01/31/14 SB 21 - Presentation: Alaska Hydrocarbons Fiscal Systems by Janak Mayer, and Public Testimony

<TARGET><BILL>SB 21</BILL><SUBJECT>01-31-14 SB 21 - Presentation Alaska Hydrocarbons Fiscal Systems by Janak Mayer, and Public Testimony</SUBJECT><COMM>STTP28</COMM></TARGET>

Senate TAPS Throughput Committee

Alaska Hydrocarbons Fiscal Systems

January 31 2013

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Part 1:

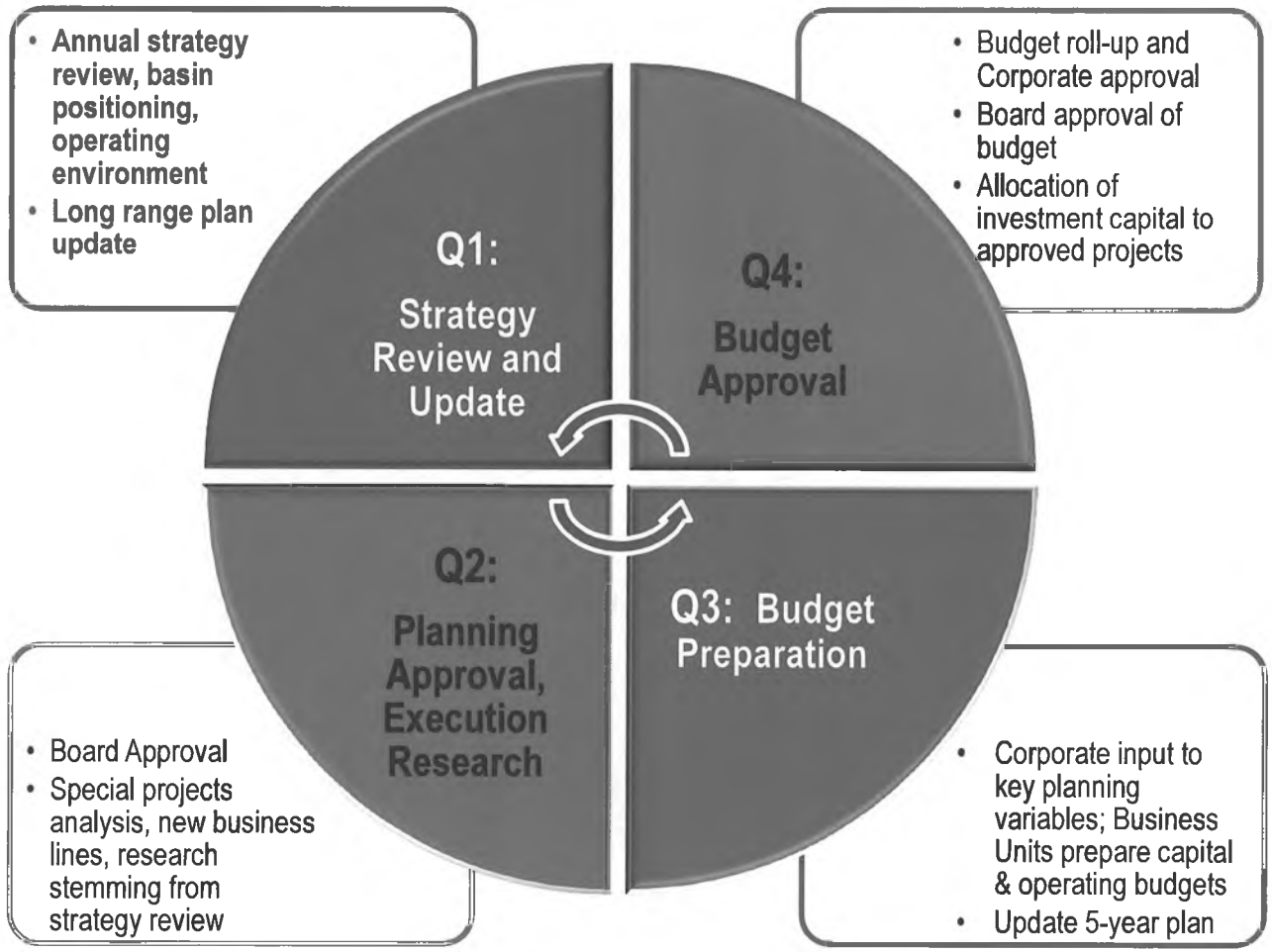
Oil & Gas Company Decision Making: Capital Allocation, Budget, and Long-Range Planning

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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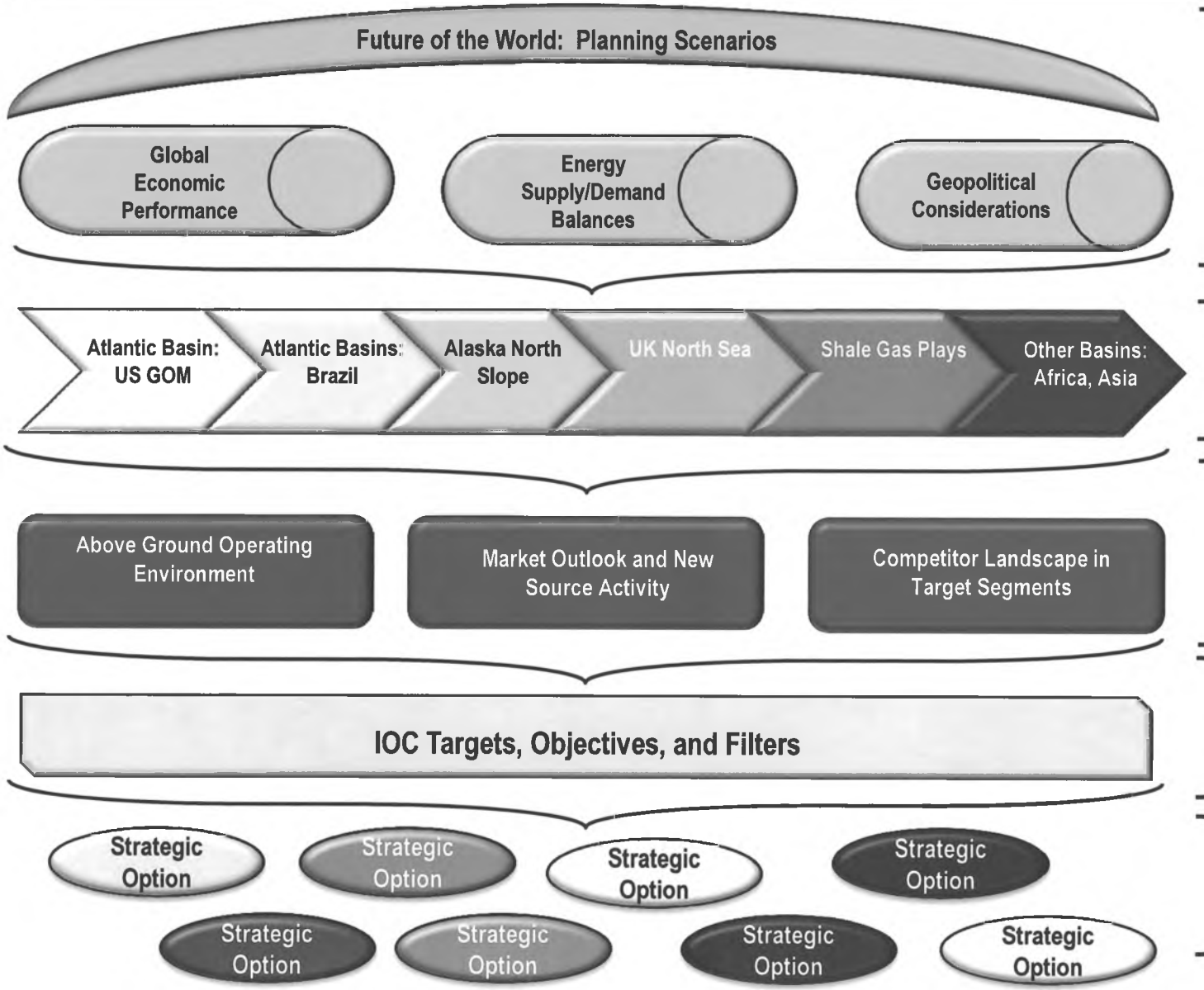
Strategy, Planning and Positioning



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Annual Planning Cycle

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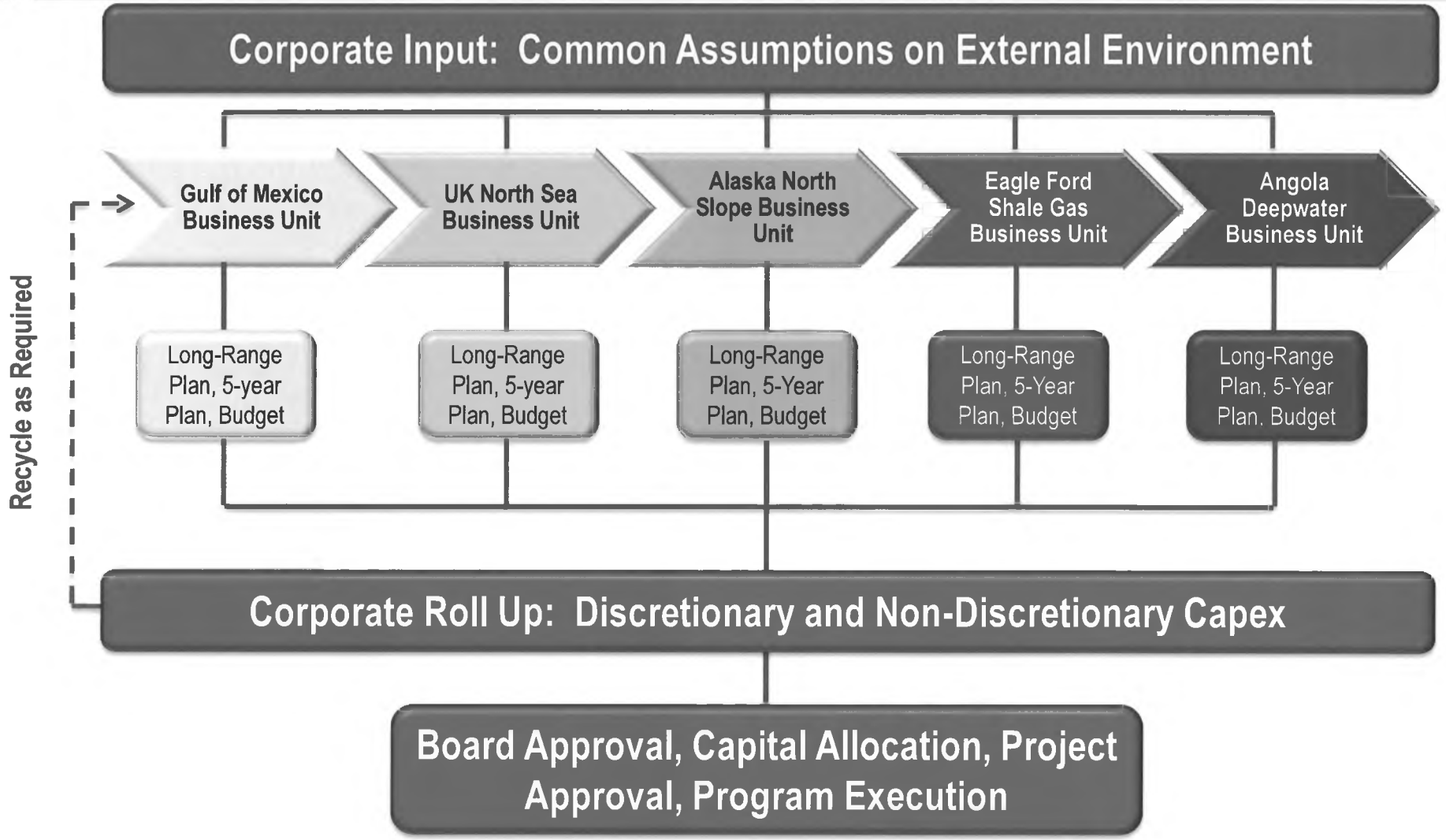
Planning Cycle and Capital Allocation



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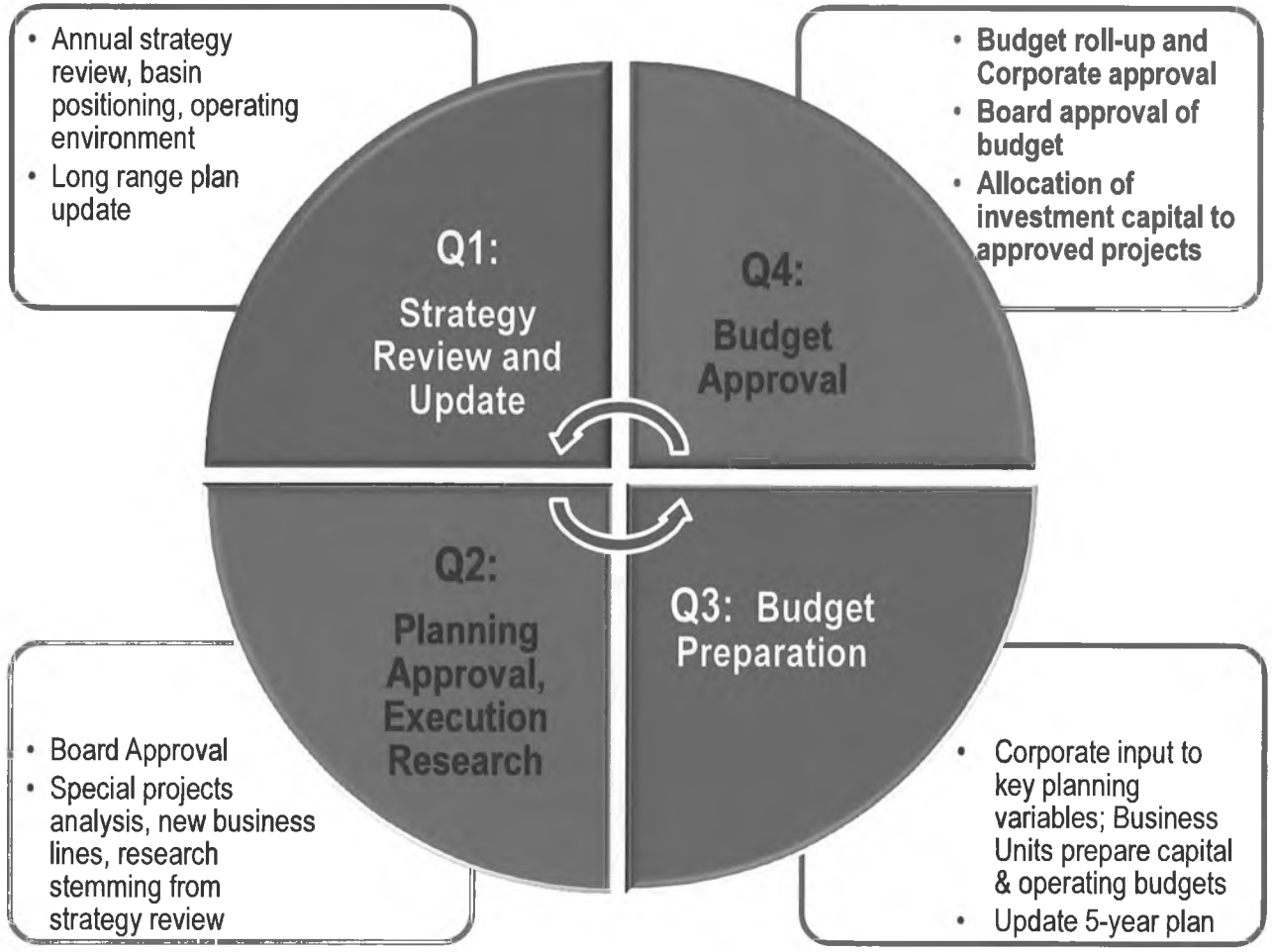
Annual Planning Cycle



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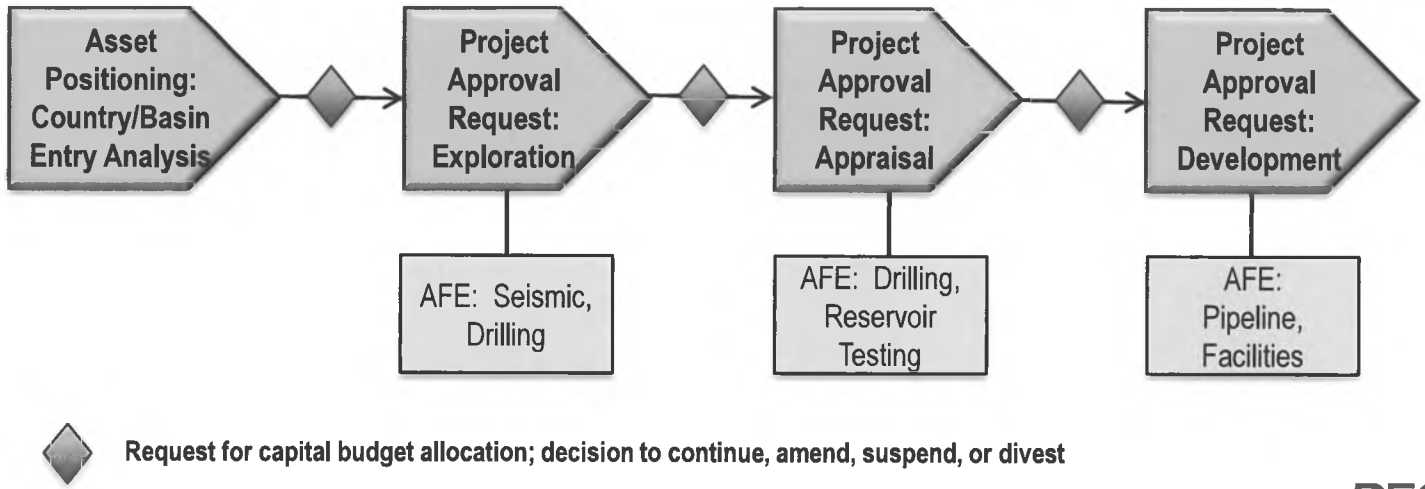
Attracting Capital: The Project Approval Process

- 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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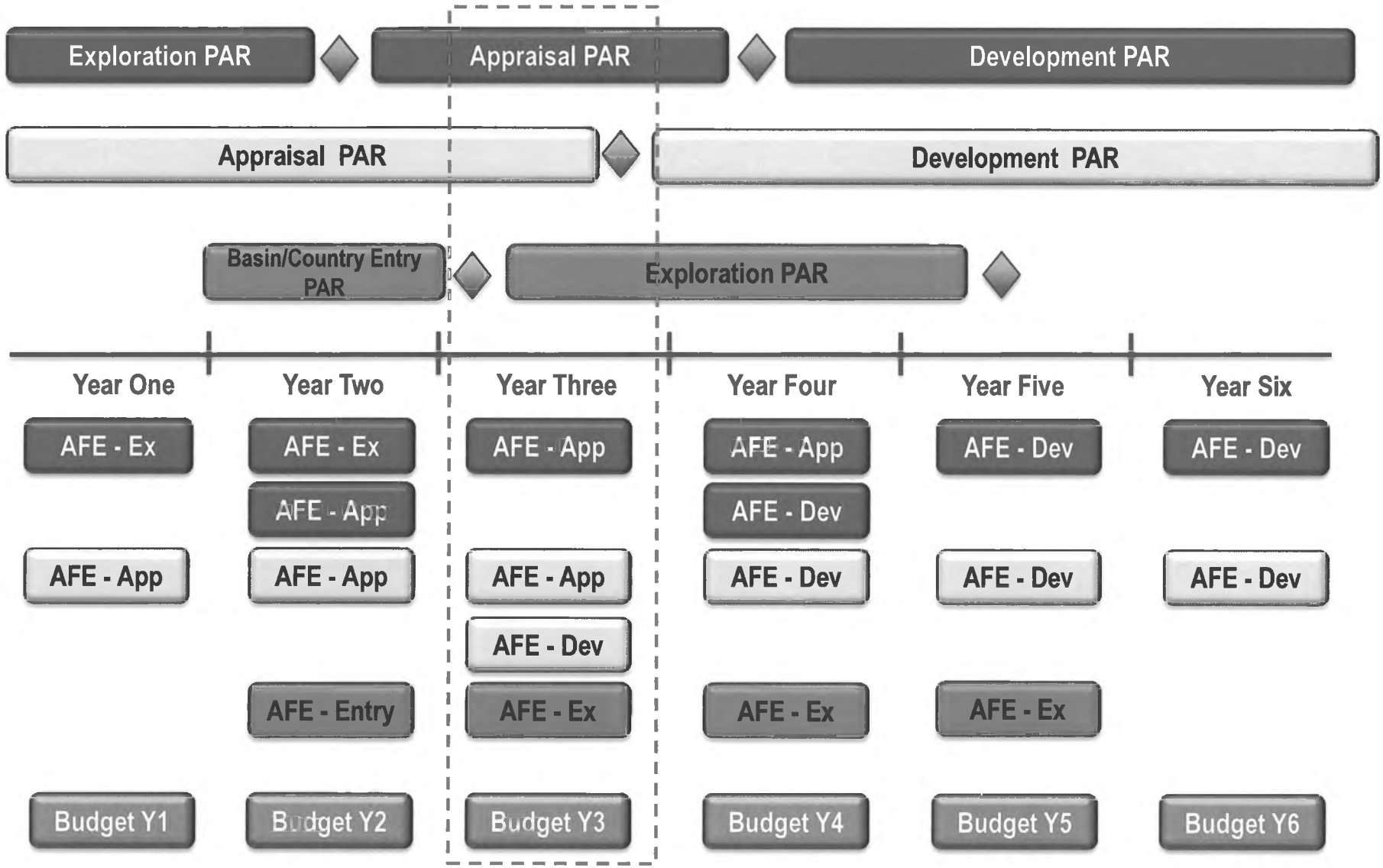
Business Control Architecture:
PAR => AFE => Budget



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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

Project Metrics: Net Present Value

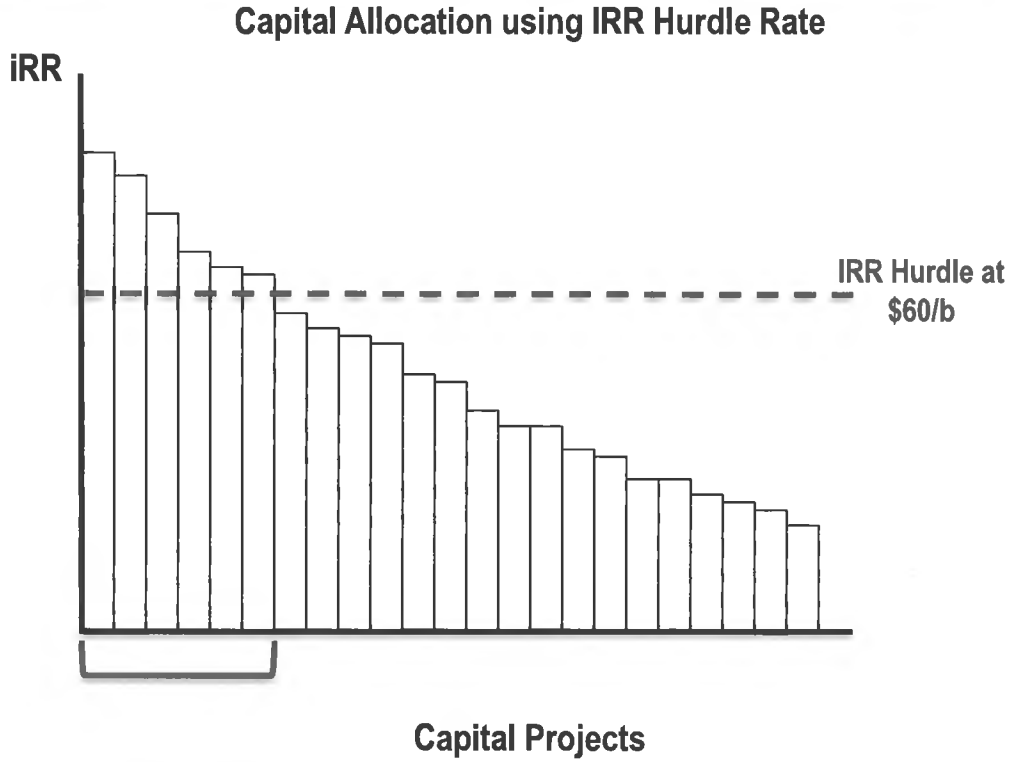
- **Net Present Value (NPV)**: The estimated value of a project when all future net cash flows are discounted to the present at an appropriate rate (the "discount factor").
- NPV > 0 => project is expected to deliver a return greater than the cost of development, including a return on capital invested (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**

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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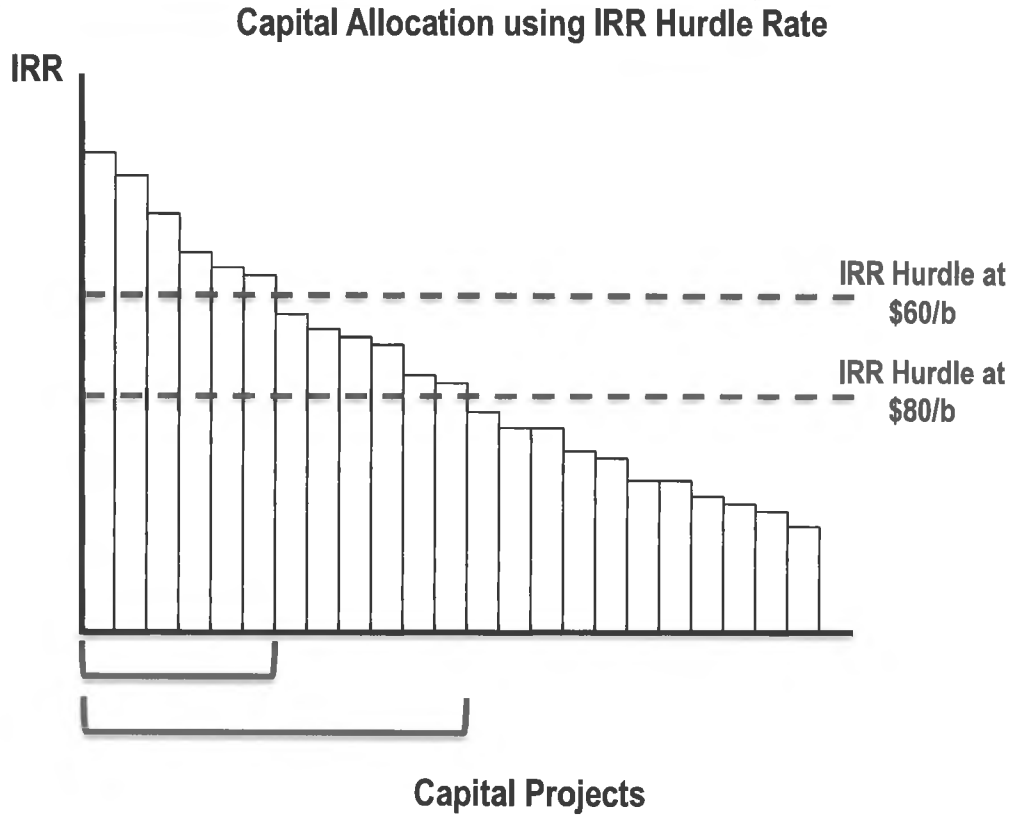
Capital Allocation: IRR Hurdle Rate

- 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



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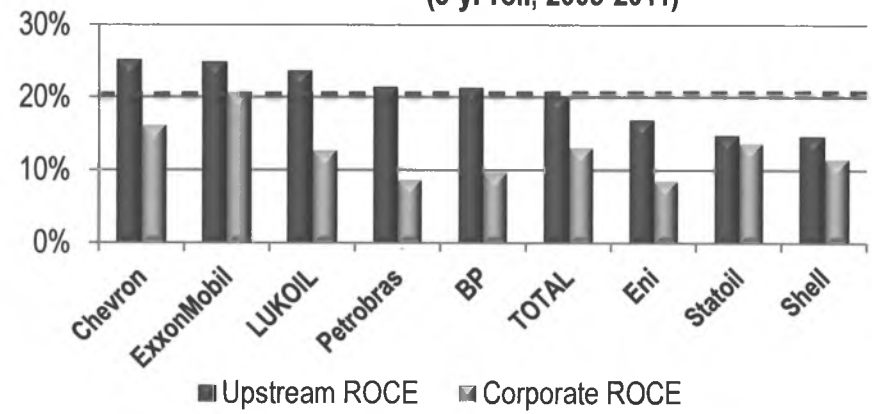
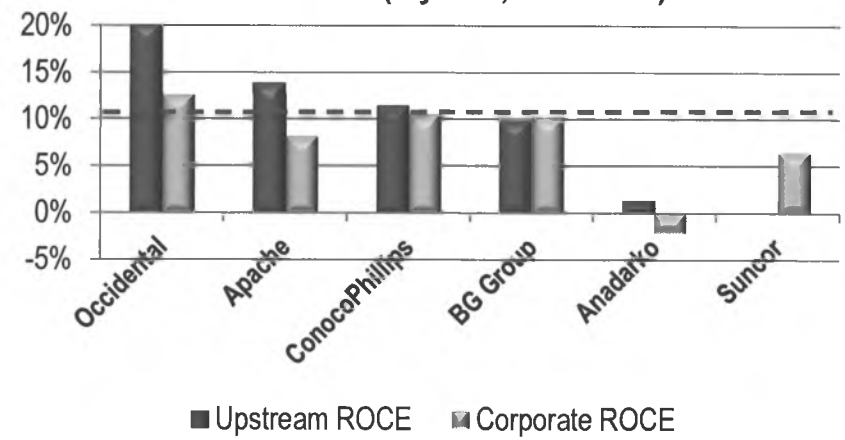
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **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

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



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



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

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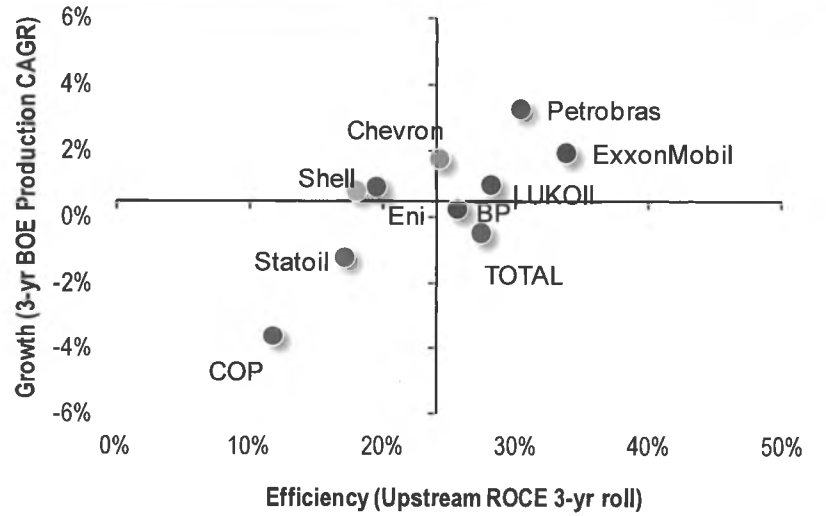
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **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

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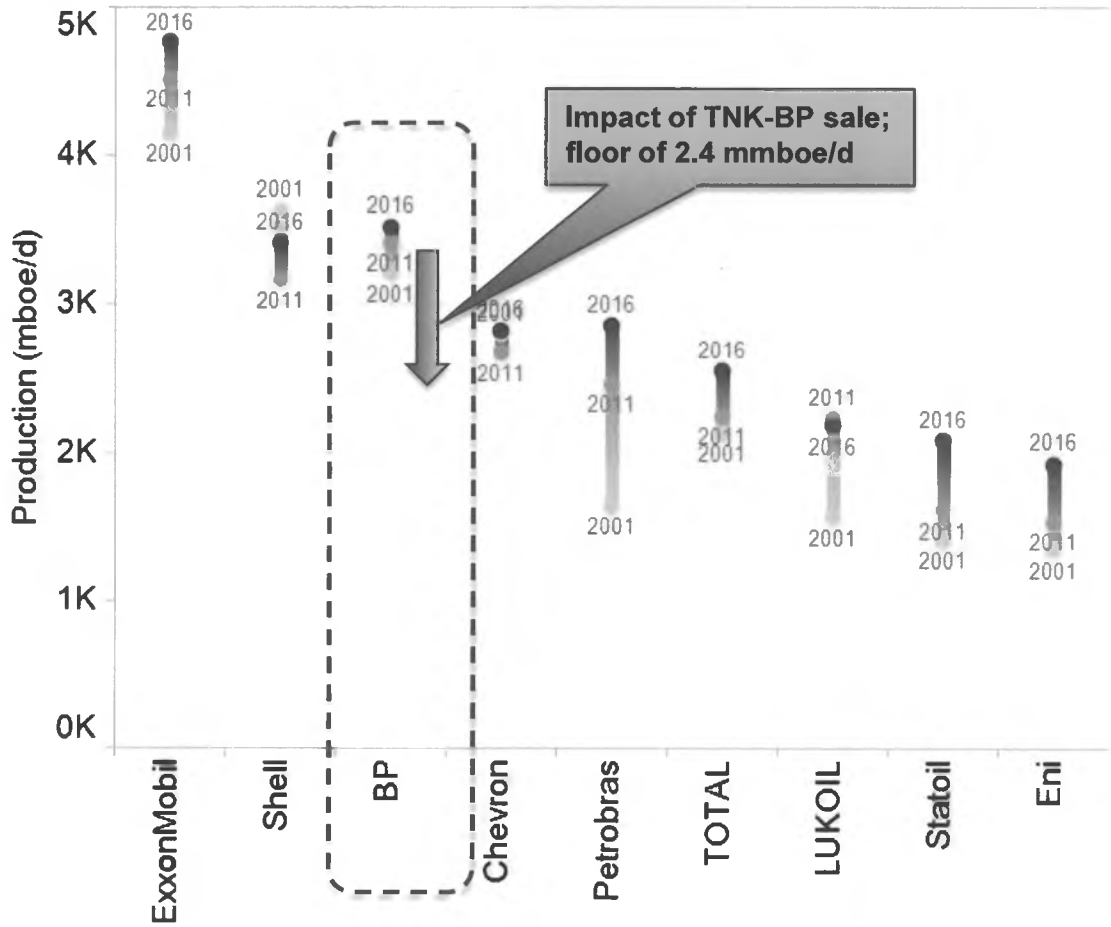
Total Portfolio Evolution: BP vis-à-vis the Competition

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

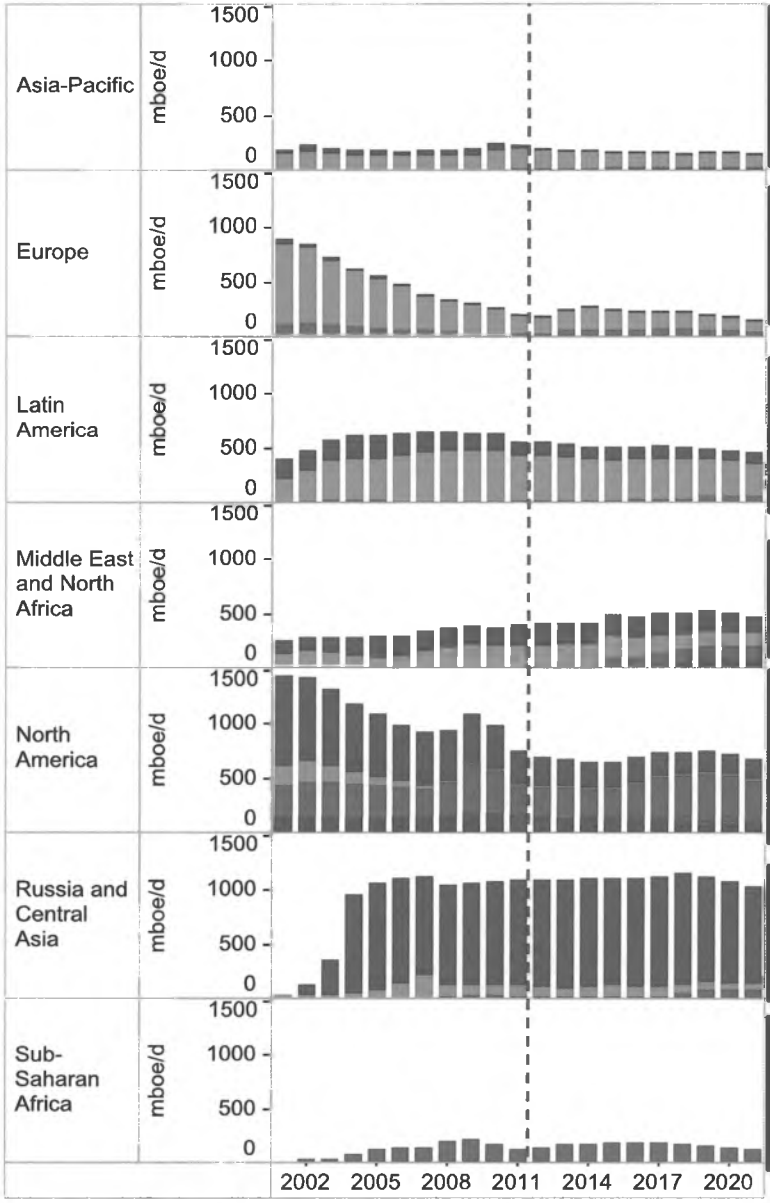


In 2011, BP was the second largest producer of the peer group. BP and COP are the only two companies forecast to deliver production declines over the 2010-2015 period.

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.

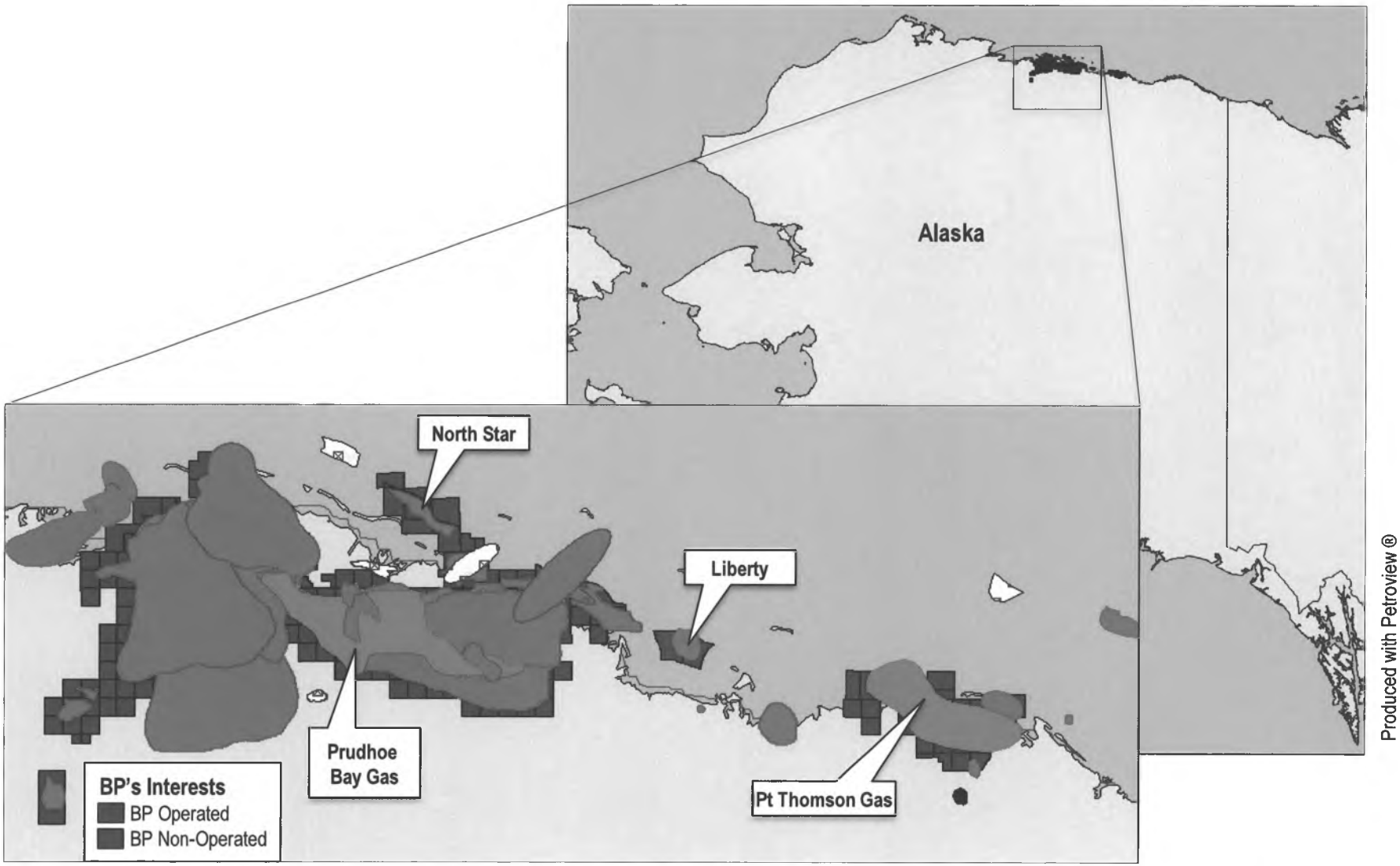
North America: ~764 mboe/d in 2011, 2nd largest production region, focused on Deepwater GOM. Sale of conventional oil and gas assets in Onshore L48, growing focus on shale gas and oil sands development(first oil from the in-situ (SAGD) Sunrise project expected in 2014).

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.**

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
  - Poceeds 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

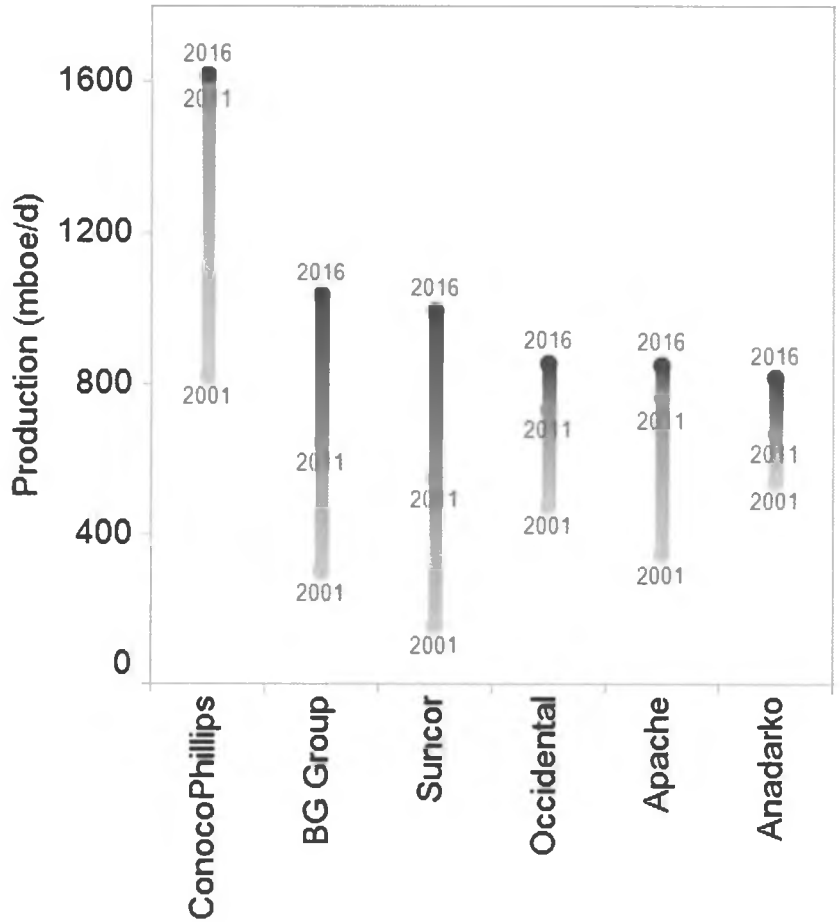
Date	Partner	Region (or Country)	Type
2003	LUKOIL	Russia	Various
2006	Cenovus	Canada	Oil Sands
2008	Origin Energy	Australia	LNG

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**

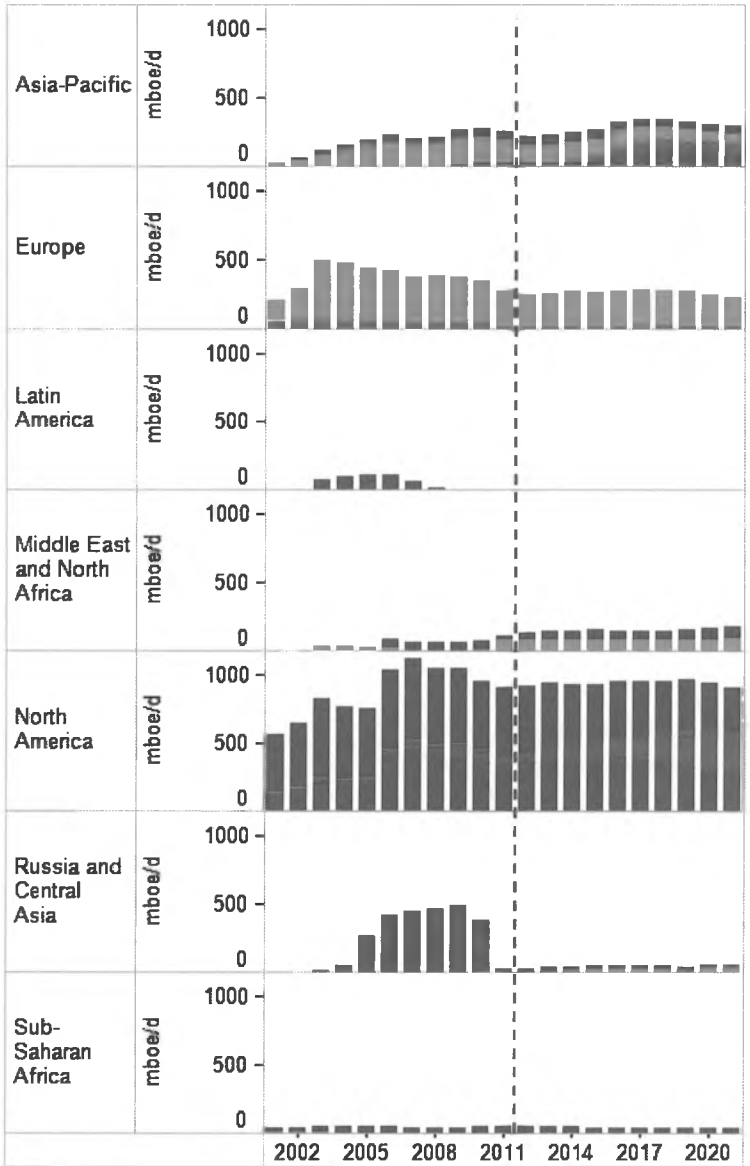
Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition

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.

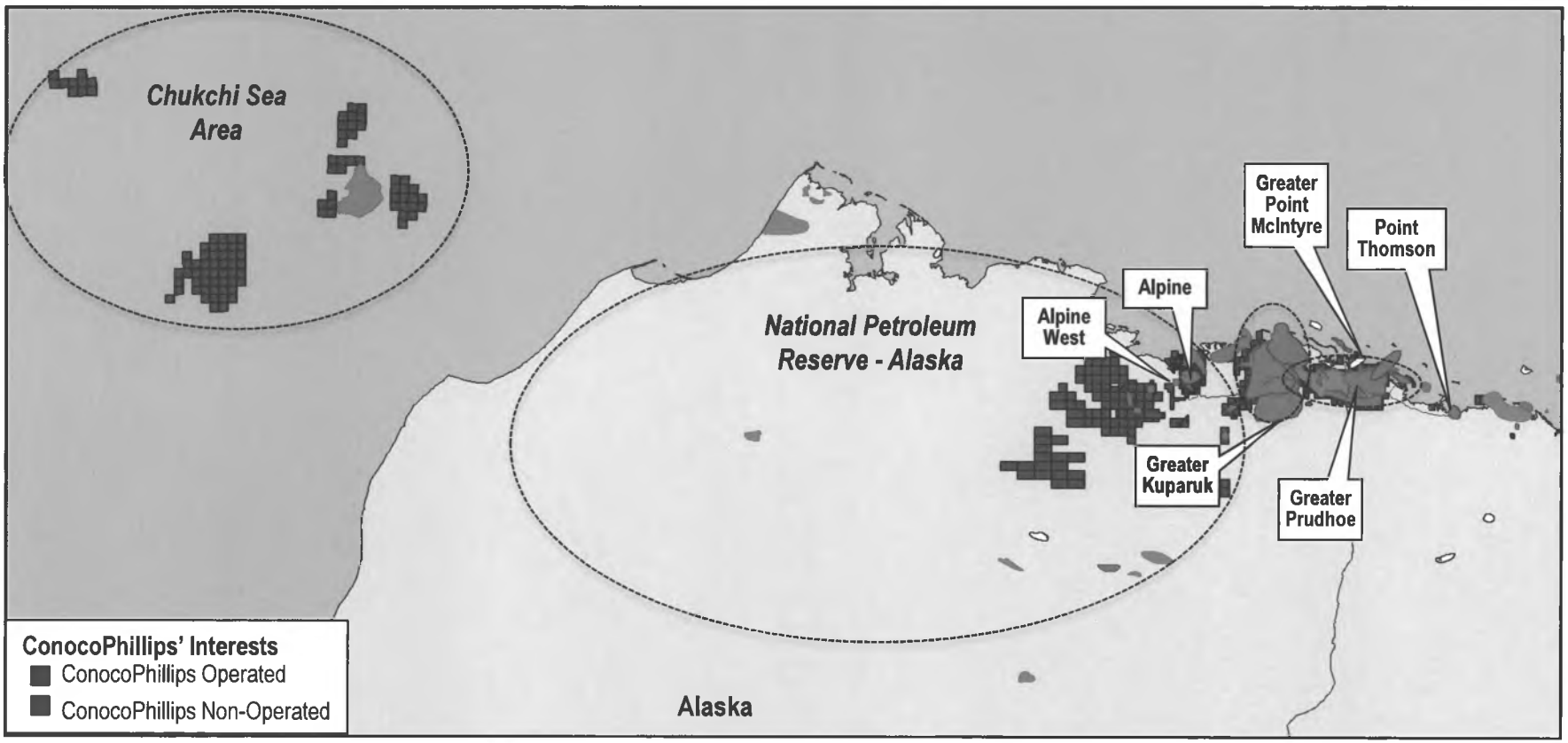
North America: ~903 mboe/d in 2011 (~56% of global volumes). New Ventures in Oil Sands, Unconventional Onshore resource plays, and GOM deepwater will provide regional growth.

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.

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

ConocoPhillips in North America—Alaska



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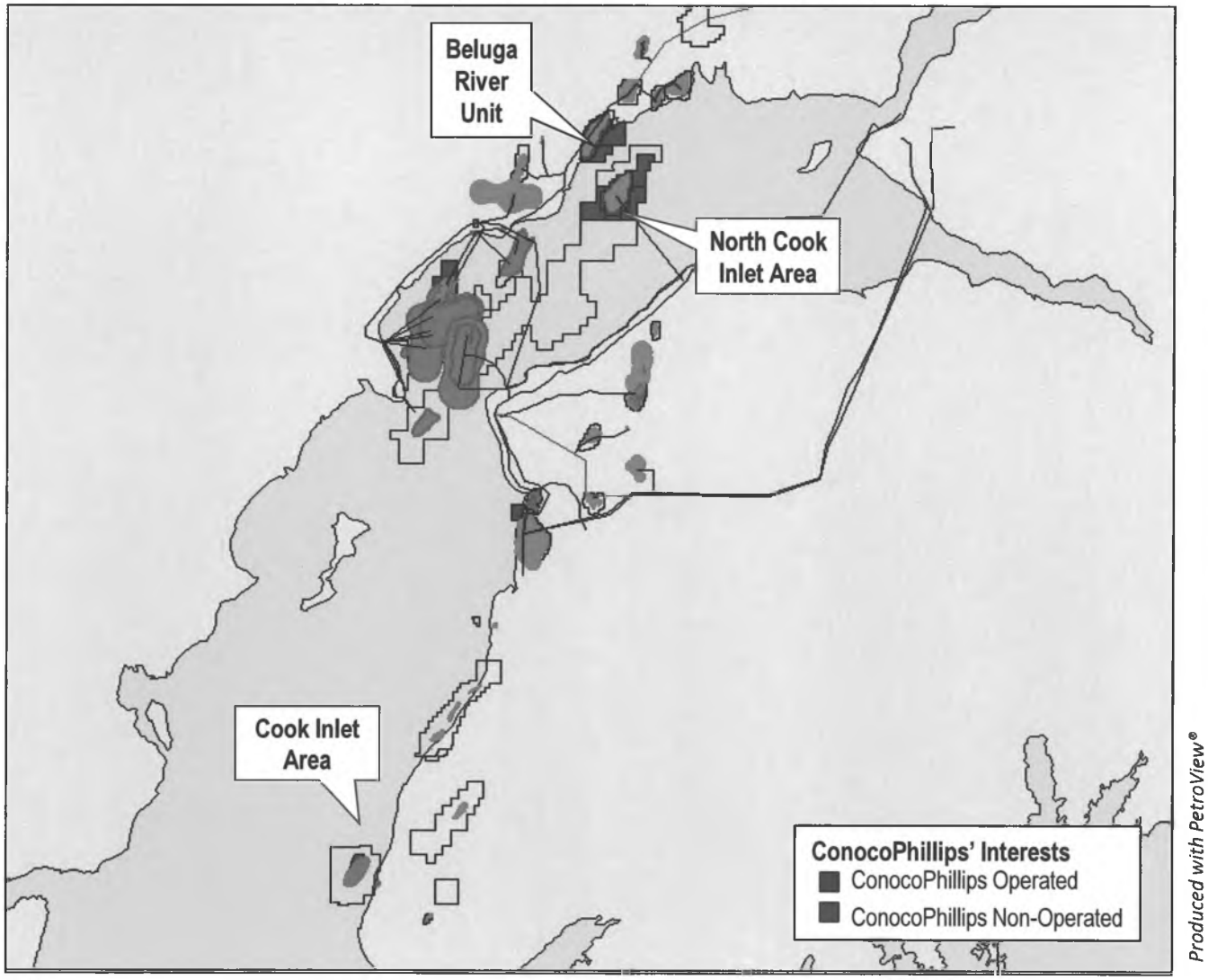
ConocoPhillips in North America—Alaska Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



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.**

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-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

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	
New Venture	Tanzania	
	Turkey	
	Vietnam	
Exit/Potential Exit	Brazil	
	Cameroon	
	Italy	
	Libya	
	Philippines	
	Yemen	
Grand Total		**4,513**

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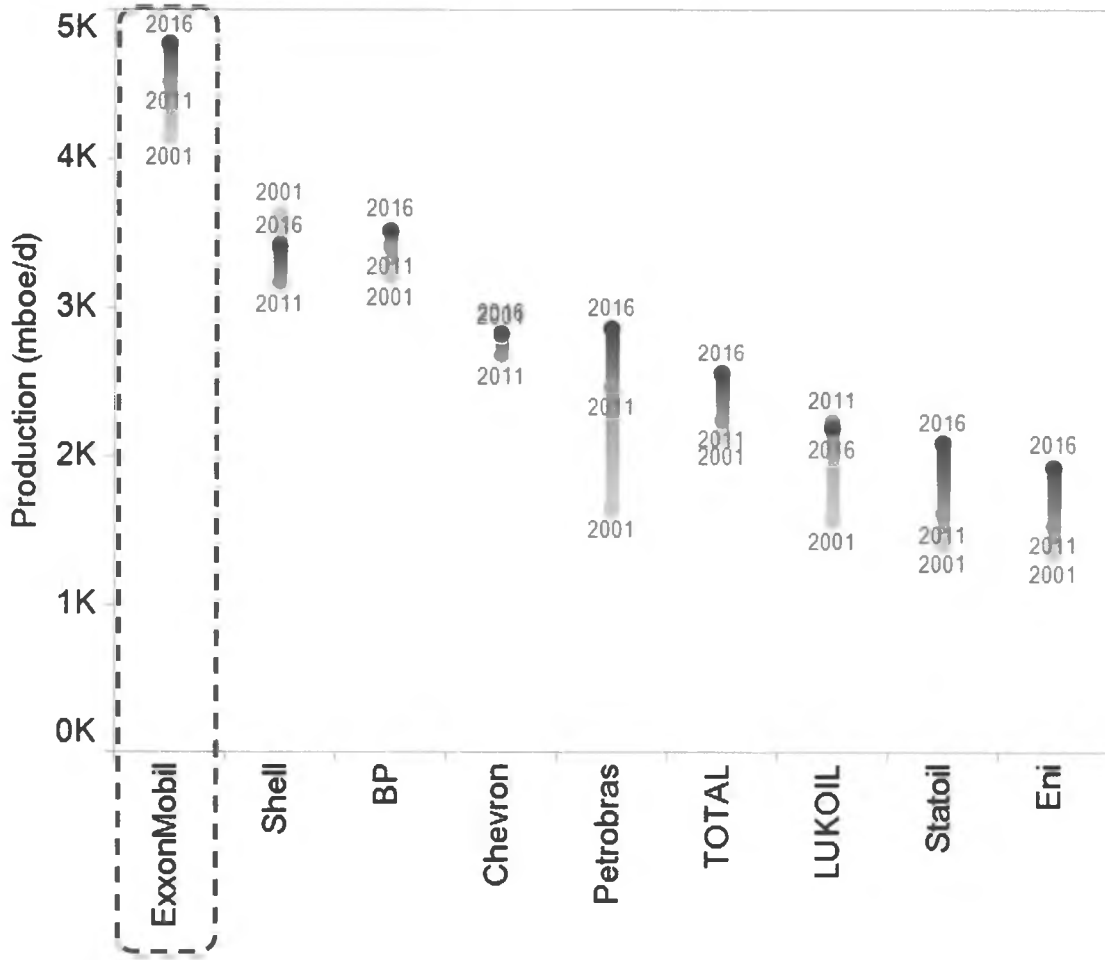
Total Portfolio Evolution: ExxonMobil vis-à-vis the Competition

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

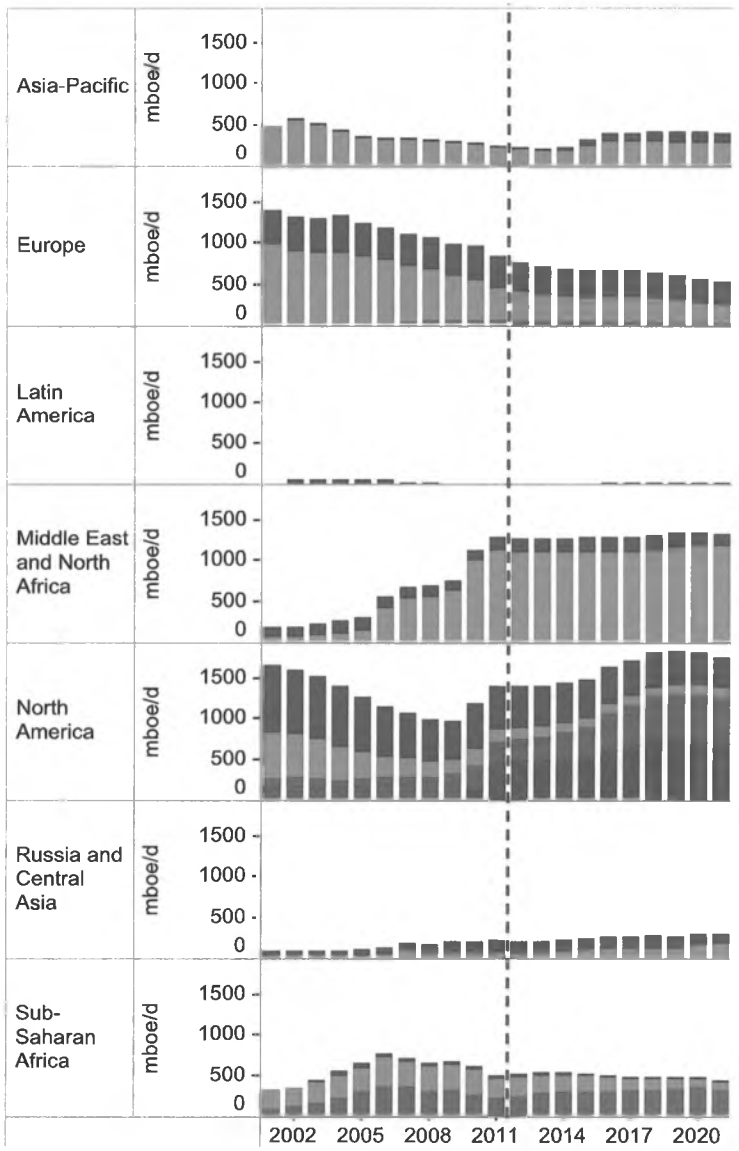


Averaging ~4.5 mmboe/d in 2011, ExxonMobil continues to lead its peer group in terms of production.

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.

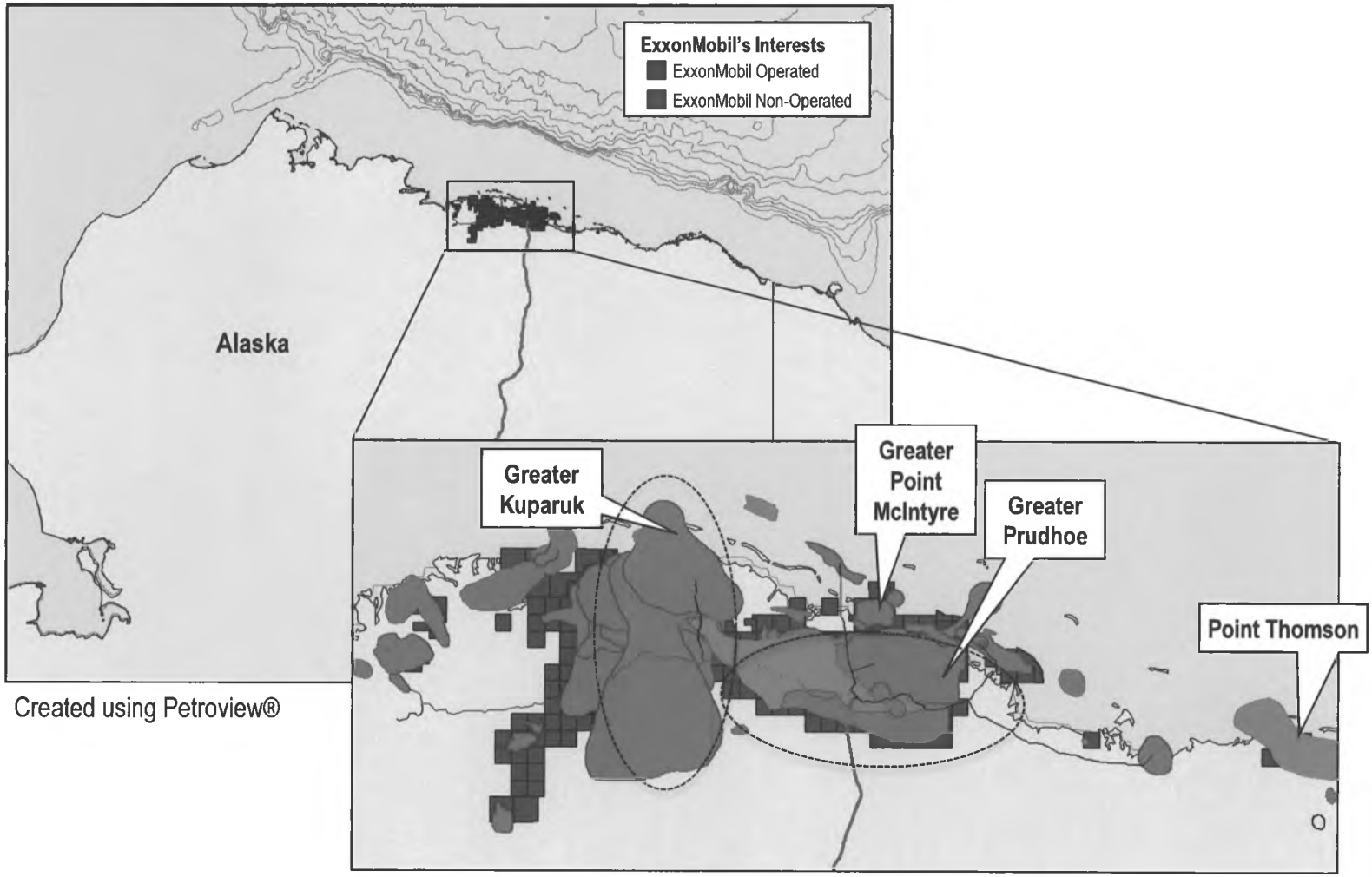
North America: ~1,389 mboe/d in 2011. Expanded positioning in the US Onshore shale gas plays, material deepwater US GOM portfolio, development projects in the Canadian Oil Sands combine to deliver material production growth over the long term.

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.

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

ExxonMobil in North America: Alaska



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PFC Energy

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-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.

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	

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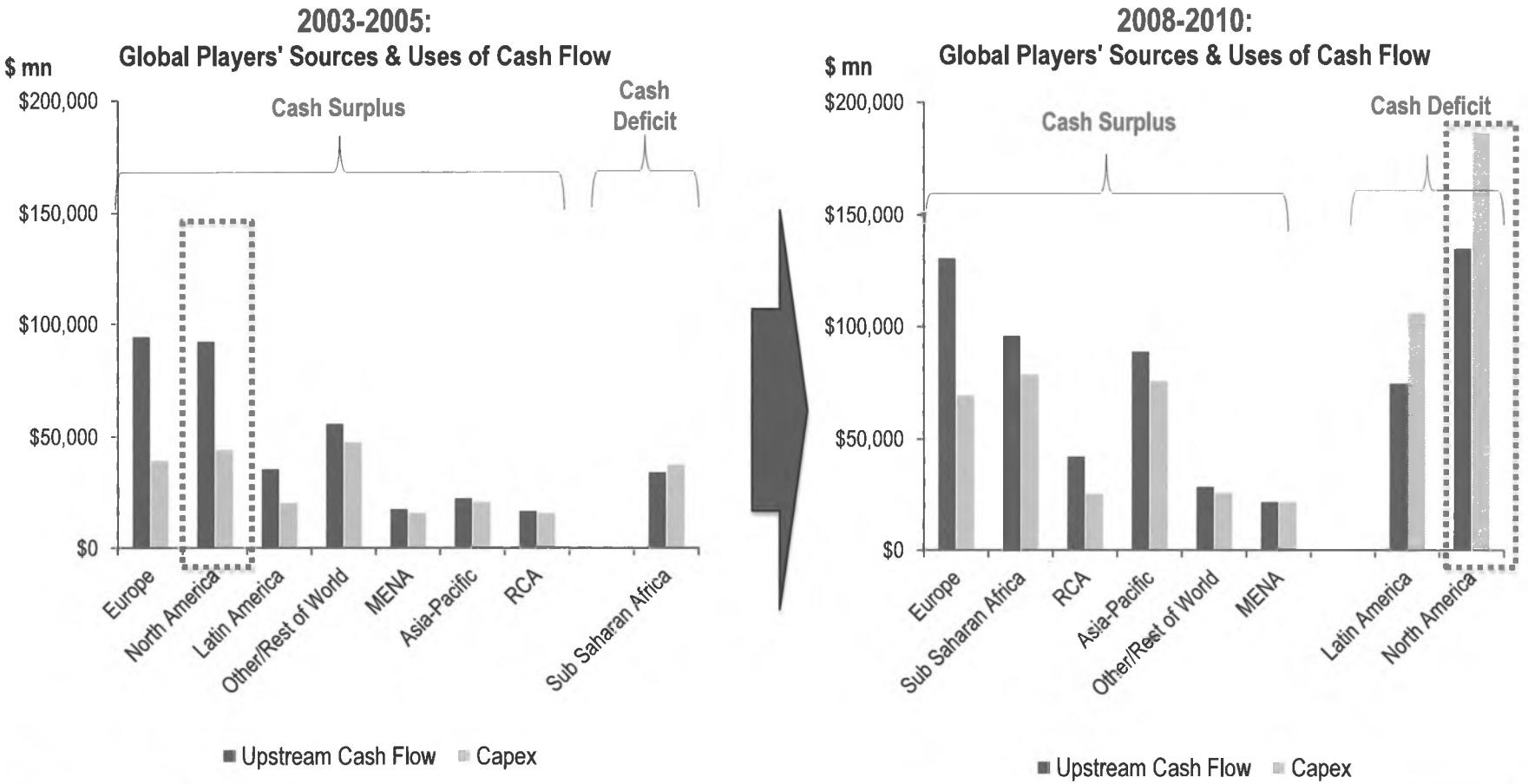
Alaska's Fiscal Regime in a Global Competitive Context

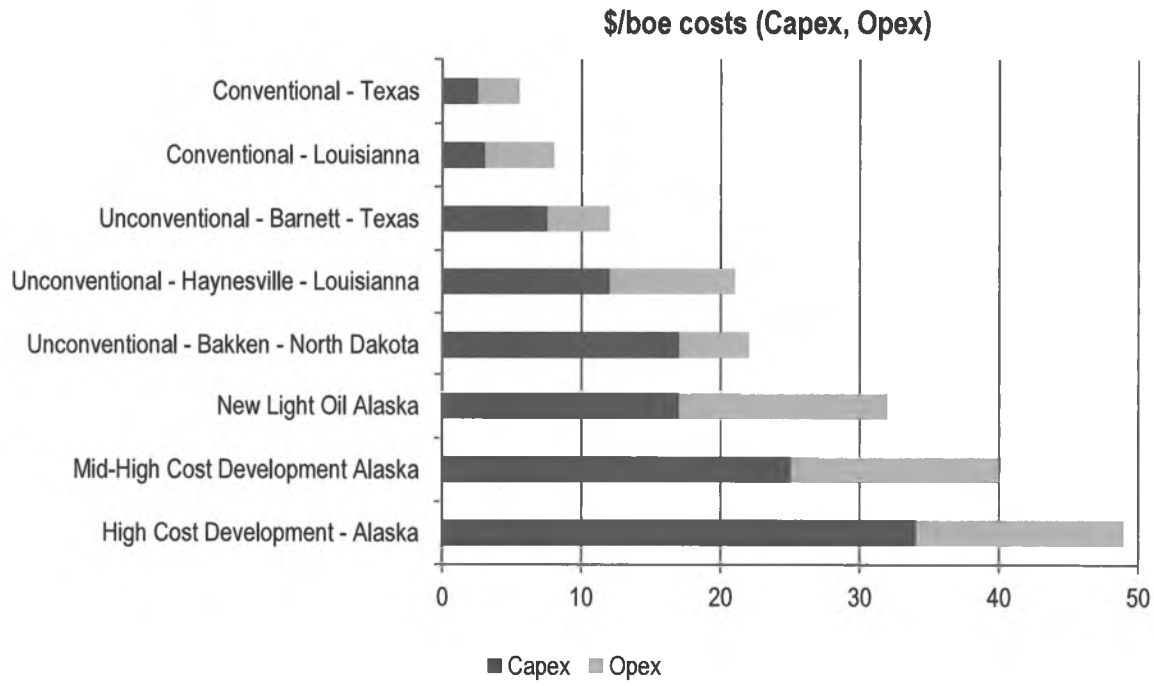
PFC Energy

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.

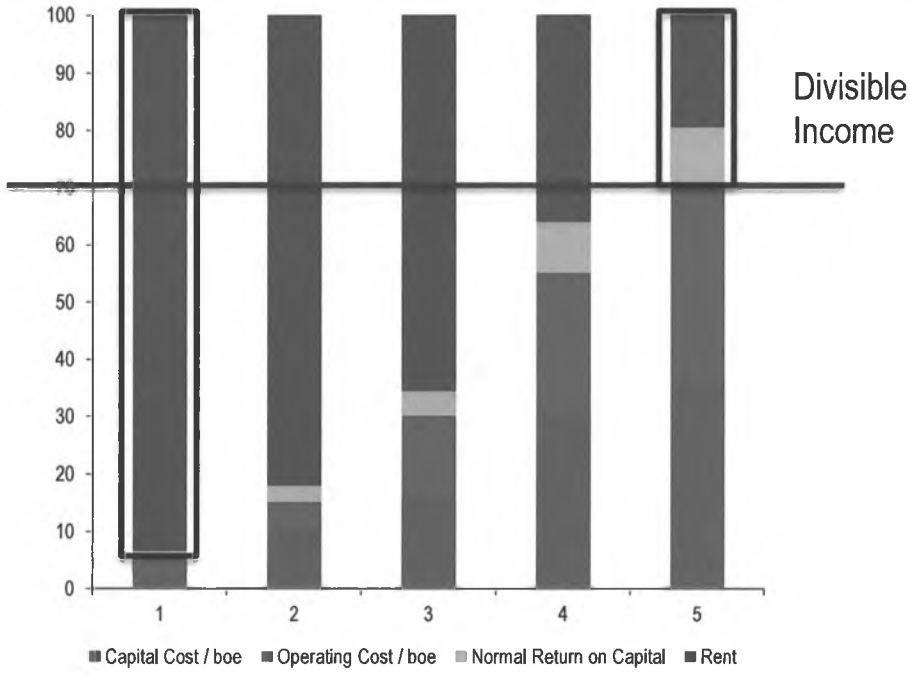
Government Take includes all payments the government mandates in its function as a sovereign:

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

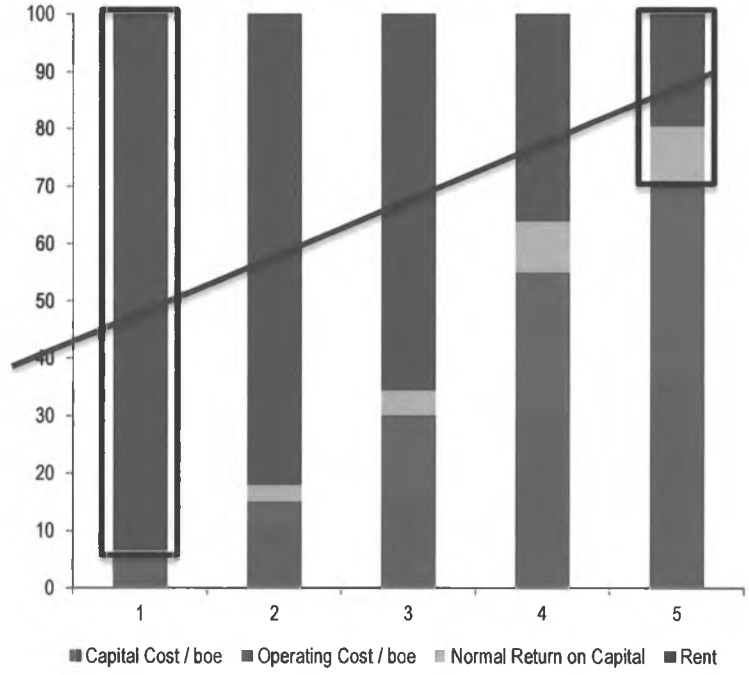
Government Take does not include amounts the government earns via a direct equity stake

Fixed Royalty v Profit Based Fiscal Systems

Incidence of a 30% Fixed Royalty on 5 Different Price Environments



Incidence of a 50% Profit-Based Tax on 5 Different Price Environments



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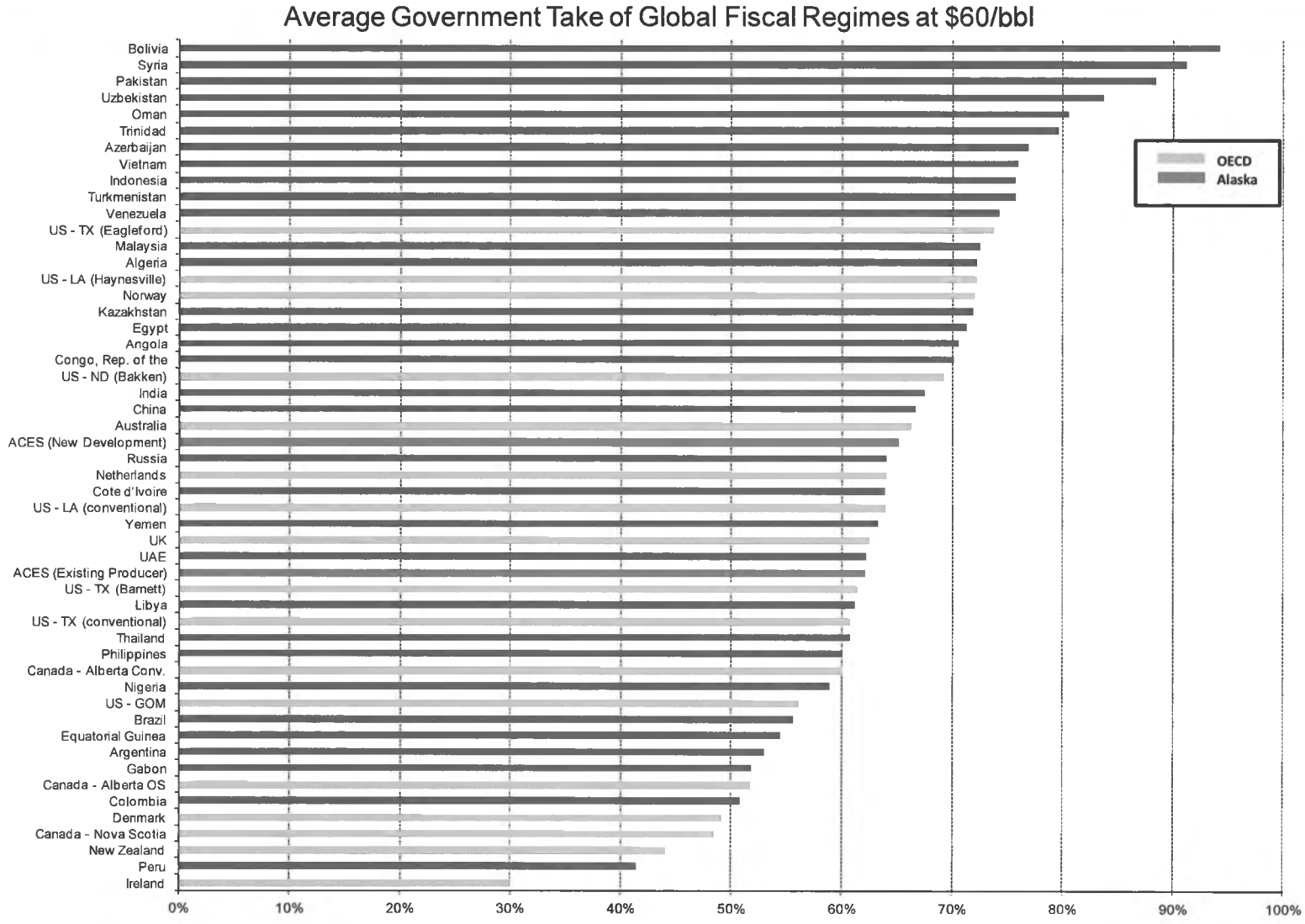
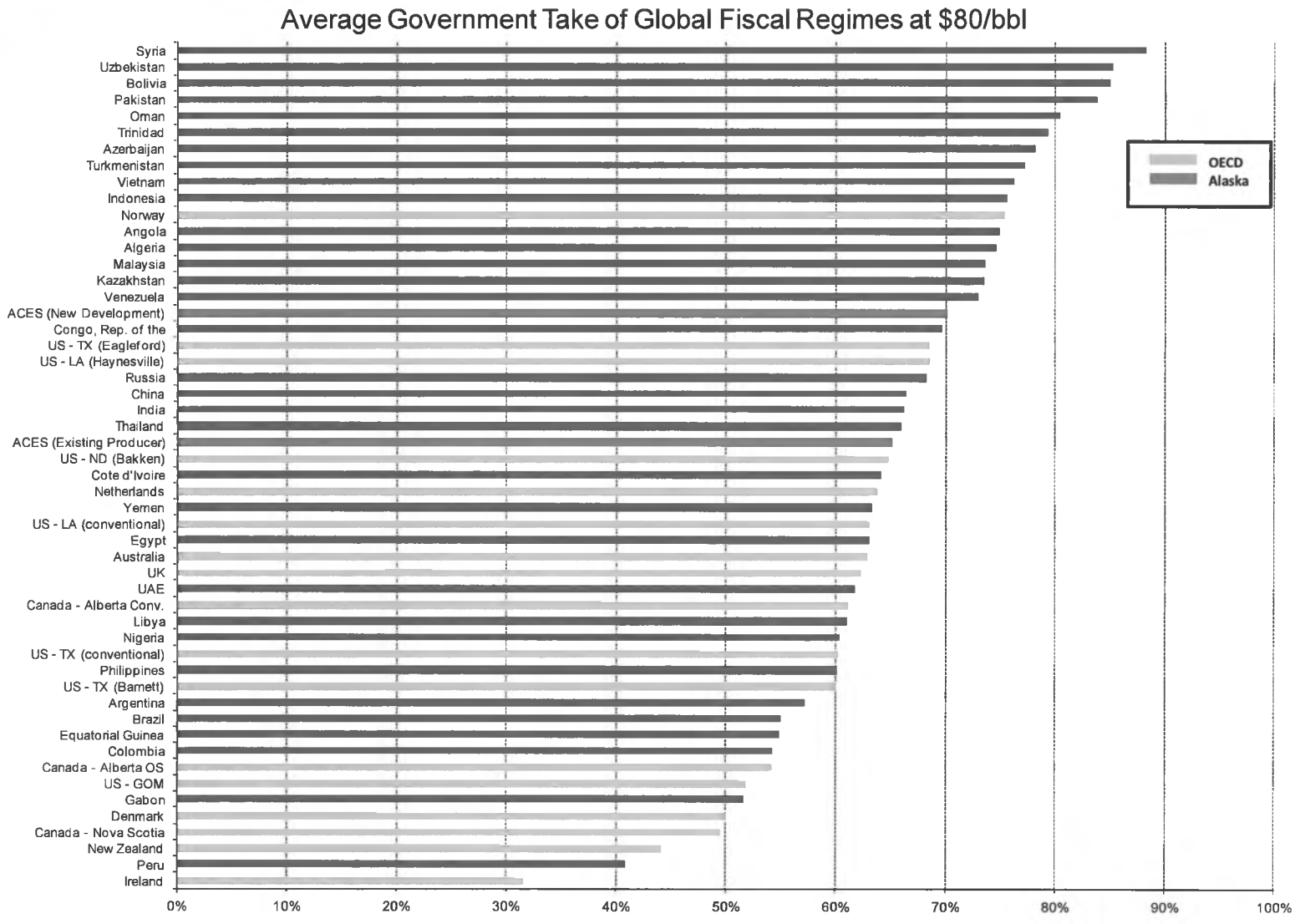
Regime Competitiveness: Average Government Take at $60/bbl



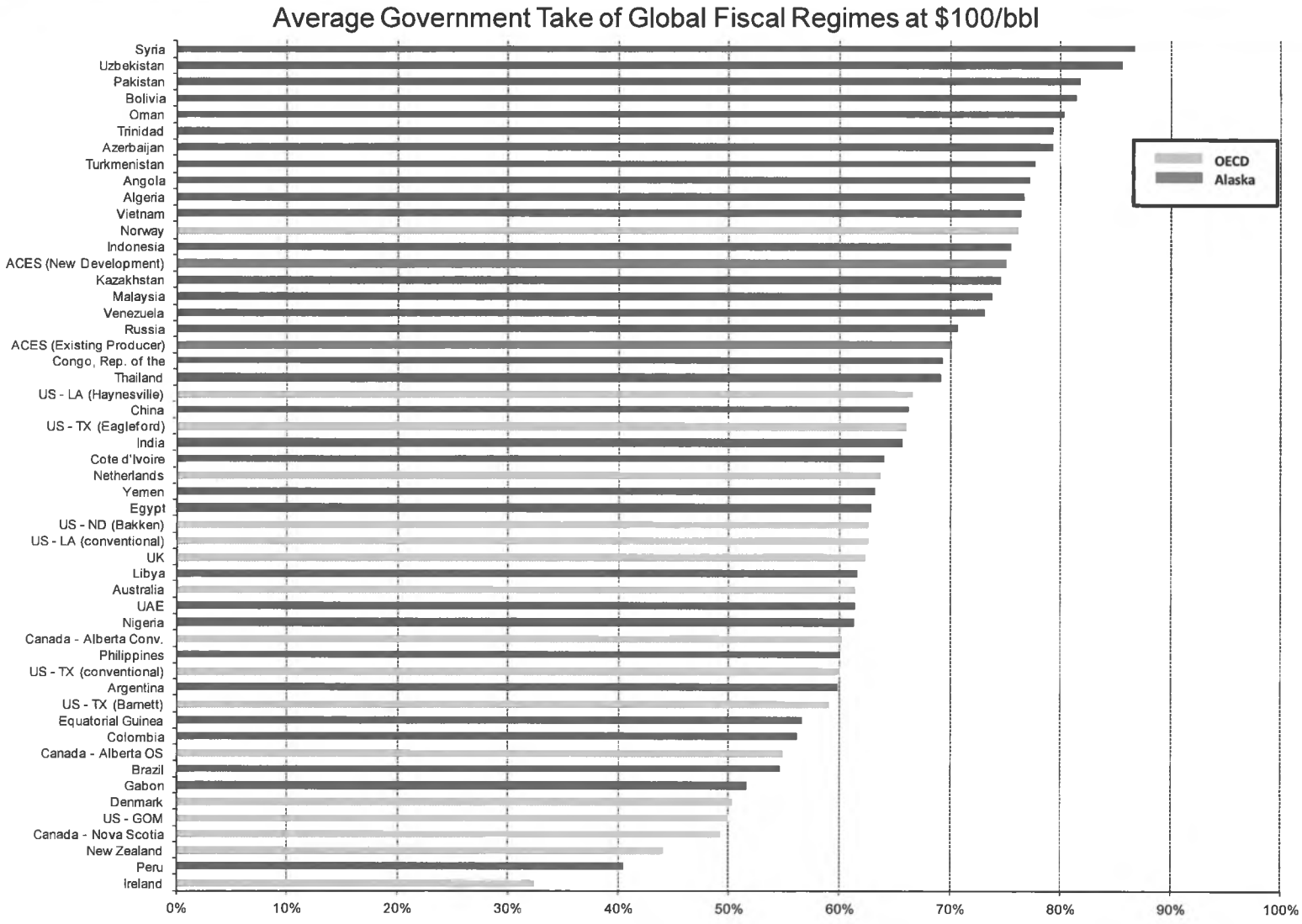
PFC Energy

Regime Competitiveness: Average Government Take at $80/bbl



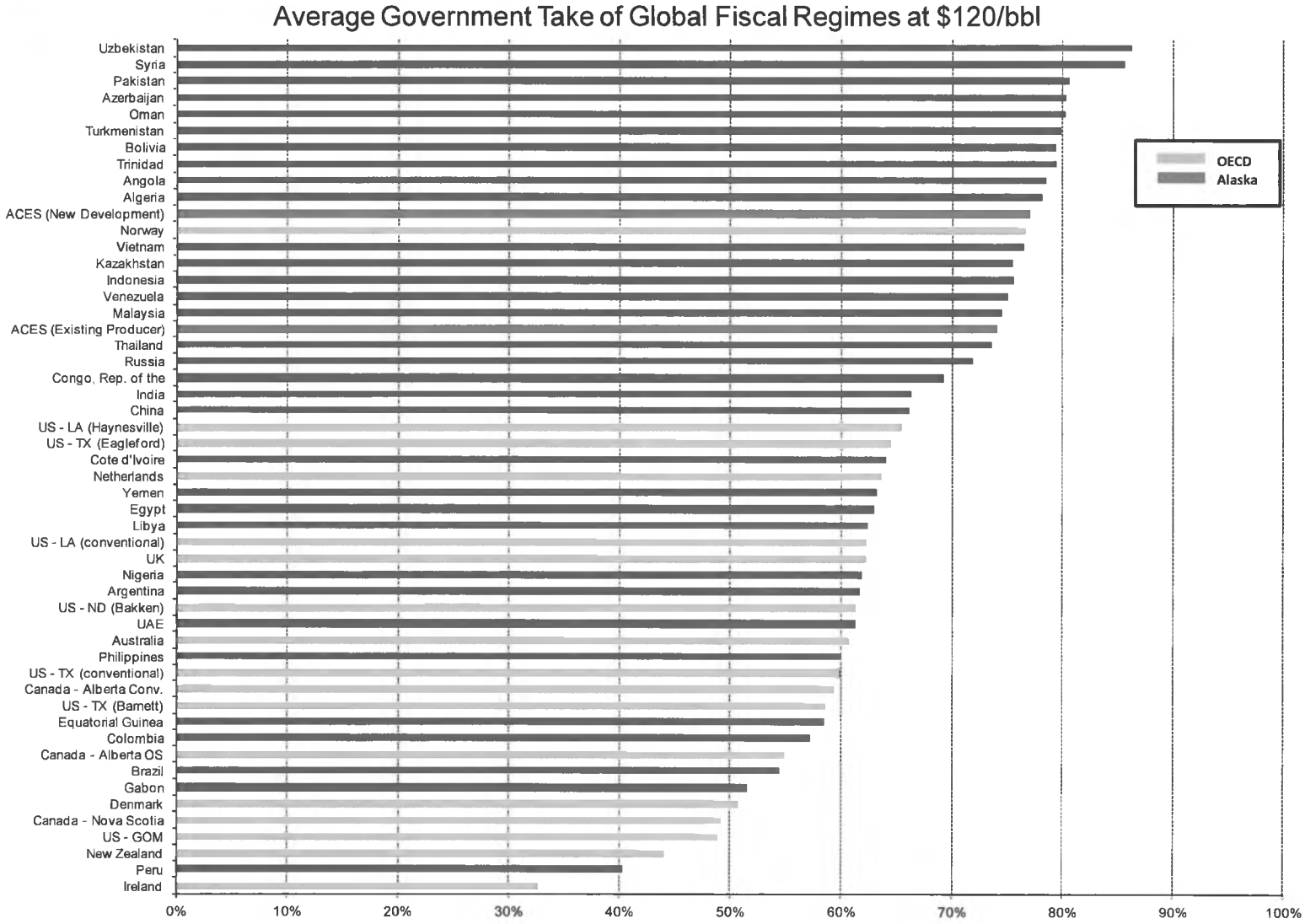
PFC Energy

Regime Competitiveness: Average Government Take at $100/bbl



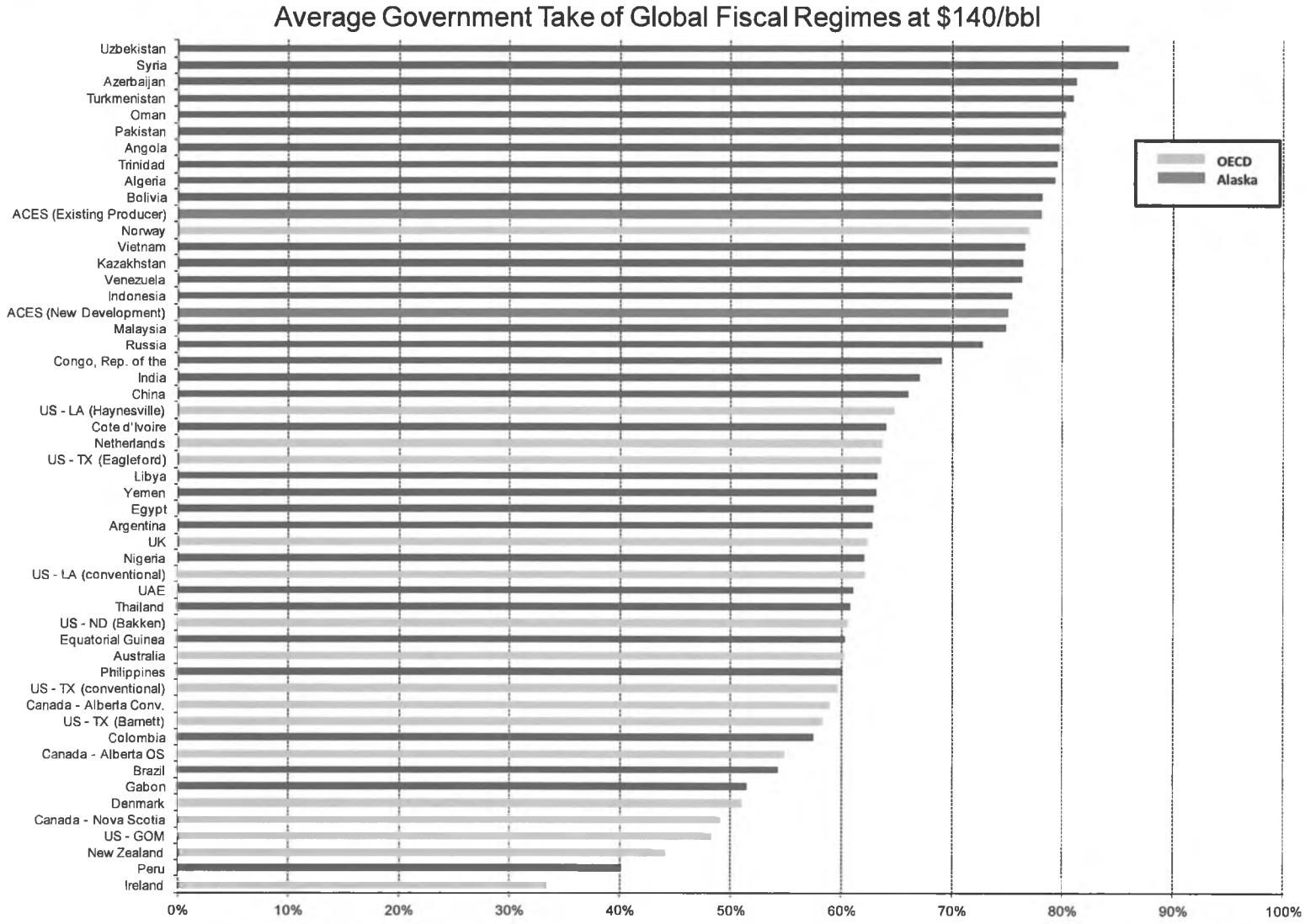
PFC Energy

Regime Competitiveness: Average Government Take at $120/bbl



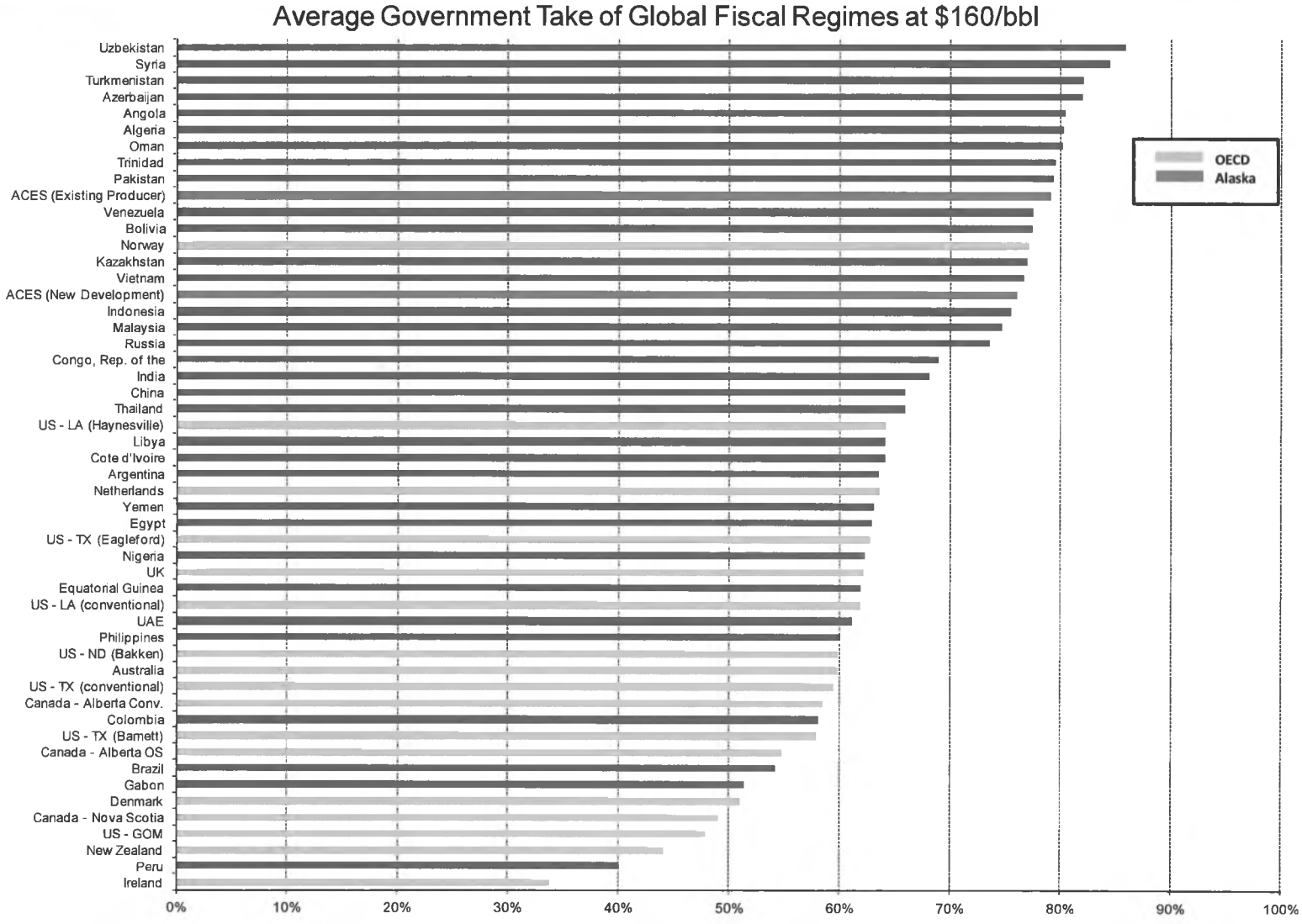
PFC Energy

Regime Competitiveness: Average Government Take at $140/bbl



PFC Energy

Regime Competitiveness: Average Government Take at $160/bbl



PFC Energy

ACES & SB 21

ACES – Existing Production – Government Take

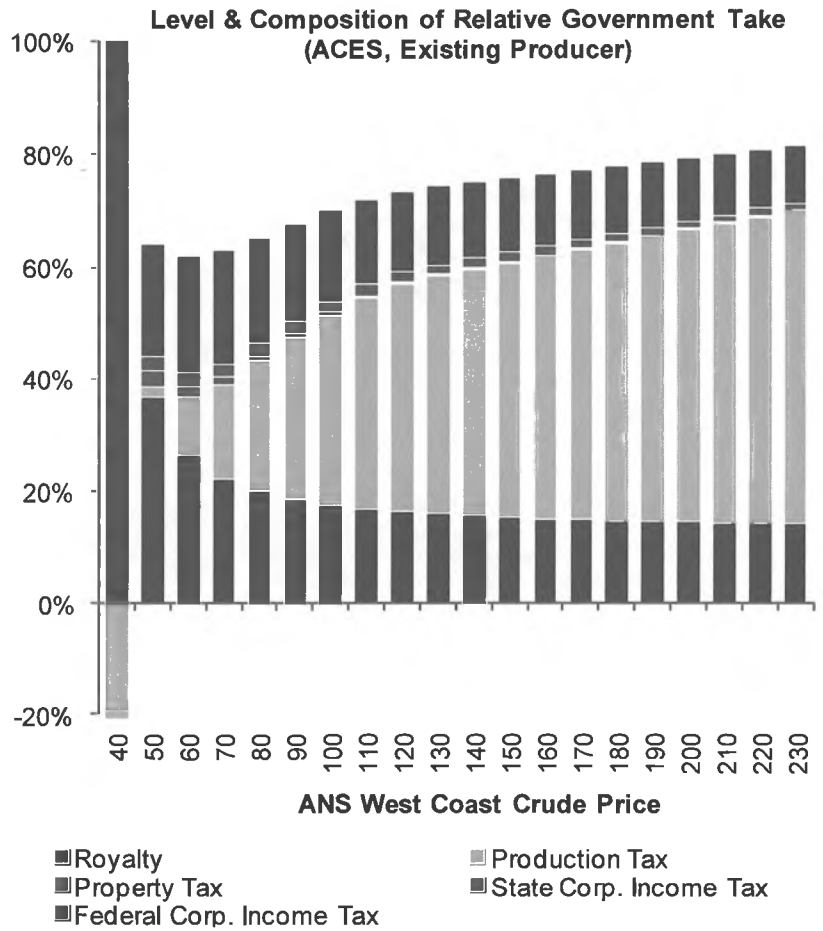


Table 1: Level & Composition of Relative Government Take (ACES, Existing Producer)

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

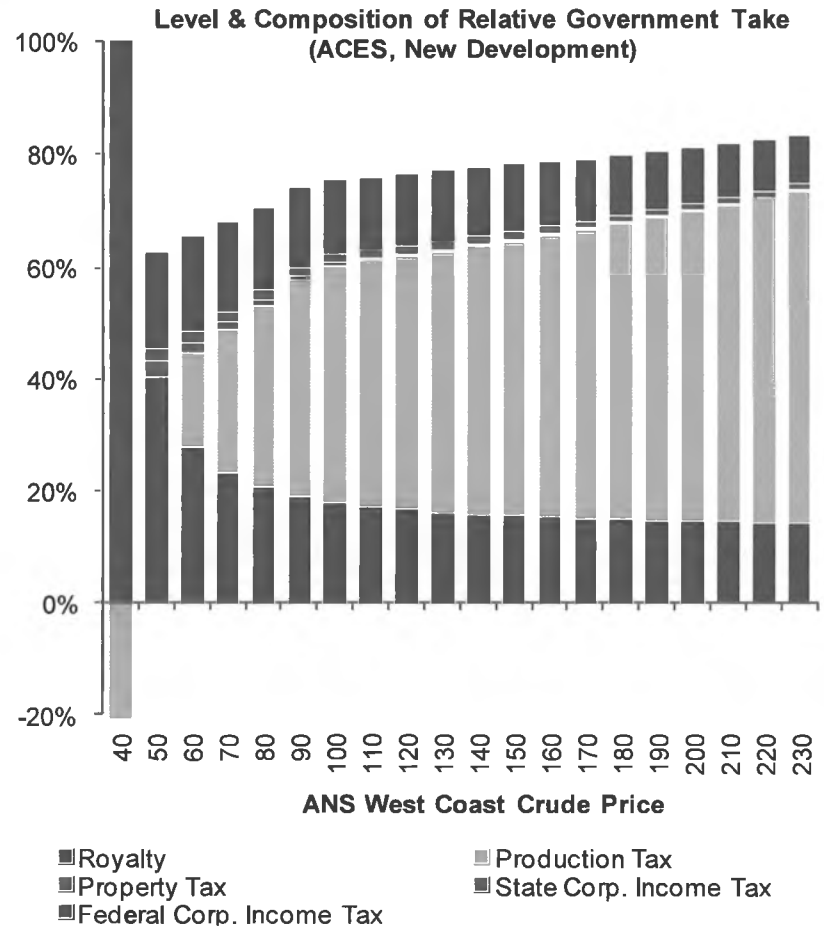


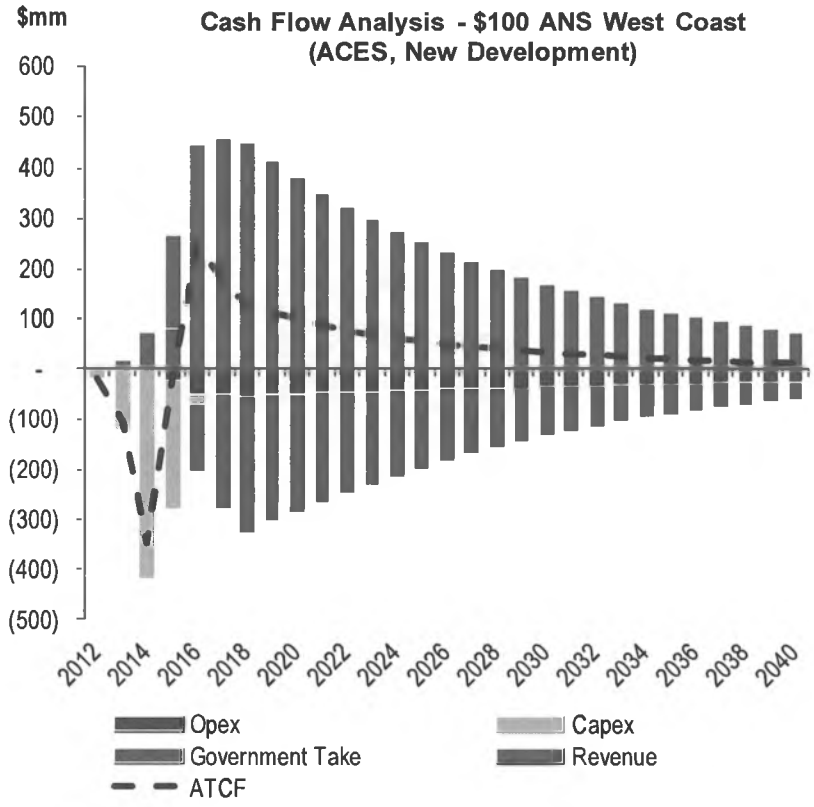
Table 1: Level & Composition of Relative Government Take (ACES, New Development)

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)

PFC Energy

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%

PFC Energy

SB21 – Existing Production – Government Take

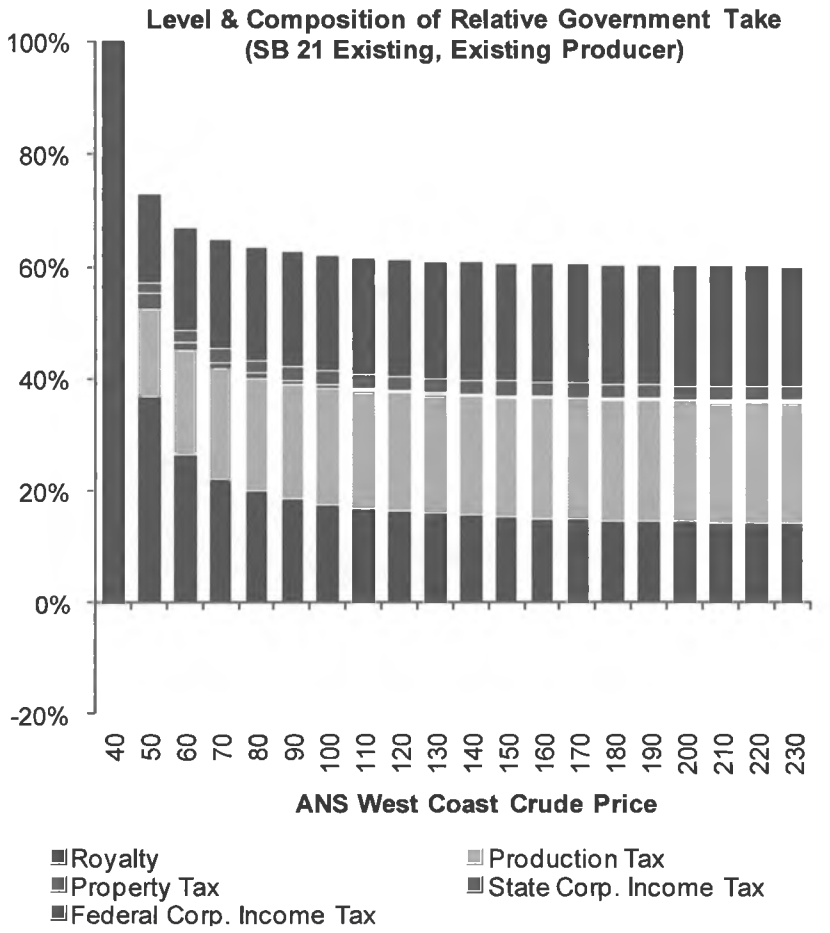


Table 1: Level & Composition of Relative Government Take (SB 21 Existing, Existing Producer)

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)

PFC Energy

SB 21 – New Development – Government Take

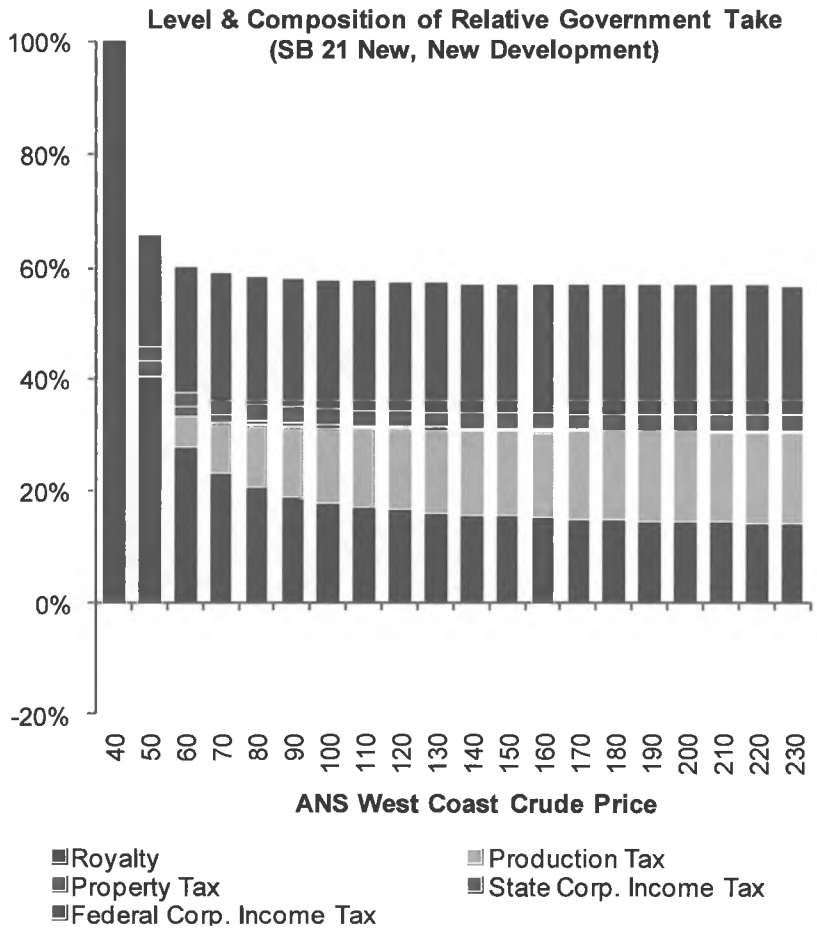


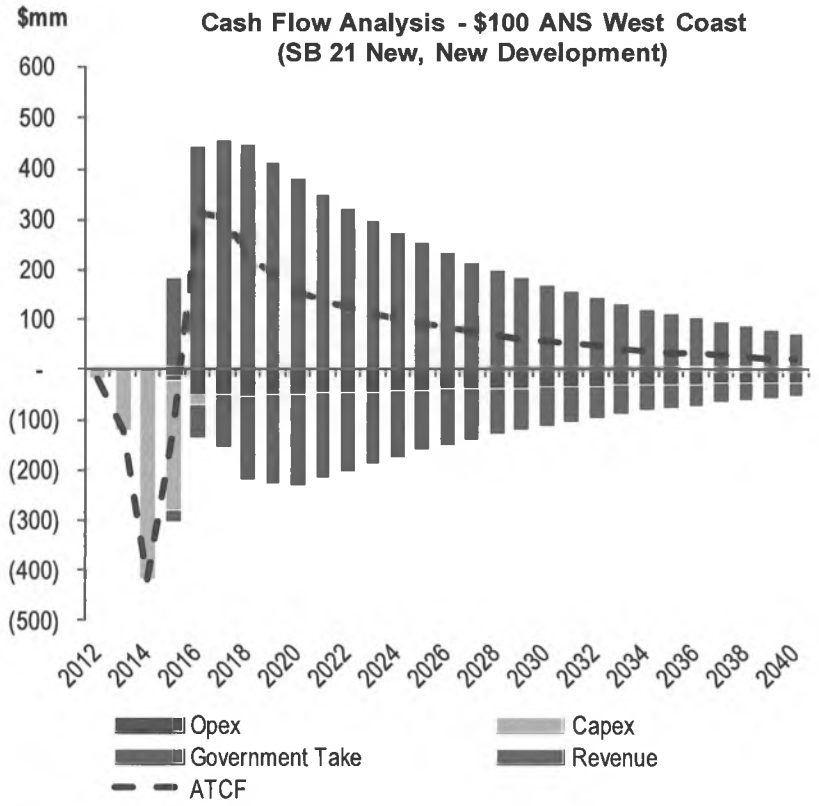
Table 1: Level & Composition of Relative Government Take (SB 21 New, New Development)

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)

PFC Energy

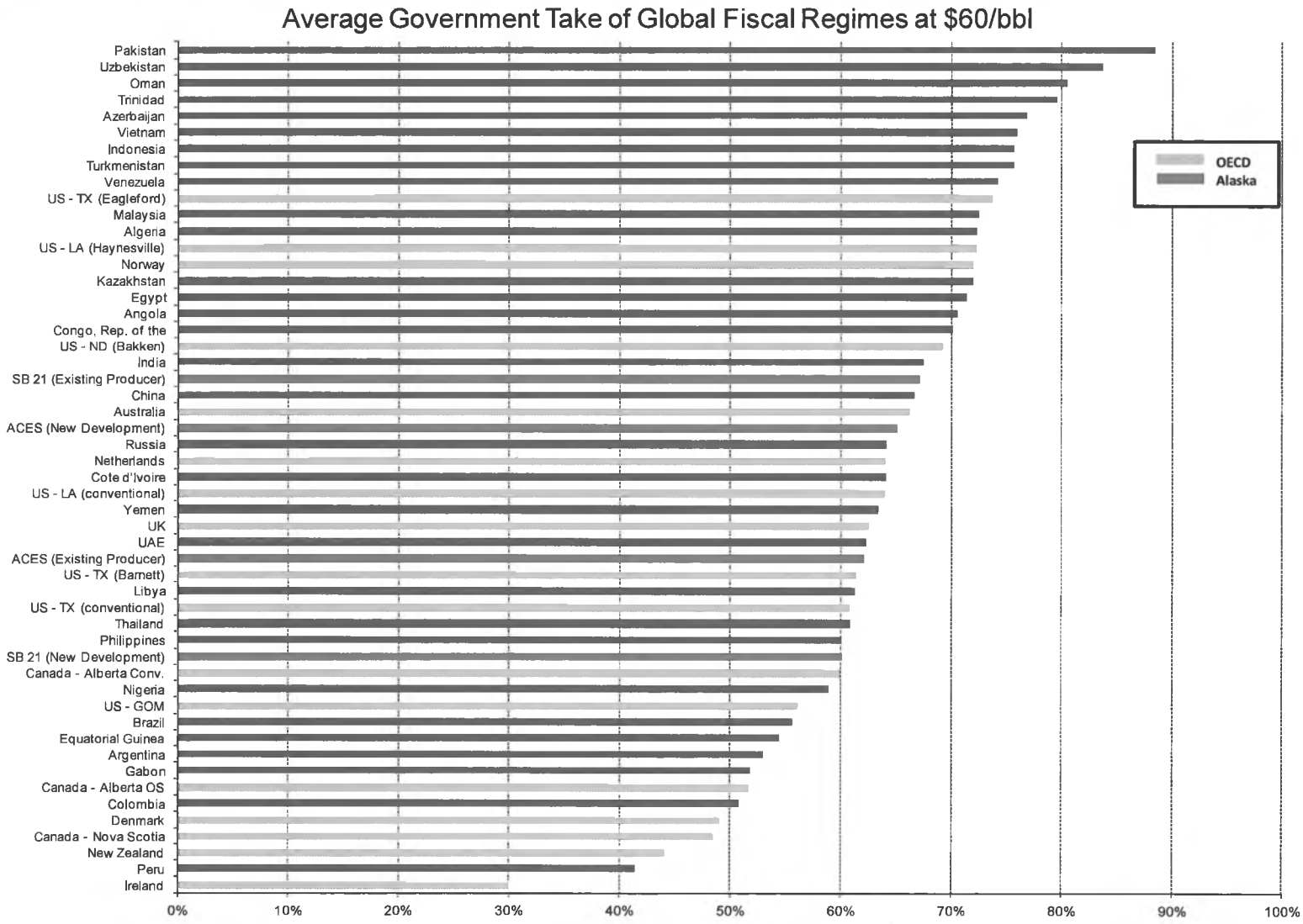
SB 21 – New Development – Cash Flow Analysis



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%

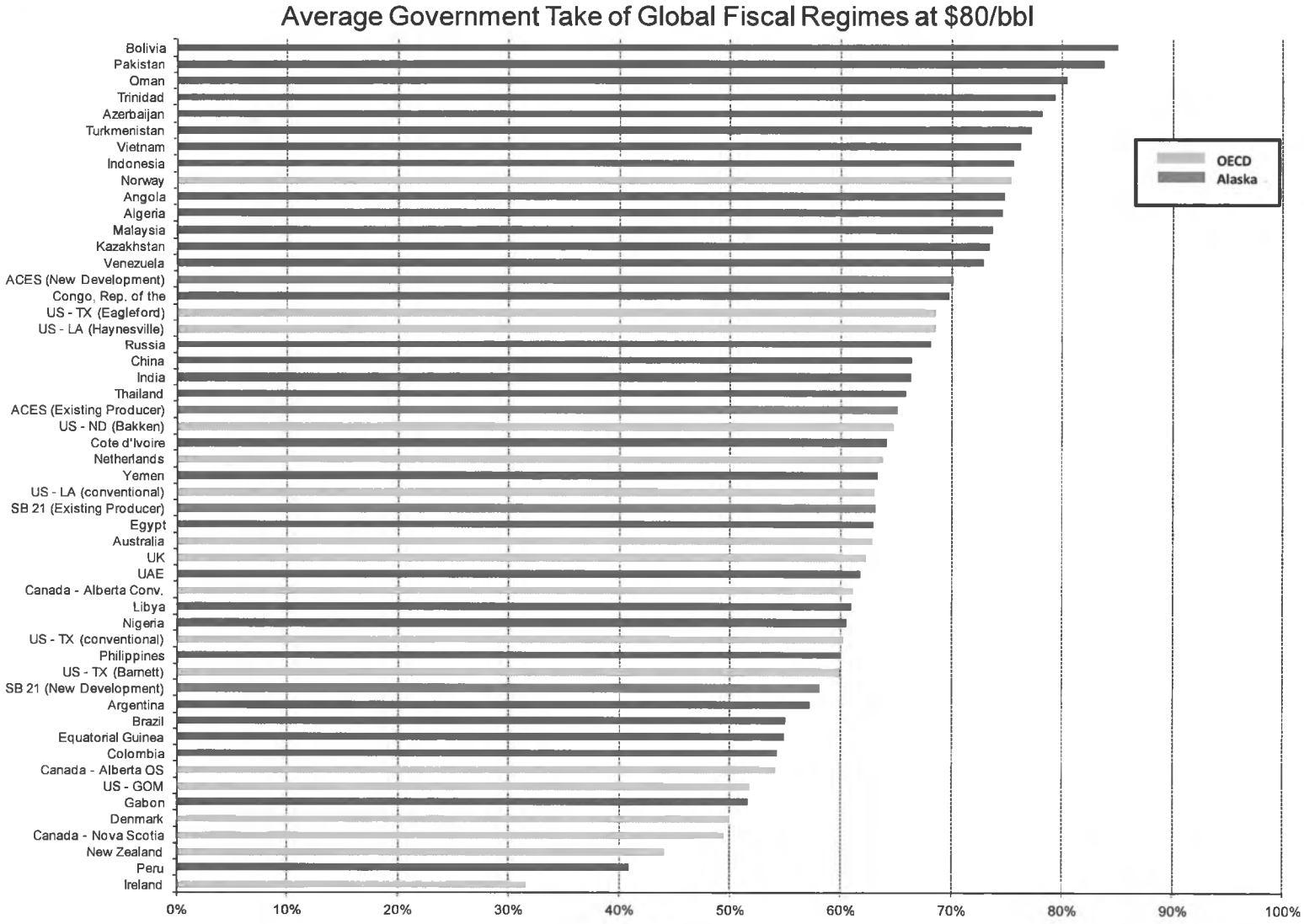
PFC Energy

Regime Competitiveness: Average Government Take at $60/bbl



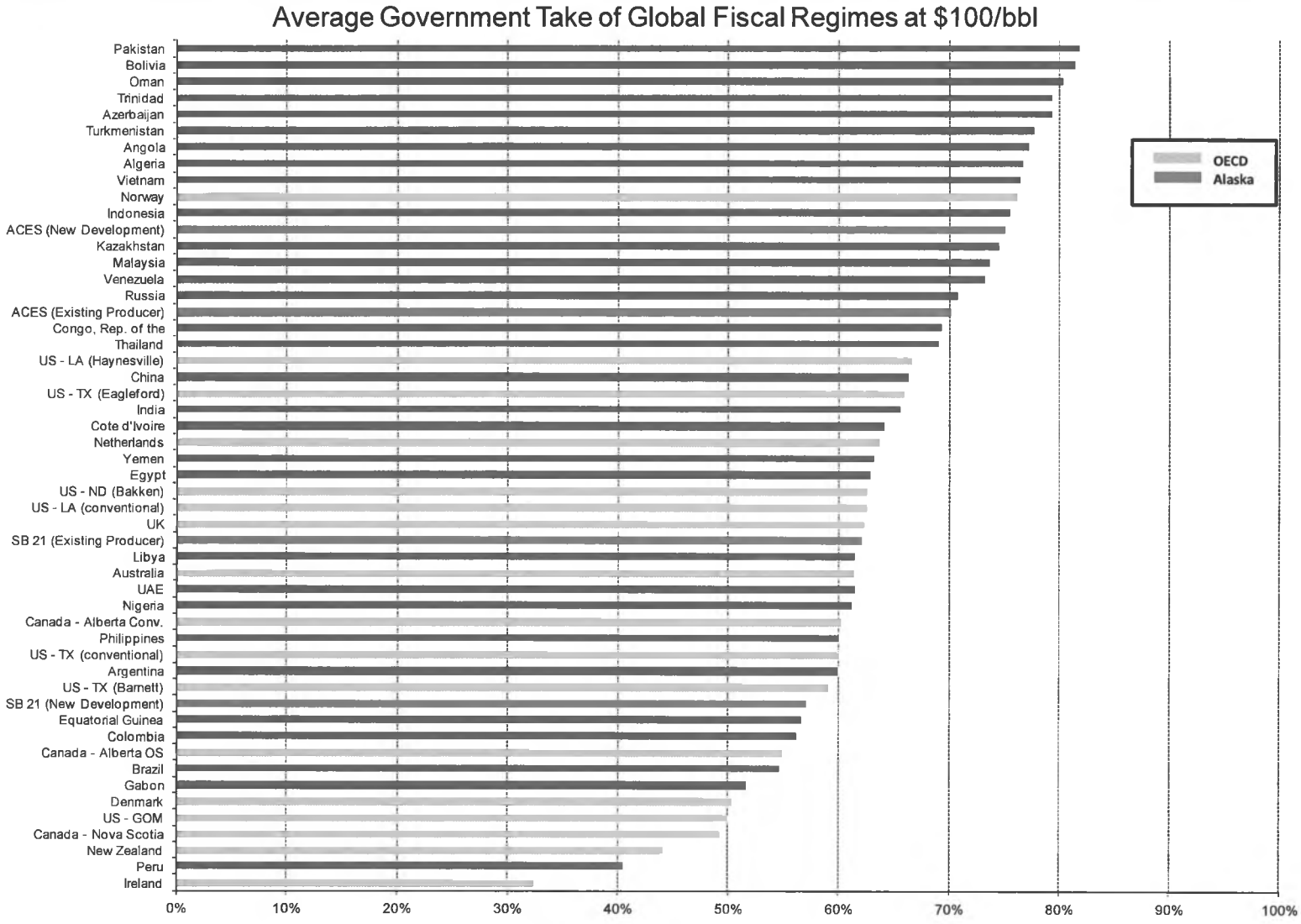
PFC Energy

Regime Competitiveness: Average Government Take at $80/bbl



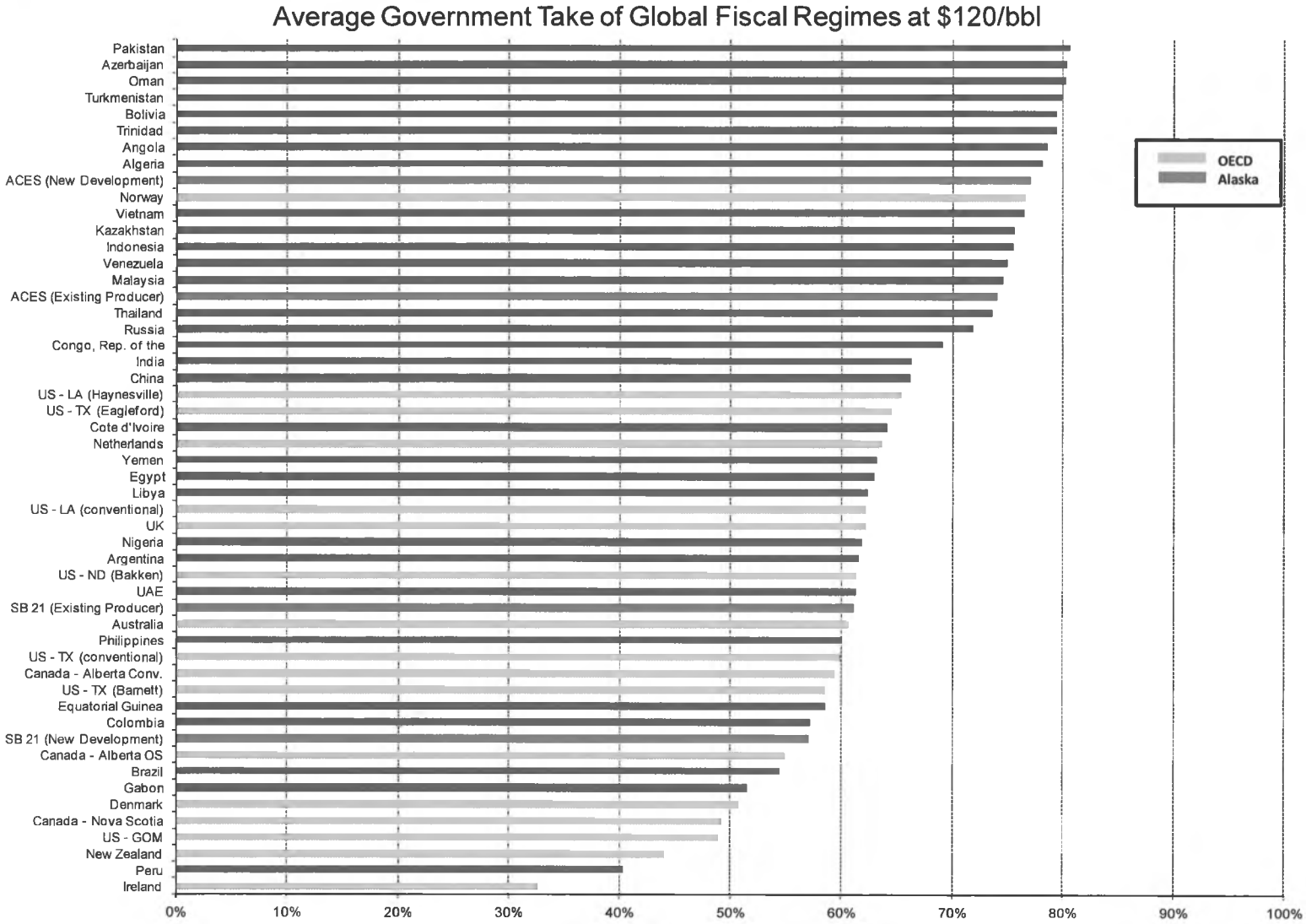
PFC Energy

Regime Competitiveness: Average Government Take at $100/bbl



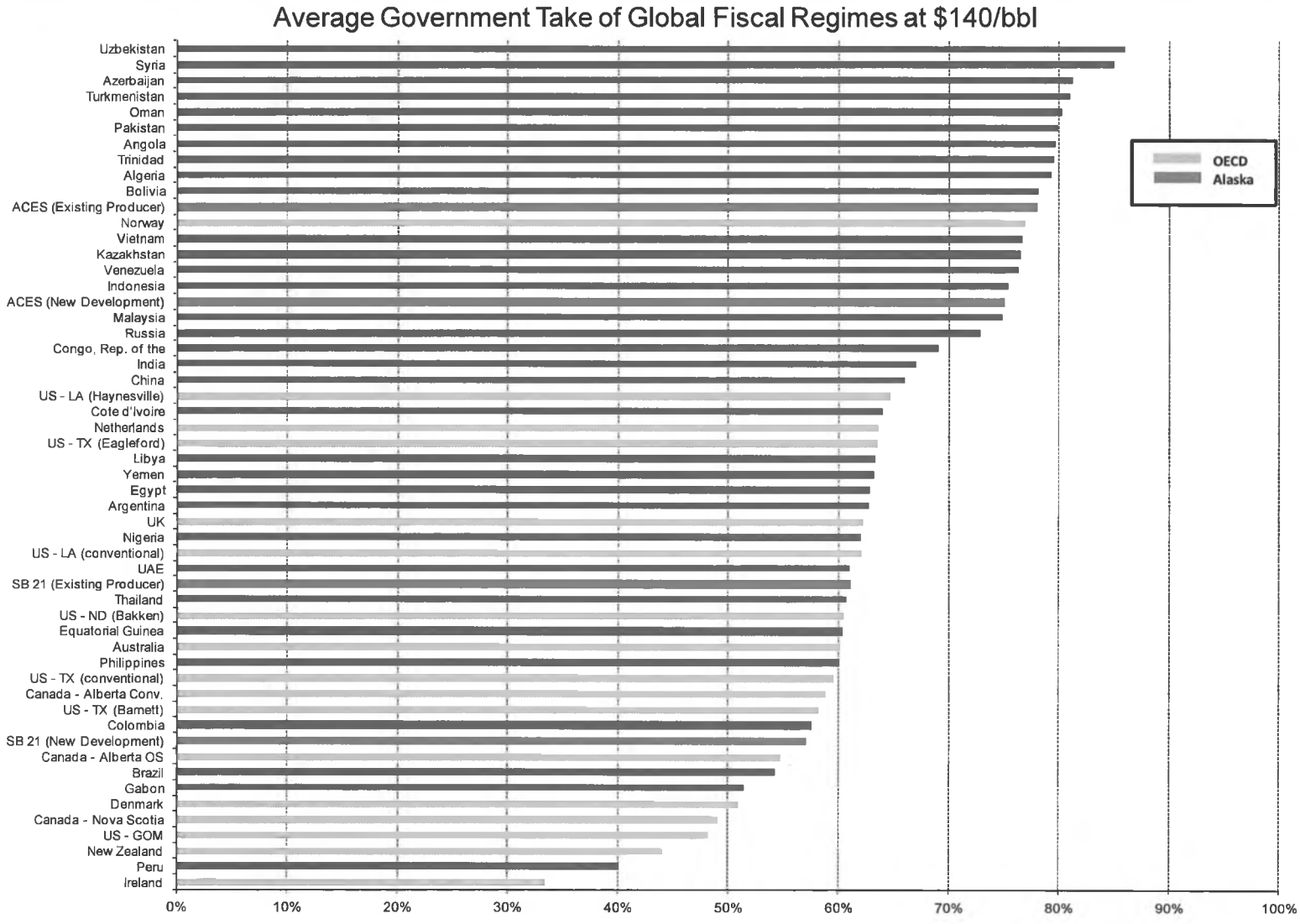
PFC Energy

Regime Competitiveness: Average Government Take at $120/bbl



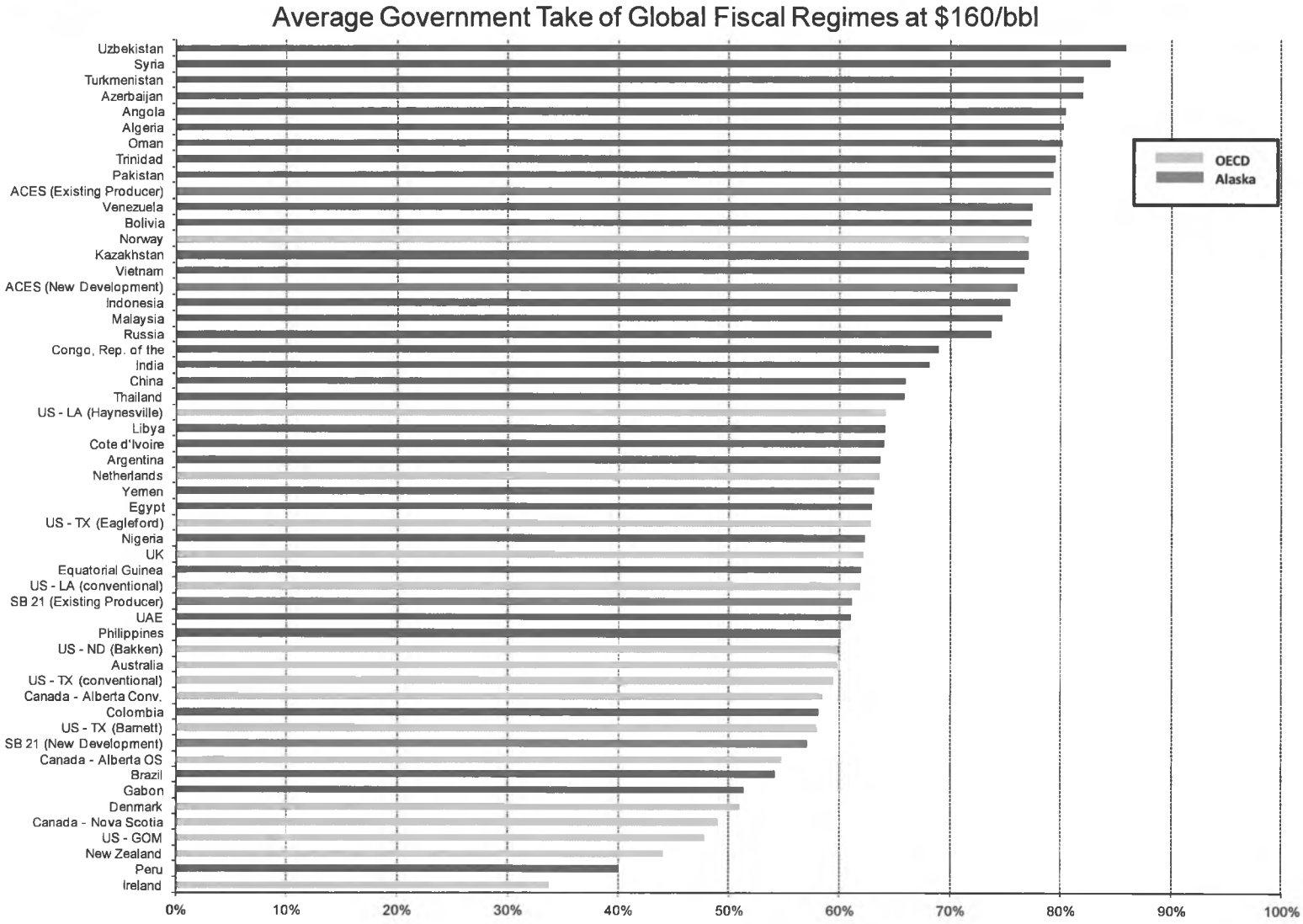
PFC Energy

Regime Competitiveness: Average Government Take at $140/bbl



PFC Energy

Regime Competitiveness: Average Government Take at $160/bbl



PFC Energy

SB21 Prog – Existing Production – Government Take

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

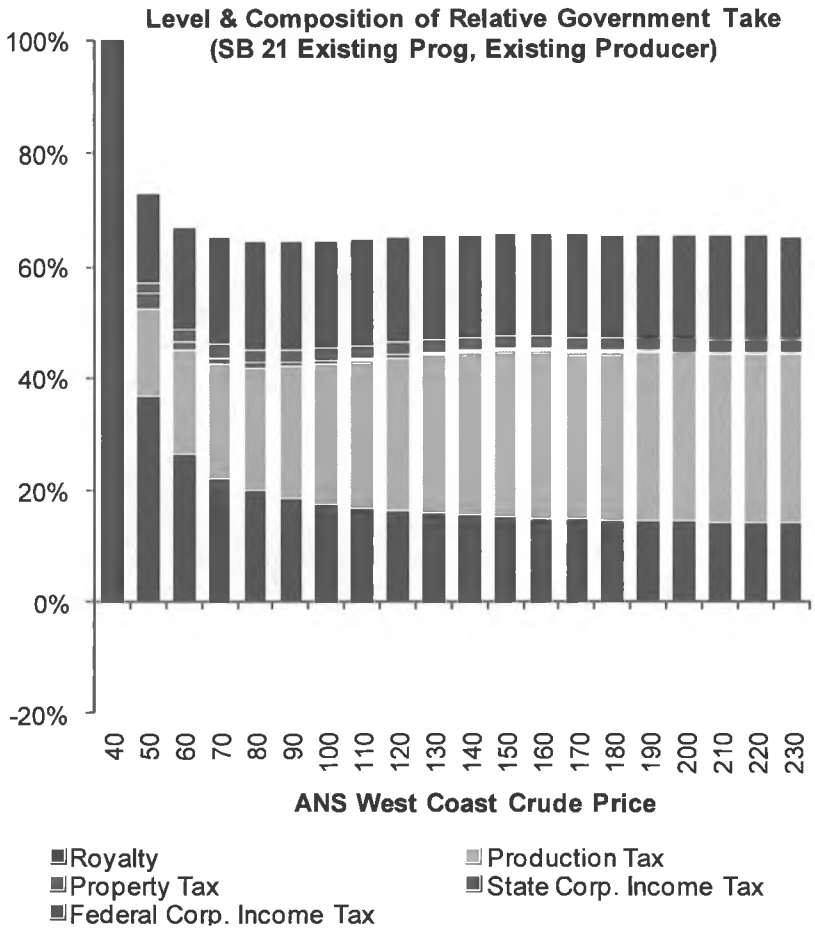


Table 1: Level & Composition of Relative Government Take (SB 21 Existing Prog, Existing Producer)

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%

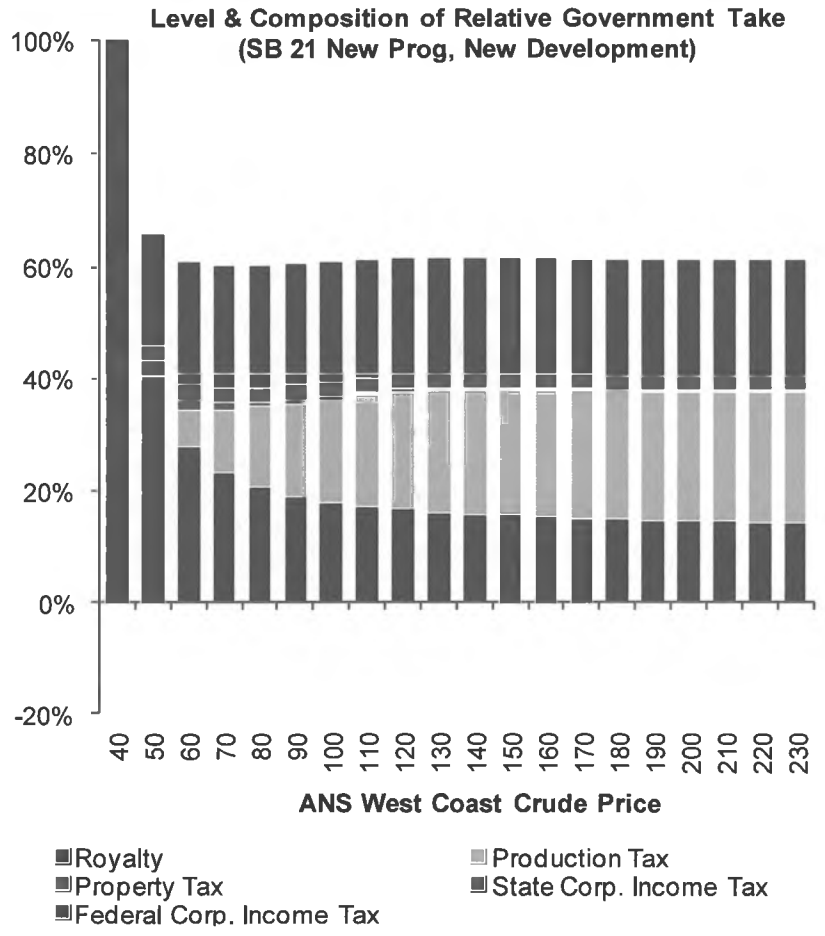


Table 1: Level & Composition of Relative Government Take (SB 21 New Prog, New Development)

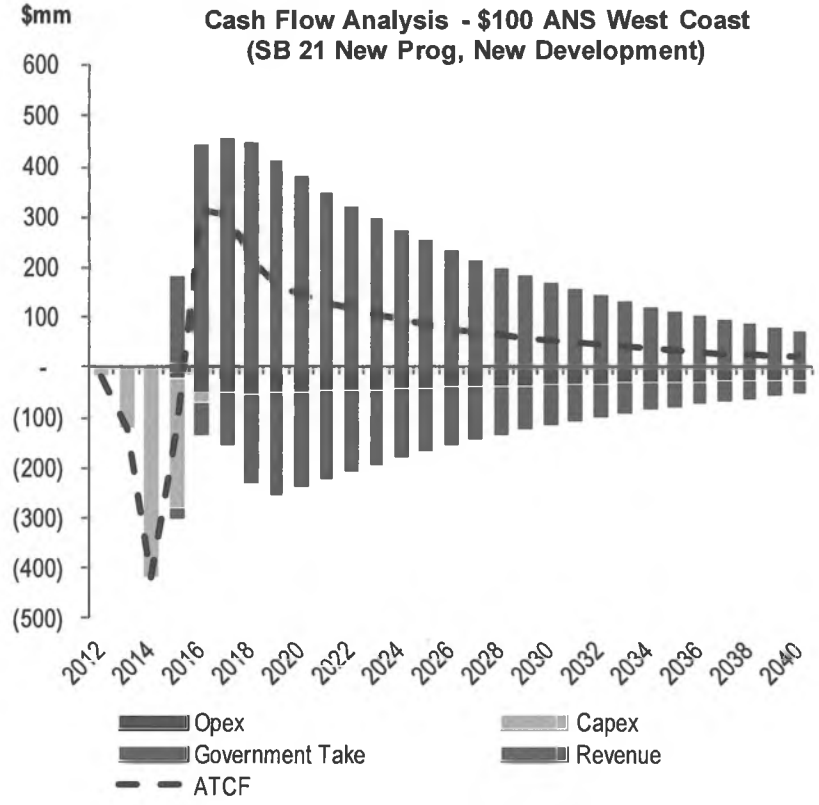
Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	155%	0%	16%	0%	**170%**	0%	**170%**
50	40%	0%	3%	2%	**46%**	20%	**66%**
60	28%	7%	2%	3%	**39%**	22%	**61%**
70	23%	11%	1%	3%	**38%**	22%	**60%**
80	21%	14%	1%	3%	**38%**	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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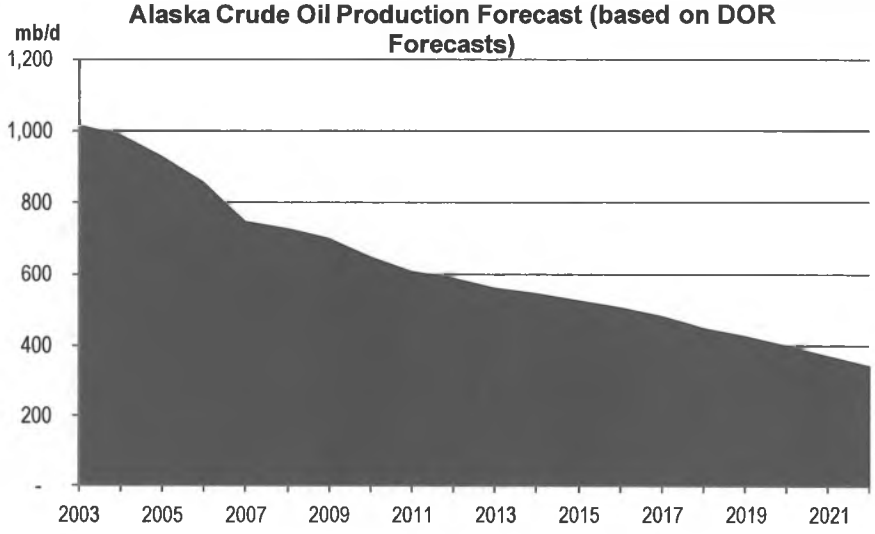
Credits and Deductions

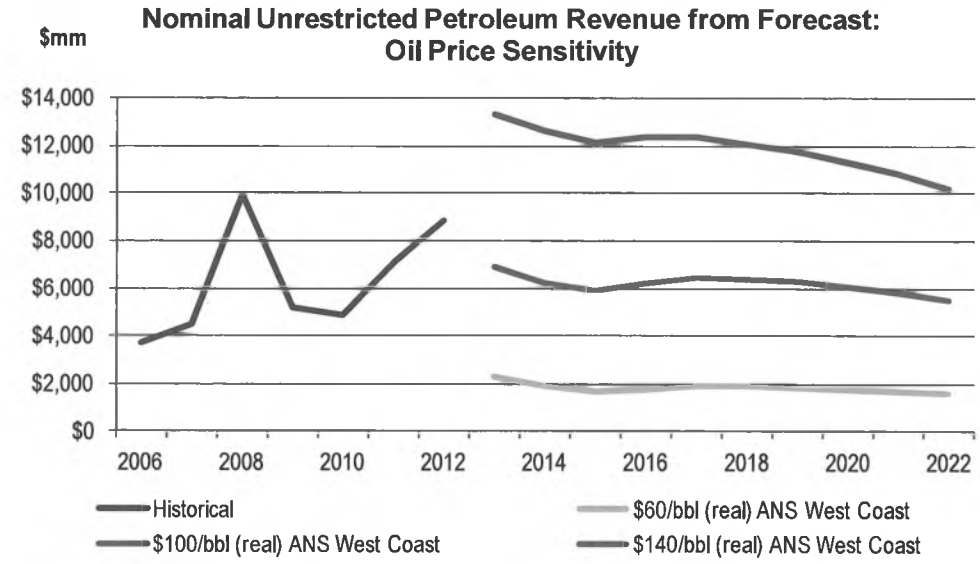
- Current credit system necessary in ACES to offset high government take, but introduces numerous distortions and unintended consequences
- In low price environments, or in the case of significant success attracting new producers to the North Slope, poses significant cashflow risk to the state
- Eliminating 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

PFC Energy

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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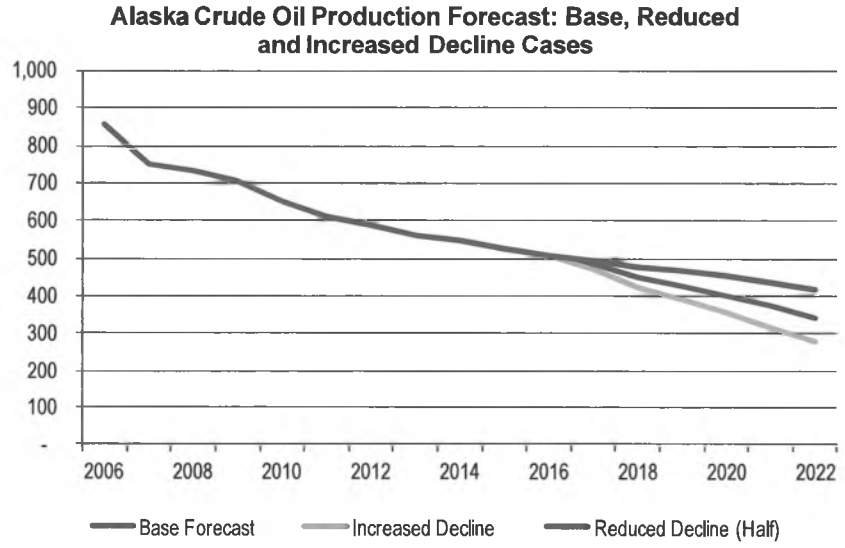
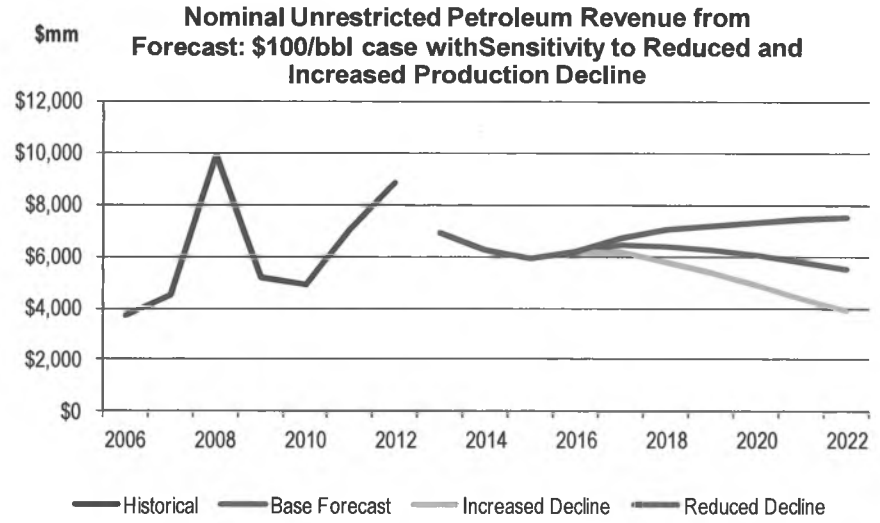
Decline Rate is the Other Major Determinant

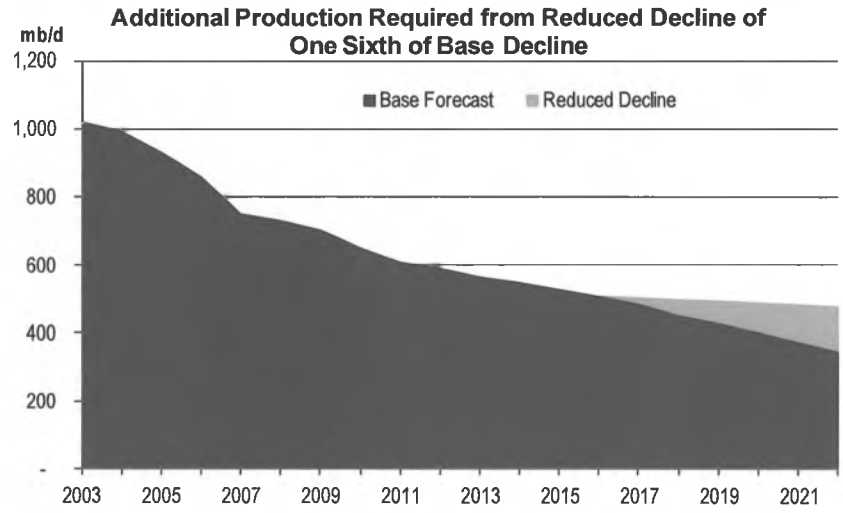


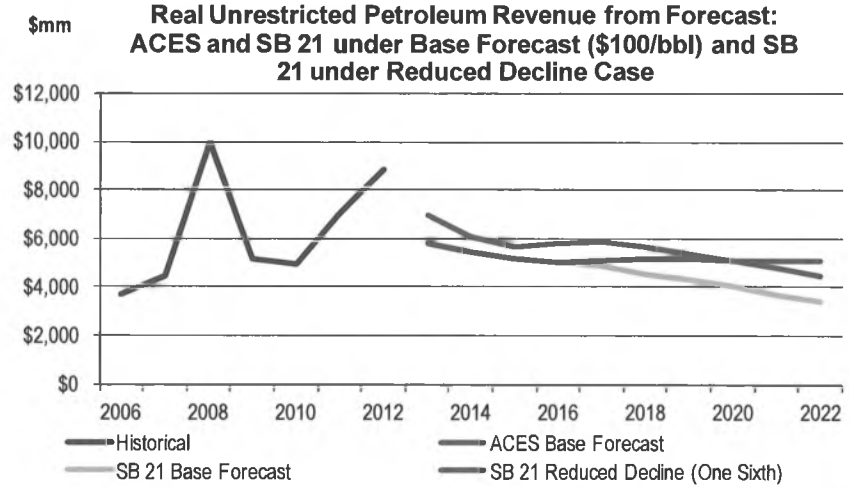


- The Base Forecast anticipates an average annual production decline between 2017 and 2022 of **~6%** (including the contribution from new producing areas brought on-stream), yielding production of ~344 mb/d in 2022
- Increasing the average decline rate by half to **9%** in every year from the base case 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

PFC Energy

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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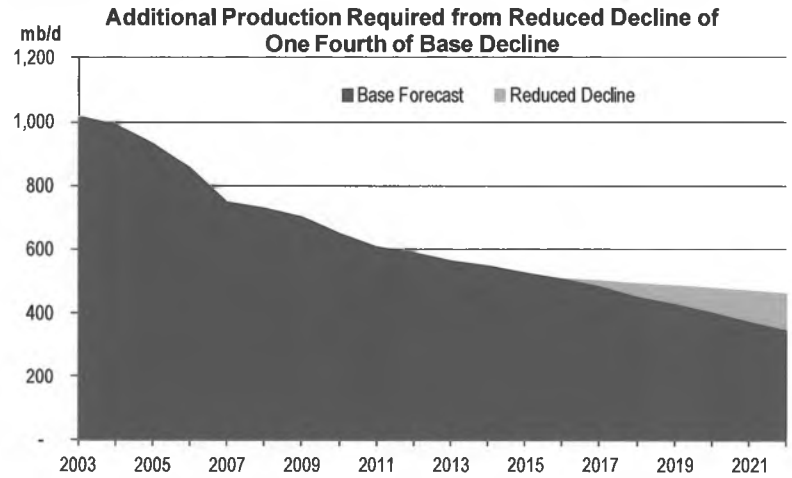
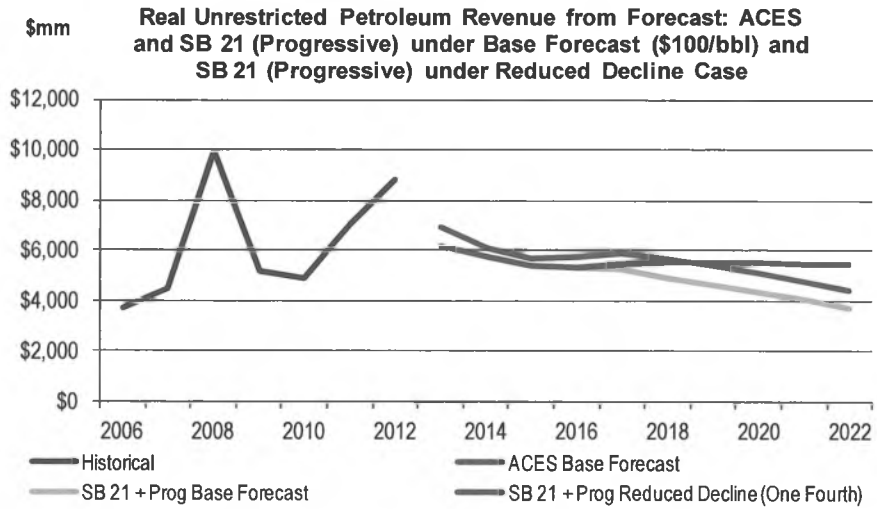
Fiscal Terms Changes and Investment Impacts





- 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%**

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

PFC Energy

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

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This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

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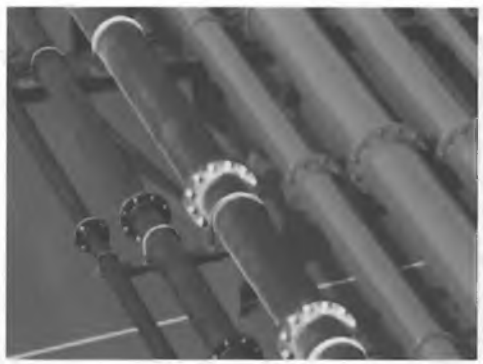
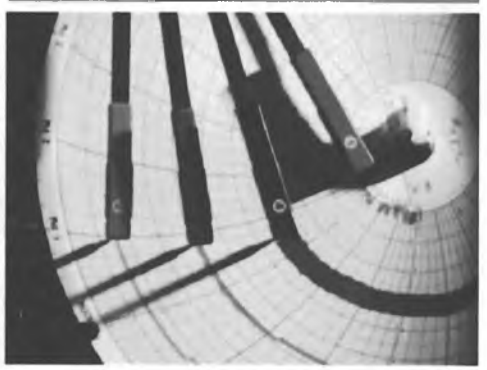
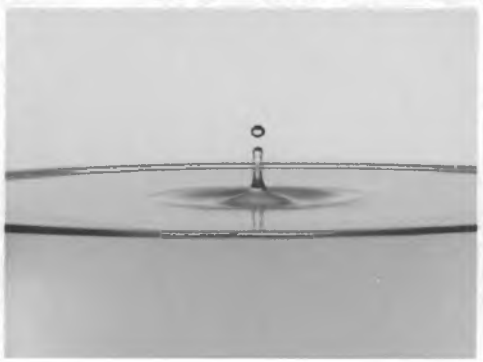






PFC Energy

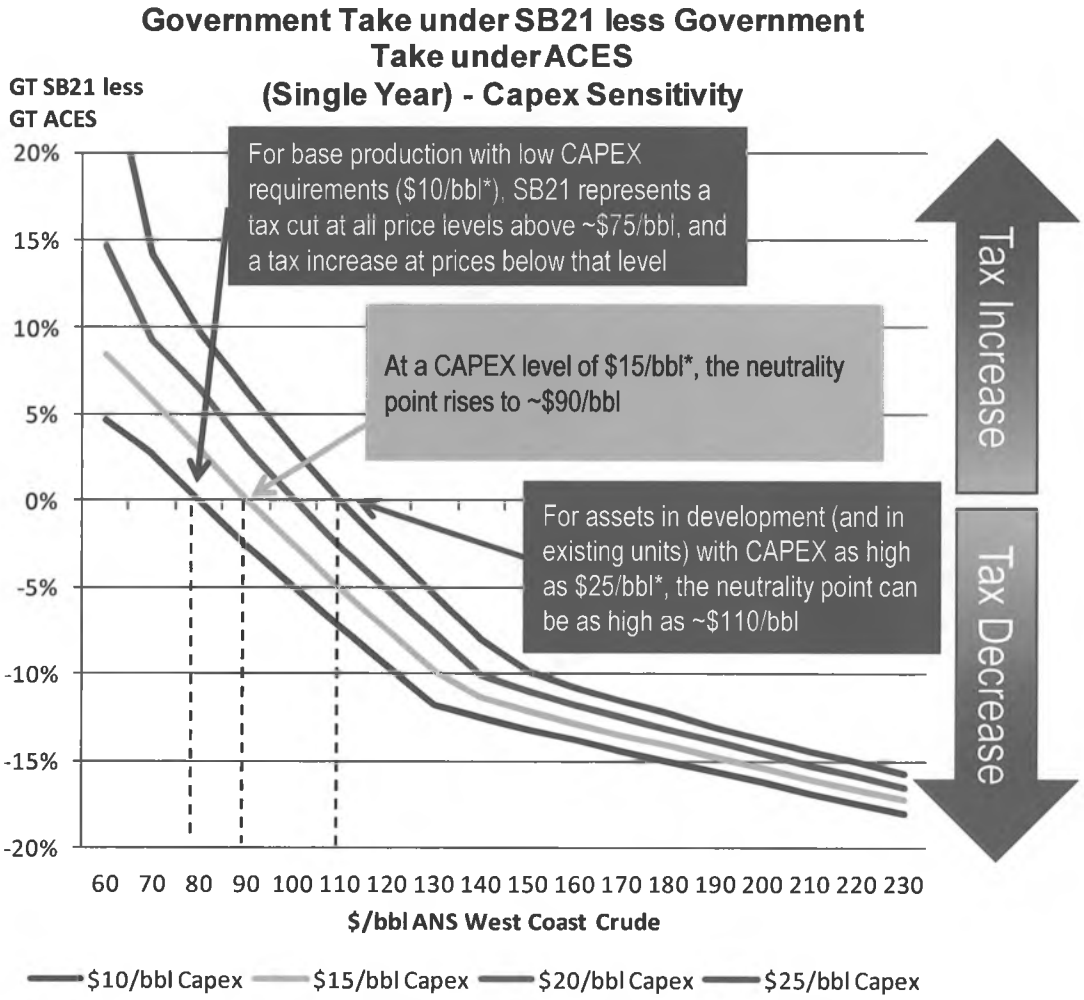
Senate TAPS Throughput Committee

Supplementary Slide to January 31 Presentation

February 4 2013

Janak Mayer
Manager, Upstream
PFC Energy

Government Take under SB21 and ACES – Capex Sensitivity



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

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

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Notice

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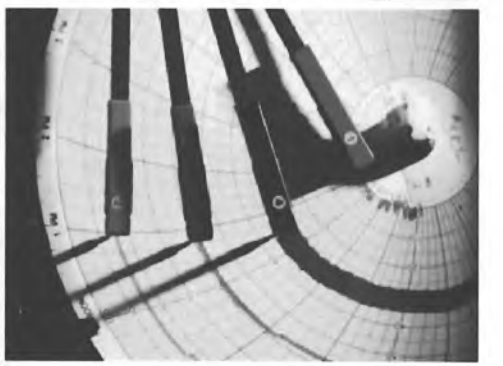

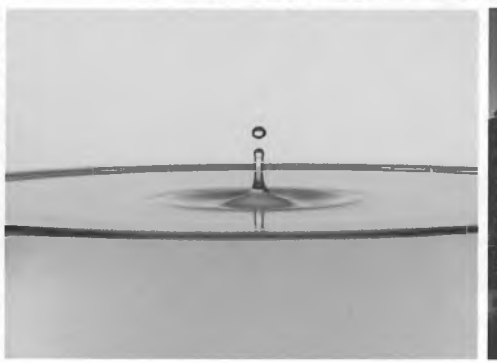

PFC Energy

3521 Andree Dr.
Anchorage, AK 99517

February 4, 2013

RE: Testimony to Senate Special Committee on TAPS Throughput on SB 21

Co-Chairs Micciche and Dunleavy and Senators on the Committee:

My name is Peter J. Stokes a professional petroleum engineer working for Petrotechnical Resources of Alaska.

Thank you for your service and for letting me and other members of the public testify on this important piece of oil tax reform that is needed to increase investment and new production in Alaska.

I live and work in Anchorage. I am on the Board of the Alliance and Chair of the University of Alaska CEM Advisory and Development Council.

I am testifying on behalf of myself, my 3 offspring who work in Anchorage and 2 grandsons and their future.

I grew up on the Kenai Peninsula, went to college in Fairbanks and have worked in oil and gas, starting in Alaska, with jobs in other states and overseas and working for the last 10 years in Anchorage.

I support the Governor's concepts to make Alaska more competitive in attracting increase investments to increase Alaska North Slope production and I urge passage of legislation to make meaningful reforms this year.

Senate Bill 21 is a good start to achieve this goal, but modifications should include:

1) Allow small explorers to continue to sell loss credits generated from exploration prior to production. Taking away this ability will negatively impact those that are currently exploring as it will change the terms which were used to attract exploration funding, it will significantly increase the cost of exploration, and in the unsuccessful case will mean that credits are not redeemable, thus changing the economic risk and rewards of exploration in Alaska.
2) Incentivize development within existing PA's by having the DNR determine a baseline decline for existing production. Any new production above this baseline will be eligible for GRE credit.

Without new exploration and the continued development of new oil within existing PA's, the efforts to increase production into TAPS will likely be reduced.

In summary, I urge you to allow Alaska to become more competitive in investments for new oil production for both explorers and existing producers.

Chairmen and Senators, thank you again for all of your efforts.

I represent the Alaska Trucking Assn. and our members in the transportation industry. Our members are known for their common sense approach, a hard work ethic and a fearless attitude in dealing with the all the obstacles that travel in Alaska brings.

We are extremely concerned with the declining oil production and the flow of TAPS. Alaska has been fortunate to have a projected 20 year pipeline now on it's 35th year. Because of that maintenance is what is currently driving much of the North Slope activity.
Increased production will ensure Alaska a stable future, with dependable state revenue, a growing economy, and profitable producers and support companies.

We agree with the Governor that a new tax plan should be simple and stimulate new production.

We must act now to keep Alaska competitive in what is now a world market. We have the resources. Now is the time to use forward thinking and creative ideas to take control of our future.

We believe that what we do now will set the standard of how business can be done with Alaska. If we get this right, the basic business model will be in place to also attract other development in natural gas, shale gas and oil, and mining. Our resources are our future and we should be in control without federal regulatory overreach.

The tax reform issue has been on the table for three years. We urge you to get a plan done and let's get back to work.

Jim Scherieble
Kenworth Alaska

Lynne Smith

From: Ken Caron <kcaron@gci.net>
Sent: Thursday, January 31, 2013 7:47 AM
To: Sen. Peter Micciche
Subject: Message concerning oil and gas production from concerned citizen

Dear Senator Micciche,

I missed the public hearings held at statewide Legislative Information Offices (LIOs) last Tuesday I would like to make the following comment:

The decline in oil production and the dwindling flow of oil through the Trans Alaskan pipeline is alarming to me. It appears the current legislature has failed to make any headway on increasing the production of State owned oil. Our Governor has a new idea that I believe could stimulate the production of oil on the North Slope, and possibly gas reserves as well. If the legislature hasn't been able to get the job done, please try something new. Give the Governor and (his advisors) a chance to prove their point. It's shortsighted to believe the oil producers won't increase production. If the lower tax levels (for the producers) fail to create greater revenue from increased oil flow or even if the revenue remains the same at least there will be jobs.

The oil companies produce jobs and community income, not just oil & gas products. Thank-you.

Ken Caron – Anchorage / Girdwood

Senate Special Committee on TAPS Throughput
SB 21: Oil & gas production tax.
January 31, 2013
Testimony by Pamela Brodie, P.O. Box 1139, Homer AK 99603 Pamela Brodie

On one side, we hear that we must "fill the pipeline." On the other, we hear that cutting oil industry taxes may do nothing to increase oil production, but it will drastically damage the state's ability to educate our young people and provide necessary services, and may lead to an income tax.

In the late 1980's we had a full pipeline, and oil sold for $10/barrel. Now it sells for around $120/barrel. Yes, those were desperate times -- but what a catastrophic waste of Alaska's precious, limited supply of natural resources to have sold off the maximum possible amount of oil at such a low price.

Oil prices are likely to rise further in the future. We should all be able to agree that the State of Alaska's goal in managing the sale of our limited supply of fossil fuel should be to *maximize total revenue to the state over the life of the supply of that fuel.* We should be able to agree that Alaskans will need the revenue in the future, and we should not use the oil up as fast as possible.

I understand that there must be a minimum flow. I understand that there are increased maintenance costs to a low flow of oil -- but those costs may be worth it. I understand that the calculations are complicated and that the facts and numbers may be in dispute. But we are certainly not going to do the right thing for the state if our goal is to "fill the pipeline," regardless of whether it makes long term economic sense to do.

Every administration is focused on the short term. They have to be. We must depend on the Legislature to protect our interests for the long term.

If the oil companies would increase the pumping of oil in response to a tax cut like SB21, they would tell us so. It would be in their interests to tell us this. But they don't. This is a mighty good indication that they won't. Even it they do increase pumping, it might not be enough to compensate for the lost revenue to the State from cutting taxes. A billion dollars/year or more is an awful lot to compensate for. And once that oil is sold at $120/barrel, it won't be around to sell when the price has risen to $200/barrel or more.

It seems to me extremely unlikely that SB21 is even in the short term interests of the people of Alaska, and almost certainly not in our long term interests. *Please vote against SB 21.* Thank you.

January 30, 2013

Respectfully submitted to the Alaska State Senate regarding SB21

I would like to express my opposition to the passage of SB 21. I do not feel that money should be gambled away from the State's coffers with no promise let alone guarantees that we as a people have purchased anything. We stand to be in the RED from this give away instead of earning the taxes due us to purchase education, health care and general prosperity. If the oil companies earned over 10B here in the state last year, they are not suffering , and if they are they are mismanaged.

ACES was developed as a fair exchange for the use of the oil product we have to sell. It is irresponsible to give away our assets without having anything to show for it. If we are to purchase something, purchase it, pay for it and get it. Do NOT throw it down a bottomless pit to be received at the other end with no recompense.

It is irresponsible to take a budget for a state that has assets and put it into the RED in order to gamble it away into the breeze. Our money should be managed not gambled with.

Mary J. Toutonghi,

Soldotna, AK.

-------- Original Message --------
Subject:SB 21
Date: Wed, 30 Jan 2013 11:20:13 -0900
From: Margo Waring <margowaring@ak.net>
To: Senator.Peter.Micciche@akleg.org

Dear Senator,

Please do not support Governor Parnell's Oil Tax bill, SB 21.

I was schooled on this issue when working for Governor Hammond when it was clear that maximizing resources' benefit to Alaskans was more important than oil companies' profits. I also worked for the legislature when the state income tax was repealed. The state's return on oil and the state income tax are historically connected. I believe that SB 21 will have the effect of returning the state income tax as a way to boost revenues lost to oil companies' pockets.

Revenues will fall under SB 21because it eliminates progressivity. This will deprive Alaskans of a fair share of oil revenues, especially when prices rise, as every forecast predicts. For example, in FY'14, this change alone would cost Alaskans $1.6 billion at $110/barrel oil as forecast, $2.4 billion at $120/barrel oil, and $4.1 billion at $140/barrel oil.

Revenues will fall under SB 21 because of the 20% gross revenue exclusion on new oil, creating exceptionally and historically low rates, especially on legacy fields. Under SB 21 the production tax rate for "new" oil would be about 17-18%, slashed from about 40% today. Additionally, the gross revenue exclusion applies to projects in Prudhoe and Kuparuk where infrastructure was paid for long ago and profits are historically high.

Revenues to the state will fall under SB 21 because it removes the 20% capital credit incentive to investment in Alaska and discourages smaller producers/investors who might boost production.

In summary, SB 21 would so significantly reduce revenues that the state will be hard pressed to fill the gap, setting the stage for the return of the income tax and other revenue measures to support state services.

Sincerely,
Margo Waring
11380 N. Douglas Hwy.
Juneau, AK. 99801

Lynne Smith

From: D. Robbins <drobbins.r@gmail.com>
Sent: Wednesday, January 30, 2013 1:03 AM
To: Sen. Mike Dunleavy; Sen. Peter Micciche; Sen. Anna Fairclough; Sen. Lesil McGuire; Sen. Berta Gardner
Subject: RE: SB 21 Oil and Gas Production Tax Cuts

Senators,

RE: SB 21 Oil and Gas Production Tax Cuts

It goes without saying that I know very little about the oil industry. What I do recognize is that SB21 appears to reduce any responsibilities for the oil industry to pay their share of expenses for a product owned by the people of Alaska. We give back to them and expect nothing in return; or at least any expectations that we might have of them are not stated in SB21. That is not sound business sense.

We "repeal this" and we "repeal that" and what do we ask in return? Not a word is mentioned that I can find about "if we do this, then you agree to give us that." We would be seen as fools to make such a deal.

Expectations of what Alaska might stand to benefit from the policy changes outlined in the bill are never mentioned. "We give you this and that, or "forgive this and that tax," and we have no reciprocal expectations.

If I was a grocer and I opened my shop doors for customers but had no one manning the cash register, or prices were unmarked on items I would be out of business in a few days. In Alaska's case, our coffers would soon be bare and our people would be out in the cold.

We are not taking care of our needs now. We continue to flat fund education as the inflation rate rises, resulting in a net cut for education dollars. Our standing in education funding and achievement is not acceptable, but apparently the governor can't seem to figure out that reduced funding, or reduced "take" in oil jargon, has any bearing in that area. He has a heart for multinational oil companies but not for Alaska's children.

There has to be a more sound way for Alaska to do business.

Sincerely,

Doris Robbins

1281 Overhill Dr.
Fairbanks, AK 99709-6753
(907) 374-0597
drobbins@gci.net

--

Lynne Smith

To: LIO Kenai
Subject: RE: Opposition to SB 21

From: Michele Vasquez [mailto:michele.s.simmons@gmail.com]
Sent: Tuesday, January 29, 2013 6:41 PM
To: LIO Kenai
Subject: re: Opposition to SB 21

Hello:

I am unable to attend to public testimony on SB 21, but I want to submit my statement of opposition for the record.

I strongly oppose the governor's bill, SB 21, that would give more tax cuts to oil companies that currently drill or want to drill for oil in Alaska. There is no reason to offer an "incentive" to a company to drill Alaska's oil unless there is an expectation of gain by one or more of our elected officials in terms of political support. We Alaskans don't need to give away our precious oil resource by offering hefty tax cuts to greedy oil companies that make billions in profit and pose such a high risk to the environment in our state. The oil is here; if a company wants to drill it, fine; but it must do so under ACES. Where is the guarantee of an increase in production for such lavish tax cuts? There is no such guarantee. Reject and oppose this outrageous giveaway to oil companies by voting against SB 21.

Sincerely,
Michele Vasquez
Soldotna, AK
907-420-0658

STATE of ALASKA

Bethel Legislative Information Office

PO Box 886
Bethel, Alaska 99559
(907) 543-3541
Fax- 543-3542

Written Testimony for the Record:

TCN: 7887 Committee: STTP

Date: 1/31/2013 Bill Number(s): SB 21

Subject(s): Oil Tax

Please enter my testimony into the record.

Fritz Grenfell
Testifer's name (s):

Representing (opt.)

P.O Box 1427, Bethel, AK 99559
Address

465-4779
Phone

LIO Bethel

From: Fritz Grenfell <fritzgrenfell@yahoo.com>
Sent: Thursday, January 31, 2013 10:13 AM
To: LIO Bethel
Subject: tele conf

i feel the oil companies are holding us hostage, lower taxes more oil in pipe why don' we build a refinery in fbks take our % off and get on with bussiness, fuel is holding us back fritz grenfell pob 1427 bethel ak

Lynne Smith

From: Deanna Geary <truckin_mama@hotmail.com>
Sent: Thursday, January 31, 2013 7:42 PM
To: Lynne Smith
Subject: HB 72/SB 21

I would like to go on record as a resident of the State of Alaska in regard to HB72/SB21.
I see no evidence that makes a correlation between the slow down in getting oil to market and the tax rate that the oil companies now enjoy here in Alaska. In fact, the amount of profits that are reported by the oil companies operating in Alaska prove that they can, and do enjoy the benifit of our oil. We afford them a safe and secure environment in which to conduct business, that should count as a bonus.
I am against lowering the S.O.A.'s tax rate for oil companies.

Thank You, Deanna Geary

KENAI LEGISLATIVE INFORMATION OFFICE

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (Oil & Gas Production Tax)

COMMITTEE & DATE: ~~Senate Special Committee Thereafter~~ 1/31/13

First of all, I want to tell you how much I appreciate you hearing my comments about the governor's oil tax proposal. I know it's not easy to be in your shoes right now, so thank you for hearing me out.

With all due respect, the governor's oil tax proposal is starting to feel like that movie, "Groundhog Day." Every day, Phil wakes up to Sonny & Cher's "I Got You, Babe", then he meets dippy Ned & steps into a puddle. Despite his fruitless attempts to escape Groundhog Day, he keeps waking up to find that nothing has changed -- he's trapped in a time loop.

Let me be clear - As an Alaskan, I do not support the governor's proposal. I am trying to get out of this time loop -- the same idea over & over & over & over & over again without any fresh ideas. The same question keeps popping up over & over & over & over & over again: How is the State of Alaska going to make up for the revenue that would be lost if this proposal goes through? This is a question that needs to be answered.

KENAI LEGISLATIVE INFORMATION OFFICE

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (oil & gas production tax)

COMMITTEE & DATE:

It seems like if you were going to give away this much money, you would ask for something in return. Perhaps companies who enjoy such a generous tax break would guarantee in writing that they would hire people who actually live in Alaska year-round. Perhaps they would agree to reduce highly paid top CEO's salaries so that their own Alaskan employees would earn higher wages, thereby allowing more money to filter into our state's home-based economy. Perhaps the industry would pledge to create renewable energy jobs in Alaska. Perhaps companies would express gratitude that Alaska is a peaceful & safe place to do business (rather than being a dangerous, war-torn nation).

In any case, you need to re-think this plan. As an Alaskan, I vote no on it. We already have a great plan called Alaska's Clear & Equitable Share. That says it all! The oil & resources belong to us, the People.

So, the question is, "Is it morning in America yet?"

KENAI LEGISLATIVE INFORMATION OFFICE

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (oil + gas production tax)

COMMITTEE & DATE:

No. It's Groundhog Day. Maybe the real question should be, "How long are we going to be stuck here in Groundhog Day, re-living the same experience over + over + over + over + over again?"

In the movie, when Phil figured out how to stop stealing money, seducing women, driving recklessly, + getting thrown into jail. When he used the time to learn how to ice skulpt, play the piano, speak French, save lives, help townspeople, + become a better human being, then + only then was the time loop broken.

You are in very respected positions of government. Please vote no on this oil tax proposal. Go back. Take the time to re-think. What's best for the People of Alaska? If you think keeping ACES is the best, great! I completely agree that it is best to keep ACES. If, after putting some thought into the matter, you come up with another plan, please re-present your proposal. I promise to look at it, listen, think about it, + assess what is best for our state.

KENAI LEGISLATIVE INFORMATION OFFICE

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

(4)

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (oil & gas production tax)

COMMITTEE & DATE:

Then, as an Alaskan, I will say yes or no. This is how democracy works.

Again, please vote no on SB 21 & have a happy Groundhog Day(!!)

Lynne Smith

From: Kevin Walker <homerkev@gmail.com>
Sent: Saturday, February 02, 2013 9:50 AM
To: Larry Semmens; Rep. Paul Seaton; Sen. Peter Micciche
Subject: Written Testimony for TTP SB21 Hearing and HB 72

Alaska must strive to research and develop energy sources to guarantee our energy security for all future generations. Fossil fuels will eventually be depleted, so the Legislature must develop our very abundant renewable resources such as geothermal, tides, wind, hydro, solar, and other renewable sources.

I have not seen any information that would lead me to support SB21. From what I hear and do see, it will cost the state $20 BILLION ($20,000,000,000). That money would probably set us up with alternative energy sources that would be fueled forever. The oil and gas will run out, and leave our kids and grandkids struggling with few developed alternatives. I can't think of any industry in the world that needs government subsidies less than Oil and Gas. Exxon made what, $44 Billion in profits last year? Do you really think they need more money?

I also understand that these bills will cut taxes on oil companies when oil prices are high, and give away $2 billion per year when oil costs $120/barrel and will create a state budget deficit this year.

To develop sustainable energy in Alaska, I strongly support directing State funds towards the development of alternative power projects such as those begun by HEA and ORPC.
http://alaskarenewableenergy.org/wp-content/uploads/2009/11/ORPC-PowerPoint-Nov-14th-Forum.pdf

Please send me information, or direct me to find some common sense that is written for a layman that may show why the Governor would introduce these bills.

Kevin Walker
Homer, Alaska

The Testimony of Jerry McCutcheon

A lifelong Alaskan who fought for Statehood against the Canned Salmon Industry sixty and seventy years ago.

It appears that North Slope Employment will set yet another new record this winter since the construction of TAPS. The growing North Slope employment numbers belie Parnell's allegations about ACES hindering development. ACES with ACES's generous oil tax credits for actual investment is promoting oil and gas development. Development like Alaska has not had since the discovery of Prudhoe Bay.

I don't think those who worked for and passed ACES realize what a marvelous piece work they did for Alaska and Alaska's future when they passed ACES with ACES's very generous oil tax credits for actual investment .

We are Now in the Second Battle for Statehood. Will have Alaskans thrown off the yoke of the Canned Salmon Industry only to take up the yoke of the oil industry?

What is hindering development on the North Slope is the fact that Parnell is trying to take away the oil tax credits for actual investment. One cannot invest and have the Governor out trying to take away the very tax credits on which one is to rely. Several of the small oil companies have said so in the press about the Chenault / Hawker's gasline affects on trying to explore for gas in Cook Inlet.

Bringing gas to Cook Inlet from the North Slope when Cook Inlet has 1.8 trillion cubic feet of proven available gas is just not stupid it is insane. Also there are between 13 and 27 tcf of gas yet to be discovered in the Cook Inlet Basin. DOE, USGS, DNR and others.

ACES should be allowed to run its course for at least a decade without modification unless there is something is glaringly wrong. The only provisions that are needed are further leveling of the playing field for the small oil companies along the lines of Rep. Gara's bill last year, equal access to or new production facilities, TAPS and the Valdez terminal.

Parnell and the republicans are attaching ACES because ACES provides for oil tax credits for the small wildcatter to explore for oil where no one else will go. Parnell wants to change ACES so only those that have production (like the majors) receive the oil tax credits. That eliminates the rank wildcatter and that is very much not in Alaska's best interest. With operation of the law of large numbers and the time value of money Alaska comes out way ahead to gamble with the wildcatter.

Second, a small reservoir may not be worthy of a standalone development, however ACES's oil tax credits allow the developer to capture some multiple of the developer's investment much sooner and progressivity rewards the State for having taken the risk.

Progressivity not only makes those gambles possible but also leads full exploration and production of the oil province. That is one the reasons the majors not only suggested progressivity but also demanded progressivity and oil tax credits druing the Governor Murkowski Administration . Never did the majors wildest dreams think that it would be small oil companies that would capitalize oil tax credits.

The legislature needs to understand that the majors are Elephant hunters and all of the Elephant structures on the Slope were drill decades ago. Elephant hunters do not hunt rabbits; they may take a rabbit if the rabbit is in their backyard.

Alaska not only needs to take bigger share of the risk but also needs start partnering in oil development like Statoil. The Harvard School of Business, business model would very much applaud ACES and taking the risks with the wildcatter. And the Harvard School of Business, business model would strongly suggest that Alaska follow Statoil's lead.

Under Alaska's laws and Constitution there is a duty to produce and it is under those provisions the Governor Murkowski took back Point Thomson. There is 1.8 trillion cubic feet of proven (DNR) available gas in Cook Inlet that is being held off the market to drive up the price of gas.

Theresa Robl

From:	Ronald Johnson <rajohnson@alaska.edu>
Sent:	Saturday, February 02, 2013 9:27 PM
To:	Sen. Mike Dunleavy; Sen. Peter Micciche; Sen. Anna Fairclough; Sen. Lesil McGuire; Sen. Berta Gardner
Cc:	Rep. Scott Kawasaki; Rep. Tammie Wilson; Sen. Pete Kelly; Sen. Bill Wielechowski; Gary Miller; drobbins r; Timothy Tilsworth; Jay Dulany; Sam Trivette; Cindy Spanyers; Bob Grove
Subject:	SB 21

Three Thoughts re SB 21

1) Pls do a better job of publicizing the off net phone in numbers for public testimony.

2) **Vote no on SB 21**. If you want to change ACES, do it in such a way that industry only gets additional tax breaks after the big players succeed in reducing the rate of decline for the legacy fields. Vague statements ahead of time don't cut it.

3) **Senator Micciche. Recuse yourself** from chairing this committee and voting on legislation that can result in billions of dollars in tax relief to your employer. If what you are doing now is not conflict of interest, I don't know what is.

Pls add this to the public testimony

--
Ron Johnson
Professor Emeritus
Mechanical and Environmental Engineering
Univ of Alaska Fairbanks

2113 Jack St
Fairbanks, AK 99709

Lynne Smith

From: Deborah Brollini <deb_brollini@yahoo.com>
Sent: Thursday, January 31, 2013 6:57 PM
To: Sen. Peter Micciche
Subject: Thank you!

Senator Micciche and TAPS Throughput Committee members,

I want to thank you for taking the time for public testimony, and I appreciate your leadership in reaching out to the public. In addition I would like to thank you for reminding the administration and your consultants that the public is watching and we do not understand terminology. I've been studying oil and gas for five years, and for the first time I will not need a translator this evening to rewatch the PFC presentation today. A huge difference from last session where I needed a tutor.

What I will tell you as someone who is with the public every week... the public blames "big oil" for their high energy costs, and they do not understand how complex our tax structure is, and they are tired of the rhetoric. One thing I hear every week is that we need "a gasline" and that will be our Hail Mary. These Alaskans do not fully understanding that natural gas will never replace oil as a high value revenue source. Your committee has a lot of work to do to find solutions to increasing oil production, and I hope the public will become more informed and engage.

Oil tax reform is a huge decision, and Alaskans from every pocket of this state should have a say. Please do not be discouraged by low public turnout this week. The committee made time to listen, and the public will remember, and they will appreciate the committee's effort.

Regards,

Deborah Brollini, Technical Writer
Alaska Energy Dudes and Divas
Voice: 206-339-7831 | deb_brollini@yahoo.com
http://alaskaenergydudesanddivas.blogspot.com

John Sturgeon - Koncor Forest Product
43 years in timber industry in Ak

During that time I have seen my industry go from a giant industry in Alaska to the whisper it is today.

At one time Aks timber industry was Alaskas second largest industry generating 10,000 well paying jobs and a billion $'s in revenue. ~~If anyone~~ At was unthinkable to us in the timber industry that our decline would be so rapid and so permanent.

Just as the supply of oil in Alaska is not an issue nor ~~was~~ is the supply of timber in Alaska. ~~that can be harvested on a sustained yield.~~ Supply is not the problem.

Infrastructure

Investment climate

The timber industry was wrong when we thought our industry would never all but disappear.

Likewise people who think the oil industry will never go away are ~~likewise~~ wrong.

Once the timber industry declined our infrastructure ~~also~~ disappeared. the businesses such as tire companies, barge services and our skilled workforce moved on. If the oil production declines then infrastructure will also disappear and it will be next to impossible to rebuild it.

And finally even if our timber supply would ~~not~~ magically return the investment climate is so bad due to environmental litigation ~~[illegible]~~ it would be extremely difficult to attract investors.

~~Mat-Su~~ Susitna
State Forest - Goal

- Make timber management a primary use
- Normally State Forest are mandated to manage on a sustained yield basis -
However, much of the timber in the valley is acreage making a sustained yield difficult if not impossible.

Belts Room 105

If ~~a~~ Alaska oil industry doesn't have an attractive investment climate it will have a similar fate.

The go away message is simple —

(1) It is very possible for the oil industry to leave Alaska if we don't give them an attractive business climate.

(2) Once the oil infrastructure goes away it will not easily return.

(3) And lastly the timber industry has all but disappeared. Act now to prevent the oil industry from disappearing. Give them a competitive business climate. Give them a competitive tax climate that ~~I support that~~ is simple and most important, predictable.