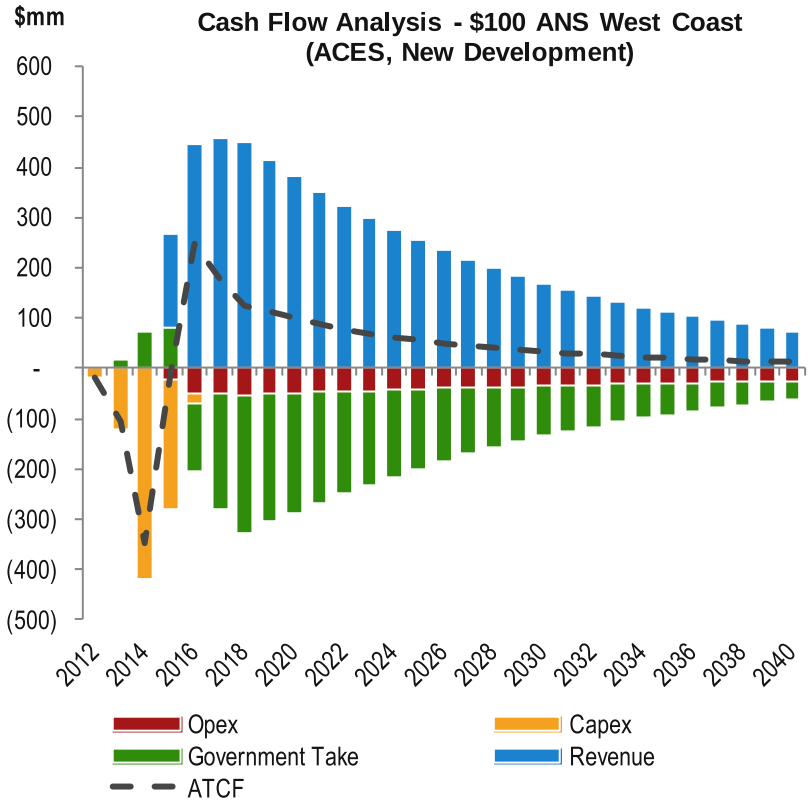


Table 1: Level & Composition of Relative Government Take (ACES, New Development)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	155%	-101%	16%	3%	**72%**	15%	**87%**
50	40%	0%	3%	2%	**45%**	18%	**63%**
60	28%	17%	2%	2%	**48%**	17%	**65%**
70	23%	26%	1%	2%	**52%**	16%	**68%**
80	21%	33%	1%	2%	**56%**	15%	**70%**
90	19%	39%	1%	2%	**60%**	14%	**74%**
100	18%	42%	1%	2%	**62%**	13%	**75%**
110	17%	44%	1%	1%	**63%**	13%	**76%**
120	17%	45%	0%	1%	**64%**	13%	**77%**
130	16%	47%	0%	1%	**65%**	13%	**77%**
140	16%	48%	0%	1%	**65%**	12%	**78%**
150	16%	49%	0%	1%	**66%**	12%	**78%**
160	15%	50%	0%	1%	**67%**	11%	**79%**
170	15%	52%	0%	1%	**68%**	11%	**79%**
180	15%	53%	0%	1%	**69%**	11%	**80%**
190	15%	54%	0%	1%	**70%**	10%	**80%**
200	15%	55%	0%	1%	**71%**	10%	**81%**
210	14%	57%	0%	1%	**72%**	9%	**82%**
220	14%	58%	0%	1%	**74%**	9%	**83%**
230	14%	59%	0%	1%	**75%**	9%	**83%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

ACES – New Development – Cash Flow Analysis



Price	NPV12	NPV/Bbl	IRR
40	(174)	(3.49)	1.3%
50	(78)	(1.56)	7.7%
60	(11)	(0.22)	11.4%
70	45	0.91	14.4%
80	95	1.91	17.1%
90	118	2.35	18.2%
100	151	3.03	19.9%
110	193	3.86	21.8%
120	228	4.56	23.4%
130	261	5.22	24.9%
140	302	6.03	26.9%

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SB21 – Existing Production – Government Take

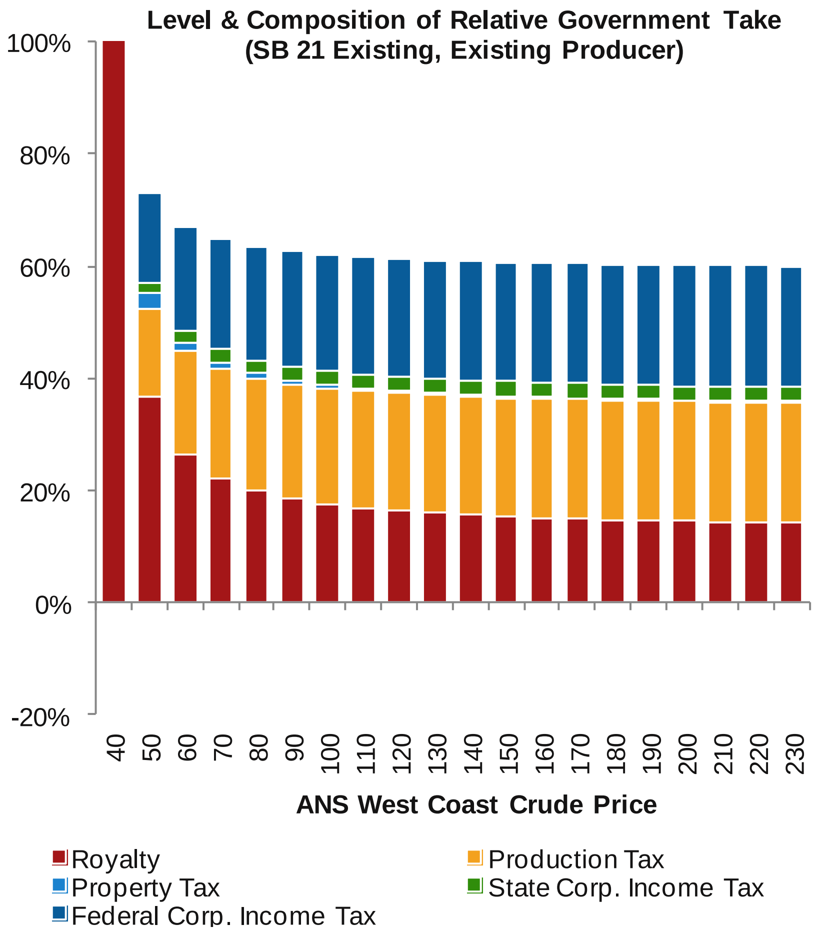


Table 1: Level & Composition of Relative Government Take (SB 21 Existing, Existing Producer)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	Total State Take	Federal Corp. Income Tax	Total Govt. Take
40	104%	21%	11%	1%	**137%**	7%	**144%**
50	37%	16%	3%	2%	**57%**	16%	**73%**
60	26%	18%	2%	2%	**49%**	18%	**67%**
70	22%	19%	1%	2%	**45%**	20%	**65%**
80	20%	20%	1%	2%	**43%**	20%	**63%**
90	19%	20%	1%	2%	**42%**	20%	**63%**
100	18%	21%	1%	2%	**41%**	21%	**62%**
110	17%	21%	1%	2%	**41%**	21%	**62%**
120	16%	21%	0%	3%	**40%**	21%	**61%**
130	16%	21%	0%	3%	**40%**	21%	**61%**
140	16%	21%	0%	3%	**40%**	21%	**61%**
150	15%	21%	0%	3%	**39%**	21%	**61%**
160	15%	21%	0%	3%	**39%**	21%	**61%**
170	15%	21%	0%	3%	**39%**	21%	**60%**
180	15%	21%	0%	3%	**39%**	21%	**60%**
190	15%	21%	0%	3%	**39%**	21%	**60%**
200	15%	21%	0%	3%	**39%**	22%	**60%**
210	14%	21%	0%	3%	**39%**	22%	**60%**
220	14%	21%	0%	3%	**38%**	22%	**60%**
230	14%	21%	0%	3%	**38%**	22%	**60%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

SB 21 – New Development – Government Take

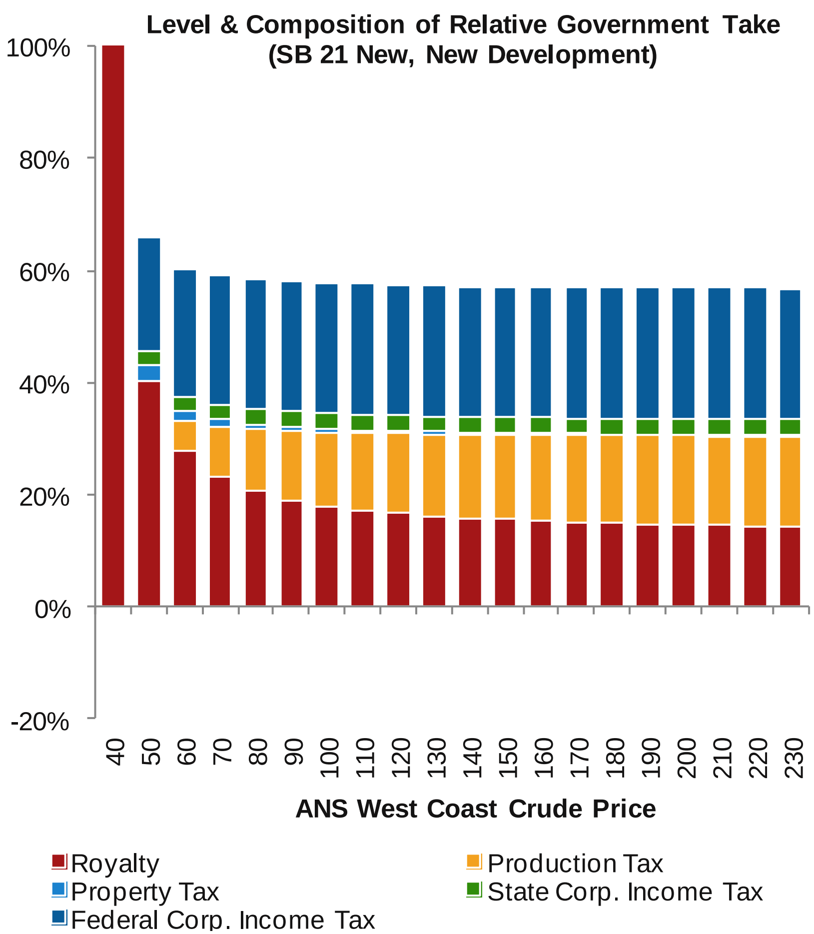
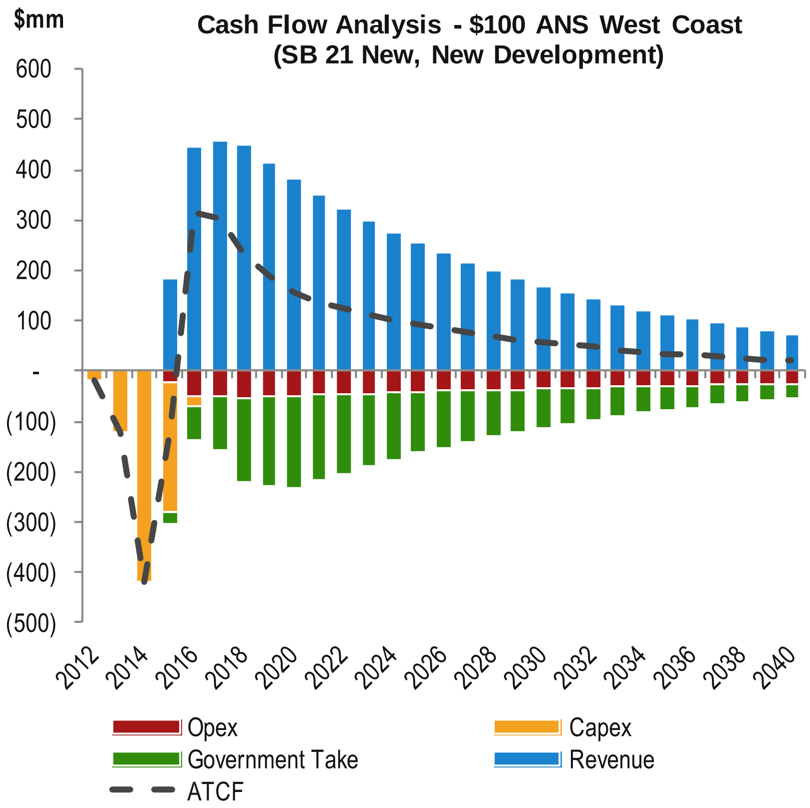


Table 1: Level & Composition of Relative Government Take (SB 21 New, New Development)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	155%	0%	16%	0%	**170%**	0%	**170%**
50	40%	0%	3%	2%	**46%**	20%	**66%**
60	28%	5%	2%	3%	**38%**	23%	**60%**
70	23%	9%	1%	3%	**36%**	23%	**59%**
80	21%	11%	1%	3%	**35%**	23%	**58%**
90	19%	12%	1%	3%	**35%**	23%	**58%**
100	18%	13%	1%	3%	**35%**	23%	**58%**
110	17%	14%	1%	3%	**34%**	23%	**58%**
120	17%	14%	0%	3%	**34%**	23%	**57%**
130	16%	15%	0%	3%	**34%**	23%	**57%**
140	16%	15%	0%	3%	**34%**	23%	**57%**
150	16%	15%	0%	3%	**34%**	23%	**57%**
160	15%	15%	0%	3%	**34%**	23%	**57%**
170	15%	16%	0%	3%	**34%**	23%	**57%**
180	15%	16%	0%	3%	**34%**	23%	**57%**
190	15%	16%	0%	3%	**34%**	23%	**57%**
200	15%	16%	0%	3%	**34%**	23%	**57%**
210	14%	16%	0%	3%	**34%**	23%	**57%**
220	14%	16%	0%	3%	**33%**	23%	**57%**
230	14%	16%	0%	3%	**33%**	23%	**57%**

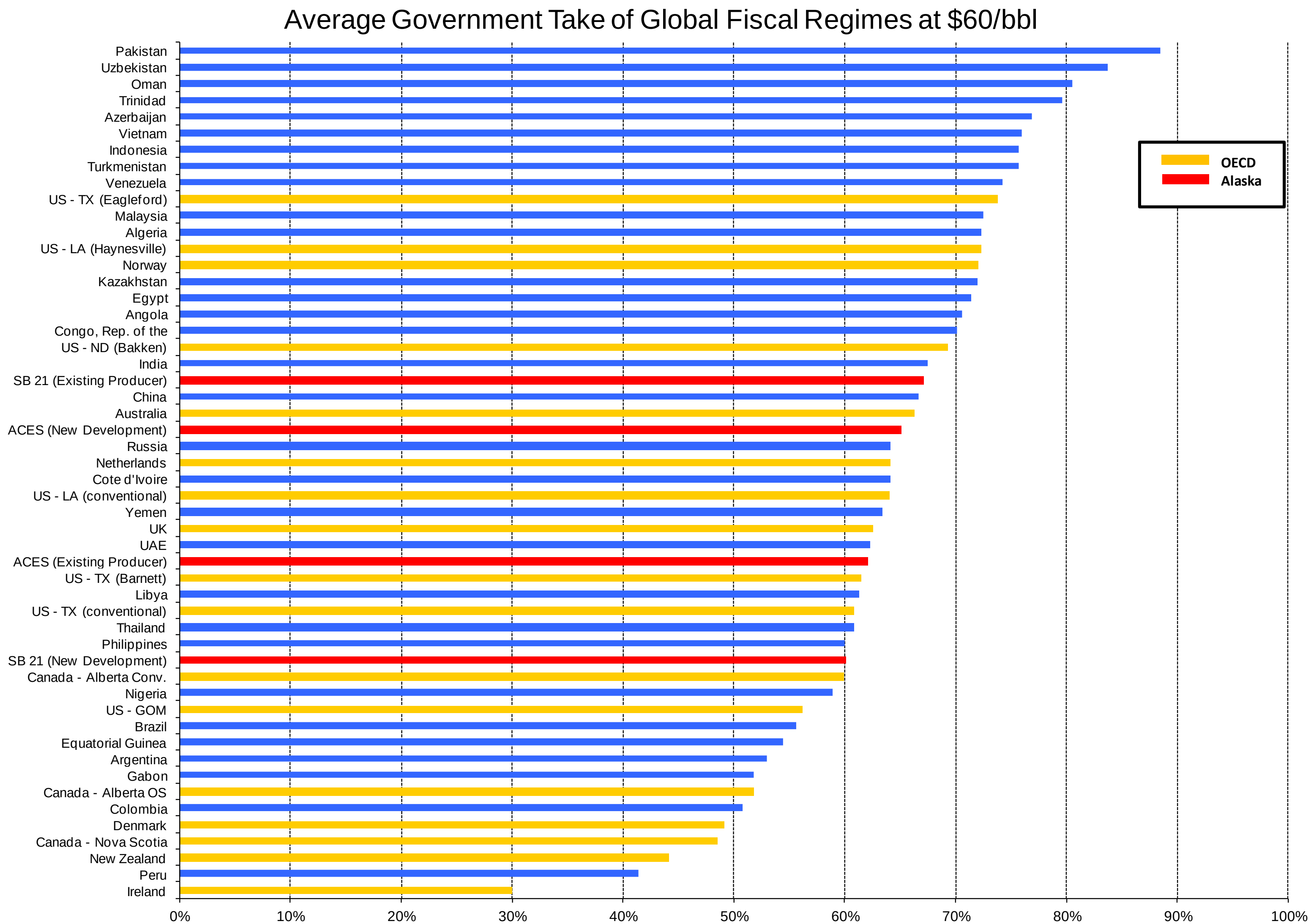
Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

SB 21 – New Development – Cash Flow Analysis



Price	NPV12	NPV/Bbl	IRR
40	(316)	(6.31)	-1.6%
50	(177)	(3.53)	4.9%
60	(64)	(1.29)	9.5%
70	34	0.68	13.3%
80	127	2.55	16.9%
90	219	4.37	20.2%
100	307	6.14	23.3%
110	394	7.89	26.3%
120	481	9.62	29.1%
130	569	11.37	32.0%
140	656	13.12	34.7%

Regime Competitiveness: Average Government Take at $60/bbl



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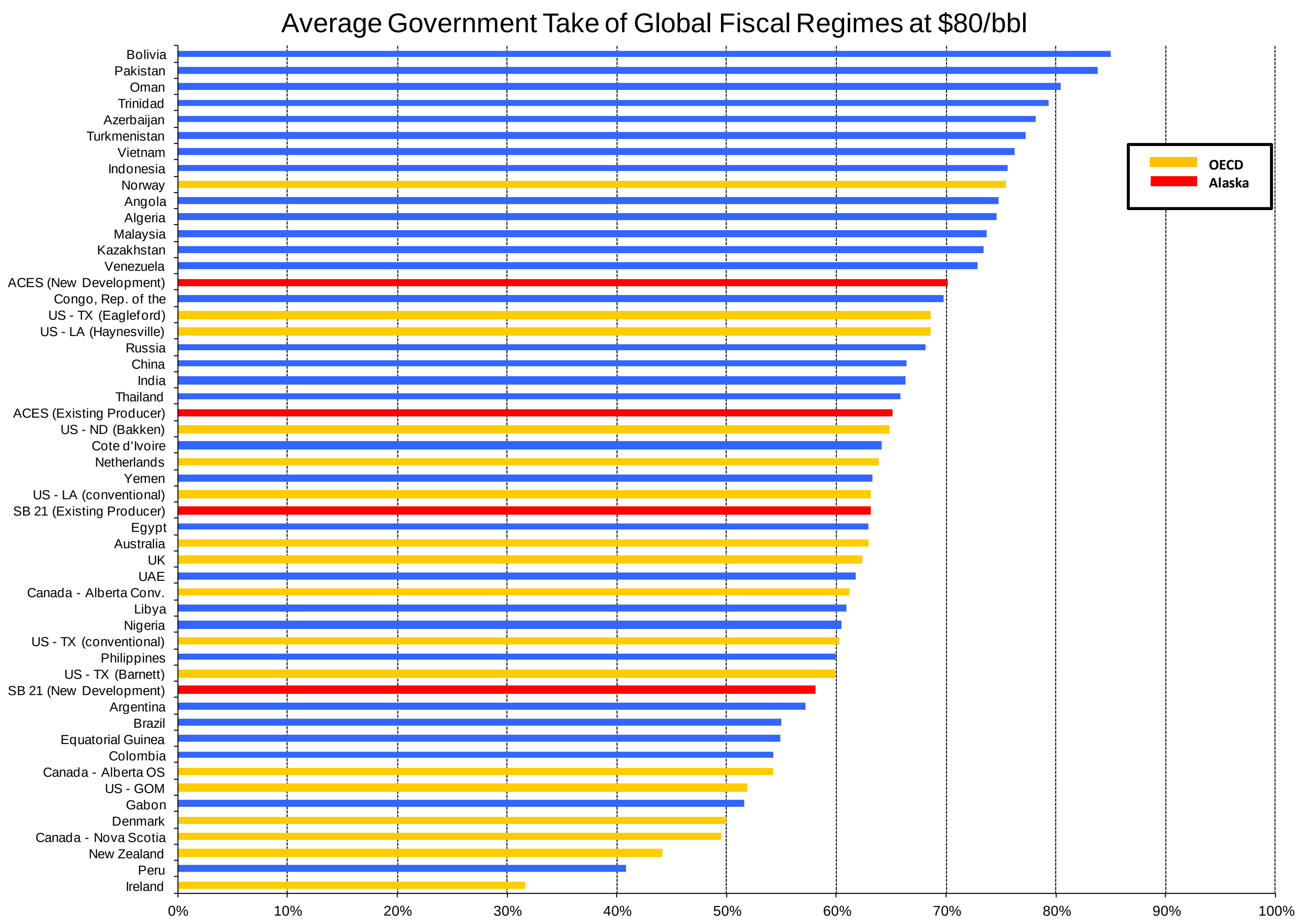
Regime Competitiveness: Average Government Take at $80/bbl



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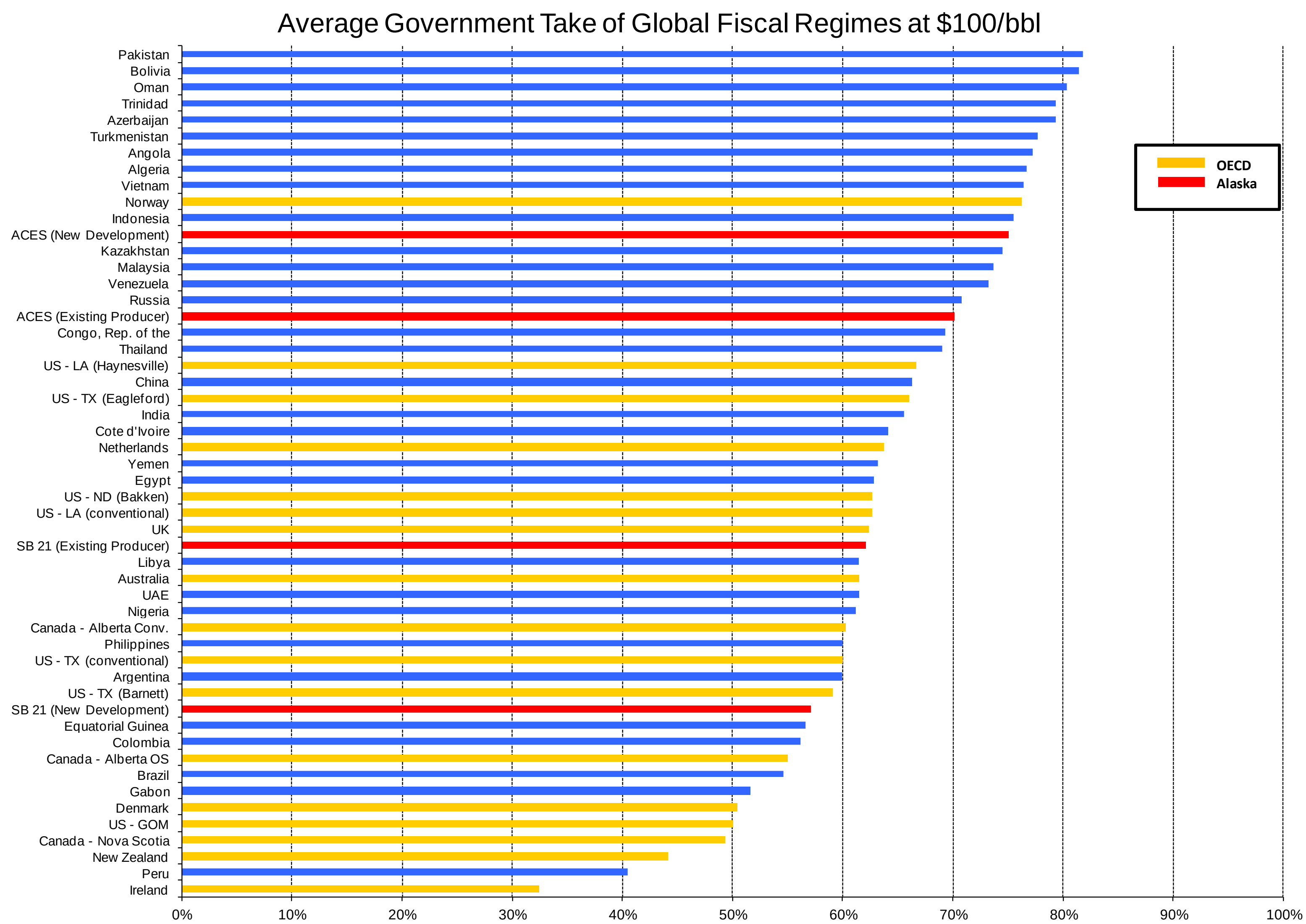
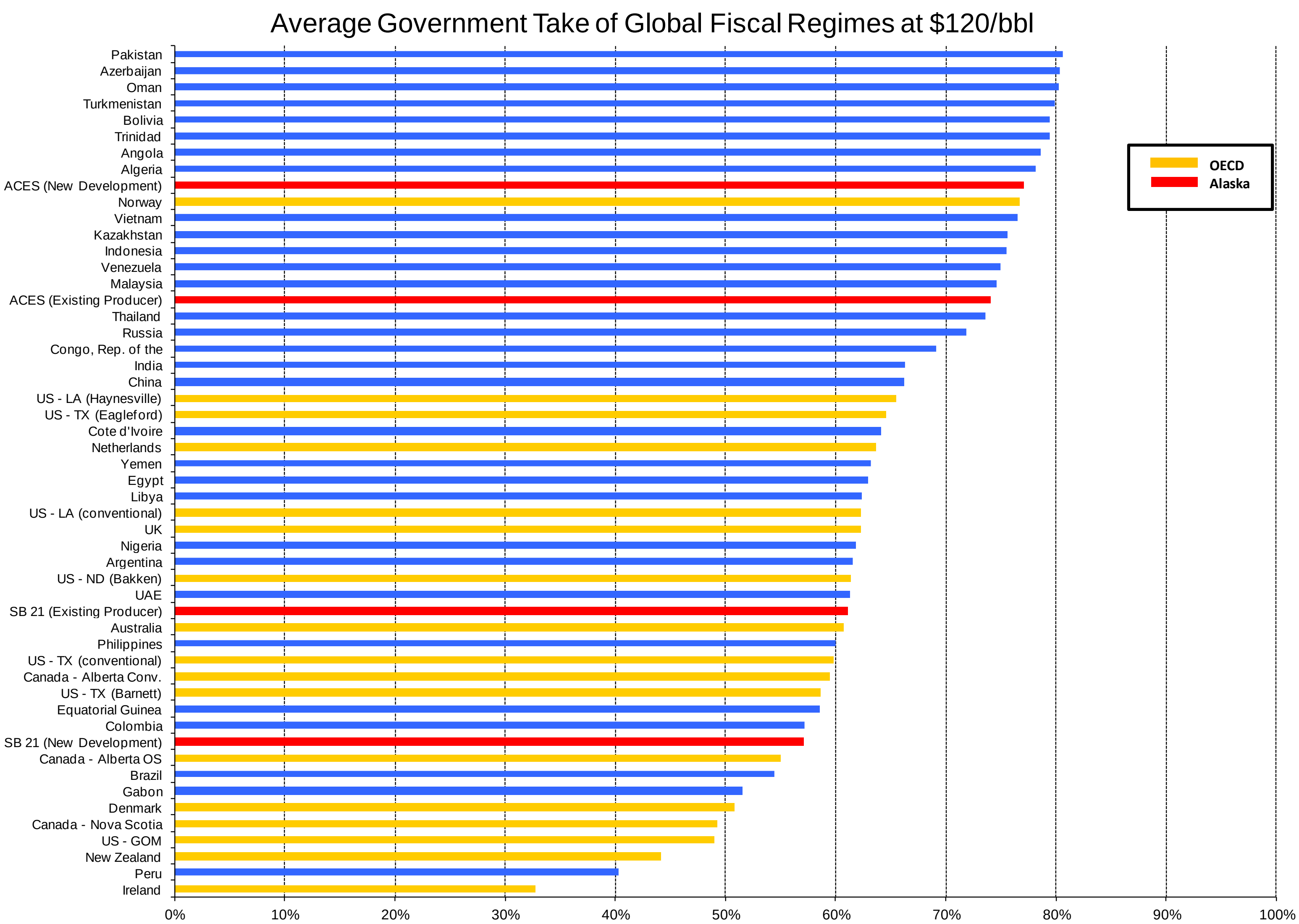
Regime Competitiveness: Average Government Take at $100/bbl



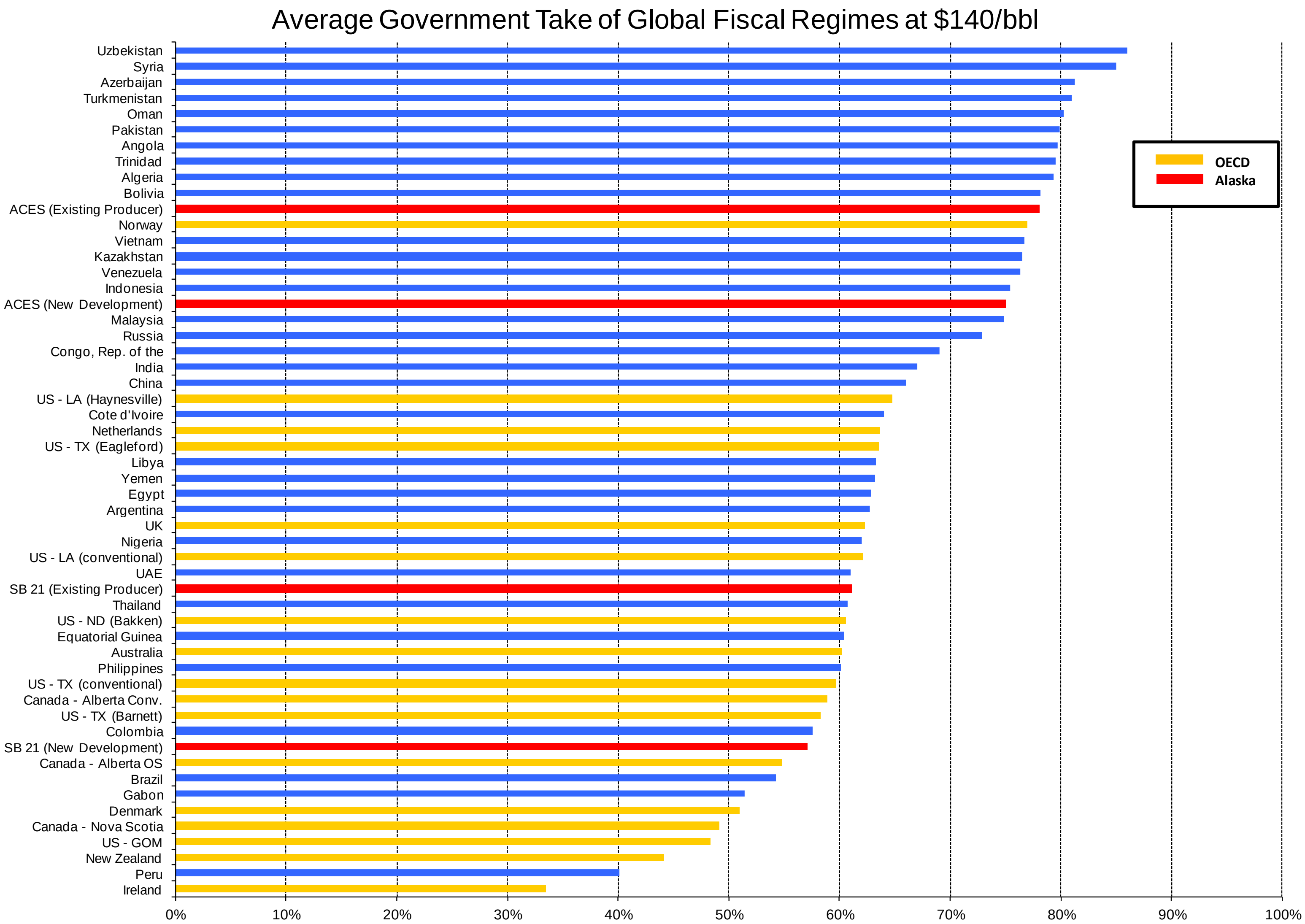
PFC Energy

Regime Competitiveness: Average Government Take at $120/bbl

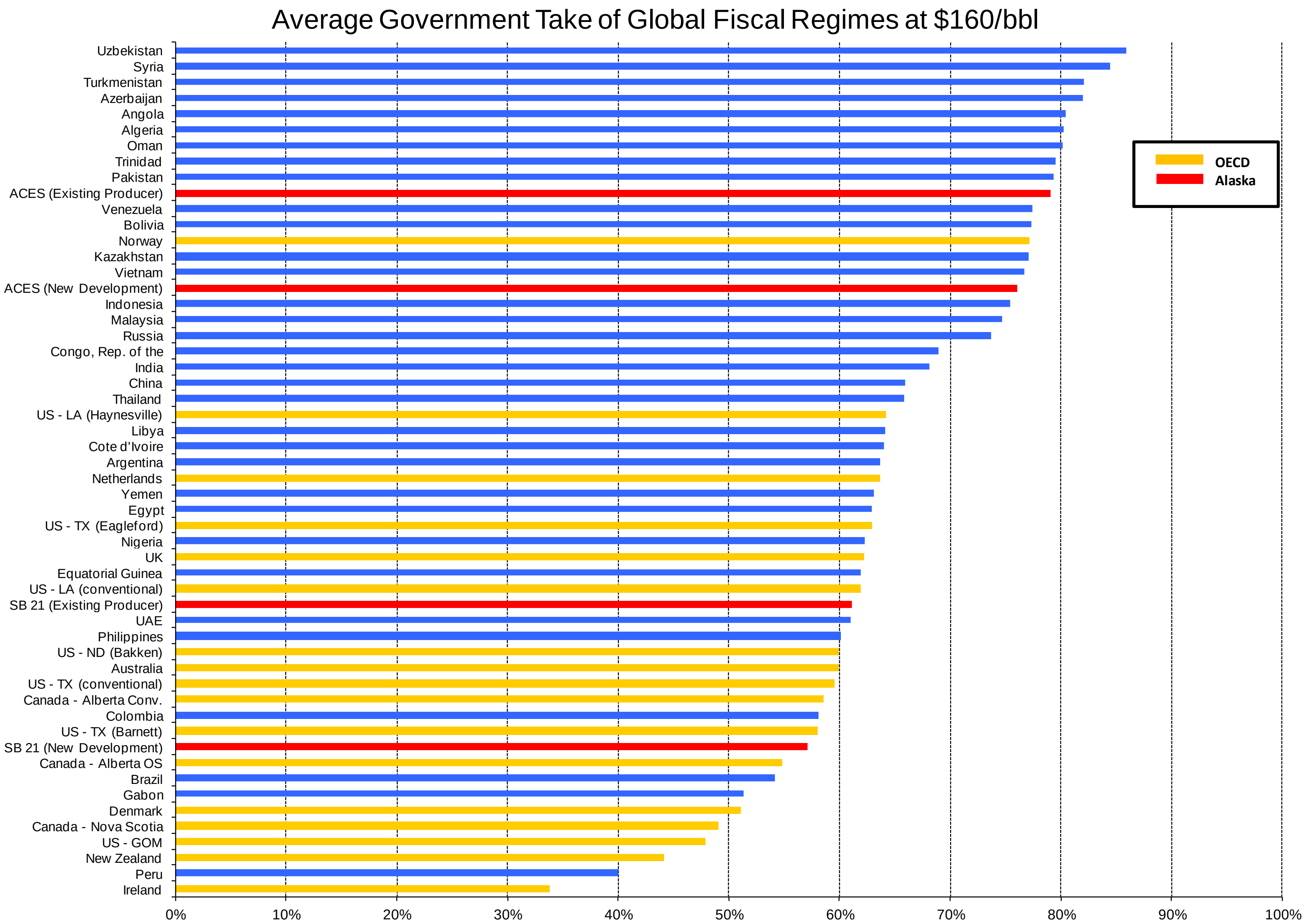


PFC Energy

Regime Competitiveness: Average Government Take at $140/bbl



Regime Competitiveness: Average Government Take at $160/bbl



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SB21 Prog – Existing Production – Government Take

Includes .01% Progressivity from $30 PTV/bbl to maximum of 35%

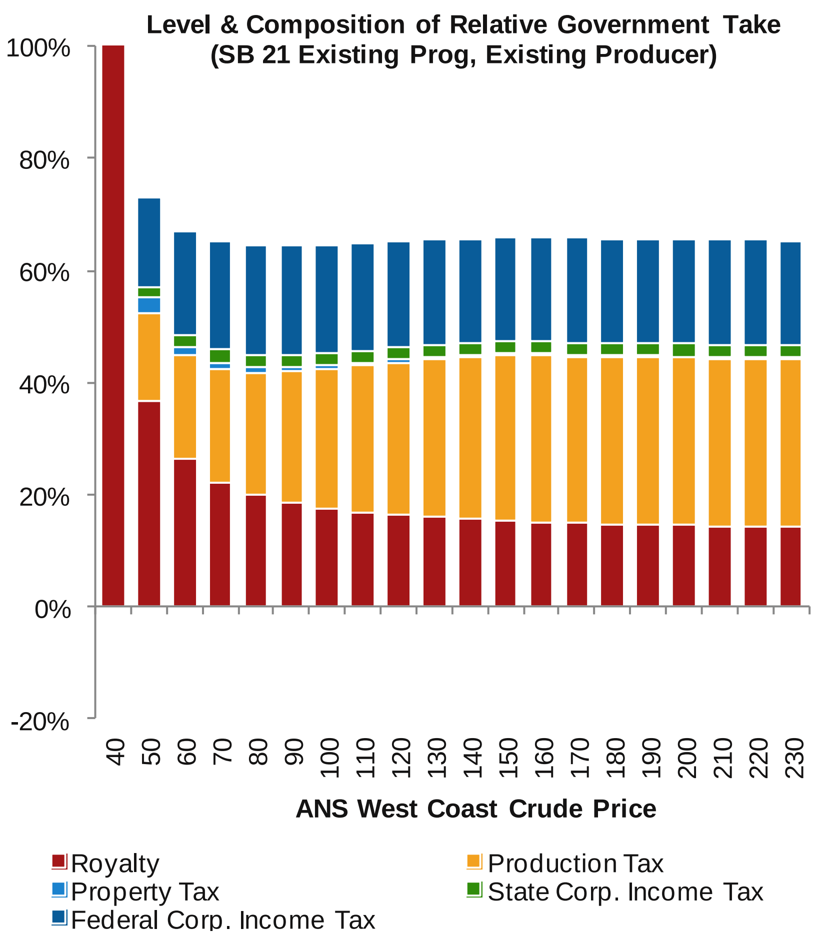


Table 1: Level & Composition of Relative Government Take (SB 21 Existing Prog, Existing Producer)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	Total State Take	Federal Corp. Income Tax	Total Govt. Take
40	104%	21%	11%	1%	**137%**	7%	**144%**
50	37%	16%	3%	2%	**57%**	16%	**73%**
60	26%	18%	2%	2%	**49%**	18%	**67%**
70	22%	20%	1%	2%	**46%**	19%	**65%**
80	20%	22%	1%	2%	**45%**	19%	**65%**
90	19%	23%	1%	2%	**45%**	19%	**64%**
100	18%	25%	1%	2%	**45%**	19%	**65%**
110	17%	26%	1%	2%	**46%**	19%	**65%**
120	16%	27%	0%	2%	**46%**	19%	**65%**
130	16%	28%	0%	2%	**47%**	19%	**66%**
140	16%	29%	0%	2%	**47%**	19%	**66%**
150	15%	29%	0%	2%	**47%**	19%	**66%**
160	15%	30%	0%	2%	**47%**	19%	**66%**
170	15%	30%	0%	2%	**47%**	19%	**66%**
180	15%	30%	0%	2%	**47%**	19%	**66%**
190	15%	30%	0%	2%	**47%**	19%	**66%**
200	15%	30%	0%	2%	**47%**	19%	**66%**
210	14%	30%	0%	2%	**47%**	19%	**65%**
220	14%	30%	0%	2%	**47%**	19%	**65%**
230	14%	30%	0%	2%	**47%**	19%	**65%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

PFC Energy

SB 21 Prog – New Development – Government Take

Includes .01% Progressivity from $30 PTV/bbl to maximum of 35%

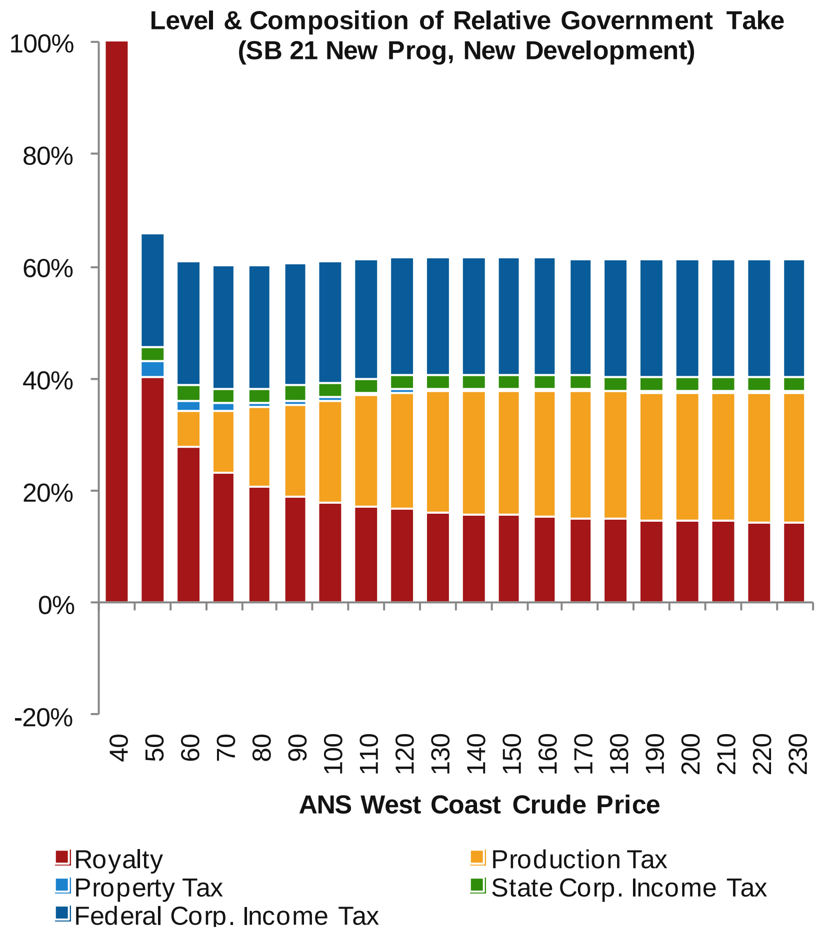


Table 1: Level & Composition of Relative Government Take (SB 21 New Prog, New Development)

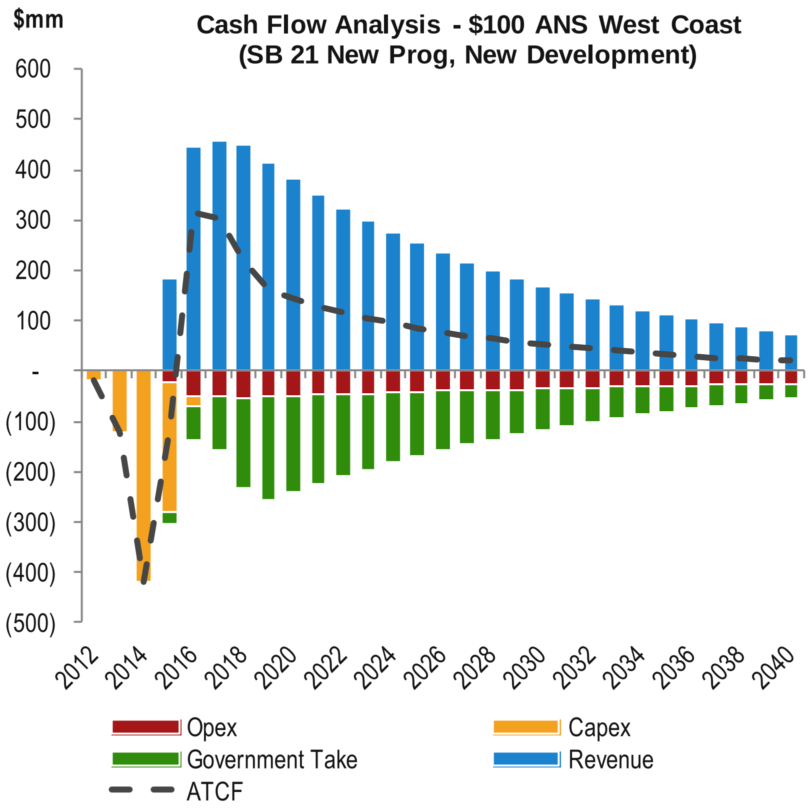
Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	Total State Take	Federal Corp. Income Tax	Total Govt. Take
40	155%	0%	16%	0%	**170%**	0%	**170%**
50	40%	0%	3%	2%	**46%**	20%	**66%**
60	28%	7%	2%	3%	**39%**	22%	**61%**
70	23%	11%	1%	3%	**38%**	22%	**60%**
80	21%	14%	1%	3%	**38%**	22%	**60%**
90	19%	16%	1%	3%	**39%**	22%	**61%**
100	18%	18%	1%	3%	**39%**	21%	**61%**
110	17%	20%	1%	3%	**40%**	21%	**61%**
120	17%	21%	0%	2%	**41%**	21%	**62%**
130	16%	22%	0%	2%	**41%**	21%	**62%**
140	16%	22%	0%	2%	**41%**	21%	**62%**
150	16%	22%	0%	2%	**41%**	21%	**62%**
160	15%	22%	0%	2%	**41%**	21%	**61%**
170	15%	23%	0%	2%	**40%**	21%	**61%**
180	15%	23%	0%	2%	**40%**	21%	**61%**
190	15%	23%	0%	2%	**40%**	21%	**61%**
200	15%	23%	0%	2%	**40%**	21%	**61%**
210	14%	23%	0%	2%	**40%**	21%	**61%**
220	14%	23%	0%	3%	**40%**	21%	**61%**
230	14%	23%	0%	3%	**40%**	21%	**61%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

PFC Energy

SB 21 Prog – New Development – Cash Flow Analysis

Includes .01% Progressivity from $30 PTV/bbl to maximum of 35%



Price	NPV12	NPV/Bbl	IRR
40	(316)	(6.31)	-1.6%
50	(177)	(3.53)	4.9%
60	(66)	(1.33)	9.4%
70	27	0.55	13.1%
80	114	2.28	16.4%
90	196	3.92	19.5%
100	273	5.47	22.3%
110	348	6.95	25.0%
120	421	8.41	27.6%
130	494	9.87	30.0%
140	570	11.41	32.5%

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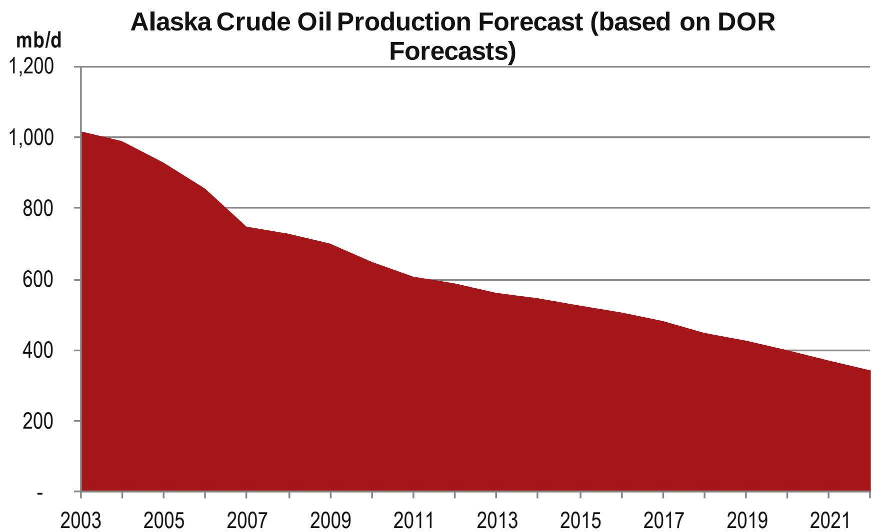
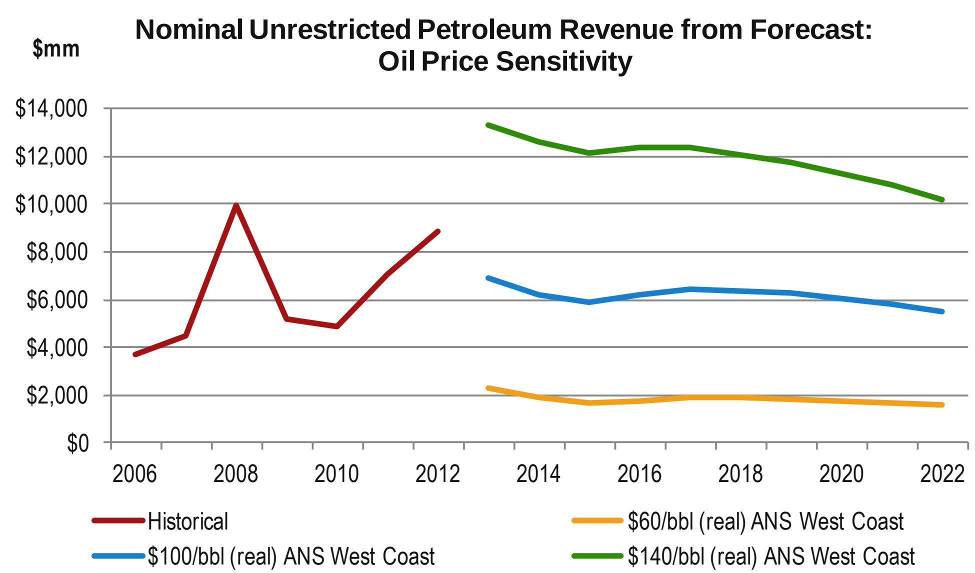
Credits and Deductions

- Current credit system necessary in ACES to offset high government take, but introduces numerous distortions and unintended consequences
- In low price environments, or in the case of significant success attracting new producers to the North Slope, poses significant cashflow risk to the state
- Eliminating 20% capital credit may pose greater issues for smaller, more capital-constrained producers
- If capital credit were to be retained in some form, may be desirable to end ability to claim directly from the state
- While some further targeting of credits may be possible, often difficult to differentiate between maintainance and development spending
- Limiting deductions – for instance in the case of pipeline tariff – also likely to be problematic – added complexity for little gain

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

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





- The major factor determining Alaska's future petroleum revenue is not oil & gas fiscal terms, or even, in the short run, production levels, but rather something entirely outside Alaska's control: the crude oil price
- Restricting a sensitivity analysis only to the a range of oil prices observed in the last 5 years, and **holding future production constant** (based on DOR forecasts) the potential variation in possible future petroleum revenue is substantial:
  - In a $140/bbl environment, revenue in 2022 under ACES would approach $10bn
  - In a $60/bbl environment, revenue in 2032 under ACES would be as low as $1.8bn

In reality, the potential for variation is even greater than this, since production also responds to price:

- In a sustained high price environment, more projects would be economic, and long-run production would improve
- In a sustained low price environment, fewer projects would be economic and sustaining capital would be lower, resulting in a more rapid decline in long run production

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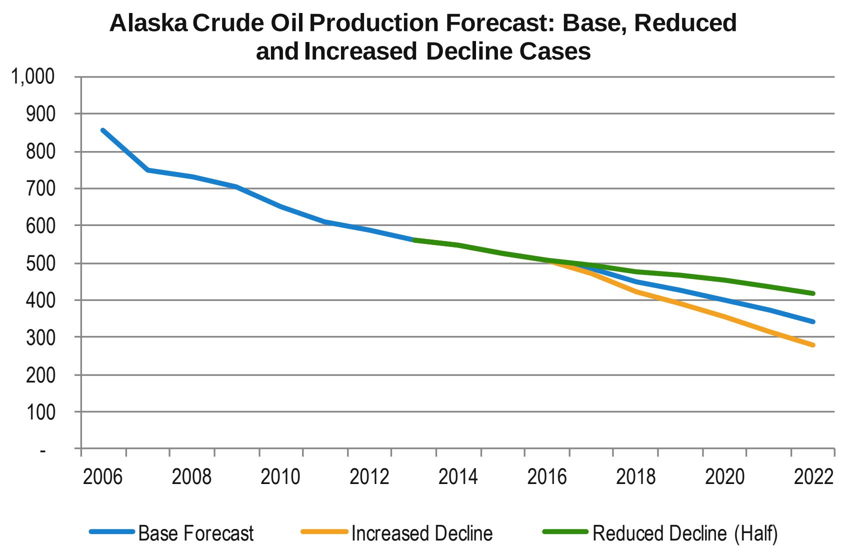
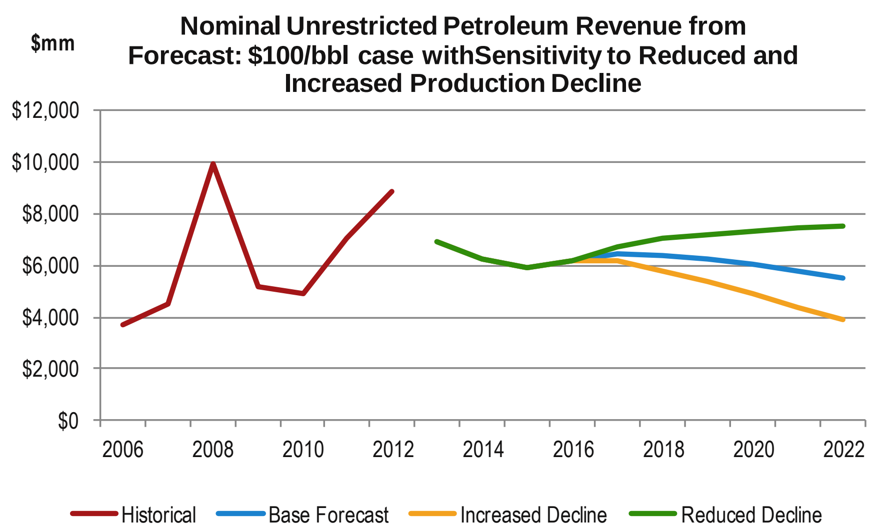
Decline Rate is the Other Major Determinant





– The Base Forecast anticipates an average annual production decline between 2017 and 2022 of **~6%** (including the contribution from new producing areas brought on-stream), yielding production of ~344 mb/d in 2022

– Increasing the average decline rate by half to **9%** in every year from the base case would see production declining to ~280 mb/d in 2032

– Reducing the average decline rate by half to **3%** in every year from the base case would see production of ~419 mb/d in 2032

– In the low decline scenario, more robust production combined with the impact of inflation mean that nominal revenues would continue to grow beyond 2017, reaching ~$7.8 bn at a nominal crude price of $100/bbl

– In the high decline scenario, 2022 nominal revenues would fall well below the $4 bn level anticipated in the Base Forecast case, reaching less than ~$4 bn even with nominal crude prices at $100/bbl

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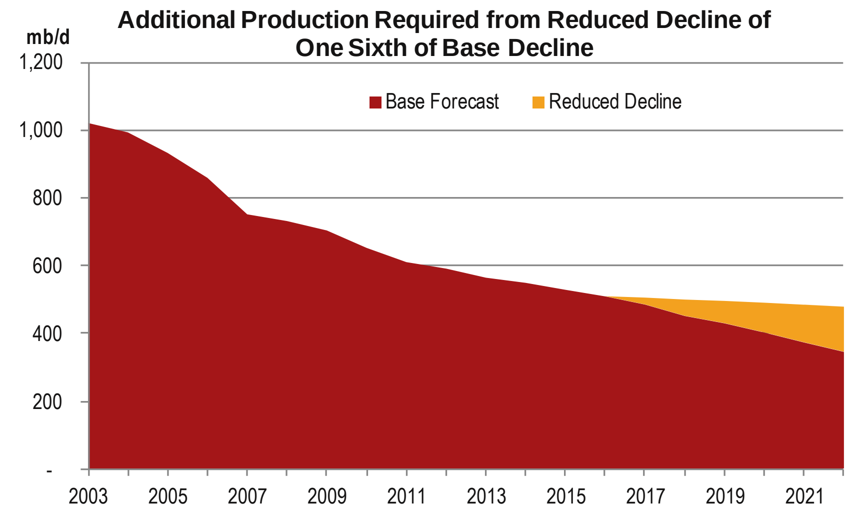
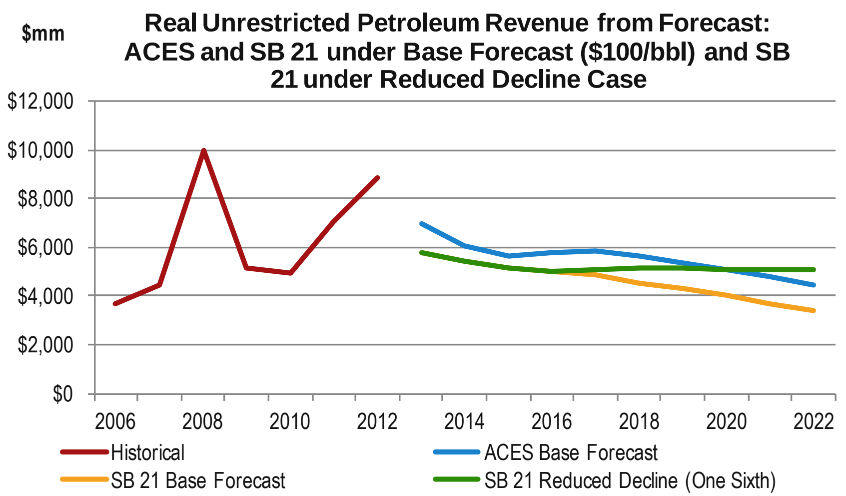
Fiscal Terms Changes and Investment Impacts





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

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

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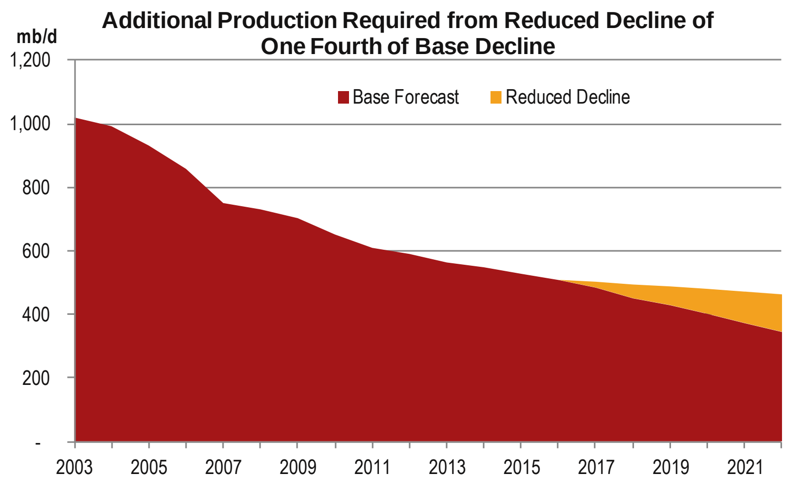
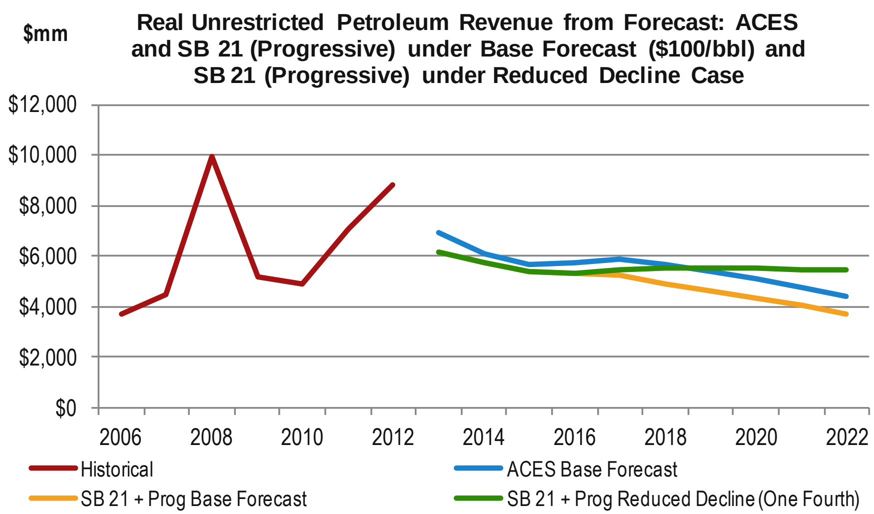
Fiscal Terms Changes and Investment Impacts





Year	2017	2018	2019	2020	2021	2022
Additional Production (mboe/day)	18	43	59	78	99	118

- Re-introducing 0.1% progressivity into SB 21 (to a maximum of 35% Production Tax) would require lower additional production post 2017 to be revenue neutral.
- To maintain revenues to the state at a steady level in real terms, a reduction in government take such as that under SB 21 with 1% progressivity would need to spur sufficient investment to **reduce the North Slope base decline from 6%** as currently forecast **to 2%**

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Fiscal Terms Changes and Investment Impacts

	Year	2017	2018	2019	2020	2021	2022
Incremental Additional Production (mboe/day)	SB 21	-	28	18	22	23	22
	SB 21 + Progressive	-	25	16	19	21	19

- The table shows incremental production needed to added every year for SB21 and SB21 (w/progressivity) regimes.
- SB21 (w/progressivity) would require marginally fewer investments and leads to earlier revenue neutrality

Main Regional Offices

Asia

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

PFC Energy, Singapore
15 Scotts Road
Thong Teck Building, #08-04
Singapore 228218
Tel no: +65 6736 4317

PFC Energy, China
79 Jianguo Road
China Central Place Tower II, 9/F, Suite J
Chaoyang District
Beijing 100025, China
Tel (86 10) 5920-4448
Fax (86 10) 6530-5093

Europe

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

North America

PFC Energy, Washington D.C.
1300 Connecticut Avenue, N.W.
Suite 800
Washington, DC 20036, USA
Tel (1 202) 872-1199
Fax (1 202) 872-1219

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

www.pfcenergy.com | info@pfcenergy.com

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

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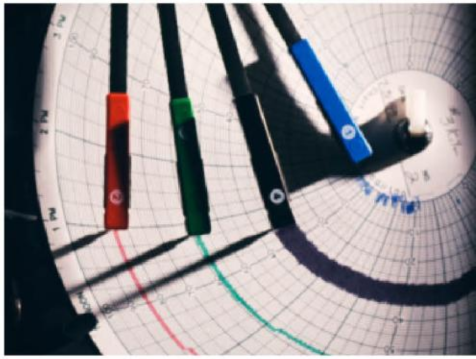

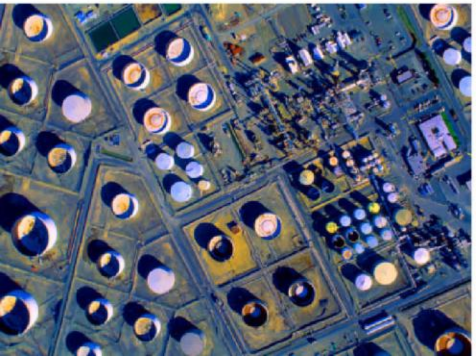

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